Boulder County

Transportation Department

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BOULDER COUNTY
BOARD OF COUNTY COMMISSIONERS
PUBLIC HEARING

May 16, 2013
4:00 P.M.

Hearing Room, Third Floor
Boulder County Courthouse

On January 24, 2013, the Board of Commissioners held a Public Hearing to finalize the *Oil and Gas Roadway Impact Study* and directed staff to: 1) Use the study to propose an impact fee or other type of cost recovery mechanism; 2) Present this fee at a Public Hearing prior to the end of the Temporary Moratorium on June 10, 2013; and 3) Propose any necessary text amendments to the transportation sections of the *Boulder County Land Use Code* oil and gas regulations, approved in Docket DC-12-0003, to conform to the proposed impact fee or other cost recovery mechanism. The purpose of the May 16, 2013, Public Hearing before the Board of Commissioners is to complete these three actions.

Oil and Gas Road Deterioration and Roadway Safety Fee

The proposed Oil and Gas Road Deterioration and Roadway Safety Fee is designed to recoup the incremental costs to the County transportation system resulting from the impacts of oil and gas development in Boulder County. It is based on the proportional expected road usage, and associated costs to the county, from development and production phase activities. The fee contains two components:

- Road Deterioration: This component of the impact fee addresses the proportional damage to gravel (unpaved), asphalt, and concrete roadway surfaces caused by increased heavy vehicle traffic.
- Safety: This component of the impact fee addresses roadway safety conflicts between the significant increase and intensity of very large vehicles beyond any anticipated or forecast levels and other roadway users, including bicycle riders, pedestrians, and equestrians traveling on asphalt surfaces.

Both components of the fee mitigate specific impacts to the public transportation system resulting from the anticipated increase in oil and gas development in unincorporated Boulder County. Other site specific transportation impacts resulting from oil and gas activities are remedied through site-specific analysis and county review of development applications, per the *Boulder County Land Use Code* Article 12 requirements.

The *Boulder County Oil and Gas Roadway Impact Study*
On December 6, 2012, the Boulder County Transportation Department initially presented the *Boulder County Oil and Gas Roadway Impact Study* to the Boulder County Board of Commissioners (Board of Commissioners). The study determined the cost of incremental impacts from significant heavy truck traffic to the county road system that is expected to result from future oil and gas drilling and associated activities. The study developed a Boulder County-specific methodology using the best available information for calculating the proportional, incremental damage to county capital transportation infrastructure. The study also determined improvements necessary to mitigate safety concerns associated with heavy truck traffic resulting from the anticipated oil and gas development. Finally, the study determined the costs to mitigate these impacts on the public transportation system on both an average per pad and per well basis.

Discussion of the impact study continued at the January 24, 2013, Board of Commissioners Public Hearing. In addition to reviewing the study's methodology and identifying the type of impacts that will result to the county's transportation system from oil and gas development and production activities, the staff presentation identified roadway and safety impact mitigation costs for three different development scenarios (low, steady, accelerated). The outcome of the hearing was Board of Commissioners direction to staff to use the *Boulder County Oil and Gas Roadway Impact Study* to propose an impact fee or other type of cost recovery mechanism in order to appropriately assign these costs to oil and gas activity.

Original Road Deterioration and Roadway Safety Fee (presented January 2013)

	Road Deterioration	**Safety**	**Total (Road & Safety)**
Pad	$1,200	**-**	
Well	$30,600	$6,200	
Total (1 pad, 1 well)	$31,800	$6,200	**$38,000**

Industry Feedback and County Response: Impact Fee as a Cost Recovery Mechanism
Boulder County staff have received feedback from oil and gas industry representatives about the concept of the impact fee as a cost recovery mechanism and the methodology underlying the impact study. This feedback was received both verbally at a meeting on March 5, 2013, and in written form. Written communications received by the county on April 5, April 15, 2013, and May 7, 2013 are included as attachments.

Issues raised by industry representatives about the impact fee as a cost recovery mechanism are summarized in the following table.

Industry Feedback: Impact fee as a cost recovery mechanism	Boulder County Response (staff)
Fee is unnecessary. County property tax collection, state severance tax, federal mineral lease revenues, and other revenue sources serve the same purpose as a potential impact fee. Thus, the impact fee would be duplicative and unnecessary.	Current taxing mechanisms, including county property tax, are fundamentally different revenue sources than an impact fee. While industry does pay taxes already, they do not provide a sufficient revenue source to remedy all affected governmental services or specific impacts to the public transportation system caused by oil and gas activity. Only a very small fraction of property taxes paid by industry are directed to the county's Road and Bridge Fund.
Fee is unfair. No other user of the public transportation system is charged an impact fee and, thus, it is unfair.	The magnitude, intensity, and type of trips made by heavy trucks for oil and gas activities will create unique impacts to the public transportation system. No other current user of the this part of the transportation system generates similar heavy truck traffic at the levels associated with oil and gas development. The impacts requiring remedy would not exist, and would not require mitigation in the time periods anticipated, absent the anticipated oil and gas development and production.
Fee violates state impact fee statute.	The fee staff is proposing complies with the statute. The impact fee would be legislatively adopted by the Board of Commissioners and would fund road system infrastructure improvements directly needed to serve new development. It would be assessed at a level that defrays impacts to capital facilities directly related to oil and gas activity. No individual operator will be required to provide any site specific dedication or improvement to meet the same need for capital facilities for which the impact fee is imposed.

After considering the above issues, Boulder County staff believes that the impact fee remains the most appropriate cost recovery mechanism to remedy road deterioration and specific safety impacts resulting from oil and gas activity.

Industry Feedback and County Response: Study Methodology

Comments from industry representatives on the impact study's methodology included several requests to modify the study's assumptions and analysis, which ultimately would affect the amount of the fee. Issues raised are summarized in the following table:

Industry Feedback: **Study assumptions and analysis**	**Boulder County Response (staff)**
Charging Industry for already programmed expenditures.	
• **County roads in poor condition** It is inappropriate to assign the full costs of bringing poor roads to industry, as these roads would need to be reconstructed regardless of oil and gas activity.	Boulder County agrees that there are county roads currently in poor condition that will need to be rehabilitated. However, as a result of the impacts of oil and gas development, these roads will have to be addressed much more quickly than would otherwise be the case due to the magnitude and intensity of anticipated heavy truck traffic from oil and gas activity. ***The staff recommendation responds to industry concerns by treating all impacted roads similarly and incorporating only the proportional, incremental cost of the rehabilitation into the proposed fee.***
• **Safety Impact Fee** It is inappropriate to include the cost of bringing shoulders up to county standards in the impact fee, as they do not meet standard irrespective of oil and gas development.	The FHU study included the cost of bringing all roads with substandard shoulders in the study area into compliance in order to address the elevated safety concerns associated with oil and gas development traffic. The county transportation sales tax includes future funding for adding shoulder to some of these facilities. ***Staff recommendation removes those facilities slated for shoulder improvements from the proposed fee.*** ***Staff does, however, believe it is appropriate to consider incorporating the opportunity costs that the county will incur by redirecting existing funding from other purposes to rehabilitate roads and construct new capital infrastructure on an accelerated schedule as a direct result of the impacts stemming specifically from oil and gas development.***
County subdivision/local roads It is inappropriate for the roadway network included in the study's travel model to include local/subdivision roads, as industry does not intend to use these roads for access unless absolutely necessary.	Boulder County, industry, and many subdivision residents share an interest in minimizing the use of subdivision roads for access. However, the oil and gas regulations found in Article 12 of the Boulder County Land Use Code do not prohibit access through subdivisions and, in some circumstances, use of local/subdivision roads may be the only feasible access to a particular site. ***Staff recommendation includes subdivision roads in the permit fee.***

Water consumption Assumptions in the study are too high. Industry has submitted an analysis conducted by Colorado State University (CSU) that documents the water volumes used in Weld County, which indicate somewhat lower usage than assumed in Boulder County's analysis. In addition, industry is working to develop more sustainable practices that use less water, increase re-use of water, and transport water through centralized piping systems.	Boulder County agrees that the CSU study provides water consumption assumptions that are more applicable to Boulder County than those used in the study and recognizes that new practices and technologies are being developed to reduce water consumption. ***Staff has accepted the submitted information in the CSU study and incorporated into the analysis of impact fees.*** ***Staff also supports periodic re-evaluation of the impact fee to reflect water /fluid recycling and treatment practices.***

After considering the above issues, Boulder County staff believes the adjustments to the study methodology should be made to address industry concerns regarding assumptions for rehabilitation of poor condition roads and to reflect locally derived water consumption information. The resulting proposed fee modifications are presented in the section below.

Staff Recommendation: Oil and Gas Road Deterioration and Roadway Safety Fee

Staff recommends that the Board of Commissioners adopt the Oil and Gas Road Deterioration and Roadway Safety Fee, with modifications to the original fee amount in response to the comments received from industry. While the initial study fairly and completely identifies the impacts (and costs) to the county transportation system that will likely result from oil and gas development, under current statute, only a portion of those costs can be recovered by the County.

