EPA United States Environmental Protection Agency

Region 8

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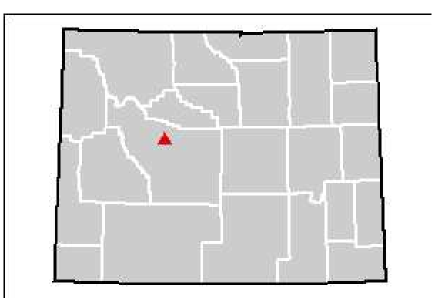
Pavillion

DRAFT REPORT

EPA has released a draft report outlining findings from the Pavillion, Wyoming groundwater investigation for public comment and independent scientific peer review. The draft report will be available for public comment through September 2013. A subsequent peer-review process will be led by a panel of independent scientists.

- Draft Report, December 8, 2011
- Press Release
- Tables and Charts
- Appendix C Figures
- Appendix D Figures
- Appendix E Figures
- Supplemental Information and Data

Groundwater Investigation



Site Type: Non-NPL
City: Pavillion
County: Fremont
ZIP Code: 82523
EPA ID: WYN000802735
SSID: 08QV
Congressional District: At Large

On this page:

- **What's New?**
- **Site Description**
- **Site Reports and Public Presentations**
- **Contacts**
- **Photo/Video Gallery**

On other pages:

- **Site Documents:** more than 800 documents related to quality assurance, monitoring well drilling information, raw laboratory data, well sampling information, lab standard operating procedures, and lab-produced reports

What's New?

June 20, 2013
EPA has announced that it will be supporting the State of Wyoming in its further investigation of drinking water quality in the rural area east of Pavillion, Wyoming. While EPA stands behind its work and data, the agency recognizes the State of Wyoming's commitment to further investigation and efforts to provide clean water and does not plan to finalize or seek peer review of its draft Pavillion groundwater report released in December 2011.

The sampling data obtained throughout EPA's groundwater investigation will be considered in Wyoming's further investigation, and EPA will have the opportunity to provide input to the State of Wyoming and recommend third-party experts for the State's consideration. The State intends to conclude its investigation and release a final report by September 30, 2014.

- View the press release
- View the state investigation document (PDF) (6 pp, 369 K, About PDF)

January 11, 2013
EPA is extending the public comment period for the draft research report to September 30, 2013. During this time, EPA will continue its public outreach activities including meeting with key stakeholders and posting additional technical information on this website. This extension will allow the public additional opportunity to comment on EPA's draft report and the latest round of sampling conducted by EPA and USGS. The Agency will take into account new data, further stakeholder input, and public comment as it continues to review the status of the Pavillion investigation and considers options for moving forward. View the Federal Register notice announcing the extension of the public comment period (PDF) (2 pp, 203 K).

November 6, 2012
EPA has updated and corrected the well completion schematics for Monitoring Wells 01 and 02 based on a detailed review of the drillers logs and field notes. View the updated schematics here:

- Monitoring Well 01 Completion Schematic (PDF) (1 pg, 202 K)
- Monitoring Well 02 Completion Schematic (PDF) (1 pg, 193 K)

October 16, 2012
EPA has extended the public comment period on the Draft Report until January 15, 2013. View the Federal Register Notice announcing the extension of the public comment period.

October 10, 2012
EPA released the methodology and results for samples collected during April 2012. Click here for more information.

September 26, 2012
The U.S. Geological Survey has released data from samples taken from a Pavillion area monitoring well earlier this year. USGS conducted this sampling at the request of the State of Wyoming and in coordination with EPA. This data will be made available to the independent peer review panel that will review EPA's draft Pavillion groundwater report beginning later this year.

- Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming, April and May 2012
- Sampling and Analysis Plan for the Characterization of Groundwater Quality in Two Monitoring Wells near Pavillion, Wyoming

June: Update on 2012 sampling activity
EPA, in cooperation with the U.S. Geological Survey, the Tribes, and the State of Wyoming, is re-sampling two monitoring wells the Agency installed in the Pavillion area in the summer of 2010. EPA is also collecting samples from four private and one public water supply well. Sample results, which are expected later this summer, will be posted on this web page. These data will be made available for public comment and included in the peer review process.

March 8: EPA extending public comment period and delaying peer review to consider additional sampling
EPA and the State of Wyoming recognize the value of further sampling of the deep monitoring wells drilled for the Agency’s ground water study in Pavillion, Wyoming. EPA will partner with the U.S. Geological Survey (USGS), the State, and the Tribes to complete this sampling as soon as possible.

To ensure that the results of this next phase of testing are available for the peer review process, EPA has delayed convening the peer review panel on the Pavillion Draft Report until a report containing the USGS data are publicly available. In addition, EPA is extending the public comment period on the Draft Report through October 2012 to provide additional time for the public to review and comment on the new data. View Federal Register Notice announcing public comment period (PDF) (5 pp, 75 K)

View the full joint statement from EPA Administrator Lisa Jackson, Governor Matt Mead and the Northern Arapaho and Eastern Shoshone Tribes.

February 8: The public comment period on the Draft Peer Review Charge opened on February 8; the comment period has closed. View public comments on the Draft Peer Review Charge that were received during the public comment period:

- Comment from Lloyd Hetrick
- Comment from John Corra
- Comment from David Stewart
- Comment from Nancy Tujague

January 31: 622 files have been added to the Site Documents page. The files include additional analytical data and QA documentation.

January 23:

- Op-ed from EPA Regional Administrator Jim Martin in the Casper Star-Tribune (1/22)
- Letter from EPA Administrator Lisa Jackson to Governor Matt Mead (1/19)

January 18: EPA is inviting the public to nominate scientific experts to be considered as peer reviewers of a draft report on the Pavillion ground water investigation. Nominations will be accepted through February 17. Details can be found in the Federal Register notice (PDF). (2 pp, 156 K)

View more information on the peer review process.

December 14, 2011: EPA has released a draft report outlining findings from the Pavillion, Wyoming groundwater investigation for public comment and independent scientific peer-review. See the box at the top right of this page for more information.

November 9, 2011: EPA released the latest data from Pavillion-area domestic and monitoring wells at a public meeting on November 9, 2011. We are sharing this data with the community, Encana, the state, tribes and federal partners as part of an ongoing process to develop sound science about contamination in the aquifer used by Pavillion residents for drinking water.

EPA will release a draft research report summarizing investigation findings. This report will be available for public comment as part of an independent peer-review process coordinated by our Office of Research and Development.

Public Documents and Presentations

- Methods, Graphics, and Data Tables Handout, November 8, 2011
- 2010-2011 Sampling Summary of Results and Next Steps Presentation, November 9, 2011
- Workgroup Meeting Presentation, November 30, 2011

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Site Description

Pavillion, Wyoming is located in Fremont County, about 20 miles northwest of Riverton. In 2003, the estimated population was 166 residents. The concern at the site is potential groundwater contamination, based on resident complaints about smells, tastes and adverse changes in water quality of their domestic wells. Community members contacted EPA in spring 2008.

The Pavillion area has approximately 80 domestic wells. The town of Pavillion provides municipal water to residents through eight groundwater wells. Private water wells just outside the town of Pavillion are used for drinking water, irrigation, and stock watering, and are completed at depths from 50 feet to 750 feet or more. Pavillion is within the Wind River Indian Reservation as described by the Northern Arapaho and Eastern Shoshone Tribes in a pending application for treatment in a similar manner as a state under the Clean Air Act. The site is located west of Boysen State Park.

January 2010 sampling

In March 2009 EPA sampled 39 individual wells (37 residential wells and two municipal wells). The purpose of this sampling was to collect data to assess groundwater conditions and evaluate potential threats to human health and the environment. EPA conducted additional sampling in Pavillion in January 2010. This effort included sampling 21 domestic wells within the area of concern, two municipal wells, and sediment and water from a nearby creek. EPA has also sampled groundwater and soil from pit remediation sites, produced water, and condensate from five production wells operated by the primary natural gas operator in the area. EPA installed two monitoring wells in the Pavillion area in 2010. Data collected from these wells will build upon prior sampling events and help us further assess groundwater hydrology and contamination in the aquifer. EPA released the latest data from domestic and monitoring wells at a public meeting on November 9, 2011.

The Pavillion groundwater investigation is being conducted by EPA's regional office in Denver in collaboration with scientists from our Office of Research and Development.

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Site Reports and Public Presentations

You will need Adobe Acrobat Reader to view some of the files on this page. See EPA's PDF page to learn more.

Best way to open a **very large file**: right-click and **save it to a folder**

Documents related to August 31, 2010 public meeting:

- Public Meeting Presentation of Phase 2 Sampling Results
- Press Release: EPA releases results of Pavillion, Wyo. water well testing
- Agency for Toxic Substances and Disease Registry Health Consultation Document (PDF) (2.2 MB)
- Fact Sheet: January 2010 Sampling Results and Site Update
- Final Analytical Results Report for the Pavillion Area Groundwater Investigation Site
    - Results Report Appendices: Lab Data, Photos, Figures, Chemicals Used
    - Figure 1: Site Location Map
    - Figure 2: Sampling Location Map of the January 2010 Event
    - Figure 3: Area of Influence and Well Locations
    - Figure 4: Conceptual Site Model of the Pavillion Area Groundwater Plume
    - Pavillion Area Groundwater Investigation: ALL tables

Phase 2 Field Sampling Plan, January 2010

Public Meeting Presentation of Phase 1 Sampling Results, August 11, 2009

Groundwater Investigation Analytical Results Report and Phase I Maps, August 2009

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Photo/Video Gallery

Click on a thumbnail below to view the full size image.

Pavillion, Wyoming landscape

January 2010 sampling

January 2010 sampling

Collecting January 2010 samples

Preparing January 2010 samples

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Contact Us to ask a question, provide feedback, or report a problem.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Subject: Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site, Intersection of PA Routes 29 & 2024 Dimock Township, Susquehanna County, Pennsylvania

From: Gerald T. Hart
f Richard M. Fetzer, On-Scene Coordinator
Eastern Response Branch (3HS31)

To: Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division (3HS30)

JAN 19 2012

I. PURPOSE

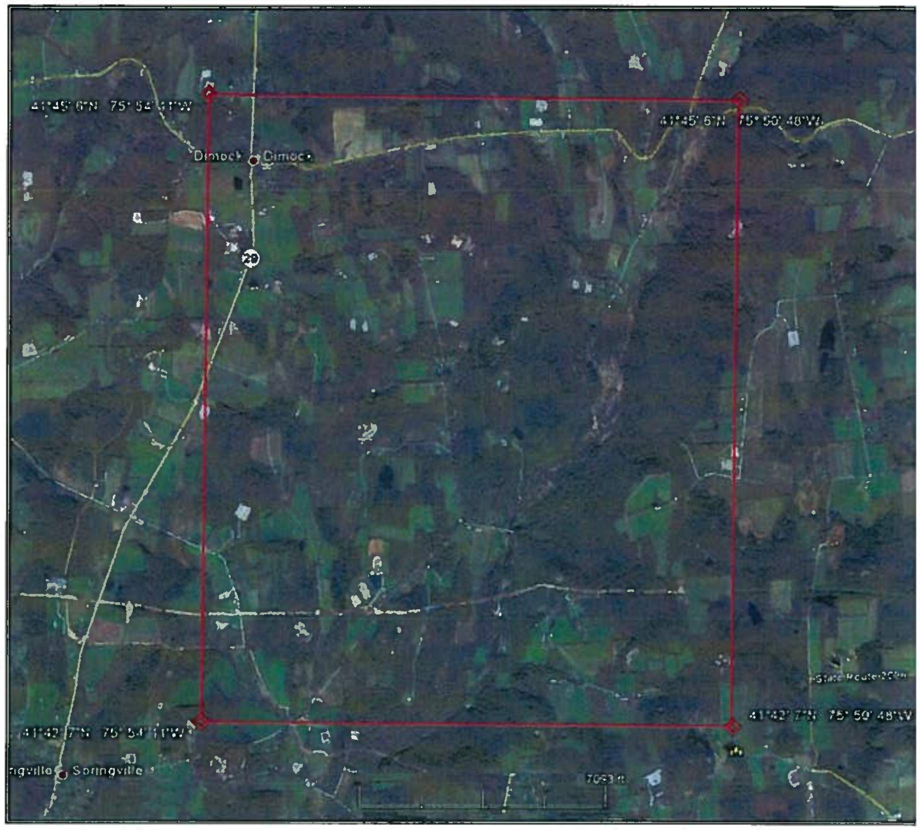
The purpose of this Action Memorandum is to request and document approval of an emergency removal action to prevent, limit, or mitigate the threats posed by the presence of hazardous substances at the Dimock Residential Groundwater Site (the "Site"), pursuant to Section 104(a) of the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9604(a) (CERCLA). The Site is located in Dimock Township, Susquehanna County, Pennsylvania. The OSC has initiated a removal site evaluation in accordance with the National Oil and Hazardous Substances Pollution Contingency Plan (NCP), 40 C.F.R. Part 300. The OSC has determined, based on Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record Of Activity (AROA), issued 12/28/11, and the recent EPA well survey effort, that a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment. Inorganic hazardous substances are present in four home wells at levels that present a public health concern. These four specific homes have been dependent upon donated water for drinking and/or household use and the reliability of the sources for donated water is at this point uncertain.

Historic drilling activities in the Dimock area may have used materials containing hazardous substances. Spills and other releases have been documented by PADEP from these drilling activities. There is reason to believe that a release of hazardous substances has occurred. The presence of hazardous substances in the four home wells constitutes a release or substantial threat of a release and the situation meets the criteria for conducting a removal action under Section 300.415 of the NCP. The OSC has determined that funds in the amount of $100,000 are needed to mitigate the human health concern initially at four homes and therefore proposes the actions included in this Action Memorandum. This action includes provision of alternate water to four homes and home well sampling at approximately 61 homes within the Site area.

II. SITE CONDITIONS AND BACKGROUND

A. Background

1. Site Description - The Site area is located in Dimock, a rural area of northeastern Pennsylvania in Susquehanna County. A map of the area is included below.



2. History - Cabot began drilling for natural gas in the Dimock area in 2008. Methane contamination was detected in private wells thereafter in concentrations exceeding those previously found. PADEP had the lead in investigating the environmental complaints in Dimock. PADEP entered into a Consent Order and Agreement (CO&A) with Cabot which required permanent restoration or replacement of the affected water supply. A public water line was initially considered. PADEP later modified the CO&A to require installation of "gas mitigation" systems for 19 homes served by 18 private wells in the Site area.[1] Until the gas mitigation systems were installed, Cabot was to provide a temporary water source. Some well owners, within the scope of the PADEP CO&A, have gas mitigation systems installed, but others do not. While the gas mitigation systems were designed to remove methane, a potential exists that they may remove some hazardous substances as a by-product of their operation. Regardless, EPA does not know what, if any, hazardous substances these "gas mitigation" systems, originally designed to address methane, are removing. Therefore, EPA is including both pre- and post-treatment sampling in the scope of this action. Furthermore, there are

[1] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

other homes served by private wells that were not covered by the scope of the PADEP CO&A, but are within this Site area.

III. Quantities/Types of Substances Present

1. Arsenic* – Arsenic is a naturally occurring element widely distributed in the earth's crust. Arsenic may also be present at elevated concentrations in the groundwater due to the use and effects of drilling fluids. Arsenic is classified as a known human carcinogen. This classification is based on animal and human studies, which indicate an increased risk for developing cancers of the skin, lung, bladder, kidney, liver, and prostate from consuming arsenic containing water. Non-cancer health effects associated with ingestion of arsenic include circulatory problems and skin damage.
2. Barium – Barium is a silvery-white metal that exists in nature only in ores containing mixtures of elements. It combines with other chemicals such as sulfur or carbon and oxygen to form barium compounds. Barium sulfate is sometimes used by doctors to perform medical tests and to take x-rays of the gastrointestinal tract. Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys. Barium is known to be a common constituent of drilling fluids.
3. Bis(2-ethylhexyl)phthalate (DEHP)* - DEHP is a manufactured chemical that is commonly added to plastics to make them flexible. The phthalates are generally considered to be of slight to moderate toxicity. DEHP may be irritating to the eyes, skin, and mucous membranes. Mild gastric disturbances and diarrhea may occur following ingestion of larger doses. Central nervous system (CNS) depression may occur if large amounts of phthalate acid esters are absorbed. EPA has determined that DEHP is a probable human carcinogen. These determinations were based entirely on liver cancer in rats and mice. DEHP is known to be associated with drilling activities.
4. Glycol Compounds (including Ethylene Glycol* and 2-Methoxyethanol) – Glycol compounds are a class of organic compounds belonging to the alcohol family. Exposure to large amounts of ethylene glycol can damage the kidneys, nervous system, lungs, and heart. Exposure to high concentrations of 2-methoxyethanol is associated with testicular damage, impaired nervous system, and anemia. Glycols are known to be common in drilling fluids.
5. Manganese* – Manganese is a naturally occurring substance found in many types of rock and soil. Manganese is also known to be a constituent of some specialized drilling fluids. Eating a small amount of manganese from food or water is needed to stay healthy. At high levels, it can cause damage to the nervous system.

6. Phenol* - Phenol is both a manufactured chemical and a natural substance. Phenol is used as a disinfectant and is found in a number of consumer products. Skin exposure to high amounts can produce skin burns, liver damage, dark urine, and irregular heart beat. Various phenols are commonly associated with drilling fluids.
7. Sodium* – Sodium is an essential nutrient and occurs naturally in most foods. Excessive sodium intake is associated with high blood pressure. Various sodium containing compounds are associated with drilling fluids.

*A hazardous substance, as defined under CERCLA Section 101(14) and designated in Section 302.4 of the National Contingency Plan (NCP), 40 C.F.R. Section 302.4.

B. National Priorities List

The Dimock Residential Groundwater Site is not on the CERCLA National Priorities List (NPL).

C. State and Local Authorities' Roles

Cabot had been sampling the home wells and providing bottled drinking water and alternate water for non-potable use, through a Consent Order and Agreement (CO&A) with PADEP. The CO&A applies only to a specific list of homes, and does not include other homes, also located within the same geographic area. Some of these additional homes have had limited sampling conducted by Cabot and/or PADEP. PADEP determined that Cabot has complied with the terms of the CO&A, as it applies to the provision of temporary water, and subsequently approved Cabot's request to stop the delivery of alternate water.

IV. THREATS TO PUBLIC HEALTH OR WELFARE OR THE ENVIRONMENT

Section 300.415 of the NCP lists the factors to be considered in determining the appropriateness of a Removal Action. Paragraphs (b)(2)(i), (ii), and (vii) of Section 300.415 directly apply to the conditions found at the Dimock Residential Groundwater Site.

In evaluating the situation, the OSC first considered whether hazardous substances were present in a home well. The levels of those hazardous substances were then considered against primary Maximum Contaminant Levels (MCLs). They were also considered for non-cancer risk to determine if the levels generate a hazard quotient greater than 2. The presence of inorganic and organic chemicals in a number of wells supports the need for this action.

300.415 (b)(2)(i) "Actual or potential exposure to nearby human populations, animals or the food chain from hazardous substances or pollutants or contaminants"

The hazardous substances listed above, present in water from home wells at this Site based on sampling data described below, could cause adverse health impacts when chronic exposure through drinking water or other uses of water in the home occurs. There are other contaminants discussed in the Agency for Toxic Substances and Disease Registry's (ATSDR) Record of Activity (AROA) issued on December 28, 2011, which could also cause adverse health impacts. ATSDR has concluded for the area originally included with the PADEP/Cabot CO&A, which includes the four homes being considered here for alternate water, that a chronic health risk exists for most wells and that the situation supports a "Do Not Use the Water" action including the consideration of alternative home water supplies until further characterization is completed. An EPA Region III toxicologist's opinion is that, of the homes evaluated to date in an on-going effort, that four home wells contain contaminants at levels that present a public health concern. In one home, manganese was detected at 628 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2. In another home, manganese (1360 ug/L) was detected at a level that generates a Hazard Quotient of approximately 4. Note that children reside at this location. In the third home, arsenic was observed at a concentration (37 ug/L) that exceeds its MCL of (10 ug/L) and would pose a long-term cancer risk of 8E-04. Note that children reside at this location. In the fourth home, manganese was detected at 669 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2.3. Available data also indicate that hazardous substances may be present in a number of other homes. Because the available data is not complete and is of uncertain quality, additional sampling is needed to facilitate a further evaluation of any potential health concerns from the drinking water at home wells in the Site area.

EPA is providing water based upon a risk of exposure to hazardous substances above health-based levels. Furthermore, the OSC notes that for those homes where the EPA toxicologist has not identified contaminants that present a public health concern, that the limited data available does identify the existence of hazardous substances. In addition, PADEP's CO&A determined that 18 home wells were impacted by drilling activities; such impact may be evidence of the migration of hazardous substances.

Again, it is noted that this determination is based upon data which was collected by parties other than EPA (Cabot and PADEP). The quality assurance/quality control (QA/QC) information has not been verified. However, what is clear is that this data strongly suggests that hazardous substances have been released and are present in some home wells at levels that may present a public health concern. Current data does show arsenic and manganese at higher levels than may be typically found, in post drilling samples. Since arsenic and manganese are naturally occurring substances, EPA's assessment will include comparisons of background concentrations and post drilling concentrations present. EPA routinely acts under CERCLA to protect public health first while it acts to further define contamination. Thus, within this action, EPA will complete an assessment of the water quality of the home wells in the Site area to close information gaps as soon as possible. This sampling will be focused initially on evaluating those homes in the Site area that have been sampled in the past. Beyond that, sampling at homes will be based upon a sampling rationale using information regarding alleged health impacts and data gaps. In addition, EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data.

300.415 (b)(2)(ii) "Actual or potential contamination of drinking water supplies or sensitive ecosystems"

The discussion of 300.415 (b) (2) (i) above applies to this factor. Both organic and inorganic contaminants have been detected in home wells. Although this action is predominantly based upon inorganic data at the four homes, it should be noted that organic compounds have been detected at other homes as detailed in the ATSDR AROA. Glycol detections included ethylene glycol, triethylene glycol, and 2,2'oxybisethanol (diethylene glycol). Some wells had all three reported glycols present in their wells but no exceedances of risk based screening criteria (note: the analytical detection level used appeared to be higher than screening levels). Bis(2-ethylhexyl) phthalate (DEHP) was detected in five samples and ranged from 0.14 µg/L to 22 ug/L. 2-methoxyethanol concentrations (ranging from 880 ug/L to 1,300 ug/L) were detected in each of six wells.

300.415 (b) (2) (vii) "The availability of other appropriate federal or state response mechanisms to respond to the release"

The four homes being considered for alternate water under this action were all dependent upon donated water, either bottled, water buffaloes (temporary storage tanks) or both. It is the OSC's understanding that the last delivery of bulk water from those organizations ceased on January 3, 2012. In any case the reliability of sources for donated water is at best uncertain.

V. PROPOSED ACTIONS AND ESTIMATED COSTS

A. Proposed Action

1. Proposed Action Description

Throughout the duration of Site activities, all personnel involved with execution of this proposed action will comply with the requirements of CERCLA and with all other applicable Federal and State regulations to the extent practicable considering the exigencies of the situation in accordance with 40 CFR § 300.415(j). Available data indicate that a number of homes in the area have hazardous substances present in the home wells, but only four indicate concentrations identified by the EPA toxicologist at a level of concern. Thus, those four homes will be immediately supplied with water. At the same time, approximately 61 home wells will be sampled by EPA to obtain data of known quality assurance to support future evaluations and response decisions. EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data. The Removal activities at the Site will include the following:

1. Mobilize and demobilize personnel and equipment to conduct the action;
2. Delivery of a temporary source of clean water for household use to the four (4) homes with wells that contain contaminants at levels of public health concern. This provision of temporary water will continue until potential exposures are further understood and mitigated as needed.
3. The sampling program will include analysis for a broad range of parameters with a special priority being placed on quick turnaround for those parameters which are most frequently observed in the data available to EPA at this time. The Agency will also do some limited sampling for methane and bacteriological constituents. Home well water sampling will be performed by EPA in the Site area using the following assigned priority:

   i. The four (4) homes considered for provision of alternate water, to assess the potential exposure to hazardous substances and to determine whether continued temporary provision of clean water for household use is required.
   ii. The seventeen (17) remaining homes located on properties included in the PADEP/Cabot CO&A[2], which were identified as being impacted by drilling activities.
   iii. Approximately thirty (30) additional homes in the immediate area that have been sampled in the past.
   iv. Additional homes in the Site area where one or more of the factors below supports sampling.
      1. Direct observation or other evidence (home well surveys) of adverse health effects potentially attributable to contaminated groundwater use.
      2. Where data gaps in groundwater measurement or sampling need to be filled to gain an adequate understanding of Site conditions.

   Approximately ten (10) homes are currently identified from well surveys, but more could be added based upon data review.
4. Maintain necessary documentation of Site activities.
5. Develop and implement appropriate health and safety protocols for the removal activity.

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[2] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

2. Contribution to Remedial Performance

A remedial action is not anticipated and therefore this removal action is not inconsistent with any proposed remedial action.

3. Applicable or Relevant and Appropriate Requirements ("ARARs")

Actions will be conducted in compliance with Applicable or Relevant and Appropriate Regulations (ARARs) to the extent practicable considering the exigencies of the situation, in accordance with 40 CFR 300.415(j).

B. Estimated Costs

Extramural Costs	Total
Regional Allowance Costs: (ERRs Contractors and Subcontractors)	$ 50,000
Other Extramural Costs Not Funded From the Regional Allowance: START Contractor	$ 25,000
Subtotal, Extramural	$ 75,000
Extramural Costs Contingency	$ 25,000
Total Removal Action Project Ceiling	**$100,000**

VI. EXPECTED CHANGE IN SITUATION SHOULD ACTION BE DELAYED OR NOT TAKEN

If no action is taken, the residents may utilize well water which poses a potential public health concern.

VII. OUTSTANDING POLICY ISSUES

Because this response action could be considered nationally significant or precedent setting, it requires the prior concurrence of the Assistant Administrator, Office of Solid Waste and Emergency Response (AA-OSWER). Furthermore, because the action appears to be nationally significant and/or precedent-setting, the Region will continue to coordinate closely with Headquarters. EPA also will maintain coordination and communications with PADEP. In taking this action, EPA is aware of and has considered the potential applicability of the natural gas exclusion under CERCLA, the Bentsen Amendment under the Resource Conservation and Recovery Act (RCRA), and the exclusions to the definition of 'underground injection' under the Safe Drinking Water Act (SDWA). EPA has concluded that this action is appropriate under CERCLA at this time.

VIII. ENFORCEMENT

The total EPA costs for this removal action based upon full-cost accounting practices that will be eligible for cost recovery are estimated below as follows:[3]

Direct Extramural Costs	$100,000
Direct Intramural Costs	$ 25,000
Total Direct Costs	$125,000
Indirect Cost (67.13% x Direct Costs)	$ 83,912
Total Costs (Direct and Indirect)	$208,912

IX. RECOMMENDATION

This Action Memorandum represents the selected Removal Action for the Dimock Residential Groundwater Site in Dimock Township, Susquehanna County, Pennsylvania, developed in accordance with CERCLA, as amended, and is consistent with the NCP. This decision is based on the administrative record for the Site. The administrative record consists of the following documents

1. 1/13/12 "Dimock Home Well Data" memo from EPA Toxicologist Dawn Ioven.
2. ATSDR AROA Issued 12/28/11.
3. Summary of Portions of data received by EPA and reviewed by the OSC.
4. PADEP Consent Order and Agreement, dated December 15, 2010.
5. EPA Data Review Memo, January 13, 2012.
6. EPA 104e request to Cabot, January 6, 2012

Conditions at the Site meet the Removal Action requirements of Section 300.415(b) of the NCP and I recommend your approval of the proposed removal action and exemption from the statutory limits. The total project ceiling, if approved, will be $100,000. Of this, as much as, $50,000 comes from the Regional removal allowance. Please indicate your approval or disapproval below.

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[3] Direct Costs include direct extramural costs and direct intramural costs. Indirect costs are calculated based on an estimated indirect cost rate expressed as a percentage of site-specific direct costs, consistent with the full cost accounting methodology effective October 2, 2000. These estimates do not include pre-judgment interest, do not take into account other enforcement costs, including Department of Justice costs, and may be adjusted during the course of a removal action. The estimates are for illustrative purposes only and their use in not intended to create any rights for responsible parties. Neither the lack of a total cost estimate nor deviation of actual total costs from this estimate will affect the United States' right to cost recovery.

Action by the Approving Official:

I have reviewed the above-stated facts and, based upon those facts and the information compiled in the documents described above, I hereby approve/disapprove the selected removal action.

APPROVED: Dennis P Carney **DATE** 1/19/2012

Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

DISAPPROVED: ____________________ **DATE**____________

Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

EPA United States Environmental Protection Agency

Newsroom

News Releases By Date

EPA Completes Drinking Water Sampling in Dimock, Pa.

Release Date: 07/25/2012
Contact Information: Terri White white.terri-a@epa.gov (215) 814-5567

PHILADELPHIA (July 25, 2012) – The U.S. Environmental Protection Agency announced today that it has completed its sampling of private drinking water wells in Dimock, Pa. Data previously supplied to the agency by residents, the Pennsylvania Department of Environmental Protection and Cabot Oil and Gas Exploration had indicated the potential for elevated levels of water contaminants in wells, and following requests by residents EPA took steps to sample water in the area to ensure there were not elevated levels of contaminants. Based on the outcome of that sampling, EPA has determined that there are not levels of contaminants present that would require additional action by the Agency.

“Our goal was to provide the Dimock community with complete and reliable information about the presence of contaminants in their drinking water and to determine whether further action was warranted to protect public health,” said EPA Regional Administrator Shawn M. Garvin. “The sampling and an evaluation of the particular circumstances at each home did not indicate levels of contaminants that would give EPA reason to take further action. Throughout EPA's work in Dimock, the Agency has used the best available scientific data to provide clarity to Dimock residents and address their concerns about the safety of their drinking water.”

EPA visited Dimock, Pa. in late 2011, surveyed residents regarding their private wells and reviewed hundreds of pages of drinking water data supplied to the agency by Dimock residents, the Pennsylvania Department of Environmental Protection and Cabot. Because data for some homes showed elevated contaminant levels and several residents expressed concern about their drinking water, EPA determined that well sampling was necessary to gather additional data and evaluate whether residents had access to safe drinking water.

Between January and June 2012, EPA sampled private drinking water wells serving 64 homes, including two rounds of sampling at four wells where EPA was delivering temporary water supplies as a precautionary step in response to prior data indicating the well water contained levels of contaminants that pose a health concern. At one of those wells EPA did find an elevated level of manganese in untreated well water. The two residences serviced by the well each have water treatment systems that can reduce manganese to levels that do not present a health concern.

As a result of the two rounds of sampling at these four wells, EPA has determined that it is no longer necessary to provide residents with alternative water. EPA is working with residents on the schedule to disconnect the alternate water sources provided by EPA.

Overall during the sampling in Dimock, EPA found hazardous substances, specifically arsenic, barium or manganese, all of which are also naturally occurring substances, in well water at five homes at levels that could present a health concern. In all cases the residents have now or will have their own treatment systems that can reduce concentrations of those hazardous substances to acceptable levels at the tap. EPA has provided the residents with all of their sampling results and has no further plans to conduct additional drinking water sampling in Dimock.

For more information on the results of sampling, visit: http://www.epa.gov/aboutepa/states/pa.html .

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September 8, 2010

By FedEx and e-mail

The Honorable Lisa Jackson
Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.

Dear Administrator Jackson:

To best protect human health, food sources, and our environment from the toxicity of contaminants found in wastes associated with the exploration, development and production of oil, gas, and geothermal energy, we believe it is appropriate for the Environmental Protection Agency (EPA) to reconsider its 1988 Regulatory Determination and regulate these wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The Natural Resources Defense Council (Petitioner) is submitting the attached rulemaking petition pursuant to Section 6974(a) of RCRA, 42 U.S.C. § 6974(a). In support of this petition, we identify numerous reports and data produced since the EPA's Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes (July 6, 1988) which quantify the waste's toxicity, threats to human health and the environment, inadequate state regulatory programs, and readily available solutions.

The Natural Resources Defense Council (NRDC) is a nonprofit environmental action group established in 1970 by a group of law students and attorneys at the forefront of the environmental movement. The Natural Resources Defense Council's purpose is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends. NRDC uses law, science and the support of 1.2 million members and online activists to protect the planet's wildlife and wild places and to ensure a safe and healthy environment for all living things. NRDC has worked for many years to ensure the proper regulation of oil and gas exploration and production operations.

Section 6974(a) of RCRA allows any person to petition the Administrator of the EPA to promulgate an environmental regulation. Within a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor. This petition asks the EPA to take specific actions and directs the EPA's attention to the ample documentation in the record, which provides full support for the designation of wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy as hazardous waste under RCRA and provides a firm and compelling basis for the reconsideration of the EPA's July 1998 Regulatory Determination.

Thank you in advance for your consideration of this petition.

Respectfully submitted by:

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I. THE EPA SHOULD REGULATE WASTE FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS UNDER SUBTITLE C OF RCRA.

We request that the U.S. Environmental Protection Agency (EPA) promulgate regulations that subject wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy to the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA). We submit this petition pursuant to 42 U.S.C. § 6974(a), seeking that EPA ensure safe management of these wastes throughout their life cycle from cradle to grave, including generation, transportation, treatment, storage and disposal. Reports concerning the toxicity of exploration, development and production wastes, their release into the environment, threats to human health, the increasing amount of these types of wastes being generated, the inadequacy of existing state regulations, enforcement and oversight, and the feasibility and economic benefits of using disposal techniques that are less harmful to the environment all support regulation under Subtitle C, as described in detail below.

A. The EPA Has Authority to Reconsider Its 1988 Regulatory Determination.

Congress gave EPA the authority to prescribe necessary regulations to carry out its functions under RCRA.[1] Congress charged EPA with the task of "assuring that hazardous waste management practices are conducted in a manner which protects human health and the environment."[2] Congress ensured that the public had a way to seek additional protections from hazardous wastes by allowing "[a]ny person . . . [to] petition the Administrator for the promulgation, amendment, or repeal of any regulation under" RCRA, and by requiring that "[w]ithin a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor."[3]

With these provisions, Congress expressed its intent that RCRA would adapt to changing hazardous waste management needs. Foreseeing the need to update regulations promulgated under RCRA to account for changing circumstances,[4] Congress provided the public a way to bring about EPA review of its regulations.[5] These provisions authorize EPA to reconsider its current treatment of wastes associated with the exploration, development, or production of oil and gas (E&P wastes).

[1] 42 U.S.C. § 6912(a)(1).
[2] 42 U.S.C. § 6902(a)(4).
[3] 42 U.S.C. § 6912(a)(1).
[4] 42 U.S.C. § 6912(b).
[5] 42 U.S.C. § 6912(a)(1).

Congress passed RCRA in 1976 as an amendment to the Solid Waste Disposal Act of 1965 in an effort to enact more comprehensive waste disposal standards nationwide.[6] Through RCRA, Congress declared that the "disposal of solid waste . . . without careful planning and management [was] a danger to human health and the environment."[7] Congress later amended RCRA with the Solid Waste Disposal Act Amendments of 1980.[8] One of the 1980 amendments, the so-called Bentsen Amendment, temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas" from regulation under RCRA.[9]

Under the Bentsen Amendment, Congress directed EPA to conduct a study to determine whether or not E&P wastes should be regulated as hazardous wastes under RCRA.[10] EPA completed the required study and submitted a Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy.[11] Shortly after submitting its report to Congress, EPA issued its Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes, in which it decided that regulation of E&P wastes under Subtitle C of RCRA was unwarranted.[12]

In the more than twenty years that have passed since EPA issued its Regulatory Determination on E&P wastes, both the oil and gas industry and the risks associated with E&P wastes have expanded dramatically, making EPA's 1988 Regulatory Determination unjustified. While E&P wastes have always been hazardous to human health and the environment, the recent expansion of drilling operations to more densely populated areas places even more people at risk. EPA's reconsideration of its 1988 Regulatory Determination is especially necessary now that the basis for its Regulatory Determination no longer reflects current conditions. In its 1988 Regulatory Determination, EPA identified three factors as the basis for its decision not to regulate E&P wastes under Subtitle C. These factors included: (1) the infeasibility of implementing alternative regulations, (2) the adequacy of state regulations, and (3) the economic harm that would befall the oil and gas industry if additional regulatory controls were imposed.[13]

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[6] Joseph F. Scavetta, *RCRA 101: A Course in Compliance for Colleges and Universities*, 72 NOTRE DAME L. REV. 1647 (1997).
[7] Natasha Ernst, Note, *Flow Control Ordinances in a Post-*Carbone *World*, 13 PENN ST. ENVTL. L. REV. 53 (2004) (citing 42 U.S.C §§ 6901–6992k (2003)).
[8] Pub. L. 96-482; *see also* James R. Cox, *Revisiting RCRA'S Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. L.J. 1, 3 (2003).
[9] 42 U.S.C. § 6921(b)(2)(A).
[10] 42 U.S.C. § 6921(b)(2)(B).
[11] EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY, Vols. 1–3 EPA530-SW-88-003 (1987) [hereinafter REPORT TO CONGRESS].
[12] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25446, 25447 (July 6, 1988).
[13] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25446.

As will be discussed at greater length below, new evidence clearly demonstrates that alternative disposal practices are feasible, state regulations remain inadequate, and the oil and gas industry is unlikely to be severely harmed by the imposition of more stringent waste disposal requirements. Because this evidence shows that the assumptions on which EPA's 1988 Regulatory Determination was based are no longer correct, EPA must revisit its decision.[14]

Nothing in RCRA prevents the EPA from reconsidering its 1988 Regulatory Determination. In *American Portland Cement Alliance*,[15] the court upheld EPA's authority to reconsider regulatory determinations made pursuant to the 1980 amendments to RCRA.[16] Moreover, statements made by EPA in its 1988 Regulatory Determination indicate that EPA never intended the Regulatory Determination to be its final word on E&P waste. Instead, EPA established a three-pronged plan and intended to take further action to fill in existing gaps in the regulations governing the disposal of E&P wastes.[17] To date this three-pronged plan has not been fulfilled. Gaps in the regulatory system governing E&P wastes have grown even wider and evidence of the substantial harm E&P wastes can cause to human health and the environment has continued to accumulate. EPA must revisit its 1988 Regulatory Determination to fulfill its obligations under the 1988 Regulatory Determination and protect human health and the environment from the significant risks posed by E&P wastes.

Unless EPA revisits its 1988 Regulatory Determination and recommends that E&P wastes be regulated under Subtitle C of RCRA, E&P wastes will continue to present substantial hazards to human health and the environment.[18]

B. EPA Should Regulate E&P Wastes Under Subtitle C of RCRA.

In light of the documented toxicity of contaminants found in E&P waste, the failure of states to adequately regulate the disposal of E&P wastes, the dramatic increase in oil and gas production that has occurred since 1988, and the availability of safer cost-effective disposal alternatives, EPA must take action in order to prevent further harm to human health and the

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[14] EPA Region 8 itself stated that "EPA may need to revisit the continued validity of the exemption in light of the advancements in practices." EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 3-14 (Working Draft 2008).
[15] 101 F.3d 772 (D.C. Cir. 1996).
[16] *Id.*
[17] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,447.
[18] [This footnote intentionally deleted in corrected copy.]

environment. EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA. Regulation under Subtitle C is not only appropriate, given that E&P wastes fall within the regulatory criteria for characteristic hazardous waste,[19] but necessary because, without such action, the oil and gas industry will lack the incentives to implement safer techniques as quickly as is necessary.[20]

1. E&P Waste Is Toxic.

E&P waste that is exempt from regulation under Subtitle C includes: drilling fluids and cuttings, produced water, used hydraulic fracturing fluids, rigwash, workover wastes, tank bottom sludge, glycol-based dehydration wastes, amine-containing sweetening wastes, hydrocarbon-bearing soil, and many other individual waste products.[21] In its 1988 Regulatory Determination, EPA admitted that E&P wastes contain toxic substances that endanger both human health and the environment.[22] Despite noting that benzene, phenanthrene, lead, arsenic, barium, antimony, fluoride, and uranium found in E&P wastes were of major concern and present at "levels that exceed 100 times EPA's health based standards,"[23] EPA declined to regulate these toxic substances under Subtitle C of RCRA. But EPA can no longer refuse to act: an ever-increasing amount of evidence demonstrates that E&P wastes are toxic, have had substantial negative effects on human health and the environment, and should be a major concern for EPA. Since 1988, numerous reports, studies, and cases have demonstrated that E&P wastes contain toxic substances that threaten both human health and the environment.

a. Contaminants Found in Different Types of E&P Wastes

E&P wastes are generally divided into three categories: produced water, drilling fluids and cuttings, and associated wastes.[24] All of these wastes contain a variety of toxic substances that present substantial risks to human health and the environment. Despite these risks, these E&P wastes are currently exempt from regulation under Subtitle C.

[19] *See* notes 282–313 *infra* and accompanying text.
[20] Closing Argument of the New Mexico Citizens for Clean Air and Water, Dec. 2007, OCD Document Image No. 14015_648_CF[1] at 9-10; *see also* AMY MALL, DRILLING DOWN: PROTECTING WESTERN COMMUNITIES FROM THE HEALTH AND ENVIRONMENTAL EFFECTS OF OIL AND GAS PRODUCTION vi (2007) [hereinafter "DRILLING DOWN"].
[21] *See* RAILROAD COMMISSION OF TEXAS, *Hazardous and Nonhazardous Oil and Gas Waste* 3–6, *in* WASTE MINIMIZATION IN THE OIL FIELD (2001).
[22] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25448.
[23] *Id.*; *see also* Cox, *supra* note 8, at 9.
[24] CLAUDIA ZAGREAN NAGY, CALIFORNIA DEP'T OF TOXIC SUBSTANCES CONTROL, OIL EXPLORATION AND PRODUCTION WASTES INITIATIVE 6 (2002).

i. Produced Water & Hydraulic Fracturing Wastewater

Produced water, also known as brine, is generally—but erroneously—considered to be "relatively clean" and contain less contaminants than other E&P waste.[25] Despite this common misconception, a study sponsored by the U.S. Department of Energy demonstrated that oil production yields "environmentally hazardous" produced water.[26] The West Virginia Department of Environmental Protection (WVDEP) found many contaminants of concern present in oil and gas wastewaters,[27] including arsenic, lead, and hexavalent chromium, while EPA Region 8 identified the presence of barium, chloride, sodium, sulfates, and other minerals,[28] and the Oklahoma Corporation Commission Oil and Gas Conservation Division stated that produced water can contain high levels of boron.[29] In 2009, the Colorado Oil and Gas Conservation Commission (COCG) documented multiple spills of produced water containing benzene levels exceeding the state's water quality standards, at least one of which was confirmed to have impacted groundwater.[30]

Knowledge of the hazardous nature of produced water is not new. In 1972, Chevron Oil Field Research Company found that "oil field produced waters contain dissolved organic compounds that are toxic to marine life."[31] More than a decade later, the U.S. General Accounting Office (GAO) acknowledged that "[b]rines associated with oil and gas production contain very high levels of chlorides . . . . Brines may also contain . . . petroleum hydrocarbons and additives, such as corrosion inhibitors, . . . and other radioactive materials."[32] EPA was aware of these hazardous constituents when it issued its 1988 Regulatory Determination. In its 1987 Report to Congress, EPA knew that "PAHs [polycyclic aromatic hydrocarbons] are a typical component of some produced waters," that "very low concentrations . . . of PAH are lethal to some forms of aquatic wildlife," and that the practice of disposing of "produced water in

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[25] KELLY CORCORAN, KATHERINE JOSEPH, ELIZABETH LAPOSATA, & ERIC SCOT, UC HASTINGS COLLEGE OF THE LAW'S PUBLIC LAW RESEARCH INSTITUTE, SELECTED TOPICS IN STATE AND LOCAL REGULATION OF OIL AND GAS EXPLORATION AND PRODUCTION 31–32.

[26] C. TSOURIS, OAK RIDGE NATIONAL LABORATORY, EMERGING APPLICATIONS OF GAS HYDRATES 7.

[27] The contaminants of concern included: "sulfate, chloride, arsenic, titanium, cobalt, nickel, silver, zinc, vanadium, tin, cadmium, lead, chromium, hexavalent chromium, copper, fluoranthene, cyanide, mercury, selenium, antimony, beryllium, barium, ammonia nitrogen, fluoride, nitrite nitrogen, nitrate nitrogen, oil and grease, total suspended solids, iron, aluminum, chloroform, benzene, phthalate esters, strontium, strontium-90, boron, lithium, gross alpha radiation, gross beta radiation, radium 226+ [and] radium 228." Letter from West Virginia Department of Environmental Protection to William Goodwin, Superintendent Clarksburg Sanitary Board, July 23, 2009.

[28] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY, WORKING DRAFT 3-11 (2008).

[29] OKLAHOMA CORPORATION COMMISSION OIL AND GAS CONSERVATION DIVISION, GUIDELINES FOR RESPONDING TO AND REMEDIATING NEW OR HISTORIC BRINE SPILLS 2 (2009).

[30] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631502, 1631508 (groundwater impact confirmed).

[31] A.H. BEYER, CHEVRON OIL FIELD RESEARCH CO., TECHNICAL MEMORANDUM, PURIFICATION OF PRODUCED WATER, PART 1—REMOVAL OF VOLATILE DISSOLVED OIL BY STRIPPING 1 (1972).

[32] U.S. GENERAL ACCOUNTING OFFICE, RCED-89-97, SAFEGUARDS ARE NOT PREVENTING CONTAMINATION FROM INJECTED OIL AND GAS WELLS 11 (1989).

unlined percolation pits [allows] PAHs and other constituents to migrate into and accumulate in soils."[33]

In addition to containing dangerous contaminants, produced water can also be radioactive. This problem first attracted national attention 1988 in southern and Gulf Coast states.[34] Shortly thereafter, GAO's 1989 report openly acknowledged the hazard.[35] A more recent analysis of normally occurring radioactive materials (NORM) levels in produced waters from the Marcellus Shale indicates that the dangers may be greater than initially thought.[36] Samples of produced water in the Marcellus Shale analyzed by the New York State Department of Environmental Conservation (NYSDEC) were reported to contain "levels of radium 226, a derivative of uranium, as high as 267 times the limit safe for people to drink."[37]

Despite knowledge of these risks, the data currently available may underestimate the actual radiation levels in produced water. A common method used by industry and EPA to measure radiation levels in produced water has been criticized because of its tendency to underestimate actual radiation levels. In the late 1980s, Exxon Mobil, along with Rogers and Associates Engineers (RAE) and the American Petroleum Institute (API), formulated correlations that could be used to estimate NORM in levels of equipment used to hold produced water.[38] The external measurement process chosen by RAE to measure the NORM levels has since been challenged as "seriously flawed" and has resulted in the reporting of a "greatly reduced radioactivity concentration of 480 pCi/gm."[39] Accurate testing could reveal that the NORM levels in produced water are even higher than currently being reported.

Wastewaters from hydraulic fracturing, largely composed of used fracturing fluids, are also toxic. Common substances found in these wastewaters include: surfactants, friction reducing chemicals, biocides, scale inhibitors, polymers, cross linkers, pH control agents, gel breakers, clay control agents and propping agents.[40] Many of these substances are possible and probable carcinogens.[41] Analysis of fracturing fluid flowback waters from Pennsylvania and West Virginia found the known carcinogen benzene present in nearly half of all fracturing fluid flowback waters at average concentrations nearly one hundred times the maximum acceptable

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[33] EPA, REPORT TO CONGRESS, *supra* note 11, at II-44.
[34] Keith Schneider, *Radiation Danger Found in Oilfields Across the Nation*, N.Y. TIMES, Dec. 3, 1990, at A1.
[35] GAO, RCED-89-97, *supra* note 32.
[36] N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 6-130 (2009) [hereinafter DRAFT SGEIS].
[37] Abrahm Lustgarten, ProPublica, *Natural Gas Drilling Produces Radioactive Wastewater*, SCIENTIFIC AMERICAN, Nov. 9, 2009; *see also* DRAFT SGEIS, *supra* note 36, at app. 13.
[38] Motion in Limine to Exclude Rogers and Associates Engineering Reports, Lester v. Exxon Mobil Corp., No. 630-402 (La. 24th Jud. Dist. Ct. 2009), at 6–7.
[39] *Id.* at 7-8.
[40] Wilma Subra, Louisiana Environmental Action Network, Comments on Hydraulic Fracturing to the Louisiana Senate Environmental Quality Committee, Mar. 11, 2010.
[41] *Id.*

contaminant levels established by EPA.[42] While this information demonstrates that these wastes contain toxic compounds, the true extent of the risks associated with hydraulic fracturing wastewaters is currently unknown as many of the compounds used in fracturing fluids and returned in the wastewaters are not publically disclosed.[43]

ii. Drilling Fluids and Drill Cuttings

Drilling fluids and cuttings make up two to four percent of oil and gas wastes.[44] They include rock removed during drilling (drill cuttings) and drilling muds, also known as drilling fluids, which can be either water or oil-based and often contain various additives.[45] A joint EPA/API survey found drilling fluids in reserve pits to contain "chromium, lead and pentachlorophenol at hazardous levels."[46] The survey also found that "oil-based fluids may contain benzene"[47] and that when oil-based fluids are used, "potentially toxic hydrocarbons" will be present in greater quantities.[48] Drilling muds may also contain other "potentially hazardous substances including . . . cadmium, arsenic . . . mercury, copper . . . diesel oil; grease; and various other hydrocarbons and organic compounds (e.g., methanol, chlorinated phenols, formaldehyde, benzene, toluene, ethyl benzene, xylene, and acrylamide)," as well as additives including acids and caustics, corrosion inhibitors, bactericides and biocides, surfactants, defoamers, emulsifiers, filtrater

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[42] Susan Riha et al, *Comments on the Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*, Jan. 2010, at 5; *see also* N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SGEIS 5-104 (2009).

[43] Wilma Subra, Comments on Hydraulic Fracturing, *supra* note 40. *See also* DRAFT SGEIS, *supra* note 36, at 5-51 (stating that the fracturing fluid additives list "[c]hemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined [under New York law] . . . .").

[44] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 67 (1992).

[45] *Id; see also* U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS 4–5 (2009).

> "Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers. Synthetic-based muds contain mineral oil and oil-based muds can contain diesel oil, although diesel oil is being replaced by a palm oil derivative or hydrated caster [*sic*] oil. Other additives typically used in drilling fluids include: polymers (partially hydrolyzed polyacrylamide (PHPA) and polyanionic cellulose (PAC)); drilling detergents; and sodium carbonate (soda ash). PHPA is used to increase viscosity of fluid and inhibit clay and shale from swelling and sticking. PAC is used to increase the stability of the borehole in unconsolidated formations. Drilling detergents or surfactants are used with bentonite drilling fluids to decrease the surface tension of the drill cuttings. Soda ash is used to raise the pH of the water and precipitate calcium out of the water." *Id.* (internal citations omitted).

[46] U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 5 (1992).

[47] *Id.*

[48] OIL & GAS ACCOUNTABILITY PROJECT, PIT POLLUTION—BACKGROUNDER ON THE ISSUES, WITH A NEW MEXICO CASE STUDY 6 (2004).

reducers, shale control inhibitors, thinners and dispersants, weighing materials, bentonite clay, and acrylamide.[49]

The use of these additives increases the risks associated with E&P waste, as many are hazardous compounds themselves.[50] EPA has already classified at least one additive, flocculant acrylamide, as a probable carcinogen.[51] Another frequently used additive, barite weighting agent, can contain cadmium and mercury.[52] When Greenpeace analyzed the heavy metal contents of one drilling fluid additive, SOLTEX® (a scale inhibitor used in both on- and off-shore drilling muds), it identified the presence of antimony, arsenic, barium, cadmium, chromium, cobalt, copper, fluoride, lead, mercury, nickel, vanadium, and zinc.[53] These reports alone create cause for concern; yet, the full extent of the risk these chemicals present is unknown, as the additives' formulas, and thus the concentrations of the various chemicals, are proprietary information and undisclosed by oil and gas companies.[54]

iii. Associated Wastes

Associated wastes include oily sludges, workover wastes, well completion and abandonment wastes and other small volume wastes associated with oil or gas production.[55] Oily sludges consist of "oily sands and untreatable emulsions segregated from the production stream, and sediment accumulated on the bottom of crude oil and water storage tanks."[56] Workover wastes include foam treatment wastes and stimulation fluids.[57] Of all the E&P wastes, associated wastes are generated in the lowest volume;[58] however, this does not mean that they are safe or that current regulations ensure they are disposed of properly. Indeed, "[a]lthough associated wastes constitute a relatively small proportion of total wastes, they are most likely to contain a range of chemicals and naturally occurring materials that are of concern to health and safety."[59] Several associated wastes identified in Colorado have the "potential to be ignitable" while others "can exhibit toxicity for heavy metals such as lead."[60]

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[49] *Id.*
[50] *Id.*
[51] U.S. EPA, *Technology Transfer Air Toxics: Acrylamide*.
[52] T.A. Kassim, *Waste Minimization and Molecular Nanotechnology: Toward Total Environmental Sustainability*, *in* 3 ENVIRONMENTAL IMPACT ASSESSMENT OF RECYCLED WASTES ON SURFACE AND GROUND WATERS: ENGINEERING MODELING AND SUSTAINABILITY 191, 204 (Tarek A. Kassim ed., 2005); Texas Railroad Commission, Waste Minimization in Drilling Operations.
[53] JONATHAN WILLS, MUDDIED WATERS, A SURVEY OF OFFSHORE OILFIELD DRILLING WASTES AND DISPOSAL TECHNIQUES TO REDUCE THE ECOLOGICAL IMPACT OF SEA DUMPING (2000).
[54] OIL & GAS ACCOUNTABILITY PROJECT, *supra* note 48, at 6–7.
[55] NAGY, *supra* note 24, at 6.
[56] *Id. at* 13.
[57] *Id.* at 14.
[58] *Id. at* 6; American Petroleum Institute, Waste Management.
[59] Dara O'Rourke & Sarah Connolly, *Just Oil? The Distribution of Environmental and Social Impacts of Oil Production and Consumption*, 28 ANNUAL REV. ENVTL. RESOURCES 587, 595 (2003).
[60] Testimony of Margaret A. Ash, OGCC Envtl. Supervisor, *In the Matter of Changes to the Rules and Regulations of the Oil and Gas Conservation Commission of the State of Colorado*, at 15.

b. Contaminants Found in Specific E&P Waste Disposal Sites

The hazardous contaminants used in oil and gas exploration and production and whose presence has been identified in E&P wastes end up being disposed of in a variety of methods. Pits, burial, land application, and injection wells are the methods most frequently used to dispose of E&P wastes. Wastewater treatment facilities are also increasing in use. Studies of some of these different types of common E&P waste disposal sites provide further evidence of the toxicity of E&P wastes.

Pits are a common E&P waste disposal method used both to store drilling muds and cuttings brought to the surface in drilling operations and to hold produced water, production fluids, used hydraulic fracturing fluid, and other wastes.[61] Numerous studies have found pits to contain toxic levels of many hazardous compounds. In 2007, an industry committee of oil and gas companies in New Mexico sponsored a sampling and analysis program of waste pits in the San Juan Basin.[62] Forty-two substances, including the "BTEX" chemicals[63] (benzene, toluene, ethylbenzene, and xylene), acetone, arsenic, barium, mercury, and radium were found in the samples.[64] Eleven of the chemicals were present at concentration levels above state limits.[65] A more recent sampling of an oilfield pit in Texas identified the presence of high levels of mercury and chromium.[66] Dirt removed from a pit in Oklahoma was contaminated with "high levels of arsenic, dioxins and total petroleum hydrocarbons."[67]

Analysis of land application sites, another method for disposing of E&P wastes, provides further evidence illustrating the hazards of E&P wastes. A study of landfarms conducted by the Arkansas Department of Environmental Quality (ADEQ) found that the substances in E&P wastes that were being land applied exceeded Arkansas' acceptable limits for chloride concentrations in most of the facilities it tested.[68] In addition, "[n]ine out of eleven facilities had

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[61] CORCORAN ET AL., *supra* note 25, at 20–21.
[62] The Endocrine Disruption Exchange, Potential Health Effects of Residues in 6 New Mexico Oil and Gas Drilling Reserve Pits Based on Compounds Detected in at Least One Sample, Nov. 15, 2007.
[63] SHANNON D. WILLIAMS, DAVID E. LADD & JAMES J. FARMER, U.S. GEOLOGICAL SURVEY, FATE AND TRANSPORT OF PETROLEUM HYDROCARBONS IN SOIL AND GROUND WATER AT BIG SOUTH FORK NATIONAL RIVER AND RECREATION AREA, TENNESSEE AND KENTUCKY, 2002–2003 10 (2006) ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."). Testing obtained by individuals residing near the pits has also confirmed the presence of dangerous contaminants. DRILLING DOWN, *supra* note 20, at 26 n.156.
[64] The Endocrine Disruption Exchange, *supra* note 62.
[65] The Endocrine Disruption Exchange, Number of Chemicals Detected in Reserve Pits for 6 Wells in New Mexico That Appear on National Toxic Chemicals Lists: Amended Document, Nov. 15, 2007.
[66] Letter from Roy Staiger, District Office Cleanup Coordinator, Texas Railroad Commission, to Exxon Mobil Corporation, Dec. 31, 2009.
[67] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[68] Arkansas Dep't of Envtl. Quality, Report on Landfarms ("Four facilities had pond chlorides greater than 3,000 mg/L and the ponds were full . . . . Eight out of eleven facilities had soil concentrations greater than 1,000 mg/Kg on at least one application area. Most were several times higher than 1,000 mg/Kg . . . .").

TPH concentrations that would indicate the application of [oil-based drilling fluids] had taken place."[69] Analysis of soil samples taken from a residential property in Texas, where pit sludge had been land applied less than 300 feet from a residence, "confirmed the presence of numerous hydrocarbons identified as Recognized and Suspected human carcinogens and neurotoxins (1, 2, 4 Trimethylbenzene, 1, 3, 5 Trimethylbenzene, 4-Isopropyltoluene, Acetone, Benzene, Carbon disulfide, Ethylbenzene, Isopropylbenzene, m&m Xylene, n-Butylbenzene, n-Propylbenzene, o-Xylene, sec-Butylbenzene, tert-Butylbenzene, Toluene)."[70] The residents of this property all reported skin rashes after the waste was applied to their land.[71]

c. The risks associated with these contaminants

i. Substances in E&P Wastes Endanger Human Health.

Many of these substances identified in E&P wastes are known carcinogens.[72] The most prevalent contaminants found in E&P wastes are the "BTEX" chemicals:[73] benzene,[74] toluene,[75] ethylbenzene,[76] and xylene.[77] Exposure to benzene has been "associated with an increased risk of leukemia in industrial workers"[78] and other serious health conditions, exposure to toluene can cause nervous system damage,[79] while xylenes can "cause dizziness, headaches and loss of balance among other problems."[80]Many of the other chemicals found in E&P waste, including

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[69] *Id.*

[70] WOLF EAGLE ENVIRONMENTAL, ENVIRONMENTAL STUDIES: FUGITIVE AIR EMISSIONS TESTING, IMPACTED SOIL TESTING, MR. AND MRS. TIMOTHY RUGGIERO (2010).

[71] Eric Griffey, *Toxic drilling waste is getting spread all over Texas farmland*, FORT WORTH WEEKLY, May 12, 2010.

[72] *See* Cox, *supra* note 8, at 4.

[73] CORCORAN ET AL., *supra* note 25, at 21.; *see also* WILLIAMS ET AL., *supra* note 63, at 10 ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."); U.S.G.S., TOXIC SUBSTANCE HYDROLOGY PROGRAM: BTEX.

[74] "Benzene is a known human carcinogen and causes leukemia." DRILLING DOWN, *supra* note 20, at vi; *see also* WILLIAMS ET AL., *supra* note 63, at 26. ("Because of the high degree of toxicity and mobility of benzene (compared to other petroleum hydrocarbons), it is commonly the main ground-water contaminant of concern at petroleum release sites.").

[75] "Toluene can cause fatigue, confusion, weakness, memory loss, nausea, hearing loss, central nervous system damage, and may cause kidney damage. It is also known to cause birth defects and reproductive harm." DRILLING DOWN, *supra* note 20, at vi (footnotes omitted).

[76] "Ethylbenzene can cause dizziness, throat and eye irritation, respiratory problems, fatigue, and headaches. It has been linked to tumors and birth defects in animals, as well as to damage in the nervous system, liver, and kidneys." *Id.* (footnote omitted).