The staff recommended fee includes adjustments to the study methodology to:

- Ensure that oil and gas industry is responsible for only the incremental costs of improving capital road infrastructure necessary to address safety and roadway impacts resulting directly from oil and gas development, and that industry is not being charged for capital improvements not otherwise programmed in the same time period.

- Reflect improved water consumption information provided by industry and recommend periodic (every two – three year) re-evaluation of fee to incorporate development of new industry practices.

- Remove shoulder improvements in the study area already planned and funded through the countywide transportation sales tax

- Provide options for the opportunity costs that the county would incur to accelerate poor road rehabilitation and funded shoulder improvements.

Staff Recommended Transportation Impact Fee

	Road Deterioration	Safety	Total
Pad	$700		$700
Well	$16,600	$4,000	$20,600
Total (1 pad, 1 well)	$ 17,300	$4,000	**$21,300**

Opportunity Cost Recovery Fee Option: Additional impacts to the County transportation system from anticipated development of oil and gas in Boulder County that cannot be recovered through the impact fees will require reprogramming and diversion of current county transportation funding from current rehabilitation and maintenance priorities and needs.

As an example, rehabilitation of a road in another part of the county system would need to be delayed in order to address impacts resulting from new oil and gas development. As a result of this delayed treatment, that road continues to deteriorate to a poor condition, necessitating much more expensive reconstruction, whereas a less expensive overlay would have only been necessary absent this diversion of funding. Reconstruction of a poor road is two to three times more expensive than is the resurfacing that would have been previously appropriate.

As a way to more accurately understand the costs to the county of redirecting existing funding to reconstruction of poor roads (or roads with substandard shoulders) more quickly than would otherwise be the case, the opportunity cost of the reprogrammed funds was evaluated. To determine this cost to the county taxpayers and residents, the cost of bonding for the difference between the full costs of reconstructing poor roads in the study area (as was assumed in the initial impact fee study) and the incremental cost to be borne by the oil and gas industry was determined. Similarly, the reprogramming of sales tax funds to roads requiring expedited shoulder improvements to ensure the safety of all road users affected by oil and gas traffic was determined.

In order to estimate the increased costs to the county resulting from the diversion of funds to address these increased impacts, the increased costs associated with bonding for this amount were calculated.

	Re-programmed County Funds	Additional Cost/Well
Opportunity Cost to Address Accelerated Poor Condition Road Reconstruction Needs	$7.3 million	$8,600
Opportunity Cost to Address Accelerated Sales Tax Shoulder Needs	$6.85 million	$8,000

Impact Fee Implementation

In addition to the amount of the impact fee, staff recommends the following procedures to implement the fee in compliance with the land development charges statute and other applicable law:

- Designated Fund: Boulder County would establish a designated fund or accounting code for revenue generated through collection of the impact fee that would enable annual tracking and reporting of collected fees. It would be managed and administered through the Transportation Department.

- Fund Use: Funds generated through the collection of the impact fee would only be for improvements to the roadway network in the affected area, as identified in the study. Improvements would be coordinated with the county's transportation Capital Improvement Program (CIP) to identify surface and safety priorities and to capitalize on efficiencies that may be gained through the timing and sequencing of improvements made through the impact fee fund and those funded by other sources. To this extent, and because funds collected through the impact fee will accumulate over time, no specific timeframes would be established for specific uses of the fund.

- Fee Collection: It is the county's interest to ensure that the impact fee is collected at a point in time proximate to the beginning of development activity to avoid administering potential fee refunds should a particular well not proceed. Thus, the county would collect the impact fee after (Development Plan Review or "DPR") approval has been granted and before drilling is to commence, at the time of county DPR Construction permit issuance. (The DPR Construction permit is a new permit issued by the county Land Use Department that will be needed for every approved development plan.)

- Re-evaluation of Fee: It is in all parties' interest to periodically revisit the fee to respond appropriately to rapidly developing changes in industry practices. Staff recommends re-evaluating the impact fee structure and amount to respond to the state of industry practice every three years.

Text Amendments to Article 12 of the Boulder County Land Use Code

Staff proposed text amendments to Article 12 of the *Boulder County Land Use Code* are intended to:

- Conform to the proposed Oil and Gas Road Deterioration and Safety Fee;
- Clearly correlate the type of impact (surface condition, maintenance, safety, or physical improvement) to the required remedy or mitigation measure to be identified in the Transportation Plan;
- Clarify that applicants may provide more information about routes and potential mitigation measures during the county's transportation review. However, applicants may not appeal for a modified impact fee amount or appeal the county's route or mitigation requirements; and
- Clarify that damage done during oil and gas operations that affects public safety must be immediately reported and repaired at the operator's expense.

Modifications to Article 12 would apply to the expedited and the standard Development Review Plan (DPR) approval processes. Staff recommended text amendments are included as an attachment.

Attachments to Impact Fee Staff Recommendation

Exhibit A – March 1, 2013 letter from industry

Exhibit B – April 5, 2013 letter from industry

Exhibit B.1, B.2, and B.3 – attachments to the April 5 letter

Exhibit C – April 15, 2013 letter from industry

Exhibit C.1 – attachment to the April 15 letter

Exhibit D – May 7, 2013 letter from industry

Exhibit D.1 – attachment to the May 7 letter

Exhibit E – Amendments to transportation section of Article 12, DC-12-0003

EXHIBIT A

MARCH 1, 2013 LETTER FROM INDUSTRY

Boulder County Oil & Gas Roadway Impact Study
Initial Points of Concern

Prepared by: Encana Oil & Gas (USA), Inc. and Noble Energy, Inc.
March 1, 2013

- Well Assumptions: A more accurate well count for the roads studies would be 1,648 wells, or 16 wells per section.

- Road Assumptions:
  - Residential streets within developments are included in the Study Area Road Network which would not be used at any time for Oil & Gas operations. Separate access roads would be built to avoid this.
  - There is no mention of the preferential use of the State highways designed for truck traffic. Access to Oil and Gas operations sites would be predominantly from the east and accessing on Highways 7, 287, 52, or 119. Only when near location would travel on Boulder County roads be required. The study report does not mention this.
  - The study report indicates that certain paved segments of the Study Area Road Network are currently in poor condition and that these poor pavement conditions will magnify the impacts of Oil and Gas traffic. How does the study ensure that the proposed impact fee will not remedy these existing roadway deficiencies, which is prohibited by Colo. Rev. Stat. § 29-20-104.5(2)?
  - The safety mitigation costs are predicated on the need to add shoulders for bicyclists and the increased traffic. The roads were not originally designed to accommodate both bicycles and motor traffic. This is not a road repair issue.

- At least some of the paved road mitigation costs are based upon generalized figures generated by CDOT. How do the CDOT cost figures compare to the actual costs that Boulder County has paid for such work? Oil and Gas Traffic Assumptions:
  - Table 7 from the study report (copied below) summarizes the truck trips assumed for a four well pad in the modeling for the study. There is no mention or allowance made in the road use study for sourcing water at or near the well location or pipelines for water. This truck trips required for local municipal or pipelined water would reduce to 5 for the poly pipe and materials, not the 4,200 used in the study for every well drilled.

Table 7. Trip Generation Estimates

Activity	1 Pad, 4 Wells
Construction Stage	
Pad and Road Construction	90
Drilling Stage	
Drilling Rig	90
Drilling Fluid and Materials	270
Drilling Equipment (casing, drill pipe, etc.)	450
Completion Stage	
Completion Rig	40
Completion Fluid and Materials	170
Completion Equipment (pipe, wellhead, etc.)	10
Fracturing Equipment (pump trucks, tanks, etc.)	320
Fracture Water	4,200
Fracture Sand	190
Flowback Water Disposal	1,400
Total Development Trips	**7,230**
Production Stage	
Oil & Water Removal	580
Operations and Maintenance	150
Total Production Trips (per year)	**730**

- The truck trip count for fracturing equipment is assuming that the fracturing equipment includes 500 bbl frac tanks. The use of the new round tanks would reduce these trips to 80, not 320 as stated in the table. The truck trip count for fracture water is a little high and for horizontal wells should be 650 to 850 trips per well for frac water. The truck trip count for frac water, if not sourced locally and or pipelined, should be 3400 for a four well pad (using 850 trips per well) and not 4,200.
- The truck trip counts make no allowance for a variety of other water management strategies that Encana and Noble are already employing and plan to expand in their Niobrara operations. These strategies will significantly reduce the estimated trip counts in the study, which assume that no such mitigation occurs. For example:
  - Noble reused and recycled about 37% of its water in the United States during 2011. As part of this effort, Noble conducted a pilot experiment in the Niobrara to treat flowback from one hydraulic fracture for reuse in a subsequent hydraulic fracture. This successful pilot is intended to be implemented on a larger scale within the Niobrara as well as in additional basins.
  - Noble's hydraulic fracturing operations in the Wattenberg field are using on average 20% less water by reducing slickwater stages and using higher sand concentrations during gel stages.

        - Noble reduced its truck mileage by approximately 5 million miles in the Wattenberg field during 2011 by strategically locating storage ponds and tanks and utilizing pumps and pipelines as alternative means of water delivery.
    - Many of the traffic assumptions appear to rely upon generalized information from Colorado or dated information from other regions, which do not accurately reflect current and future practices in the Wattenberg field. Water management is highly dynamic and rapidly evolving, and current local information is therefore vital.

- Tax Revenues Generated From Oil and Gas Development:
    - The study does not address the substantial tax revenues that Boulder County receives from oil and gas development or explain why such revenues are insufficient to pay the transportation mitigation costs attributable to such development. Given the magnitude of these revenues, no additional impact fee appears necessary for this purpose.
        - Boulder County reportedly received about $985,000 in ad valorem taxes during 2011 attributable to oil and gas development within the County.
        - Boulder County reportedly received another $83,000 from the State during 2011 reflecting its share of severance taxes and federal royalty payments.
        - These ad valorem and severance tax revenues will increase dramatically if significant new oil and gas development occurs in Boulder County as assumed in the study. Indeed, the study predicts that such development will consist of horizontal wells, which are highly productive. A rough calculation is that during the first year of production a typical new horizontal well in the Wattenberg field will generate about $300,000 in local ad valorem taxes at a 6% rate and another $300,000 in state severance taxes at current rates. Just the local ad valorem taxes for that one year would be more than eight times the transportation mitigation costs that the study attributes to the well.

EXHIBIT B

APRIL 5, 2013 LETTER FROM INDUSTRY

Davis Graham & Stubbs LLP

April 5, 2013

George Gerstle
Boulder County Transportation Director
ggestle@bouldercounty.org

Kim Sanchez
Boulder County Planning Division Manager
ksanchez@bouldercounty.org

Ben Doyle
Assistant Boulder County Attorney
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Dear George, Ben, and Kim:

On behalf of our client Noble Energy, Inc., we are submitting this letter in further response to the Boulder County Oil and Gas Roadway Impact Study prepared by Felsburg Holt & Ullevig and BBC Research and Consulting dated January 14, 2013 ("Roadway Impact Study").

According to the Study, "[t]he most frequent heavy-truck activity during the development of a well comes from the transportation of water to and from the well during the drilling and hydraulic fracturing process (completion stage) . . . . This demand for water translates into about 4,200 trips . . . . Workers [also] transport produced water and flowback water, extracted during the production phase, to a separate wastewater site, resulting in about 1,400 additional trips . . . . Study at 34. These trip generation figures are based upon two- to-four-year-old studies of oil and gas development in the Northeastern U.S. and a six-year-old study of oil and gas development in Utah. *Id.* at 9-10. The Roadway Impact Study further assumes that Noble and other operators will take no action to reduce or otherwise manage their use of water and the truck traffic associated with such usage.

Contrary to these assumptions, Noble currently employs and plans to expand a number of water management strategies for its DJ Basin operations in Colorado. These strategies have already reduced both the volume of fresh water that Noble uses for drilling and hydraulic

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fracturing and the amount of truck traffic associated with such activity, and these reductions are likely to increase in the future as these strategies are expanded and refined. This letter encloses the following publically-available documents that provide additional detail on and substantiation of these strategies and the resulting reductions in water use and truck traffic.

2012 Carbon Disclosure Project Water Disclosure Response. Noble's 2012 Carbon Disclosure Project Water Disclosure Response provides detailed information on Noble's water management strategies and results. Relevant sections of the Response include:

- Section 1.1a, which recognizes that water "must be managed sustainably and strategically" and explains that Noble's strategy and plan includes "defining and performing location-specific best practices; striving to reduce our use of freshwater; increase water treatment, recycle and reuse; and mitigate competition with other water users/risks whenever and wherever possible."
- Section 1.1d (Recycling and reusing water goals), which states that Noble "is actively researching and implementing treatment technologies that help capture, treat, reuse, and recycle an increasing percentage of our flowback and produced waters," that Noble "has conducted a pilot experiment in the Niobrara to treat flowback from one hydraulic fracture to be reused in a subsequent hydraulic fracture," and that "[t]his successful pilot is on-going and is intended to be implemented on a larger scale within the Niobrara."
- Section 1.1d (Efficiency goals), which notes that "[i]n Colorado, all of Noble Energy's drilling" uses "a closed-loop system" that "allows for the reuse of all drilling fluids" and "decreases reliance on water resources" and that "Noble Energy's hydraulic fracturing operations in the Wattenberg (DJ basin) have increased efficiency by using on average 20% less water" through "reducing the amount of slickwater stages and using higher sand concentrations during gel stages."
- Section 1.2, which recognizes that Noble is "a primary sponsor of the Colorado Energy Water Consortium" whose purpose is "to bring together industry, academic, agriculture, government, environmental and consulting stakeholder to address water issues through research and related activities."
- Section 3.1a (Inadequate infrastructure), which observes that "Noble Energy is in the process of developing a more robust water infrastructure that will provide us with water and reduce our dependency on trucks to transport water."
- Section 5.1a, which explains that Noble is "committed to increasing water recycling and reuse by implementing best management practices in the industry" and that "[t]his example of performing environmental stewardship also increases fiscal responsibility."
- Sections 7.1a and 7.2a, which state that Noble withdrew 1925 megaliters of surface, ground, and municipal water in the U.S. during 2011, and that 1113 megaliters of this water was recycled or resused.

2011 Sustainability Report. Noble's 2011 Sustainability Report provides additional information on this subject. Relevant excerpts from the Report include:

- Page 29, which notes that in 2011 Noble "implemented a Life-Cycle Water Management program for our DJ Basin operations focused on responsible sourcing, transport, use, treatment, recycling and disposal of water resources," that this program "supplements our ongoing efforts to collaborate with communities as we work to minimize consumption, properly dispose of produced water, and test and implement new water-treatment and –reuse technologies," and that during 2011 Noble's U.S. operations "used an estimated 19 million barrels of water [and] approximately 7 million of these barrels were reused during subsequent drilling and maintenance activities."
- Page 30, which provides a graphic overview of Noble's Life-Cycle Water Management program for its DJ Basin operations.
- Page 31, which sets forth several examples of how Noble applies its water management strategy in the DJ Basin, including Noble's use of "brine aquifers, grey water or produced water," Noble's practice of "strategically locating storage ponds and tanks, and utilizing pumps and pipelines as alternative means of water delivery" to "reduce the number of truck trips needed to transport water," and Noble's efforts to "continually identify[] and assess[] opportunities to conserve water." These actions reduced Noble's "truck mileage by approximately 5 million miles in the Wattenberg field" during 2011 and "resulted in a 10 percent reduction in the volume of water consumed per well in the region."
- Page 33, which explains how Noble "initiated its EcoNode Centralized Facilities program at our well sites in the DJ Basin" during late 2011. This program allows "up to 32 wells" to operate "on a single EcoNode," which reduces the land footprint "by more than 70 percent." Moreover, the program "minimizes . . . water consumption and road use" because "[w]ater for multiple wells can be pumped from a single location, enabling the efficient collection of produced fluids" while "utilizing pipelines to transport fluids" reduces "truck traffic."

2012 Report on Life Cycle Analysis of Water Use and Intensity of Noble Energy Oil and Gas Recovery in the Wattenberg Field of Northern Colorado. A March 2012 Report by Noble and Colorado State University proposes a framework "to assess the lifecycle of water and energy resources" of Noble's Wattenberg field assets and uses "[d]ata from Noble's Wattenberg wells . . . to assess the overall water use and average water intensity in the region." Report at 1. This Report is based upon water use data from 445 Noble wells completed during 2010 and 2011 in the Wattenberg field, including 386 vertical wells and 59 horizontal wells. *Id.* at 10-11. It determined that the vertical wells used an average of 77,000 gallons of water for drilling and 310,000 gallons of water for hydraulic fracturing while the horizontal wells used an average of 130,000 gallons of water for drilling and 2,700,000 gallons of water for hydraulic fracturing. *Id.* at 15-22. This is less water than the Roadway Impact Study assumes will be used for this purpose. Page 34 of that Study assumes that "between three and five million gallons of water are used during the drilling and completion stages of developing a well" based upon information from Chesapeake Energy regarding its water use in what are presumably other regions of the U.S.

Collectively, these documents indicate that the Roadway Impact Study overstates the truck traffic associated with future oil and gas development in Boulder County by relying upon generalized information from other regions and ignoring the water conservation, site development, and alternative transportation measures that Noble and other operators are already employing to reduce water use and associated truck traffic in the DJ Basin. These documents also reflect the importance that Noble and other operators place upon these issues and the dynamic and rapidly evolving nature of their practices.

Please let us know if you have any questions regarding this letter or the enclosed documents.

Respectfully,

Dave Neslin
Kirk Mueller
for
DAVIS GRAHAM & STUBBS LLP

Counsel for Noble Energy, Inc.

EXHIBIT B.1, B.2, AND B.3

ATTACHMENTS TO THE APRIL 5 LETTER

Module: Introduction - 2012 CDP Water Disclosure

Page: Introduction - 2012 CDP Water Disclosure

0.1

Introduction

Please give a general description and introduction to your organization.