[77] "Xylene can cause headaches; dizziness; confusion; balance changes; irritation of the skin, eyes, nose and throat; breathing difficulty; memory difficulties; stomach discomfort; and possibly changes in the liver and kidneys." *Id.* (footnote omitted).

[78] N.Y. DEP'T OF ENVTL. CONSERVATION, *supra* note 36, at 5-62 (2009).

[79] CORCORAN ET AL., *supra* note 25, at 21.

[80] *Id.*

acetone,[81] arsenic,[82] barium,[83] mercury,[84] and radium,[85] all found in E&P waste samples, also raise serious concerns for human health.

The impacts of these contaminants have been documented. In a 1997 Louisiana case against U.S. Liquids & Exxon, plaintiffs reported that shortly after the dumping of more than fifty million gallons of E&P waste containing benzene, toluene, and lead occurred at a facility located less than 500 feet from the nearest resident's home, "[a] strange smell blew over the community and . . . . [m]any people in the area felt sick . . . . For nearly three weeks, most residents, including children, suffered from stomach pains, sinus problems and other ailments."[86] Other evidence demonstrates that exposure to contaminants in E&P wastes can result in delayed and long-term health effects. One study conducted in the Amazon Basin of Ecuador found that pregnant women who resided in areas where there was discharge of untreated oilfield wastes into the environment experienced higher levels of spontaneous abortion.[87] Another epidemiological study in the same area showed "significantly higher incidence of cancer for all sites combined in both men and women living in proximity to oil fields . . . . [specifically,] [s]ignificantly higher incidences were observed for cancers of the stomach, rectum skin melanoma, soft tissue and

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[81] Acetone can cause nose, throat, lung and eye irritation, respiratory problems, fatigue and headaches. *See* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ACETONE (1995); DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[82] "Chronic arsenic exposure can cause damage to blood vessels, a sensation of 'pins and needles' in hands and feet, darkening and thickening of the skin, and skin redness. It is a known human carcinogen and can cause cancer of the skin, lung, bladder, liver, kidney, and prostate." DRILLING DOWN, *supra* note 20, at vi (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ARSENIC (2007) ("Exposure to lower levels can cause nausea and vomiting, decreased production of red and white blood cells, abnormal heart rhythm . . . ."); SCIENCELAB.COM, CHEMICALS & LABORATORY EQUIPMENT, MATERIAL SAFETY DATA SHEET: ARSENIC MSDS 1 (2008), ("[Arsenic is] toxic to kidneys, lungs, the nervous system, mucous membranes.")

[83] "Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys . . . . Some people who eat or drink amounts of barium above background levels found in food and water for a short period may experience vomiting, abdominal cramps, diarrhea, difficulties in breathing, increased or decreased blood pressure, numbness around the face, and muscle weakness. Eating or drinking very large amounts of barium compounds that easily dissolve can cause changes in heart rhythm or paralysis and possibly death. Animals that drank barium over long periods had damage to the kidneys, decreases in body weight, and some died." AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR BARIUM (2007).

[84] "Mercury can permanently damage the brain, kidneys, and developing fetus and may result in tremors, changes in vision or hearing, and memory problems. Even in low does, mercury may affect an infant's development, delaying walking and talking, shortening attention 'span,' and causing learning disabilities." DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[85] "Radium is a known human carcinogen, causing bone, liver, and breast cancer." *Id.* (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR RADIUM (1999).

[86] Chris Gray, *Pits Cause Stink in Lafourche*, TIMES-PICAYUNE, July 14, 1997, at A1.

[87] Miguel San Sebastian, Ben Armstrong, & Carolyn Stephens, *Outcomes of Pregnancy among Women Living in the Proximity of Oil Fields in the Amazon Basin of Ecuador*, 8 INTL. J. OF OCCUPATIONAL AND ECON. HEALTH 312 (2002).

kidney in men and for cancers of the cervix and lymph nodes in women.[88] As reports and first-hand accounts indicate, the risks posed by the contaminants found in E&P waste are not merely speculative. And the risks will not decrease anytime soon. As many pits containing E&P wastes are buried and forgotten, the buried E&P wastes have the potential to threaten future generations who will be unaware of the hazards just below the surface.

Human health can also be harmed by exposure to radiation in NORM-contaminated E&P wastes. Exposure can occur through inhalation of radium-bearing particles, through direct contact with NORM-contaminated soils and water, or through ingestion of radium-barium particles found in plants or animals exposed to NORM-contaminated soils or water.[89] Exposure to radium can result "in an increased risk of bone, liver, and breast cancer . . . . [it] has been shown to cause effects on the blood (anemia) and eyes (cataracts). It also has been shown to affect the teeth, causing an increase in broken teeth and cavities."[90] And the risks associated with NORM-contaminated soils and waters can persist for decades. In particular, land contaminated by radium 226, such as that found in produced water from the Marcellus Shale,[91] can pose a threat to "many generations of individuals living or working on NORM-contaminated land for a period covering nearing 20,000 years."[92]

ii. Substances in E&P Wastes Endanger Wildlife and Livestock.

In addition to harming human health, exposure to contaminants in E&P waste can sicken and kill wildlife. A recent report prepared by the U.S. Fish and Wildlife Service (USFWS) indicates that pits present significant risks to wildlife. Pits can "entrap and kill migratory birds and other wildlife . . . . Birds are attracted to reserve pits by mistaking them for bodies of water. . . . The sticky nature of oil entraps birds in the pits and they die from exposure and exhaustion."[93] In 2009, ExxonMobil pled guilty to violating the Migratory Bird Treaty Act,[94] after numerous birds (including mallard ducks, grebes, white-faced ibis, gadwell ducks, owls, Wilson pharalopes, Northern Shoveler ducks, avocets, curlew, a green-winged teal, a Cassin's sparrow, a purple

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88 Anna-Karin Hurtig & Miguel San Sebastian, *Geographical Differences in Cancer Incidence in the Amazon Basin of Ecuador in Relation to Residence near Oil Fields*, 31 INT'L. J. OF EPIDEMIOLOGY 1021, 1025 (2002).
89 Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 43 (1997).
90 AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, *supra* note 85.
91 *See supra* note 37.
92 Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 41 (1997).
93 U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS i (2009).
94 16 U.S.C. §§ 703-708.

martin, and a hawk) were found sick and dead after being exposed to pit contents, including hydrocarbons, in multiple states.[95]

E&P wastes have the potential to destroy lands upon which wildlife depend, disrupt food chains, and prevent wildlife from reproducing.[96] The New Mexico Department of Game & Fish has expressed concern about the hazards of hydrocarbon toxicity to wildlife including "acute and chronic ingestion or absorption toxicity, loss of thermal stability from oiling of fur or feathers, and reproductive failure due to absorption of chemicals from the maternal bird body through the shell of eggs."[97] Other researchers are concerned about the bioaccumulation of E&P wastes in wildlife, a process that would cause their harmful effects to magnify as they progress up the food chain.[98] Wildlife habitat may also be harmed by E&P waste. The New Mexico Department of Game and Fish has stated that it "is concerned that chloride contamination of the soil vadose zone may permanently impact the ability of a closed pit location to support vegetation necessary for productive wildlife habitat."[99] Just as E&P wastes can harm humans in ways that are not immediately apparent but can cause harm to future generations, so too can they harm successive generations of wildlife.

Domesticated animals are also harmed by E&P wastes. The Pennsylvania Department of Agriculture quarantined cattle after they came into contact with hydraulic fracturing wastewater being stored in a pit that leaked into an adjacent field. The owners of the property where the pit was located noticed seepage from the pit for as long as two months prior to the leak. The Department stated that wastewater "contains dangerous chemicals and metals." Tests of the wastewater found that it contained strontium as well as other substances.[100] E&P waste is sometimes disposed of on land used for cattle grazing.[101] Residents of the Barnett Shale have reported seeing cattle drinking from sludge pits.[102] Cattle have been lost due to exposure to E&P waste in New Mexico[103] and 54 out of 56 hair samples from sick cattle analyzed by the Texas Veterinary Medical Diagnostic Laboratory contained petroleum.[104]

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[95] Joint Factual Statement, U.S. v. Exxon Mobil Corp., ¶¶ 10–27 (D.Col. 2009).
[96] BRYAN M. CLARK, DIRTY DRILLING: THE THREAT OF OIL AND GAS DRILLING IN LAKE ERIE 25 (2002).
[97] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Jan. 20, 2006); *see also* Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Mar. 7, 2006).
[98] BRYAN M. CLARK, *supra* note 96, at 25.
[99] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to EMNRD Oil Conservation Division (Feb. 2, 2007).
[100] Press Release, Pa. Dep't of Envtl. Prot., *Cattle from Tioga County Farm Quarantined after Coming in Contact with Natural Gas Drilling Wastewater* (July 1, 2010).
[101] *See e.g.*, Amended Complaint, Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., No. 209CV01100, at ¶ 32 (W.D. La. filed Sept. 14, 2009), 2009 WL 4701364.
[102] Bluedaze: Drilling Reform for Texas blog (July 25, 2008).
[103] DRILLING DOWN, *supra* note 20, at 26.
[104] Test results from Veterinary Medical Diagnostic Laboratory on July 26, 2005, August 18, 2005, and September 6, 2005; DRILLING DOWN, *supra* note 20, at 26.

In response to occurrences like these, cattle ranchers and others whose animals are at risk have sought to prevent E&P waste disposal facilities from opening near their properties.[105] Protecting cattle and other domesticated animals from exposure to E&P wastes is particularly important as the hazardous contaminants of E&P wastes have the potential to bioaccumulate in these animals and potentially make their way into the human food chain.[106]

2. Current State Regulations and Enforcement Are Inadequate and Allow E&P Waste to Be Released into the Environment.

Waste produced in E&P operations is disposed of in a variety of ways, with underground injection and burial of waste historically being the most widely used methods.[107] Wastewater treatment facilities are another growing disposal method. Even before EPA made its 1988 Regulatory Determination, data indicated that commonly used disposal practices failed to prevent E&P wastes from contaminating soil and groundwater.[108] A 1987 report documented "the migration of leachate 400 feet from reserve pits buried in . . . North Dakota and reported groundwater contamination 50 feet below the buried reserve pits."[109] Incidences of soil and groundwater contamination have continued to occur since then.

E&P wastes may leak, spill, or evaporate into the air, allowing the chemicals used in oil and gas operations to be released into the environment. These releases occur in large part because many states' regulations do not adequately account for all of these potential modes of contamination, despite the fact that releases are occurring with alarming regularity, or are not vigorously enforced. The regulations of the Railroad Commission (RRC) of Texas have been described as providing only weak assurance that the "quality of waters (and land) will not be impacted by a gas operator's activity."[110] Assurances are similarly minimal in other states where regulations provide virtually useless oversight of E&P waste disposal because they fail to "clearly indicate acceptable disposal practices for all drilling wastes."[111]

An Ohio resident with 23 years of experience in drilling oil and gas wells testified before the state legislature that existing regulations are inadequate and cannot be appropriately enforced: "… the [Ohio Department of Natural Resources] has a serious lack of ability to enforce their own regulations due to the way the current law and this bill are written."[112] A review of Tennessee oil

[105] Susan Hylton, *Drilling Waste Feud, Neighbors of Maverick Energy Services Think Water is Being Polluted*, TULSA WORLD, Mar. 21, 2010, at A11
[106] DRILLING DOWN, *supra* note 20, at 26.
[107] *See* E&P FORUM, EXPLORATION AND PRODUCTION (E&P) WASTE MANAGEMENT GUIDELINES 5 (Report No. 2.58/196, 1993).
[108] U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4.
[109] *Id.*
[110] League of Women Voters of Tarrant County, Gas Drilling Waste-Water Disposal (2008).
[111] BRYAN M. CLARK, *supra* note 96, at 35.
[112] Testimony of James E. McCartney to the 128th General Assembly, Ohio Senate Environmental and Natural Resources Committee. Opponent Testimony on Senate Bill 165, Oct. 28, 2009.

and gas regulations found that the state does not have technical criteria for E&P waste management practices or any certification for E&P haulers.[113] Although all pits must be lined in Tennessee, pits are not considered or tracked through the permitting process and there are no security or wildlife protection measures.[114]

A 2009 letter from the EPA to the RRC of Texas states that the Commission should have "more rigorous evaluation" of conditions for waste disposal wells.[115] Texas also "allows companies to hire their own environmental consultants to check for contamination."[116] These regulatory failures existed when EPA issued its 1988 Regulatory Determination, and have been exacerbated in the wake of EPA's decision not to regulate E&P wastes under Subtitle C of RCRA.

a. Pits

Pit construction requirements vary greatly across the country. While a few states, such as New Mexico and Colorado, have recently adopted stricter rules governing the disposal of E&P wastes in pits, other states have minimal regulations and often do not even require the use of pit liners.[117]

The open design of pits, combined with the often minimal regulatory requirements governing their construction and use, present greater opportunities for their dangerous contents to be released into the environment. Reports indicate that the release of E&P wastes from pits is far too common.

In September 2008, New Mexico compiled its data on cases where pit substances contaminated New Mexico's groundwater.[118] The numbers were staggering: More than 700 incidents of groundwater contamination by oilfield wastes or products were documented.[119] Elsewhere, in 2001, E&P wastes from the Black Mountain disposal facility in Colorado contaminated nearby soil and groundwater when its clay lined pits began to leak.[120] Since then, many more releases of E&P wastes have occurred in Colorado. The Colorado Oil and Gas Conservation Commission (COGCC) documented several pits at the same pad site in Garfield

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[113] TENNESSEE DEP'T OF ENV'T & CONSERVATION, STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., TENNESSEE STATE REVIEW 13, 19, 22, 24 (2007).
[114] *Id.* at 30.
[115] FY2008 EPA Region 6 End-of-year Evaluation of the Railroad Commission of Texas Underground Injection Control Program, with transmittal letter from Bill Luthans, Acting Director, Water Quality Protection Division, Region 6 to Tommie Seitz, Director, Oil and Gas Division (June 19, 2009).
[116] Joe Carroll, *Exxon's Oozing Texas Oil Pits Haunt Residents as XTO Deal Nears*, Bloomberg Businessweek, April 16, 2010.
[117] *See infra* notes 146–160 and accompanying text; *see also* OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[118] NEW MEXICO ENERGY, MINERALS AND NATURAL RES. DEP'T, OIL CONSERVATION DIV., CASES WHERE PIT SUBSTANCES CONTAMINATED NEW MEXICO'S GROUND WATER (2008).
[119] Oil & Gas Accountability Project, Groundwater Contamination.
[120] Kim Weber, Regarding Support of HB 1414—Evaporative Waste Facilities Regulations.

County whose liners had torn and allowed wastes to be released on multiple occasions between April and August 2008.[121] The reports indicated that the pits were located on rocky terrain and that some of the liners had been torn by rocks on the site.[122] In total, more than 6,000 barrels of pit contents escaped the pits because of the tears.[123] In La Plata County, a landowner reported the possible contamination of his well by an unlined reserve pit located a mere 350 feet uphill from his well.[124] The COGCC eventually concluded that "it appear[ed] that fluids from the unlined reserve pit infiltrated into the shallow groundwater, flowed downhill and impacted the Thomson water well."[125] The COGCC has documented numerous other incidents where pits have leaked,[126] overflowed, [127] or been unlined,[128] thereby allowing their contents to be absorbed by unprotected ground.

In May, 2008, a Colorado citizen drank water from his spring and fell ill. The COGCC found benzene in the groundwater that exceeded standards by 32 times and benzene in faucet water that exceeded standards by 13 times, as well as elevated levels of toluene and xylenes. Although the COGCC began investigating this complaint in June, 2008, it wasn't until October, 2008, that the operator stated that it became aware that the production pit was never permitted. The state appears to have been unaware that the pit was never permitted even though it was investigating the pit as a possible source of groundwater contamination. In July, 2010, the COGCC found that the operator failed to properly permit, construct, maintain, and repair the pit, leading to a release or releases of E&P waste that impacted groundwater. The agency found that the liner had been stretched over rocks and had improperly sealed seams.[129]

In addition to the reports from New Mexico and Colorado, there have been many complaints by citizens of contamination reportedly caused by E&P wastes in other states. NYSDEC has received numerous reports of E&P waste releases, many of which have contaminated soil and

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[121] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424, 1630426, 1630427, 1630428, 1630429, 1630430.
[122] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO. 1630428.
[123] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424 (714 bbls), 1630426 (2000 bbls), 1630427 (500 bbls), 1630428 (1250 bbls), 1630429 (204 bbls), 1630430 (2017 bbls).
[124] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water; COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1953000.
[125] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, NOAV REPORT, DOC. NO. 200085988; *see also* Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water.
[126] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631518, 1631599, 2605176, 2605847.
[127] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200225543, 200225547, 200225546.
[128] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO.1632846.
[129] Colorado Oil and Gas Conservation Commission, Cause No. 1V, Order No. 1V, Docket No. 1008-OV-06

groundwater.[130] In June 1987, in West Seneca, N.Y., product from an open pit containing oil and other solvents was found running from the pit towards a nearby creek.[131] In November 1996, in Reading, N.Y., a produced water pit overflowed and spilled approximately two hundred gallons of produced water into a creek feeding into Seneca Lake.[132] NYSDEC determined that no cleanup was possible.[133] When a property owner in Bolivar, N.Y., called in June 2002 to report leaking oil wells, NYSDEC inspectors also found unlined leaking containment ponds.[134]

E&P wastes in pits have been released into the environment in other states as well. Pennsylvania's Department of Environmental Protection (PADEP) has documented several incidents of dangerous E&P waste releases into the environment. Notably, at two of Atlas Resources LLC's well sites in Pennsylvania, "compromised" pit liners allowed fracturing flowback fluids to escape.[135] In Ohio, a fracturing flowback pit was cut with a track hoe in 2010, causing more than 1.5 million gallons of fluid were spilled into the environment.[136] In 2008, the back wall of a pit in Ohio gave way, causing pit contents to spill and flow towards a creek.[137]

In addition to releases caused by torn liners and overflows, pits allow the hazardous contaminants in E&P wastes to be released into the environment through evaporation into the air. E&P wastes such as produced water stored in open pits can "release methane, toxic volatile organic chemicals and sulfur based compounds into the air."[138] Rocky Mountain Clean Air Action collected data showing that wastewater evaporation pits in Garfield County, Colorado are "major sources of air pollution and pose greater threats to human health than previously reported."[139] The data indicated that high levels of hydrocarbons and other hazardous air pollutants were being released into the air. [140] Also in Garfield County, beginning in October 2005, a resident repeatedly notified the COGCC that severe odors were emanating from an E&P waste pit located close to her home.[141] In early December 2005, the resident reported smelling "a different sort of stench . . . the 'Benzene smell'" to the COGCC and requested that the agency

[130] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST (2009).
[131] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 37 (2009) (Spill Number: 8702469).
[132] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 53 (2009) (Spill Number: 9610217).
[133] *Id.*
[134] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 124-25 (2009) (Spill Number: 0275147).
[135] Consent Assessment of Civil Penalty, In re Atlas Resources LLC, Dancho-Brown 4, ¶¶ AV–AZ, Groves 8, ¶¶ BA–BE.
[136] Ohio Department of Natural Resources, Notice of Violation No. 1278508985, June 21, 2010.
[137] Ohio Department of Natural Resources, Notice of Violation No. 2016754140, May 16, 2008.
[138] Subra, *supra* note 43.
[139] Phillip Yates, *Clean Air Group Contends Evaporation Ponds in Garfield County More Dangerous than Previously Believed*, POST INDEPENDENT, Jan. 9, 2008.
[140] *Id.*
[141] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development.

install full-time air monitoring equipment.[142] At the end of the month, the resident learned that sampling of the air fairly close to the pit "showed that benzene and xylenes exceeded the [EPA's] 'non-cancer risk levels' for these compounds – at 67 µg/m3, benzene was present at more than double the risk level. Other detectable compounds included acetone, toluene and ethylbenzene."[143]

While some incidents are effectively reported and prosecuted by state authorities, many more incidents occur that are not addressed adequately by state officials. In these cases, the citizens affected by such releases into the environment have instead turned to the judicial system in order to hold the oil and gas companies accountable. John Preston Stephenson, Jr. sued Chevron U.S.A alleging that waste from Chevron oil pits contaminated his property with "hazardous toxic and carcinogenic chemicals."[144] Similarly, the Sweet Lake Land and Oil Company sued multiple defendants, including Exxon, Noble Energy, Inc., and Texas Eastern Skyline Oil Company, for contamination of "the soil and groundwater with produced water, oil, drilling muds, technologically enhanced naturally occurring radioactive materials (sometimes referred to as 'TENORM'), hydrocarbons, metals, and other toxic and/or hazardous substances, wastes and pollutants," claiming that the defendants knew the pits contents would contaminate the plaintiff's surface and subsurface soil and water.[145] Sweet Lake Land and Oil Company further alleged that "[t]he presence of the pits, substances and scrap on and under the Property constitutes a nuisance."[146] These claims are only a handful of many more by citizens who have been harmed by E&P wastes released from pits.[147]

These reports of contamination are at least partially attributable to inadequate state efforts to regulate E&P waste disposal in pits. Despite the fact that pit contents have been found to contain hazardous contaminants,[148] many states fail to require operators to use the most basic of precautions. Tennessee, for example, does not even take pits into account in its permitting process, thereby "making their management and disposal difficult to track" and increasing the

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142 COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, COMPLAINT REPORT, DOC. NO. 200081602.
143 Oil &Gas Accountability Project, *supra* note 141.
144 Amended Complaint at ¶ 9, Stephenson v. Chevron U.S.A, Inc., No. 209CV01454, (W.D. La. filed Sept. 11, 2009), 2009 WL 4701406.
145 Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., *supra* note 101, at ¶ 10.
146 *Id.* at ¶ 27.
147 *See also* Petition for Damages, Brownell Land Corp., LLC v. Honey Well Int'l., No. 08CV04988, ¶¶ 11-12 (E.D. La. filed Nov. 21, 2008), 2008 WL 5366168; Rice Agricult. Corp., Inc., v. HEC Petroleum Inc., 2006 WL 2032688 (E.D. La); Petition for Damages, Tensas Poppadoc, Inc. v. Chevron U.S.A., Inc., No. 040769, ¶ 8 (7th Judicial Court La. filed Sept. 21, 2005), 2005 WL 6289654; Petition for Damages to School Lands, Louisiana v. Shell Oil Co., No. CV04-2224 L-O, (W.D. La. filed Oct. 29, 2004), 2004 WL 2891505 (where the State of Louisiana and the Vermilion Parish School Board made similar allegations against Shell Oil, claiming they had contaminated school property. In July 2006, the case was remanded to state court).
148 *See* notes 62–67 *supra*.

likelihood that the locations of the wastes will be forgotten in the future.[149] In addition, Tennessee has no freeboard or liner integrity requirements,[150] does not require testing or tracking of pit wastes,[151] and fails to require oil to be removed from pits.[152] Kentucky similarly turns a blind eye to the risks E&P wastes present to the public through its failure to require testing of E&P waste characteristics and its treatment of all E&P wastes except production brines and drilling muds as solid wastes, subject to less stringent disposal requirements "irrespective of the risk posed to human health or the environment from the waste."[153]

States also fail to take other simple steps that would dramatically decrease the likelihood of E&P wastes being released into the environment, for example, requiring pits to be lined with impermeable barriers. In Oklahoma, neither emergency pits nor pits holding water-based drilling fluids are required to have any lining.[154] This failure to require the use of a liner in pits holding water-based drilling fluids increases the risk that the "barite, clays, lignosulfonate, lignite, caustic soda and other specialty additives" found in water-based muds will contaminate the environment.[155] Kentucky's liner requirements are also inadequate. Kentucky does not require the use of liners in drilling pits that are used for less than thirty day storage and has "minimal liner requirements for holding pits" for storage over thirty days.[156]

Wildlife protection devices are another important and too often underused safety measure. Tennessee,[157] Louisiana,[158] and Kentucky all fail to require any "fencing, flagging or netting of pits," thereby increasing the risks the pits present to wildlife and domestic animals.[159] And according to a recent report prepared by Region 6 of the U.S. Fish & Wildlife Service, these three states are not alone.[160] As reported by Region 6, only thirteen states require pits or open tanks to be screened or netted to prevent wildlife from coming into contact with E&P wastes.[161] The failure to require pit operators to use even the most basic protection devices such as fencing or netting greatly increases the likelihood that wildlife will come into contact with E&P waste and suffer significant harm.

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[149] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[150] *Id.*
[151] *Id.* at 32.
[152] *Id.* at 31.
[153] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., KENTUCKY STATE REVIEW 50–51 (2006).
[154] OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[155] CORCORAN ET AL., *supra* note 25, at 20; *see also* U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4–5 ("Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers.").
[156] KENTUCKY STATE REVIEW, *supra* note 153, at 54.
[157] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[158] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., LOUISIANA STATE REVIEW 29 (2004).
[159] *Id.*
[160] U.S. FISH & WILDLIFE SERVICE, *supra* note 93, at 13 fig. 15.
[161] *Id.*

States also fail to regulate where pits may be located, allowing them to be placed near residences, schools, and other areas frequently used by the public. In some cases, homes are located so close to pits that residents have been forced indoors because of the foul odors and health symptoms emanating from the pits. One Pennsylvania family reported severe headaches caused by fumes from a pit less than 200 feet from their home.[162] As of 2005, when STRONGER, Inc. conducted a review of Indiana's E&P waste disposal practices and regulations, Indiana regulations had no requirements regarding "specifications for the location, orientation and construction of drilling pits. There [were] no required setbacks of minimum distances from buildings, homes or other structures for drilling pits." Since then, although Indiana has adopted a new rule requiring pits to be located at least one hundred feet from streams, rivers, lakes and drainage ways, it still does not specifically require pits to be setback from other structures.[163] By allowing pits to be sited close to where people live and children attend school, state regulators are bringing health risks literally closer to the citizens across the country.

b. Land application

EPA has stated that hazards also exist with land application of E&P wastes, finding that hydrocarbons, salts, and metals can all cause contamination when E&P wastes are land applied.[164] The Oil Industry International Exploration and Production Forum (E&P Forum), an international industry association, has also issued warnings, stating that land application may result in contaminants accumulating "in the soil [at] a level that renders the land unfit for further use."[165] New York State allows waste to be disposed of in municipal landfills.[166] Land where only oil and gas waste is applied is often called a "landfarm." Studies of landfarm conditions confirm that these hazards are real. When the Arkansas Department of Environmental Quality conducted a study of landfarms in Arkansas, it found that "all 11 sites that land applied fluids at some point had improperly discharged the fluids so as to cause runoff into the waters of the state."[167]

Land application sites outside of Arkansas are sources of similar concerns. Near Holdenville, Oklahoma, residents protested the opening of a landfarm because they were worried about

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[162] Christie Campbell, *Foul Odor from Impoundment Upsets Hopewell Woman*, OBSERVER-REPORTER, Apr. 14, 2010. June Chappel, who lives near a pit, stated that the odor "reminded her of a hair perm. It smelled like ammonia . . . [and] 'took your breath away.'" *Id.* Other times the fumes have smelled like gasoline, diesel fuel, and sewage. *Id.*
[163] 312 IND. ADMIN. CODE 16-5-13 (2010).
[164] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 49 (2000).
[165] E&P FORUM, *supra* note 107, at 17.
[166] Letter from Gary M. Maslanka, New York State Division of Solid & Hazardous Materials, to Joseph Boyles, Casella (April 27, 2010).
[167] Press Release, Arkansas Dep't of Envtl. Quality, ADEQ Releases Landfarm Study Report (Apr. 20, 2009).

potential "water contamination and land spoilage."[168] After the residents lost two appeals in which they tried to prevent its opening, the landfarm finally began operations and made the residents' fears a reality. Claudia Olivo, who owns a cattle ranch adjacent to the landfarm, filed a complaint with EPA after she noticed "strange glistening spots in the water" on her property.[169] In response, EPA issued a cease-and-desist order against the landfarm after finding that it had made unauthorized discharges of drilling mud into a creek that ran through Olivo's property, in violation of the Clean Water Act.[170] The Crouch Mesa landfarm in Aztec, New Mexico, is located directly across the street from a residential area and is the source of considerable visible dust observed blowing toward homes.[171]

Despite these risks, many states inadequately regulate land application. In Oklahoma, one-time land applications may occur as close as one hundred feet from any perennial stream, freshwater pond, lake or wetland.[172] Tennessee regulations fail to provide any explicit guidance regarding the use of land applications.[173] Meanwhile, Kentucky has no siting criteria for land application specific to E&P wastes.[174]

These lax regulations result in E&P wastes being land applied near, and in some cases, on residential property, increasing the likelihood that humans will be exposed to E&P waste's toxic compounds.[175] In Martha, Kentucky, produced water and tank bottoms were land applied on farmland near where a family of two adults and two children lived.[176] The family grew the majority of the vegetables and meat they consumed on the farm,[177] and the portion of the family's land used for storing E&P waste disposal was located a mere 100 feet from a small creek which "drains into a marsh, which then drains into a larger creek" from which the farm's cattle drank.[178] The family no longer drinks from its well, which has been contaminated with benzene.[179] Lead and arsenic were found in soil samples.[180] In addition, areas of the farm where E&P wastes had been disposed were found to be NORM-contaminated sites which "will remain radioactive for many thousands of years," "creating many opportunities for radium to enter the soil and be taken up by plants or cattle grazing on the land," and threatening "[f]uture inhabitants or workers on the NORM-contaminated land [who] may also be directly exposed to ionizing

[168] Susan Hylton, *supra* note 105, at A11.
[169] *Id.*
[170] *Id.*
[171] DRILLING DOWN, *supra* note 20, at 22.
[172] OKLA. ADMIN. CODE § 165:10-7-26(c)(6) (2009).
[173] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 32.
[174] KENTUCKY STATE REVIEW, *supra* note 153, at 50.
[175] *See* WOLF EAGLE ENVIRONMENTAL, *supra* note 70.
[176] Spitz et al., *supra* note 92, at, 45.
[177] *Id.* at 46.
[178] *Id.* at 45.
[179] *Id.*
[180] *Id.* at 55.

radiation or inhale radium-bearing particles."[181] As demonstrated by the contamination that occurred in Martha, Kentucky, inadequate state regulations too frequently fail to protect the public and the environment from the hazards associated with land application of E&P wastes.

A Texas resident lives fifty feet away from a 100-acre land farm, where the Texas Railroad Commission issued 22 minor permits for 22 different operations that are all located on one property. A second land farm is located just down the road.[182]

c. Injection Wells

Underground injection, the most widely used disposal method,[183] also poses concerns. If the formation into which E&P wastes are injected does not meet certain levels of permeability, porosity, and low reservoir pressure, the formations can form a poor seal around the E&P wastes and threaten nearby aquifers.[184] Under the Underground Injection Control (UIC) Program, E&P wastes may be injected in Class II wells, while wastes designated as hazardous under RCRA can only be disposed of in the more strictly regulated Class I wells.[185]

The lower standards applicable to Class II wells have proven inadequate to prevent E&P wastes from contaminating groundwater. In 1988, GAO released a report, *Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wells,* which examined the effectiveness of EPA's UIC program.[186] Although GAO speculated that it was likely that more incidents had occurred, it reported that the EPA was aware of at least 23 cases across the country where Class II injection wells had contaminated drinking water supplies.[187] Since then more incidences of concern have occurred.

In September 2007, a state inspector in Texas inspected an underground injection disposal well site outside of Fort Worth and found no problems. Yet a resident complained of "spilled oil, overflowing dikes and green-colored fluid in standing puddles." Inspectors returned and found that "oil-stained soil" had seeped several inches into the ground, that the "containment dike will not hold estimated capacity," and that standing water had oil in it. State records showed that the well site was not being used, when in fact it was actively being injected with oil and gas waste.[188]

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[181] *Id.* at 57.
[182] *See* Griffey, *supra* note 71
[183] M.G. PUDER & J.A. VEIL, ARGONNE NATIONAL LABORATORY, OFFSITE COMMERCIAL DISPOSAL OF OIL AND GAS EXPLORATION AND PRODUCTION WASTE: AVAILABILITY, OPTIONS, AND COSTS, S-2 (2006) ("By far, the most common commercial disposal method for produced water is injection.").
[184] *See* E&P FORUM, *supra* note 107, at 15.
[185] DRILLING DOWN, *supra* note 20, at 17; *see also* 42 U.S.C § 300h-4; 42 U.S.C § 300h(b); 42 U.S.C. § 300(h)-1(c).
[186] U.S. GENERAL ACCOUNTING OFFICE, *supra* note 32, at 2.
[187] *Id.* at 3.
[188] Abrahm Lustgarten, *State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs,* ProPublica, December 30, 2009.

Residents in DeBerry, Panola County, Texas, first began complaining that their groundwater was contaminated in 1996.[189] An underground injection disposal facility began operations one-eighth of a mile away from the community in 1987, injecting produced water into the ground at depths between 1,080 and 1,110 feet.[190] In 1996, while the well was still in operation, DeBerry residents told an EPA Region 6 employee that their water was discolored, was staining their kitchen and bath fixtures, and that they were experiencing gastrointestinal problems.[191] The residents of DeBerry ultimately stopped using their drinking water and instead began to obtain water from other sources.[192] No government agency tested DeBerry's drinking water for several years after residents first complained. Not until 2002 did the site operator of the injection wells in DeBerry, Basic Energy, sample the drinking water.[193] When it did, the residents' suspicions were confirmed. The results showed the presence of contaminants above the EPA's maximum contaminant levels.[194] In 2003, the Texas RRC found benzene, barium, arsenic, cadmium, lead and mercury in wells at levels exceeding the state's drinking water standards.[195] Because the Texas RRC never completed a full assessment of the contamination, the source of the contamination is not definitively known; however, residents strongly believe the injection wells were the cause of the contamination, and EPA has been unable to rule this possibility out conclusively.[196]

Also in Texas, an underground injection disposal facility in Daisetta is linked to contamination of a fresh water aquifer. The EPA found a lack of compliance reviews, inappropriate monitoring, and incomplete record-keeping, as well as a lack of evidence that all problems were ever remedied. This problematic facility led to a surface collapse and a large sinkhole.[197]

The likelihood that similar incidents will continue to occur exists as long as underground injection associated with oil and gas exploration, production, and development only has to meet the requirements for Class II wells and states fail to require better monitoring.

In addition, a vast amount of E&P waste is being injected underground without any UIC regulation whatsoever. Used hydraulic fracturing fluid—perhaps millions of gallons per each

[189] EPA OFFICE OF THE INSPECTOR GENERAL, COMPLETE ASSESSMENT NEEDED TO ENSURE RURAL TEXAS COMMUNITY HAS SAFE DRINKING WATER, NO. 2007-P-00034 2 (2007).
[190] *Id.* at 3.
[191] *Id.* at 2.
[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Hearing Before the Subcomm. on Superfund and Environmental Health of the S. Comm. on Environment and Public Works* 12–13 (2007) (statement of Robert D. Bullard, Dir. Environmental Justice Resource Center).
[196] EPA, OFFICE OF THE INSPECTOR GENERAL, *supra* note 189, at 3.
[197] EPA, *supra* note 115.

well—remain underground permanently. It has been estimated that up to 90% of hydraulic fracturing fluids used in the Marcellus shale formation remain underground.[198] Yet this waste disposal and storage activity is not subject to any federal underground injection regulations.

d. Wastewater Treatment Facilities

In regions where underground injection is not readily available, hydraulic fracturing wastewater and produced water may be sent to wastewater treatment plants prior to release to surface water. The plants may be publicly owned treatment works (POTWs) that typically process municipal sewage or centralized wastewater treatment (CWT) facilities that process industrial wastes. None of the POTWs and few of the CWT plants currently in operation have the capacity to reduce to safe levels all of the chemical contaminants commonly found in E&P waste. As a result, toxins are released to surface water, with adverse impacts on drinking water quality. The very high concentrations of total dissolved solids (TDS)—principally salts—that are common in hydraulic fracturing wastewater and produced water present a particular problem for wastewater treatment facilities.

Without adequate pretreatment, pollutants in oil and gas waste will pass through a POTW into the receiving stream, and they may interfere with ordinary sewage treatment systems.[199] Even with pretreatment, POTWs are not effective in removing salts from those wastes.[200] The use of POTWs for treatment of E&P waste in western Pennsylvania produced TDS levels in the Monongahela River in excess of drinking water standards, forcing the Commonwealth to limit the waste to one percent of influent at nine plants along the river.[201] Unauthorized discharges of pollutants, including fecal matter, from a POTW into the Susquehanna River were attributed to the plant's acceptance of oil and gas wastes.[202] Even CWT plants rarely have the evaporation and crystallization technologies needed to reduce extremely high levels of TDS in hydraulic fracturing wastewater and produced water (up to 300,000 mg/l) to levels consistent with water quality standards (500 mg/l). There is not a single CWT facility with that capacity in all of New York or Pennsylvania.[203]

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[198] PROCHEMTECH INTERNATIONAL, INC., MARCELLUS GAS WELL HYDROFRACTURE WASTEWATER DISPOSAL BY RECYCLE TREATMENT PROCESS.
[199] N.Y. State Water Res. Inst., *Waste Management of Cuttings, Drilling Fluids, Hydrofrack Water and Produced Water*; Oh. Envtl. Prot. Agency, *Marcellus Shale Gas Well Production Wastewater*.
[200] *Id.*
[201] Joaquin Sapien, *With Natural Gas Drilling Boom, Pennsylvania Faces an Onslaught of Wastewater*, ProPublica, Oct. 4, 2009; *Municipal Authorities' Perspective: Marcellus Shale Natural Gas Wastewater Treatment, Hearing Before the S. Comm. on Envtl. Res. & Energy* (Pa. 2010) (statement of Peter Slack, Pennsylvania Municipal Authorities Ass'n).
[202] Press Release, Pa. Dep't Envtl. Prot., DEP Says Jersey Shore Borough Exceeds Wastewater Permit Limits (June 23, 2009).
[203] N.Y. State Water Res. Inst., *supra* note 199; Joaquin Sapien, *supra* note 201.

e. Other spills, leaks, and intentional dumping

In addition to those releases that commonly occur when these common E&P waste disposal methods are being used properly, many other spills and releases occur before E&P wastes reach these storage or disposal sites. These other releases can be the result of equipment failure, accidents, negligence, or intentional dumping. Consistent federal regulations for waste management, storage and disposal would help prevent them in the future.

For example, in Pennsylvania, Atlas Resources LLC "discharged residual and industrial waste, including diesel and production fluids, onto the ground at seven of the 13 well sites."[204] At three of the wells Atlas allowed produced water to be released into the environment.[205] Pennsylvania records also show that pipes used to transport waste, sometimes for miles, have leaked. In October, 2009, a pipe carrying diluted wastewater spilled about 10,500 gallons into a high-quality stream, killing about 170 small fish and salamanders. In December, 2009, a pipe failed in five places, spilling an estimated 67,000 total gallons of fluid, tests of which found elevated levels of salts, barium and strontium.[206]

NYSDEC has documented numerous other examples of releases. In October 1997, a produced water tank in Willing, New York, containing produced water from natural gas extraction overflowed and contaminated the surrounding soil and a nearby creek from which cows drank with fifteen thousand gallons of produced water.[207] The produced water killed vegetation in its path.[208] More recently, in September 2005, eight hundred gallons of production brine from another tank in Pine City, New York, overflowed when it was not emptied on schedule, causing an impact on nearby streams.[209] In July 1996, crude oil tank bottoms were dumped into a pit and set on fire.[210] In March 2003, a property owner in Ithaca, New York, called to report that a driller was dumping mud on his property.[211] In May 2007, NYSDEC received an anonymous tip indicating that produced water from a natural gas well was being

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[204] Press Release, Pa. Dep't Envtl. Prot., DEP Fines Atlas $85,000 for Violations at 13 Well Sites, Jan. 7, 2010.
[205] Consent Assessment of Civil Penalty, *In re Atlas Resources LLC*, Pevarnik 8, ¶¶ Z–AD, Willis 18, ¶¶ AE–AI, Thompson 33 ¶¶ AP–AU.
[206] Laura Legere, *Massive Use of Water in Gas Drilling Presents Myriad Chances for Pollution*, SCRANTON TIMES-TRIBUNE, June 22, 2010.
[207] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 3 (2009) (Spill Number: 9707892).
[208] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 4 (2009) (Spill Number: 9707892).
[209] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 8 (2009) (Spill Number: 0507041).
[210] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 23 (2009) (Spill Number: 9604701).
[211] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 68 (2009) (Spill Number: 0212276).

dumped on the ground near Cayuga Creek in Sheldon, New York.[212] In May 2009, eight hundred gallons of produced water contaminated soils in Westfield, New York, after equipment failed and allowed the fluids to be released into the environment a mere 1200 yards away from nearby homes.[213]

The COGCC has also documented incidents where tanks have been improperly sealed[214] or allowed to overflow,[215] where corroded equipment allowed produced water to contaminate the ground,[216] and where equipment failure has allowed produced water to escape from underground injection wells.[217] Between June 2002 and June 2006, 555 produced water spills were reported to the COGCC.[218]

In Texas, between 2001 and 2006, thirty percent of spill complaints were inspected "either late or not at all."[219] Most recently in the Texas town of Flower Mound, the Texas RRC sent out a notification stating that approximately 3,000 gallons of "flowback water containing fracturing fluid and associated additives" spilled out of gas well pad site.[220] To date, the RRC has not publically released either the cause of the spill or the exact contents of the flowback water.[221]

The mayor of West Union, West Virginia, wrote a letter to the WVDEP in October 2009 to express his concern over WVDEP's failure to notify the town until two months after a spill occurred.[222] The mayor was even more concerned about WVDEP's failure to have any emergency notification system in place, stating that the continued failure to establish such a system "will only result in less time for the water system to react [to future spills] and [result in] a greater chance of catastrophe."[223] Elsewhere in West Virginia, Luanne McConnell Fatora reported a release of between fifty and seventy barrels of some type of oil and gas waste in a

[212] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 159 (2009) (Spill Number: 0750225).
[213] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 143 (2009) (Spill Number: 0902327).
[214] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1630697.
[215] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631155, 1631831, 1631794, 1632853.
[216] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630885, 1631496, 1631519, 1632057, 2605191, 1632995.
[217] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200226284, 200225725, 2605709.
[218] OIL & GAS ACCOUNTABILITY PROJECT, COLORADO OIL AND GAS INDUSTRY SPILLS: A REVIEW OF COGCC DATA (JUNE 2002-JUNE 2006) 1-2 (2006).
[219] Lustgarten, *supra* note 188.
[220] *Frac Fluid Spill Reported in Flower Mound*, CROSS TIMBERS GAZETTE, Mar. 17, 2010.
[221] *Id.*
[222] Letter from Robert F. Fetty, Mayor, Town of West Union, to Barbara Taylor, Director, WVBPH/Office of Environmental Health Services, Oct. 28, 2009.
[223] *Id.*

stream in Doddridge County.[224] Fatora's son discovered the spill when he tried to go fishing in the stream in late August 2009 and found the water to be "acrid" and covered with a "red/orange gel" that had an oily smell which got on his hands and did not "go away for some time despite repeated washing."[225] Although the Chief of the West Virginia Oil and Gas Office stated that the fluids were consistent with oil and gas waste, more than a month after the spill the WVDEP remained uncertain about what caused the release.[226]

These releases, and the undoubtedly numerous other unreported incidents, demonstrate that current regulations and regulatory enforcement is inadequate to prevent E&P wastes from being released into the environment.

3. Oil & Gas Production Has Increased Dramatically Since 1988.

When EPA released its 1988 Regulatory Determination, the domestic oil and natural gas industry was struggling. Since then, oil and natural gas production in the United States has increased dramatically. Tens of thousands of new oil wells have been drilled. According to the U.S. Energy Information Administration (US EIA), between 1989 and 2008 the number of producing gas wells nationwide almost doubled, increasing from roughly 262,000 to 479,000 wells.[227]

Bureau of Land Management (BLM) statistics also demonstrate the growth in oil and gas operations under its jurisdiction. In most years during the 1990s, there were less than four thousand applications for permits to drill (APDs) filed with the BLM.[228] BLM has stated that "[s]ince 1996, the number of new APDs has risen dramatically."[229] BLM received more than ten thousand APDs in 2006.[230] Although BLM projects that the number of APDs will decline by 2010,[231] BLM still expects to receive a staggering number, approximately 7,000, of APDs in 2010. Furthermore, BLM attributes this projected decrease to the fact that a larger percentage of proposed drilling is expected to occur on existing leases and not to a decrease in drilling.[232]

State agency statistics also demonstrate an increase in the amount of domestic drilling: one example is Texas, where the number of permits issued by the RRC for drilling in the Barnett

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[224] Ken Ward Jr., *What Caused Big Fracking Fluid Spill in Doddridge County?*, SUSTAINED OUTRAGE: A GAZETTE WATCHDOG BLOG (Oct. 2, 2009); *see also* Letter from Louanne McConnell Fatora to Gov. Manchin, West Highlands Conservancy (Aug. 30, 2009).
[225] Letter from Louanne McConnell Fatora to Gov. Manchin, (Aug. 30, 2009).
[226] Ward Jr., *supra* note 224.
[227] U.S. ENERGY INFO. ADMIN., NUMBER OF PRODUCING GAS WELLS (2009).
[228] BUREAU OF LAND MGT., BLM FY 2010 BUDGET JUSTIFICATIONS III-120 (2010).
[229] *Id.* at III-119.
[230] *Id.* at III-120.
[231] *Id.*
[232] *Id.* at III-122.

Shale increased from 273 in 2000 to 3,653 in 2007,[233] and 4,145 in 2008.[234] Industry-wide, API statistics confirm that these increases are not isolated incidents. The API reported that 2006 was a record year for gas drilling, in which more than 29,000 new wells were drilled.[235] The API expected that this trend would continue and it did: a new 21-year record was reached when 11,771 wells were drilled in the first-quarter of 2007.[236]

Along with this increase in drilling, there has been an associated increase in the amount of E&P waste produced. In Utah's Uintah County the amount of produced water generated from oil and gas operations increased from approximately 800,000 barrels per month in January 1999 to over 1,600,000 barrels per month in January 2007.[237] Even though some techniques have been implemented to reduce the amount of produced water generated from oil and gas extraction activities, EPA's Region 8 noted an overall two percent increase in the amount of produced water generated from 2002 to 2008.[238] The increases in both drilling and E&P waste that have occurred since 1988 indicate that the risks associated with E&P wastes have become even more substantial and that EPA must revisit its Regulatory Determination in light of these developments.

4. Regulation Under Subtitle C of RCRA Would Not Harm the Oil & Gas Industry.

In its 1988 Regulatory Determination, EPA placed significant weight on the potential harm that increased regulation of E&P waste could cause the oil and natural gas industry in making its determination not to regulate E&P wastes under Subtitle C of RCRA. EPA claimed that regulating E&P wastes under Subtitle C would be "extremely costly" for industry.[239] EPA also asserted that "[a]ny program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use."[240] While in 1988 EPA did not believe that the oil and gas industry would develop new waste management technologies, its belief has proved to be incorrect.

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[233] Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENVTL. L. REV. 115, 124 (2009) (citing Texas Railroad Commission, Newark, East (Barnett Shale), Drilling Permits Issued (1993–2007)).
[234] Texas Railroad Commission, Newark, East (Barnett Shale) Field, Drilling Permits Issued (1993–2009).
[235] Daniel Cusick, *Industry Sets Record for Drilling, Well Completions*, LAND LETTER, Jan. 18, 2007.
[236] Am. Petroleum Inst., "U.S. Q1 drilling & completion estimates at 21-year high—API," Apr. 26, 2007.
[237] DIV. OF OIL, GAS AND MINING, UTAH DEP'T OF NATURAL RES., PRODUCED WATER DISPOSAL, graph slide 6 (2007).
[238] EPA REGION 8, *supra* note 28, at fig. 3-9.
[239] 53 FED. REG. at 25446-01, 25456.
[240] *Id.* at 25,451. EPA's Report to Congress indicates that EPA did not truly believe this assertion that it made in the 1988 Regulatory Determination: "Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices." EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY III-2 (1987)

Evidence since 1988 demonstrates that new technologies and practices are available and that the use of these safer practices often results in significant cost savings. In 2008, EPA itself stated that "It has been 20 years since the RCRA exemption for oil and gas exploration and production was implemented, and many practices and chemicals used have changed during that time,"[241] and has noted that many safer drilling fluids have been developed[242] and the use of alternatives to pits has become increasingly practical.[243] In addition to the savings that can result from the use of these new disposal methods, companies using safer disposal practices also obtain cost benefits by preventing pollution in the first place, as opposed to being allowed to use "cheaper" practices and later required to clean up the damage they create.[244] The State of New Mexico found that drilling activity more than doubled in the year immediately following establishment of more protective rules for oil and gas waste pits.[245]

It is time for EPA to require oil and gas companies to use these new, safer technologies.

a. New Waste Disposal Technologies

Safer disposal methods for E&P wastes have been developed since 1988. Although EPA acknowledged that such developments were likely in its 1987 Report to Congress, it chose not to require the use of then-emerging safer technologies because it believed that requiring their use would be prohibitively expensive for the oil and gas industry. Recent cost analyses indicate that those fears were unfounded; in many instances, the use of more environmentally sound disposal practices actually saves oil and gas companies money. For example, a study conducted in New Mexico found that eliminating pits, traditionally considered the cheapest disposal method, is actually more cost-effective than their continued use.[246]

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241 EPA REGION 8, *supra* note 28, at 3–13.
242 EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 29 (2000).
243 EPA, REGION 8, OIL AND GAS ENVIRONMENTAL ASSESSMENT REPORT 1996–2002 13 (2003).
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> [W]e've had testimony through here that the costs of remediation are, you know, in the hundreds of thousands to, typically millions of dollars. And there's a huge cost benefit to business to prevent pollution versus us allowing them to pollute water and then come back and require them to clean it up. I think that's really a disservice to industry, not to help them prevent that from occurring.

Statement of Commissioner William Olson before the New Mexico Oil Conservation Division, Apr. 16, 2008, OCD Document Image 14015_657_CF[1] at 30.
245 Press Release, State of New Mexico, Governor Bill Richardson Announces Oil and Gas Drilling Activity in New Mexico Is Strong: Environmental regulations are not driving business away (May 19, 2010).
246 DORSEY ROGERS, GARY FOUT & WILLIAM A. PIPER, NEW INNOVATIVE PROCESS ALLOWS DRILLING WITHOUT PITS IN NEW MEXICO (2006).

An Oil and Gas Accountability Project (OGAP) analysis demonstrates that closed-loop drilling systems, which use storage tanks and other equipment instead of pits, are cost-effective and can save money compared to conventional waste management with pits.[247] Mary Ellen Denomy, an expert in petroleum accounting, testified before the New Mexico Oil Conservation Division and reported her findings that the costs associated with a typical closed loop drilling system, also known as a pitless drilling system, are only 3.58% of total drilling costs, a significant reduction from the costs associated with typical on-site pit burial (6.58% of total drilling costs) and digging up and hauling wastes to a centralized facility (9.38% of total drilling costs).[248] While initial costs may be higher, closed-loop drilling systems create long-term savings because there is no need to construct pits, drilling waste can be dramatically reduced, water use can be reduced by as much as eighty percent, truck traffic is reduced by as much as seventy-five percent, and tanks can be reused.[249] Comparisons have found closed-loop drilling can result in a cost savings of up to $180,000 per pit,[250] and a project in New Mexico found that:

> [T]he average cost of using a pit and hauling the waste elsewhere for disposal is about 45% more compared to following the same process without a reserve pit. Moreover, the analysis showed that burying the waste on-site costs about 24% more when using a reserve pit as opposed to employing the closed-loop system.[251]

Individual case studies provide further support for these conclusions. A survey of Prima Energy Corporation's closed-loop system in Colorado indicated that closed-loop drilling could be more cost effective than conventional rotary drilling with reserve pits.[252] Prima Energy Corporation drilled over 68 wells in Colorado using closed-loop systems and compared their costs to the costs of using conventional rotary drilling with reserve pits.[253] The closed-loop drilling systems' average cost was $15,600 compared to conventional rotary drilling's cost of $17,020.[254] The study further demonstrated that closed-loop drilling systems result in significant waste minimization. Conventional rotary drilling was found to generate 5,200 barrels more barrels of produced water than closed-loop drilling.[255]

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[247] Oil & Gas Accountability Project, Alternatives to Pits.
[248] Oil & Gas Accountability Project, Closing Argument and Proposed Changes to Proposed Rule 50, *Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, Dec. 10, 2007, at 10.
[249] Oil & Gas Accountability Project, *supra* note 247.
[250] *Id; see also* ROGERS ET AL., *supra* note 246, at 4–5.
[251] Dorsey Rogers, Dee Smith, Gary Fout & Will Marchbanks, *Closed-loop drilling system: A Viable Alternative to Reserve Waste Pits*, WORLD OIL, Dec. 2008, at 46.
[252] *See* Oil & Gas Accountability Project, *supra* note 247.
[253] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[254] *Id.*
[255] *Id.*

Similarly a study of two wells drilled two hundred feet apart in Matagorda County, Texas provides further support for assertions that closed-loop drilling systems can provide cost savings.[256] In Matagorda County, two wells were drilled two hundred feet apart "through the same formations, using the same rig crew, mud company and bit program."[257] One well used a closed-loop system while the other used traditional solids-control equipment. The closed-loop system "resulted in some significant savings" including: a forty-three percent savings in drilling fluid costs, twenty-three percent fewer rotating hours, fewer days to drill the wells to comparable depths, a thirty-seven percent reduction in bits used, and up to thirty-nine percent improvement in penetration rates.[258]

EPA's own studies confirm that closed-loop drilling systems are a safer and cost-saving waste disposal process.[259] Because of these types of findings, EPA has promoted the use of closed-loop drilling systems in Region 8.[260] The RRC of Texas has confirmed that closed-loop systems can result in significant cost savings;[261] and many other government agencies also support the use of closed-loop drilling systems.[262] In addition to the already demonstrated economic advantages of closed-loop systems, there is a great likelihood that the costs of constructing closed-loop systems will decrease even more in the future "as economies of scale and innovations in operations" continue to occur.[263] If these systems are manufactured in the United States, they add the benefit of new job creation in addition to lower environmental risk.

Although safer and economical, even closed loop systems can leak or spill. Strong regulations are required to govern the storage and transport of toxic waste. In some cases, waste may be transported via pipeline to storage or disposal sites. Yet in Texas, State officials declared at a public meeting that the state has no "rule-making authority" over such pipelines.[264]

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[256] *Id.*
[257] *Id.*
[258] *Id.*
[259] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 69 (2000).
[260] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 4-4 (Working Draft 2008).
[261] Abrahm Lustgarten, *Underused Drilling Practices Could Avoid Pollution*, PROPUBLICA, Dec. 14, 2009.
[262] U.S. Fish & Wildlife Serv., *Wildlife Mortality Risk in Oil Field Waste Pits*, U.S. FWS CONTAMINANTS INFORMATION BULLETIN (2000) (recommending the use of closed loop containment systems and elimination of open pits and ponds); BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT (4th ed. 2007). "To prevent contamination of ground water and soils . . . it is recommended that operators use a closed-loop drilling system or line reserve pits with an impermeable liner." *Id.* at 17.
[263] Controlled Recovery Inc.'s Written Closing Argument, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc*., Dec. 10, 2007, at 3.
[264] Lowell Brown, *Officials Give Few Answers to Argyle*, DENTON RECORD-CHRONICLE, Jan. 30, 2010.

b. Waste Minimization, Reuse, and Recycling Techniques

Waste minimization, reuse and recycling techniques also can be economical for companies. According to the RRC of Texas, "[w]aste minimization has been proven to be an effective and beneficial operating procedure," while recycling "is becoming a big business and more recycling options are available every day." [265] Both serve to reduce the total amount of E&P wastes that must be disposed and thereby decrease the risks associated with E&P wastes. In its manual *Waste Minimization in the Oilfield*, the RRC of Texas offers oil and gas companies more than one hundred ways to minimize wastes.[266] This manual, along with reports from individual companies implementing various waste minimization and recycling techniques, demonstrates that improved practices are possible.

Studies by the E&P Forum attest to the benefits of waste recycling[267] and identify several ways industry can reduce waste, "through process and procedure modifications . . . [For example,] improved solids control equipment and new technology can reduce the volumes [of drilling fluids] discharged to the environment, . . . more effective drillbits can reduce the need for chemical additions, [and] gravel packs and screens may reduce the volume of formation solids/sludge produced."[268] An analysis by OGAP found that the use of closed-loop drilling systems, in addition to providing cost benefits, maximizes the ability to reuse and recycle drilling fluids.[269] And waste reduction is not just beneficial from an environmental perspective. It can provide further opportunities for the oil and gas industry to save money. A study on land owned by the U.S. Army Corps of Engineers in Oklahoma found that a reduction in "wastes by close to 1.5 million pounds" resulted in "[a] material and disposal cost savings of $12,700."[270]

Both the government and industry are aware of the cost saving opportunities associated with the use of waste minimizing technologies and recycling and reuse projects. For example, STW Resources has developed a technology for use in the Barnett Shale that can reclaim approximately seventy percent of the flowback water produced by hydraulic fracturing operations in the region and thereby reduce the total amount of waste associated with hydraulic fracturing while also enabling the wastes to be reused.[271] And in July of 2008, the RRC of Texas approved Devon Energy's "third pilot program to treat and reuse frac fluid . . . . As a result of its water recycling efforts, Devon is the industry leader in water recycling and now used recycled

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[265] Railroad Commission of Texas, *supra* note 52.
[266] DRILLING DOWN, *supra* note 20, at 29.
[267] E&P FORUM, *supra* note 107, at14 ("There are potential benefits in the sale of recovered hydrocarbons. All hydrocarbon wastes should be returned to the production stream where possible.").
[268] UNEP E&P FORUM, ENVIRONMENTAL MANAGEMENT IN OIL AND GAS EXPLORATION AND PRODUCTION: AN OVERVIEW OF ISSUES AND MANAGEMENT APPROACHES 54 (1997).
[269] Oil & Gas Accountability Project, *supra* note 247.
[270] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[271] STW RES., INC., CONTAMINATED WASTE WATER RECLAMATION OPPORTUNITIES 2–3.

frac water at one out of every 10 frac jobs in its Barnett Shale operations."[272] Devon's wastewater recycling program "is projected to produce 75 percent reusable fracture fluid and 25 percent high concentrate and solids. The concentrate will be used as a drilling fluid or disposed of in an authorized facility."[273] Devon Energy Production Central Division's vice president estimated that "[a]t full treatment capacity, up to 85 percent of [the] water [Devon] recover[s] from fracture completions in the Barnett Shale could be reused." [274] And Devon Energy is not alone: Fountain Quail Water Management, DTE Gas Resources Inc., Burlington Resources, and Stroud Energy have all engaged in reuse and recycling efforts.[275]

New projects are underway at the national level: the U.S. Department of Energy's National Energy Technology Laboratory launched nine new projects in October 2009 focused on developing new technologies "to improve management of water resources, water usage, and water disposal."[276] These projects add to the fifteen already underway that are focused on "assess[ing] options and technologies for handling, cleaning, and reuse of produced and flowback water" in the Barnett and Appalachian shale plays.[277] When combined with pitless drilling through a closed-loop system, recycling of waste is clearly an effective, available, and economical way to manage E&P waste more safely and allow for compliance with stronger regulations.

c. New Substitutes for Toxic Materials

Studies indicate that the use of less toxic drilling and hydraulic fracturing fluids can both reduce the risks associated with E&P wastes and also reduce oil and gas companies' liability, thus potentially saving them money in the long run.[278] Other agencies confirm EPA's findings on the benefits of using safer cost effective alternatives. Numerous agencies encourage operators "to substitute less toxic, yet equally effective products for conventional drilling products."[279] And most recently, ExxonMobil announced that it "'supports the disclosure of the identity of the ingredients being used in fracturing fluids.'"[280] OGAP sees ExxonMobil's statement as a "significant step" and believes that "[o]nce the chemicals are widely known . . . companies will

[272] News Release, Railroad Commission of Texas, Commissioners Approve of Devon Water Recycling Project for the Barnett Shale, July 29, 2008.
[273] *Id.*
[274] *Energy Companies Strive to Reuse Water*, WEATHERFORD TELEGRAM, July 25, 2007, at 3C.
[275] *Id.*
[276] U.S. Dep't of Energy, National Energy Technology Lab, *Nine New Projects*, OIL & GAS PROGRAM NEWSLETTER (Dep't), Winter 2009, at 8.
[277] *Id.* at 6.
[278] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006 (2000).
[279] BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT, at 39 (4th ed. 2007).
[280] Katie Burford, *ExxonMobil Favors Fracing Disclosure, Environmental Group Welcomes Position from Oil Industry Giant*, DURANGO HERALD, Apr. 19, 2010.

be more likely to use green alternatives" which will result in "a lessening of the toxicity of the fluids" over time.[281]

In addition, the search for chemicals with lower potential environmental impacts has "result[ed] in the generation of less toxic wastes . . . . [For] example . . . mud and additives that do not contain significant levels of biologically available heavy metals or toxic compounds."[282] These types of new synthetic drilling fluids already have been developed and are less toxic, "free of polynuclear aromatic hydrocarbons and have . . . faster biodegradability and lower bioaccumulation potential."[283] Safer alternatives to current drilling fluids are available—all that remains is for the oil and gas industry to adopt widespread use of them.

Industry has already proven itself to be capable of switching to less hazardous compounds in the past. In the 1990s many drilling companies voluntarily phased out the use of benzene in their operations.[284] EnCana stopped using a chemical, 2-Butoxyethanol, linked with reproductive problems in animals, while BJ Services, "one of the largest fracturing service providers in the world, has discontinued the use of fluorocarbons, a family of compounds that are persistent environmental pollutants."[285] Schlumberger has developed "GreenSlurry," which the company claims is "earth-friendly."[286] Antero Resources Corporation pledged to use only "green frac" materials in the communities of Rifle, Silt and New Castle in western Colorado.[287] Yet these reported less toxic fluids are not used everywhere. While the oil and gas industry clearly has the capability to adapt its operations to safer technologies, most companies have been reluctant to make such changes. EPA should thus act and require the oil and gas industry to expand the use of the safer, less toxic drilling fluids that are currently available.

5. Oil and Gas Waste Meets the Statutory and Regulatory Criteria for Hazardous Waste.

Absent their special exclusion from RCRA, E&P wastes would properly be regulated under Subtitle C of RCRA. Congress defined hazardous wastes under RCRA as:

> [A] solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical or infectious characteristic may—

281 *Id.*
282 E&P FORUM, *supra* note 107, at12-23.
283 Drilling Waste Management Information System, Drilling Waste Management Fact Sheet: Using Muds and Additives with Lower Environmental Impacts.
284 Susan Riha et al., *supra* note 42, at 6.
285 Lustgarten, *supra* note 261.
286 Schlumberger, "Earth-friendly GreenSlurry system for uniform marine performance," March, 2003.
287 The Rifle, Silt, New Castle Community Development Plan, Jan. 1, 2006.

> (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
> (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.[288]

Under RCRA, Congress instructed EPA to "define hazardous waste using two different mechanisms: by listing certain specific solid wastes as hazardous . . . and by identifying characteristics . . . which, when exhibited by a solid waste, make it hazardous."[289] Under RCRA, "[c]haracteristic wastes are wastes that exhibit measurable properties which indicate that a waste poses enough of a threat to warrant regulation as a hazardous waste."[290] The four technical criteria EPA uses to determine if a waste is a characteristic waste include:[291] ignitability, corrosivity, reactivity, and toxicity.[292] Waste will be considered hazardous if it exhibits *any* of the four characteristics.[293] Because various types of E&P wastes exhibit several of these characteristics, E&P wastes should properly be regulated under Subtitle C of RCRA as characteristic hazardous wastes.

a. <u>Ignitability</u>

Ignitability is a criterion used to identify wastes that "can readily catch fire and sustain combustion."[294] A substance's flashpoint is indicative of its ignitability.[295] A waste's flash point is "the lowest temperature at which the fumes above a waste will ignite when exposed to flame."[296] Eleven percent of oily sludges sampled in California had a flash point exceeding the regulatory threshold.[297]

The risks associated with E&P wastes having hazardous flashpoints under RCRA's criteria have been demonstrated in the past decade. In January 2003, a fire occurred when hydrocarbon vapor from basic sediment and water, a type of E&P waste, ignited at a Texas open area collection pit.[298] Three people were killed in the fire and four others were severely burned.[299] In

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[288] 42 U.S.C. § 6903(5).
[289] EPA, RCRA ORIENTATION MANUAL, CHAPTER III: RCRA SUBTITLE C—MANAGING HAZARDOUS WASTE, at III-17.
[290] *Id.* at III-22.
[291] Hazardous Waste Treatment Council v. U.S. EPA, 861 F.2d 277, 279 (D.C. Cir. 1988).
[292] *See* 40 CFR § 261.20 et seq.
[293] *Id.*
[294] EPA, *supra* note 2899, at III-22.
[295] NAGY, *supra* note 24, at 36.
[296] EPA, *supra* note 2899, at III-23.
[297] NAGY, *supra* note 24, at 31.
[298] U.S. Dep't. of Labor, Occupational Safety & Health Admin., Potential Flammability Hazard Associated with Bulk Transportation of Oilfield Exploration and Production (E&P) Waste Liquids, SHIB-03-24-2008.
[299] *Id.*

May 2006, a natural gas condensate tank and pit caught on fire in Colorado.[300] Nearby residents were described as "'terrified' by the 200-foot flames."[301] Residents were also concerned because they were not able to learn what potential health impacts they were exposed to from the burning waste "since neither the company nor local or state authorities bothered taking air quality samples during the blaze."[302]

More recently, a wastewater impoundment pond in Washington County, Pennsylvania caught fire.[303] George Zimmerman reported seeing "flames shooting 100 feet in the air" at the fire that occurred at the hydraulic fracturing site located on his property.[304] A state police fire marshal determined that the fire was an accident caused by "a malfunction [that] ignited fumes [most likely in the frac tank] and caused $375,000 in damages."[305] The fire also "badly damaged" the frac pit liner, causing a spokeswoman from the Pennsylvania DEP to be concerned that the pit's contents might escape.[306] Instances such as these fires and the sampling data from California indicate that E&P wastes are ignitable, and that this characteristic of E&P wastes has resulted in serious harm. E&P wastes with these flash points would appropriately be regulated as characteristic hazardous wastes under Subtitle C of RCRA. Such regulation is necessary to prevent future incidents similar to the January 2003 and March 2010 fires.

b. Corrosivity

Waste is corrosive if "it is acqueous and has a pH less than or equal to 2 or greater than or equal to 12.5" or if "[i]t is a liquid and corrodes steel . . . at a rate greater than 6.35 mm per year."[307] Drilling wastes sampled in California had elevated pH levels approaching the 12.5 regulatory limit.[308] In addition, corrosive chemicals are frequently found in E&P wastes. For example, hydrogen sulfide is a corrosive and "toxic gas occurring naturally in some oil and gas reservoirs."[309] The corrosive characteristics of E&P wastes have already been responsible for many incidents where E&P wastes have been improperly released. On numerous occasions, spills of E&P wastes have been reported as originating from corroded equipment that had begun to leak because of corrosion attributed to the substances the equipment contained.[310] Again, because a waste is properly regulated under Subtitle C of RCRA when it exhibits *any* of the four

[300] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[301] *Id.*
[302] *Id.*
[303] Janice Crompton, *Residents Reported Gas Odors Before Explosion*, PITTSBURGH POST-GAZETTE, Apr. 1, 2010, at B-1.
[304] Kathie O. Warco, *Fumes Ignite at Gas Well*, OBSERVER-REPORTER, Apr. 1, 2010.
[305] *Id.*
[306] *Id.*
[307] 40 CFR § 261.22.
[308] NAGY, *supra* note 24, at 37.
[309] E&P FORUM, *supra* note 107, at28.
[310] *See supra* note 216 and accompanying text.

criteria of characteristic hazardous wastes, corrosive E&P wastes should be regulated under Subtitle C.

c. Reactivity

A waste is reactive if "(1) it is normally unstable and readily undergoes violent change without detonating, (2) [i]t reacts violently with water, (3) [i]t forms potentially explosive mixtures with water, (4) [w]hen mixed with water, it generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (5) [i]t is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5, can generate toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (6) [i]t is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement, (7) [i]t is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure, [or] (8) [i]t is a forbidden explosive . . . ."[311]

Out of the four criteria for determining characteristic hazardous wastes, reactivity is the most difficult to test: "In many cases, there is no reliable test method to evaluate a waste's potential to explode, react violently, or release toxic gas under common waste handling conditions."[312] In some cases, a waste's reactivity can be evaluated by a releasable sulfide test.[313] Although no regulatory threshold valuable for releasable sulfides has been established, EPA established an interim guidance value.[314] Testing of E&P wastes in California found samples of sludge and tank bottoms exceeding EPA's interim guidance value.[315]

d. Toxicity

The Code of Federal Regulations describes the specific levels/concentrations at which various chemicals will be considered toxic for the purposes of RCRA. To determine whether a chemical meets the required level, EPA uses the Toxicity Characteristic Leaching Procedure (TCLP). Many E&P wastes would be considered toxic under this test. The New Mexico Oil Conservation Division (OCD) found that several samples taken from E&P waste disposal pits in the state contained levels of chemicals that failed the TCLP test.[316] Specifically, the OCD found pits that contained levels of arsenic, lead, mercury, 2,4-Dinitrotoluene, and 2-Methylnaphthalene that exceeded TCLP levels.[317] Its report indicated that the levels of lead they found alone would have allowed the wastes to be considered characteristically hazardous if not for the RCRA

[311] 40 CFR § 261.23.
[312] EPA, *supra* note 2899, at III-23.
[313] NAGY, *supra* note 24, at 38.
[314] *Id.*
[315] *Id.* at 38–39.
[316] *See* Earthworks, OCD's 2007 Pit Sampling Program: What Is in that Pit?, at 31.
[317] *Id.* at 34.

exemption.[318] Analysis of E&P waste in California determined that both produced water and oily sludge met the federal toxicity characteristic and would be considered hazardous, again, if not for the RCRA exemption.[319] Because of this evidence, and the multitude of evidence discussed above indicating that E&P wastes have caused, and present substantial risk of continuing to cause, hazards to human health and the environment, EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA, as would be proper given the fact that they frequently exhibit the same traits as characteristic hazardous wastes.

II. REQUEST FOR PROMULGATION OF REGULATIONS

The Petitioner, the Natural Resources Defense Council, respectfully requests that the EPA promulgate regulations classifying wastes from the exploration, development and production of oil and natural gas as hazardous waste subject to provisions of Subtitle C of RCRA. This request is based on overwhelming evidence that waste from the exploration, development and production of oil and natural gas is hazardous, taking into account its toxicity, corrosivity, and ignitability, that it is released into the environment where it can cause harm, that state regulations are inadequate, and that there are numerous methods available to manage it as hazardous waste. As set forth in this Petition, evidence exists for EPA to document that, because of its quantity, concentration, and chemical characteristics, E&P waste may cause or significantly contribute to an increase in mortality and serious incapacitating illness and that it may pose a substantial present or potential hazard to wildlife and the environment when improperly treated, transported or disposed of, or otherwise managed, as is occurring throughout the U.S. in the absence of sufficient mandatory federal oversight. *See* 42 U.S.C. § 6902(4)-(5).

The Petitioner requests that the EPA consider the relevant statutory and regulatory factors, as well as the factors set forth in the July 1988 Regulatory Determination, and promulgate regulations applying to wastes from the exploration, development and production of oil and natural gas under Subtitle C of RCRA.

Respectfully submitted this 8th day of September, 2010.

[318] *Id.* at 35.
[319] NAGY, *supra* note 24, at 40.

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Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists

January 6, 2012

A tower for removing gas at the Marcellus Shale Formation in Pennsylvania. Credit: Ruhrfisch/Wikimedia Commons.

Earthquakes that have shaken an area just outside Youngstown, Ohio in the last nine months—including a substantial one on New Year's Eve—are likely linked to a disposal well for injecting wastewater used in the hydraulic fracturing process, say seismologists at Columbia University's **Lamont-Doherty Earth Observatory** who were called in to study the quakes. Ohio Gov. John Kasich has shut down the injection well and put four other proposed wells on hold. In the meantime, steps have been taken to ease pressure in the well to avert further rumblings.

The concern comes as natural gas drilling in shale formations that underlie much of the Northeast grows. To extract the gas, a mix of water, sand and chemicals is pumped under high pressure into shale rocks, in a process called hydraulic fracturing, or fracking. Once the gas has been removed, wastewater is either recycled or trucked off-site and injected deep underground. As the pressurized water seeps through cracks deep below ground, it can sometimes cause earthquakes on ancient fault lines.

Ohio is home to 177 such disposal wells, including the Youngstown well, which lies in a seismically dormant region bordering Pennsylvania. The first rumblings surfaced in March, several months after injection of fracking waste from Pennsylvania began. Nine small temblors followed. In late November, Ohio authorities asked Lamont scientists to monitor the area with mobile instruments that could provide a more accurate location of subsequent earthquakes. On Dec. 24, the four instruments recorded a magnitude 2.7 quake 2.2 miles below the surface–a half-mile away and about 2,000 feet below the 1.7 mile deep well.

"The location of the earthquake was sufficient evidence that there could be a link," Lamont seismologist **John Armbruster** told **NPR's All Things Considered**. Later in the week, D&L Energy, which owns the site, agreed to shut down the well. Then, on Dec. 31, a magnitude 4.0 quake struck. The Lamont instruments located it at about 300 feet east, and some 500 feet under the previous event. A 4.0 is about 40 times more powerful than a 2.7. At that point, the state put a moratorium on activity on four other wells within a five-mile radius, all of them already inactive.

Hydrofracking by its nature causes tiny earthquakes, because it involves fracturing of rock—but these are largely imperceptible, as the process takes place in relatively weak, shallow shales that crack before building up much strain. Quakes triggered by waste injection wells can be potentially more powerful because more fluid is usually being pumped underground at a site for longer periods, said **Roger Anderson**, an energy geophysicist at Lamont-Doherty who is not involved in the study. Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake. The Lamont data suggests that the Dec. 31 movement near the Ohio well was a strike-slip motion, in which one rock face slides across the other horizontally.

The chance of triggering an ancient fault by injecting fluid underground is relatively slim—maybe one in 200, said Lamont seismologist **Won-Young Kim**, who heads the **Lamont-Doherty Cooperative Seismic Network**. But, he said, the potential damage and injuries from an earthquake could far outweigh the cost of closing the well. "Once you get one earthquake, it's better to stop then, because you may get another," he said. That point was echoed by Armbruster on NPR: "I would advocate monitoring of wells to know when triggering of earthquakes first begins," he said. "Then you can decide whether to continue using that well."

Seismologists have known about the potential for injection wells to trigger earthquakes since the 1960s, when injected wastewater from weapons production at the Rocky Mountain Arsenal in Colorado was tied to a **series of earthquakes** including several of magnitude 5.0 or greater that caused minor damage in Denver and other cities. Earthquakes in Arkansas, Texas, Oklahoma and the United Kingdom have been linked in recent years to disposal of fracking fluids. In 2001, scientists linked a magnitude 4.2 quake in Ashtabula, Ohio to a waste disposal well there, a "carbon copy" of the recent activity near Youngstown, said Kim.

After the New Year's quake, Kim said that the risk could continue for another year or two, as it could take that long for pressurized fluid to dissipate. To minimize that risk, Ohio officials announced Jan. 5 that they would start letting the injected fluids bubble back into storage tanks at the surface rather than capping the well under standard procedures.
The Lamont-Doherty scientists will continue to monitor the area with colleagues from Youngstown State University and Ohio Geological Survey. They are also talking with the university about upgrading its own seismic station.

More:
Watch how injected fluids trigger an earthquake in **this video** from Next media Animation.
For ongoing coverage of the scientific debate over hydrofracking see Scientific American's **Storify blog.**

Related Projects:

Lamont Cooperative Seismographic Network (LCSN)

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THE WALL STREET JOURNAL.
WSJ.com

BUSINESS | November 3, 2011

Study Ties Fracking to Quakes in England

By ALEXIS FLYNN

LONDON—The company leading efforts to unlock the U.K.'s potentially vast shale-gas reserves suffered a setback Wednesday after a report found it was "highly probable" a controversial production technique caused two small earthquake tremors in the country earlier this year.

The report, which was financed by U.K. energy company Cuadrilla Resources Ltd., pointed to "strong evidence" that the two minor earthquakes and 48 weaker seismic events resulted from Cuadrilla's pumping drilling fluids used in hydraulic fracturing, or "fracking." At the same time, the report said the events were the result of a "rare combination of geological factors."

Bloomberg News

Cuadrilla Resouces' shale gas exploration site, in July.

The report could complicate efforts by privately held Cuadrilla to resume hydraulic-fracturing activity that was halted after the two seismic incidents.

The company said the report concluded that none of the events recorded, including one in April of 2.3 and one in May of 1.5 on the Richter scale, had any structural impact on the surface above.

The U.K. has become the latest venue in Europe to see shale gas spur major debate over fracking, which has been heavily criticized by environmental groups. In June, France became the first country to ban shale-gas exploration.

More

Cuadrilla statement

Earlier: U.K. Gets Big Shale Find

EXPERIENCE WSJ PROFESSIONAL

Editors' Deep Dive: Shale Rush Hits Hurdles

PLATTS COMMODITY NEWS
US Interior To Issue Frack Fluid Disclosure Rule

ENERGY WASHINGTON WEEK
Gas Industry Criticizes EPA Fracking Well Air Rules

The Staffordshire, England-based company said the report vindicated its stance that its operations pose "no threat to people or property in the local area," but it pledged to implement an early-warning system and other recommendations to mitigate the risk.

Cuadrilla in September announced a big shale-gas discovery, but development is on hold after the company and government agreed in June to stop its shale-gas test drilling until its potential consequences were better understood.

U.K. regulators said they would review the findings before shifting policy. Leading environmental groups and local-government officials also called for caution on fracking, which has been a key component in the rise of shale gas in the U.S. and other areas.

The U.K. Department of Energy and Climate Change will study the implications of the report, a department spokesman said. "The implications of this report will be reviewed very carefully—in consultation with the British Geological Survey, independent experts, and the other key regulators," said the spokesman.

The report found that the combination of geological factors that caused the quakes was rare and would be unlikely to occur together again at future well sites.

"If these factors were to combine again in the future, local geology limits seismic events to around magnitude 3 on the Richter scale as a worst-case scenario," the report said.

The Richter scale measures magnitude, which is expressed in whole numbers and decimal fractions, and not damage caused. Each whole number represents a tenfold increase in measured amplitude, so a 5.3 tremor might be rated moderate, while a strong earthquake could be recorded at 6.3.

Cuadrilla said the report was overseen by an independent team of seismic experts and was prepared in consultation with the Department of Energy and Climate Change. A department spokesman said the report was commissioned by the company and that it would comment on the substance of the conclusions after it studied the report's findings.

An earlier study by the British Geological Survey put the epicenter for each earthquake as being 500 meters (1,650 feet) away from the Preese Hall-1 well, at Weeton, near Blackpool, England.

British Geological Survey Earthquake Seismologist Dr. Brian Baptie said Wednesday's report confirmed his organization's own initial conclusion that fracking was responsible for the earthquakes. "It seems quite possible, given the same injection scheme in the same well, that there could be further earthquakes," he said.

Dr. Baptie said a way to minimize future risks could include the type of traffic-light monitoring system proposed by Cuadrilla but pointed out that even an "acceptable magnitude 2.6 earthquake might, at a depth of three kilometers (1.9 miles), result in an intensity of shaking that would not be expected to cause any damage but would be widely felt by people indoors and out, and may displace objects on shelves."

Spotting these types of seismic events could also be tricky, explained Dr. Baptie. "Earthquakes such as this result from very small movements on small faults that may be very difficult to identify," he said.

Nick Molho, head of energy policy at environmental group WWF-UK, said the findings "are worrying, and are likely to add to the very real concerns that people have about fracking and shale gas."

Local Liberal Democrat Councillor Sue McGuire, who also leads a residents' group opposed to fracking, said that if Cuadrilla drilled the 400 to 800 wells proposed than "we cou ld be looking at significant seismic activity in the area, which could have major impact on peoples' homes and businesses in the area, not to mention the impact on the environment."

"A moratorium would give the government time to ensure that industry specific legislation can be put in place," she said.

Cuadrilla has said some 200 trillion cubic feet of shale gas may be contained in northwest England,enough to meet the country's gas demand for 64 years, although it has cautioned the actual recoverable figure may be much lower.

—Guy Chazan contributed to this article.

Write to Alexis Flynn at alexis.flynn@dowjones.com

Corrections & Amplifications
An earlier version of this story erroneously referred to a Cuadrilla estimate of 200 million feet of gas in northwest England; the estimate is for 200 trillion cubic feet of gas.

FINAL

RULE H-1 - CLASS II DISPOSAL AND CLASS II COMMERCIAL DISPOSAL WELL PERMIT APPLICATION PROCEDURES

a) Definitions:

1) "Class II Disposal Well"-- means:

A) A permitted Class II well in which Class II Fluids are injected into zones not productive of oil and gas, and brine used to produce bromine, within the field boundary established by an order of the Commission for the production of liquid hydrocarbons or brine used to produce bromine, where the well is located or will be located, for the purpose of disposal of those fluids; or

B) A permitted Class II well in which Class II Fluids are injected into a zone or zones~~,~~ which are not commercially productive of dry gas, within the same common source of supply, where the well is located or will be located, for the purpose of disposal of those fluids.

2) “Class II Commercial Disposal Well"-- means a permitted Class II well in which Class II Fluids are injected, for which the Permit Holder receives deliveries of Class II Fluids by tank truck from multiple oil and gas well operators, and either charges a fee at the disposal well facility or purchases the Class II Fluids at the source for subsequent transport to the disposal well facility for the specific purpose of disposal of the delivered Class II Fluids.

3) "Class II Fluids" means:

A) Produced water and/or other fluids brought to the surface in connection with drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells;~~,~~ Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations; or

B) Produced water and/or other fluids from (A) above, which prior to re-injection have been used on site for purposes integrally associated to oil and natural gas well drilling, completion, or fracture treatments, workover or recompletion and plugging of oil and natural gas wells; Class II or wells that are required to be permitted as water supply wells by the Commission; enhanced recovery operations; or natural gas storage operations, or chemically treated or altered to the extent necessary to make them usable for purposes integrally related to oil and natural gas well drilling, completion, workover and plugging, oil and gas production, enhanced recovery operations, or natural gas storage operations, or commingled with fluid wastes resulting from fluid treatments outlined above, and including any other exempted oil and gas related fluids under the Resource Conservation and Recovery Act, provided the commingled fluid wastes do not constitute a hazardous waste under the Resource Conservation and Recovery Act; or

C) Waste fluids from gas plants (including filter backwash, precipitated sludge, iron sponge, hydrogen sulfide and scrubber liquid) which are an integral part of oil and gas production operations; and waste fluids from gas dehydration plants (including glycol-based compounds and filter backwash), unless the gas plant or gas dehydration plant wastes are classified as hazardous under the federal Resource Conservation and Recovery Act.

4) "Confining layer" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone. It is composed of rock layers that are impermeable or distinctly less permeable than the injection zone beneath it. There may be multiple confining layers above an injection zone.

5) "Permit Holder" means the entity or person to whom the permit is issued and who is responsible for all regulatory requirements relative to the Class II Disposal or Class II Commercial Disposal Well.

6) "USDW" means Underground Source of Drinking Water which is defined in Title 40, Code of Federal Regulations (40 CFR) Section 144.3, as an aquifer or its portion which:

A) Supplies any public water system (see 40 CFR); or

B) Contains a sufficient quantity of groundwater to supply a public water system (see 40 CFR) and currently supplies drinking water for human consumption; or

C) Contains fewer than 10,000 mg/l total dissolved solids (see 40 CFR); and

D) Which is not an exempted aquifer (see 40 CFR)

b) No person shall drill, deepen, re-enter, recomplete or operate any well for use as a Class II Disposal or Class II Commercial Disposal Well or inject into any well, without the applicable permits from the Commission, application for which shall be made on forms prescribed by the Director. Permits are valid only for the Permit Holder stated on the permit, and shall remain valid only with ongoing compliance with established operating requirements specified in General Rule H-2 or H-3, except that permits to drill, deepen, or re-enter shall automatically expire six (6) months from the date of issuance, unless commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit has occurred, which are to be continued with due diligence, but not to exceed one (1) year from the date of commencement of the drilling, deepening or re-entry of plugged well operations authorized by the permit, at which time the well shall be plugged, injection casing set, or a new permit application, along with a new permit fee and plat, must be filed. Failure to comply with the operating requirements in General Rule H-2 or H-3 may result in revocation of the Class II Disposal Well or Class II Commercial Disposal Well permit in accordance with subparagraph q) below.

1) Authority to conduct an injectivity test, step rate test or trial injection test prior to, or after the issuance of a permit may be approved as follows:

A) An injectivity test, step rate test or trial injection test of less than twelve (12) hours duration may be approved by the Director upon review of the well construction to determine well mechanical integrity for the protection of the USDW's and oil and gas resources during the test. The Director shall establish the protective parameters of the test, require the submittal of any information or test data deemed necessary and may require the witnessing by Commission staff of the test.

B) An Applicant may request approval from the Commission, by filing an application in accordance with General A-2 and A-3 and other applicable hearing procedures, of an injectivity test, step rate test or trial injection test of twelve (12) hours or more in duration.

2) No Class II Disposal or Class II Commercial Disposal Well may be drilled at a surface location other than that specified on the permit, except that if a permit holder has commenced drilling operations and the Class II Disposal or Class II Commercial Disposal Well is lost due to adverse drilling conditions prior to surface casing being set, the permit holder may request an amendment of the permit without a fee for the new location, provided the Class II Disposal or Class II Commercial Disposal Well remains on the same surface owners property where the Class II Disposal or Class II Commercial Disposal Well was originally permitted and all other aspects of the permit request remain the same. Movement of the Class II Disposal or Class II Commercial Disposal Well location off the original surface owners' property, or after surface casing has been set, will require the filing of a new permit application, along with a new permit fee and plat. Drilling may not commence prior to the issuance of a new permit.

3) Permits to recomplete or operate shall automatically expire one year from the date of issuance, unless commencement of the operations authorized by the permit has occurred, or a new permit application, along with a new permit fee has been filed.

4) Upon issuance of a permit, a copy of the permit shall be displayed at the site where the Class II Disposal or Class II Commercial Disposal Well is being drilled for review by Commission staff.

5) Permits to drill, deepen, or re-enter a Class II Disposal or Class II Commercial Disposal Well may only be issued if the location complies with General Rule B-3.

c) The application to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well shall include at a minimum:

1) The information required by subparagraph (h) below, for the existing or proposed well and any additional information deemed necessary by the Director for the protection of USDWs; and

2) Accompanied by a permit fee in the amount of $300.00 if the Class II Disposal or Class II Commercial Disposal Well is drilled, deepened, or re-entered; and

3) Accompanied by a non-refundable fee of $100.00 for a Class II Disposal Well or $500.00 for a Class II Commercial Disposal Well to recomplete or operate the Class II Disposal or Class II Commercial Disposal Well; and

4) Accompanied by the required financial assurance in accordance with General Rule B-2; and

5) Accompanied by a Form 1 Organizational Report in accordance with General Rule B-13; and

6 Be executed under penalties of perjury; and

7) If the applicant is a corporation, limited liability company, limited liability partnership or other business entity, it must be incorporated, organized, or authorized to do business in the State of Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

8) If the applicant is an individual, partnership, or other entity that is not a resident of Arkansas, the applicant must be authorized to do business in Arkansas, and by filing an application, the applicant irrevocably waives, to the fullest extent permitted by law, any objection to a hearing before the Commission or in a court of competent jurisdiction in Arkansas; and

9) Proof that the Class II Disposal or Class II Commercial Well location complies with General Rule B-3.

d) No person shall inject into USDWs or be issued a permit to inject into USDWs unless an aquifer exemption has been granted in accordance with US Environmental Protection Agency procedures.

e) Unless otherwise approved by the Commission, no person shall inject into a well which does not have at a minimum, five hundred (500) feet for a Class II Disposal Well or seven hundred-fifty (750) feet for a Class II Commercial Disposal Well, of confining layers between the base of the lowermost USDWs and the top of the injection interval, with no individual confining layer being less than 50 feet in thickness. A lesser amount of confining layer(s) may be approved, provided the Applicant provides substantial information as to the integrity of the confining layers to inhibit the upward migration of the injection fluids so as not to endanger the lowermost USDW in the area of the well.

f) If the application does not contain all of the required information or documents, the Director shall notify the Applicant in writing. The notification shall specify the additional information or documents necessary for an evaluation of the application and shall advise the Applicant that the application will be deemed denied unless the information or documents are submitted within sixty (60) days following the date of notification.

g) Applications for a Class II Disposal Well shall contain the names of all permit holders who are to utilize the proposed disposal well.

h) Contents of Application

1) A specification as to the type of Class II well being permitted as a Class II Disposal Well or a Class II Commercial Disposal Well.

2) The Applicant shall provide the name, address, phone, fax and e-mail (if available) of the local or on-site supervisory or field personnel responsible for the disposal well.

3) If the well is not located within the boundaries of an operating oil and gas leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement or an affidavit of a surface use agreement, indicating the Applicant’s right to drill and to operate the proposed disposal well. If the well is located within the boundaries of an operating oil and gas leasehold or drilling unit, and the Applicant is someone other than the operator of the leasehold or drilling unit, the Applicant shall provide documentation, in the form of a surface use agreement, or an affidavit of a surface use agreement, indicating the Applicant's right to drill and to operate the proposed disposal well.

4) A survey plat of the location and ground elevation of the proposed disposal well or if the application is for an existing well, the well name and permit number of the existing well. A new survey is not required for a well to be converted or deepened well or a plugged well to be re-entered, if the original well location was surveyed, a copy of which shall be submitted with the application.

5) The name, geologic description and the approximate top and bottom elevation, from sub-sea, of the formation (indicating the perforated or open hole interval) into which fluid will be injected and the geologic description and top and bottom elevation, from sub-sea, of the above confining layers, in the proposed or existing disposal well. If an existing well is to be converted, a geophysical log of the well shall be submitted showing the above information. For a proposed well, an induction log from a well in the immediate vicinity of the proposed disposal well shall be submitted. If the geologic name of the interval is unclear include any additional geological evidence such as a cross section, structure or isopach map that may be necessary to adequately define the proposed injection interval.

6) A well bore diagram of the proposed or existing well showing casing for the injection well, indicating from the well head to total depth of the well, all casings and cementing of casings, any obstructions within well, all plugs set, tubing and packer setting depth, and all perforations and or open hole intervals. If application is for an existing well, a cement bond log (CBL) shall be submitted with the application, or if submitted after the application is filed, the CBL shall be submitted prior to commencement of operations as a condition of the permit.

7) The proposed daily amounts to be injected, the source and the type of fluid to be injected, and standard laboratory report from an accredited laboratory reporting the laboratory results of a representative sample of the proposed disposal fluids for the following parameters: chloride, pH, specific gravity, total dissolved solids (TDS) and total percent hydrocarbon (TPH). The sample shall be obtained and analyzed no earlier than one hundred-eighty (180) days prior to the date of filing of the application and analyzed in a timely fashion after collection.

8) The maximum injection pressure.

A) The Director shall determine the maximum permitted injected pressure, measured at the wellhead, by multiplying the results of the formula below by ninety percent (90%):

i) A maximum fracture gradient not to exceed 1.1 psi/ft (x) depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in Ashley, Bradley, Calhoun, Columbia, Hempstead, Lafayette Miller, Nevada, Ouachita, and Union counties for injection into formations below the Midway Shale Formation; or

ii) A maximum fracture gradient not to exceed 1.0 psi/ft**(**x**)** depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss in all other counties for injection into formations below the Fayetteville Shale Formation in the areas covered by General Rule B-43 (c) and (d), General Rule B-44, and the portions of Franklin, Logan, Scott, Sebastian, and Yell Counties not covered by General Rule B-44; or

iii) A maximum fracture gradient not to exceed 0.73 psi/ft**(x)** depth to injection formation (-)weight of fluid column (specific gravity of injection fluid) (+) injection tubing friction loss for all other formations and/or counties.

The following calculation is included only as an example, and for informational and demonstrative purposes only. For purposes of this example, assume the well is in ColumbiaCounty, the total depth to the injection formation is 2,500 feet, the specific gravity is 1.085, and the injection tubing friction loss is 250 psi. Using the formula provided above, the maximum permitted injection pressure for the well would be 1,642 psig, calculated as follows:

Step 1: 0.9 x [(1.1 psi/ft x 2500 ft) – [0.433psi/ft x 2500 ft) x 1.085 (specific gravity)] + 250 tubing friction loss]

Step 2: 0.9 x [2750 psi – 1175 + 250 tubing friction loss]

Step 3: 0.9 x [1825]

Step 4: Result = 1642 psig

B) An Applicant may request an increase in the maximum injection pressure specified in subparagraph h) 8) A) above, or appeal a Director’s decision to issue a permit utilizing a fracture gradient less than the maximum fracture gradient specified in subparagraph h) 8) A) above, by filing an application in accordance with General A-2, A-3 and other applicable hearing procedures. Any increase in the maximum injection pressure may be granted if the Applicant presents sufficient evidence to justify the requested increased injection pressure will not initiate or propagate fractures in the overlying confining layer(s) that could enable the injection fluid or the fluid in the injection interval to leave the permitted injection intervals or cause movement of the injection fluid or formation fluids into USDWs.

9) A map showing:

A) The surveyed location of the well proposed to be drilled, deepened or converted, showing distances to the nearest property or lease lines; and

B) The location of all known plugged and unplugged wells, which penetrate the proposed injection interval, within the 1/2 mile radius from the proposed disposal well, and showing the status of each well as producing, shut-in, disposal, enhanced recovery, plugged and abandoned, or other status.

10) The Applicant shall submit evidence, where available, that all plugged and unplugged wells which penetrate the injection formation, within the ½ mile radius shown on the above plat in subparagraph h) 9) B), contain an adequate amount of cement and are constructed or plugged in a manner which will prevent the injection fluid and the fluid in the injection formation from entering USDWs. The types of evidence that will be considered acceptable include, but are not limited to: well completion reports, cementing records, well construction records, cement bond logs, tracer surveys, oxygen activation logs, and plugging records.

11) The Applicant shall submit evidence and/or information showing that the proposed injection interval or formation is not a USDW.

12) The Applicant shall submit information as to the depth (subsea) of the fresh water supply in the nearest known private water well and in the nearest known public water system water well.

13) If the application is for a Class II UIC Commercial Disposal Well, a listing of all previous and current violations of any statute, rule, regulation, permit condition, or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution Control and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities.

i) Notice of the application shall be given by the Applicant by one (1) publication in a legal newspaper having a general circulation in the county, or in each county, if there shall be more than one, in which the one-half mile radius from the proposed disposal well is situated, and by mailing via certified mail, FedEx,UPS,or other method that provides proof of mailing and delivery, a copy of the application to each permit holder of all permitted, drilling or producing wells within a one-half mile radius of the proposed disposal well. Such notice shall be published or mailed no more than thirty (30) days, prior to the date on which the application is filed with the Commission. The cost of such notice and mailing of the application shall be paid for by the Applicant. Attached to the application shall be evidence that the application was mailed or sent asrequired and a proof of publication of the application from the newspaper.

j) If notice is for a commercial disposal well, in addition to compliance with subparagraph i) above, the commercial disposal well application shall also be sent via certified mail, FedEx, or UPS to the County Judge of the county where the well is located and to the landowner (surface owner) where the well is located. In addition, the public notice should be large font and surrounded by a printed border to highlight the published notice.

k) Objections received by the Director, must be received by the Director within fifteen (15) days after the publication date of the notice and the date of mailing or sending to all parties specified in subparagraphs i) and j) above.

l) If an objection is received the application shall be deemed denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

m) If an objection is not received by the Director and the application is deemed complete, the permit shall be issued following the required notice period specified in subparagraph i) above, unless the Director deems it necessary, for the purpose of protecting USDWs or oil and gas resources, that the application may be referred to the Commission for determination, and no additional filing fee is required from the applicant.

n) If the application does not satisfy the requirements of this Rule, the application shall be denied. If the application is denied under this section, the Applicant may request to have the application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures.

o) If the Applicant satisfies the requirements of all applicable statutes and this Rule, a permit shall be issued, unless:

1) The Applicant has falsified or otherwise misstated any material information on or relative to the permit application; or

2) For purposes of Class II Commercial Disposal Wells, the Applicant:

A) Has an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest in the entity exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

B) Was an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

C) Is a Permit Holder or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5%;

i) That has failed to abate an outstanding violation of the oil and gas statutes or rules, regulations, or comply with an orders of the Commission as specified in a final administrative decision of the Commission; or

ii) For which funds have been obligated and remain outstanding from the Plugging and Restoration Fund to plug wells, under General Rule G-1 or G-2; or

iii) Who is delinquent in payment of any annual well fees under General Rule B-2.

D) If the Director determines that the applicant, or an owner, officer, director, partner, or member or manager of a limited liability company, or other person with an interest exceeding 5% in the applicant, has a history of violating an oil and gas statute, rule, regulation, permit condition or order of the Commission, the Arkansas Department of Environmental Quality, the Arkansas Pollution and Ecology Commission, or any other state or federal environmental regulatory agency, including those of other states, regarding oil or gas related activities, which pose a potential danger to the environment and public health and safety. In making the determination, the Director may consider:

i) The danger to the environment and public health and safety if the applicant's proposed activity is not conducted in a competent and responsible manner; and

ii) The degree to which past and present oil and gas related activities directly bear upon the reliability, competence, and responsibility of the applicant.

E) If a permit is not issued in accordance with subparagraph o) 2) above, the Applicant may request to have the permit application referred to the Commission for determination, in accordance with General Rules A-2 and A-3, and other applicable hearing procedures, except that no additional filing fee is required.

p) The Commission retains jurisdiction to determine zones suitable for disposal injection based on the porosity, permeability, fluid capacity, structure, geology and overall suitability of the zone as a disposal injection interval with respect to protection of USDWs and oil and gas resources.

q) Class II Disposal or Class II Commercial Disposal Well Drilling Permit or Transfer Revocation Procedures

1) The Director may revoke a Class II Disposal or Class II Commercial Disposal Well permit or transfer approval if the Permit Holder fails to meet permit conditions as specified in the Class II Disposal or Class II Commercial Disposal Well permit or transfer approval, the Class II Disposal or Class II Commercial Disposal Well permit or transfer

approval was issued in error, or the Permit Holder falsified or otherwise misstated any material information in the application form.

2) The Director shall notify the Permit Holder of the Class II Disposal or Class II Commercial Disposal Well permit or transfer revocation in writing. Following the revocation notice the Permit Holder is required to plug the Class II Disposal or Class II Commercial Disposal Well. The Permit holder shall have thirty (30) days from the date of the Class II Disposal or Class II Commercial Disposal Well permit or transfer revocation to appeal the Director's Decision to revoke the Class II Disposal or Class II Commercial Disposal Well permit or transfer approval in accordance with General Rule A-2, A-3 and other applicable hearing procedures. Operations may not commence or continue during the appeal process. A revocation of a Class II Disposal or Class II Commercial Disposal Well permit or transfer approval for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the revocation.

r) Class II Disposal or Class II Commercial Disposal Well Transfer Procedures

1) Definitions

A) "Current Permit Holder" means the individual or entity required to hold the permit or to whom the permit was issued and who is the owner of the right to operate said Class II Disposal or Class II Commercial Disposal Well(s), possesses the full rights and responsibilities for operating the Class II Disposal or Class II Commercial Disposal Well(s) in accordance with applicable Arkansas law and has the current obligation to plug said Class II Disposal or Class II Commercial Disposal Well(s), who is the assignor, transferor or seller (whether voluntary or involuntary) of the Class II Disposal or Class II Commercial Disposal Well(s).

B) "New Permit Holder" means the individual or entity acquiring the Class II Disposal or Class II Commercial Disposal Well(s) and the right to operate said Class II Disposal or Class II Commercial Disposal Well(s), who obtains the full rights and responsibilities for operating the Class II Disposal or Class II Commercial Disposal Well(s) in accordance with applicable Arkansas law and/or rule, regulation, or order of the Commission, who~~m~~ will obtain the obligation to plug said Class II Disposal or Class II Commercial Disposal Well(s), and who as owner or operator in accordance with applicable Arkansas law and/or rule, regulation, or order of the Commission is required to hold the permit.

C) "Transfer" means any assignment, devise, release, transfer, takeover, buyout, merger, sale, conveyance, or other transfer of any kind, whether voluntarily or involuntarily.

2) The provisions of this subparagraph apply to all transfers of the interest of the individual or entity required to hold and to whom the Class II Disposal or Class II Commercial Disposal Well transfer approval is issued (Permit Holder), including but not limited to:

A) a change of ownership of the right to drill and/or operate said Class II Disposal or Class II Commercial Disposal Well(s), along with the full rights and responsibilities for operating the Class II Disposal or Class II Commercial

Disposal Well(s) and the obligation to ultimately plug said Class II Disposal or Class II Commercial Disposal Well(s); or

B) a change in the designation of the owner or operator under an operating or other similar agreement; or

C) a change pursuant to the action of the owners of separate interests who designate an owner to be Permit Holder; or

D) a change required by the appointment, by a court of competent jurisdiction, of a trustee or a receiver to exercise custody and control over the Class II Disposal or Class II Commercial Disposal Well(s), including the right to drill and/or operate said well(s) along with the full right and responsibilities for operating the well(s).

3) The provisions of this subparagraph shall not apply to the transfer of working interests not affecting the rights or responsibilities of the Permit Holder.

4) The provisions of this subparagraph shall not apply to transfers of Class II Disposal or Class II Commercial Disposal Well(s) abandoned or orphaned in accordance General Rule G-1 or G-2. Transfers of Class II Disposal or Class II Commercial Disposal Wells deemed abandoned or orphaned are subject to the transfer provisions in General Rule G-3.

5) Notification of a transfer shall be given to the Director, or his designee, by the Current Permit Holder, on a form prescribed by the Director, of the transfer of any Class II Disposal or Class II Commercial Disposal Well or any Class II Disposal or Class II Commercial Disposal Well required to be permitted within thirty (30) days after the effective date of the transfer.

6) A separate form shall be completed for each lease, Class II Disposal or Class II Commercial Disposal Well, or other unit transferred.

7) The notification shall be signed by the Current Permit Holder and the New Permit Holder, or by authorized representatives specified on the Organizational Report filed in accordance with General Rule B-13, except as follows:

A) In lieu of the signature of the Current Permit Holder, the New Permit Holder may submit a court order or other legal document evidencing ownership of the lease or unit to be transferred in the event that the Current Permit Holder cannot be located or refuses to sign the notification of transfer form.

B) In lieu of the signature of the New Permit Holder, the Current Permit Holder may submit documentation evidencing transfer of the ownership of the Class II Disposal or Class II Commercial Disposal Well, lease, or unit in the event the New Permit Holder refuses to sign the notification of transfer form.

8) A New Permit Holder may operate Class II Disposal or Class II Commercial Disposal Wells covered by the Class II Disposal or Class II Commercial Disposal Well transfer request, until such time as the transfer request has been approved or denied by the Director or his designee, provided the request was submitted within thirty (30) days of the actual transfer of the Class II Disposal or Class II Commercial Disposal Well.

However, Class II Disposal or Class II Commercial Disposal Wells may not be operated by the New Permit Holder, until a Class II Disposal or Class II Commercial Disposal Well transfer request is approved, if the request was received by the Director, or his designee, more than thirty (30) days after the actual transfer of the Class II Disposal or Class II Commercial Disposal Well.

9) A New Permit Holder that acquires the right to operate a Class II Disposal or Class II Commercial Disposal Well(s) pursuant to a transfer shall apply for and must receive transfer approval from the Director, or his designee, prior to operating the Class II Disposal or Class II Commercial Disposal Well(s) beyond the timeframe specified in subparagraph (r)(8) above.

10) Prior to the Director, or his designee, approving the transfer request, the New Permit Holder shall provide the required financial assurance, if applicable, in accordance with General Rule B-2, and file the required organizational report, if applicable, in accordance with General Rule B-13.

11) A transfer to a New Permit Holder may be denied by the Director, or his designee, if the New Permit Holder meets any of the conditions specified in subparagraph o) above.

12) The New Permit Holder shall be responsible for all regulatory requirements relative to all Class II Disposal or Class II Commercial Disposal Wells and all other surface production facilities in existence at the time of the transfer related to the Class II Disposal or Class II Commercial Disposal Wells. The New Permit Holder shall not be responsible for regulatory requirements relative to spills of crude oil or other production fluids which occurred prior to the date of the transfer, unless the New Permit Holder has otherwise agreed with the Current Permit Holder.

13) If any Class II Disposal or Class II Commercial Disposal Well, or any lease or other unit associated with the Class II Disposal or Class II Commercial Disposal Well, is in violation at the time of the transfer request to the New Permit Holder, the transfer request shall be denied pending abatement of all violations by the Current Permit Holder. However, if the New Permit Holder, after being notified of the violation(s), agrees in writing to the transfer approval including conditions to abate all violations, the transfer may be approved by the Director, or his designee. Failure to abate the violations within the time period specified by the Director or his designee may result in revocation of the transfer approval in accordance with subparagraph q) above, and/or other applicable enforcement actions in accordance with General Rule A-5.

14) The Current Permit Holder is not responsible for any regulatory violation caused by the actions of the New Permit Holder during the permit transfer process, after notice is given to the Director, or his designee, by the Current Permit Holder of the pending transfer if the transfer is approved. However, if the transfer is denied by the Director or his designee, the Current Permit Holder assumes all responsibility for the violations caused by the New Permit Holder. Nothing in this subsection shall affect the contractual rights and obligations between the person or entity transferring the Class II Disposal or Class II Commercial Disposal Well(s) and the person or entity acquiring the Class II Disposal or Class II Commercial Disposal Well(s).

15) The transfer approval pursuant to this subparagraph shall not affect the rights of the Commission, or any obligation or duty of the Current Permit Holder arising under any

applicable Arkansas laws, or rules, regulations, or orders of the Commission. Any cause of action accruing or any action or proceeding which has commenced, whether administrative, civil or criminal, may be instituted or continued without regard to the transfer approval.

16) The Director shall notify the Current and New Permit Holder of the transfer approval or denial in writing. Following the approval or denial of the transfer approval request, the Current or New Permit holder shall have thirty (30) days from the date of the approval or denial to appeal the Director's Decision in accordance with General Rule A-2, A-3 and other applicable hearing procedures. A transfer request approval or denial, for which an appeal has not been filed, shall become a final administrative decision of the Commission thirty (30) days following the date of the approval or denial.

s) Miscellaneous Provisions and Requirements for Class II Disposal or Class II Commercial Disposal Wells Within General Rule B-43 Section c) lands.

1) Definitions:

a. "Regional Fault" means the identified fault zones named by the Arkansas Geological Survey as the Clinton, Center Ridge, Heber Springs, Enders and Morrilton Fault zones; and which are part of a general east-west turning north-east (approximately N55ºE to N75ºE) trending, down thrown to the south, fault system generally occurring below the Fayetteville Shale Formation displacing the Lower Mississippian through Precambrian strata and truncating upward at the unconformity between the Mississippian and Pennsylvanian age strata; and which are identified on the Arkansas Geological Survey map attached hereto as Exhibit 1 to this Rule; and as updated for purposes of this Rule following notice and a hearing in accordance with General Rule A-2.

b. "Moratorium Zone Deep Faults" means deeper faults associated with the Guy-Greenbrier Earthquake Swarm; and which are part of a general northeast-southwest (approximately N30ºE) trending deeper fault system displacing the Lower Ordovician through Precambrian strata occurring in the general B-43 Section c) lands area.

2) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill, deepen, re-enter, recomplete or operate a Class II Disposal or Class II Commercial Disposal Well may be granted for any Class II or Class II Commercial Disposal wells in any formation within the following area ("Moratorium Zone")located in Cleburne, Conway, Faulkner, Van Buren, and White Counties:

Sections	Township	Range
ALL	4N	13W
ALL	5N	12W
ALL	5N	13W
ALL	5N	14W
ALL	6N	12W
ALL	6N	13W
ALL	7N	11W
ALL	7N	12W
ALL	7N	13W
ALL	8N	11W
ALL	8N	12W
ALL	8N	13W
ALL	9N	10W
ALL	9N	11W
ALL	9N	12W
ALL	10N	10W
ALL	10N	11W
ALL	11N	10W
ALL	11N	11W
1-12, 14-23, 27-33	4N	12W
1-30, 35-36	4N	14W
1-2, 10-15, 23-25	4N	15W
4-9, 17-20, 30-31	5N	11W
25, 35-36	5N	15W
6	6N	10W
1-23, 26-34	6N	11W
1-4, 9-36	6N	14W
24-25, 36	6N	15W
3-9, 16-20, 29-31	7N	10W
1, 11-14, 22-27, 34-36	7N	14W
6-7	8N	9W
1-24, 26-35	8N	10W
25, 36	8N	14W
3-10, 15-21, 29-32	9N	9W
1-5, 7-36	9N	13W
1-23, 27-34	10N	9W
1-3, 9-17, 19-36	10N	12W
25, 33, 34, 36	10N	13W
17-22, 27-35	11N	9W
13, 23-27, 34-36	11N	12W

3) Unless otherwise approved by the Commission after notice and a hearing, no permit to drill or re-enter, a new Class II Disposal or Class II Commercial Disposal Well may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

4) Unless otherwise approved by the Commission after notice and a hearing, no permit to deepen or re-complete any existing Class II Disposal or Class II Commercial Disposal Well in a zone stratigraphically below the Fayetteville Shale formation, may be granted within one (1) mile of a Regional Fault or within five (5) miles of a known or identified Moratorium Zone Deep Fault within any remaining B-43 Section c) lands.

5) Unless otherwise approved by the Commission after notice and a hearing, the following provisions shall apply to any permit to drill, deepen, or operate a new Class II Disposal or Class II Commercial Disposal Well proposed to be located within in any remaining B-43 Section c) lands:

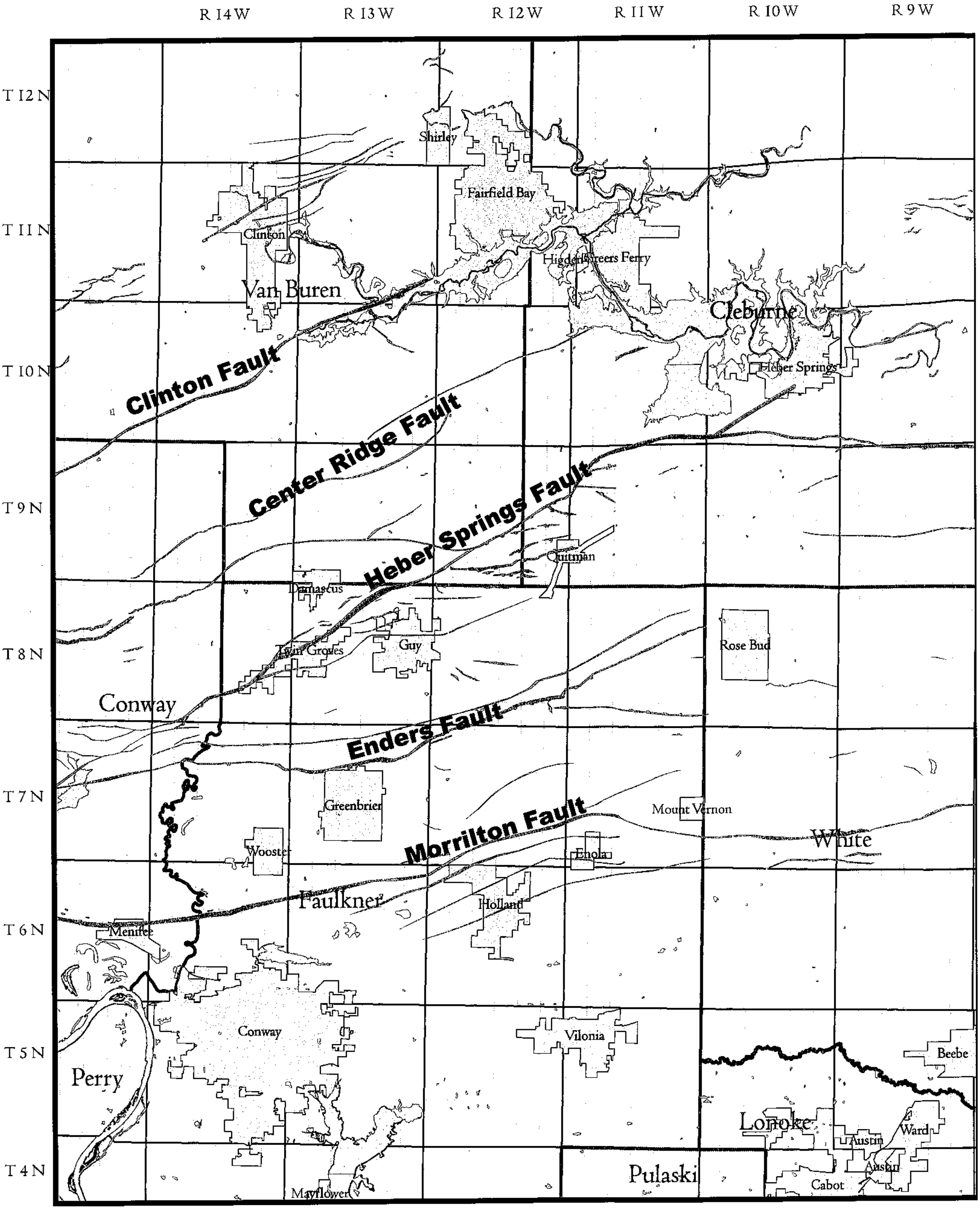
   a) No Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation shall be located within five (5) miles of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically below the Fayetteville Shale formation.

   b) No Class II Disposal or Class II Commercial Disposal well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation shall be located within one-half (1/2) mile of another Class II Disposal or Class II Commercial Disposal Well disposing in a zone occurring stratigraphically above the Fayetteville Shale formation.

6) The Applicant shall provide technical information to the Director in support of the application. The technical justification shall include information related to the location of any Moratorium Zone Deep Fault within five (5) miles or Regional Fault within two miles (2) of the proposed location of the Class II Disposal or Class II Commercial Disposal Well, with special emphasis on identifying any deep faults occurring below the Fayetteville Shale formation which extend to the basement rock.

7) Flow meters, or other measuring devices approved by the Director, shall be installed on all Class II Disposal and Class II Commercial Disposal Wells and Permit Holders shall submit accurate injection volume and pressure information, on no less than a daily basis, on a form prescribed by the Director.

Named Regional Faults



SSA 2012

Session: The M5.8 Central Virginia and the M5.6 Oklahoma Earthquakes of 2011

ARE SEISMICITY RATE CHANGES IN THE MIDCONTINENT NATURAL OR MANMADE?

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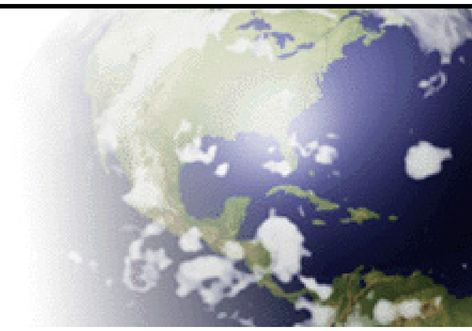
A remarkable increase in the rate of M 3 and greater earthquakes is currently in progress in the US midcontinent. The average number of M >= 3 earthquakes/year increased starting in 2001, culminating in a six-fold increase over 20th century levels in 2011. Is this increase natural or manmade? To address this question, we take a regional approach to explore changes in the rate of earthquake occurrence in the midcontinent (defined here as 85° to 108° West, 25° to 50° North) using the USGS Preliminary Determination of Epicenters and National Seismic Hazard Map catalogs. These catalogs appear to be complete for M >= 3 since 1970. From 1970 through 2000, the rate of M >= 3 events averaged 21 +- 7.6/year in the entire region. This rate increased to 29 +- 3.5 from 2001 through 2008. In 2009, 2010 and 2011, 50, 87 and 134 events occurred, respectively. The modest increase that began in 2001 is due to increased seismicity in the coal bed methane field of the Raton Basin along the Colorado-New Mexico border west of Trinidad, CO. The acceleration in activity that began in 2009 appears to involve a combination of source regions of oil and gas production, including the Guy, Arkansas region, and in central and southern Oklahoma. Horton, et al. (2012) provided strong evidence linking the Guy, AR activity to deep waste water injection wells. In Oklahoma, the rate of M >= 3 events abruptly increased in 2009 from 1.2/year in the previous half-century to over 25/year. This rate increase is exclusive of the November 2011 M 5.6 earthquake and its aftershocks. A naturally-occurring rate change of this magnitude is unprecedented outside of volcanic settings or in the absence of a main shock, of which there were neither in this region. While the seismicity rate changes described here are almost certainly manmade, it remains to be determined how they are related to either changes in extraction methodologies or the rate of oil and gas production.

Wednesday, April 18th / 3:45 PM Oral / Pacific Salon 4 & 5

Air Emissions



Various Energy Resources

- Air Emissions
- Water Resource Use
- Water Discharges
- Solid Waste Generation
- Land Resource Use

Electricity generation is the dominant industrial source of air emissions in the United States today. Fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide emissions, 23 percent of nitrogen oxide emissions, and 40 percent of man-made carbon dioxide emissions. These emissions can lead to smog, acid rain, and haze. In addition, these power plant emissions increase the risk of climate change. Congress is currently considering proposals to require further reductions of emissions from power plants, including the President's Clear Skies Initiative. However, renewable energy is receiving increased attention by environmental policymakers because renewable energy technologies have significantly lower emissions than traditional power generation technologies. To find out more about the air emissions generated by U.S. power plants, you can use EPA's Emissions and Generated Resource Integrated Database, or eGRID. eGRID provides emissions data on virtually every power plant and company that generates electricity in the United States.

The air emissions impacts of electricity generation vary from technology to technology, as described below.

Natural Gas

At the power plant, the burning of natural gas produces nitrogen oxides and carbon dioxide, but in lower quantities than burning coal or oil. Methane, a primary component of natural gas and a greenhouse gas, can also be emitted into the air when natural gas is not burned completely. Similarly, methane can be emitted as the result of leaks and losses during transportation. Emissions of sulfur dioxide and mercury compounds from burning natural gas are negligible.

The average emissions rates in the United States from natural gas-fired generation are: 1135 lbs/MWh of carbon dioxide, 0.1 lbs/MWh of sulfur dioxide, and 1.7 lbs/MWh of nitrogen oxides.[1] Compared to the average air emissions from coal-fired generation, natural gas produces half as much carbon dioxide, less than a third as much nitrogen oxides, and one percent as much sulfur oxides at the power plant. In addition, the process of extraction, treatment, and transport of the natural gas to the power plant generates additional emissions.[2]

Coal

When coal is burned, carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury compounds are released. For that reason, coal-fired boilers are required to have control devices to reduce the amount of emissions that are released.

The average emission rates in the United States from coal-fired generation are: 2,249 lbs/MWh of carbon dioxide, 13 lbs/MWh of sulfur dioxide, and 6 lbs/MWh of nitrogen oxides.[3]

Mining, cleaning, and transporting coal to the power plant generate additional emissions. For example, methane, a potent greenhouse gas that is trapped in the coal, is often vented during these processes to increase safety.

Oil

Burning oil at power plants produces nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and mercury compounds. The amount of sulfur dioxide and mercury compounds can vary greatly depending on the sulfur and mercury content of the oil that is burned.

The average emissions rates in the United States from oil-fired generation are: 1672 lbs/MWh of carbon dioxide, 12 lbs/MWh of sulfur dioxide, and 4 lbs/MWh of nitrogen oxides.[4]

In addition, oil wells and oil collection equipment are a source of emissions of methane, a potent greenhouse gas. The large engines that are used in the oil drilling, production, and transportation processes burn natural gas or diesel that also produce emissions.

Nuclear Energy

Nuclear power plants do not emit carbon dioxide, sulfur dioxide, or nitrogen oxides. However, fossil fuel emissions are associated with the uranium mining and uranium enrichment process as well as the transport of the uranium fuel to the nuclear plant.

Municipal Solid Waste

Although municipal solid waste (MSW) includes renewable resources, its use as a source of energy has been met with controversy. Despite recent toughening of emission standards for MSW combustion, the process creates significant emissions, including trace amounts of hazardous air pollutants.

Burning MSW produces nitrogen oxides and sulfur dioxide as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Although MSW power plants do emit carbon dioxide, the primary greenhouse gas, the biomass-derived portion is considered to be part of the Earth's natural carbon cycle. The plants and trees that make up the paper, food, and other biogenic waste remove carbon dioxide from the air while they are growing, which is returned to the air when this material is burned. In contrast, when fossil fuels are burned, they release carbon dioxide that has not been part of the Earth's atmosphere for a very long time (i.e., within a human time scale).