Noble Energy, Inc. is a leading independent energy company engaged in worldwide oil and gas exploration and production. Noble Energy is a Delaware corporation, formed in 1969, that has been publicly traded on the New York Stock Exchange (NYSE) since 1980 under the ticker symbol NBL. Noble Energy has five core operating areas: the Denver-Julesburg (DJ) Basin (onshore US), the Marcellus Shale (onshore US), the deepwater Gulf of Mexico (offshore US), offshore West Africa, and offshore Eastern Mediterranean. Proved reserves are geographically balanced amongst the international and domestic operations, with 1,209 million barrels of oil equivalent (BOE) proved at the end of 2011. In 2011, net oil and gas production averaged 222 million BOE per day (BOE/D). Visit Noble Energy online at www.nobleenergyinc.com.

0.2

Reporting Year
Please state the start and end date of the year for which you are reporting data.

Enter the period that will be disclosed.
Sat 01 Jan 2011 - Sat 31 Dec 2011

0.3

Reporting Boundary

Please indicate the category that describes the reporting boundary for companies, entities, or groups for which water-related impacts are reported.

Companies, entities or groups over which operational control is exercised

0.4

Exclusions

Are there any geographies, facilities or types of water inputs/outputs within this boundary which are not included in your disclosure?

No

0.4a

List of Exclusions

Please describe any exclusion(s) in the following table.

Exclusion	Please explain why you have made the exclusion

Module: 2012-Water-Management

Page: 2012-Water-1-ManagementGovernance

1.1

Does your company have a water policy, strategy or management plan?

Yes

1.1a

Please describe your policy, strategy or plan, including the highest level of responsibility for it within your company and its geographical reach.

Country or geographical reach	Description of policy, strategy or plan	Position of responsible person
Global	Water is an essential component of our value chain that must be managed sustainably and strategically. Water is used during many oil and gas activities, including the drilling and completion of new oil or gas wells, maintenance and upgrades on existing oil or gas wells, and site construction. The Water Manager at Noble has the highest level of direct oversight for water management within the organization. To ensure communication to the highest level in the company, the Water Manager reports to the VP for EHSR, who in turn reports to the board on global water management matters. The Water Manager is supported by two Water Resources Engineers. Noble Energy has a water management strategy and plan, and is committed to a macro-level analysis of water. Our strategy and plan includes: defining and performing location-specific best practices; striving to reduce our use of freshwater; increase water treatment, recycle and reuse; and mitigate competition with other water users/risks whenever and wherever possible. Noble Energy strives to achieve EHS excellence, and water management is no exception.	Officer/manager not directly reporting to the board

1.1b

Does the water policy, strategy or plan specify water-related targets or goals?

Yes

1.1c

Please describe these water-related targets or goals and the progress your company has made against them.

Country or geographical reach	Category of target or goal type	Description of target or goal	Progress against target or goal
United States of America	Direct operations	Water resource procurement goals	By the end of 2013, Noble Energy anticipates that it will have secured the vast majority of its water resources through independent water supplies that we own and/or control.
United States of America	Direct operations	Recycling and reusing water goals	Noble Energy is actively researching and implementing treatment technologies that help capture, treat, reuse, and recycle an increasing percentage of our flowback and produced waters. Noble Energy has conducted a pilot experiment in the Niobrara to treat flowback from one hydraulic fracture to be reused in a subsequent hydraulic fracture. This successful pilot is on-going and is intended to be implemented on a larger scale within the Niobrara as well as in additional basins. Additionally, in our Kansas and Texas operations Noble Energy supplements 62% and 100% of water flood volumes with reused produced water.
United States of America	Direct operations	Efficiency goals	Noble Energy recognizes the value in environmental stewardship and fiscal responsibility. Increasing water efficiency positively affects all stakeholders. We are committed to increasing water efficiency through innovation and best management practices. One of the ways in which Noble Energy increases water efficiency is through closed-loop drilling. In Colorado, all of Noble Energy's drilling is a closed-loop system. This process allows for the reuse of all drilling fluids, which decreases reliance on water resources. Closed-loop drilling also eliminates the need to store discarded drilling fluid in open reserve pits and prevents evaporative losses at the drilling site. By not using these pits, we are decreasing the chance of a release to the subsurface that could impact local groundwater. Also, Noble Energy's hydraulic fracturing operations in the Wattenberg (DJ basin) have increased efficiency by using on average 20% less water. This increase in efficiency occurred by reducing the amount of slickwater stages and using higher sand concentrations during gel stages. These both represent examples of Noble Energy using best management practices in the industry to increase efficiency, increase fiscal responsibility, decrease waste and decrease potential impact to human health and the environment.
Global	Community engagement	Stewardship	Noble Energy is committed to reducing competition with municipal, domestic and agricultural water sources in recognition of the necessity for a collaborative working relationship with communities. Competition for available water resources is minimized by our focus on alternative water sources and reuse.

1.1d

You may explain here why your company does not have a water policy, strategy or plan and if you intend to put one in place.

1.2

Do you wish to report any actions outside your water policy, strategy or management plan that your company has taken to manage water resources or engage stakeholders in water-related issues?

Country or geographical reach	Category of action	Description of action and outcome
Equatorial Guinea	Community engagement	Responsible engagement with local stakeholders is essential to our operational success. Providing increased access to clean, drinking water is one way to engage stakeholders in water-related issues. Noble Energy has drilled wells to increase access to potable water in Equatorial Guinea.
United States of America	Public policy	Noble Energy is proud to be a primary sponsor of the Colorado Energy Water Consortium (CEWC). The purpose of the CEWC is to bring together industry, academic, agriculture, government, environmental and consulting stakeholders to address water issues through research and related activities. CEWC addresses social, environmental, and economic values related to the water and energy industry. Noble Energy is also an active member of the Colorado Oil and Gas Association (COGA). COGA's mission is to foster and promote the beneficial, efficient, responsible and environmentally sound development, production and use of Colorado oil and natural gas.

Module: 2012-Water-RisksOps

Page: 2012-Water-2-indicators-op

2.1

Are any of your operations located in water-stressed regions?

Yes

2.1a

Please specify the method(s) you use to characterize water-stressed regions (you may choose more than one method).

Method used to define water stress	Please add any comments here:
WRI water scarcity definition	

2.1b

Please list the water-stressed regions where you have operations and the proportion of your total operations in that area.

Country or geographical reach	Region within country	Proportion of operations located in this region (%)	Further comments
United States of America	Colorado	1 – 10	3.1% of Noble Energy-operated wells are in water stressed regions of Colorado. Operations include new wells in 2011 as well as wells drilled prior to 2011 that are still producing.
United States of America	New Mexico	1 – 10	1.9% of Noble Energy-operated wells are in water stressed regions of New Mexico. Operations include new wells in 2011 as well as wells drilled prior to 2011 that are still producing.
United States of America	West Texas	1 – 10	0.3% of Noble Energy-operated wells are in water stressed regions of Texas. Operations include new wells in 2011 as well as wells drilled prior to 2011 that are still producing.

2.1a

Please specify the method(s) you use to characterize water-stressed regions.

Method used to define water stress	Please add any comments here:

2.1c

You may explain here why you are not able to identify which of your operations are located in regions subject to water stress and whether you have plans to investigate this in the future.

2.2

Are there other indicators (besides water stress) which you wish to report that help you to identify which of your operations are located in regions subject to water-related risk?

Yes

2.2

Are there other indicators (besides water stress) which you wish to report that help you to identify which of your operations are located in regions subject to water-related risk?

2.2

Are there other indicators (besides water stress) which you wish to report which help you to identify which of your operations are located in regions subject to water-related risk?

2.2a

Please list the regions at risk where you have operations, the relevant risk indicator and proportion of your total operations in that area.

Country or geographical reach	Region within country	Risk Indicator	Proportion of operations located in this region (%)	Further comments
Global		Tightening of regulations	91-100	Operations include new wells in 2011 and wells drilled prior to 2011 that are still producing.
Global		Other: Reputation	91-100	Operations include new wells in 2011 and wells drilled prior to 2011 that are still producing.
Global		Other: Legal	91-100	Operations include new wells in 2011 and wells drilled prior to 2011 that are still producing.

2.2a

Please list the regions at risk where you have operations, the relevant risk indicator and proportion of your total operations in that area.

Country or geographical reach	Region within country	Risk Indicator	Proportion of operations located in this region (%)	Further comments

2.2a

Please list the regions at risk where you have operations, the relevant risk indicator and proportion of your total operations in that area.

Country or geographical reach	Region within country	Risk Indicator	Proportion of operations located in this region (%)	Further comments

2.2b

You may explain here why you do not wish to report or why you do not use other indicators to identify which of your operations are located in regions subject to water-related risk.

2.2b

You may explain here why you do not use or wish to report other indicators to identify which of your operations are located in regions subject to water-related risk.

2.2b

You may explain here why you do not use or wish to report other indicators to identify which of your operations are located in regions subject to water-related risk.

2.3

Please specify the total proportion of your operations that are located in the regions at risk which you identified in questions 2.1 and/or 2.2.

100%

2.3

Please specify the total proportion of your operations that are located in the regions at risk which you identified in questions 2.1 and/or 2.2.