The average air emission rates in the United States from municipal solid waste-fired generation are: 2988 lbs/MWh of carbon dioxide, (it is estimated that the fossil fuel-derived portion of carbon dioxide emissions represent approximately one-third of the total carbon dioxide emissions) 0.8 lbs/MWh of sulfur dioxide, and 5.4 lbs/MWh of nitrogen oxides.[5]

The variation in the composition of MSW raises concerns. For example, if MSW containing batteries and tires are burned, toxic materials are released into the air. A variety of air pollution control technologies are used to reduce most toxic air pollutants from MSW power plants.

If MSW were to be incinerated anyway, little or no environmental impact would be attributable to using the resulting heat to generate electricity. However, there are alternatives to incineration, such as recycling waste, storing waste in landfills, and source reduction.

Hydroelectricity

Hydropower's air emissions are negligible because no fuels are burned. However, if a large amount of vegetation is growing along the riverbed when a dam is built, it can decay in the lake that is created, causing the buildup and release of methane, a potent greenhouse gas.

Non-Hydroelectric Renewable Energy

Solar

Emissions associated with generating electricity from solar technologies are negligible because no fuels are combusted.

Geothermal

Emissions associated with generating electricity from geothermal technologies are negligible because no fuels are combusted.

Biomass

Biomass power plants emit nitrogen oxides and a small amount of sulfur dioxide. The amounts emitted depend on the type of biomass that is burned and the type of generator used. Although the burning of biomass also produces carbon dioxide, the primary greenhouse gas, it is considered to be part of the natural carbon cycle of the earth. The plants take up carbon dioxide from the air while they are growing and then return it to the air when they are burned, thereby causing no net increase. Biomass contains much less sulfur and nitrogen than coal;[6] therefore, when biomass is co-fired with coal, sulfur dioxide and nitrogen oxides emissions are lower than when coal is burned alone.[7] When the role of renewable biomass in the carbon cycle is considered, the carbon dioxide emissions that result from co-firing biomass with coal are lower than those from burning coal alone.[8]

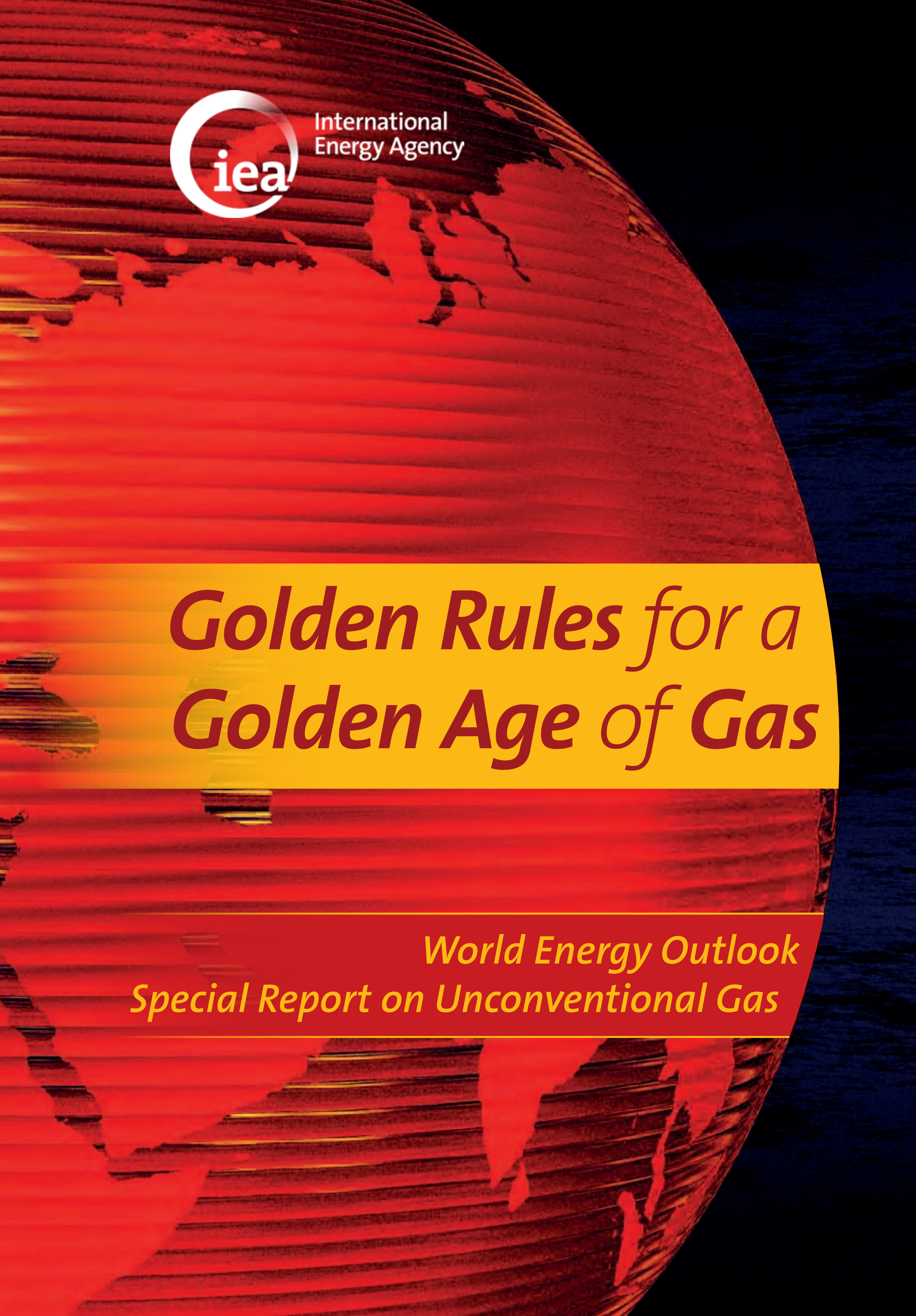
Landfill Gas

Burning landfill gas produces nitrogen oxides emissions as well as trace amounts of toxic materials. The amount of these emissions can vary widely, depending on the waste from which the landfill gas was created. The carbon dioxide released from burning landfill gas is considered to be a part of the natural carbon cycle of the earth. Producing electricity from landfill gas avoids the need to use non-renewable resources to produce the same amount of electricity. In addition, burning landfill gas prevents the release of methane, a potent greenhouse gas, into the atmosphere.

Wind

Emissions associated with generating electricity from wind technology are negligible because no fuels are combusted.

1. U.S. EPA, eGRID 2000.
2. Ibid.
3. Ibid.
4. Ibid.
5. U.S. EPA, Compilation of Air Pollutant Emission Factors (AP-42).
6. U.S. Department of Energy, Energy Efficiency and Renewable Energy Clearinghouse, Biomass Cofiring: A Renewable Alternative for Utilities. June 2000. DOE/GO-102000-1055.
7. Ibid.
8. Ibid.



International Energy Agency

Golden Rules for a Golden Age of Gas

World Energy Outlook
Special Report on Unconventional Gas

Golden Rules for a *Golden Age* of *Gas*

World Energy Outlook Special Report on Unconventional Gas

Natural gas is poised to enter a golden age, but this future hinges critically on the successful development of the world's vast unconventional gas resources. North American experience shows unconventional gas – notably shale gas – can be exploited economically. Many countries are lining up to emulate this success.

But some governments are hesitant, or even actively opposed. They are responding to public concerns that production might involve unacceptable environmental and social damage.

This report, in the *World Energy Outlook* series, treats these aspirations and anxieties with equal seriousness. It features two new cases: a Golden Rules Case, in which the highest practicable standards are adopted, gaining industry a "social licence to operate"; and its counterpart, in which the tide turns against unconventional gas as constraints prove too difficult to overcome.

The report:

- Describes the unconventional gas resource and what is involved in exploiting it.
- Identifies the key environmental and social risks and how they can be addressed.
- Suggests the Golden Rules necessary to realise the economic and energy security benefits while meeting public concerns.
- Spells out the implications of compliance with these rules for governments and industry, including on development costs.
- Assesses the impact of the two cases on global gas trade patterns and pricing, energy security and climate change.

For more information, and the free download of this report, please visit: ***www.worldenergyoutlook.org***

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International Energy Agency

Golden Rules *for a* Golden Age *of* Gas

World Energy Outlook Special Report on Unconventional Gas

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

IEA member countries:

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United States

The European Commission also participates in the work of the IEA.

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Robert Priddle carried editorial responsibility.

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A high-level workshop organised by the IEA and hosted by the Polish Ministry of Economy and co-hosted by the Mexican Ministry of Energy was held on 7 March 2012 in Warsaw to gather essential input to this study. The workshop participants have contributed valuable new insights, feedback and data for this analysis. More details may be found at www.worldenergyoutlook.org/aboutweo/workshops/.

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The individuals and organisations that contributed to this study are not responsible for any opinions or judgements contained in this study. All errors and omissions are solely the responsibility of the IEA.

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Natural gas is poised to enter a golden age, but will do so only if a significant proportion of the world's vast resources of unconventional gas – shale gas, tight gas and coalbed methane – can be developed profitably and in an environmentally acceptable manner. Advances in upstream technology have led to a surge in the production of unconventional gas in North America in recent years, holding out the prospect of further increases in production there and the emergence of a large-scale unconventional gas industry in other parts of the world, where sizeable resources are known to exist. The boost that this would give to gas supply would bring a number of benefits in the form of greater energy diversity and more secure supply in those countries that rely on imports to meet their gas needs, as well as global benefits in the form of reduced energy costs.

Yet a bright future for unconventional gas is far from assured: numerous hurdles need to be overcome, not least the social and environmental concerns associated with its extraction. Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse-gas emissions must be minimised both at the point of production and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources.

The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily meets these challenges, but a continuous drive from governments and industry to improve performance is required if public confidence is to be maintained or earned. The industry needs to commit to apply the highest practicable environmental and social standards at all stages of the development process. Governments need to devise appropriate regulatory regimes, based on sound science and high-quality data, with sufficient compliance staff and guaranteed public access to information. Although there is a range of other factors that will affect the development of unconventional gas resources, varying between different countries, our judgement is that there is a critical link between the way that governments and industry respond to these social and environmental challenges and the prospects for unconventional gas production.

We have developed a set of "Golden Rules", suggesting principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts.[1] We have called them Golden Rules because their application can bring a level of environmental performance and public acceptance that can maintain or earn the industry a "social licence to operate" within a given jurisdiction, paving the way for the widespread development of unconventional gas resources on a large scale, boosting overall gas supply and making the golden age of gas a reality.

The Golden Rules underline that full transparency, measuring and monitoring of environmental impacts and engagement with local communities are critical to addressing public concerns. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata. Leaks from wells into aquifers can be prevented by high standards of well design, construction and integrity testing. Rigorous assessment and monitoring of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water for all types of unconventional gas can ensure informed and stringent decisions about water handling and disposal. Production-related emissions of local pollutants and greenhouse-gas emissions can be reduced by investments to eliminate venting and flaring during the well-completion phase.

We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%. However, for a larger development project with multiple wells, additional investment in measures to mitigate environmental impacts may be offset by lower operating costs.

In our Golden Rules Case, we assume that the conditions are in place, including approaches to unconventional gas development consistent with the Golden Rules, to allow for a continued global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas has a strong moderating impact on gas prices and, as a result, global gas demand rises by more than 50% between 2010 and 2035. The increase in demand for gas is equal to the growth coming from coal, oil and nuclear combined, and ahead of the growth in renewables. The share of gas in the global energy mix reaches 25% in 2035, overtaking coal to become the second-largest primary energy source after oil.

1. Consultations with a range of stakeholders when developing these Golden Rules included a high-level workshop held in Warsaw on 7 March 2012, which was organised by the IEA, hosted by the Polish Ministry of Economy and co-hosted by the Mexican Ministry of Energy. In addition to the input received during this workshop, we have drawn upon the extensive work in this area undertaken by many governments, non-governmental and academic organisations, and industry associations.

Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 trillion cubic metres in 2035. This accounts for nearly two-thirds of incremental gas supply over the period to 2035, and the share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Most of the increase comes after 2020, reflecting the time needed for new producing countries to establish a commercial industry. The largest producers of unconventional gas over the projection period are the United States, which moves ahead of Russia as the largest global natural gas producer, and China, whose large unconventional resource base allows for very rapid growth in unconventional production starting towards 2020. There are also large increases in Australia, India, Canada and Indonesia. Unconventional gas production in the European Union, led by Poland, is sufficient after 2020 to offset continued decline in conventional output.

Global investment in unconventional production constitutes 40% of the $6.9 trillion (in year-2010 dollars) required for cumulative upstream gas investment in the Golden Rules Case. Countries that were net importers of gas in 2010 (including the United States) account for more than three-quarters of total unconventional upstream investment, gaining the wider economic benefits associated with improved energy trade balances and lower energy prices. The investment reflects the high number of wells required: output at the levels anticipated in the Golden Rules Case would require more than one million new unconventional gas wells worldwide between now and 2035, twice the total number of gas wells currently producing in the United States.

The Golden Rules Case sees gas supply from a more diverse mix of sources of gas in most markets, suggesting growing confidence in the adequacy, reliability and affordability of natural gas. The developments having most impact on global gas markets and security are the increasing levels of unconventional gas production in China and the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. These developments in tandem increase the volume of gas, particularly liquefied natural gas (LNG), looking for markets in the period after 2020, which stimulates the development of more liquid and competitive international markets. The share of Russia and countries in the Middle East in international gas trade declines in the Golden Rules Case from around 45% in 2010 to 35% in 2035, although their gas exports increase by 20% over the same period.

In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of the unconventional gas resource base is accessible for development. As a result, unconventional gas production in aggregate rises only slightly above current levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal. The volume of inter-regional trade is higher than in the Golden Rules Case and some patterns of trade are reversed, with North America requiring significant quantities of imported LNG. The Low Unconventional Case reinforces the preeminent position in global supply of the main conventional gas resource-holders.

Energy-related CO_2 emissions are 1.3% higher in the Low Unconventional Case than in the Golden Rules Case. Although the forces driving the Low Unconventional Case are led by environmental concerns, this offsets any claim that a reduction in unconventional gas output brings net environmental gains. Nonetheless, greater reliance on natural gas alone cannot realise the international goal of limiting the long-term increase in the global mean temperature to two degrees Celsius above pre-industrial levels. Achieving this climate target will require a much more substantial shift in global energy use. Anchoring unconventional gas development in a broader energy policy framework that embraces greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including carbon capture and storage, would help to allay the fear that investment in unconventional gas comes at their expense.

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.
- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

Technology is opening up possibilities for unconventional gas to play a major role in the future global energy mix, a development that would ease concerns about the reliability, affordability and security of energy supply. In North America, production of unconventional gas – notably shale gas – has risen rapidly in recent years and is expected to dominate growth in overall US natural gas production in the coming years and decades. Naturally, there is keen interest in replicating this success in other parts of the world, where sizeable resources of unconventional gas are known to exist. This could give a major boost to gas supply worldwide and help take us into a "Golden Age of Gas" – the subject of a special *WEO* report released last year (IEA, 2011) (Box).

Box ▻ Linking the Golden Rules to a "Golden Age of Gas"

The IEA released an analysis in June 2011 whose title asked the question "Are We Entering a Golden Age of Gas?" (IEA, 2011). How does this report link back to that analysis?

The Golden Age of Gas Scenario (GAS Scenario) in 2011 built a positive outlook for the future role of natural gas on four main pillars: more ambitious assumptions about gas use in China; greater use of natural gas in transportation; an assumption of slower growth in global nuclear power capacity; and a more optimistic outlook for gas supply – primarily though the availability of additional unconventional gas supplies at relatively low cost. In the GAS Scenario, as a result, natural gas increased its role in the future global energy mix from 21% to 25% over the period to 2035.

However, the question mark in the title of this publication was not accidental. It reflected continued uncertainties over the future of natural gas, in particular those connected with the potential for growth in unconventional gas supply. The present analysis zooms in on the environmental impacts of unconventional gas supply, how they are being, and might be, addressed and what the consequences might be. It should therefore be understood as a more detailed examination of a key pre-condition for a golden age of gas.

A range of factors will affect the pace of development of this relatively new industry over the coming decades. In our judgement, a key constraint is that unconventional gas does not yet enjoy, in most places, the degree of societal acceptance that it will require in order to flourish. Without a general, sustained and successful effort from both governments and operators to address the environmental and social concerns that have arisen, it may be impossible to convince the public that, despite the undoubted potential benefits, the impact and risks of unconventional gas development are acceptably small. The IEA offers this special report as a contribution to the solution of this dilemma. The objective is to suggest what might be required to enable the industry to maintain or earn a "social licence to operate".

In Chapter 1 of this special report, we analyse the specific characteristics of each type of unconventional gas development and their environmental and social impacts, examining the technologies and their associated risks, why they have raised public anxiety and why and how they require special attention from policy-makers, regulators and industry. This chapter develops a set of "Golden Rules", the application of which would reduce the impact of unconventional gas developments on land and water use, on the risk of water contamination, and on methane and other air emissions. It also analyses the implications of compliance with the Golden Rules for governments and for industry.

In Chapter 2, we set out the results of two sets of projections of future energy demand, supply and energy-related CO_2 emissions, which explore the potential impact of unconventional gas resources on energy markets. The first of these, to which the main part of this chapter is devoted, is a *Golden Rules Case*, which assumes that the conditions are put in place to allow for a continued expansion of gas supply from unconventional gas resources, including the effective application of the Golden Rules. This situation allows unconventional output to expand not only in North America but also in other countries around the world with major resources. A *Low Unconventional Case*, examined at the end of this chapter, considers the opposite turn of events, in which Golden Rules are not observed, opposition to unconventional gas hardens and the constraints prove too difficult to overcome.

Chapter 3 takes a closer look at unconventional gas in four key regions and countries: North America (United States, Canada and Mexico), China, Europe and Australia. The prospect of increased unconventional gas production is prompting many countries to review their regulatory frameworks to accommodate (or, in some cases, to restrict) the development of these resources. This chapter provides an overview of the main debates and challenges around unconventional production in the selected countries and regions, presented together with our projections for future output.

Addressing environmental risks

Why do we need "Golden Rules"?

Highlights

- Unconventional gas resources are trapped in very tight or low permeability rock and the effort required to extract them is greater than for conventional resources. This means higher intensity of drilling, entailing more industrial activity and disruption above ground. Producing gas from unconventional formations in many cases involves the use of hydraulic fracturing to boost the flow of gas from the well.
- The environmental and social hazards related to these and other features of unconventional gas development have generated keen public anxiety in many places. Means are available to address these concerns. "Golden Rules", as developed here, provide principles that can guide policy-makers, regulators, operators and other stakeholders on how best to reconcile their interests.
- Critical elements are: full transparency, measuring, monitoring and controlling environmental impacts; and early and sustained engagement. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata.
- Sound management of water resources is at the heart of the Golden Rules. Alongside robust rules on well design, construction, cementing and integrity testing to prevent leaks from the well into aquifers, this requires rigorous assessment, monitoring and handling of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water (in all cases).
- Unconventional gas has higher production-related greenhouse-gas emissions than conventional gas, but the difference can be reduced and emissions of other pollutants lowered by eliminating venting and minimising flaring during the well completion phase. Releases of methane, wherever they occur in the gas supply chain, are particularly damaging, given its potency as a greenhouse gas.
- The potential environmental impacts and the scale of unconventional gas development make it essential for policy-makers to ensure that effective and balanced regulation is in place, based on sound science and high-quality data, and that adequate resources are available for enforcement.
- Operators have to perform to the highest standards in order to win and retain the "social licence to operate". Application of the Golden Rules does affect costs, with an estimated 7% increase for a typical individual shale gas well. However, when considered across a complete licensing area, additional investment in measures to mitigate environmental impact can be offset in many cases by lower operating costs.

The environmental impact of unconventional gas production

Although known about for decades, the importance of global unconventional gas resources and their full extent has only recently been appreciated. Allowing for the uncertainties in the data, stemming, in part, from difficulties in distinguishing and categorising different types of gas (Box 1.1), we estimate that the remaining technically recoverable resources of unconventional gas worldwide approach the size of remaining conventional resources (which are 420 trillion cubic metres [tcm]). Remaining technically recoverable resources of shale gas are estimated to amount to 208 tcm, tight gas to 76 tcm and coalbed methane to 47 tcm. The economic and political significance of these unconventional resources lies not just in their size but also in their wide geographical distribution, which is in marked contrast to the concentration of conventional resources.[1] Availability of gas from a diverse range of sources would underpin confidence in gas as a secure and reliable source of energy.

Box 1.1 ▷ Unconventional gas resources

Unconventional gas refers to a part of the gas resource base that has traditionally been considered difficult or costly to produce. In this report, we focus on the three main categories of unconventional gas:

- **Shale gas** is natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. These formations are often rich in organic matter and, unlike most hydrocarbon reservoirs, are typically the original source of the gas, *i.e.* shale gas is gas that has remained trapped in, or close to, its source rock.
- **Coalbed methane**, also known as coal seam gas in Australia, is natural gas contained in coalbeds. Although extraction of coalbed methane was initially undertaken to make mines safer, it is now typically produced from non-mineable coal seams.
- **Tight gas**[2] is a general term for natural gas found in low permeability formations. Generally, we classify as tight gas those low permeability gas reservoirs that cannot produce economically without the use of technologies to stimulate flow of the gas towards the well, such as hydraulic fracturing.

Although the development cycle for unconventional gas and the technologies used in its production have much in common with those used in other parts of the upstream industry, unconventional gas developments do have some distinctive features and requirements, particularly in relation to the perceived higher risk of environmental damage and adverse

1. The extent and distribution of recoverable resources of unconventional gas is discussed in more detail in Chapter 2.

2. Tight gas is often a poorly defined category with no clear boundary between tight and conventional, nor between tight gas and shale gas.

social impacts. This helps to explain why the issue of unconventional gas exploitation has generated so much controversy.

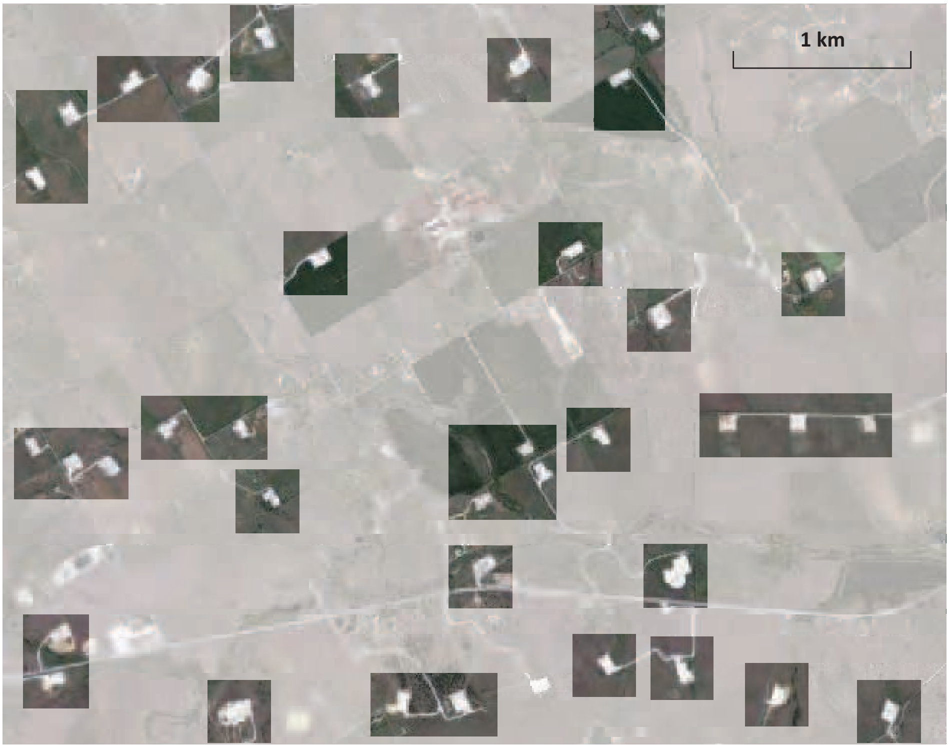
This chapter addresses these issues by examining in some depth what is involved in exploiting each category of unconventional gas and the associated hazards. It then proposes a set of principles, the "Golden Rules", applicable to future operations in this sector. The objective is to define the conditions which might enable the industry to gain or retain a "social licence to operate". The consequences for the energy sector of securing such an outcome are discussed in Chapters 2 and 3, together with the possible consequences of failing to do so.

The main reason for the potentially larger environmental impact of unconventional gas operations is the nature of the resources themselves: unconventional resources are less concentrated than conventional deposits and do not give themselves up easily. They are difficult to extract because they are trapped in very tight or low permeability rock that impedes their flow. Since the resources are more diffuse and difficult to produce, the scale of the industrial operation required for a given volume of unconventional output is much larger than for conventional production. This means that drilling and production activities can be considerably more invasive, involving a generally larger environmental footprint.

One feature of the greater scale of operations required to extract unconventional gas is the need for more wells. Whereas onshore conventional fields might require less than one well per ten square kilometres, unconventional fields might need more than one well per square kilometre (km^2), significantly intensifying the impact of drilling and completion activities on the environment and local residents.[3] A satellite image from Johnson County in Texas, United States illustrates this point, showing the density of well sites producing from the Barnett shale (Figure 1.1). This image highlights 37 well sites in an area of around 20 km^2, with each well site potentially having more than one well. Another important factor is the need for more complex and intensive preparation for production. While hydraulic fracturing is already used on occasions to stimulate conventional reservoirs, tight gas and shale gas developments almost always require the use of this technique in order to generate adequate flow rates into the well. The same technique is also often used, albeit less frequently, to produce coalbed methane. The associated use and release of water gives rise to a number of environmental concerns, including depletion of freshwater resources and possible contamination of surface water and aquifers.

3. It should be noted that conventional gas fields in mature areas, such as onshore United States or Canada, often have well densities (number of wells per unit area) comparable to those of unconventional gas. However, burgeoning unconventional gas production today tends to replace production that would have come from offshore locations or countries rich in conventional gas, such as Russia or Qatar, in which the well densities are much smaller.

Figure 1.1 ▷ **Drilling intensity in Johnson County, Texas**



Source: © 2012 Google, DigitalGlobe, GeoEye, Texas Orthoimagery Program, USDA Farm, Farm Service Agency source. Google Maps, http://g.co/maps/j9xws, with well sites highlighted.

The production of unconventional gas also contributes to the atmospheric concentration of greenhouse gases and affects local air quality. In some circumstances, unconventional gas production can result in higher airborne emissions of methane, a potent greenhouse gas, of volatile organic compounds (VOCs) that contribute to smog formation, and of carbon dioxide (CO_2) (from greater use of energy in the production process, compared with conventional production). Just how much greater these risks may be is uncertain: it depends critically on the way operations are carried out. On the other hand, there are potential net benefits from unconventional gas production, to the extent that, having been produced and transported to exacting environmental standards, it leads to greater use of gas instead of more carbon-intensive coal and oil.

In addition to the smaller recoverable hydrocarbon content per unit of land, unconventional developments tend to extend across much larger geographic areas. The Marcellus Shale in the United States covers more than 250 000 km^2, which is about ten times larger than the Hugoton Natural Gas Area in Kansas – the country's largest conventional gas producing zone. Moreover, areas with high unconventional potential are not always those with a strong or recent tradition of oil and gas industry activity; they are not necessarily rich in conventional hydrocarbons and in some cases there may have been little or no recent hydrocarbon production (and none expected). This tends to exacerbate the problem of public acceptance.

Shale and tight gas developments

Characteristics of the resource

By contrast to conventional gas reservoirs, shale gas reservoirs (Box 1.2) have very low permeability due to the fine-grained nature of the original sediments (gas does not flow easily out of the rock), fairly low porosities (relatively few spaces for the gas to be stored, generally less than 10% of the total volume), and low recovery rates (because the gas can be trapped in disconnected spaces within the rock or stuck to its surface). The last two factors (low porosity and low recovery) are responsible for the fact that the volume of recoverable hydrocarbons per square kilometre of area at the surface is usually an order of magnitude smaller than for conventional gas. Low permeability is responsible for shale gas requiring specific technologies, such as hydraulic fracturing, to achieve commercial flow rates.

Tight gas reservoirs originate in the same way as conventional gas reservoirs: the rock into which the gas migrates after being expelled from the source rock just happens to be of very low permeability. As a result, tight gas reservoirs also require special techniques to achieve commercial flow rates. On the other hand, they tend to have better recovery factors than shale gas deposits and, therefore, higher density of recoverable hydrocarbons per unit of surface area.

Box 1.2 ▷ What are shales and shale gas?

Shales are geological rock formations rich in clays, typically derived from fine sediments, deposited in fairly quiet environments at the bottom of seas or lakes, having then been buried over the course of millions of years. When a significant amount of organic matter has been deposited with the sediments, the shale rock can contain organic solid material called kerogen. If the rock has been heated up to sufficient temperatures during its burial history, part of the kerogen will have been transformed into oil or gas (or a mixture of both), depending on the temperature conditions in the rock. This transformation typically increases pressure within the rock, resulting in part of the oil and gas being expelled from the shale and migrating upwards into other rock formations, where it forms conventional oil and gas reservoirs. The shales are the source rock for the oil and gas found in such conventional reservoirs. Some, or occasionally all, of the oil and gas formed in the shale can remain trapped there, thus forming shale gas or light tight oil reservoirs.[4]

4. Terminology in this area remains to be standardised (see Box 1.1). Previous WEOs have classified light tight oil from shales as conventional oil. Note that the term light tight oil is preferred to that of shale oil, as the latter can bring confusion with oil shales, which are kerogen-rich shales that can be mined and heated to produce oil (IEA, 2010; IEA, 2011a).

Shales are ubiquitous in sedimentary basins: they typically form about 80% of what a well will drill through. As a result, the main organic-rich shales have already been identified in most regions of the world. Their depths vary from near surface to several thousand metres underground, while their thickness varies from just a few metres to several hundred.[5] Often, enough is known about the geological history to infer which shales are likely to contain gas (or oil, or a mixture of both). In that sense there is no real "exploration" required for shale gas. However, the amount of gas present and particularly the amount of gas that can be recovered technically and economically cannot be known until a number of wells have been drilled and tested. Each shale formation has different geological characteristics that affect the way gas can be produced, the technologies needed and the economics of production.[6] Different parts of the (generally large) shale deposits will also have different characteristics: small "sweet spots" or "core areas" may provide much better production than the rest of the play, often because of the presence of natural fractures that enhance permeability. The amount of natural gas liquids (NGLs) present in the gas can also vary considerably, with important implications for the economics of production. While most dry gas plays in the United States are probably uneconomic at the current low natural gas prices, plays with significant liquid content can be produced for the value of the liquids only (the market value of NGLs is correlated with oil prices, rather than gas prices), making gas an essentially free by-product.

Well construction[7]

The drilling phase is the most visible and disruptive in any oil and gas development – particularly so in the case of shale gas or tight gas because of the larger number of wells required. On land, a drilling rig, associated equipment and pits to store drilling fluids and waste typically occupy an area of 100 metres by 100 metres (the well site). Setting up drilling in a new location might involve between 100 and 200 truck movements to deliver all the equipment, while further truck movements will be required to deliver supplies during drilling and completion of the well.

Each well site needs to be chosen taking account not only of the subsurface geology, but also of a range of other concerns, including proximity to populated areas and existing infrastructure, the local ecology, water availability and disposal options, and seasonal restrictions related to climate or wildlife concerns. In North America, there has recently

5. Thin shales are generally considered as not exploitable. Depth can cut both ways: shallower shales require shallower, *i.e.* cheaper, wells, but deeper shales have higher pressures, which increases the areal density of recoverable gas (which is measured at surface conditions, while the gas in the shale is compressed by the formation pressure).

6. For example, horizontal wells with multi-stage hydraulic fracturing have been pivotal to the economic success of shale gas in the United States, while in Argentina, YPF has recently reported successful tests with vertical wells with only three or four hydraulic fractures (YPF, 2012).

7. The construction of a well to access unconventional gas deposits is divided into two phases: the drilling phase, where the hole is drilled to its target depth in sections that are secured with metal casing and cement; and the completion phase, where the cemented casing across the reservoir is perforated and the reservoir stimulated (generally by hydraulic fracturing) in order to start the production of hydrocarbons.

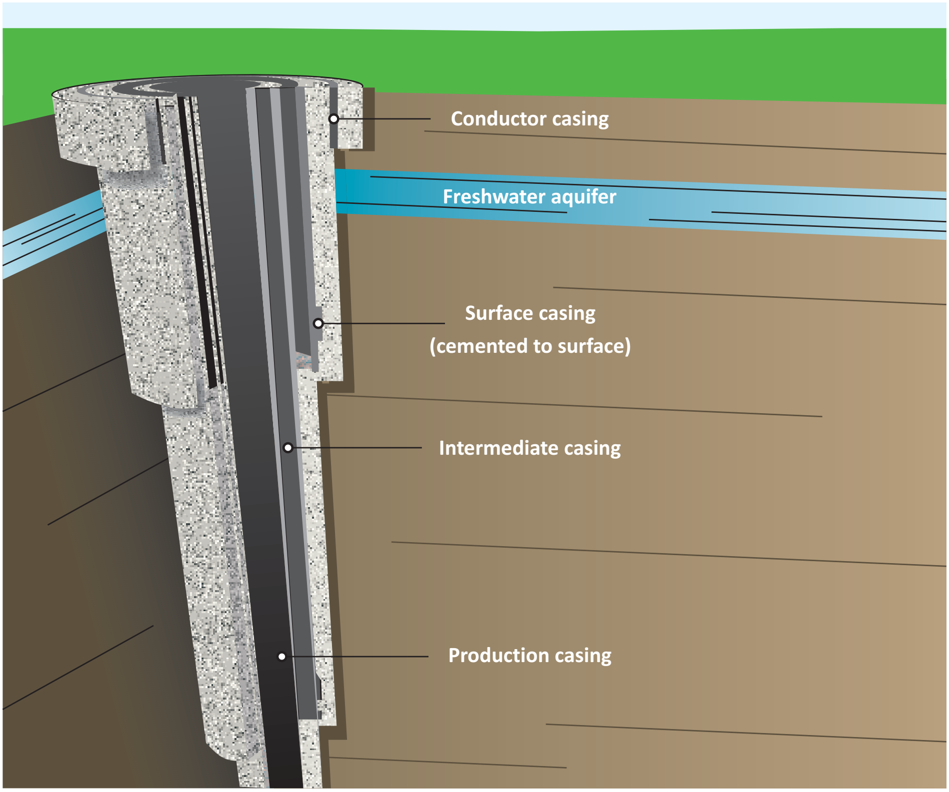
been a move towards drilling multiple wells from a single site, or pad, in order to limit the amount of disruption and thereby the overall environmental impact of well construction.[8] In 2011, according to industry sources, around 30% of all new shale and tight gas wells in the United States and Canada were multiple wells drilled from pads.

Once drilling starts, it is generally a 24-hour-per-day operation, creating noise and fumes from diesel generators, requiring lights at night and creating a regular stream of truck movements during mobilisation/demobilisation periods. Drilling operations can take anything from just a few days to several months, depending on the depth of the well and type of rock encountered. As the drill bit bores through the rock, drilling fluid known as "mud" is circulated through the wellbore in order, among other tasks, to control pressure in the well and remove cuttings created by the drill bit from the well. This lubricating "mud" consists of a base fluid, such as water or oil, mixed with salts and solid particles to increase its density and a variety of chemical additives. Mud is stored either in mobile containers or in open pits which are dug into the ground and lined with impermeable material. The volume of material in the pits needs to be monitored and contained to prevent leaks or spills. A drilling rig might have several hundred tonnes of mud in use at any one time, which creates a large demand for supplies. Once used, the mud must be either recycled or disposed of safely. Rock cuttings recovered from the mud during the drilling process amount to between 100 and 500 tonnes per well, depending on the depth. These, too, need to be disposed of in an environmentally acceptable fashion.

A combination of steel casing and cement in the well (Figure 1.2) provides an essential barrier to ensure that high-pressure gas or liquids from deeper down cannot escape into shallower rock formations or water aquifers. This barrier has to be designed to withstand the cycles of stress it will endure during the subsequent hydraulic fracturing, without suffering any cracks. The design aspects that are most important to ensure a leak-free well include the drilling of the well bore to specification (without additional twists, turns or cavities), the positioning of the casing in the centre of the well bore before it is cemented in place (this is done with centralisers placed at regular intervals along the casing as it is run in the hole, to keep it away from the rock face) and the correct choice of cement. The cement design needs to be studied both for its liquid properties during pumping (to ensure that it gets to the right place) and then for its mechanical strength and flexibility, so that it remains intact. The setting time of the cement is also a critical factor – cement that takes too long to set may have reduced strength; equally, cement that sets before it has been fully pumped into place requires difficult remedial action.

8. Pad drilling has long been used in northern areas, such as Alaska and in Russia, but the introduction of this practice to places such as Texas is relatively new.

Figure 1.2 ▷ Typical well design and cementing



Source: Adapted from ConocoPhillips.

Well completion

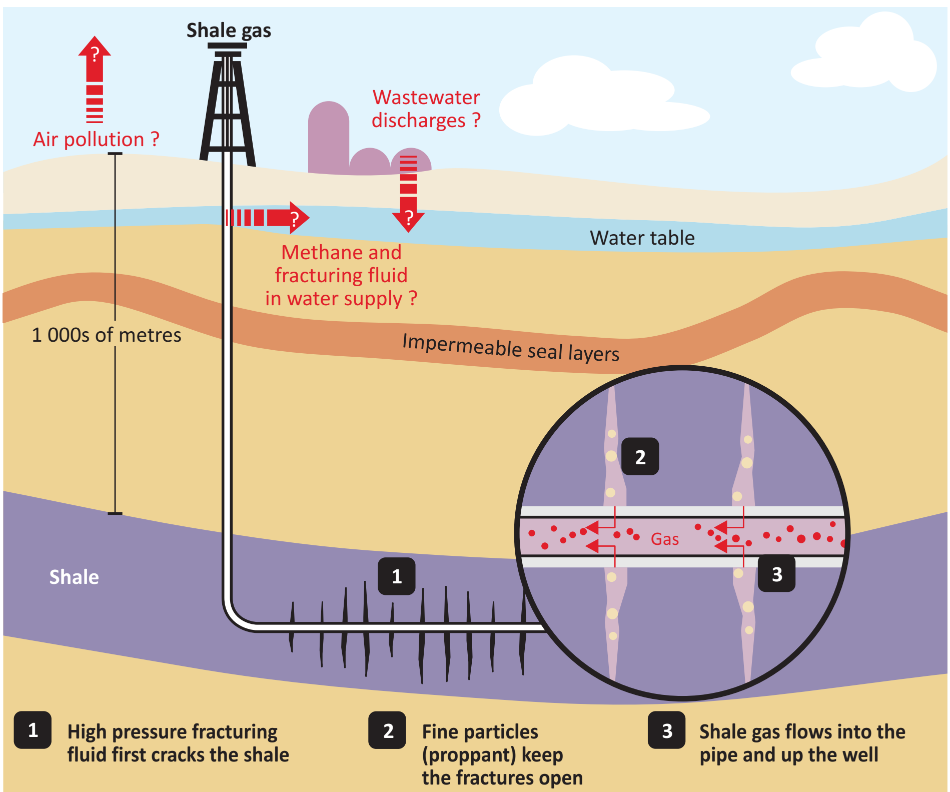
Once the well has been drilled, the final casing cemented in place across the gas-bearing rock has to be perforated in order to establish communication between the rock and the well.[9] The pressure in the well is then lowered so that hydrocarbons can flow from the rock to the well, driven by the pressure differential. With shale and tight gas, the flow will be very low, because of the low permeability of the rock. As the rate of hydrocarbon flow determines directly the cash flow from the well, low flow rates can mean there is insufficient revenue to pay for operating expenses and provide a return on the capital invested. Without additional measures to accelerate the flow of hydrocarbons to the well, the operation is then not economic.

Several technologies have been developed over the years to enhance the flow from low permeability reservoirs. Acid treatment, involving the injection of small amounts of strong acids into the reservoir to dissolve some of the rock minerals and enhance the permeability

9. Some wells are completed "open-hole", in which there is no casing in the final part of the well in the gas-bearing rock; this is not uncommon in horizontal wells.

of the rock near the wellbore, is probably the oldest and is still widely practised, particularly in carbonate reservoirs. Wells with long horizontal or lateral sections (known as horizontal wells) can increase dramatically the contact area between the reservoir rock and the wellbore, and are likewise effective in improving project economics. Hydraulic fracturing, developed initially in the late 1940s, is another effective and commonly-practised technology for low-permeability reservoirs. When rock permeability is extremely low, as in the case of shale gas or light tight oil, it often takes the combination of horizontal wells and hydraulic fracturing to achieve commercial rates of production (Figure 1.3). Advances in the application of these two techniques, in combination, largely explain the surge in shale gas production in the United States since 2005.

Figure 1.3 ▷ Shale gas production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows. Although the figure illustrates a shale gas well with multi-stage hydraulic fracturing, some similar hazards are present with conventional gas wells, and with tight gas developments.

Hydraulic fracturing involves pumping a fluid – known as fracturing fluid – at high pressure into the well and then, far below the surface, into the surrounding target rock. This creates fractures or fissures a few millimetres wide in the rock. These fissures can extend tens or, in some cases, even hundreds of metres away from the well bore. Once the pressure is released, these fractures would tend to close again and not produce any lasting improvement in the flow of hydrocarbons. To keep the fractures open, small particles, such as sand or ceramic beads, are added to the pumped fluid to fill the fractures and to act as proppants, *i.e.* they prop open the fractures thus allowing the gas to escape into the well.

Box 1.3 ▷ Unconventional gas production and earthquake risks

There have been instances of earthquakes associated with unconventional gas production, for example the case of the Cuadrilla shale gas operations near Blackpool in the United Kingdom, or a case near Youngstown, Ohio, in the United States, which has been provisionally linked to injection of waste water, an operation that is similar in some respects to hydraulic fracturing. The registered earthquakes were small, of a magnitude of around two on the Richter scale, meaning they were discernible by humans but did not create any surface damage.

Because it creates cracks in rocks deep beneath the surface, hydraulic fracturing always generates small seismic events; these are actually used by petroleum engineers to monitor the process. In general, such events are several orders of magnitude too small to be detected at the surface: special observation wells and very sensitive instruments need to be used to monitor the process. Larger seismic events can be generated when the well or the fractures happen to intersect, and reactivate, an existing fault. This appears to be what happened in the Cuadrilla case.

Hydraulic fracturing is not the only anthropogenic process that can trigger small earthquakes. Any activity that creates underground stresses carries such a risk. Examples linked to construction of large buildings, or dams, have been reported. Geothermal wells in which cold water is circulated underground have been known to create enough thermally-induced stresses to generate earthquakes that can be sensed by humans (Cuenot, 2011). The same applies to deep mining (Redmayne, 1998). What is essential for unconventional gas development is to survey carefully the geology of the area to assess whether deep faults or other geological features present an enhanced risk and to avoid such areas for fracturing. In any case, monitoring is necessary so that operations can be suspended if there are signs of increased seismic activity.[10]

In many cases, a series of fractures is created at set intervals, one after the other, about every 100 metres along the horizontal well bore. This multi-stage fracturing technique has played a key role in unlocking production of shale gas and light tight oil in the United States and promises to do likewise elsewhere in the world. A standard single-stage hydraulic fracturing may pump down several hundred cubic metres of water together with proppant and a mixture of various chemical additives. In shale gas wells, a multi-stage fracturing

10. Detailed recommendations, following analysis of the Cuadrilla event, are under consideration by the United Kingdom Department of Energy and Climate Change (DECC, 2012).

would commonly involve between ten and twenty stages, multiplying the volumes of water and solids by 10 or 20, and hence the total values for water use might reach from a few thousand to up to twenty thousand cubic metres of water per well and volumes of proppant of the order of 1 000 to 4 000 tonnes per well. The repeated stresses on the well from multiple high-pressure procedures increase the premium on good well design and construction to ensure that gas bearing formations are completely isolated from other strata penetrated by the well.

Once the hydraulic fracturing has been completed, some of the fluid injected during the process flows back up the well as part of the produced stream, though typically not all of it – some remains trapped in the treated rock. During this flow-back period, typically over days (for a single-stage fracturing) to weeks (for a multi-stage fracturing), the amount of flow back of fracturing fluid decreases, while the hydrocarbon content of the produced stream increases, until the flow from the well is primarily hydrocarbons.

Best practice during this period is to use a so-called "green completion" or "reduced-emissions completion", whereby the hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling or disposal. However, while collecting and processing the fluid is standard practice, capturing and selling the gas during this initial flow-back phase requires investment in gas separation and processing facilities, which does not always take place. In these cases, there can be venting of gas to the atmosphere (mostly methane, with a small fraction of VOCs) or flaring (burning) of hydrocarbon or hydrocarbon/water mixtures. Venting and/or flaring of the gas at this stage are the main reasons why shale and tight gas can give rise to higher greenhouse-gas emissions than conventional production (see the later section on methane and other airborne emissions).

Production

Once wells are connected to processing facilities, the main production phase can begin. During production, wells will produce hydrocarbons and waste streams, which have to be managed. But the well site itself is now less visible: a "Christmas tree" of valves, typically one metre high, is left on top of the well, with production being piped to processing facilities that usually serve several wells; the rest of the well site can be reclaimed. In some cases, the operator may decide to repeat the hydraulic fracturing procedure at later times in the life of the producing well, a procedure called re-fracturing. This was more frequent in vertical wells but is currently relatively rare in horizontal wells, occurring in less than 10% of the horizontal shale-gas wells drilled in the United States.

The production phase is the longest phase of the lifecycle. For a conventional well, production might last 30 years or more. For an unconventional development, the productive life of a well is expected to be similar, but shale gas wells typically exhibit a burst of initial production and then a steep decline, followed by a long period of relatively low production. Output typically declines by between 50% and 75% in the first year of production, and most recoverable gas is usually extracted after just a few years (IEA, 2009).

Well abandonment

At the end of their economic life, wells need to be safely abandoned, facilities dismantled and land returned to its natural state or put to new appropriate productive use. Long-term prevention of leaks to aquifers or to the surface is particularly important. Since much of the abandonment will not take place until production has ceased, the regulatory framework needs to ensure that the companies concerned make the necessary financial provisions and maintain technical capacity beyond the field's economic life to ensure that abandonment is completed satisfactorily, and well integrity maintained over the long term.

Coalbed methane developments

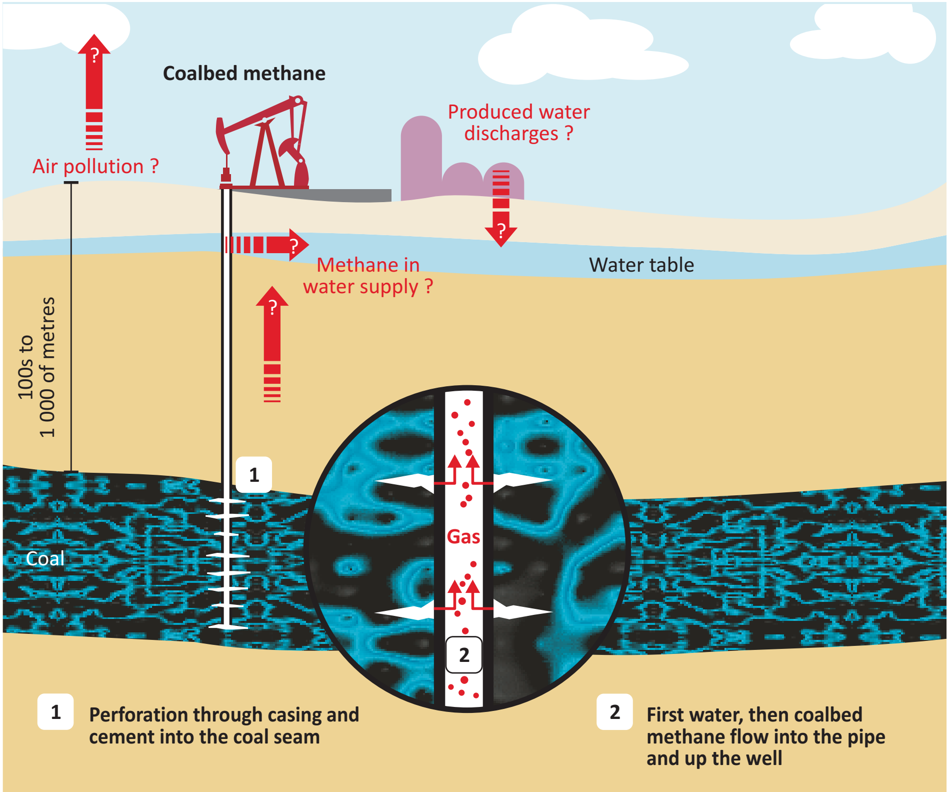
Coalbed methane refers to methane (natural gas) held within the solid matrix of coal seams. Some of the methane is stored within the coal as a result of a process called adsorption, whereby a film of methane is created on the surface of the pores inside the coal. Open fractures in the coal may also contain free gas or water. In some cases, methane is present in large volumes in coalbeds and can constitute a serious safety hazard for coal-mining operations. Significant volumes of CO_2 may also be present in the coal.

There are both similarities and differences between coalbed methane and the two other main types of unconventional gas discussed, which are linked to the way in which coalbed methane is extracted, the associated costs and the impact on the environment. The main similarity is the low permeability of the gas-bearing reservoir – a critical factor for the technical and economic viability of extraction. Virtually all the permeability of a coalbed is due to fractures, in the form of cleats and joints. These fractures tend to occur naturally so that, within a small part of the seam, methane is able to flow through the coalbed. As with shale and tight gas deposits, there are major variations in the concentration of gas from one area to another within the coal seams. This, together with variations in the thickness of the seam, has a significant impact on potential production rates.

Above ground, coalbed methane production involves disruption to the landscape and local environment through the construction of drilling pads and access roads, and the installation of on-site production equipment, gas processing and transportation facilities. As is often the case with shale gas and tight gas, coalbed methane developments require the drilling of more wells than conventional oil and gas production; as a result, traffic and vehicle noise levels, noise from compressors, air pollution and the potential damage to local ecological systems are generally more of an issue than for conventional gas output.

There are some important differences between coalbed methane and shale or tight gas resources. Coalbed methane deposits can be located at shallow depths (these are predominantly the deposits that have been exploited thus far), whereas shale and tight gas are usually found further below the surface. Water is often present in the coalbed, which needs to be removed to allow the gas to flow to the well. In addition, coalbed methane contains very few heavier liquid hydrocarbons (natural gas liquids or gas condensate), which means the commercial viability of production depends heavily on the price at which the gas itself can be sold; in the case of shale gas produced together with large volumes of associated natural gas liquids, the price of oil plays a very important role in determining the overall profitability of the development project.

Figure 1.4 ▷ Coalbed methane production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows.

Considerable progress has been made over the last 25 years in honing techniques to extract coalbed methane on a commercial basis, paving the way to production on a significant scale, initially in North America and, since the mid-1990s, in Australia. Coalbed methane can be produced from vertical or horizontal wells. The latter are becoming increasingly common, though less so than for shale gas. Generally, the thinner the coal seam and the greater the depth of the deposit, the more likely it is that a horizontal well will be drilled. Although a depth of 800 to 1 200 metres is typical, in some cases coalbed methane is located in shallow formations as little as 100 metres below the surface, making it more economical to drill a series of vertical wells, rather than a horizontal well with extended reach along the coal seam. For shallow deposits, wells can often be drilled using water-well drilling equipment, rather than rigs designed for conventional hydrocarbon extraction, with commensurately cheaper costs (US EPA, 2010). For deeper formations (400 to 1 200 metres), both vertical and horizontal wells are used and custom-built small drilling rigs, capable of handling blow-out risks, have been developed.

Once a well is drilled, the water in the coalbed is extracted, either under natural pressure or by using mechanical pumping equipment – a process known as dewatering (water use and contamination risks are discussed in more detail in the next section). As subsurface pressure drops with dewatering, the flow of natural gas previously held in place by water pressure increases initially as it is released from the natural fractures or cleats within the coalbed. The gas is separated from the water at the surface and is then compressed and injected into a gas-gathering pipeline for onward transportation.

As in the case of shale gas, the rate of production of coalbed methane is often significantly lower than that achieved in conventional gas reservoirs; it also tends to reach a peak quickly as water is extracted, before entering a period of decline as the well pressure drops further. A well's typical lifespan is between five and fifteen years, with maximum gas production often achieved after one to six months of water removal (Horsley & Witten, 2001). In most cases, the low natural permeability of the coal seam means that gas can flow into the well from only a small segment of the coal seam – a characteristic shared with shale and tight gas. As a result, a relatively large number of wells is required over the area of the coalbed, especially if they are drilled vertically.

In some cases, it may also be necessary to use hydraulic fracturing to increase the permeability of the coal seam in order to stimulate the release of water and gas. This is normally practised only in deeper wells, typically at several hundred metres below the ground. The decision to proceed with hydraulic fracturing needs to be made before drilling begins, as the well and surface facilities need to be designed accordingly. The approach is similar to that described above, but in contrast to current practice with shale gas and tight gas wells, fracturing for coalbed methane production is frequently a single-stage process, *i.e.* one fracturing job per well, rather than multi-stage. Since wells are often drilled in batches, the water required for hydraulic fracturing can be sourced from neighbouring wells that are being de-watered. The flow-back fluids recovered from the well are pumped to lined containment pits or tanks for treatment or offsite disposal.

Water use

The extent of water use and the risk of water contamination are key issues for any unconventional gas development and have generated considerable public concern. In the case of a shale gas or tight gas development, though some water is required during the drilling phase, the largest volumes of water are used during the hydraulic fracturing process: each well might need anything between a few thousand and 20 000 cubic metres (between 1 million and 5 million gallons). Efficient use of water during fracturing is essential. Average water use per well completion in the Eagle Ford play in west Texas has been reduced from 18.5 to 13.6 thousand cubic metres since mid-2010, primarily through increased recycling of waste water from flow-back of fracturing fluid, an important step forward, given that more than 2 800 drilling permits were issued by the Railroad Commission of Texas for Eagle Ford wells in 2011 (RCT, 2012).[11] The amount of water required for shale gas or tight gas developments, calculated per unit of energy produced, is higher than for conventional gas but comparable to the amount used for the production of conventional oil (Table 1.1).

Table 1.1 ▷ Ranges of water use per unit of natural gas and oil produced (cubic metres per terajoule)

	Water consumption	
	Production	Refining
Natural gas		
Conventional gas	0.001 - 0.01	
Conventional gas with fracture stimulation	0.005 - 0.05	
Tight gas	0.1 - 1	
Shale gas	2 - 100	
Oil		
Conventional oil*	0.01 - 50	5 - 15
Conventional oil with fracture stimulation*	0.05 - 50	5 - 15
Light tight oil	5 - 100	5 - 15

Source: IEA analysis.

* The high end of this range is for secondary recovery with water flood; the low end is primary recovery.

Note: Coalbed methane is not included in this table as it tends to produce water, rather than require it for production (but see below for the discussion of waste water disposal).

Water for fracturing can come from surface water sources (such as rivers, lakes or the sea), or from local boreholes (which may draw from shallow or deep aquifers and which may already have been drilled to support production operations), or from further afield (which generally requires trucking). Transportation of water from its source and to disposal locations can be a large-scale activity. If the hydraulic fracturing of a well requires 15 000 cubic metres, this amounts to 500 truck-loads of water, on the basis that a typical truck can hold around 30 cubic metres of water. Such transportation congests local roads, increases wear and tear to roads and bridges and, if not managed safely, can increase road accidents.

In areas of water-scarcity, the extraction of water for drilling and hydraulic fracturing (or even the production of water, in the case of coalbed methane) can have broad and serious environmental effects. It can lower the water table, affect biodiversity and harm the local

11. If these 2 800 wells each require 13.6 thousand cubic metres for well completion, the water requirement of 38 million cubic metres represents 0.2% of annual water consumption of the state of Texas, or 12% of the annual water consumption of the city of Dallas, Texas.

ecosystem. It can also reduce the availability of water for use by local communities and in other productive activities, such as agriculture.

Limited availability of water for hydraulic fracturing could become a significant constraint on the development of tight gas and shale gas in some water-stressed areas. In China, for example, the Tarim Basin in the Xinjiang Uyghur Autonomous Region holds some of the country's largest shale gas deposits, but also suffers from severe water scarcity. Although not on the same scale, in terms of either resource endowment or water stress, a number of other prospective deposits occur in regions that are already experiencing intense competition for water resources. The development of China's shale gas industry has to date focused on the Sichuan basin, in part because water is much more abundant in this region.

Hydraulic fracturing dominates the freshwater requirements for unconventional gas wells and the dominant choice of fracturing fluid for shale gas, "slick-water", which is often available at the lowest cost and in some shale reservoirs may also bring some gas-production benefits, is actually the most demanding in terms of water needs. Much attention has accordingly been given to approaches which might reduce the amount of water used in fracturing. Total pumped volumes (and therefore water volumes required) can be decreased through the use of more traditional, high viscosity, fracturing fluids (using polymers or surfactants), but these require a complex cocktail of chemicals to be added. Foamed fluids, in which water is foamed with nitrogen or CO_2, with the help of surfactants (as used in dish washing liquids), can be attractive, as 90% of the fluid can be gas and this fluid has very good proppant-carrying properties. Water can, indeed, be eliminated altogether by using hydrocarbon-based fracturing fluids, such as propane or gelled hydrocarbons, but their flammability makes them more difficult to handle safely at the well site. The percentage of fracturing fluid that gets back-produced during the flow-back phase varies with the type of fluid used (and the shale characteristics), so the optimum choice of fluid will depend on many factors: the availability of water, whether water recycling is included in the project, the properties of the shale reservoir being tapped, the desire to reduce the usage of chemicals and the economics.

Treatment and disposal of waste water

Waste water from hydraulic fracturing

The treatment and disposal of waste water are critical issues for unconventional gas production – especially in the case of the large amounts of water customarily used for hydraulic fracturing. After being injected into the well, part of the fracturing fluid (which is often almost entirely water) is returned as flow-back in the days and weeks that follow. The total amount of fluid returned depends on the geology; for shale it can run from 20% to 50% of the input, the rest remaining bound to the clays in the shale rock. Flow-back water contains some of the chemicals used in the hydraulic fracturing process, together with metals, minerals and hydrocarbons leached from the reservoir rock. High levels of salinity are quite common and, in some reservoirs, the leached minerals can be weakly radioactive, requiring specific precautions at the surface.[12] Flow-back returns (like waste water from drilling) requires secure storage on site, preferably fully contained in stable, weather-proof storage facilities as they do pose a potential threat to the local environment unless handled properly (see next section).

Once separated out, there are different options available for dealing with waste water from hydraulic fracturing. The optimal solution is to recycle it for future use and technologies are available to do this, although they do not always provide water ready for re-use for hydraulic fracturing on a cost-effective basis. A second option is to treat waste water at local industrial waste facilities capable of extracting the water and bringing it to a sufficient standard to enable it to be either discharged into local rivers or used in agriculture. Alternatively, where suitable geology exists, waste water can be injected into deep rock layers.

Box 1.4 ▷ What is in a fracturing fluid?

Environmental concerns have focused on the fluid used for hydraulic fracturing and the risk of water contamination through leaks of this fluid into groundwater. Water itself, together with sand or ceramic beads (the "proppant"), makes up over 99% of a typical fracturing fluid, but a mixture of chemical additives is also used to give the fluid the properties that are needed for fracturing. These properties vary according to the type of formation. Additives (not all of which would be used in all fracturing fluids) typically help to accomplish four tasks:

- To keep the proppant suspended in the fluid by gelifying the fluid while it is being pumped into the well and to ensure that the proppant ends up in the fractures being created. Without this effect, the heavier proppant particles would tend to be distributed unevenly in the fluid under the influence of gravity and would, therefore, be less effective. Gelling polymers, such as guar or cellulose (similar to those used in food and cosmetics) are used at a concentration of about 1%. Cross-linking agents, such as borates or metallic salts, are also commonly used at very low concentration to form a stronger gel. They can be toxic at high concentrations, though they are often found at low natural concentrations in mineral water.
- To change the properties of the fluid over time. Characteristics that are needed to deliver the proppant deep into subsurface cracks are not desirable at other stages in the process, so there are additives that give time-dependent properties to the fluid, for example, to make the fluid less viscous after fracturing, so that the hydrocarbons flow more easily along the fractures to the well. Typically, small concentrations of chelants (such as those used to de-scale kettles) are used, as are small concentrations of oxidants or enzymes (used in a range of industrial processes) to break down the gelling polymer at the end of the process.