2.3

Please specify the total proportion of your operations that are located in the regions at risk which you identified in questions 2.1 and /or 2.2.

2.4

Please specify the basis you use to calculate the proportions used for questions 2.1 and/or 2.2.

Basis used to determine proportions	Please add any comments here
Other: Wells	Noble Energy maintains accurate counts of its wells worldwide.

2.4

Please specify the basis you use to calculate the proportions used for questions 2.1 and/or 2.2.

Basis used to determine proportions	Please add any comments here

2.4

Please specify the basis you use to calculate the proportions used for questions 2.1 and/or 2.2

Basis used to determine proportions	Please add any comments here

Page: 2012-water-indicators-sc

2.5

Do any of your key inputs or raw materials (excluding water) come from regions subject to water-related risk?

Yes

2.5a

Please state or estimate the proportion of your key inputs or raw materials that come from regions subject to water-related risk.

Input or material	Proportion of key input or raw material that comes from region at risk (%)	Unit used for calculating percentage	Further comments
Guar	71 – 80	Other: Estimate	Guar gum is a necessary component to some forms of hydraulic fracturing. It is a plant based material that serves as a thickening agent. Currently, India and China are the only producers of guar.

2.5b

You may explain here why you are not able to identify if any of your key inputs or raw materials come from regions subject to water-related risk and whether you have plans to explore this issue in the future.

Page: 2012-water-3-riskassess-op

3.1

Is your company exposed to water-related risks (current or future) that have the potential to generate a substantive change in your business operation, revenue or expenditure?

Yes

3.1a

Please describe (i) the current and/or future risks to your operations, (ii) the ways in which these risks affect or could affect your operations before taking action, (iii) the estimated timescale of these risks, and (iv) your current or proposed strategies for managing them.

Country or geographical reach	Risk type	Potential business impact	Estimated timescale (years)	Risk management strategies
United States of America	03. Physical: Increased water stress or scarcity	Noble Energy has identified that portions of its operations are in areas that have been identified as physically water scarce. Should this continue, we could face possible restrictions on groundwater and surface water withdrawal, which would likely lead to interruptions to our operations and increased operational costs.	Unknown	Noble Energy is assessing best management practices on environmental stewardship as well as implementing innovative ways to increase water efficiency and decrease water use in our operations.
United States of America	11. Regulatory: Statutory water withdrawal limits/changes to water allocation	Statutes and regulations that address groundwater withdrawals could impact our ability to operate in certain areas due to limited water availability permitting restrictions, and/or additional permitting requirements.	Unknown	To manage this risk, Noble Energy engages in the review of and provides comments on proposed legislation and regulations that could affect our operations, including those which deal specifically with water. We also actively measure and monitor our water usage, and try to lessen usage wherever possible.
Global	04. Physical: Other	In the event of an unintentional release or contamination of a water source, Noble Energy has the potential to face spill or water contamination risks.	Unknown	To effectively manage physical risks such as potential spills or contamination, Noble Energy has a Global Environmental, Health and Safety Management System (GMS) which includes process safety along with 13 other core safety elements. Process safety involves the prevention of leaks, spills, equipment malfunctions, over-pressures, over-temperatures, corrosion, metal fatigue and other similar conditions that may result in the unintentional releases of chemicals and other materials used in drilling and completions operations. We focus on process safety as a means to protect our assets, employees and contractors, the environment, and communities. As part of the Process Safety and Environmental Information element of our GMS, we evaluate risks inherent to our operations using industry best practice assessment methods and reduce these risks to the most feasible level at the design stage.
Global	10. Regulatory: Regulatory	As a result of ongoing review and refinement of applicable statutes and regulations, Noble Energy	Unknown	To manage this risk, Noble Energy engages in the review of and provides comments on proposed

Country or geographical reach	Risk type	Potential business impact	Estimated timescale (years)	Risk management strategies
	uncertainty	has the potential to face regulatory risks throughout its global operations. Should water-related regulations be passed, the cost of meeting regulatory requirements may have an adverse impact on Noble Energy's financial condition. This and additional uncertainty around water procurement and disposal related regulation may cause delays in operations and increase the cost of doing business.		legislation and regulations that could affect our operations, including those which deal specifically with water. We also actively measure and monitor our water usage, and try to lessen usage wherever possible.
Global	15. Other: Reputational damage	Reputational damage could impact Noble Energy's ability to do business in certain areas, decrease demand for our products and negatively impact share price.	Current	Public concern over the use of chemicals in fracturing liquids has led to increasing demands for the disclosure of these chemicals. We take transparency and disclosure around hydraulic fracturing very seriously. To that end, Noble Energy is an active member and participant in FracFocus, a national fracturing chemical registry. We began participating in FracFocus in mid-2011 with 370 wells registered by year end. On the FracFocus website, we are providing voluntary disclosure so anyone can look up the chemicals used at Noble Energy wells. We will have a policy established to voluntarily disclose all onshore U.S. fracturing activities through FracFocus starting in 2012.
Global	16. Other: Inadequate infrastructure	A water infrastructure that is insufficient to support Noble Energy's current operations may require us to rely on additional trucks to haul water for the production process. This will likely result in increased operational costs and increase our exposure to additional safety risks.	Current	Noble Energy is in the process of developing a more robust water infrastructure that will provide us with water and reduce our dependency on trucks to transport water.
United States of America	02. Physical: Flooding	Flooding in our areas of operation may result in unintentional releases that could result in water contamination, which would likely delay operations and increase operating costs.	Unknown	Noble Energy maintains its locations in accordance with applicable storm water management requirements, constructs and maintains secondary containment in accordance with applicable requirements, and conducts impact assessments of potential drilling sites to determine whether a site should be avoided based on its location relative to floodplains.

3.1b

Please explain why you do not consider your company to be exposed to any water-related risks that have the potential to generate a substantive change in your business operation, revenue or expenditure.

3.1c

Please explain why you do not know if your company is exposed to any water-related risks that have the potential to generate a substantive change in your business operation, revenue or expenditure, and if you have plans to assess this risk in the future.

3.2

What methodology and what geographical scale (e.g. country, region, watershed, business unit, facility) do you use to analyze water-related risk across your operations?

Risk methodology	Country or geographical scale
Noble Energy is committed to reducing its exposure to water related risks through an innovative procurement strategy that secures an independently owned and/or operated water supply, and strives to mitigate competition with other water users/risks whenever possible. Noble Energy is also committed to reducing its exposure to water related risks through increasing water treatment, recycling and reuse efforts, and increasing water efficiency.	Country

Page: 2012-water-riskassess-sc

3.3

Do you require your key suppliers to report on their water use, risks and management?

No

3.4

Is your supply chain exposed to water-related risks (current or future) that have the potential to generate a substantive change in your business operation, revenue or expenditure?

3.4a

Please describe (i) the current and/or future risks to your supply chain, (ii) the ways in which these risks affect or could affect your operations before taking action, (iii) the estimated timescale of these risks and, (iv) your current or proposed strategies for managing them.

Country or geographical reach	Risk type (to supplier)	Potential business impact (to responding company)	Estimate timescale (years)	Risk management strategies (by responding company)

3.4b

Please explain why you do not consider your supply chain to be exposed to any water-related risks that have the potential to generate a substantive change in your business operation, revenue or expenditure.

3.4c

Please explain why you do not know if your supply chain is exposed to any water-related risks that have the potential to generate a substantive change in your business operation, revenue or expenditure, and if you have plans to assess this risk in the future.

Page: 2012-Water-4-Impacts

4.1

Has your business experienced any detrimental impacts related to water in the past five years?

Yes

4.1a

Please describe these detrimental impacts including (i) their financial impacts and (ii) whether they have resulted in any changes to company practices.

The uncertain regulatory environment surrounding hydraulic fracturing, water procurement and water disposal has caused delays in operations and increased the cost of doing business. As a result, Noble Energy has committed to explore alternative water sources and minimize water procurement and disposal through increased water recycling. Additionally, Noble Energy is committed to transparently addressing hydraulic fracturing by engaging stakeholders and participating in education and voluntary reporting programs like FracFocus. Finally, Noble Energy has prioritized water-related risk assessments of all existing and new ventures.

4.1b

Please explain why you do not know whether your business has experienced any detrimental impacts related to water in the past five years and if you have any plans to explore this in the future?

Page: 2012-Water-5-Opportunities

5.1

Do water-related issues present opportunities (current or future) that have the potential to generate a substantive change in your business operation, revenue or expenditure?

Yes

5.1a

Please describe (i) the current and/or future opportunities, (ii) the ways in which these opportunities affect or could affect your operations (iii) the estimated timescale and (iv) your current or proposed strategies for exploiting them.

Country or geographical reach	Opportunity type	Potential business impact	Estimated timescale	Strategy to exploit opportunity
United States of America	Cost savings	With Noble Energy's water procurement strategy, the company will continue to save on the costs of water and reduce production risks related to shortages.	Current	Noble Energy is committed to our innovative procurement strategy that secures an independently owned and/or operated water supply.
United States of America	Cost savings	Noble Energy seeks opportunities for innovative water recycling and treatment methods which could reduce disposal and transportation costs and risks.	Current	Noble Energy is committed to increasing water recycling and reuse by implementing best management practices in the industry. This example of performing environmental stewardship also increases fiscal responsibility.