12. These naturally occurring radioactive materials, or NORMs, are not specific to unconventional resources; some conventional reservoirs are also known to produce them.

- To reduce friction and therefore reduce the power required to inject the fluid into the well. A typical drag-reducing polymer is polyacrylamide (widely used, for example, as an absorbent in baby diapers).
- To reduce the risk that naturally occurring bacteria in the water affect the performance of the fracturing fluid or proliferate in the reservoir, producing hydrogen sulphide; this is often achieved by using a disinfectant (biocide), similar to those commonly used in hospitals or cleaning supplies.

Until recently, the chemical composition of fracturing fluids was considered a trade secret and was not made public. This position has fallen increasingly out of step with public insistence that the community has the right to know what is being injected into the ground. Since 2010, voluntary disclosure has become the norm in most of the United States.[13] The industry is also looking at ways to achieve the desired results without using potentially harmful chemicals. "Slick-water", made up of water, proppant, simple drag-reducing polymers and biocide, has become increasingly popular as a fracturing fluid in the United States, though it needs to be pumped at high rates and can carry only very fine proppant. Attention is also being focused on reducing accidental surface spills, which most experts regard as a more significant risk of contamination to groundwater.

Produced water from coalbed methane production[14]

In the case of coalbed methane, additional water supplies are rarely required for the production process, but the satisfactory disposal of water that has been extracted from the well during the dewatering process is of critical importance. The produced water is usually either re-injected into isolated underground formations, discharged into existing drainage systems, sent to shallow ponds for evaporation or, once properly treated, used for irrigation or other productive uses. The appropriate disposal option depends on several factors, notably the quality of the water. Depending on the geology of the coal deposit and hydrological conditions, produced water can be very salty and sodic (containing high concentrations of sodium, calcium and magnesium) and can contain trace amounts of organic compounds, so it often requires treatment before it can be used for irrigation or other uses. Using saline water for irrigation can inhibit germination and plant growth, while excessively sodic water can change the physical properties of the soil, leading to poor drainage and crusting and adversely affecting crop yields.

The potential cost of water disposal depends on both the extent to which treatment is required and the volume of water produced. In practice, the total amount of water that must be removed from each well to allow gas to be produced varies considerably. It can be very large; for example, an estimated 65 cubic metres of water (17 000 gallons) are

13. See the voluntary disclosure web site FracFocus (www.fracfocus.org).

14. Both conventional gas and other types of unconventional gas production can also be accompanied by produced water, but the flow rates involved are normally much smaller than for coalbed methane.

pumped from each coalbed methane well every day on average in the Powder River Basin in Montana and Wyoming. For the United States as a whole, it is estimated that, in 2008, more than 180 million cubic metres (47 billion gallons) of produced water were pumped out of coal seams (US EPA, 2010), equivalent to the annual direct water consumption of the city of San Francisco. In principle, produced water can be treated to any desired quality. This may be costly, but the treated water may have economic value for productive uses – as long as the cost of transporting the water is not excessive.

The options for treatment and disposal of produced water and the market value of water in the near vicinity are often key factors in the economics of coalbed methane developments. Many of the areas where coalbed methane is produced today, or where prospects for production are good, are arid or semi-arid and could benefit from additional freshwater supplies. For now, evaporation or discharge into drainage systems (in some cases, after treatment) are still the most common methods in North America (reuse of treated water is growing in Australia) because of the high cost of purifying the water for irrigation or reinjection into a deeper layer. In the United States, approximately 85 million cubic metres (22 billion gallons) of produced water, or about 45% of the total, were discharged to surface waters in 2008 with little or no treatment (US EPA, 2010).

There is limited experience of assessing the actual environmental impacts of produced water from coalbed methane production. A recent study by the US National Research Council found that the eventual disposal or use of produced water can have both positive and negative impacts on soil, ecosystems, and the quality and quantity of surface water and groundwater (NRC, 2010). Although the study found no evidence of widespread negative effects, allowance must be made for the fact that the industry is relatively young and that few detailed investigations into local impacts have been carried out yet.

The risk of water contamination

Significant concern has been expressed about the potential for contamination of water supplies, whether surface supplies, such as rivers or shallow freshwater aquifers, or deeper waters, as a result of all types of unconventional gas production. Water supplies can be contaminated from four main sources:

- Accidental spills of fluids or solids (drilling fluids, fracturing fluids, water and produced water, hydrocarbons and solid waste) at the surface.
- Leakage of fracturing fluids, saline water from deeper zones or hydrocarbons into a shallow aquifer through imperfect sealing of the cement column around the casing.
- Leakage of hydrocarbons or chemicals from the producing zone to shallow aquifers through the rock between the two.
- Discharge of insufficiently treated waste water into groundwater or, even, deep underground.

None of these hazards is specific to unconventional resources; they also exist in conventional developments, with or without hydraulic fracturing. However, as noted, unconventional developments occur at a scale that inevitably increases the risk of incidents occurring. Public concern has focused on the third source of potential contamination, *i.e.* the possibility that hydrocarbons or chemicals might migrate from the produced zone into aquifers through the intervening rock. However, this may actually be the least significant of the hazards, at least in the case of shale gas and tight gas production; in some cases a focus on this risk may have diverted attention, including the time of regulators, away from other more pressing issues.

Box 1.5 ▻ Coalbed methane production and effects on groundwater

There are concerns about the impact of coalbed methane production on groundwater flows and the supply and purity of water in aquifers adjacent to the coal seams being exploited. The extent to which this can occur is very location specific and depends on several factors, the most important of which are the overall volume of water initially in the coalbed and the hydrogeology of the basin; the density of the coalbed methane wells; the rate of water pumping by the operator; the connectivity of the coalbed and aquifer to surrounding water sources and, therefore, the rate of recharge of the aquifer; and the length of time over which pumping takes place.

In the United States, various agencies now monitor water in producing areas in order to learn more about this process. Depletion of aquifers because of coalbed methane production has been well-documented in the Powder River Basin: in the Montana portion of the basin, 65% to 87% recovery of coalbed groundwater levels has occurred after production ceased (NRC, 2010). However, the extent to which water levels in shallow alluvial and water table aquifers have dropped has not been measured (recent legislation in Queensland in Australia now requires such measurements to be performed). There is evidence that groundwater movement provoked by dewatering during coalbed methane production has increased the amount of dissolved salt and other minerals in some areas.

Because productive coal seams are often at shallower depths than tight or shale gas deposits, there is also a greater risk that fracturing fluids might find their way into an aquifer directly or via a fracture system (either a natural system or one that is created through fracturing). This risk is mitigated in part by the fact that, in contrast to shale or tight gas, the dewatering required for production of coalbed methane means that less water may be left in the ground in aquifers near the vicinity of the well, limiting the potential for contamination. As with shale or tight gas production, the flow-back fluids removed from the well after fracturing need to be treated before disposal.

The first hazard – the risk of spills at the surface – can be mitigated through rigorous containment of all fluid and solid streams. Accidents can always happen but good procedures, training of personnel and availability of spill control equipment can ensure they have a limited impact. As discussed below, greater use of pipelines to move liquids can reduce the risks associated with trucking movements.

Controlling the second hazard – leakage into a shallow aquifer behind the well casing – requires use of best practice in well design and well construction, particularly during the cementing process, to ensure a proper seal is in place, systematic verification of the quality of the seal and ensuring the seal does not deteriorate through the life of a well. This is a particular issue for wells in which multi-stage hydraulic fracturing is performed: the repeated cycles of high pressure pumping can apply repeated stress to the casing and to the cement column, potentially weakening them; selection of an appropriate strength of casing is therefore important.

The third hazard – leakage through the rock from the producing zone – is unlikely in the case of shale gas or tight gas because the producing zone is one to several thousand metres below any relevant aquifers and this thickness of rock usually includes one or several very impermeable layers. For example, the deepest potential underground sources of drinking water in the Barnett shale are at a depth of 350 metres, whereas the shale layer is at 2 000 to 2 300 metres. However, the hazard may be encountered if the producing zone is shallower or if there are shallow pockets of naturally occurring methane above the target reservoir. It is also theoretically possible if there are no identified impermeable layers in between or if deep faults are present that can act as a conduit for fluids to move from the deep producing zone towards the surface (such fluid movements are generally slow, but can occur on time scales of tens of years). One particular possibility is that hydraulic fractures may not be contained in the targeted rock layer and may break through important rock barriers or connect to deep faults. This is a rare occurrence because hydraulic fracturing is designed to avoid this (potentially costly) situation[15], but it cannot be completely excluded when the local geology is insufficiently understood.

Appropriate prior studies of the local geology to identify such situations are therefore a must before undertaking significant developments. Indeed, methane seeps to the surface have long been known (for example, the flame that has been burning for centuries in the village of Mrapen in Central Java, Indonesia, or the gas that fuels the "Eternal Flame Falls" in New York State, United States) and they have been used as a way to identify the presence of hydrocarbon deposits underground, showing that perfect rock seals do not always exist. On the other hand, the existence of seeps, and for that matter the presence of methane in many aquifers (Molofsky, 2011), shows that not all contamination is linked to industrial activity; it can also occur as a result of natural geological or biological processes.

15. This would increase losses of fracturing fluid and could mean in turn that the fracturing does not translate into the desired increase in gas production.

Addressing the fourth hazard – discharge of insufficiently treated waste water into groundwater or, even, deep underground – requires a regulatory response including appropriate tracking and documentation of waste water volumes and composition, how they are transported and disposed.

Methane and other air emissions

Shale gas and tight gas have higher production-related greenhouse-gas emissions than conventional gas. This stems from two effects:

- More wells and more hydraulic fracturing are needed per cubic metre of gas produced. These operations use energy, typically coming from diesel motors, leading to higher CO_2 emissions per unit of useful energy produced.
- More venting or flaring during well completion. The flow-back phase after hydraulic fracturing represents a larger percentage of the total recovery per well (because of more hydraulic fracturing, the flow-back takes longer and the total recovery per well is typically smaller due to the low permeability of the rock).

We have previously released estimates of these effects both in the case of flaring and for venting during flow-back, based on EPA data, in order to see what difference these practices make (IEA, 2011b). In the case of flaring, total well-to-burner emissions are estimated to be 3.5% higher than for conventional gas, but this figure rises to 12% if the gas is vented. Eliminating venting, minimising flaring and recovering and selling the gas produced during flow-back, in line with the Golden Rules, would reduce emissions below the lower figure given here.

Similar concerns about emissions attach to coalbed methane production, where significant volumes of methane can be vented into the atmosphere during the transition phase from dewatering to gas production and, where hydraulic fracturing is applied, during the well completion phase. Careful management of drilling, fracturing and production operations is essential to keep such emissions to a minimum.[16] This requires specialised equipment to separate gas from the produced water (and fracturing fluids) before injecting it into a gas-gathering system (or into temporary storage). If this is not possible for technical, logistical or economic reasons, it is preferable that the gas should be flared rather than vented for safety reasons and because the global-warming effect is considerably less.

The general issue of greenhouse-gas emissions from the production, transportation and use of natural gas, as well as the additional emissions from unconventional gas compared with conventional gas, has been the subject of some controversy. Some authors (Howarth, 2011) have argued that emissions from using natural gas as a source of primary energy have been significantly underestimated, particularly for unconventional gas. It has even been argued that full life-cycle emissions from unconventional gas can be higher than from

16. Coalbed methane production can reduce methane emissions if the gas would in any case have been released by subsequent coal-mining activities.

coal. The main issue revolves around methane emissions not only during production, but also during transportation and use of natural gas.

Methane is a more potent greenhouse gas than CO_2 but has a shorter lifetime in the atmosphere – a half-life of about fifteen years, versus more than 150 years for CO_2. As a result, there are different possible ways to compare the effect of methane and CO_2 on global warming. One way is to evaluate the Global Warming Potential (GWP) of methane, compared to CO_2, averaged over 100 years. The 4th Assessment report of the IPCC (IPCC, 2007) gives a value of 25 (on a mass basis) for this 100-years GWP, revised up from their previous estimate of 21. This value is relevant when looking at the long-term relative benefits of eliminating a temporary source of methane emissions versus a CO_2 source.

Averaged over 20 years, the GWP, estimated by the IPCC, is 72. This figure can be argued to be more relevant to the evaluation of the significance of methane emissions in the next two or three decades, which will be the most critical to determine whether the world can still reach the objective of limiting the long-term increase in average surface temperatures to 2 degrees Celsius (°C). Moreover, some scientists have argued that interactions of methane with aerosols reinforce the GWP of methane, possibly bringing it to 33 over 100 years and 105 over 20 years (Shindell, 2009): these recent analyses are under review by the IPCC. Such higher values would, of course, have implications not only for methane emissions from the gas chain but also for all other methane emissions, from livestock, landfills, rice paddies and other agricultural sources, as well as from natural sources (Spotlight).

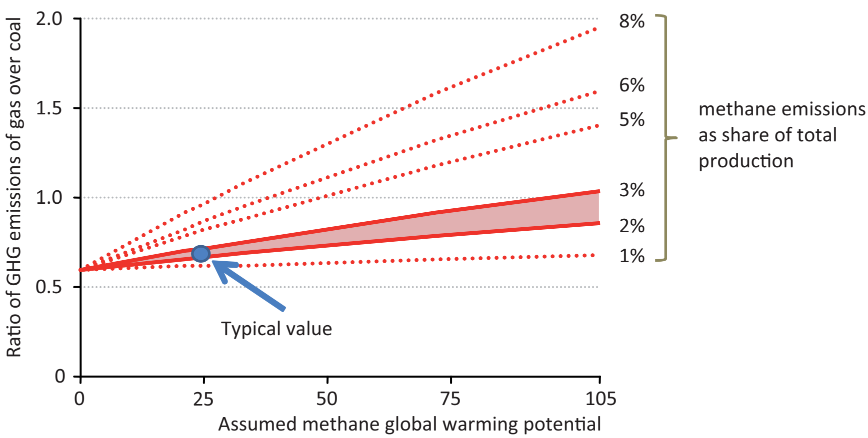
Methane emissions along the gas value chain (whether conventional or unconventional) come from four main sources:

- Intentional venting of gas for safety or economic reasons. Venting during well completions falls into this category, but venting can also take place as part of equipment maintenance operations.
- Fugitive emissions. These might be leaks in pipelines, valves or seals, whether accidental (*e.g*. corrosion in pipelines) or built into the equipment design (*e.g.* rotating seals, open tanks).
- Incidents involving rupture of confining equipment (pipelines, pressurised tanks, well isolation).
- Incomplete burning. The effectiveness of gas burning in gas flares varies according to wind and other conditions and is typically no better than 98%. (A similar effect can be seen when starting a gas stove: it can take a few seconds before a steady flame is established).

By their very nature, these emissions are difficult to quantify. Most estimates are based on emission factors for various parts of the chain (wells, various equipment, pipelines and so on), derived from studies conducted in the United States by the EPA and the Gas Research Institute in the 1990s (US EPA and GRI, 1996). It is by no means clear that these studies give a good indication for emissions in other parts of the world, or for the possible evolution of methane emissions in the future. Estimates of methane emissions from the gas chain at the global level vary between 1% and 8% of produced natural gas volumes (Howarth, 2011 and references therein; Petron, 2012; Cathles, 2012; Jiang 2011; and Skone 2011). The most comprehensive projections of future emissions, from the EPA (US EPA, 2011), assume no change in emission factors, for want of a better approach, and project a 26% increase in methane emissions from the oil and gas industry between 2010 and 2030.

Different assumptions about the level and impact of methane emissions can have a profound effect on the perception of gas as a "cleaner" fossil fuel. Figure 1.5 shows the well-to-burner emissions of natural gas compared to coal, as a function of various assumptions on GWP and average methane emissions. As seen from this figure, standard values (25 GWP, 2% to 3% methane emissions as a share of total production) substantiate the widely accepted advantage of gas, thanks to its lower combustion CO_2 emissions per unit of energy; but it is clear that more pessimistic assumptions can make gas a worse greenhouse-gas emitter than coal. It is very important that additional scientific work should pinpoint the most relevant GWP value and that efforts are redoubled to measure methane emissions more systematically.[17]

Figure 1.5 ▷ The impact of changing assumptions about methane on comparative well-to-burner greenhouse-gas emissions of natural gas versus coal



Note: Values below 1.0 on the vertical axis show points at which gas has lower well-to-burner emissions than coal. The comparison is for equivalent volumes of primary energy; however, gas also tends to be transformed, into other energy carriers (such as electricity) with higher efficiency than coal, so the ratio can be lower when calculated for the same end-use energy.

17. See, for example, a recent paper included in the Proceedings of the US National Academy of Sciences on methane leakage from natural gas infrastructure (Alvarez *et al.*, 2012)

One advantage attributable to expanded unconventional gas production and use over production and use of conventional gas is the distance to market; in general, unconventional resources are developed closer to the point of consumption, thereby reducing the distance required for transportation. All else being equal, this tends to reduce the level of fugitive emissions, as well as CO_2 emissions from the energy used for transportation.

SPOTLIGHT

How large are global methane emissions?

It is estimated that about 550 million tonnes (Mt) of methane (IPPC, 2007) are released into the atmosphere every year, but data on global methane emissions are poor. Converted into CO_2 equivalent (using the standard IPCC 100-years Global Warming Potential of 25), this amounts to about 14 gigatonnes CO_2-eq, roughly one-fourth of global greenhouse-gas emissions. Natural emissions (not related to man's activities) represent about 40% of total methane emissions. They come from natural seeps, wetlands, animals, such as termites, and vegetation decay. In addition, massive amounts of methane are stored in permafrost in Arctic regions and in underwater methane hydrates deposits. Some of this stored methane is released by natural processes, which are considered likely to accelerate with global warming: there is a risk of natural emissions increasing dramatically over the coming decades.

Non-energy related anthropogenic emissions come mostly from livestock, agriculture, landfills and wastewater. These represent about 38% of total methane emissions (64% of anthropogenic methane emissions). Energy-related methane emissions come from oil, gas and coal production, transportation, distribution and use as well as some biomass combustion: together they are estimated to be 125 Mt per year, about 20% of global methane emissions (36% of anthropogenic methane emissions). The gas and oil industry account for the lion's share of this: 70%, or 90 Mt per year, representing about 15% of total methane emissions (26% of anthropogenic emissions).

If current emissions are poorly known and the numbers above mere estimates, projecting future methane emissions is fraught with even more uncertainties. Natural emissions could be dramatically altered by the evolution of the climate. For anthropogenic emissions, activity levels in the energy and other industries as well as in livestock and agriculture can be projected, based on econometric analysis and assumptions on GDP and population growth, but the evolution of emission factors (volume of methane emitted per unit of activity) is very uncertain.[18] Many mitigation measures are considered to have low or even negative costs: reducing leaks in a gas

18. The IEA model (developed in collaboration with the OECD, using the ENV-linkages OECD model) uses the costs of mitigation measures (as derived from EPA studies; EPA, 2006) and a pseudo-price of carbon (whether coming from taxes, a carbon market or from regulations) to determine the likely evolution of emissions from an economic point of view. EPA has recently released draft updated costs of mitigation (EPA, 2012).

distribution system, for example, can allow more gas to be sold; the gas collected from a landfill can be marketed; changing the feed given to livestock to reduce methane production can allow more of the energy content of the feed to be transformed into marketable meat or milk. On the other hand, because of the very (spatially) distributed nature of most methane emission sources, it is not obvious that economic considerations alone will be sufficient to induce change. To achieve the trajectories of methane emissions consistent with the internationally agreed goal to limit the rise in global mean temperature to 2°C above pre-industrial levels, additional policy measures will be needed.

Golden Rules to address the environmental impacts

The outlook for unconventional gas production around the world depends critically on how the environmental issues described earlier are addressed. Society needs to be adequately convinced that the environmental and social risks will be well enough managed to warrant consent to unconventional gas production, in the interests of the broader economic, social and environmental benefits that the development of unconventional resources can bring. The Golden Rules, which are set out below with some explanatory background, suggest principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts in order to earn or retain that consent. We have called them Golden Rules because they can pave the way for the widespread and large-scale development of unconventional gas resources, boosting overall natural gas supply so as to realise a Golden Age of Gas (IEA, 2011b).

Abiding by these Golden Rules – or any rules – cannot reduce to zero the impacts on the environment associated with unconventional gas production. In any such undertaking, there are inevitable trade-offs between reducing the risks of environmental damage, on the one hand, and achieving the benefits that can accrue to society from the development of economic resources. In designing an appropriate regulatory framework, policy-makers need to set the highest reasonable social and environmental standards, assessing the cost of any residual risk against the cost of still higher standards (which could include the abandonment of resource exploitation). What is reasonable will evolve over time, as technology and industrial best practice evolve: in this spirit, these are not rigid rules, set in stone, but principles intended to guide regulators and operators. The format of regulation is also critical to achieving the intended result: it may include some specific and inflexible requirements but it should also encourage and reward performance to the highest standards, not supporting the notion that enough has been done if the instructions of others are mechanically observed, however meticulously. Ultimately, operators are responsible for the results of their operations. In framing these Golden Rules, we find that both governments and industry need to intensify their associated work if public confidence in this new industry is to be gained and retained.

Measure, disclose and engage

- ***Integrate engagement with local communities, residents and other stakeholders into each phase of a development, starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance, listen to concerns and respond appropriately and promptly.*** Simply providing information to the public is not enough; both the industry and the public authorities need to engage with local communities and other stakeholders and seek the informed consent that is often critical for companies to proceed with a development. Operators need to explain openly and honestly their production practices, the environmental, safety, and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development. The primary role of the public authorities in this context is to provide credible, science-based background information that can underpin an informed debate and provide the necessary stimulus for joint endeavour between the stakeholders.
- ***Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, and continue monitoring during operations.*** This is a shared responsibility between the regulatory authorities, industry and other stakeholders. The data gathered needs to be made public and opportunities provided for all stakeholders to address any concerns raised, as an essential part of earning public trust. At a minimum, resource management or regulatory agencies must have groundwater quality information (and, for coalbed methane production, information on groundwater levels) in advance of new drilling activities, so as to provide a baseline against which changes in water level and quality can be compared.
- ***Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.*** Good data, measurement and transparency are vital to public confidence. For example, effective tracking and documentation of waste water is necessary to incentivise and ensure its proper treatment and disposal. Reluctance to disclose the chemicals used in the hydraulic fracturing process and the volumes involved, though understandable in terms of commercial competition, can quickly breed mistrust among local citizens and environmental groups.
- ***Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.*** Existing legislation and regulations usually require operators to act in an environmentally and socially responsible manner, but operators need to go beyond minimally satisfying legal requirements in demonstrating their commitment to local development and environmental protection, for example through attention to local concerns about the volume and timing of truck traffic. Particularly in jurisdictions where mineral rights are owned by the state (rather than as in parts of the United States, where surface landowners might also be subsurface mineral rights holders,

entitled to royalty payments), it is essential that tangible benefits are evident at the local level, where production occurs. This can be difficult to achieve in a timely manner, given the delay between the start of a development project and the moment at which revenues start to flow, whether to government, the mineral rights' owner or the operator. Early public commitment by authorities and developers to expand local infrastructure and services in step with exploration and production activities can help. Governments need to be willing to consider using part of the revenues (from taxes, royalties, etc.) to invest in the development of the areas in question.

Watch where you drill

- ***Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.*** The choice of well site is a moment when engagement with local stakeholders and regulators needs to be handled with the utmost care. Each well site needs to be chosen based on the subsurface geology, but also taking into consideration populated areas, the natural environment and local ecology, existing infrastructure and access roads, water availability and disposal options and seasonal restrictions caused by climate or wildlife concerns. Sensitivity at this stage to a range of above-ground concerns can do much to mitigate or avoid problems later in a development.
- ***Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.*** Careful planning can greatly improve the productivity and recovery rates of wells, reducing the number of wells that need to be drilled and minimising the intensity of hydraulic fracturing and the associated environmental impact. Although the risk of triggering an earthquake is small, even minor earth tremors can easily undermine public confidence in the safety of drilling operations. A careful study of the geology of the area targeted for drilling is necessary to allow operators to avoid operations in areas where deep faults or other characteristics create higher risks. Producers also need to survey for the presence of old boreholes or naturally occurring methane in shallow pockets above the source rock and adjust drilling sites (or the pathway of the wellbore) to avoid these areas.
- ***Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.*** The risk of leakage of the fracturing fluid used for shale and tight gas production through the rock from the producing zone into aquifers is minimal because the aquifers are located at much shallower depths; but such migration is theoretically possible in certain exceptional circumstances (described in the preceding section). A good understanding of the local geology and the use of micro-seismic (or other) measuring techniques for monitoring fractures is necessary to minimise the residual risk.

Isolate wells and prevent leaks

- ***Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.*** Regulations need to ensure wells are designed, constructed and operated so as to ensure complete isolation. Multiple measures need to be in place to prevent leaks, with an overarching performance standard requiring operators to follow systematically all recommended industry best practices. This applies up to and including the abandonment of the well, *i.e.* through and beyond the lifetime of the development.
- ***Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.*** Alongside measures to ensure that wells are designed, built and cemented to a high standard, the regulator may choose to define an appropriate depth limitation for shale and tight gas wells, based on local geology and any risk of communication with freshwater aquifers, above which hydraulic fracturing is prohibited.
- ***Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.*** This requires both stringent regulations and a strong performance commitment by all companies involved in drilling and production-related activities to carry out operations to the highest possible standard. Good procedures, training of personnel and ready availability of spill-control equipment are essential to prevent and limit the impact of accidents if they do occur. Upgrading fluid-disposal systems so that storage and separation tanks replace open pits (closed-loop systems) can reduce the risk of accidental discharge of wastes during drilling.

Treat water responsibly

- ***Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.*** Regulations covering shale and tight gas production (coalbed methane operations are net producers of water) need to be designed to encourage operators to use water efficiently and to reuse and recycle it. The largest volumes of water are required for hydraulic fracturing: where the necessary economies of scale are present, it should be feasible to reuse and recycle significant volumes of the flow-back water from fracturing operations, reducing the issues and costs associated with truck traffic and with securing water supplies and wastewater disposal.
- ***Store and dispose of produced and waste water safely.*** Within an overarching performance framework, rigorous and consistent regulations are needed to cover safe storage of waste water, with measures to ensure the robust construction and lining of open pits or, preferably, the use of storage tanks. Technology exists to treat produced and waste water to any standard, with the cost varying accordingly. It is

the responsibility of regulators to set and enforce appropriate standards based on local factors, including the availability of freshwater supplies and options for disposal, without diminishing the operators' ultimate responsibility for operation in accordance with evolving best practice standards. The least-cost solution for producers may not be the most economically optimal solution, when the potential long-term benefits of using treated water and the wider social and environmental costs of discharges into water courses or evaporation ponds are taken into consideration.

- ***Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.*** Disclosure of fracturing fluid additives can and should be compatible with continued incentives for innovation. The industry should commit to the development of fluid mixtures that, if they inadvertently migrate or spill, do not impair groundwater quality, or adopt techniques that reduce the need to use chemical additives.

Eliminate venting, minimise flaring and other emissions

- ***Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.*** Best practice is to recover and market gas produced during the completion phase of a well, and public authorities need to consider imposing restrictions on venting and flaring and specific requirements for installing equipment to help minimise emissions. Measures in this area will also lower emissions of conventional pollutants, including VOCs. Operators should consider setting targets on emissions as part of their overall strategic policies to win public confidence that they are acting to minimise the environmental impact of their activities, taking into account the financial benefits of commercialising the gas that would otherwise be vented or flared. The gas industry as a whole, including conventional gas producers and companies operating in the midstream and downstream, needs to demonstrate that they are just as concerned by methane emissions beyond the production stage, for example in transportation and distribution.
- ***Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.*** Pollution from vehicles and equipment is often controlled by existing environmental and fuel-efficiency standards (it is a responsibility of governments to ensure that appropriate standards are in place). Operators and service providers should consider the advantages of deploying the cleanest vehicles and equipment available, for example, electric vehicles and gas-powered rig engines, to reduce both local air and noise pollution.

Be ready to think big

- ***Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.*** Investments in infrastructure to reduce environmental impacts that may be commercially impossible to justify for an individual well can be justified for a larger development. Good regulation can help to realise these gains by ensuring appropriate spatial planning of licensing areas and of the associated infrastructure (such as access roads, water resources and disposal facilities, gas processing units, compression stations and pipelines). The concept of utility corridors and multi-use rights of way can be useful to concentrate infrastructure development and so limit the wider environmental impacts. Operators can realise these gains in various ways, for example by drilling multiple wells from a single pad (with horizontal bores tapping different parts of the reservoirs): this may result in greater disruption in the immediate vicinity of the site but can significantly reduce the wider environmental footprint. Another example is the construction of a pipeline network for water that requires upfront investment but obviates the need for many thousands of truck movements over the duration of a project and can lower unit costs.[19] Good project and logistical planning by operators needs to go hand-in-hand with early strategic assessments and timely interventions by public authorities.
- ***Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.*** Development of any hydrocarbon resource involves a large amount of activity to build the necessary infrastructure, bring in supplies, drill wells, extract the resource, process it and transport it to market. This activity is enhanced for unconventional developments, because of the larger number of wells required. As a result, the level of activity that might be tolerable for individual wells, such as volumes of road traffic, land and water use or noise from drilling activity, can increase by orders of magnitude. Regulators need to assess the cumulative impact of these effects and respond appropriately. Assessment on a regional basis is particularly important in the case of water requirements.

19. See the next sub-section for an assessment of the impact of such infrastructure developments on project costs; this is also covered in a recent paper on water management economics for shale gas developments (Robart, 2012).

Ensure a consistently high level of environmental performance

- ***Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate level, sufficient permitting and compliance staff, and reliable public information.*** An important focus for governments should be on ensuring there is a sufficient knowledge base on all environmental and technical aspects of unconventional gas development, that high-quality data are available and that sound science is being applied and promoted. Well-funded, suitably skilled and motivated regulators, in sufficient numbers, are essential to the responsible development of an unconventional resource.
- ***Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.*** In some areas, detailed rules and checks are indispensable to guarantee environmental performance; but it is not always possible, or desirable, to regulate every aspect of a process in which technology is moving rapidly. Setting performance criteria and allowing operators to find the best way to meet them can often provide a better outcome than a prescriptive approach. Examples of performance criteria might be a mandated minimum level of improvement in water usage or a requirement that a "best-in-class" cement quality measurement is run, the burden being on the operator to prove the use of best-in-class. Whichever approach or combination of methods is chosen, there needs to be strict enforcement and penalties in the case of non-compliance, ultimately including loss of the licence to operate.
- ***Ensure that emergency response plans are robust and match the scale of risk.*** Operators and local emergency services should have robust plans and procedures in place to respond quickly and effectively to any accident, including appropriate training and equipment.
- ***Pursue continuous improvement of regulations and operating practices.*** Technology and best practice are constantly evolving. While respecting the advantages of clarity and stability in regulation, governments must be ready to incorporate lessons learned from experience in a dynamic industrial sector. For industry, following best practice means constant readiness to raise standards and providing the means to meet them.
- ***Recognise the case for independent evaluation and verification of environmental performance.*** Credible, third-party certification of industry performance can provide a powerful tool to earn and maintain public acceptance, as well as providing a powerful tool to assist companies to adhere to best practices. These independent assessments should come from institutions that enjoy public trust, whether academic or research institutes or independent regulatory or certification bodies.

Complying with the Golden Rules

Application of these Golden Rules requires action to be taken by both governments and industry. While the ultimate responsibility for sustaining public confidence rests with the industry, it is governments that that need to set the regulatory framework, promulgate the required principles and provide support through many related activities, *e.g.* scientific research. Trying to specify precisely the roles of governments, gas producers and other private sector operators in each area is not practicable on a global scale. Conditions vary from country to country, including the legal, geological, social and political background, farming/land-use practices, water availability and many others.[20] But the general principles are clear and, in the sections that follow which examine the implications of the Golden Rules for governments and for industry, we have included some observations on the allocation of responsibilities between the public authorities and operators.

Implications for governments

Ensuring responsible development of unconventional gas resources, in line with these Golden Rules, puts substantial demands on policy-makers and regulators. First and foremost, the intensive nature of unconventional gas developments – and the scope for rapid growth in unconventional supply discussed in Chapter 2 – means that existing regulatory arrangements may have to be revised and licensing, compliance and enforcement staff reinforced. The need for new regulatory bodies may need to be considered or, more likely, existing ones may require new resources, functions and powers. This reinforcement of capacity needs to anticipate the expansion of industrial activity, so an appropriate regulatory regime is in place in good time. In keeping with regulatory best practice, such regulators will need to be independent of industry (although this certainly does not exclude ongoing consultation with industry), and have the right (often new) skills and funding. Scope exists to secure the necessary funding from industry in advance of development, for example through fees attached to the award of exploration rights.

The overarching challenge for policy-makers, to find the right balance between the need to minimise adverse environmental and social impacts while encouraging the responsible development of resources for the benefit of the local and national economy, will require judgement at the highest political level. Once that judgement is made, operational decisions of considerable weight remain to be made, for example as to the level of detail required in regulating industry operations – detailed or prescriptive provisions may be necessary, but they can also deny legitimate scope for operators to minimise costs and can impose onerous monitoring and enforcement responsibilities on regulators; performance-based regulation can work better in many areas, particularly for an industry in which technology is changing quickly.

20. Examples of regulation and best practice, from different countries, in areas covered by these Golden Rules are available on the IEA website at http://www.worldenergyoutlook.org/goldenrules.

In a number of jurisdictions, significant advances have been made in regulatory arrangements in recent years. However, the situation is very dynamic and industry has the capacity to expand rapidly; governments in resource-rich areas need to act quickly to anticipate future needs and to put the necessary measures in place. The challenge for governments and regulators can be acute in relation to water resources and the risk of water contamination. Rigorous data collection, assessment and monitoring of water requirements (for shale and tight gas), and measurement of the quality of produced water (for coalbed methane) and of waste water (in all cases) are needed to allow informed decisions to be made. Existing users are deeply suspicious that their rights and water availability might be compromised. There is a need, among other things, for transparent, speedy and equitable procedures for compensating existing users who suffer loss.

Box 1.6 ▷ Getting the market setting right

Alongside attention to environmental issues, there are many other policy areas that affect the prospects for unconventional gas development, including: the terms for access to resources; clarity on mineral rights; a consistent fiscal and overall investment framework; the provision of infrastructure; and the structure and regulatory framework in a given market (see also the assumptions underpinning the projections in Chapter 2). Market developments are at varying stages in different countries and regions. North America has well-functioning gas markets and, to take one example, many observers consider reliable third-party access to pipelines has been a pivotal part in its unconventional gas development by giving gas producers confidence that their new gas output will be able to reach market. Other key supportive market or regulatory conditions for gas production (both conventional and unconventional) include: the removal of wellhead price controls; the absence of undue restrictions on trade and export; a competitive upstream environment that encourages innovation; and efficiency and market-based pricing for gas. While these market conditions have been under discussion for many years in most OECD jurisdictions, implementation of the necessary reforms remains at best incomplete; and the challenges are greater in many non OECD countries.

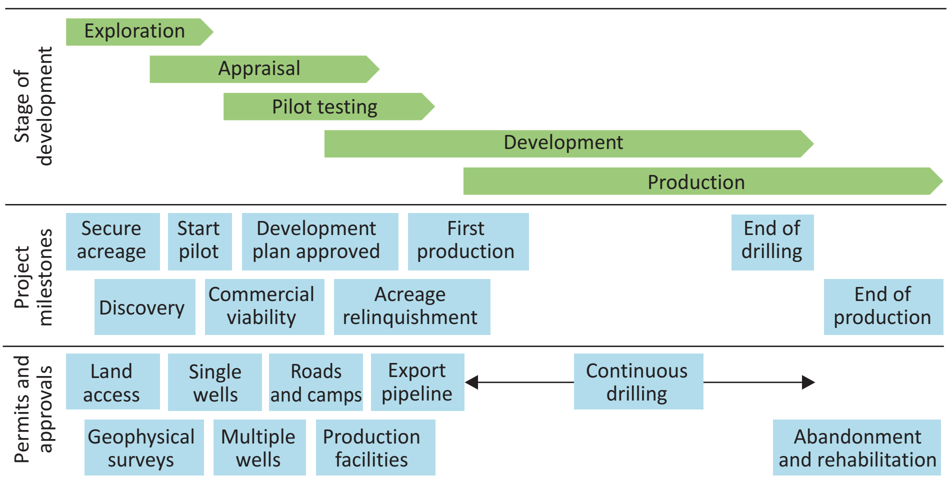
Governments everywhere have a central role in ensuring a sound, scientific, credible, knowledge base is publicly available prior to widespread development. Policy-makers and regulators themselves need access to the necessary expertise in order to understand and mitigate the environmental risks.[21] Baselines for various indicators, water in particular, are critical in this regard, but this requirement also encompasses basic geological and geophysical information. Good quality data are essential, not just as an input to good

21. An example is the decision of the Australian Government in late 2011 to establish an expert Scientific Committee, funded with AUD 150 million ($150 million) over four years, to oversee regional assessments and research on water-related impacts in areas where coalbed methane developments are proposed.

policy-making, but also to make it possible to demonstrate that the regulatory system is functioning effectively and to identify areas where improvements are needed.

Within large federal systems (for example the United States, Canada and Australia) environmental powers are usually exercised at state or provincial level, facilitating approaches that respond to local factors, such as the geology, the chosen technology and specific environmental risk factors. Local social and environmental concerns are often best dealt with at local levels. Clarity is often required as to the division of responsibilities between different levels of government, with the national authorities responsible for ensuring reasonable consistency of regulation and that adequate funding is available for region-wide work (for example, in river systems that cross internal or international boundaries).

Figure 1.6 ▻ Stages in an unconventional gas development



Note: The stages, milestones and permits shown here are not unique to unconventional developments, but the distinctive element is the overlap between stages of development, as opposed to a more sequential pattern for a typical conventional project.

Differences between the way in which conventional and unconventional resources are developed need to be taken into account in designing an effective legal and regulatory system. Conventional oil and gas developments generally follow a fairly well-defined sequence, but the distinctions between the phases of an unconventional development can be much less clear-cut – development generally proceeds in a more incremental fashion (Figure 1.6).[22] At any given time an operator may be exploring or appraising part of a

22. Often, the initial question is not whether the unconventional resource exists but whether the gas or liquids can be produced in a particular location at economic flow rates. Whereas each appraisal well of a conventional reservoir tends to increase knowledge about the overall reservoir structure and its limits, it is much more difficult with an unconventional play to extrapolate the results of individual appraisal wells to the acreage as a whole.

licence area, developing another part and producing from a third, with different regulatory approvals and permits applying at each stage. The blurred lines between the stages of an unconventional resource project development increase the complexity of the interactions between operator and regulators (and between the operator and local communities) throughout the life cycle of the development. For example, the regulatory system in most jurisdictions requires the submission and approval of a detailed field development plan at the end of the exploration phase. However, the longer learning curve for unconventional plays makes it much more difficult to develop comprehensive plans at this stage, with the risk that relatively small subsequent alterations might trigger the need to resubmit and re-approve the entire development plan – a lengthy and burdensome process for both sides.

Beyond their focus on the proper construction of individual wells and installations, regulators also need to take a broader view of the impact of multiple projects and wells over time. This broader scope is essential when it comes to assessments of water use and disposal and of future water requirements, but can be also required in other areas, including land use, air quality, traffic and noise. In general, a regulatory system that focuses primarily on well-by-well approvals rather than project level authorisations, can fail to provide for some environmental risks and miss opportunities to relieve them. For example, there are investments in infrastructure that may not proceed for an individual well but which would serve appreciably to reduce the cumulative environmental impacts of large-scale development, such as centralised water treatment plants or pipeline networks for water supply or removal (see below). One of the ways that a regulatory framework can facilitate this sort of investment is through issuing licences for sufficiently large areas and durations.

Governments are usually instrumental in promoting the co-ordinated and timely expansion of regional infrastructure alongside a gas development, including either directly putting in place alternatives to road transportation or ensuring that the regulatory framework serves to encourage or require the construction of gas transportation capacity or an expansion of local power supply. Either way, strong co-ordination and communication is necessary between different branches and levels of government, as the rapid growth of a new industry puts pressure not only on the local physical infrastructure, but also on local social services.

Implications for industry

All parts of the unconventional gas industry have to contribute to proving to society that the benefits of unconventional gas development more than offset the costs in social and environmental terms. This entails, among other things, demonstrating that environmental and social risks are being properly addressed at all stages of a development: adoption and application in full of these Golden Rules is one way to support and accelerate this process. Elements of these Golden Rules are already being applied today, incorporated into best practice or embodied in regulation. The challenge is to ensure that the highest reasonable standards are in place and are applied and enforced in a consistent and credible way across the industry. Companies have to convince society that they have both the interest and the incentive to constantly seek ways of improving their performance.

There is a cost entailed. Compliance with these Golden Rules can in many cases increase the overall financial cost of development. How much will vary, depending on the starting point and on how each jurisdiction formulates its rules but, based on our analysis of the impact on the costs of a typical 2011 shale gas well (presented below), the additional costs are likely to be limited. For a single well, application of the Golden Rules can add around 7% to the overall cost of drilling and completion. The increase in costs could be significantly lower when considered across a full development project, as additional upfront capital costs incurred to reduce environmental impacts can, in many cases, be offset by lower operating costs.

Major cost elements in a shale gas well

The major cost elements in the drilling and completion of a shale gas well are the rig and associated drilling services, and the hydraulic fracturing stage of well completion. Well construction costs are primarily influenced by the geographical location, the well depth and, to some extent, reservoir pressure, and by the market and infrastructure conditions in the country or region under consideration. For example, a typical onshore shale gas well in the Barnett shale in Texas may currently cost $4 million to construct, while a similar well in the Haynesville shale costs twice as much, because of the depth and pressure. A similar well in Poland might cost $10 million to $12 million, because the current size of the market means that the drilling and service industry is much less developed in Poland than in the United States.

In general, more technical services are required during drilling and completing a shale or tight gas well than for a similar onshore conventional gas well, which makes it more expensive. The cost of multi-stage hydraulic fracturing can add anything between $1 million and $4 million to the construction costs of a well in the United States, depending on location, depth and the number of stages. In a shale reservoir, when drilling a well with a long lateral section, roughly 40% of the total cost goes toward the drilling and associated hardware and the remaining 60% to well completion, of which multi-stage hydraulic fracturing is the largest component. In a conventional well, the completion cost would be only about 15% of the overall well cost.

Break-even costs of shale-gas production in the United States have fallen sharply in recent years, thanks to an increase in the proportion of horizontal wells, the length of horizontal sections and the number of hydraulic fracturing stages per well, as well as the benefits of ever-better knowledge and experience of the various resource plays. The share of horizontal wells in the total number of shale-gas wells drilled increased from less than 10% in 2 000 to well over 80% today. Over the same period, the average length of the lateral sections has increased from around 800 metres to well over 1 200 metres and the typical number of hydraulic fracturing stages has risen from single figures to around 20.[23]

Operational costs, similarly, vary with local conditions: for example, just as for drilling, operating costs in Europe are expected to be 30% to 50% higher than in the United States for a similar shale gas operation. Dry gas requires less processing than wet gas (gas containing a small fraction of liquid hydrocarbons), but also has lower market value, particularly in the current context of very high oil-to-gas price ratios in some markets.

It is worth noting that two of the key subsurface drivers of well cost – depth and well pressure – are expected to be higher in many of the areas being explored outside North America. On the other hand, for all unconventional deposits, there is considerable potential for cost savings through organising development so as to exploit economies of scale, learning, and optimising well selection and locations for hydraulic fracturing.

Impact on the cost of a single well

The typical shale gas well that we use as a basis for this analysis is not a "worst case" but rather a well of the type that was regularly drilled in 2011 into deep shale reservoirs (such as the Haynesville and Eagle Ford shale plays) in the United States, taking in many industry best practices that were not always systematically followed in the previous decade. The well is assumed to reach a vertical depth of the order of 3 000 metres, have a horizontal section of around 1 200 metres and be completed with 20 fracture stages using a total of 2 000 tonnes of proppant and 15 000 cubic metres of water (requiring 500 trucks). This type of well would typically be drilled in three sections of successively smaller diameter, each one being lined with steel casing and cemented in place before the next section is drilled.[24] The well considered is a development well rather than an exploratory well.

Such a well might be expected to cost $8 million, take a month to drill and a further month to complete. The hydraulic fracturing process accounts for around 40% of the total well cost – around twice as much as the second most expensive item, the rig itself. By comparison, a typical onshore conventional vertical gas well in the same area would cost around $3 million, with 40% being spent on the rig.

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23. Some wells have lateral sections reaching up to 3 000 metres in length, with up to 40 individual geological zones for hydraulic fracturing, carried out one at a time. However, there are practical mechanical limits to the length of horizontal sections and multi-stages due to the pressure and temperature effect on the casing which mean that laterals longer than 1 800 metres or more than 20 fracture stages carry more mechanical risk (Holditch, 2010).

24. Since the well being considered already had two barriers over the shallow aquifer region with hydrocarbons being produced through production tubing, we did not include an additional casing string in our calculation of the additional costs of compliance.

Applying the Golden Rules to this well would be expected to have the following effects on costs, summarising various elements of the Rules under four indicative headings:

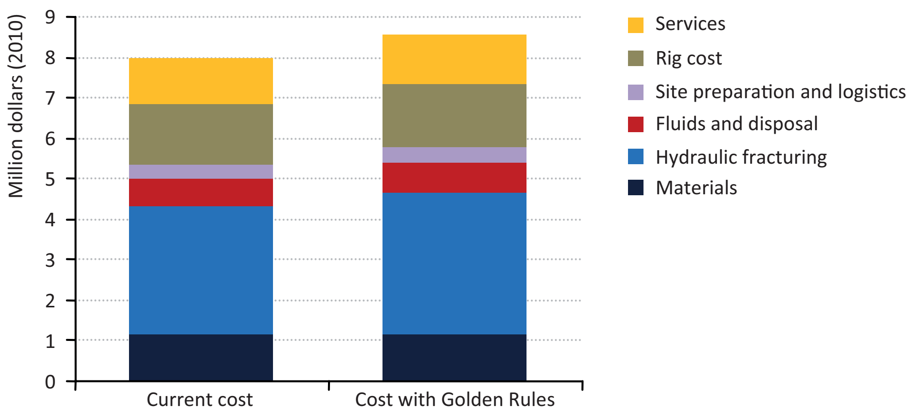
- **Isolate wells and prevent leaks:** measures in this area could include increased spending on cement design, selection and verification, coupled with a slight increase in drilling time to ensure the quality of the well-bore and provide a contingency for remedial cementing, if required. For the purposes of our analysis, we have assumed that the cement would be designed to withstand all expected stresses over the life span of the well, including the stresses induced during the 20 stages of hydraulic fracturing. The well would be drilled with appropriate tools and mud to produce a smooth and regular well-bore, to ensure that the cement bonds tightly with the wall of the well. Flexible cements or cements incorporating other technical advances that give better performance against the design criteria would be used. The cement would be pressure-tested and measurements taken to validate the quality of the cement bond on the exterior casing wall, with a contingency for remedial work if required. The American Petroleum Institute (API) publishes comprehensive standards and best practices pertaining to the construction of wells to ensure their integrity so that they are leak-free. In our analysis, 10% was estimated as the increment to drilling and cementing service costs needed to take account of these measures.
- **Eliminate venting, minimise flaring and other emissions:** this could be achieved by installing separator equipment for the hydrocarbons when they are brought to surface. For the purposes of our analysis, we have estimated a 10% addition to the cost of services required during the flow-back phase (but have not assumed that it is offset by sales of the recovered oil or gas[25]).
- **Treat water responsibly:** measures in this area could involve upgrading of fluid-disposal systems to ensure zero discharge at any stage and maximum re-use of water, as well as the use of green fracturing fluids with minimum chemical additives. In our analysis, 10% has been added to the cost of hydraulic fracturing on this basis, and a further 10% to the cost of rig fluids and disposal.
- **Disclose and engage:** responsiveness to local community concerns might involve reducing the noise from rig operations by cladding the rig with sound-proof material or imposing trucking restrictions at times at which they would otherwise cause greatest local disturbance or risk of accident. $20 000 has been added to the rig cost to cover sound-proofing of the rig and 10% to the logistics cost to cover some trucking restrictions.

In addition to these measures, we have included other actions that would add little to the cost of operations but would increase understanding of the environmental impact of shale-gas operations and facilitate dialogue with stakeholders. Simple measurement of airborne

25. According to the US EPA (EPA, 2011), general adoption of this type of "green completion" could also cut emissions of VOCs from new hydraulically fractured gas wells by 95%. The EPA further estimates that operators could expect to recover the additional cost associated with green completions within 60 days through the sale of captured hydrocarbons.

emissions at well sites in a consistent manner would provide valuable information to narrow the uncertainty around the extent of fugitive emissions of methane. Similarly, tests of local water wells that draw from an aquifer being drilled through would determine if there was contamination from any source. In total, we estimate that all the measures listed above would add around $580 000, or 7%, to the overall cost of drilling and completing this shale-gas well (Figure 1.7).

Figure 1.7 ▹ Impact of the Golden Rules on the cost of a single deep shale-gas well



Notes: Materials include all tangible material that is used in the well construction and remains in the well when it is completed, such as steel casing, valves and plugs.

Services include various services, other than hydraulic fracturing services, that are used in well construction: directional drilling services, cementing services, casing services, wire line and testing services.

Source: IEA analysis.

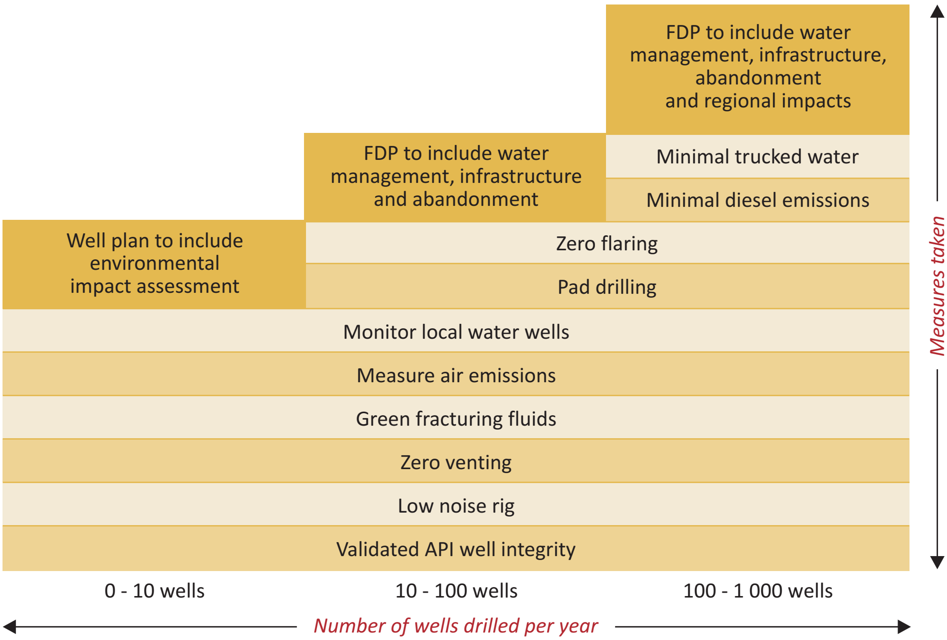
Impact on larger-scale developments

In practice, within a single licensing area, each operator typically drills a large number of wells at different sites. Applying the Golden Rules to entire unconventional gas developments could diminish the impact on overall production costs, because of economies of scale. While many of the environmental impacts discussed earlier in this chapter demand action chiefly where the scale of operations is large, large-scale operations also provide opportunities to minimise or eliminate environmental risks by optimising the process of drilling and completing each well. As the size of a development increases, measures to reduce environmental effects become both necessary and economically feasible (Figure 1.8), in a way that may not be possible for a single well.[26] In the case of gas, water and potentially

26. Many best practices can and should be applied to all wells, regardless of the size of the development. However, practices such as pad drilling, zero flaring and the minimisation of diesel emissions or trucked water involve the installation of infrastructure that, as well as not being cost effective, might even cause more environmental disruption if serving only single wells. For example, the number of truck journeys required to install water pipelines to a single isolated well would probably be more than the number of truck journeys required for the water itself.

electricity networks, greater upfront capital expenditure is required, but operating costs can be reduced, leaving the overall economics of a large-scale development no worse and in some cases improved.

Figure 1.8 ▷ Indicators of best practice as unconventional gas developments grow in size



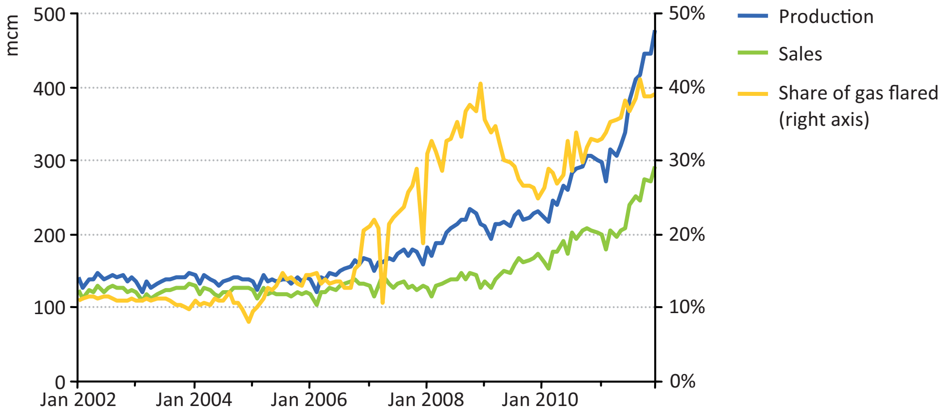
Notes: FDP = Field Development Plan; API = American Petroleum Institute Standards.

A well thought-out field development plan, based on a thorough environmental impact assessment, can help to capture these economies of scale and ensure that the hazards are well identified and that preventative or mitigating measures are in place. A key assumption in our analysis is that operators are able to plan developments optimally, both in space and in time. For this, licensing areas need to be large enough and be held for periods that are long enough for efficient development planning and the sharing of infrastructure. This needs a supportive regulatory framework.[27] Realising these gains also tends to rely on early investment in project infrastructure, often before production comes on stream and revenues start to flow: this can be a constraint for smaller companies, particularly where they are investing in marginal developments.

27. In certain regions of the United States, this is not possible due to smaller acreage blocks and lease expiration acting as a driver for development planning.

Good logistics and project planning is essential, both from the industry and from the public authorities, in view of the envisaged scale of a development. It is particularly important that infrastructure development keeps pace with upstream activity as the consequences of failure to do so can fall on the environment. For example, Figure 1.9 illustrates how the rapid development of light tight oil production in the Bakken shale was accompanied by a rise in the flaring of associated gas, as the necessary increase in gas transport infrastructure did not occur at the same pace as the increase in drilling.

Figure 1.9 ▷ Monthly natural gas production and flaring in North Dakota



Source: North Dakota Mineral Resources Department.

For the purposes of our analysis of the implications of applying the Golden Rules at scale, we considered a development of 120 wells per year.[28] In order to be able to plan and implement the types of measures described in Figure 1.8, the licensing area would need to comprise contiguous blocks and be held for at least a ten-year period, with freedom to develop according to the best environmental plan (rather than drilling to retain leases or avoid relinquishment clauses).

For this scale of development, we envisaged the following:

- **Zero venting or flaring of gas at all stages of operations:** this would require the installation of test equipment and gas-gathering infrastructure before any wells are completed. The scale of operation would mean that it would be economically viable to have this equipment dedicated to the development, although it remains challenging to estimate expected production rates with sufficient accuracy to ensure that the infrastructure is correctly sized. The early installation of gas-gathering infrastructure would bring forward capital expenditure, but would not increase the net cost, as any additional charges, including interest charges, would probably be offset by the value of the gas captured. *Estimated cost impact on a large-scale development: neutral.*

28. We considered ten rigs drilling eight wells from each pad, where the drilling phase of each well lasts 30 days, including the rig move. Thus, each rig would move every eight months to a new pad location.

- **Zero in-field trucking of water within the concession area:** this is an area where regulation and licensing requirements can play an important role. If these facilitate the necessary investment, capital expenditure on building water supply pipelines could be offset over the ten-year period by the reduction in truck movements. *Estimated cost impact: neutral.*
- **Central purpose-built water-treatment facilities:** these facilities, allowing closed-loop recycling of waste water, could be linked by pipeline to each pad location. They would reduce the overall water supply required for operations and minimise the need for off-site disposal, thereby reducing total transportation, water and disposal costs. Based on industry case studies, *we estimate savings at $100 000 to $150 000 per well*.
- **A long-term monitoring program for the development:** this could take different forms but might include performing a 3-D seismic survey over the licensing area before drilling commences to establish a geological baseline for the location of faults and sweet spots, as well as the temporary or permanent installation of micro-seismic monitoring to monitor seismic events and the propagation of fractures, and the installation of equipment to monitor the quality of water in aquifers that are being drilled through. *We estimate the additional cost of these three measures at between $100 000 and $150 000 per well*.
- **Systematic learning about the shale:** this could involve taking the opportunity provided by each well to learn more about the reservoir by capturing data (typically by using down-hole measuring instruments) that will enable the character and behaviour of the shale to be better understood. This understanding is an important contributory factor in improving the operational performance (and therefore the environmental impact per unit of production) of each well drilled and in eliminating wells and fracture stages that do not contribute significantly to production. *We estimate the additional cost at $200 000 per well*.

Most of these measures would involve a marginal increase in the overall cost of a large-scale development. But there is potential for reducing costs through better planning of operations, which would also reduce environmental risks:

- **Exploiting economies of scale:** pad drilling and the associated ability to carry out simultaneous operations on more than one well has been shown to bring significant cost savings as well as reducing the total surface footprint. Typically the drilling phase of a number of wells on the pad would be finished first, enabling the completion phase to be carried out for multiple wells in parallel. "Simultaneous operations" of this sort can allow for more efficient use of equipment for hydraulic fracturing. The US company, Continental Resources, has reported a 10% drop in average well cost in the Bakken Shale, from $7.2 million to $6.5 million, by using such an approach at eight well pads. Other industry sources report savings of up to 30%, due to a combination of economies of scale and improvements in operational efficiency. *On this basis, we have estimated savings of 10% per well.*

- **Optimising the number of fracture stages:** this can achieved by acquiring better information about where the sweet spots are likely to be and fracturing only in those zones, rather than simply fracturing every 100 metres, with no science applied. Industry data from different shale plays in the United States show that, on average, between 30% and 40% of fractures do not contribute any production at all. We have assumed conservatively that at least two hydraulic fracturing stages out of twenty could be saved as a result of better reservoir characterisation by systematically learning about the shale. *This would represent a cost saving of around $400 000 per well or equivalent gains in production for the same number of stages.*
- **Learning from experience:** there is a learning curve associated with the drilling and completion of shale-gas wells that, on a large scale of development, can bring significant cost savings as time goes on: these savings are often quoted in conjunction with economies of scale and the optimisation of fracture stages. *For the purposes of our analysis, we have not added any additional saving related to the learning curve.*

Summing up the effects of the more stringent environmental measures applied to the development and the efficiency savings from better planning yields an overall net cost saving of approximately 5%. Most of these savings come from economies of scale and reduced hydraulic fracturing, which more than offset the additional cost of implementing well-specific measures and monitoring environmental effects.

There is potential for even larger cost savings in large-scale developments by optimising the number and location of wells drilled. Given the enormous variability in geology, there are significant variations in the economics of unconventional gas wells, driven largely by differences in the expected cumulative output of each one (referred to as Estimated Ultimate Recovery [EUR]). The ability of operators to locate sweet spots within an unconventional gas play, where output is particularly high, (or their good fortune in doing so) explains a large part of the difference in EUR between wells. The adoption of advanced technologies in drilling and completing wells can also help to increase EUR.

At present, in the vast majority of shale gas developments wells are drilled and hydraulically fractured “geometrically”, that is to say at regular intervals, without regard for the changing geology between those intervals. Some wells give very good initial production and others close to zero. A detailed study of more than 7 000 wells in the Barnett Shale in *WEO-2009* showed that half of the horizontal wells drilled were unprofitable, even at the 2009 gas price of $6 per MBtu, while some others were profitable at much lower prices (IEA, 2009). This reflects differences in the amount of gas produced, itself a reflection of the local geology of the formation, but also of differences in the suitability and effectiveness of the well design and hydraulic fracturing operations. Reservoir characterisation and modelling techniques for shales is applied only in a limited manner at present. It is not unreasonable to expect that, had there been smarter selection of drilling targets, the least profitable 20% of wells in our sample would not have been drilled at all. Better understanding of the science of hydrocarbon flows within unconventional gas reservoirs is needed for improved reservoir characterisation and modelling to be achieved (Box 1.7).

Box 1.7 ▻ The potential benefits of better petroleum science

For all the advances that have been made in shale gas production in the United States in recent years, a large number of wells that prove to be very unproductive are still being drilled. Often, the value of the gas and liquids they yield is insufficient to cover the cost, the losses on such wells generally being offset by other wells that prove to be very productive. In addition, recovery factors for shale gas and light tight oil are very low, compared to conventional reservoirs: estimates in most cases do not exceed 15% of the original oil and gas in place. A better scientific understanding of both the geological structure and hydrocarbon flows within shale and tight gas rock should allow producers to target better and to refine their drilling and well-completion operations, driving down the number of unproductive wells and pushing up the estimated ultimate recovery – a tremendous prize for all stakeholders.

Thus far, improvements in unconventional gas technology have largely been concerned with how, on a cost-effective basis, to pump more fluid into more fracture stages in longer horizontal sections in order to increase reservoir contact, and how to better manage the environmental effects. But while advances in drilling and hydraulic fracturing technology have unlocked unconventional reserves that were previously uneconomic, the science of the behaviour of the reservoirs is still not well understood. This makes it very hard to predict decline rates and the ultimate production potential of each play and individual areas and wells. Traditional methods of computer modelling and simulation of oil and gas reservoirs do not work well in the case of shale gas or light tight oil.

This scientific challenge has attracted a significant research effort from industry experts and academia. Breakthroughs in understanding the behaviour of shale and tight-gas reservoirs are expected and are likely to trigger a shift from the current "brute force" approach to production towards a more scientific one, enabling operators to avoid drilling poor wells and using ineffective well-completion methods. This would allow for more efficient use of water and other resources, minimising the environmental footprint and lowering production costs.

The Golden Rules Case and its counterpart

How might unconventional gas re-shape energy markets?

Highlights

- In a Golden Rules Case, we assume that the conditions are in place, including the application of the Golden Rules, to allow for an accelerated global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas supply has a strong moderating impact on gas prices and, as a result, demand for gas grows by more than 50% to 2035 and the share of gas in the global energy mix rises to 25% in 2035, overtaking that of coal.
- Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 tcm in 2035. The share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Whereas unconventional gas supply is currently concentrated in North America, in the Golden Rules Case it is developed in many other countries around the world, notably in China, Australia, India, Canada, Indonesia and Poland.
- The Golden Rules Case sees a more diverse mix of sources of gas in most markets, suggesting an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies. An increased volume of gas, particularly LNG, looking for markets in the period after 2020 stimulates the development of more liquid and competitive international markets. The projected levels of output in the Golden Rules Case would require more than one million new unconventional gas wells to be drilled worldwide between now and 2035.
- In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of unconventional gas resources is accessible for development and, as a result, global unconventional gas production rises only slightly above 2010 levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use remains well behind that of coal. The requirement for imported gas is higher and some patterns of trade are reversed, with North America needing significant quantities of imported LNG, and the preeminent position in global supply of the main conventional gas resource-holders is reinforced.
- Although the forces driving the Low Unconventional Case are led by environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. Reaching the international goal to limit the long-term increase in the global mean temperature to two degrees Celsius would, in either case, require strong additional policy action.

Paths for unconventional gas development

There are factors on both the demand and supply sides pointing to a bright future for natural gas, but the key element in the supply outlook is the growth in production of – and expectations for – unconventional gas resources. For the moment, production of unconventional gas is still overwhelmingly a North American phenomenon: in 2010, 76% of global unconventional gas output came from the United States (360 billion cubic metres [bcm]) and a further 13% from Canada (60 bcm). Outside North America, the largest contribution to unconventional gas production came from China and Australia, producing around 10 bcm and 5 bcm of coalbed methane, respectively.[1] But, in light of the North American experience and with evidence of a large and widely dispersed resource base, there has been a surge of interest from countries all around the world in improving their security of supply and gaining economic benefits from exploitation of domestic unconventional resources.

Box 2.1 ▷ Overview of cases

This chapter sets out projections from two cases, for the period to 2035, which explore the potential impact and implications of different trajectories for unconventional gas development.

- A ***Golden Rules Case***, to which the main part of this chapter is devoted, assumes that the conditions are put in place to allow for a continued global expansion of gas supply from unconventional resources. This allows unconventional gas output to expand not only in North America but also in other countries around the world with major resources.
- A ***Low Unconventional Case*** considers the opposite turn of events, where the tide turns against unconventional gas, as environmental and other constraints prove too difficult to overcome.

These projections are assessed against an updated ***baseline***, which takes as its starting point the central scenario (the New Policies Scenario) from the most recent *World Energy Outlook*, *WEO-2011*. The two main cases test a range of favourable and unfavourable assumptions about the future of unconventional gas. A necessary, but not sufficient, condition of the Golden Rules Case is the effective application of the Golden Rules, in order to earn or maintain the "social licence" for the industry to operate. Neither case is advanced as more probable; they are rather designed to inform the debate about the implications of different policy choices for energy markets, energy security and for climate change and the environment.

1. A proportion of gas production in Russia is classified as unconventional, tight gas.

The potential is there for unconventional gas supply to grow rapidly in the coming decades, but the speed at which this supply will grow is still highly uncertain. Outside North America, the unconventional gas business is in its formative years, with major questions still to be answered about the extent and quality of the resource base and the ability of companies to develop it economically. Moreover, as discussed in Chapter 1, social concerns about the impact of producing unconventional gas, particularly the threat of unacceptable environmental damage, have risen as production has grown. Reports of water contamination, earthquakes, and other disruptions to local communities have given unconventional gas production, and the practice of hydraulic fracturing in particular, a bad name in many countries.

It remains to be seen how this social and environmental debate will play out in different parts of the world. In parts of Canada, the United States and Australia, moratoria have been placed on hydraulic fracturing, pending the results of additional studies on the environmental impact of the technology. Even in advance of any commercial production, similar prohibitions are already in force in parts of Europe. There is a distinct possibility that, if these concerns are not directly and convincingly addressed, then the lack of public acceptance in some countries could mean that unconventional production is slow to take off, or, indeed, falters at the global level.

This chapter examines two scenarios, the Golden Rules Case and the Low Unconventional Case (Box 2.1), in the first of which these challenges are overcome and a second in which they are not successfully addressed. The difference in outcomes between them posits a critical link between the way governments and operators respond to these social and environmental challenges and the prospects for unconventional gas production. The strength of this link differs among countries depending on the ways that public concerns and perceptions of risk affect political decision-making. But the assumptions underlying these cases reflect our judgement that the development of this relatively new industry is contingent, in many places, on a degree of societal consent that in some places has yet to be achieved. Moreover, the perception of the industry as a whole is likely to be cast by the performance of its weakest players, not its strongest. Without a general and sustained effort from both governments and operators, the public may not be convinced that the undoubted benefits outweigh potential risks.

Golden Rules and other policy conditions

The Golden Rules, presented and discussed in Chapter 1, are principles designed to minimise the undesirable effects of unconventional gas production on society and the environment. Implementing such principles is in many cases a question of appropriate regulation; but this is not the whole story. The task for policy-makers and regulators is to find the right equilibrium that deals convincingly with social and environmental concerns without removing the economic incentives for developing an important national resource. This balance will vary from country to country, given differing energy security, economic and environmental priorities.

In the Golden Rules Case, we assume that all resource-rich countries formulate their approach to environmental regulation of unconventional gas production in line with these principles and thereby achieve a level of environmental performance and public acceptance that provides the industry with a "social licence to operate". In that sense, the Golden Rules become a necessary (but not sufficient) condition for a wide expansion of unconventional gas supply.

In the Low Unconventional Case, this balance is not found and the Golden Rules are either not adopted or inadequately applied. Whether in response to new incidents of environmental damage or evidence of poor industry performance, the potential social and environmental threats are deemed to be too significant in some countries or regions, to the extent that there are substantial obstacles to developing the resource. Longer-lasting prohibitions are imposed in some countries on technologies that are essential to unconventional gas development, such as hydraulic fracturing, or exclusion zones are created and tight restrictions applied to drilling locations that restrict access to all or part of the resource. Alternatively, either a combination of very strict and detailed regulation imposes prohibitive compliance costs or fears about future regulatory change deter investment.

The application of these Golden Rules is not sufficient in itself to determine successful resource development in countries with unconventional gas potential. Based on experience in the United States, other key factors include:

- **Access to resources:** these considerations include access to geological data on a reasonable and transparent basis, the size of the area covered by a licence and the duration of the licence, and freedom for companies to engage in upstream activities on a competitive basis.
- **The fiscal and regulatory framework:** some countries have high potential in terms of resources but unattractive overall conditions for investment, such as unpredictable fiscal regimes or weak institutions.
- **Availability of expertise and technology:** not least because unconventional gas production requires a large number of wells, the industry needs a skilled and experienced workforce and a well-developed service sector with access to the necessary equipment.
- **Existing infrastructure:** although there are possibilities for small-scale gas gathering arrangements and direct conversion to power (or liquefied natural gas [LNG]), the density of the gas transport infrastructure in areas targeted for unconventional development is an important consideration, as is the existence of guaranteed access to this infrastructure.
- **Markets and pricing:** gas is relatively expensive to transport (compared with its well-head production costs and also with the cost of transporting oil) so companies will be attracted to resources with reliable, proximate markets that offer the necessary

incentives to develop the gas. The absence of market pricing in the host market can eliminate the commercial case for unconventional gas development.

- **Water availability:** water is essential to the production process for shale gas and tight gas (see Chapter 1), and competition with established users in water-stressed areas may constrain unconventional developments.[2]

Experience in the United States points to additional factors such as the number of entrepreneurial and independent companies willing to take the risk of venturing into a new industrial sector, which is coupled with their ability to mitigate market risk via well-developed financial markets. In the absence of widespread examples outside the United States, it is impossible for the moment to say which of the ingredients listed above are essential for large-scale unconventional gas development, which of them are merely desirable, and which might play only a limited role. What can be said, though, is that the mix of conditions and constraints varies by country: in some, environmental and social issues will be decisive; in others, the quality of the resource, the nature of the upstream supply chain, market conditions and prices, or the overall legal system and investment security, may be more significant.

Our general assumption in the Golden Rules Case is that all of the potential obstacles listed are either overcome or do not prove a serious constraint on unconventional gas development. A major motivation for supportive policies is assumed to be the desire of countries to secure the economic benefits of a valuable indigenous resource and, in many cases, also to improve energy security by reducing dependence on imported gas. The essence of the Golden Rules is that they bolster public confidence in the determination of public authorities and operators alike to overcome the social and environmental hazards, thereby creating a political environment that allows for the enactment of other policies encouraging investment in this sector. In the Low Unconventional Case, weak or absent political support deters the implementation of supportive measures for unconventional gas development, such as attractive fiscal and investment terms.

In the projections for the different cases, which are presented later in this chapter, the results of adopting the Golden Rules, in the Golden Rules Case, and the results of failing to do so, in the Low Unconventional Case, are compared against the outcome in a baseline case. This baseline case uses the central scenario of the *WEO-2011* (the New Policies Scenario) as its starting point, but incorporates more recent data, where these have become available, and certain new assumptions, such as the rate of GDP growth, which are described more fully later in the chapter. The baseline case sees natural gas prices converge towards the levels assumed in the *WEO-2011* New Policies Scenario, whereby prices in the United States reach $8.2 per million British thermal units (MBtu) in 2035 (in year-2010 dollars) and average import prices into Europe and Japan reach $12.2/MBtu and $14.2/MBtu respectively. However, the baseline case excludes the application in full of the

2. The *WEO-2012* will include a dedicated chapter on the links between energy and water use.

Golden Rules and the other supportive policies that generate faster growth in natural gas production in the Golden Rules Case.

Unconventional gas resources

Our projections depend, first, on the size of the available resource. Drawing on data from a variety of sources, we estimate that remaining technically recoverable resources of shale gas amount to 208 trillion cubic metres (tcm), tight gas 76 tcm and coalbed methane 47 tcm (Table 2.1). Russia and countries in the Middle East are the largest holders of conventional gas resources (and Russia has by a distance the largest overall gas resources). However, a large part of the world's remaining recoverable unconventional gas lies in countries or regions that are currently net gas importers and face increasing import dependency, such as China, and the United States, which before the recent boom in unconventional gas in North America was looking at the prospect of rising LNG imports (Figure 2.1). Different assumptions about the terms of access to the unconventional resource base in China and in the United States, and in other unconventional resource-rich countries around the world, are a main determinant of the variations between levels of production in the Golden Rules Case and the Low Unconventional Case.

Table 2.1 ▷ Remaining technically recoverable natural gas resources by type and region, end-2011 (tcm)

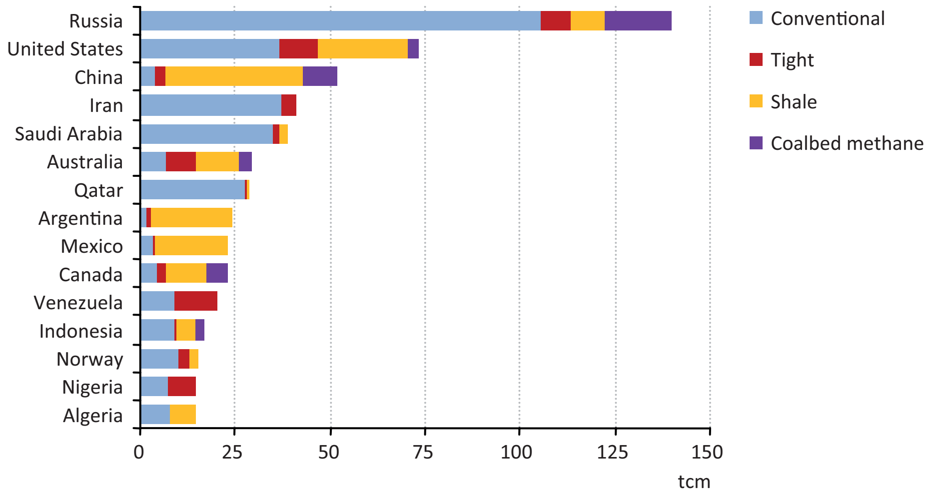
	Total		Unconventional		
	Conventional	Unconventional	Tight Gas	Shale Gas	Coalbed methane
E. Europe/Eurasia	131	43	10	12	20
Middle East	125	12	8	4	-
Asia/Pacific	35	93	20	57	16
OECD Americas	45	77	12	56	9
Africa	37	37	7	30	0
Latin America	23	48	15	33	-
OECD Europe	24	21	3	16	2
World	**421**	**331**	**76**	**208**	**47**

Source: IEA analysis.

Note: The resource estimate for coalbed methane in Eastern Europe and Eurasia replaces a figure given in the *WEO-2011* and in the *Golden Age of Gas* publications (IEA, 2011a and 2011b), which included a "gas-in-place" estimate for Russia instead of the estimate for technically recoverable resources.

Although they are undoubtedly large, unconventional gas resources are still relatively poorly known, both in terms of the extent of the resource in place and judgements about how much might be economically extracted. The industry is still in the learning phase when it comes to many resources outside North America: each unconventional resource play brings with it distinctive challenges and it has not yet been demonstrated that technologies well adapted to existing production areas can unlock the resource potential in all areas.

Figure 2.1 ▷ Remaining recoverable gas resources in the top fifteen countries, end-2011



Source: IEA analysis.

In particular for shale gas, our analysis and projections in this report rely on estimates from the pioneering work of Rogner (Rogner, 1997) and the landmark study from Advanced Resources International (ARI), published by the US Energy Information Administration (EIA) in 2011 (US DOE/EIA, 2011a); these are distinctive in applying consistent standards of evaluation to a large number of countries. On the one hand, resources could easily be even larger than indicated in these studies, as they do not examine all possible shale gas reservoirs around the world. On the other hand, several publications have provided estimates significantly lower than the ARI study: the United States Geological Survey (USGS), whose resource assessments are generally among the most authoritative, has recently published several regional studies indicating lower resources. This is the case, for example, for the Krishna-Godavari shale gas basin in India (USGS, 2012) for which they report a mean estimate of 116 bcm (4.1 trillion cubic feet [tcf]), compared with the ARI estimate of 765 bcm (27 tcf); this much more conservative estimate can be traced back to a smaller estimate for the productive area of the shale and to a smaller mean recovery per well (assuming the same drainage area).[3] Studies by the Polish Geological Institute with support from USGS also give a much lower estimate (a range of 346 bcm to 768 bcm versus the 5.3 tcm given in the ARI study[4]) for shale gas resources in Poland (PGI, 2012). China has

3. The methodologies used for the two studies are different. ARI first estimates gas-in-place and then applies a recovery factor. USGS estimates directly the recoverable resources based on recovery per well and well drainage areas derived by analogy with reservoirs in the United States for which data is available. The methodology used to determine well drainage areas has not been published yet by USGS, making it difficult to compare with industry-accepted values.

4. The different resource estimates can have a substantial impact on the outcome of our projections: see the references to Poland in Chapter 3.

also released new estimates of shale gas resources that are about 20% lower than those given by ARI (MLR, 2012). The much talked-about USGS study of the Marcellus shale in the northeast United States estimated the undiscovered shale resources there at 2.4 tcm (84 tcf), much lower than the 11.6 tcm (410 tcf) recoverable resources reported by the US EIA in 2011 (USGS, 2011).[5] US EIA subsequently reduced their estimate for recoverable gas in the Marcellus to 4 tcm (141 tcf) (US DOE/EIA, 2012).

Estimates of coalbed methane resources are drawn from the German Federal Institute for Geosciences and Natural Resources (BGR, 2011) and US EIA. Tight gas resources are generally poorly defined and known: the exceptions are the United States, Canada and Australia, for which national resource data are used. Tight gas resource estimates for other countries are derived from Rogner.

In the Golden Rules Case, the entire resource base for unconventional gas is assumed to be accessible for development, including in countries and regions where moratoria or other restrictions are currently in place. In the Low Unconventional Case, however, the constraints imposed by the absence of supportive policies (in particular the Golden Rules themselves) and the uncertainties over the size and quality of the resource base were modelled by assuming that only a small part of the ultimately recoverable unconventional resource base is accessible for development. The key assumptions by country or region for the Low Unconventional Case are:

- **United States**: only 65% of tight gas, 45% of coalbed methane and 40% of shale gas resources are accessible. For shale gas, this could, as an example, correspond to excluding all new developments in the northeast United States[6], in California and in the Rocky Mountains, while the more traditional oil and gas producing regions, such as Texas, Oklahoma or the Gulf Coast, would continue to develop their shale resources. Alternatively, restrictions could apply to some parts of the prospective acreage in all regions, such as the more densely populated parts, or those with serious competition in uses for water. For coalbed methane, this could essentially restrict developments to regions that are already producing. Tight gas has been produced for many years in numerous traditional hydrocarbon-producing regions, so tight gas production is not assumed to be restricted as much as the other categories.

5. Strictly speaking, the USGS and US EIA numbers cannot be compared as USGS reports undiscovered gas resources while US EIA reports total recoverable resources, which differ from undiscovered by proven reserves and discovered-but-undeveloped resources. However, neither organisation has provided a breakdown of these three categories. Overall, unconventional gas challenges the usual definitions, as there is no real discovery process (the locations of most gas bearing shales in the world are already known); it is more an appraisal process: the process of establishing that a given shale, and/or what part of the shale, can produce economically. As a result the difference between undiscovered and discovered-but-not-developed is blurred and it is important to clarify the assumption used in various resources estimates.

6. The *World Energy Model* (*WEM*) currently uses the US EIA 2011 resources numbers (US DOE/EIA, 2011b), before their downward revision for the Marcellus shale, pending publication of more details for the background of this revision. So the northeast United States, and the Marcellus shale in particular, represents about half of the estimated resources. Note that *WEM* treats the United States as a single region, so there is no projection of production by basin.

- **China**: only 40% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. Public acceptance is likely to be a lesser influence in China than in other countries (although we are looking forward 25 years and, if the changes that have occurred in the last 25 years in China are any guide, public sensitivity to environmental issues could become significantly greater during the projection period), but other factors could restrict the ambitious official plans for unconventional gas production (Box 2.4).
- **India**: only 30% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. The large projected gas import requirements of India make it unlikely that public opposition would force a complete ban. On the other hand, on current estimates, unconventional gas resources in India are not sufficient to make more than a dent in these imports and our assumption is consistent with a political decision to restrict development of all but the less contentious resource areas.
- **Australia**: only 40% of coalbed methane and none of the shale gas resources are assumed to be accessible. Development of both types of resources has already become controversial in Australia. About 5 bcm of coalbed methane was produced in Australia in 2010 and there are three large-scale projects underway to build LNG plants fed by coalbed methane. The restriction to 40% of available resources essentially amounts to no new projects being authorised beyond those announced.
- **Rest of the world**: no new unconventional gas resources are assumed to be developed outside Canada (for which we use percentages about half of those in the United States, to reflect similar dynamics, but the smaller part of the resources so far developed) and Russia (where, in any event, unconventional resources are not expected to play a significant role).[7]

Development and production costs

The costs of developing and producing unconventional gas are made up of several elements: capital costs, operational costs, transportation costs, and taxes and royalties. Capital costs, often called finding and development costs, are usually dominated by the costs of constructing wells. As discussed in Chapter 1 (under "Implications for Industry"), shale gas wells do cost more than conventional gas wells in the same conditions, because of the additional costs of multistage hydraulic fracturing; the same consideration applies to tight gas wells, for the same reason. Coalbed methane wells have so far been relatively cheap, compared with conventional gas wells, because production has been at shallow depths in regions with well-developed markets. Operational costs, also called lifting costs, are those variable costs that are directly linked to the production activity: they may differ according to local conditions (but not necessarily between conventional and

7. This assumption about the rest of the world (with the partial exception of Canada and Russia) has the virtue of simplicity, although it is a little extreme in some countries that are already producing coalbed methane without any controversy; however, the amounts involved are too small to have any impact on prices or energy security.

unconventional gas produced under similar conditions). The cost of bringing gas to market is distance-dependent and is identical for conventional and unconventional gas.

The final element, taxes and royalties, varies greatly between jurisdictions; in addition to a profit tax component, it very often includes fixed or production-related taxes (paid to governments) and/or royalties (paid to the resource owner, which may or may not be governments). Countries or regions that have higher capital and operating costs, due to their geography or market conditions, often create a more attractive fiscal regime in order to attract investment. This can go as far as offering subsidies: China provides subsidies for coalbed methane and shale gas production.

On the basis of these costs, one can estimate a "break-even cost", or "supply cost", the market value required to provide an adequate real return on capital for a new project (normally taken to be 10% for a project categorised as risk-free and rising with incremental risk). This break-even cost does not apply to legacy production from largely depreciated installations. Lifting costs, transport costs, and taxes and royalties are usually directly expressed in US dollars per unit of gas produced. The significance of capital costs is very dependent on the amount of gas recovered per well. This also varies greatly: the best shale gas wells in the United States are reported to have Estimated Ultimate Recovery (EUR) of 150 to 300 million cubic metres (mcm) (5 to 10 billion cubic feet [bcf]); but many shale gas wells have EUR that is 10 or 100 times less. The average EUR varies from one shale to another, but also depends on the experience of the industry in a given shale: with time, the industry optimises the technologies used and extracts more gas from each well. Outside the United States, there is essentially no experience so far, but drilling longer horizontal wells should help improve EUR per well (in many jurisdictions in the United States, horizontal well length is limited by acreage unit size regulations).

It follows from the discussion of costs that the break-even costs for gas can vary greatly from one location to the next, or within a single country (Table 2.2). For example in the United States, break-even costs for dry gas wells probably range from $5/MBtu to $7/MBtu; gas containing liquids has a lower (gas) break-even cost, which can be as low as $3/MBtu, as the liquids add considerable value for a small increase in costs (associated gas from wells producing predominantly oil can have an even lower break-even cost). Since conventional gas resources are already fairly depleted onshore and most future conventional gas production will therefore come from more expensive offshore locations, the range of break-even costs for conventional and unconventional gas in the United States is fairly similar.

In Europe, the costs of production are expected to be about 50% higher, with a range of break-even costs between $5/MBtu and $10/MBtu. Conventional and unconventional gas are expected to be in the same range, as conventional resources are depleted and new projects are moving to the more expensive Norwegian Arctic. China has a cost structure similar to that of the United States, but shale reservoirs there tend to be deeper and more geologically complex; similarly, coalbed methane reservoirs in China tend to be in remote locations, so we estimate the break-even cost range to be intermediate between that of the United States and that of Europe – from $4/MBtu to $8/MBtu (although there are production subsidies in place that can bring this figure down). This estimate for China applies to both conventional and unconventional gas, as the easy conventional gas is depleting and production is moving to offshore or more remote regions. In countries that have large, relatively easy, remaining conventional gas, such as the Middle East, with break-even costs of less than $2/MBtu, the break-even cost range for unconventional gas is expected to be higher (similar to that for unconventional gas in the United States).

Table 2.2 ▷ Indicative natural gas well-head development and production costs in selected regions (in year-2010 dollars per MBtu)

	Conventional	Shale gas	Coalbed methane
United States	3 - 7	3 - 7	3 - 7
Europe	5 - 9	5 - 10	5 - 9
China	4 - 8	4 - 8	3 - 8
Russia	0 - 2, 3 - 7*	-	3 - 5
Qatar	0 - 2	-	-

* The lower range for Russia represents production from the traditional producing regions of Western Siberia and the Volga-Urals; the higher range is for projects in new onshore regions such as Eastern Siberia, offshore and Arctic developments.

In the Golden Rules Case, the development and production cost assumptions are not increased because of the application of the Golden Rules; as discussed in Chapter 1, the application of the Golden Rules does have some cost impact, but not sufficient to push up the costs of production significantly (and, possibly, not at all). The same starting point is used for development and production costs in the Low Unconventional Case; costs in this case, though, are subject to the general assumption (built into the modelling) that production tends to become more costly as a given resource starts to become scarcer. Since access to unconventional gas resources is limited in this case, the rate of increase in the costs of production is higher than in the Golden Rules Case.

Natural gas prices

The price assumptions in the Golden Rules Case and in the Low Unconventional Case vary substantially, reflecting the different regional and global balances between supply and demand in each case (Table 2.3). The price assumptions in the Golden Rules Case reflect the favourable outlook for unconventional gas supply that results from successfully addressing the potential barriers to its development. Greater availability of gas supply has a strong moderating impact on gas prices. Conversely, lower production of unconventional gas in the Low Unconventional Case means that higher natural gas prices are required to bring the different regional markets into balance.

Table 2.3 ▷ Natural gas price assumptions by case
(in year-2010 dollars per MBtu)

		Golden Rules Case		Low Unconventional Case	
	2010	2020	2035	2020	2035
United States	4.4	5.4	7.1	6.7	10.0
Europe	7.5	10.5	10.8	11.6	13.1
Japan	11.0	12.4	12.6	14.3	15.2

Note: Natural gas prices are expressed on a gross calorific value basis. Prices are for wholesale supplies exclusive of tax. The prices for Europe and Japan are weighted average import prices. The United States price reflects the wholesale price prevailing on the domestic market

North America is the region where the unconventional gas industry has grown most rapidly and, unsurprisingly, is also the region where the impact on markets and prices has thus far been greatest. Historically low prices are being obtained for natural gas, relative to other energy forms such as oil. More surprisingly, given the relative isolation of North American markets from other major gas-using regions, this development has already had profound international impacts. These have arisen because North America has become almost self-sufficient in gas, whereas many LNG investments in the decade 2000 to 2010 were made in the expectation that the North American region would be a substantial net LNG importer. Import infrastructure in excess of 100 bcm was built in the United States alone in this period, with matching LNG supply investments in major producers, such as Qatar. However, in 2011, net LNG imports to North America were less than 20 bcm, out of a total market exceeding 850 bcm: 8 bcm into the United States and 9 bcm into Mexico and Canada. Hence, major quantities of LNG supply became available for other global markets, including Asia and Europe.

Natural gas prices in the United States are assumed to rise from today's historic lows in both cases, but they increase much more quickly in the Low Unconventional Case. The contrasting future roles of North America in global gas trade in the two cases help to explain these different price trajectories. In the Golden Rules Case, the region becomes a significant net LNG exporter, on the back of continued increases in unconventional gas output in the United States and Canada and an expansion in LNG export capacity. Natural gas prices in the United States are assumed to reach a plateau of between $5.5/MBtu and $6.5/MBtu during the 2020s (the levels which we assume are sufficient to support substantial volumes of dry gas production) before rising to $7.1/MBtu in 2035. Exports at the levels anticipated in this case are relatively small, compared with the overall size of the United States' gas market, and do not play a decisive role in domestic price-setting (although they are significant for other markets). By contrast, in the Low Unconventional Case, North America remains a net importer of gas, with imports growing rapidly after 2025. With the region needing to draw its incremental gas supply from international markets, the natural gas price in the United States is pushed up much more quickly than in the Golden Rules Case, reaching $10/MBtu in 2035.

The weighted average import price assumptions for Europe and for Japan are likewise lower in the Golden Rules Case than in the Low Unconventional Case. Within this basic trend, differences between the two markets reflect the different balances between gas supply and demand in each case, as well as the various pricing mechanisms present and how these mechanisms are assumed to evolve. At present, gas prices are set freely in several markets, including North America, the United Kingdom and, to a somewhat lesser extent, Australia, an approach known as gas-to-gas competition. However, much of the gas traded across borders in the Asia-Pacific region is sold under long-term contracts, with linkages to the price of oil or refined products. Prices in continental Europe are predominantly oil-linked, though in recent years a mixture of the two systems (and many variations in between) has emerged, with oil-indexed prices co-existing – often uneasily – with prices set by gas-to-gas competition. We assume that pressure to move away from prices set by oil-indexation and towards those established through gas-to-gas competition is significantly greater in the Golden Rules Case than in the Low Unconventional Case.

In the Golden Rules Case, the United States is expected to play an important role in the evolution of international natural gas pricing mechanisms. Initial contracts for United States LNG exports have been written on the basis of the price at the main domestic natural gas trading hub (Henry Hub), plus liquefaction and transport costs, plus profit, rather than the traditional oil-price indexation prevailing in many of the markets where this gas will be sold. In the Golden Rules Case, this is assumed to put pressure on oil-indexed price formulas for natural gas, moderating gas price increases and provoking a greater degree of convergence in international prices towards those set by gas-to-gas competition. We do not, though, assume that this process of creating a single, liquid or competitive international gas market is completed in the Golden Rules Case (a situation in which natural gas price differentials between regions would reflect only the costs of transportation between them). An important moderating factor in importing regions, especially in Asia, is that most existing natural gas import contracts will continue to remain in force for many years and are based on oil indexation, so average prices cannot be expected to fall dramatically. In addition, some major new export projects (including, for example, from Canadian plants) are greenfield LNG operations, likely to push for traditional pricing arrangements. Hence, while the rise of North American LNG exports in the Golden Rules Case is a major development in global gas markets, we anticipate that wholesale prices in the United States remain at least $5 to $6 below Japanese import prices, with European import prices between these two.

Other assumptions

Both cases include updated assumptions on GDP, compared with the *WEO-2011*, with average annual GDP growth of 3.5% for the period 2012 to 2035, compared with 3.4% in *WEO-2011* for the same period (this allows the global economy in 2035 to reach the same overall size as assumed in *WEO-2011*). World population is assumed to expand from an estimated 7.0 billion in 2012 to 8.6 billion in 2035, as in *WEO-2011*. The projections for natural gas incorporate new demand and supply data by country and region for 2011, where these are available. Prices for oil, coal and carbon-dioxide (CO_2) are likewise updated to include new data for 2011, but they still converge towards the levels assumed in the central scenario of the *WEO-2011,* the New Policies Scenario. This means that the average IEA crude oil import price – a proxy for international oil prices – reaches $120/barrel in 2035 in year-2010 dollars (a nominal oil price of $212/barrel). The IEA steam coal import price increases to $112/tonne in 2035.

In the Golden Rules Case, to complement the impact on gas demand arising from lower prices that improve the competitive position of gas compared with other fuels, we also assume intervention by governments to foster demand growth in countries experiencing a large rise in indigenous gas production. In the United States, for example, supportive policies are assumed to facilitate increased use of natural gas in the road-transport sector, in particular for the commercial fleet. These additional demand-side policies are not included in the baseline case nor in the Low Unconventional Case, because the motivation for their adoption, *i.e.* higher indigenous production and lower prices, is absent.

Another notable change in policy assumptions, compared with the *WEO-2011*, occurs in Japan, where, pending the outcome of the ongoing review of Japan's Strategic Energy Plan, the future contribution of the nuclear sector to power generation is revised downwards in all cases.

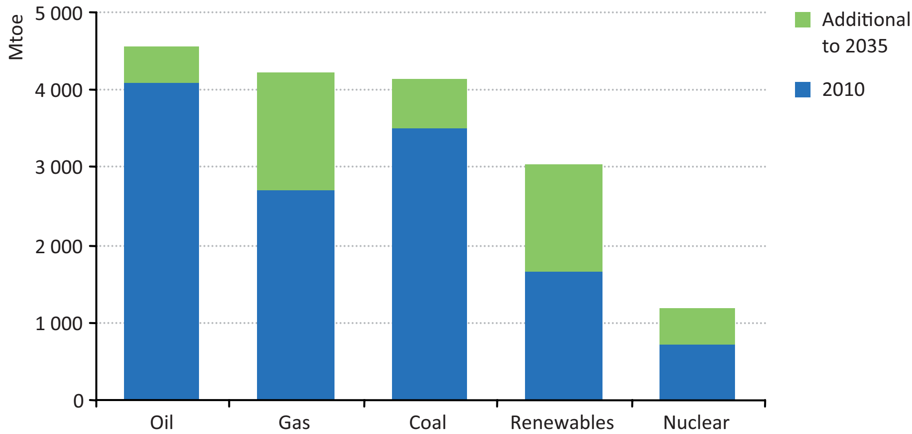
Otherwise, all assumptions remain constant from the New Policies Scenario of the *WEO-2011* (which takes into account policies and declared future intentions as of mid-2011), including the assumption that new measures are introduced to implement announced policy commitments, but only in a relatively cautious manner. These commitments include national pledges to reduce greenhouse-gas emissions and, in certain countries, plans to phase out fossil-fuel subsidies.

The Golden Rules Case

Demand

Global primary energy demand in the Golden Rules Case rises from around 12 700 million tonnes of oil equivalent (Mtoe) in 2010 to 17 150 Mtoe in 2035, an increase of 35%. Natural gas demand increases in the period to 2020 by more than 700 bcm (compared with 2010 levels), the equivalent of adding another United States to the global demand balance, and by a further 1.1 tcm in the period from 2020 to 2035, reaching a total of 5.1 tcm (4 230 Mtoe) in 2035. This is around 300 bcm, or 6%, higher than in the baseline case in 2035, with average annual growth over the projection period of 1.8%, compared with 1.5%. In the Golden Rules Case, gas accounts for about one-third of the overall increase in primary energy demand, a larger contribution than that made by any other fuel and equivalent to the growth in demand for coal, oil and nuclear combined (Figure 2.2). By 2035, natural gas has overtaken coal to become the second most important fuel in the energy mix.

Figure 2.2 ▷ World primary energy demand by fuel in the Golden Rules Case



Different rates of gas demand growth, albeit less pronounced than in the exceptional year of 2011[8], are expected to characterise gas markets in the longer term (Table 2.4). In the Golden Rules Case, 80% of the growth in gas demand comes from outside the OECD; China, India and the countries of the Middle East require an additional 900 bcm of gas in 2035, compared with consumption in 2010. In China and India and other emerging economies, natural gas at present often has a relatively low share of total energy consumption and its use is being specifically promoted as a way to diversify the fuel mix and reap some environmental benefits, often displacing coal as the preferred fuel to supply fast-growing urban areas. While growth in gas demand is healthy even in many of the more mature OECD gas markets – a development that is encouraged by the lower prices for natural gas in the Golden Rules Case – the growth in China alone is more than the anticipated growth in all of the OECD countries put together. Gas demand in China grows over the period 2010 to 2035 by 480 bcm, reaching a total of around 590 bcm in 2035 (larger than current gas demand in the European Union), meaning that developments on both the supply and demand sides in China will continue to have a substantial impact not just in the Asia-Pacific region but – via the wider effects on trade and prices – in markets around the world.

Gas used for generating power and heat is the single largest component of gas demand, accounting for around 40% of total gas consumed. Alongside the lower perceived risk of building gas-fired plants and the lower environmental impact, compared with other fossil fuels, the natural gas prices assumed in the Golden Rules Case improve the competitive

8. Preliminary data suggest that gas consumption in Europe declined by around 11% compared with the previous year, pulled down by warm weather, a sluggish European economy and a weak competitive position in the power sector compared with coal. This was in marked contrast to developments in the Asia-Pacific region: Korea and Japan showed a dramatic upsurge in demand for LNG, the latter linked to reduced output of nuclear energy following Fukushima, and Chinese gas demand continued its meteoric rise, becoming a larger gas consumer than any OECD country except the United States. The United States also saw growth in consumption, of around 2.5%, spurred by low prices that neared $2/MBtu in late 2011.

position of natural gas and push up gas demand for power generation to more than 2 tcm by 2035. The role of gas in power generation increases from 22% to 24%, with coal and oil (the latter a marginal fuel in power generation) ceding share in response. Gas use in buildings and in industry also increases substantially, reaching 1 060 bcm and 970 bcm respectively by the end of the projection period.

Table 2.4 ▷ Natural gas demand by region in the Golden Rules Case (bcm)

	2010	2020	2035	2010-2035*
OECD	**1 601**	**1 756**	**1 982**	**0.9%**
Americas	841	921	1 051	0.9%
United States	*680*	*717*	*787*	*0.6%*
Europe	579	626	692	0.7%
Asia Oceania	180	209	239	1.1%
Japan	*104*	*130*	*137*	*1.1%*
Non-OECD	**1 670**	**2 225**	**3 130**	**2.5%**
E. Europe/Eurasia	662	736	872	1.1%
Russia	*448*	*486*	*560*	*0.9%*
Asia	398	705	1 199	4.5%
China	*110*	*323*	*593*	*7.0%*
India	*63*	*100*	*201*	*4.7%*
Middle East	365	453	641	2.3%
Africa	101	130	166	2.0%
Latin America	144	200	252	2.3%
World	**3 271**	**3 982**	**5 112**	**1.8%**
European Union	*547*	*592*	*644*	*0.7%*

* Compound average annual growth rate

Although volumes are small compared with the other end-use sectors, the Golden Rules Case sees strong growth in gas use in the transport sector. This is encouraged both by lower prices, compared with oil, and also by government policies, for example support for developing the necessary refuelling infrastructure. Use of natural gas for road transportation increases by more than six times in the period to 2035, reaching close to 150 bcm in 2035. For the moment, transport is the only major end-use sector where gas is not widely used: although there are viable natural gas vehicle technologies, there are only a few countries where these are deployed at scale. More than 70% of all natural gas vehicles and half of all fuelling stations are found in just five countries: Pakistan, Iran, Argentina, Brazil and India. In our projections, India and the United States lead the growth in natural gas consumption for transport, primarily in commercial fleets, buses and municipal vehicles that can use central depots for refuelling.

Implications for other fuels

The implications of applying the Golden Rules to unconventional natural gas extend beyond gas to other competing fuels. As the share of gas rises from 21% of global primary energy consumption in 2010 to 25% by 2035 (compared with 23% in the baseline case), growth in demand for oil and coal is constrained and, marginally, also demand for nuclear and renewable energy (Table 2.5).

Table 2.5 ▷ World primary energy demand by fuel in the Golden Rules Case

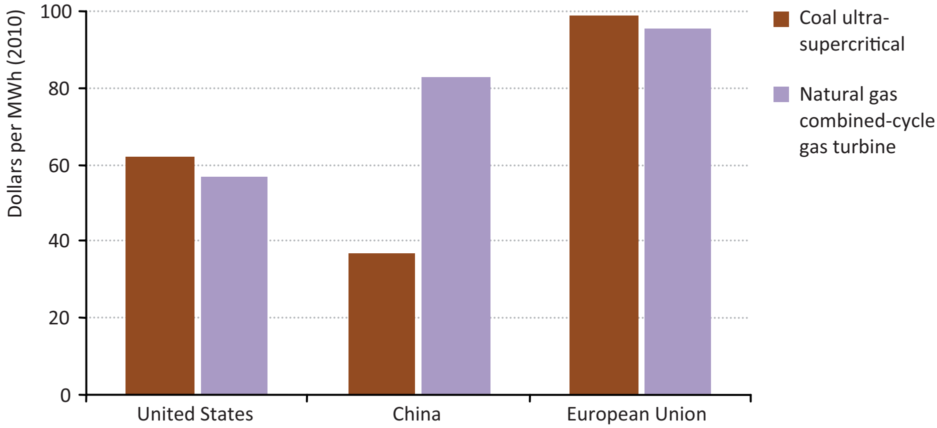
	Demand (Mtoe)			Share		
	2010	2020	2035	2010	2020	2035
Coal	3 519	4 109	4 141	28%	28%	24%
Oil	4 094	4 381	4 548	32%	29%	27%
Gas	2 700	3 291	4 228	21%	22%	25%
Nuclear	719	927	1 181	6%	6%	7%
Hydro	295	376	472	2%	3%	3%
Biomass	1 262	1 496	1 896	10%	10%	11%
Other renewables	110	287	676	1%	2%	4%

Oil continues to be the dominant fuel in the primary energy mix, with demand increasing from about 4 100 Mtoe in 2010 to 4 550 Mtoe in 2035, but its share in the primary energy mix drops from 32% in 2010 to 27% in 2035. Compared with the baseline case, lower gas prices promote substitution for oil in the transport and power sectors, resulting in global oil demand being reduced by some 2 million barrels per day (mb/d) in 2035.

Primary coal consumption in the Golden Rules Case rises until around 2025 and then levels off. Its share in the energy mix declines from 28% in 2010 to 24% in 2035. In that year, coal demand is around 3% lower (115 Mtoe) than in the baseline case, an amount greater than total current European imports of hard coal. Three-quarters of coal demand growth stems from the power sector. Lower gas prices favour gas over coal for new builds in most countries (Figure 2.3). However, in some countries, such as China, coal remains cheaper than gas, in the absence of prices that internalise environmental externalities, such as local pollution or CO_2 emissions. In this situation, Chinese government policies aimed at increasing gas use are crucial to its development. Globally, excluding China, 3.5 units of gas-fired electricity generation are added for each new unit of coal-fired electricity generation.

Over the *Outlook* period, nuclear output grows, but it is marginally below our baseline case in 2035. Gas prices have a direct influence on new nuclear construction in liberalised markets, mostly in OECD countries, where we expect nuclear output to grow 12% less than our baseline. However, most of the global growth in nuclear will occur in non-OECD countries, where specific national plans to expand nuclear capacity are less likely to be affected by changing market conditions.

Figure 2.3 ▷ Electricity generating costs for new coal- and natural gas-fired power plants in selected regions in the Golden Rules Case, 2020



The global outlook for renewable sources of energy is not affected substantially by the increased use of gas in the Golden Rules Case, with volumes and shares of output remaining very close to those in the baseline case. Due to lower gas (and consequently electricity) prices, the growth of electricity output from non-hydro renewables is reduced globally by 5% compared with our baseline. This global average figure hides some larger differences in specific countries, where the impact is stronger, due to the price levels and to the type of support policies in place. This is, for example, the case in the United States, where the growth of electricity from non-hydro renewables is some 10% lower with respect to the baseline.

There are factors working both against, and in favour of, renewables in a world of more abundant gas supplies. Depending on the type of policies in place, an abundance of natural gas might diminish the resolve of governments to support low and zero-carbon sources of energy: lower gas prices (and therefore lower electricity prices) can postpone the moment at which renewable sources of energy become competitive without subsidies and, all else being equal, therefore make renewables more costly in terms of the required levels of support. However, an expansion of gas in the global energy mix can also facilitate greater use of renewable energy, if policies are in place to support its deployment, given that gas-fired power generation can provide effective back-up to variable output from certain renewable sources. Moreover, lower electricity prices can encourage customer acceptance of a higher component of electricity from renewable sources. Ultimately, the way that renewables retain their appeal, in a gas-abundant world, will depend on the resolve of governments. We assume that existing policies and support mechanisms remain in place as part of the efforts by governments to address the threat of a changing climate.

Supply

In the Golden Rules Case, total gas production grows by around 55%, from 3.3 tcm in 2010 to 5.1 tcm in 2035. Over the same period, unconventional gas production increases from around 470 bcm in 2010 to more than 1.6 tcm in 2035. Although unconventional gas output grows relatively slowly in the early part of the projection period, reflecting the time required for new producing countries to develop commercial production, for the projection period as a whole, unconventional gas represents nearly two-thirds of incremental gas supply (Table 2.6).

Table 2.6 ▷ Natural gas production by region in the Golden Rules Case (bcm)

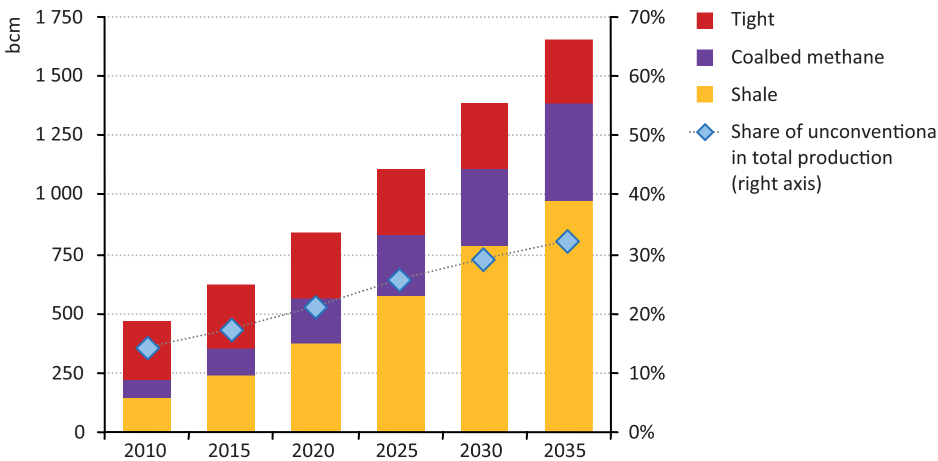
	2010		2020		2035		2010-2035**
	Total	*Share of unconv**	Total	*Share of unconv**	Total	*Share of unconv**	
OECD	**1 183**	**36%**	**1 347**	**49%**	**1 546**	**60%**	**1.1%**
Americas	821	51%	954	62%	1 089	68%	1.1%
Canada	*160*	*39%*	*174*	*57%*	*177*	*67%*	*0.4%*
Mexico	*50*	*3%*	*52*	*12%*	*87*	*43%*	*2.2%*
United States	*609*	*59%*	*726*	*67%*	*821*	*71%*	*1.2%*
Europe	304	0%	272	4%	285	27%	-0.3%
Poland	*6*	*11%*	*9*	*37%*	*34*	*90%*	*7.1%*
Asia Oceania	58	9%	121	49%	172	64%	4.5%
Australia	*49*	*11%*	*115*	*51%*	*170*	*65%*	*5.1%*
Non-OECD	**2 094**	**2%**	**2 635**	**7%**	**3 567**	**20%**	**2.2%**
E. Europe/Eurasia	826	3%	922	3%	1 123	6%	1.2%
Russia	*637*	*3%*	*718*	*4%*	*784*	*6%*	*0.8%*
Asia	431	3%	643	20%	984	56%	3.4%
China	*97*	*12%*	*246*	*45%*	*473*	*83%*	*6.6%*
India	*51*	*2%*	*75*	*21%*	*111*	*80%*	*3.2%*
Indonesia	*88*	*-*	*106*	*2%*	*153*	*37%*	*2.2%*
Middle East	474	0%	581	1%	776	2%	2.0%
Africa	202	1%	264	1%	397	5%	2.7%
Algeria	*79*	*-*	*101*	*1%*	*135*	*8%*	*2.2%*
Latin America	159	2%	226	4%	286	22%	2.4%
Argentina	*42*	*9%*	*53*	*9%*	*72*	*48%*	*2.1%*
World	**3 276**	**14%**	**3 982**	**21%**	**5 112**	**32%**	**1.8%**
European Union	*201*	*1%*	*160*	*7%*	*165*	*47%*	*-0.8%*

* Share of unconventional production in total natural gas production.

** Compound average annual growth rate.

The share of unconventional gas in total gas production increases in the Golden Rules Case from 14% in 2010 to 32% in 2035 (Figure 2.4). Of the different sources of unconventional supply, tight gas, at 245 bcm, accounted for just over half of global unconventional production in 2010. However, it is rapidly overtaken in our projections by production of shale gas, which rises from around 145 bcm in 2010 (31% of total unconventional output) to 975 bcm in 2035 (almost 60% of the total). Production of coalbed methane likewise grows rapidly, from 80 bcm in 2010 to nearly 410 bcm in 2035.

Figure 2.4 ▻ Unconventional natural gas production by type in the Golden Rules Case



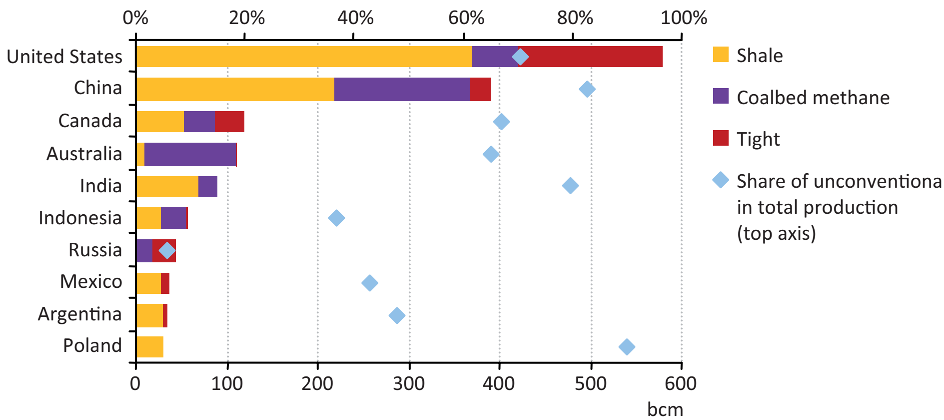
The continued expansion of unconventional gas production in North America means that the United States moves ahead of Russia as the largest global gas producer, with about 820 bcm of total gas production in 2035, compared with 785 bcm in Russia. North American unconventional output, with substantial contributions also from Canada and Mexico, rises to nearly 740 bcm in 2035 in the Golden Rules Case. But increased unconventional production also occurs widely around the world: whereas unconventional gas production in 2010 is dominated by North America, the share of North America in global unconventional production falls to around 70% in 2020 and only 45% in 2035.[9]

China becomes a major gas producer in the Golden Rules Case and the second-largest global producer of unconventional gas, after the United States (Figure 2.5). Progress with developing unconventional gas resources is bolstered by the twin policy commitments of increasing the share of natural gas in the Chinese energy mix and developing, where possible, the domestic resource base so as to mitigate increased reliance upon energy imports. The large resource base for shale gas and coalbed methane allows very rapid growth in unconventional production from around 2017 onwards and total unconventional

9. More detailed discussion of the regulatory issues and production outlooks for North America, China, Europe and Australia are included in Chapter 3 of this report.

production reaches just over 110 bcm in 2020 and 390 bcm in 2035, 83% of total Chinese gas production.

Figure 2.5 ▷ Ten largest unconventional gas producers in the Golden Rules Case, 2035



Similar policy objectives are assumed to drive an expansion in unconventional gas production elsewhere in Asia, notably in India where unconventional gas supply rises to nearly 90 bcm in 2035 (80% of total gas output). The currently known unconventional gas resource base in India can meet only a part of India's incremental needs, given the prospect of strong growth in gas demand, and production growth starts to tail off towards the end of the projection period. In Indonesia, by contrast, resources of both conventional and unconventional gas are very large; some recent conventional discoveries are offshore and relatively expensive to develop, so the onshore unconventional plays, including rich potential for coalbed methane, are attractive by comparison. Unconventional gas production in Indonesia rises to around 55 bcm in 2035 (almost 40% of total output). Australia is another country that has the opportunity to develop both conventional and unconventional resources with a mix of coalbed methane, tight and shale gas. In the Golden Rules Case, unconventional gas makes up about 65% of Australia's 170 bcm of total gas output by 2035.

The expansion of unconventional gas production in China and the United States (and, to a lesser extent, also in Europe) creates strategic challenges for existing gas exporters. This is evident in the projections for Russia, which remains by far the largest producer of conventional gas.[10] Developments in the Golden Rules Case call into question the speed at which Russia will need to develop relatively expensive new fields in the Yamal peninsula, in the Arctic offshore and in Eastern Siberia. In our projections, Russia's total gas production rises to about 785 bcm in 2035, more than 20% above 2010, but below the levels foreseen in

10. A part of Russia's production is classified as tight gas although this is very similar to conventional production in practice; hydraulic fracturing to enhance flow rates is rarely used in gas wells. Russia is, though, projected to expand its output of coalbed methane by 2035.

Russian policy or company outlooks and in our baseline. In the Middle East, an increasingly important challenge for gas producers – with the exception of an export-oriented producer like Qatar – is to meet increasing demand for gas on domestic markets. In our Golden Rules Case projections, this imperative to meet domestic needs leads to small amounts of shale gas being produced, mainly in Saudi Arabia and Oman, but conventional gas continues to predominate. In North Africa, though, unconventional gas plays a slightly more significant role, with Algeria, Tunisia and Morocco starting to produce shale gas in the early 2020s. By the end of the projection period, unconventional gas production reaches around 8% of total output in Algeria; with conventional resources becoming scarcer by this time, unconventional gas helps to maintain consistently high levels of production and export. Overall gas production in Africa is bolstered by expanded conventional output from a traditional producer, Nigeria, but also by output from new conventional producers, such as Mozambique and Angola.

Latin America has large potential for unconventional gas development, with Argentina (primarily shale gas) having the largest resource base, followed by Venezuela (tight gas) and then Brazil (shale gas). Attention in Argentina is focused on the Neuquén Basin in Patagonia, which helps Argentinean unconventional production reach 35 bcm by 2035 in the Golden Rules Case, almost half of the total gas output. Both Venezuela and Brazil have ample conventional resources, which means that there is less need to develop their unconventional potential during the projection period; however, some unconventional gas is produced by 2035 in Bolivia (5 bcm), Peru (5 bcm), Paraguay (3 bcm) and Uruguay (3 bcm).

Implications for other fuels

In the Golden Rules Case, the conditions supportive of unconventional gas production also support increased output of natural gas liquids (NGLs), extracted from liquids-rich shale gas, as well as light tight oil.[11] This oil is analogous in many ways to shale gas, both in terms of its origins – it is oil that has not migrated, or at least not migrated far, from the (shale) source rock – and in terms of the production techniques required to exploit it. Light tight oil is being produced from many of the same basins as unconventional gas in the United States, and, in a price environment combining high oil prices and very low prices for natural gas, there is a strong economic incentive to target plays with higher liquids content. In the Golden Rules Case, we project a strong increase in production of light tight oil in the United States, with the potential for production to spread also to other countries rich in this resource (Box 2.2).

11. Almost all shale gas plays produce some liquids and light tight oil production likewise comes with some associated gas. The distinction between liquids-rich unconventional gas plays and gas-rich light tight oil reservoirs is not clear-cut; it normally depends on the relative energy content of the gas versus the liquids produced, but this can vary over time for a single well.

Box 2.2 ▷ The liquid side of the story – light tight oil

The spectacular rise in oil production from North Dakota and Texas in the United States clearly illustrates the growth potential for light tight oil. The Bakken formation under North Dakota has been known about since the 1950s, but production from this formation remained under 100 thousand barrels per day (kb/d) until only a few years ago, since when it has surged to over 500 kb/d and looks set to continue growing. The Eagle Ford shale in south Texas, adjacent to the Mexican border, also shows considerable promise, with production expected to grow from almost nothing three years ago to around 400 kb/d by the end of 2012. Combined production from the Bakken, the Eagle Ford and other emerging light tight oil plays in the United States is expected to reach 2 mb/d by 2020 in the Golden Rules Case.

United States' NGL production from shales such as the Barnett, Eagle Ford and Marcellus is also increasing rapidly and up to 1 mb/d of new capacity is expected to be added by 2020. The growth in NGL production is creating new opportunities for the petrochemical industry, but action will be required to remove pipeline bottlenecks and provide additional fractionation and storage facilities if the benefits are to be fully realised. The growth in global production of NGLs from shale formations and light tight oil in the period to 2020, predominantly in North America, makes up almost half the incremental growth in oil supply over this period.

Production outside North America of NGLs from shale and of light tight oil is unlikely to make a large contribution to global liquids production before 2020 as much evaluation work still needs to be done. However, the Neuquén basin in Argentina shows promise, YPF announcing potential resources of 7 billion barrels (YPF, 2012), while the extension of the Eagle Ford shale into Mexico is also a focus of attention. Our projections for light tight oil production outside North America remain small even beyond 2020, as we have yet to see sufficient progress in confirming resources, so there is some upside potential. It should be noted, however that on the basis of current knowledge, light tight oil resources are expected to be of less consequence than shale gas resources: whereas the estimated shale gas resources in the United States represent at least 35 years of 2010 domestic gas demand, the known light tight oil resources make up no more than four years of domestic oil demand. This is why we currently project light tight oil production in the United States to peak in the 2020s.

The liquids content of shale gas plays is an important consideration in their economic viability as NGLs are easily transported to world markets, while market opportunities for gas are often only local, at prices that may not be aligned to international prices for reasons of policy or infrastructure. However there is always a degree of uncertainty about the extent of liquids content until new shales have been drilled and tested.

International gas trade, markets and security

In the Golden Rules Case, the developments having the most impact on gas markets and security are the increasing levels of unconventional production in China and in the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. The implication of these two developments in tandem is to increase the volume of gas, particularly LNG, looking for markets in the period after 2020.

China's requirement for imported natural gas in the Golden Rules Case grows from around 15 bcm in 2010 to 80 bcm in 2020 and then to 120 bcm in 2035. These volumes are about half the corresponding imports in the baseline case. Chinese gas imports at the levels projected in the Golden Rules Case could be covered by existing contractual arrangements for LNG and pipeline supplies (from Central Asia and Myanmar) until well into the 2020s, pushing back the need for additional projects aimed at the Chinese market.

With the United States developing as an LNG exporter over the period to 2020 and Canada also starting to export LNG from its west coast, exports from North America reach 35 bcm by 2020, after which they stabilise just above these levels as the opportunities for export start to narrow. The influence of these exports on trade flows and pricing is larger than these volumes suggest. LNG from the United States, if priced at the prices prevailing on the domestic gas trading hub, can compete with oil-indexed gas in both the European and Asia-Pacific markets in the Golden Rules Case, and the mere presence of this source of LNG (more so than the actual level of export) plays an important role in creating a more competitive international market for gas supply.

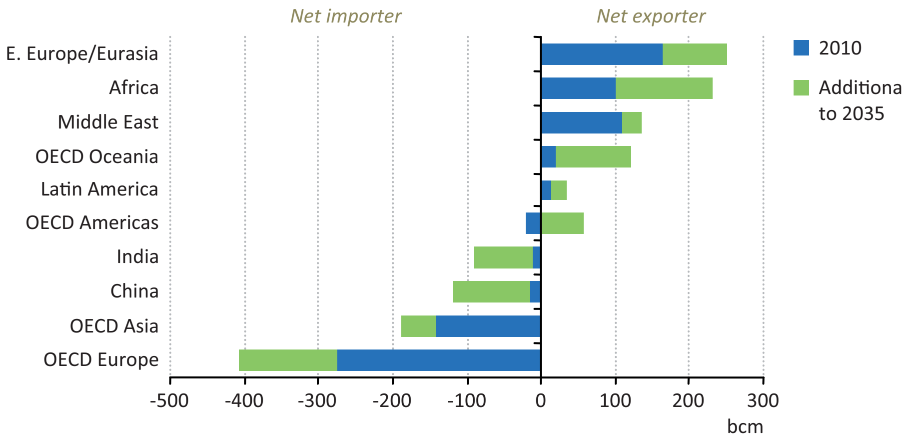
The total volume of gas traded between *WEO* regions[12] in the Golden Rules Case in 2035 is 1 015 bcm. This represents an increase of nearly 50%, compared with the volume of inter-regional trade in 2010 (Figure 2.6), but it is some 15% below the figure for 2035 in our baseline case. The share of inter-regional trade in global supply rises to 22% in 2015, but international market conditions start to ease over the period to 2020 and beyond, as new sources of unconventional gas start to be developed closer to the main areas of consumption. This pick-up in unconventional gas production means that the share of inter-regional trade in global supply plateaus after 2015 before falling to 20% by 2035, reversing the expectation that international trade will play an increasingly important role in meeting global needs.