5.1b

Please explain why you do not consider water-related issues to present opportunities to your company that have the potential to generate a substantive change in your business operation, revenue or expenditure or supply chain.

5.1c

Please explain why you do not know whether water-related issues present opportunities to your company that have the potential to generate a substantive change in your business operation, revenue or expenditure.

Page: 2012-Water-6-tradeoffs

6.1

Has your company identified any linkages or trade-offs between water and carbon emissions in its operations or supply chain?

Yes

6.1a

Please describe the linkages or trade-offs and the related management policy or action.

Linkage or trade-off	Policy or action
Increasing demand for energy and water will further demonstrate the dependent nature of these two resources; large volumes of water are consumed to generate energy, and large quantities of energy are required to access, treat and deliver clean water. Noble Energy's energy portfolio in 2011 was approximately 60 percent natural gas. At the end point of use, natural gas is less carbon emission intense but more water intense than alternative fossil fuels such as oil and coal. A key process to the exploration and production of natural gas is hydraulic fracturing, which uses a large amount of water. However, completing this process using water-based fluids increases the amount of cleaner-burning natural gas we can recover. There are many benefits to using natural gas as an alternative fossil fuel, demonstrating the trade-off between water and carbon emissions in the exploration and production of natural gas. These include reducing the carbon footprint of energy use, reducing the country's dependence on foreign oil, and serving as a bridge fuel until renewable energies become more readily available.	Although exploration and production of natural gas is extremely water intensive, it is less emission intensive than coal or oil. In our natural gas strategy, we see two major opportunities to replace other more carbon intensive fossil fuels. One is that we see natural gas as a replacement for coal in power generation or, should renewable resources such as wind or solar power become more prevalent, natural gas-fired electric plants may provide an alternative backup to maintain consistent energy supply. The other major opportunity is that we see natural gas increasing its share of transportation fuels. Natural gas vehicles are cleaner than traditional gasoline or diesel vehicles, resulting in 70-90 percent less carbon monoxide, 75-95 percent less nitrogen oxide, and 20-30 percent less carbon dioxide emissions. Additionally, natural gas is significantly less expensive: on average, natural gas is over one-third less expensive than gasoline and between 25-42 percent cheaper than diesel.
Some of our company's water efficiency practices include technologies and equipment that utilize energy.	Noble Energy is working to develop and implement innovative emissions reductions activities at an operational level, as well as continuing to practice

Linkage or trade-off	Policy or action
	water efficiency wherever possible.

Module: 2012-Water-Account

Page: 2012-Water-7-Withdrawals

7.1

Are you able to provide data, whether measured or estimated, on water withdrawals within your operations?

Yes

7.1a

Please report the water withdrawals within your operations for the reporting year.

Country or geographical reach	Withdrawal type	Quantity (megaliters/year)	Proportion of data that has been verified (%)	Comments
United States of America	Other: Surface Water, Ground Water, Municipal	1925	0	The data has not been third party verified; however, most of our data is internally crosschecked through AP and operations data.
Rest of world	Other: Surface Water, Ground Water, Municipal	52	0	The data has not been third party verified; however, most of our data is internally crosschecked through AP and operations data.

7.1b

Please explain why you are not able to provide data for water withdrawals.

7.2

Are you able to provide data, whether measured or estimated, on water recycling/reuse within your operations?

Yes

7.2

Are you able to provide data, whether measured or estimated, on water recycling/reuse within your operations?

7.2a

Please report the water recycling/reuse within your operations for the reporting year.

Country or geographical reach	Quantity (megaliters/year)	Proportion of data that has been verified (%)	Comments
United States of America	1113	0	The data has not been third party verified; however, most of our data is internally crosschecked through AP and operations data.

7.2a

Please report the water recycling/reuse within your operations for the reporting year.

Country or geographical reach	Quantity (megaliters/year)	Proportion of data that has been verified (%)	Comments

7.2b

Please explain why you are not able to provide data for water recycling/reuse within your operations.

7.2b

Please explain why you are not able to provide data for water recycling/reuse within your operations.

7.3

Please use this space to describe the methodologies used for questions 7.1 and 7.2 or to report withdrawals or recycling/reuse in a different format to that set out above.

7.3

Please use this space to describe the methodologies used for questions 7.1 and 7.2 or to report withdrawals or recycling/reuse in a different format to that set out above.

7.4

Are any water sources significantly affected by your company's withdrawal of water?

No

7.4a

Please list any water sources significantly affected by your company's withdrawal of water.

Country or geographical reach	Water source	Impact	Company action and outcomes

7.4b

You may explain here why your company's withrawal of water does not significantly affect any water sources.

Noble Energy is committed to increasing water efficiency, increasing water recycling and reuse, and responsible procurement. This balanced strategy is specifically designed to avoid significant impacts to water sources with our company's withdrawals of water.

7.4c

Please explain why you do not know if any water sources are significantly affected by your company's withdrawal of water.

Page: 2012-Water-8-Discharges

8.1

Are you able to identify discharges of water from your operations by destination, by treatment method and by quality using standard effluent parameters?

Yes

8.1a

Please explain why you are not able to identify discharges from your operations by destination, treatment method and quality and whether you have any plans to put in place systems that would enable you to do so.

8.2

Did your company pay any penalties or fines for significant breaches of discharge agreements or regulations in the reporting period?

No

8.2a

Please describe the location and impact of the discharge that was the subject of the significant breach(es), the associated fines and any actions taken to minimise the risk of future non-compliance.

Country or geographical reach	Impact	Fines and penalties	Company action and outcomes

8.3

Are any water bodies and related habitats significantly affected by discharges of water or runoff from your operations?

No

8.3a

Please list any water bodies and associated habitats which are significantly affected by discharge of water or runoff from your operations.

Country or geographical reach	Water body	Impact	Company action and outcomes

8.3b

You may explain here why your company's discharge of water does not significantly affect any water bodies or associated habitats.

All discharges are subject to permit limits that are based on receiving water quality parameters. Noble Energy has not experienced any adverse runoffs nor breached any permit limits in 2011, therefore no bodies or habitats have been significantly affected from our operations.

8.3c

Please explain why you do not know if any water bodies and associated habitats are significantly affected by discharge of water or runoff from your operations.

Page: 2012-Water-9-Intensity

9.1

Please provide any available financial intensity values for your company's water use across its operations.

Country or geographical region	Financial metric	Water use type (megaliters)	Currency	Financial intensity (Currency/mega-liter)	Please provide any contextual details that you consider relevant to understand the units or figures you have provided.
Global	Other: Revenue (in millions of dollars)	Withdrawals	USD($)	1.9034	Published 2011 revenue of $3,763 million divided by stated withdrawals of 1,977 ML.

9.2

Please provide any available water intensity values for your company's products across its operations.

Country or geographical region	Product	Product unit	Water unit	Water intensity (Water unit/product unit)	Water use type	Please provide any contextual details that you consider relevant to understand the units or figures you have provided.
Global	Produced volumes of crude oil, natural gas, and condensates	Other: Thousands of barrels of oil equivalent	megaliters	.0229	Withdrawals	ML/MBOE produced- Stated withdrawal of 1,977 ML in 2011 divided by production volumes of 86,409 MBOE for 2011.

Lifecycle Analysis of Water Use and Intensity of Noble Energy Oil and Gas Recovery in the Wattenberg Field of Northern Colorado

**Prepared by Noble Energy, Inc.
and Colorado State University**

March 2012

Department of Civil and Environmental Engineering

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Executive Summary

Introduction and Project Objectives Water resources in Colorado and the western U.S. are constantly strained given the historical agricultural needs, burgeoning development, and the semi-arid environment. With continued population increases and the importance of agriculture to the overall economy, the pressure on water and other natural resources is expected to intensify. Even though the oil and gas industry has long been a part of the economy in Colorado and the West, recent technological advances have stimulated considerable growth in oil and gas development and operations and therefore have increased the industry's need for water resources.

Competition over water resources will continue to escalate to meet expanding municipal and industrial demands, including those associated with the oil and gas industry. In October, 2011 the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) organization issued a report on rules developed by the Colorado Oil and Gas Conservation Commission (COGCC) related to hydraulic fracturing. One of the five recommendations of the report was the following:

> *"The review team recommends that the COGCC and the DWR jointly evaluate available sources of water for use in hydraulic fracturing. Given the significant water supply issues in this arid region, this project should also include an evaluation of whether or not availability of water for hydraulic fracturing is an issue and, in the event that water supply is an issue, how best to maximize water reuse and recycling for oil and gas hydraulic fracturing."*

Another organization, the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board (SEAB) stated in its November, 2011 report, "At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management". They recommend that new partnerships or mechanisms be developed to study the lifecycle of water resources as one approach to protecting the quality of water resources in the future.

The project described in this report is the first step in addressing the concerns raised by these and other studies. A framework is proposed to assess the lifecycle of water and energy resources of Noble Energy assets in the Wattenberg field. Data from Noble's Wattenberg wells are used to assess the overall water use and average water intensity in the region as a first application of the general framework.