The European Union's growing requirement for imported gas accounts for 40% of the increase in global inter-regional gas trade in the Golden Rules Case. Here too, the development of indigenous unconventional gas moderates somewhat the growth in imports, so that they reach 480 bcm in 2035, about 135 bcm more than in 2010. Among importing countries in Asia, Japan and Korea (which do not have potential to develop

12. Trade between the 25 regions included in the *WEM*. It does not include trade between countries within a single region.

indigenous production) see imports rise steadily, as does India, whose import requirement rises to nearly 90 bcm from around 10 bcm in 2010.

Figure 2.6 ▷ Natural gas net trade by major region in the Golden Rules Case



Box 2.3 ▷ Implications for prices and pricing mechanisms

In an environment where gas is potentially available from a greater variety of sources, buyers not only in Europe but also in Asia could well insist on greater independence from oil prices in the pricing of gas supplies, particularly when gas is used in the fast-growing power sector in which oil is disappearing as an energy source. The Golden Rules Case is likely to see accelerated movement towards hub-based pricing or a hybrid pricing system in which alternatives to oil-price indexation plays a much larger role in both Europe and across Asia.

The way such a change might play out in practice would depend to a large degree on the reaction of the main traditional exporters, who could confront greater risks in financing expensive upstream developments and transportation projects. Producers such as Russia and Qatar, the largest current exporters of natural gas, have access to ample conventional reserves, with costs that are in most cases substantially lower than those of unconventional gas (and other conventional producers as well). With well-developed export infrastructure, these countries could undercut the prices offered by most other exporters on international markets, retaining or expanding export volumes by offering gas to markets on more attractive terms than others. Alternatively, they could aim to maintain higher prices for their exports, but at the risk of losing market share. In the Golden Rules Case, their strategic choice would have substantial implications for the location of investment and production, including the speed of development of unconventional resources. The net result for gas consumers, however, would be broadly the same: lower prices for imported natural gas.

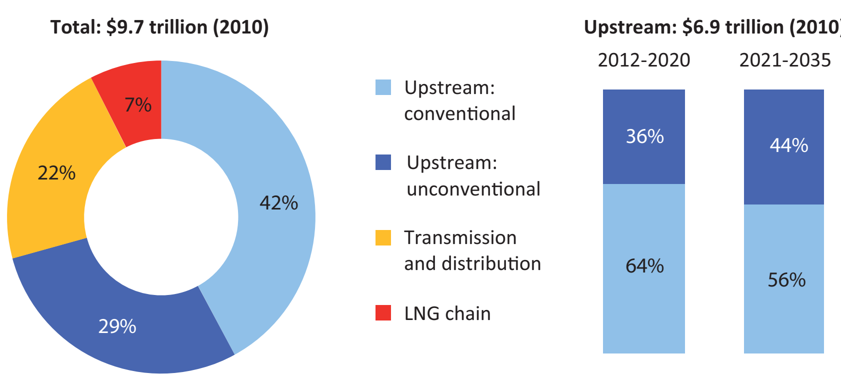
Russia and the Middle East supplied around 45% of inter-regional gas trade in 2010; this declines to 35% in 2035 in the Golden Rules Case, as other players announce or expand their presence in the market, notably Australia, the United States and producers in Africa and Latin America. From around 20 bcm in 2010, Australia's exports rise quickly to 120 bcm in 2035, based on a rapid expansion of LNG capacity, which permits new markets to be captured in the earlier part of the projection period, during which demand for imports remains relatively strong. By around 2020, African exports – based on new conventional projects and LNG, thanks to the large recent discoveries offshore east and west Africa – overtake those from the Middle East.

Overall, the Golden Rules Case presents an improved picture of security of gas supplies. High dependence on imports, in itself, is not necessarily an indicator of insecure supply; but the conditions observed in the Golden Rules Case of a more diverse mix of sources of gas in most markets, including both indigenous output and imports from a range of potential suppliers, suggests an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies.

Investment and other economic impacts

At the global level, for conventional and unconventional gas together, the Golden Rules Case requires \$9.7 trillion in cumulative investment in gas-supply infrastructure in the period 2012 to 2035 (in year-2010 dollars). This represents an increase of \$390 billion, compared with the baseline case, reflecting the need to bring on more production to meet higher demand and a slight increase in unit production costs as unconventional resources make up a growing share of production. Spending on gas exploration and development, to find new fields and bring them into production and to maintain output from existing ones, amounts to nearly \$6.9 trillion, bolstered by the large number of new wells required (see Spotlight).

Figure 2.7 ▷ Cumulative investment in natural gas-supply infrastructure by type in the Golden Rules Case, 2012-2035 (in year-2010 dollars)



SPOTLIGHT

How many wells? How many rigs?

Expanded unconventional gas production requires a significant increase in the number of unconventional gas wells over the coming decades, though there is a huge range of uncertainty when calculating the extent of the requirement for unconventional gas wells for a projected level of production. Key variables are the average ultimate recovery per well and the average decline rate of production in the early years, both of which vary significantly between shale gas, tight gas and coalbed methane wells.[13]

We estimate that, to meet the global unconventional gas production requirements of the Golden Rules Case, more than one million unconventional gas wells would need to be drilled globally between 2012 and 2035. For comparison, around 700 000 oil and gas wells have been drilled in the United States over the last 25 years and half a million are currently producing gas. At present, global drilling activity for both conventional and unconventional resources is heavily concentrated in the United States, where more than half of the world's drilling rig fleet (around 2 000 active oil and gas drilling rigs, including those used for unconventional gas) is deployed to sustain production of just 9% of the world's oil and 19% of the world's gas.

In the Golden Rules Case, the United States would still account for around 500 000 of the new unconventional gas wells required by 2035, with the yearly drilling requirement rising from around 7 000 wells per year to 25 000 per year by 2035 (and the unconventional gas rig count increasing by the same order of magnitude, given that the efficiency of rig use probably has potential for only modest increases).

China would have a cumulative requirement of some 300 000 unconventional gas wells over the projection period and an annual requirement increasing from around 2 000 in the early years to 20 000 wells nearer 2035. Assuming that drilling becomes more efficient with time, this might correspond to an increase in the number of unconventional gas drilling rigs from around 400 to 2 000, a demanding increase in the rig count. There are an estimated 1 000 rigs in China at present, but only a fraction of these are capable of horizontal drilling.

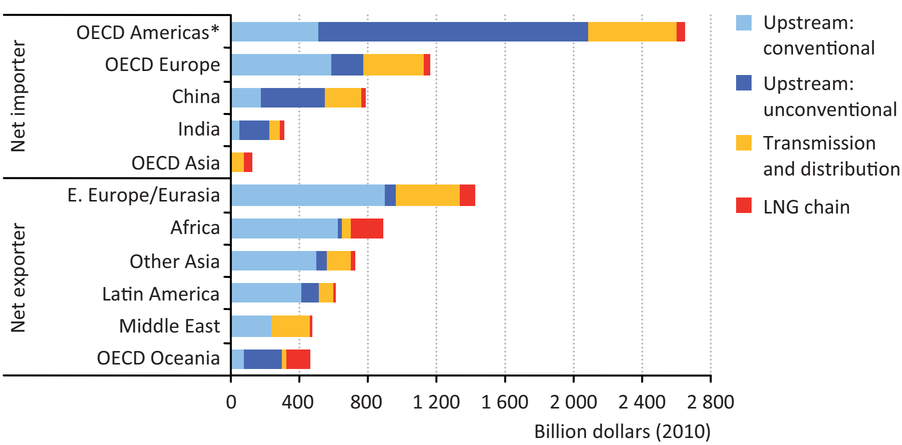
In the European Union, the cumulative number of wells in the projection period is around 50 000, increasing to around 3 000 per year by the 2030s. The number of drilling rigs required is between 500 and 600; there are currently around 50 land rigs in Europe, of which only around half may be capable of horizontal drilling.

13. For the purpose of these calculations, we have used an average EUR of around 1 bcf, assumed that about 50% of EUR is recovered in the first three years of production, and a 15% average decline rate of current unconventional gas production (in the United States). Varying these assumptions within a reasonable range produces very different outcomes in terms of the number of wells.

Unconventional resources attract an increasing share of this upstream investment – about 36% before 2020 and 44% in the subsequent period to 2035 – as prospective areas mature (Figure 2.7). Being geographically well-dispersed and closer to demand centres, unconventional gas diminishes the need for long-distance gas transport infrastructure to some degree. Nevertheless, growing trade in the Golden Rules Case requires additional LNG facilities and new long-haul pipelines. Cumulative investment in the LNG chain is $0.7 trillion and investment in gas transmission and distribution infrastructure, including smaller scale networks to connect end-users, absorbs $2.1 trillion.

The proportion of upstream investment made in countries that hold unconventional resources increases. Spending on exploration and development for unconventional gas in the United States alone is more than double total upstream spending in any other country or region.[14] China also becomes one of the world's leading locations for upstream gas investment, thanks to its huge resource base. Countries that were net importers of gas in 2010 make some of the most significant investments in unconventional gas, accounting for more than three-quarters of total unconventional upstream investment (Figure 2.8). This investment can generate the wider economic benefits associated with improved energy trade balances, lower energy prices and employment, all of which add economic value for unconventional resource holders.

Figure 2.8 ▷ Cumulative investment in natural gas-supply infrastructure by major region and type in the Golden Rules Case, 2012-2035



* OECD Americas become a net exporter of natural gas by 2020 in the Golden Rules Case.

The outlook for energy trade balances improves for unconventional resource holders in the Golden Rules Case. China and the European Union remain large net importers of gas,

14. Because of the rapid decline in production in shale gas wells, maintaining production requires continuous investment in drilling new wells. This explains why the United States needs the lion's share of the investment in unconventional gas: although it does not grow supply as much as China for example, it needs investment just to sustain its already substantial level of unconventional gas production.

but indigenous unconventional gas production tempers their import bills, which stabilise at about 0.2% and 0.7% of GDP, respectively, after 2020. Australia, where production far outstrips domestic gas demand, sees export revenues reach nearly 2% of GDP in 2035. Net exports of gas bring revenues to the United States after it ceases to be a net gas importer; the more substantial impact on energy trade balances in the United States results from light tight oil production and increased NGLs from higher unconventional gas production, which contribute to a considerable reduction in its oil import bill – to 0.8% of GDP in 2035, compared with a peak of 2.8% of GDP in 2008.

Climate change and the environment

Energy-related CO_2 emissions in the Golden Rules Case reach 36.8 gigatonnes (Gt) in 2035, an increase of over 20% compared with 2010 (Table 2.7) but lower than the 2035 baseline projection by 0.5%. At the global level, there are two major effects of the Golden Rules Case on CO_2 emissions, which counteract one another. Lower natural gas prices mean that, in some instances, gas displaces the use of more carbon-intensive fuels, oil and coal, pushing down emissions. At the same time, lower natural gas prices lead to slightly higher overall consumption of energy and, in some instances, to displacement of lower-carbon fuels, such as renewable energy sources and nuclear power. Overall, the projections in the Golden Rules Case involve only a small net shift in anticipated levels of greenhouse-gas emissions.

Table 2.7 ▷ World energy-related CO_2 emissions in the Golden Rules Case (million tonnes)

	2010	2020	2035	2010-2035*
OECD	12 363	12 157	10 716	-0.6%
of which from natural gas	3 034	3 336	3 758	0.9%
Non-OECD	16 960	21 327	24 674	1.5%
of which from natural gas	3 082	4 118	5 781	2.5%
World	**30 336**	**34 648**	**36 795**	**0.8%**

* Compound average annual growth rate.

The Golden Rules Case puts CO_2 emissions on a long-term trajectory consistent with stabilising the atmospheric concentration of greenhouse-gas emissions at around 650 parts per million, a trajectory consistent with a probable temperature rise of more than 3.5 degrees Celsius (°C) in the long term, well above the widely accepted 2°C target. This finding reinforces a central conclusion from the *WEO* special report on a Golden Age of Gas (IEA, 2011b), that, while a greater role for natural gas in the global energy mix does bring environmental benefits where it substitutes for other fossil fuels, natural gas cannot on its own provide the answer to the challenge of climate change. This conclusion could be changed by widespread application of technologies such as carbon capture and storage, which could reduce considerably the emissions from the consumption of gas (and other fossil fuels); but this is not assumed in the period to 2035.[15]

At country level, the impact of the Golden Rules Case on greenhouse-gas emissions from gas depends to a large degree on the structure of domestic fuel use, in particular for power generation. In countries where the average greenhouse-gas intensity of power generation is already close to that of natural gas, as for example in Europe, the addition of extra natural gas to the fuel mix has relatively little impact on the overall emissions trajectory. By contrast, in countries heavily reliant upon coal for electricity generation, such as China, the increased availability of natural gas has a more substantial impact on CO_2 emissions. Such increased use of gas also reduces emissions of other pollutants; compared with burning coal, combustion of natural gas results in lower emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_X) and gas also emits almost no particulate matter. Local emissions of particulate matter and NO_X are the main causes of low air quality – a particularly important consideration for emerging economies seeking to provide energy for fast-growing urban areas.

Unconventional gas production itself inevitably results in some changes to the land, to surface water and to groundwater systems, particularly given the scale of the production envisaged in the Golden Rules Case. As indicated in the Spotlight, we estimate that production at these levels would require the drilling of over one million new wells in the course of the projection period, over half of which would be in the United States and China. These operations have to be managed strictly in accordance with the Golden Rules, or the associated social and environmental damage will cut short attainment of the Golden Rules Case.

The Low Unconventional Case

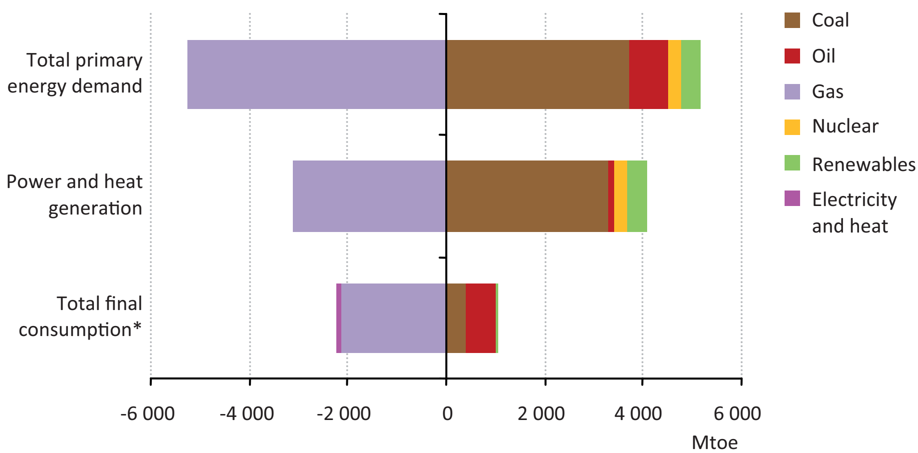
Demand

In the Low Unconventional Case, where the Golden Rules are not applied and environmental and other constraints on unconventional gas development provide too difficult to overcome, the competitive position of gas in the global fuel mix deteriorates, compared with the Golden Rules Case, as a result of lower availability and higher prices. Global demand for gas grows more slowly, reaching 4.6 tcm in 2035. The difference in primary gas demand in 2035 between the Low Unconventional Case and the Golden Rules Case is about 535 bcm, an amount close to total gas demand in the European Union in 2010. In the global energy mix, whereas in the Golden Rules Case gas overtakes coal by 2035, in the Low Unconventional Case the share of gas in the global energy mix increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal (whose share decreases from 28% to 26%) and of oil.

15. There is the possibility that the capacities for CO_2 storage might be affected by hydraulic fracturing. A recent study (Elliot and Celia, 2012) estimated that 80% of the potential area to store CO_2 underground in the United States could be prejudiced by shale and tight gas development, although others have argued that, even if the rock seal in one place were to be broken by hydraulic fracturing, other layers of impermeable rock underneath the fractured area would block migration of the CO_2.

The fall in gas demand in the Low Unconventional Case, relative to the Golden Rules Case, is mostly compensated for by increased consumption of coal (Figure 2.9). The cumulative difference in total primary gas demand over the projection period is around 5 200 Mtoe (6.3 tcm); coal accounts for almost three-quarters of the increase in the demand for other fuels, the largest coming in China (accounting for about 40% of the additional coal demand). The total primary energy used for power and heat generation is higher in the Low Unconventional Case because of the substitution of gas-fired generation by coal-fired generation; being less efficient, coal plants require more energy to produce the same amount of electricity. In power generation, around 75% of the fall in gas-fired power is taken up by coal. In total final consumption, the effect is felt primarily through the increase in demand for oil, because gas fails to make the same inroads in the transportation sector.

Figure 2.9 ▷ **Cumulative change in energy demand by fuel and sector in the Low Unconventional Case relative to Golden Rules Case, 2010-2035**



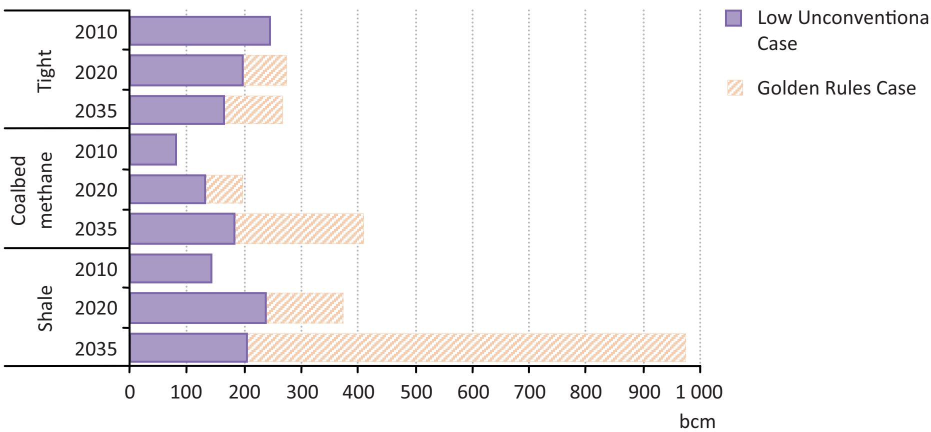
* Total final consumption is the sum of consumption by the end-use sectors industry, transport, buildings (including residential and services) and other (including agriculture and non-energy use).

Supply

In the Low Unconventional Case, total gas supply is lower, at 4.6 tcm, and unconventional production is much lower than in the Golden Rules Case. Unconventional gas production in aggregate rises above 2010 levels of 470 bcm but reaches only 570 bcm in 2020 and falls back to 550 bcm by 2035. Unconventional gas contributes only 6% to global gas production growth over the projection period, meaning that the share of unconventional gas in total gas output falls slightly over time, from 14% in 2010 to 12% in 2035. This is a long way below the 32% share reached by unconventional gas in 2035 in the Golden Rules Case. The difference in unconventional gas production in 2035 between the cases is over 1 tcm, equivalent to 5% of total primary energy supply.

In the Low Unconventional Case, the largest impact is on production of shale gas (Figure 2.10). At a global level, shale gas production increases by 40% over the projection period, reaching just above 200 bcm in 2035, about one-fifth of the level reached in the Golden Rules Case. Tight gas production falls to 165 bcm. Output of coalbed methane is slightly more resilient, rising by two-and-a-half times to around 185 bcm, 45% of the level reached in the Golden Rules Case. This is accounted for by the fact that coalbed methane resources are typically in areas that have existing coal mining operations, in which there is often less resistance to coalbed methane operations than to other types of unconventional gas development – and that the case can be made on environmental grounds that producing the gas is preferable to mining the coal.[16]

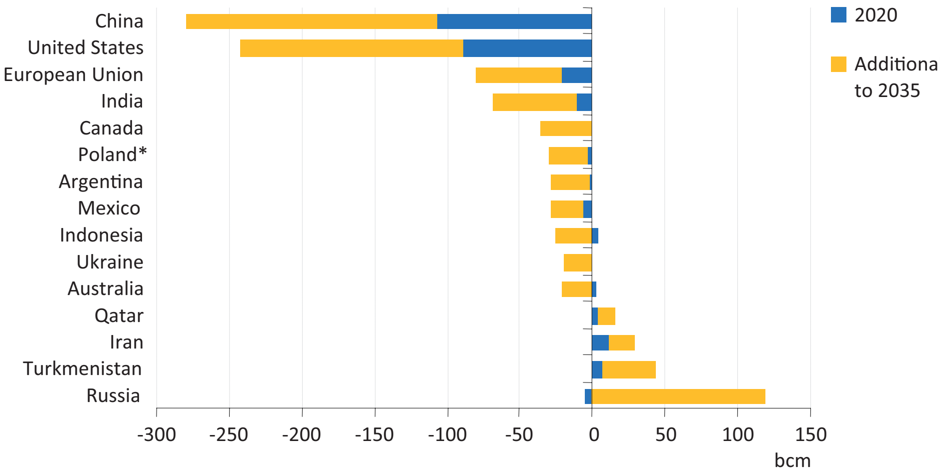
Figure 2.10 ▻ Unconventional gas production by type and case



The reduction in unconventional gas output in the Low Unconventional Case has most impact on China and the United States; their total gas production is lower in 2035 by 280 bcm and 240 bcm, respectively. This represents a 30% reduction in US output, but a much larger fall, 60%, in Chinese production relative to the Golden Rules Case (Figure 2.11 and Box 2.4). There are also major declines in output in the European Union (particularly Poland), India, Canada, Argentina, Mexico, and Indonesia. By contrast, the Low Unconventional Case shores up the preeminent position of the main conventional gas resource-holders. Even though total gas supply is lower than in the Golden Rules Case, Russia (around +115 bcm), Iran (nearly +30 bcm) and Qatar (just over +15 bcm) all post significant increases in their 2035 production, compared to the Golden Rules Case. In the Low Unconventional Case, increased demand from Europe and China for Russian gas means that Russia accounts for 20% of global supply, compared with 15% in the Golden Rules Case.

16. Coalbed methane production can actually reduce methane emissions if the gas would have been released by subsequent coal mining activities (this is sometimes referred to as coal mine methane production).

Figure 2.11 ▷ **Change in natural gas production by selected region in the Low Unconventional Case relative to the Golden Rules Case**



* The change in Polish output is included also in the figures for the European Union.

Box 2.4 ▷ **What could lead to a Low Unconventional Case in China?**

The Chinese government has announced ambitious targets for future production of coalbed methane and shale gas: 6.5 bcm of shale gas and 30 bcm of coalbed methane in 2015, and 60 to 100 bcm of shale gas in 2020. These targets are supported by large producer subsidies for both types of resources. Our projections for the Golden Rules Case show a somewhat slower rate of increase before 2020, but are generally in line with official targets. Public opposition to unconventional gas developments is not currently manifest in China; if it were to develop over the projection period without gaining a commensurate regulatory and industry response, including application of the Golden Rules, the result could be production restrictions leading to an output plateau near the level of the 2020 targets, instead of the continuing growth projected in the Golden Rules Case. There are other hurdles which could also hold back the development of unconventional gas in China:

- The resource base could turn out to be much smaller than currently estimated. The current resource estimates are largely extrapolations from a small number of wells.
- Recovery factors or production rates could be lower than thought. In the United States, different gas shale deposits and different coalbed methane deposits yield very different levels of production. Not enough is known yet about the Chinese reservoirs to confirm that the range of productivity will be similar to that observed

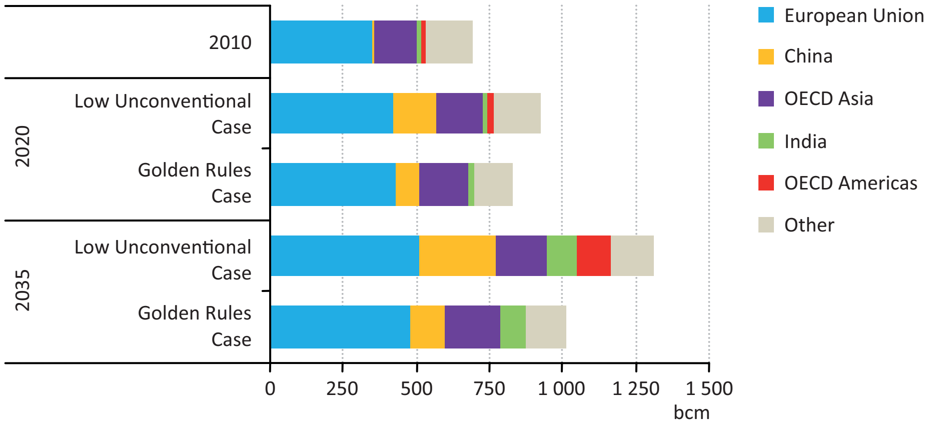
in the United States. On the assumption of similar productivity, the Golden Rules Case will require drilling something like 300 000 new unconventional gas wells in China during the projection period, already a very demanding level of activity. Even modest reductions in productivity would test the limits of the drilling capacity of the country.

- The economics could turn out to be disappointing. Many of the shale gas reservoirs in China are known to be deeper and more complex that those currently exploited in the United States. Both of these factors have a strong influence on the economics. The costs of well construction scale up rapidly with depth. Moreover, most of the coalbed methane resources are located far from large consumption centres: transportation costs make such resources not much more attractive than imports.
- Water availability: a significant part of the shale gas resources is located in regions where either water availability is limited or where competition with agricultural users of the water resources is likely to be a serious issue. This could limit the number of wells and hydraulic fracturing treatments that can be performed in those regions.
- Wavering government support: shale gas and coalbed methane production currently benefit from large subsidies in order to promote their development. When the volumes get large, such subsidies may not be sustainable. Or subsidies to fossil fuels in general may become unacceptable in the later part of the projection period. Loss of subsidies and worsening economics could curb the growth of unconventional gas production from the mid-2020s.

International gas trade, markets and security

The picture of inter-regional trade in the Low Unconventional Case is radically different from that described in the Golden Rules Case. The volume of trade is almost 300 bcm higher in the Low Unconventional Case in 2035, up about 30%, and some patterns of trade are also reversed, with North America requiring large quantities of imported gas to meet its net requirements (Figure 2.12). The United States, a strategically significant gas exporter in the Golden Rules Case, imports nearly 100 bcm by the end of the projection period in the Low Unconventional Case. Despite lower overall gas demand, China's demand for pipeline and LNG imports in 2035 reaches 260 bcm in the Low Unconventional Case, nearly 145 bcm higher than in the Golden Rules Case.

Figure 2.12 ▷ **Major natural gas net importers by case**



Among the exporters, the share of Russia and the Middle East in global inter-regional trade increases slightly to 46% in 2035 in the Low Unconventional Case, compared with a drop to 35% in the Golden Rules Case. Against a backdrop of rising import dependence in some key gas-consuming regions and a more limited number of potential suppliers, the outlook for customers for gas in the Low Unconventional Case looks less bright. Competition among importers becomes more intense, contributing to tighter markets in Europe and Asia. In North America, with the marginal supply coming from international markets, relatively expensive LNG imports pull up domestic prices in the United States – the opposite effect from the Golden Rules Case, where competitively priced exports have a mitigating effect on prices in export markets.

Box 2.5 ▷ **A hybrid case**

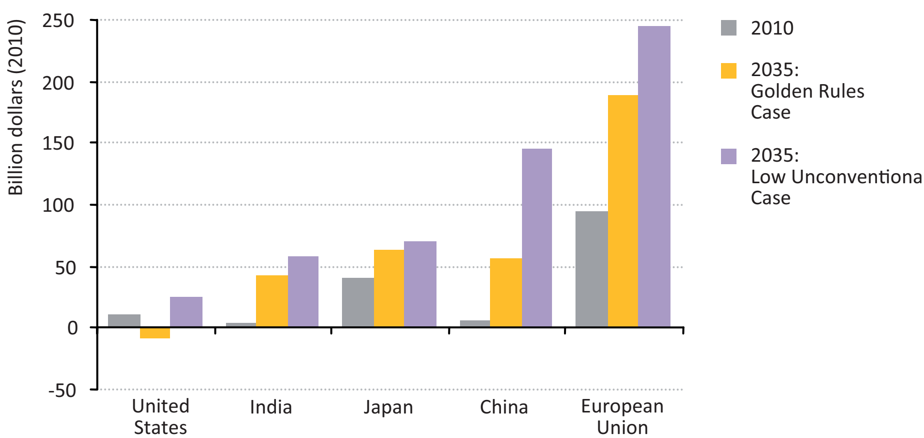
The two cases examined here apply favourable and unfavourable assumptions, respectively and uniformly, to all countries' prospects for unconventional gas development. But it is also possible that some countries follow a path of rapid growth in unconventional resource development along the lines of the Golden Rules Case, while others make slow progress or opt not to develop these resources, as in the Low Unconventional Case. Perhaps the most plausible of these hybrid cases is one in which enhanced attention to environmental issues sustains growth in unconventional output in North America and Australia, while elsewhere – with the partial exception of China – countries fail to realise the regulatory mix that would allow unconventional gas output to grow fast, at least until well into the 2020s. This case is not modelled here, but bears a resemblance to the central scenario of the *WEO-2011* that will be updated in full in this year's *Outlook*, to be published in November 2012.

Investment and other economic impacts

Various constraints in the Low Unconventional Case – moratoria on the use of hydraulic fracturing, overly strict regulation, unreasonably high compliance costs, arbitrary restrictions on drilling locations, less attractive fiscal terms, limitations on water availability and emerging resource limitations – serve to deter upstream investment in unconventional resources. Global cumulative investment in unconventional gas falls by half, to some $1.4 trillion, compared with the investment in the Golden Rules Case, and 60% of investment in unconventional gas is made in the United States. Even so, the share of the United States in global cumulative upstream gas investment declines from 24% to 21%. Limited prospects for unconventional gas prompt $0.7 trillion more cumulative investment in conventional resources. This underscores the relative shift in market power from unconventional resource holders to the major conventional producers, notably in Russia, the Middle East and North Africa.

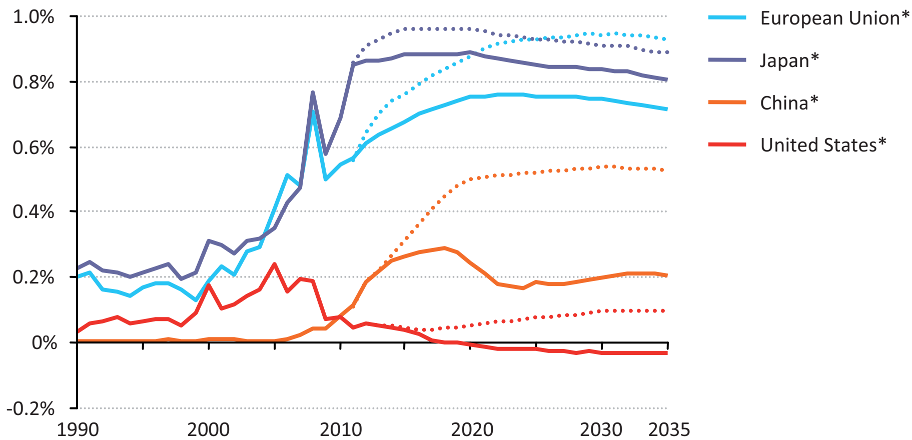
The import bills attached to inter-regional trade rise to $630 billion in 2035 (in year-2010 dollars) in the Low Unconventional Case, nearly 60% higher than in the Golden Rules Case. The proportionate impact on import bills is highest in China and the European Union, but the effect in other countries is also marked (Figure 2.13). China's spending on gas imports in 2035 in the Low Unconventional Case reaches almost $150 billion, or almost three times the level reached in the Golden Rules Case. Gas-import bills in the European Union rise to $245 billion in 2035, 30% above the $190 billion reached in the Golden Rules Case. Spending by the United States on gas imports in 2035 in the Low Unconventional Case totals $25 billion, around double the level of 2010, whereas the United States is a net exporter from 2020 in the Golden Rules Case, with export earnings increasing steadily to around $10 billion in 2035.

Figure 2.13 ▷ Natural gas-import bills by selected region and case



It follows that gas import bills expressed as a share of GDP are also sharply higher in the Low Unconventional Case than in the Golden Rules Case (Figure 2.14). For example, China's import bills stabilise at 0.5% of GDP towards the end of the projection period compared with a plateau of just 0.2% in the Golden Rules Case.

Figure 2.14 ▷ Spending on net-imports of natural gas as a share of real GDP at market exchange rates by case



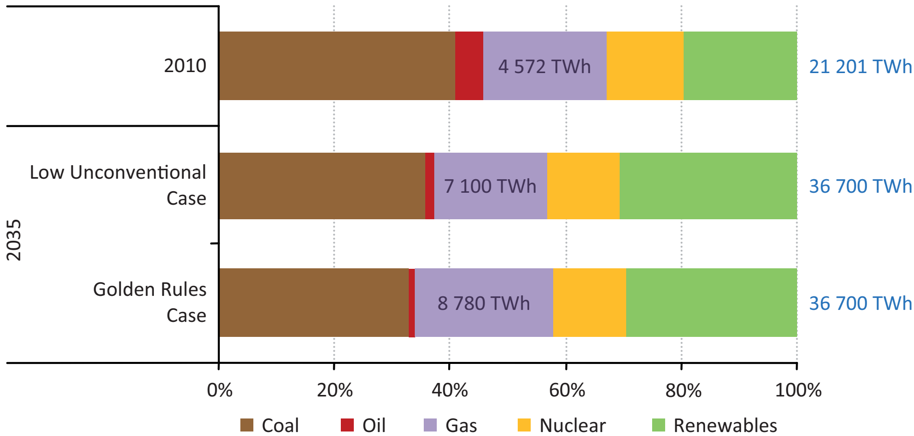
* Solid lines represent the Golden Rules Case; dotted lines represent the Low Unconventional Case.

Climate change and the environment

Although the forces driving the Low Unconventional Case derive in part from environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. The global power generation mix (Figure 2.15) involves a higher share of coal-fired power in the Low Unconventional Case, stemming from the more limited role for natural gas. Additional investment in coal-fired generation locks in additional future emissions, since any new coal-fired power plant has an anticipated operating lifetime in excess of 40 years.

Though many of those concerned with environmental degradation may find it difficult to accept that unconventional gas resources have a place in a sustainable energy policy, a conclusion from this analysis is that, from the perspective of limiting global greenhouse-gas emissions, a Golden Rules Case has some advantages compared with the Low Unconventional Case, while also bringing with it other benefits in terms of the reliability and security of energy supply.

Figure 2.15 ▷ **World power generation mix by case**



Note: TWh = terawatt-hours.

Nonetheless, reaching the international goal of limiting the long-term increase in the global mean temperature to 2°C above pre-industrial levels cannot be accomplished through greater reliance on natural gas alone. Achieving this climate target will require a much more substantial shift in global energy use, including much greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including power plants and industrial facilities equipped for carbon capture and storage. Anchoring unconventional gas development in a broader energy policy framework that embraces these elements would help to allay the fear that investment in unconventional gas comes at the expense of investment in lower-carbon alternatives or energy efficiency.

Country and regional outlooks

Are we moving towards a world of Golden Rules?

Highlights

- The United States is the birthplace of the unconventional gas revolution and regulatory developments at both federal and state levels will do much to define the scope and direction of similar debates in other countries. Moves are underway to build on existing regulation and practice, for example by tightening the rules on air emissions, ensuring disclosure of the composition of fracturing fluids and improving public information and co-operation among regulators.
- In North America, both Mexico and Canada also have significant unconventional gas resources and Canada is one of only a handful of countries outside the United States where commercial production is underway. Which way the regulatory debate turns could have a substantial effect on future unconventional supply: in the Golden Rules Case, total production from North America reaches 1 085 bcm in 2035, of which almost 70% is unconventional supply, whereas the equivalent figure in the Low Unconventional Case is only 780 bcm; this makes the difference between the region exporting to, or importing from, global gas markets.
- The prospects for unconventional gas in China are intertwined with the much broader process of gas market and pricing reform, and with open questions about the extent and quality of the resource. Over the longer term, environmental policies and constraints, notably water availability, are also set to play a role. Our projections for the Golden Rules Case are for unconventional output to reach just over 110 bcm in 2020, a very rapid increase but still somewhat lower than ambitious official targets, and 390 bcm in 2035. Unconventional production is some 280 bcm lower in 2035 in the Low Unconventional Case.
- In advance of any substantial unconventional output, the regulatory framework in Europe is under examination at both national and EU levels, with a variety of outcomes ranging from enthusiastic support for unconventional development from Poland to the bans on hydraulic fracturing in place in France and Bulgaria. In our projections in the Golden Rules Case, growth in unconventional supply in the European Union reaches almost 80 bcm in 2035, which is sufficient post-2020 to offset the decline in conventional output.
- New unconventional gas projects in Australia are coming under increased environmental scrutiny, in particular related to the risk of water contamination from coalbed methane projects. This could constrain future unconventional gas output, although Australia has ample conventional resources with which to achieve growth in supply and export; exports of 120 bcm by 2035 in the Golden Rules Case come mainly from unconventional gas developments, whereas a comparable level of export in the Low Unconventional Case is driven by mainly by conventional output.

United States

Resources and production

Until recently, unconventional natural gas production was almost exclusively a US phenomenon. Tight gas production has the longest history, having been expanding steadily for several decades. Commercial production of coalbed methane began in the 1980s, but only took off in the 1990s; it has levelled off in recent years. Shale gas has also been in production for several decades, but started to expand rapidly only in the mid-2000s, growing at more than 45% per year between 2005 and 2010. Unconventional gas production was nearly 60% of total gas production in the United States in 2010. While tight gas and shale gas account for the overwhelming bulk of this, shale gas is expected to remain the main source of growth in overall gas supply in the United States in the coming decades. The United States and Canada still account for virtually all the shale gas produced commercially in the world, though – as discussed in Chapter 2 of this report – many countries are now trying to replicate this experience.

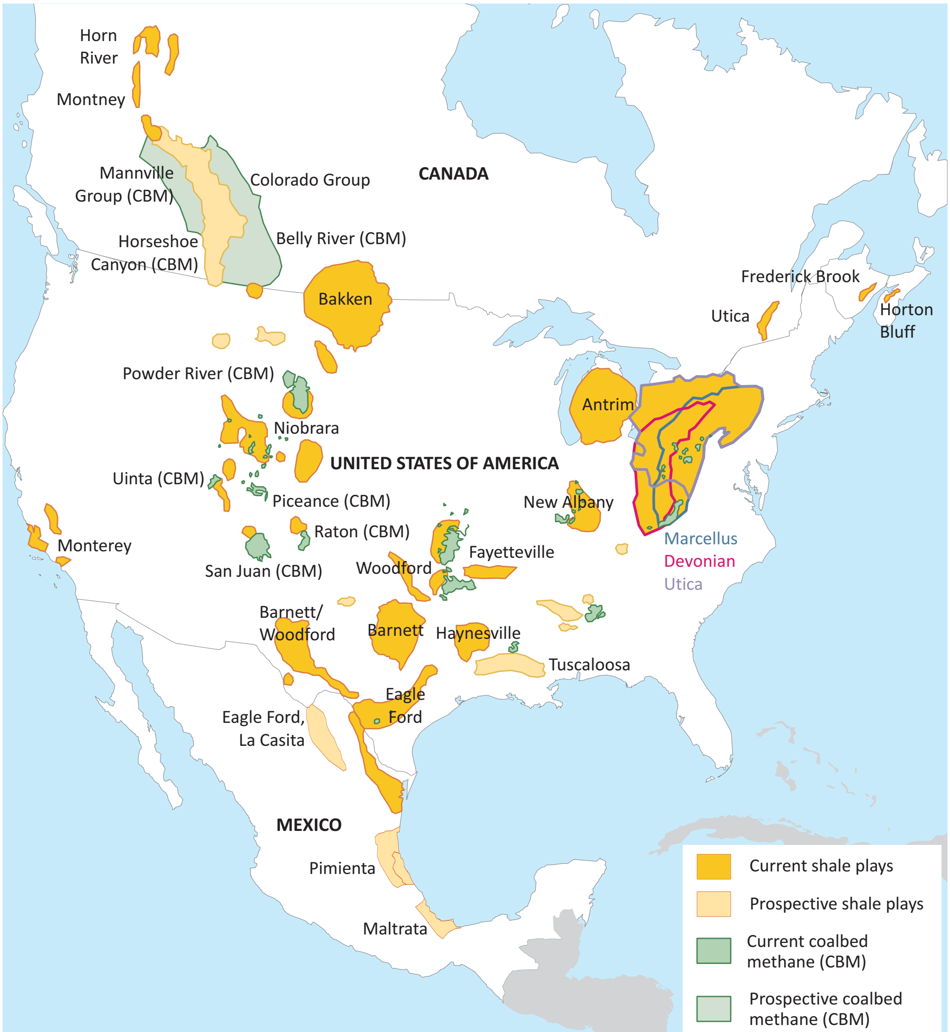
There are large resources of all three types of unconventional gas across the United States. Of the 74 trillion cubic metres (tcm) of remaining recoverable resources of natural gas at end-2011, half are unconventional (Table 3.1); in total, gas resources represent around 110 years of production at 2011 rates. Major unconventional gas deposits in the United States are distributed across much of the country (Figure 3.1). Coalbed methane resources are found principally in the Rocky Mountain states of Wyoming, Utah, New Mexico, Colorado and Montana. Tight gas and shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico. Two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, taken as single reservoirs are among the largest known gas fields of any type in the world.

Table 3.1 ▷ Remaining recoverable natural gas resources and production by type in the United States

	Recoverable resources (tcm)		Production (bcm)		
	End-2011	Share of total	2005	2010	Share of total (2010)
Unconventional gas	37	50%	224	358	59%
Shale gas	24	32%	21	141	23%
Tight gas	10	13%	154	161	26%
Coalbed methane	3	4%	49	56	9%
Conventional gas	37	50%	288	251	41%
Total	**74**	**100%**	**511**	**609**	**100%**

Sources: IEA analysis and databases.

Figure 3.1 ▷ Major unconventional natural gas resources in North America



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Regulatory framework

As pioneers of large-scale unconventional gas development, policy-makers, regulators, producers and the general public in the United States have been the first to face the question of how to evaluate and minimise the associated environmental risks. The emergence of unconventional gas production on a large scale has prompted a broad debate, particularly as production has moved out of traditional oil and gas producing areas. It has also led to changes in the regulatory framework and industry practices. As described in Chapter 1, the principal areas of concern are the impact of drilling on land use and water resources (in particular, the possible contamination of aquifers and surface water) and possible increases in air emissions, particularly of methane and volatile organic compounds.

The legal and regulatory framework for the development of unconventional resources in the United States is a mixture of laws, statutes and regulations at the federal, state, regional and local levels. Most of these rules apply to oil and gas generally and were in place before unconventional resource development took off. They cover virtually all phases of an unconventional resource development, from exploration through to site restoration, and include provisions for environmental protection and management of air, land, waste and water. States carry the primary responsibility for regulation and enforcement on lands outside federal ownership. This approach allows for some regionally specific conditions, such as geology or differing economic or environmental priorities, to be taken into account, with consequential variations in regulatory practices among states. However, on federal lands (extensive in the western United States), the federal government owns the land and mineral resources and directly regulates the extraction process.

Federal laws applicable to unconventional gas resource development are directed mainly at environmental protection. They include the Clean Air Act, Clean Water Act and Safe Drinking Water Act. Certain exemptions from federal rules have been granted; for example, hydraulic fracturing is excluded from the list of regulated activities under the Underground Injection Program authorised by the Safe Drinking Water Act (unless diesel-based fracturing fluids are used). Federal regulations related to community protection and occupational health and safety require that operators make information on certain hazardous chemicals used in drilling operations, including fracturing fluids, available to officials and those responsible for emergency services. Federal rules do not pre-empt additional state-level regulations and public concerns about the risk of pollution have prompted some states to require wider public disclosure about the types and volumes of chemicals used.

State-level regulations relevant to unconventional resources are typically specified in state oil and gas laws; in some cases, these are being updated to respond to public concerns about the environmental impact of unconventional gas development. Typical changes include rules about disclosure of information on fracturing fluids, additional measures to ensure adequate integrity in well casing and cementing, and rules on the treatment and disposal of waste water. Yet regulatory gaps remain in many states, not least because some have limited experience with oil and gas development. The states of New York, New Jersey and Maryland have enacted temporary bans on hydraulic fracturing pending further review of its environmental impacts and the need for changes to regulations; at the time of writing, Vermont also seems set to enact a ban.

Efforts to strengthen the United States' regulatory framework are a public priority, in order to ensure responsible development of unconventional resources and respond to rising public anxiety and pressure. Among the many public organisations focusing on the environmental aspects of unconventional gas development, two are working specifically on improving the quality of regulatory policy: the Ground Water Protection Council and the State Review of Oil and Natural Gas Environmental Regulations (STRONGER). They have both been advising states on regulatory matters to do with unconventional gas. The industry itself has taken steps to promote best practice, both through industry bodies, such as the American Petroleum Institute and through initiatives such as the creation of the FracFocus website, a voluntary online registry to which companies submit data about chemicals used in hydraulic fracturing operations (API, 2011). The site is managed through a partnership with the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

The United States Environmental Protection Agency has issued federal regulations under the Clean Air Act that aim to reduce emissions of volatile organic compounds from all operations of the oil and gas industry; these will also cut methane emissions. The regulations apply to wells that are hydraulically fractured and will, in essence, enforce the use of "green completions", as already mandated in Colorado and Wyoming. The Bureau of Land Management, responsible for regulation of most energy-related activities on federal land, has proposed new rules that would require companies to disclose the composition of fracturing fluids, seek additional permits and conduct stringent well integrity tests. These initiatives have sparked an intense debate among interested parties as to whether hydraulic fracturing should be regulated at both state and federal level, and whether harmonised regulations on federal lands and on neighbouring leases are required.

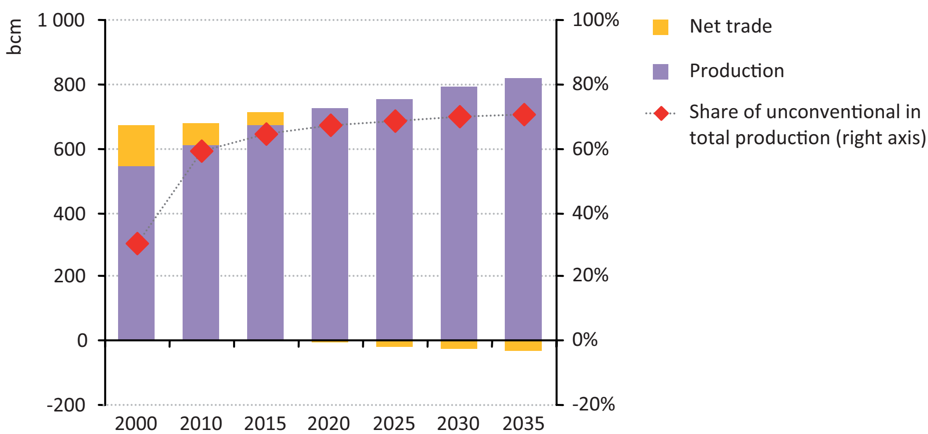
At the end of 2011, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a set of twenty recommendations for short-term and long-term actions by federal and state agencies to reduce the environmental impact and improve the safety of shale gas production (US DOE, 2011). A major study by the National Petroleum Council on the future of oil and gas resources in the United States has also emphasised the need for "prudent development" and concluded that the benefits of the country's oil and gas resources can be realised by ensuring that they are developed and delivered in a safe, responsible and environmentally acceptable manner in all circumstances (NPC, 2011). These studies and recommendations have been important in defining the scope of regulatory change in the United States and setting its direction; by extension, they could be influential in many countries that are seeking to undertake unconventional gas development.

Within this diverse structure, a major challenge is to maintain reasonable consistency of regulation (for example, among the different states), closing regulatory gaps, where necessary, and doing this in a way that encourages best practice and responds to changes in production technology. Unconventional resource production may be well underway in United States, but shale gas development – and hydraulic fracturing in particular – has become an emotive public issue, with strong and well-organised positions taken by many of the parties involved. This has complicated the prospects for constructive engagement, limiting the common ground on which new regulation (at federal or state level) or new projects (at local level) might be based. Given the scale and pace of development in the United States, there is a likelihood that regulation will be driven by events. For example, an environmental incident linked to unconventional gas development could crystallise public views and prompt new restrictions on unconventional gas production or the use of hydraulic fracturing.

Projections and implications

Assumptions about the regulatory environment have a marked impact on the results of the two cases examined in this report.[1] In the Golden Rules Case, total gas production in the United States grows from around 610 billion cubic metres (bcm) in 2010 to 820 bcm in 2035 (Figure 3.2). Almost all of this increase comes from shale gas production: output of conventional gas, coalbed methane and tight gas remain close to current levels. As a result, the share of shale gas in total gas production rises from 23% in 2010 to 45% in 2035; total unconventional production takes a 71% share of gas output by 2035.

Figure 3.2 ▷ Natural gas balance in the United States in the Golden Rules Case*



* Positive values for net trade denote imports, while negative values represent exports. The sum of production and net trade represents total demand.

In the Low Unconventional Case, total gas production goes into decline after peaking at 660 bcm around 2015, falling to 580 bcm in 2035, 30% less than in the Golden Rules Case (Table 3.2). Production of shale gas in the United States grows until 2017 before limitations on access to resources cause output to fall back to 2010 levels; tight gas and coalbed methane production also decline, to levels seen around 2000 and 1990, respectively. In the Low Unconventional Case, the share of unconventional gas in total supply decreases to only 47% by the end of the *Outlook* period – 23 percentage points less than in the Golden Rules Case. On the other hand, higher gas prices and limited unconventional production in the Low Unconventional Case prompt a mini-renaissance in conventional gas output, with an increase of more than 50 bcm over 2010 production, driven by the investment capital

1. See Chapter 2 for details of assumptions in both cases.

and rigs freed up by the shrinking unconventional sector and the possible opening of more offshore and Arctic acreage as the United States struggles to reduce its imports and the associated bills.

These results point in two very different directions for the United States' domestic consumers of gas and its gas industry and its role in international markets. On the domestic market, although gas prices are set to increase in both cases, the rate of the price increase is moderated in the Golden Rules Case by the availability of domestic unconventional gas. United States gas consumption grows by 0.6% per year in this case, a modest rate of increase by global standards (reflecting the maturity of the gas market), but much more impressive considering that overall energy demand growth in the United States averages 0.1% per year (so gas consumption grows six times faster than overall energy demand[2]). In the United States, IHS Global Insight estimates that the lower gas prices attributable to shale gas production will save households $926 per year between 2012 and 2015 (IHS, 2011). Cheaper gas also stimulates industries – chemicals and fertilisers, in particular – that rely on gas as a key feedstock or source of energy. Several chemical companies have announced expansion plans in the United States (PWC, 2011). In the Low Unconventional Case, gas consumption in the United States grows until 2020 and then declines thereafter, ending almost 15% lower by 2035 than in the Golden Rules Case.

3

Table 3.2 ▷ Natural gas indicators in the United States by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	609	726	821	637	578	242
Unconventional	358	489	580	383	274	306
Share of unconventional	59%	67%	71%	60%	47%	23%
Cumulative investment in upstream gas, 2012-2035**		1 648		1 293		355
Unconventional		1 308		854		454
Net trade (bcm): net imports (+) / net exports (-)	71	-9	-33	57	97	-131
Imports as a share of demand	10%	n.a.	n.a.	8%	14%	n.a.
Share of gas in the energy mix	25%	26%	28%	25%	24%	4%
Total energy-related CO_2 emissions (million tonnes)	5 343	5 218	4 618	5 173	4 511	108

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

2. This figure for the United States is higher, for example, than the comparable figure for China, where gas demand grows by an average of 7% per year in the Golden Rules Scenario, "only" about four times faster than total energy growth averaging 1.9% per year.

The boom in shale gas thus far has already transformed prospects for gas trade. The future of this unconventional "revolution" will determine whether the United States becomes an influential gas exporter over the coming decades or, alternatively, sees its imports rise from current levels. As recently as 2008, the United States was projected to require increasing imports of liquefied natural gas (LNG) to meet incremental gas demand (US DOE/EIA, 2008). In the Low Unconventional Case, this again becomes a prospect as domestic production declines.

In the expectation of a more favourable outlook for unconventional gas supply, a number of projects have been proposed to convert idle regasification terminals into liquefaction facilities to enable LNG exports (see Chapter 2). The most advanced of these, Sabine Pass on the United States Gulf Coast, cleared the last of its regulatory hurdles in April 2012 and could be exporting as soon as late 2015, with a target throughput of 22 bcm per year. A further seven projects await Department of Energy export approval, totalling in excess of 120 bcm of capacity. While not all these projects will proceed by 2020, even an additional two projects could see United States LNG export capacity exceed 60 bcm by 2020.

The prospect of LNG export has ignited a debate in the United States about the possible impact on price levels, with domestic gas-intensive industrial users expressing concern that they might lose an element of their current competitive advantage. We assume that other LNG export projects besides Sabine Pass are approved to begin operation but, in the Golden Rules Case, because of limited opportunities for export, the additional capacity may not be needed: LNG exports out of North America reach 40 bcm in 2035 but this is split between the United States and Canada. As discussed in Chapter 2, such exports and capacity would nonetheless have significant implications for the structure of international gas markets and for gas security, especially since a part of these exports would be based on a gas-priced formula, derived from the Henry Hub price.

Successfully meeting public concerns by putting in place the regulatory conditions that deal convincingly with environmental risks could be expected to have a significant impact on the pace of development of unconventional gas resources in other parts of the world. The United States has been the testing ground for unconventional gas technology and the place where this technology has been most widely and most productively applied. Just as experience from the United States has prompted both global interest in developing unconventional resources and reservations about their environmental impact, so too will other countries look to the United States for evidence that social and environmental risks can be managed successfully, in part with appropriate regulation.

Canada

Resources and production

Canada is endowed with large unconventional gas resources of all three types and is one of only a handful of countries outside the United States where commercial production is underway. Production of tight gas was around 50 bcm in 2010 and production of coalbed methane (concentrated in the province of Alberta) close to 8 bcm. Shale gas is believed to have the greatest production potential in the longer term, although commercial production is only 3 bcm. The main Canadian shale gas plays currently being explored and appraised are the Horn River Basin and Montney shales in northeast British Columbia, the Colorado Group in Alberta and Saskatchewan, the Utica Shale in Quebec and the Horton Bluff Shale in New Brunswick and Nova Scotia (Figure 3.1). Remaining recoverable unconventional resources in Canada at end-2011 are estimated to be 18 tcm (11 tcm shale gas, 5 tcm coalbed methane and 2 tcm tight gas), representing around 6% of world unconventional resources. 80% of Canada's total remaining recoverable gas resources are unconventional.

Regulatory framework

Unconventional gas in Canada is subject to a set of federal, provincial and local laws and regulations governing upstream activities, including those relating to environmental impacts. Most oil and gas regulations are provincial, as the resources belong to the provinces (with the exception of those on native lands). The National Energy Board is the federal regulatory body for international and inter-provincial energy issues, while Environment Canada is the federal agency responsible for environmental protection, including the administration and enforcement of federal laws.

The regulatory picture in Canada varies by province, but in response to public pressure and the heightened commercial interest in Canadian unconventional gas opportunities, regulators across the country are paying increasing attention to the potential pollution risks from hydraulic fracturing and to the disposal of waste water from unconventional wells. While each province has its own particular regulations, all jurisdictions have laws to protect fresh water aquifers and to ensure responsible development. In western Canada, gas producers are required by regulation to re-inject produced water into deep saline zones located far below the base of the groundwater, using water disposal wells. In other regions, where no such disposal wells are available, provincial regulations set requirements for treating and disposing of produced water.

Approvals for water use are required from the responsible regulatory agency or government department. Regulators and governments have a variety of control mechanisms available to manage water use and mitigate potential impacts, including the ability to limit the rate at which water is used from any source and to specify aggregate water use limits. There are also regulations aimed at minimising the environmental footprint of drilling and production operations, for example by requiring centralised drilling pads and requiring land restoration after production has ceased.

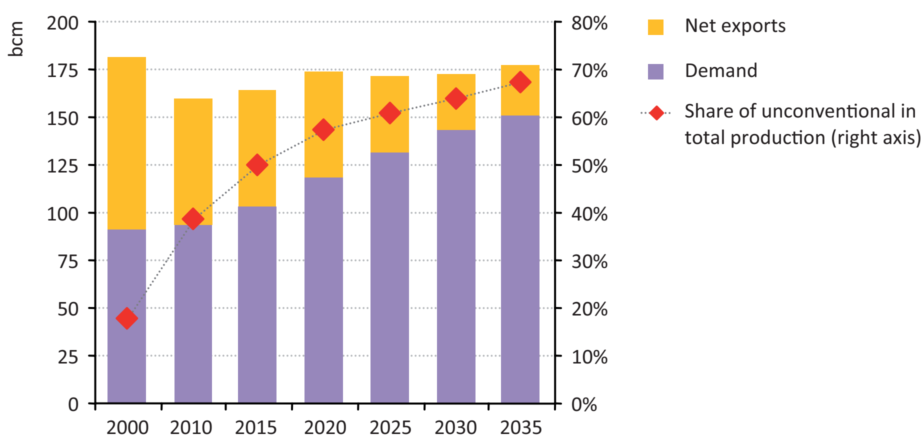
As in the United States, industry bodies are promulgating and promoting best practices. The Canadian Association of Petroleum Producers has recently issued new guidelines for its members, covering many of the issues in the Golden Rules (CAPP, 2012). The Energy Resources Conservation Board, the regulator for the Province of Alberta, a province with a long history of oil and gas production, has initiated a review of its regulatory framework as it applies to unconventional gas (ERCB, 2011). Five of Canada's provinces and one territory are associate members of the United States Interstate Oil and Gas Compact Commission.

The prospect of expanded drilling for shale gas has generated some public and political concern; the clearest incidence of this led the provincial government in Quebec to call a halt in 2011 to the use of hydraulic fracturing, pending an environmental review of the impacts of this practice on water supplies. This followed commercial interest in developing the Utica shale which, running near population centres along the St Lawrence River, generated substantial local opposition. The review is expected to report in 2013.

Projections and implications

Unconventional gas in Canada is expected to play an increasingly important role in offsetting a projected decline in conventional gas production and meeting rising domestic demand. In the Golden Rules Case, unconventional gas production rises from 62 bcm in 2010 to about 120 bcm in 2035, its share of total gas output increasing from just under 40% to two-thirds (Figure 3.3). Shale gas and, to a slightly lesser extent, coalbed methane drive this growth. Total gas production increases from 160 bcm to nearly 180 bcm between 2010 and 2035. Canadian gas demand grows even faster, so net exports drop sharply – from around 65 bcm in 2010 to 25 bcm in 2035. The United States has less need – possibly none at all – to import gas from Canada as its own production of unconventional gas is projected to outpace its domestic gas needs. While Canadian LNG exports to Pacific markets commence before 2020, further growth in exports to Asia is limited in the Golden Rules Case by the large increase in domestic production in China, as well as the rise in unconventional production in Indonesia and Australia.

Figure 3.3 ▷ Natural gas balance in Canada in the Golden Rules Case*



* The sum of demand and net exports represents total production.

In the Low Unconventional Case, shale gas production remains relatively robust, even with the assumed limitations on access to resources. It is about the only unconventional gas resource type with room to grow to offset otherwise rising North American demand for imports. However, overall gas production peaks before 2025 and falls back below current levels by the end of the projection period (Table 3.3). The higher prices that result from slower development constrain demand, which reaches around 130 bcm in 2035, 15% lower than in the Golden Rules Case. Although production is lower in the Low Unconventional Case, it is noteworthy that the required upstream investment is at a level similar to that in the Golden Rules Case; this is because of the relative resilience of shale gas production in the Low Unconventional Case and to the assumption (built into the model) that production tends to become more costly as a given resource starts to become more difficult to access. Since access to shale gas resources is limited in this case, the cost of production rises in a way that balances the effect of lower output on the overall investment requirement.

Table 3.3 ▷ Natural gas indicators in Canada by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	160	174	177	173	141	37
Unconventional	62	100	119	82	84	35
Share of unconventional	39%	57%	67%	48%	60%	7%
Cumulative investment in upstream gas, 2012-2035**		292		296		-4
Unconventional		218		207		11
Net exports (bcm)	66	55	26	63	12	14
Share of gas in the energy mix	30%	34%	40%	32%	35%	5%
Total energy-related CO_2 emissions (million tonnes)	523	547	540	533	521	19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Mexico

Resources and production

Mexico's large resources make it one of the most promising countries for shale gas development. Its 19 tcm of shale gas is the fourth-largest shale gas resource base in the world after China, the United States and Argentina; this figure represents some 85% of Mexico's remaining recoverable gas resources. While known about for more than two decades, as elsewhere, shale gas was not considered economically viable to produce until recently.

The government is keen to exploit shale gas resources to boost the country's flagging output of conventional oil and gas. In its National Energy Strategy 2012-2026, for the first time, the Mexican Ministry of Energy has included two scenarios for the development of shale gas: the baseline scenario foresees production of 2 bcm (200 million cubic feet per day [mcf/d]) starting in the Eagle Ford shale play in 2016 and reaching 14 bcm (1 343 mcf/d) in 2026 (Secretaria de Energia, 2012). The "strategy scenario" assumes the additional development of the La Casita shale play, which leads to total shale gas production of 34 bcm (3 279 mcf/d) in 2026.

In line with this strategy, Pemex, the national oil company, is looking in particular at the areas in the north that are extensions of the Eagle Ford shale play (Figure 3.1). Pemex sunk its first shale gas well, Emergente 1, in the Burgos basin in February 2011 and this has been producing at a rate of almost 30 million cubic metres (3 mcf/d). Pemex plans to drill around 175 wells during the period 2011 to 2015 to evaluate reserves and delineate priority areas for development. Pemex also plans to acquire about 10 000 square kilometres of three-dimensional seismic data, which it will use to carry out detailed geological and geochemical modelling studies.

If this exploration effort demonstrates the commercial viability of shale gas production, the large-scale development of these resources would require a huge increase in drilling. Pemex estimates that the development of 8.4 tcm (297 trillion cubic feet) of shale gas – its central estimate of recoverable resources – would call for drilling a total of more than 60 000 wells[3] over the next 50 years, requiring a very large-scale capital investment.

In addition to the need for adequate investment, a number of technical challenges would need to be overcome for this to happen, notably adequate access to water for hydraulic fracturing. Coahuila, where much of the Eagle Ford play is located, is one of Mexico's driest states, with rainfall less than half the national average and all of the surface water rights have already been allocated. Three-quarters of the state's water is used in agriculture for the production of grains and other crops that can survive the desert climate, while the rest is for industrial consumption. Hydraulic fracturing on a large scale would require very careful treatment and recycling of waste water to reduce the need for fresh water. Other hurdles to shale gas development, such as the lack of pipeline infrastructure to deliver gas to market, could complicate operations and make the cost of drilling shale gas wells in Mexico significantly higher than in the United States. A plan to increase the transport and distribution capacity for natural gas is being implemented, including a pipeline that will run close to the main gas-rich areas in the northern parts of the country.

3. Information provided in a presentation by Carlos Morales, Director General, PEMEX Exploration & Production, to the IEA Workshop on Unconventional Gas in Warsaw, 7 March 2012. This appears to be based on an Estimated Ultimate Recovery (EUR) of 5 bcf per well; this is representative of good wells in the United States but could overestimate a likely average EUR per well; if so, the number of wells required to produce this volume of shale gas could be higher.

Regulatory framework

The environmental impact of gas development in Mexico is covered by existing environmental, health and safety laws and regulations. There are no specific national regulations in place yet for shale gas; however, the new National Energy Strategy 2012-2026 recognises that the new targets for shale gas production might require specific regulatory provisions and calls for the future development of an "integrated strategy" for shale gas, addressing environmental, social and financial challenges. This will require not only attention to the regulatory framework, but also the allocation of sufficient resources to regulatory bodies to ensure adequate supervision and enforcement.

Pemex holds monopoly rights over all upstream activities in Mexico and no other company is allowed to own hydrocarbons reserves or undertake exploration or production for its own benefit. A law adopted in 2008 allows Pemex to sign incentive-based development contracts with other companies, though the price paid for services cannot be linked to production: three such contracts for the development of small, mature onshore fields were awarded in August 2011. Larger contracts, which could have a more substantial impact on the country's production, are expected to be offered in future.

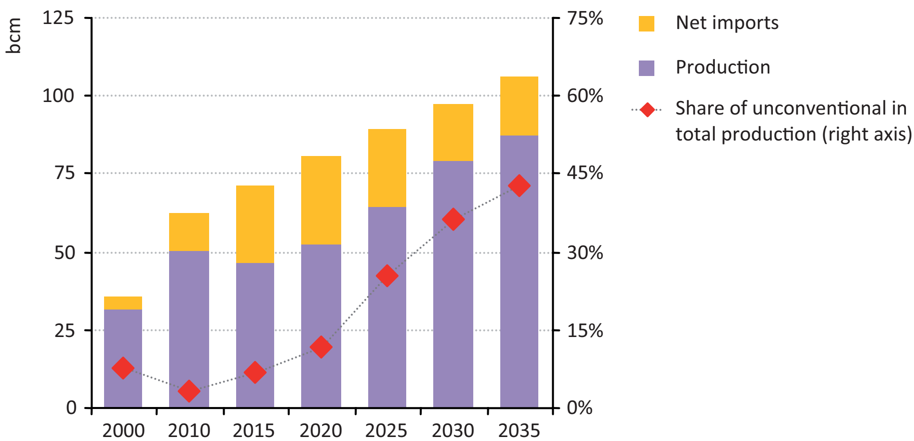
The strategy to be developed for shale gas could follow one of a range of possibilities: it could rest heavily on assistance from companies under service contracts, either basic in terms of remuneration or more strongly incentive-based, although it is also possible that Pemex could decide to handle all shale development on its own. The pace of shale gas development will depend in part on the approach chosen; a greater involvement of private firms, beyond the arrangements already provided for in current legislation, could accelerate the process, but may be politically challenging.

Projections and implications

Shale gas could make a significant contribution to meeting Mexico's gas needs in the longer term, but much will depend on the regulatory regime governing participation by private companies and whether the environmental challenges – notably related to the use and recycling of water for hydraulic fracturing – can be overcome. Development costs will have to be low enough to allow domestic resources to compete with imports from the United States, the price of which recently hit new lows. The alternative – to try and protect the domestic market from cheaper gas imports – is difficult in the context of Mexico's participation in the North American Free Trade Agreement.

In the Golden Rules Case, Mexican gas production grows from 50 bcm in 2010 to almost 90 bcm in 2035, with nearly all of the increase coming from unconventional gas (mostly shale gas, plus some tight gas); conventional gas production grows slightly to around 50 bcm by the end of the projection period, as new fields struggle to compensate for the continuing decline in output from the Cantarell field and other mature fields.[4] Shale and tight gas production reach about 37 bcm combined in 2035, accounting for close to 45% of total Mexican gas production (Figure 3.4). In the Low Unconventional Case, unconventional gas production remains negligible through to 2035.

Figure 3.4 ▷ Natural gas balance in Mexico in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Rapid growth in unconventional gas would have a major impact on Mexico's overall energy mix, with the lower gas prices encouraging gas use and leading to an increase in gas demand. In the Golden Rules Case, demand rises from around 60 bcm in 2010 to 105 bcm in 2035, the share of gas in total primary energy use increasing from 29% to 35% (Table 3.4). The country's need to import gas varies over time. It currently imports about 20% of its gas needs, by pipeline from the United States and in the form of LNG; these imports rise to nearly 30 bcm by 2020, but then fall back to about 20 bcm by 2035 as gas production outstrips demand growth. Higher gas demand and lower imports promise energy security and economic benefits to Mexico, with the possibility of net environmental benefits. In the Low Unconventional Case, the share of gas in primary energy demand actually drops, to 28% by 2035, leading to higher energy-related carbon-dioxide (CO_2) emissions relative to the Golden Rules Case.

4. In the strategy scenario, or high case, included in Mexico's National Energy Strategy 2012-2026, conventional gas production increases from around 60 bcm in 2011 to almost 85 bcm in 2026. Shale gas production, on its own, contributes around 34 bcm to total natural gas production in 2026.

Table 3.4 ▷ Natural gas indicators in Mexico by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	50	52	87	46	59	28
Unconventional	2	6	37	0	0	37
Share of unconventional	3%	12%	43%	0%	0%	43%
Cumulative investment in upstream gas, 2012-2035**		140		111		29
Unconventional		47		-		47
Net imports (bcm)	12	28	19	25	28	-9
Imports as a share of demand	19%	35%	18%	35%	32%	-14%
Share of gas in the energy mix	29%	32%	35%	29%	28%	7%
Total energy-related CO_2 emissions (million tonnes)	402	449	492	455	511	-19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

China

Resources and production

The size of unconventional gas resources in China is at an early stage of assessment, but it is undoubtedly large. At end-2011, China's remaining recoverable resources of unconventional gas totalled almost 50 tcm, comprised of 36 tcm of shale gas, 9 tcm of coalbed methane and 3 tcm of tight gas.[5] This is around thirteen times China's remaining recoverable conventional gas resources. China's shale gas resources lie in several large basins spread across the country, with plays in the Sichuan and Tarim Basins believed to have the greatest potential. The main coalbed methane deposits are found in the Ordos, Sichuan and Junggar Basins (Figure 3.5).

Coalbed methane is currently the primary source of unconventional gas produced commercially in China, with output of around 10 bcm in 2010. Most of this output comes from coal producers PetroChina and China United Coal Bed Methane Company. Shale gas exploration activities have increased in recent years under a government-driven programme to evaluate the resource base. Results from several pilot projects, to be completed in 2012, are expected to inform the selection of high potential areas for further exploration. As of early 2012, an estimated 20 shale gas wells had been drilled by Chinese companies. Based on what is known about China's geology at this early stage, shale gas resources may prove more difficult and more expensive to develop than those in North America. Early

5. We use the ARI estimate for shale gas to be consistent with our methodology for other countries. This is higher than the 25 tcm estimated by China's Ministry of Land and Resources for recoverable shale gas resources; however the MLR number does not yet include all provinces (MLR, 2012).

indications are that kerogen quality in the shale plays is relatively poor, resulting in low organic content. This suggests that, for China to achieve a similar output to that of the United States, it would need to drill more wells, with longer reach.

Figure 3.5 ▷ Major unconventional natural gas resources in China

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The Chinese government has outlined ambitious plans for boosting unconventional gas exploration and production. These call for coalbed methane production of more than 30 bcm and for shale gas production of 6.5 bcm in 2015; the targets for shale gas output in 2020 are between 60 and 100 bcm. They are accompanied by the goal to add 1 tcm of coalbed methane and 600 bcm of shale gas to proven reserves of unconventional gas by 2015. In support of this effort, China plans to complete a nationwide assessment of shale gas resources and build nineteen exploration and development bases in the Sichuan Basin in the next four years. Efforts are also supported by the international partnerships that Chinese companies have formed in North America to develop shale gas acreage, which will provide valuable development experience.

An initial tender for four blocks of shale gas exploration acreage in the Sichuan Basin was held in June 2011, with participation limited to six eligible state-controlled companies. Of those, Sinopec and Henan Provincial Coal Seam Gas Development and Utilization Company obtained licences. An expanded group of bidders, including privately-owned Chinese companies (qualified based on sufficient capital, technology and expertise), are expected to participate in a second round of licensing in mid-2012. Foreign firms will not be allowed to participate directly, but may enter into partnerships with eligible companies that submit successful bids. Various major international oil companies have already entered into some form of partnership with state-controlled companies, reflecting their strong interest in pursuing unconventional gas development opportunities in China.

Regulatory framework

China's huge unconventional gas potential and strong policy commitment suggest that these resources will provide an increasingly important share of gas in the longer term, though the pace of development through to 2020 – the key period of learning – remains uncertain. Because of China's highly centralised regulatory and policy-making framework and the high priority placed on industrial and economic development, unconventional gas projects may face fewer hurdles stemming from environmental concerns than those in Europe or the United States. Nonetheless, the regulatory framework is evolving, and different features of it could affect the pace of development in different ways, for example the terms of access, the pace of diffusion of advanced technology, financial incentives, the pricing regime, environmental constraints and infrastructure development.

Strategic policy decisions in China relating to resource management and environmental protection are made nationally, with implementation and enforcement responsibilities often delegated to local authorities. Many aspects of China's legal and regulatory framework for oil and gas development are broadly defined, giving local regulators latitude to consider project-specific circumstances in their decisions (although this can also lead to unpredictable outcomes). Challenges arise from the fragmentation and overlap of responsibilities among various regulating entities, uncertainty about effective co-ordination between them and potentially inconsistent enforcement of regulations.

Domestic petroleum exploration and development has traditionally been the domain of China's state-owned enterprises. Under the Law on Mineral Resources, only state-controlled entities may acquire mineral rights, foreign companies being confined to minority partnerships with state-controlled entities and, in some cases, production-sharing agreements. Although the strategic importance of unconventional gas means that China's national oil companies are likely to be the primary drivers of production growth, there are some changes underway in response to China's ambitious plans for shale gas exploration and development, and the need for the advanced technology and investment that foreign companies can bring. The legal classification of shale gas as a separate "mineral resource" in late 2011 means that the current regulations that give CNPC and SINOPEC exclusive rights for exploration of onshore oil and gas resources do not apply to shale gas, and this step may presage an intention to grant greater access to others. Foreign companies have already been allowed to take a majority stake in coalbed methane projects.

All project promoters must conduct an environmental impact assessment, which must be filed with national and local regulators and approved in advance of submission of a field-development plan. Drilling permits are issued on the basis of the development plan, rather than well-by-well; and any significant changes to the plan, for example related to the density of drilling, require submission of a new environmental impact assessment. Project delays during the early phases of development may occur because of the limited experience of producing unconventional gas in China.

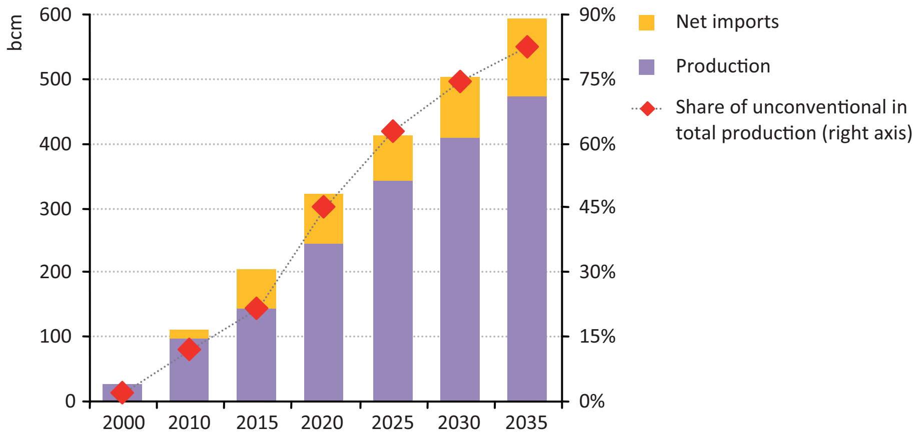
Water availability may prove to be one of the biggest obstacles to unconventional gas development in China, particularly in the north and west, where water is scarce and may be already strained by agricultural or urban needs. Water policies, regulations and plans are determined nationally, though responsibilities for management and enforcement are delegated locally. Many different entities are involved at the national, regional and local levels, which risks limited co-ordination of water resources at the river basin level. National standards establish maximum discharge concentrations for pollutants into water sources and the Circular Water Law promotes reuse and recycling of waste and produced water.

The fiscal regime, gas pricing policies and pipeline access are other regulatory variables that will critically influence the pace of unconventional gas development in China. The 12th Five-Year Plan promises favourable fiscal incentives to producers, namely direct subsidies, preferential tax treatment and priority land use. The domestic coalbed methane industry receives price subsidies of RMB 0.2 ($0.03) per cubic metre for extracted gas and RMB 0.25/m^3 ($0.04) for gas produced for some specific end-users. Shale gas might be expected to attain a similar or higher level of subsidy. According to the 12th Five-Year Plan, the pricing regime for shale gas will be market-based, an important signal that the government is willing to allow higher end-user prices (relative to current controlled prices for natural gas) to encourage development. China's gas pipeline network will necessarily have to expand to reach into unconventional gas production areas in order to avoid becoming a bottleneck as output increases. As major gas pipelines are currently run by national oil companies, making access more available to other producers will be vital.

Projections and implications

Gas is set to play an increasingly important role in meeting China's burgeoning energy needs and the successful development of the country's unconventional resources could accelerate that trend, given effective resource and environmental management. In the Golden Rules Case, unconventional gas production is projected to jump from 12 bcm in 2010 to just over 110 bcm in 2020 and 390 bcm in 2035. Total gas production rises from just under 100 bcm in 2010 to nearly 475 bcm in 2035 (Figure 3.6). Unconventional gas accounts for 83% of total gas production by the end of the projection period. Unconventional gas production in 2035 is predominately from shale gas (56%) and coalbed methane (38%); tight gas (6%) takes a smaller share.

Figure 3.6 ▷ Natural gas balance in China in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Table 3.5 ▷ Natural gas indicators in China by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	**2020**	**2035**	**2020**	**2035**	**2035**
Production (bcm)	97	246	473	139	194	279
Unconventional	12	112	391	37	112	279
Share of unconventional	12%	45%	83%	27%	58%	25%
Cumulative investment in upstream gas, 2012-2035**		554		311		243
Unconventional		374		170		204
Net imports (bcm)	14	77	119	143	262	-143
Imports as a share of demand	12%	24%	20%	51%	57%	-37%
Share of gas in the energy mix	4%	8%	13%	7%	10%	3%
Total energy-related CO_2 emissions (million tonnes)	7 503	9 792	10 449	9 877	10 695	-246

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

In the Low Unconventional Case, output of shale gas and coalbed methane grows much less rapidly, reaching a combined level of less than 115 bcm in 2035 (Table 3.5). The reduced availability of local gas supplies increases the country's dependence on imports at higher average prices. Less ambitious policies to boost demand, coupled with higher prices, lead to slower growth in Chinese gas demand, as the Chinese authorities seek to limit the country's reliance on imports. Demand reaches only 455 bcm by 2035, almost one-quarter lower than in the Golden Rules Case. The share of gas in total primary energy is correspondingly markedly lower: 10% versus 13% in 2035. This results in increased dependence on coal and, to a lesser extent, on nuclear and renewables.

Rapid growth in unconventional gas would greatly strengthen China's energy security and have major implications for international gas trade. In the Golden Rules Case, imports amount to nearly 120 bcm in 2035, about 20% of the country's gas demand, compared with just over 260 bcm or nearly 60% of demand in the Low Unconventional Case. The overall cost of gas imports is correspondingly much lower, by 60%, in the Golden Rules Case. Lower import volumes would improve China's negotiating position *vis-à-vis* its suppliers, including producers of LNG, existing suppliers by pipeline from Central Asia and Myanmar, and Russia, which has the potential to become a major supplier of gas to China but whose opportunities to do so would be much more limited in the Golden Rules Case. The uncertainty surrounding the prospects for China's unconventional gas industry may favour investment in LNG over pipeline projects (and, in both cases, lessen the attractiveness of large long-duration supply contracts) as China may seek more flexibility to allow for gas-import needs turning out to be smaller than expected.

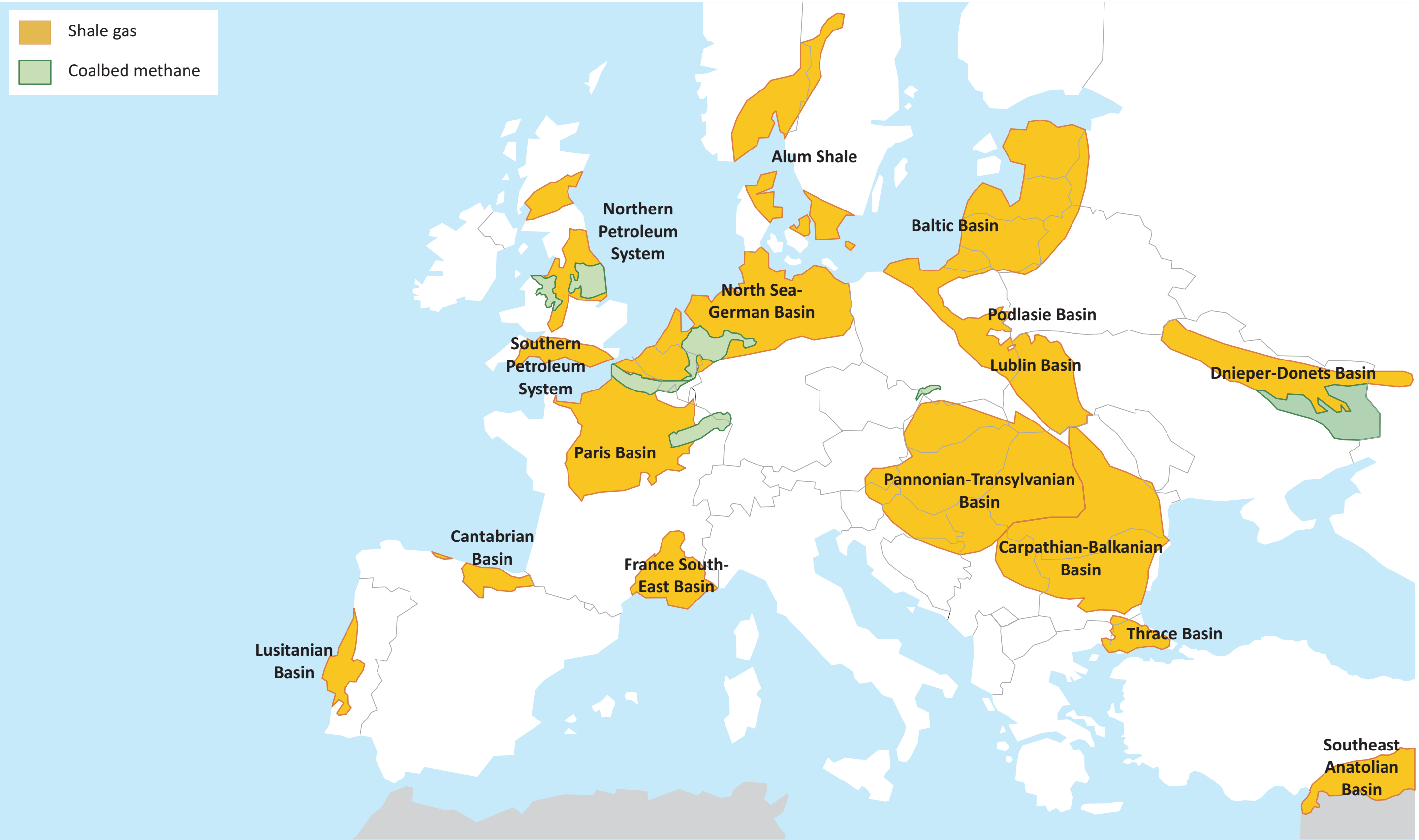
Europe

Resources and production

Europe's unconventional gas resources have attracted considerable interest in the last few years, although in practice the push to develop this resource varies considerably by country, depending on the mix of domestic fuels and imports and perceptions of the risks to energy security and the environment. Attention to unconventional gas focused initially on coalbed methane and tight gas, but has now switched to shale gas. Recoverable resources of shale gas are believed to be large, though how much can be recovered economically remains uncertain.

Europe's shale gas resources are found in three major areas that contain multiple basins, sub-basins and different plays: from eastern Denmark and southern Sweden to northern and eastern Poland (including Alum shales in Sweden and Denmark, and Silurian shales in Poland); from northwest England, through the Netherlands and northwest Germany to southwest Poland; and from southern England through the Paris Basin in France, the Netherlands, northern Germany and Switzerland (Figure 3.7). Poland and France are thought to have the largest shale-gas resources, followed by Norway, Ukraine, Sweden, Denmark and the United Kingdom. Potential coalbed methane resources in Europe are reasonably well established and are significant in some countries, notably in Ukraine, the United Kingdom, Germany, Poland and Turkey.

Figure 3.7 ▷ **Major unconventional natural gas resources in Europe**



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As yet, there is no large-scale production of unconventional gas in Europe. How soon it will begin and how quickly it will grow remain to be seen, though there are several factors favouring development. The European Union is the second-largest regional gas market in the world, with demand amounting to around 550 bcm in 2010, and it is set to become increasingly dependent on imports as indigenous production of conventional gas continues to decline and demand continues to expand. The region has a well-established pipeline and storage network (albeit not as densely developed as in the United States). And, crucially, natural gas prices are high compared with North America, adding to the attractiveness of developing new indigenous gas resources.

But there are above-ground factors that are likely to impede rapid growth in unconventional gas production, the most significant of which is the high population density in many of the prospective areas. This increases the likelihood of opposition from local communities, especially in areas with no tradition of oil and gas drilling. State ownership of oil and gas rights can also reduce the incentives for communities to accept development of local unconventional gas resources, compared with parts of the United States where these rights are held by private land-owners.

The European regulatory framework

Most regulations applicable to upstream oil and gas in the European Union are determined at the national level: member states define their own energy mix and make decisions concerning domestic resource development. At the EU level, there is a common set of rules (under the Hydrocarbons Licensing Directive) to secure transparent and non-discriminatory access to the opportunities for exploration, development and production of hydrocarbons, but the main area in which Europe-wide regulation applies is environmental protection, including:

- Water protection (Water Framework Directive, Groundwater Directive and Mining Waste Directive).
- The use of chemicals (under REACH regulation, administered by the European Chemicals Agency).
- The protection of natural habitats and wildlife.
- Requirements to carry out an environmental impact assessment, under general environmental legislation.
- Liability for upstream operators to incur penalties for environmental damage (under the Environmental Liability Directive and the Mining Waste Directive).

Public concerns about the environmental risks associated with hydraulic fracturing have prompted calls for new regulation on aspects of this practice, often based on the "precautionary principle" that is a statutory requirement in European Union law. A 2011 report commissioned by the Directorate General for Energy of the European Commission found that European environmental legislation applies to all stages of unconventional gas developments. It also concluded that, both on the European level and at the national level (in the countries studied), there are no significant gaps in the legislative framework when it comes to regulating shale gas activities at the present level of intensity (Philippe & Partners, 2011). However, it did suggest that the situation might change if activities were to expand significantly and did suggest some improvements to national legislation, including procedures to include local citizens at earlier stages in the impact assessment process.

Additional assessments of various aspects of unconventional gas are currently being carried out within the European Commission. These include: a study on the economics of shale gas, by the Joint Research Centre in collaboration with the Directorate General for Energy; a study on methane emissions, by the Directorate General for Climate Action; and an assessment of the adequacy of the current regulatory framework to ensure an appropriate level of protection to the environment and to human health, by the Directorate General for the Environment. On the basis of the results of these assessments, the Commission will decide whether to put forward regulatory proposals specifically related to unconventional gas.

The European Parliament has also taken up the debate about various aspects of shale gas development. An assessment presented to the Committee on Environment, Public Health and Food Safety (European Parliament, 2011a) found that the current regulatory framework concerning hydraulic fracturing has a number of deficiencies, most importantly, the high threshold before an environmental impact assessment is required[6]; it also called for the coverage of the Water Framework Directive to be re-assessed focusing on the possible impacts of hydraulic fracturing on surface water and urged consideration of a ban on the use of toxic chemicals. A draft report to the same committee, prepared by a Polish parliamentarian, is more supportive of unconventional gas development (European Parliament, 2011b), while recognising the need to address concerns about the environmental effects of extraction. A separate draft report, focusing on the energy and industrial implications of shale gas development, is also under consideration by the Parliament's Committee on Industry, Research and Energy (European Parliament, 2012).

Poland

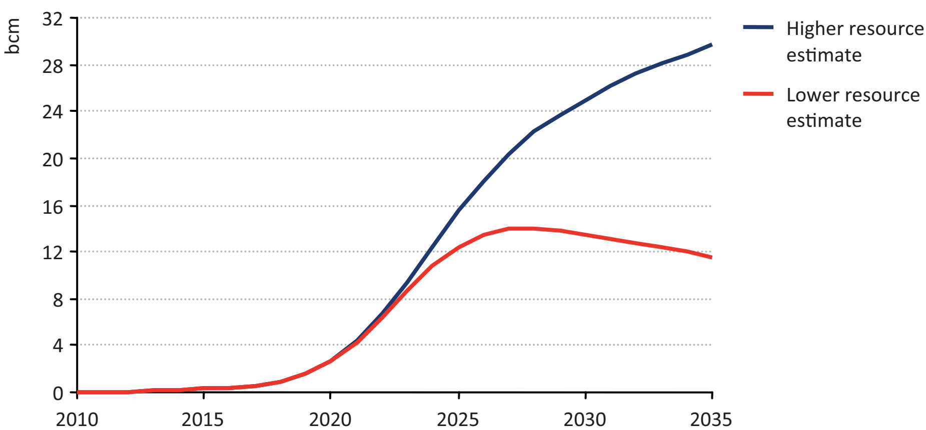
Medium-term prospects for unconventional gas production in Europe appear brightest in Poland, where exploratory drilling for shale gas is most advanced and where above-ground factors are generally less of an obstacle to development than elsewhere. Optimism about Poland's shale gas potential stems from the size of its resources, although these are still subject to considerable uncertainty. The US EIA put technically recoverable resources in Poland at 5.3 tcm (US DOE/EIA, 2011), while an assessment by the Polish Geological Institute (with the support of the United States Geological Survey), studying archive data on the Baltic, Podlasie and Lublin Basins, estimated recoverable resources at 346 bcm to

6. The Environmental Impact Assessment Directive does though include an obligation to screen for possible adverse environmental effects in projects which fall below any relevant thresholds.

768 bcm (PGI, 2012). The large difference is explained primarily by differences in methodologies between the two studies; the range of resource assessments should narrow as more data become available from exploratory drilling.

As described in Chapter 2, the model used for the projections in this report relies on the Rogner and ARI estimates for shale gas resources, which are so far the only assessments that apply a consistent methodology across a large enough number of countries. If actual resources in Poland are significantly lower than assumed, inevitably this would have a considerable impact on our projections, all else being equal. This is illustrated in Figure 3.8, which shows projections for shale gas production in Poland for a higher and lower recoverable resource estimate, respectively, based on the ARI estimate of 5.3 tcm and using a mid-range figure of 0.55 tcm from the Polish Geological Institute estimate.

Figure 3.8 ▹ Impact of different resource assessments on projected shale gas production in Poland



Poland has one of the oldest petroleum industries in the world and has been producing oil and gas from conventional reservoirs since the 1850s, though production has fallen to low levels over recent decades. Interest in shale and tight gas began towards the end of the last decade. A series of exploration licensing rounds has led to a large influx of international companies, with a number of firms that are already active in the United States – including ExxonMobil, Chevron, Eni, Talisman and Marathon – buying up drilling rights, either directly or through joint ventures (although the national oil and gas company, PGNiG, holds the most licences). Over 100 exploration licences, most of which have a duration of five years, have so far been issued, covering most of the prospective shale gas areas.

Early results from exploration drilling have put something of a damper on the initial hopes for a rapid take-off in production. Since PGNiG completed Poland's first shale well in 2009, 18 exploration wells have been drilled, with a further 14 underway and 39 planned (as of March 2012). Flow rates were low in the few wells for which data have been made public, with some reportedly proving unresponsive to normal drilling and well-completion techniques. ExxonMobil has announced that two wells that it drilled and completed in 2011 are not commercially viable, though it is looking into whether different fluids, proppants or pumping techniques might produce better results. ExxonMobil and other companies continue to drill new wells.

The Polish government has been very supportive of drilling for shale and tight gas, reflecting the potentially large economic and energy security benefits that could be gained from supplementing the country's dwindling resources of conventional gas and reducing its heavy dependence on gas imports from Russia. Gas demand is expected to grow in the coming years, particularly for power generation, as older, low-efficiency coal-fired stations close. Although shale gas production costs are likely to be above those in the United States, high oil-indexed prices for imported gas should make shale developments profitable. Relatively low population density in the main basins as well as a history of oil and gas activities may favour public acceptance.

The regulatory framework applicable to unconventional gas development is changing with the prospect of commercial production. Until the recent arrival of foreign firms, the upstream sector was dominated by PGNiG, which ensured that the government captured a large part of any rent on hydrocarbons production and reduced the need for explicit regulation for that purpose. The legislative system for the upstream is now being adjusted to the reality of many new market entrants and participants, including changes to the licensing system and the fiscal framework for upstream activity.

A new Geological and Mining Law came into force in Poland at the start of 2012, which clarifies some administrative and legal questions regarding the development of Poland's unconventional gas potential. The most significant change was that licences for exploration of hydrocarbons in Poland can now be granted only through tenders (exploration licences issued over the last five years were on a first-come, first-served basis). Since most prospective gas exploration acreage in Poland has already been awarded, the new regulations will become more significant when the first production licences are sought. The new law also modifies the system of mineral rights ownership, more clearly defining the division between state rights and those of landowners, but shale gas, as a strategic mineral, remains the exclusive property of the state.

France

With resources almost as large as those in Poland, France was expected to be one of the first European countries to produce unconventional gas commercially. Shale gas potential is primarily in two major shale basins: the Paris Basin and the Southeast Basin. The Southeast Basin is considered to be the more prospective, in view of the low depth of parts of the basin, possible liquids content and low levels of clay. The government had issued three licences for shale gas exploration drilling in the Southeast Basin but, in May 2011, in the face of a strong public opposition over the potential environmental impacts of hydraulic fracturing, the government announced a moratorium on its use and later prohibited it by law. Two firms that held licences – France's Total and the US-based Schuepbach Energy – subsequently had their licences cancelled. Schupebach Energy had maintained their intention to use hydraulic fracturing, whereas Total had submitted a report where they committed not to use it. A third company that committed not to use hydraulic fracturing has had its permit maintained.

Public opposition was linked to the fact that part of the prospective basin underlay scenic regions that are heavily dependent on the tourism industry. Resentment was exacerbated by a lack of public consultation: under French mining laws, public consultation is required only at the production stage and not at the exploration stage. Revision of the mining code is under consideration to include earlier public consultation.

A report was commissioned jointly by the Ministry of Ecology and Sustainable Development and the Ministry of Industry, Energy and Economy to provide information on shale gas and light tight oil, the environmental concerns surrounding their development and the applicability of existing hydrocarbon regulation in France to this new potential energy source. A preliminary report recommended some drilling in France, under strict controls, while more information was gathered about the impact of hydraulic fracturing elsewhere in Europe and the United States (Leteurtrois, 2011). However, the final report was not issued because the ban on hydraulic fracturing was voted in the meantime.

In France, as in some other countries, the debate around shale gas developments became a proxy for a much broader question about the approach to sustainable energy policy. In a separate report prepared for the National Assembly, the co-authors did not share a common vision of France's future energy mix, writing two separate conclusions (Gonnot, 2011). One concluded that more study was required to understand the extent of the country's resource and the technologies to safely develop it, with a view to then taking a decision on whether to proceed developing the resources. The second asserted that the development of new hydrocarbon resources has no place in a national energy policy striving to meet agreed climate change objectives.

The Paris Basin has a long history of conventional oil production. In the early 1980s, high hopes were held that significant volumes might be found, but exploration turned out to be disappointing and production has not exceeded a few thousand barrels per day. Production is mostly from the rural Seine et Marne Région, southeast of Paris, where several hundred wells have been drilled. Some geologists have argued recently that the reason large oil fields have not been discovered is that the hydrocarbons have not been expelled from the source rocks. Indeed, there are indications from wells that have intercepted some of the shales that they may be hydrocarbon bearing, probably mostly light tight oil, with some shale gas. Estimates of oil-in-place vary from 1 to 100 billion barrels, though the fraction which might be technically and economically recoverable is not known.

In the Golden Rules Case, we assume a reversal of the ban on hydraulic fracturing. Shale gas production rises after 2020 to reach 8 bcm in 2035, which would allow France to exceed its peak gas production from the end of the 1970s. At the same time, light tight oil production could reach several tens of thousands of barrels per day. Some of the resources, located in sensitive areas, are likely to remain barred from development but, if productivity can be established, there should be enough resources in other areas to sustain such production.

Other EU member countries

There has been a good deal of discussion about unconventional gas prospects in several other EU member countries, but little exploration activity as yet. Most of the wells that have been drilled are for coalbed methane. There appears to be significant potential for shale gas development in several other EU member countries, notably in Sweden, the United Kingdom and Germany.

Sweden's shale gas resources are located in the Scandinavian Alum shale, which extends from Norway to Estonia and south to Germany and Poland. The Alum shale has been mined for oil shale for many decades in central and southern Sweden (and in Estonia), where it is close to the surface. It has the advantages of high organic content and thermal maturity and is relatively shallow, with depths averaging less than 1 200 metres. But it lacks overpressure and contains a high concentration of uranium, which poses problems for water treatment and recycling. Shell has been most active in assessing the shale, having drilled three exploration wells in the Skåne region of southern Sweden, but it ceased operations when they proved to be dry. Opposition to hydraulic fracturing had delayed the programme and threatens to deter renewed exploration activity.

In the *United Kingdom*, a main shale play is the Bowland shale formation (in the Northern Petroleum System), which is relatively shallow, with an average depth of only 1 600 metres, and with certain areas rich in liquids. Cuadrilla Resources has drilled two exploration wells, one of which encountered gas. It subsequently announced that the formation could hold as much as 5.7 tcm (200 trillion cubic feet) of technically recoverable gas. However, operations have been suspended as a result of two small earthquakes that occurred after hydraulic fracturing was carried out. A report commissioned by Cuadrilla concluded that it is "highly probable" that the fracturing and subsequent earthquakes were linked, although future occurrences should be rare given the unique local geology at the well site (de Pater and Baisch, 2011). The UK Department of Energy and Climate Change commissioned an independent report on the causes of the earthquakes and appropriate means of mitigating seismic risks (Green, Styles and Baptie, 2012). It recommended cautious continuation of Cuadrilla's hydraulic fracturing operations and several safety provisions, including greater use of micro-seismic monitoring and new safeguards that would lead to a suspension of operations in case of seismic activity. At the time of writing, the government was awaiting comments on this report before making any decision regarding additional hydraulic fracturing.

The UK government appears to be supportive of continuing shale gas exploration and development. A parliamentary inquiry in 2011 found no evidence that hydraulic fracturing poses a direct risk to underground water aquifers, provided the drilling well is constructed properly, and concluded that, on balance, a moratorium on shale gas activity in the United Kingdom is not justified or necessary at present (UK Parliament, 2011). Nonetheless, the inquiry urged the UK Department of Energy and Climate Change to monitor drilling activity extremely closely in its early stages in order to assess its impact on air and water quality.

Germany has shale resources, estimated at 230 bcm, in the large North Sea-German basin, which extends from Belgium to Germany's eastern border along the North Sea coast. Several companies have acquired exploration licences and ExxonMobil has drilled at least three exploratory shale gas wells in Lower Saxony as part of a ten-well programme. Germany has a history of tight gas production with relatively large hydraulic fracturing treatments having been common practice for the last 20 years. As in France, there has been strong opposition to shale gas drilling on environmental grounds, but attention to the need for indigenous energy sources, including unconventional gas, has been intensified by a decision to phase out nuclear power.

Shale gas exploration efforts are advancing elsewhere in the European Union: there are plans by OMV to drill several test wells in *Austria* in the next two years; in *Lithuania*, exploration licences were being tendered at the time of writing. *Bulgaria* and *Romania* have awarded shale gas exploration licences, but these countries have experienced strong public opposition over fears about the environmental impact of hydraulic fracturing and, in Bulgaria, this has led to parliament voting in early 2012 to ban the use of the technique, making it the second country in the European Union to do so.

EU projections and implications

Against a backdrop of declining indigenous production and a policy priority to diversity sources of gas supply, the European Union has reasons to be interested in exploiting its domestic unconventional gas potential. At the same time, environmental concerns could easily delay or derail development. In our projections in the Golden Rules Case, unconventional gas production is slow to take off but accelerates in the longer term, as confidence grows in the effective application of the Golden Rules in the most prospective countries. In our projections, unconventional production in the European Union climbs to just over 10 bcm by 2020, but it grows more rapidly thereafter, reaching almost 80 bcm by 2035 (Table 3.6). Shale gas accounts for the bulk of this output. Unconventional gas contributes almost half of the European Union's total gas production and meets just over 10% of its demand by 2035. As a result, even though there are not dramatic shifts in the trade balance, as seen in the United States, growth in unconventional production offsets continued decline in conventional output from 2020 (Figure 3.9).

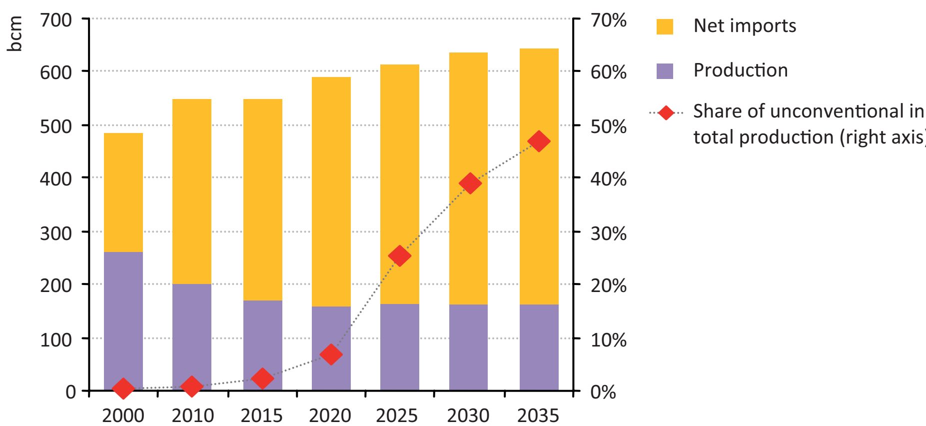
Rising unconventional gas production (both in Europe and worldwide) helps to restrain the rise in gas prices in Europe, which – together with additional policies to encourage gas use – drives up gas demand. As a result, the upward trend in net gas imports into the European Union continues throughout the projection period, reaching 480 bcm in 2035, or three-quarters of total demand (compared with 345 bcm, or more than 60%, in 2010). In the Low Unconventional Case, in which there is very little commercial unconventional production before 2035, European Union net gas imports are 30 bcm higher in 2035 than in the Golden Rules Case (and gas import prices are higher). Consequently, the cost of those imports reaches about $250 billion in 2035 (in year-2010 dollars) – an additional import bill of almost $60 billion relative to Golden Rules Case.

Table 3.6 ▷ Natural gas indicators in the European Union by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	201	160	165	139	84	81
Unconventional	1	11	77	0	0	77
Share of unconventional	1%	7%	47%	0%	0%	47%
Cumulative investment in upstream gas, 2012-2035**		434		235		199
Unconventional		181		-		181
Net imports (bcm)	346	432	480	423	510	-30
Imports as a share of demand	63%	73%	74%	75%	86%	-11%
Share of gas in the energy mix	26%	28%	30%	26%	28%	2%
Total energy-related CO_2 emissions (million tonnes)	3 633	3 413	2 889	3 414	2 873	16

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Figure 3.9 ▷ Natural gas balance in the European Union in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Ukraine

Ukraine has considerable unconventional gas potential in the form of coalbed methane in the main coal-mining areas of eastern Ukraine and in two shale gas basins: a portion of the Lublin Basin, which extends across from Poland, and the Dnieper-Donets Basin in the east.

Coalbed methane resources are estimated at close to 3 tcm. Technically recoverable shale gas resources in Ukraine are 1.2 tcm, around one-third less than remaining recoverable resources of conventional gas. The Ukrainian section of the Lublin Basin is large and reportedly has higher average total organic content than the Polish section and lower average depth. The Dnieper-Donets Basin – which currently provides most of the country's conventional oil, gas and coal production – also has high organic content, but is deeper.

The government is keen to develop new sources of gas in order to reduce the country's heavy dependence on imports from Russia – it has set a target of producing 3 to 5 bcm of unconventional gas by 2020. Coalbed methane is the most likely source of unconventional production growth in the short to medium term, but, if the conditions are in place, shale gas also offers considerable promise. A new tender for two large shale gas blocks in both basins is underway, offering foreign companies the opportunity to bid for the right to enter a production-sharing contract. Naftogaz, the state-owned oil and gas company, signed a memorandum of understanding with ExxonMobil in 2011 to co-operate on shale gas exploration; other companies are also interested in Ukraine's potential. An earlier shale gas tender led to some exploration drilling. Hawkley, an independent Australian company, drilled a shale gas well in the Dnieper-Donets basin in 2011. Kulczyk Oil, an international upstream company, announced in November 2011 that it had successfully completed the hydraulic fracturing of a well in a previously non-commercial zone of the Dnieper-Donets basin, yielding 65 thousand cubic metres per day (2.3 mcf/d) of gas and condensates.

In the Golden Rules Case, production of unconventional gas in Ukraine reaches 3 bcm in 2020, before ramping up to around 20 bcm in 2035. The Golden Rules Case assumes, importantly, that supportive measures are adopted to facilitate investment in the gas sector: Ukraine has a poor investment climate and upstream conventional gas output currently stands at around 20 bcm per year.

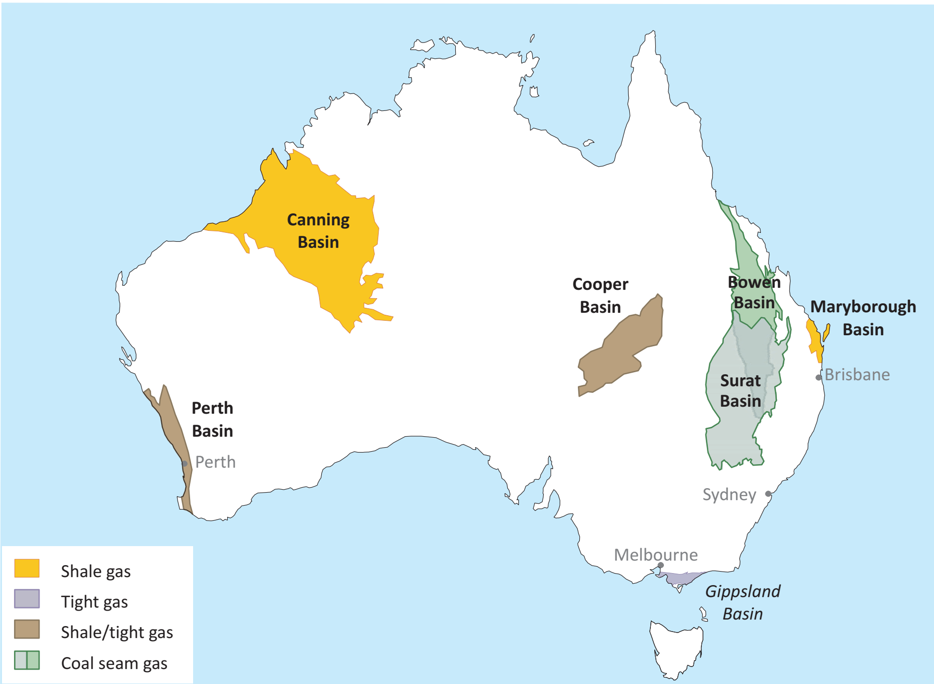
Australia

Resources and production

As a sizeable producer of coalbed methane (known as coal seam gas), Australia is one of only a handful of countries already producing commercial volumes of unconventional gas. Its large resources of shale gas, tight gas and coalbed methane hold the promise of continuing strong growth in unconventional gas output in the long term. The attraction of unconventional gas developments is heightened by the fact that Australia's conventional gas resources, while sizeable, tend to be offshore, expensive to develop and far from national markets.

More is known about the size of the country's coalbed methane resources than about the other two categories of unconventional gas. According to official estimates, demonstrated economically recoverable coalbed methane resources were 930 bcm at the end of 2010 (Geoscience Australia, 2012). The estimates of these resources have grown substantially in recent years, as exploration and development has expanded. Nearly all current reserves are contained in the Surat (69%) and Bowen (23%) basins in central Queensland, with almost all the balance in New South Wales (Figure 3.10).

Figure 3.10 ▷ Major unconventional natural gas resources in Australia



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Commercial production of coalbed methane began in 1996 in eastern Australia and has grown sizeably over the last few years. Output reached 5 bcm in 2010, accounting for about 15% of total Australian gas consumption. Virtually all output comes from the Surat and Bowen basins, with small volumes also now produced from the Sydney Basin. The rapid growth of the unconventional gas industry has been supported by strong demand growth in the eastern Australian market, reflecting in part the Queensland government's energy and climate policies, including a requirement that 13% of power generation in the state be gas-fired by 2005 and 15% by 2010. The abundance of coalbed methane has led to a number of LNG-export projects being proposed in Queensland; and three large plants to be sited at the port of Gladstone are under construction: Queensland Curtis LNG (BG), Gladstone LNG (Santos), and Australia Pacific LNG (Origin and ConocoPhillips), with a fourth – Arrow LNG (Shell/PetroChina) – at an advanced stage of development. Total investment in the three projects underway is projected to be some $40 billion; their capacity of 29 bcm more than doubles current national export capacity. However, policy uncertainty and public reaction to the potential environmental impacts of coalbed methane production has slowed upstream development, particularly in New South Wales.

Remaining recoverable resources of tight gas in Australia are estimated at 8 tcm. The largest resources of these are in low permeability sandstone reservoirs in the Perth, Cooper and Gippsland Basins. Tight gas resources in these established conventional gas-producing basins are located relatively close to existing infrastructure and are currently being considered for commercial exploitation.

Although shale gas exploration is in its infancy in Australia, exploration activity has increased significantly in the last few years. Australia is estimated to contain 11 tcm of remaining recoverable shale gas resources. These are found predominately in the Cooper, Maryborough, Perth and Canning basins. The first vertical wells specifically targeting shale gas were drilled in the Cooper Basin in early 2011 and significant exploration is now underway in this basin and, to a lesser extent, in other promising areas. But a boom in shale gas production is unlikely in the near future because of logistical difficulties and the relatively high cost of labour and hydraulic fracturing.

Regulatory framework

Under the existing regulatory framework governing the upstream hydrocarbons sector in Australia, powers and responsibilities are shared between the federal, state and territory governments and local authorities. The states hold rights over coastal waters from the coast line to the three-mile limit and joint regulatory authority over the federal waters adjacent to each state and the Northern Territory. In addition to various petroleum and pipelines laws, there is an extensive body of legislation governing upstream petroleum activities, covering such aspects as the environment, heritage, development, native title and land rights, and occupational health and safety; most are not specific to the oil and gas sector. A number of bodies across all levels of government have a role in regulating upstream petroleum activities.

Under Australian law, hydrocarbon resources are owned by the state (at federal, state or territory level) on behalf of the community, and governments at all levels have a "stewardship" role in petroleum resource management (AGPC, 2009). Farmers or graziers may hold freehold or leasehold title to land, but generally do not have rights to mineral or petroleum resources – these are subject to petroleum tenure rights granted by the state or territory governments. Underlying native title can coexist with other land title rights. In general, landowners have no right to refuse access to the petroleum tenure holder for petroleum operations; but they do have a claim to compensation for the impact of those operations. Approvals, generally a state or territory responsibility, are required to construct petroleum pipelines and facilities such as LNG trains. Landowners do not have the incentive of ownership of mineral resources to facilitate surface access to unconventional gas projects, but state and territory governments do have an incentive to promote development, as they can benefit from any taxes or royalties levied on production.

Within each jurisdiction, environmental regulation of upstream activities can include hydrocarbon-specific environmental approvals, though there are few rules specific to unconventional gas. The main federal regulations are the Offshore Petroleum and Greenhouse Gas Storage Act 2006 and the Environment Protection and Biodiversity Protection Act 1999 (EPBC Act). Under the EPBC Act, if a project affects matters of national environmental significance, it requires federal approval. LNG projects in Queensland, including their upstream coalbed methane operations, trigger the need for such federal approval. In general, an environmental impact assessment must be carried out in advance of all upstream projects that are likely to have a significant impact on the environment.

The rapid expansion of the coalbed methane industry has led to increased public concern over access issues and the potential environmental risks, particularly the drawdown and contamination of aquifers and groundwater and problems arising from the disposal of produced water. As described in Chapter 1, the techniques used in coalbed methane production differ significantly from those for shale gas; in particular there is a need to remove large amounts of water from the coal formation. This causes concern that those already drawing water from the same formations will be adversely affected and that the disposal of the large water volumes involved in coalbed methane production will not be properly handled. Given the semi-arid conditions in the producing areas, evaporation or discharge of even suitably-treated formation water to existing watercourses may not be appropriate. This has led to delays in issuing approvals for some upstream developments.

The federal government announced in 2011 that all future coalbed methane and other coal projects would come under increased environmental scrutiny. A new, well-resourced and independent scientific committee, established under the EPBC Act, will evaluate most future projects prior to approval to ensure that they do not pose a hazard to underground and surface water sources. Protocols are being developed at federal and state level to determine which projects will be referred to this committee. In Queensland, where most coalbed methane activity is concentrated, new proposals to manage the impact of water extraction on groundwater are being finalised. They provide for cumulative assessment of the impacts on groundwater resources in defined management areas. This work will be based on a major groundwater flow model, designed to predict impacts on aquifers, as well as new monitoring arrangements. A major report, the Surat Underground Water Impact Report, is expected to be published for public consultation by the Queensland Water Commission in mid-2012. A key principle in the regulatory approach is that petroleum operators must make good any impairment of water supply that they cause and that any consequence of underestimating that risk should lie with the operator, not the water source owner or the state government. The upstream industry has argued that the new regulations will hamper the development of the country's nascent unconventional gas sector. In New South Wales, where regulatory activity is less advanced, the state government has introduced a moratorium on hydraulic fracturing while it considers new regulation.

In December 2011, energy and resources ministers at both federal and state levels agreed to develop a nationally harmonised framework for coalbed methane regulation to address the following areas of community concern:

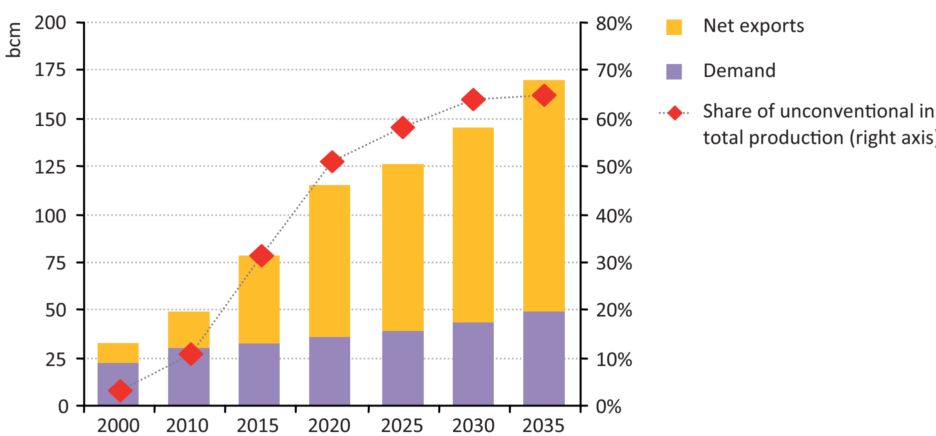
- Water management.
- The need for a multiple land-use framework, meaning measures to reconcile the ability for extraction of coalbed methane with existing and potential agricultural or pastoral uses.
- The application of best practice standards to production activities.
- Minimising environmental and social impacts.

The objective is to achieve measures in these areas which maximise transparency and generate greater public confidence in the effective regulation of the industry while supporting commercial extraction of coalbed methane.

Projections and implications

The prospects for unconventional gas production in Australia hinge to a large degree on whether policy-makers and the industry itself can sustainably manage the associated environmental risks on a basis that retains public confidence in the outcomes. In the Golden Rules Case, this is achieved, with unconventional gas output continuing to expand rapidly, reaching about 60 bcm by 2020 and 110 bcm in 2035. Coalbed methane contributes almost all of this increase, with shale gas production growing more slowly. As a result, total gas production more than triples, with unconventional gas accounting for more than half of gas output after 2020 (Figure 3.11). The projected level of coalbed methane production for 2020 assumes that the four LNG-export projects in Queensland proceed as planned and enter the market before the large increase in unconventional production in other countries, notably China, gains momentum.

Figure 3.11 ▷ Natural gas balance in Australia in the Golden Rules Case*



* The sum of demand and net exports represents total production.

Gas production is driven primarily by exports, based on both conventional and unconventional sources, which rise by 100 bcm in the Golden Rules Case. Exports reach 80 bcm in 2020, based on developments under construction, and continue to grow throughout the projection period. The value of those exports increases seven-fold to just over $55 billion in 2035 (in year-2010 dollars).

In both the Golden Rules and Low Unconventional Cases, east coast Australian domestic prices rise towards the export netback price (the delivered export price less liquefaction and transport costs) from their current very low levels. The high capital costs of Australian LNG plants meaning that these netback levels are likely to be at least $5 to $6/MBtu below the price of LNG delivered to Asian markets. In the Golden Rules Case, Australia's gas consumption nonetheless continues to expand on the back of government policies to encourage switching to gas for environmental reasons (including the recently agreed carbon trading scheme).

In the Low Unconventional Case, coalbed methane production expands at a much slower pace on the assumption of bigger hurdles to development of these resources, while there is no shale gas production at all. In 2035, unconventional gas production falls to around 35 bcm – this is 75 bcm lower than in the Golden Rules Case. The higher international price environment in the Low Unconventional Case means that the upward pull on Australian domestic prices is stronger.

Gas exports still reach more than 110 bcm in the Low Unconventional Case, as investment is shifted to LNG projects based on conventional gas. In this case, the needs of importing countries are much increased and so any gas exporter with the capacity to export has an incentive to do so; this is certainly the case for Australia, with its conventional resources and existing export infrastructure, even if these conventional resources are more costly to develop. Export earnings are even higher in this case, as international gas prices are higher. Unsurprisingly, Australia would stand to benefit from restrictions on unconventional gas developments in other parts of the world, especially in Asia-Pacific, as it is able to expand its own production of conventional and unconventional gas.

Units and conversion factors

This annex provides general information on units and general conversion factors.

Units

Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	gCO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	toe	tonne of oil equivalent
	Mtoe	million tonnes of oil equivalent
	Mt LNG	million tonnes of liquefied natural gas
	MBtu	million British thermal units
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	mcf	million cubic feet
	bcf	billion cubic feet
	tcf	trillion cubic feet
Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)

Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

Convert to:	bcm	bcf	Mt LNG	TJ	GWh	MBtu	Mtoe
From:	multiply by:						
bcm	1	35.315	0.7350	4.000 x 10^4	11.11 x 10^3	3.79 x 10^7	0.9554
bcf	2.832 x 10^{-2}	1	2.082 x 10^{-2}	1.133 x 10^3	3.146 x 10^2	1.074 x 10^6	2.705 x 10^{-2}
Mt LNG	1.360	48.03	1	54 400	15 110	5.16 x 10^7	1.299
TJ	2.5 x 10^{-5}	8.829 x 10^{-4}	1.838 x 10^{-5}	1	0.2778	947.8	2.388 x 10^{-5}
GWh	9.0 x 10^{-5}	3.178 x 10^{-3}	6.615 x 10^{-5}	3.6	1	3 412	8.6 x 10^{-5}
MBtu	2.638 x 10^{-8}	9.315 x 10^{-7}	1.939 x 10^{-8}	1.0551 x10^{-3}	2.931 x 10^{-4}	1	2.52 x 10^{-8}
Mtoe	1.047	36.97	0.7693	4.1868 x 10^4	11 630	3.968 x 10^7	1

Notes

- Gas volumes are measured at a temperature of 15°C and a pressure of 101.325 kilopascals.
- The Gross Calorific Value (GCV) of gas is defined as 40.0 MJ/cm for conversion purposes in the table above.
- The global average GCV varies with the mix of production over time, in 2009 it was 38.4 MJ/cm.
- 1 Mtoe is equivalent to 10^7 gigacalories.

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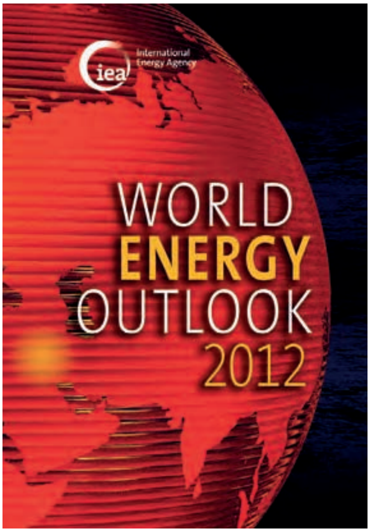

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