The specific objectives of this project are:

- Determine water use associated with Noble Energy wells in the Wattenberg field and delineate them with respect to horizontal and vertical, drilling and completion.
- Determine the water intensity of Noble Energy wells and compare with industry averages.
- Compare the water intensity for extraction and processing of Noble Energy wells with other energy sources.
- Compare the lifecycle water intensity by energy source for electric power generation.

In consideration of the potential volume of produced water and treatment requirements, it is possible that the net water consumption and water intensity can be driven to nearly zero (i.e. lifecycle production of non-appropriated, non-tributary water is greater than or equal to the volume consumed). Further work needs to be done to estimate the amount of water produced over the lifetime of the well, as well as treatment scenarios and associated energy requirements but the goal of this work would be to assist industry toward meeting water neutrality (no net life-cycle consumption of water).

Scope and Methods The study is divided into two sections: (1) an assessment of the current water intensity of Noble Energy wells, and (2) a water intensity comparison and discussion of other energy sources, such as coal and renewable energy sources. To determine the water intensity of current Noble Energy wells, the water consumption and estimated ultimate recovery (EUR) is found using a decline curve analysis. This ratio is used as a basis for a discussion and comparison of water intensity. Unlike other water and energy studies, which often provide broad estimates from literature, both water consumption and EUR were determined from field data of several individual wells. To best assess current water use and predict future water needs, sampled wells were limited to wells that have been completed in 2010 and 2011 by Noble Energy. The final sample includes 445 wells: 386 vertical wells and 59 horizontal wells.

Water consumption data were collected using Noble Energy's WellView® program. Wells were classified as either horizontally or vertically drilled. Directional and deviated wells were classified as vertical wells. Water use is categorized as either drilling water or completion (hydraulic fracturing) water.

Daily oil and gas production from the same 445 wells were collected using Noble Energy's Carte® program. Data is added to Carte® remotely by the lease operator of the well, who is at each well every day. For this analysis, it was assumed that each well would be economically productive for a 30-year period. The decline curves are extrapolated to estimate future oil and gas production over the expected 30-year lifespan of the well. The EUR is estimated by integrating each decline curve. A trapezoidal integration method with a daily step size was used to integrate the curves.

Water Consumption Vertical and horizontal wells operated by Noble Energy in the Wattenberg during 2010 and 2011 consumed an average 380,000 and 2,800,00 gallons of water. On average, vertical wells used 77,000 gallons to drill and an additional 310,000 gallons to hydraulically fracture the well. Horizontal wells used 130,000 gallons to drill and 2,700,000 gallons to hydraulically fracture the well.

Estimated Ultimate Recovery A decline curve analysis was used to estimate the ultimate recovery from each individual well. Exponential and harmonic decline curves were fit to the production data to project low and high production scenarios, respectively. Vertical wells are expected to have an estimated ultimate recovery between 24 and 60 BBtu for oil and between 32 and 84 BBtu for gas. Horizontal wells are expected to have an estimated ultimate recovery between 390 and 1,100 for gas and between 180 and 520 BBtu for oil.

Water Intensity For this study, water intensity is defined as the ratio of water consumed and energy recovered. A schematic of the water and energy flows of a typical oil and gas well or well-field is shown in Figure 1. A mass and energy balance is used to determine the net water consumed and net energy recovered for each well or a well-field and the boundary for the system defined by the balance is shown in the schematic. Using the materials balance presented in Figure 1, a general equation for the water intensity, the ratio of the net water consumption and net energy recovered can be developed (Eq-1 and Eq-2). For the current project, the water intensity assessment scenario incorporates only water consumed and energy produced.

$$\text{Water Intensity} = \frac{\left[\text{Volume of Drilling Water} + \text{Volume of Hydraulic Fracturing Water}\right] - \left[\text{Volume of Flowback Water} + \text{Volume of Produced Water} - \text{Volume of Injected Water} - \text{Volume of Evaporated Water}\right]}{\left[\text{Energy from Oil} + \text{Energy from Natural Gas}\right] - \text{Energy Used for Drilling} - \text{Energy Used for Hydraulic Fracturing} - \text{Energy Used for Water Treatment}} \qquad \text{Eq-1}$$

Equation 1 is reduced to:

$$\text{Water Intensity} = \frac{[V_{drill} - V_{frac}] - [V_{flowback} + V_{produced} - V_{injection} - V_{evap}]}{E_{recovered} - E_{drilling} - E_{drilling} - E_{treatment}} \Rightarrow \text{Water Intensity} = \frac{[V_{in}] - [V_{out}]}{E_{net}} \qquad \text{Eq-2}$$

Vertical and horizontal wells operated by Noble Energy in the Wattenberg during 2010 and 2011 are expected to have an average water intensity of 6.9 and 4.3 gal/MMBtu, respectively. Vertical wells have an expected water intensity ranging between 5.4 and 14 gal/MMBtu and horizontal wells have an expected water intensity between 2.9 and 9.7 gal/MMBtu.

Material Balance

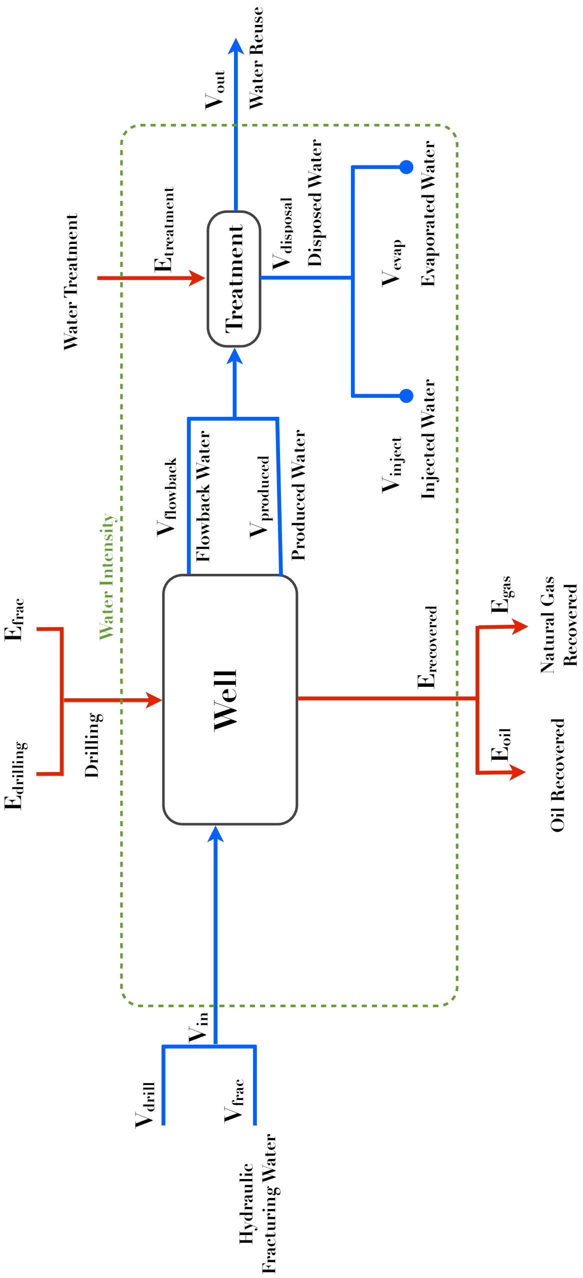

Figure 1: Material balance defining the water intensity assessment. The red and blue lines represent the flow of energy and water, respectively.

A literature review was performed to compare the water intensities found in the study with a variety of fuel sources, including coal, oil, natural gas, uranium, solar, wind, biofuels, and geothermal energy sources. The water intensities are categorized by life-cycle stages (extraction, processing, transport, etc.) and end-use (electricity generation). This study provides a detailed analysis of the water intensity of shale gas on a per well basis and a comparison of vertical and horizontal wells. Previous studies have reported broad generalization of water intensity for shale gas. Water intensity for electrical generation is presented in Figure 2. Generating electricity with natural gas has a lower water intensity than coal, uranium and concentrating solar power but a greater water intensity than photovoltaic solar and wind energy.

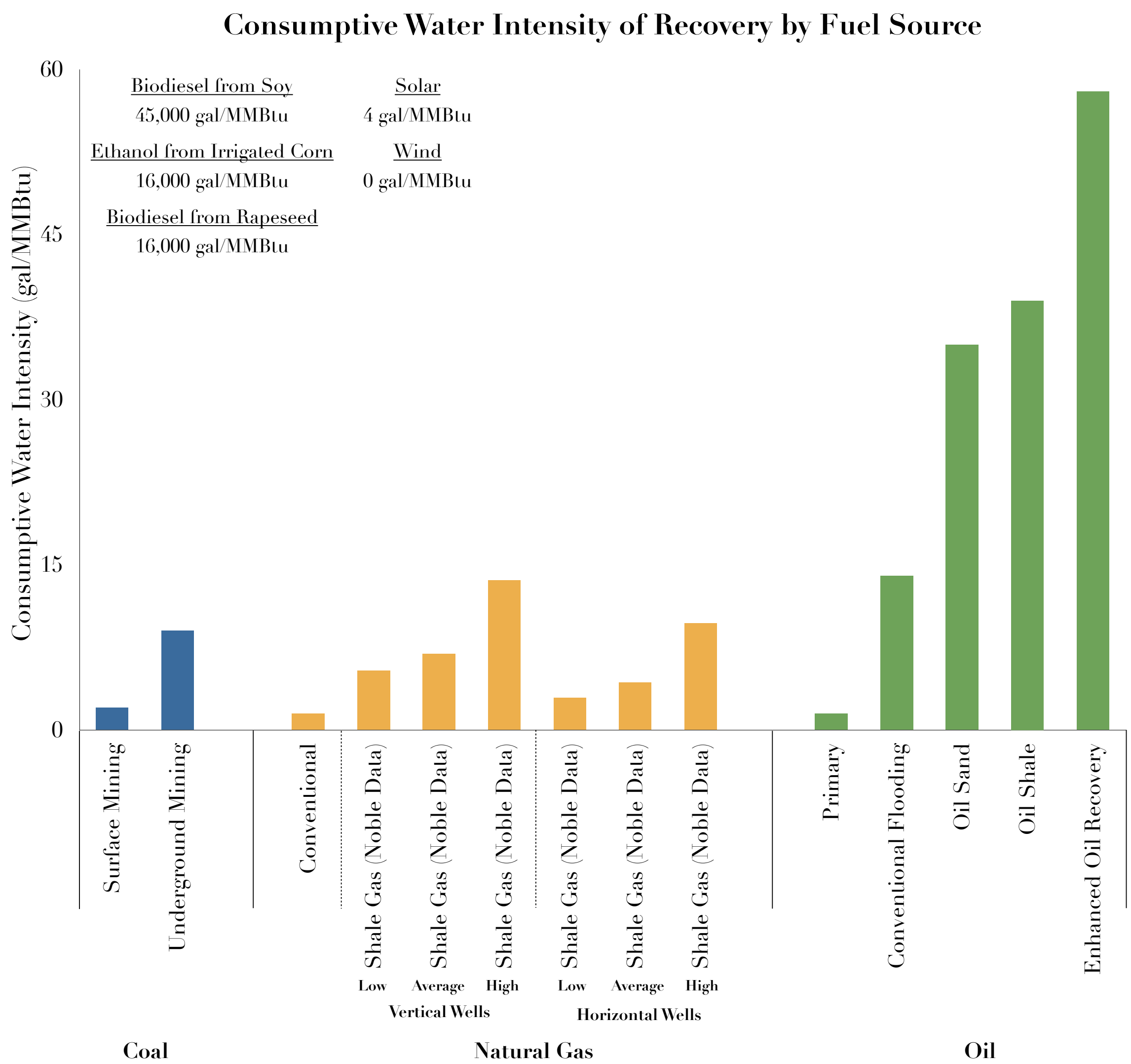

Figure 2: A comparison of the consumptive water intensity for recovery of various energy sources and the water intensity from the sample set from Noble Energy.

Although recovery of unconventional shale gas requires large volumes of water, the water intensity value of recovery is one of the lowest. Horizontal wells, which require the most water, have an average water intensity value that is lower than vertical wells for energy recovery. When processing and end uses (e.g. electricity

Table 1: A comparison of the average consumptive water intensity for the recovery of various energy sources and the water intensity of Noble Energy wells.

Coal (gal/MMBtu)	
Surface Mining	2
Underground Mining	9
Natural Gas (gal/MMBtu)	
Conventional	1.5
Noble Data Natural Gas (gal/MMBtu)	
Vertical: Low	5.4
Vertical: Average	6.9
Vertical: High	13.6
Horizontal: Low	2.9
Horizontal: Average	4.3
Horizontal: High	9.7
Oil (gal/MMBtu)	
Primary	1.5
Conventional Flooding	14
Oil Sand	35
Oil Shale	39
Enhanced Recovery	58
Solar (gal/MMBtu)	
Photovoltaic	4
Wind (gal/MMBtu)	
Turbine	0
Biofuels (gal/MMBtu)	
Biodiesel from soy	45,000
Ethanol from irrigated corn	16,000
Biodiesel from rapeseed	16,000

generation) are considered, natural gas has one of the lowest water intensity values. Furthermore, if the large volumes of produced water can be treated for reuse in an energy efficient manner the water intensity may be reduced further.

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Introduction

Water resources in Colorado and the western U.S. are constantly strained given the historical agricultural needs, burgeoning development, and the semi-arid environment. With continued population increases and the importance of agriculture to the overall economy, the pressure on water and other natural resources is expected to intensify. Even though the oil and gas industry has long been a part of the economy in Colorado and the West, recent technological advances have stimulated considerable growth in oil and gas development and operations and therefore have increased the industry's need for water resources.

In October, 2011 the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) organization issued a report on the Colorado hydraulic fracturing program and the rules developed by the Colorado Oil and Gas Conservation Commission (COGCC) related to this. [1] The report, which was generally positive, made five recommendations for improvement. One of the key recommendations in this report was regarding the availability of water:

> *"The review team recommends that the COGCC and the DWR jointly evaluate available sources of water for use in hydraulic fracturing. Given the significant water supply issues in this arid region, this project should also include an evaluation of whether or not availability of water for hydraulic fracturing is an issue and, in the event that water supply is an issue, how best to maximize water reuse and recycling for oil and gas hydraulic fracturing."*

Other recommendations regarding the management of water resources associated with hydraulic fracturing were made by the Natural Gas Subcommittee of the Secretary of Energy's Advisory Board (SEAB) in November, 2011. [2] The subcommittee was charged in April 2011 to study ways to improve the safety and environmental performance of natural gas hydraulic fracturing from shale formations.

In its final report, the subcommittee stated "At present neither EPA or the states are engaged in developing a systems/lifecycle approach to water management". They recommend that new partnerships or mechanisms be developed to study the lifecycle of water resources as one approach to protecting the quality of water resources in the future.

The project described in this report is the first step in addressing the concerns raised by these and other studies. A framework is proposed to assess the lifecycle of water and energy resources of Noble Energy (Noble) assets in the Wattenberg field. Data from Noble Wattenberg wells is used to assess the overall water use and average water intensity in the region as a first application of the general framework.

The specific objectives of this project are:

- Determine water use associated with Noble Energy wells in the Wattenberg field and delineate them with respect to horizontal and vertical, drilling and completion.
- Determine the water intensity of Noble Energy wells and compare with industry averages.
- Compare the water intensity for extraction and processing of Noble Energy wells with other energy sources.
- Compare the lifecycle water intensity by energy source for electric power generation.

The research performed as part of this study will assist Noble, the oil and gas industry, governing agencies and the greater public in making informed decisions regarding future energy development through the use of empirical data.

Chapter 1

Water Intensity

1.1 Literature Review

Gleick [3] provided one of the first broad reviews of water intensity, presenting direct, consumptive water intensity values for each life cycle phase (i.e. mining, fuel preparation, generation, etc.) of several different fuel sources in 1994. Sovacool and Sovacool [4] expanded the scope of a water intensity analysis to separate water use into both water withdrawals and consumption. Fthenakis and Kim [5] were the first to include upstream water use in the analysis, which includes water requirements associated with energy and material inputs to each life-cycle phase of electricity generation technologies.

In recent years, increasing concern about water and energy resources in the U.S. has led to significantly more available literature particularly from government agencies [6–14], most notably, a 2006 report to Congress from the Department of Energy. [6] The report was a response to a Congressional directive asking for "a report on energy and water interdependencies, focusing on threats to national energy production that might result from limited water supplies."

Perhaps the most comprehensive and recent review of water intensity comes from the Harvard Kennedy School, titled *Water Consumption of Energy Resource Extraction, Processing, and Conversion.* [15]

Several regional studies [12–14, 16–18] have assessed water resource challenges with increasing demands for water. The majority of these studies provide a broad estimate of water requirements, without a detailed analysis of water use on an individual well basis. An analysis of the water intensity of each individual well provides a more detailed and accurate assessment of the water intensity. Other studies focus solely on electricity generation[7, 10, 19–25] or transportation[26–28], the two largest energy sectors in the United States.

Few studies have been completed that assess the water required for shale gas development and production in the United States [29, 30] and nearly all of the studies provide only broad, general estimates. Recent development of shale gas in the

United States has raised concern about the associated impacts on water resources. The goal of this study is to provide a detailed assessment of water requirements for shale gas in the Wattenberg field. The same water intensity framework, developed by previous studies, will be used and compared with the water intensity assessments from previous studies.

1.2 Water Intensity Approach For This Study

Water intensity can be defined in several ways (e.g. water use by economic activity, water use by sector, water use per person etc.), but by any definition it is a measure of how efficiently a water resource is used. For this study, water intensity is defined as the ratio of water consumed and energy recovered. A schematic of the water and energy flows of a typical oil and gas well or well-field is shown in Figure 1.1. A mass and energy balance is used to determine the net water consumed and net energy recovered for each well or a well-field and the boundary for the system defined by the balance is shown in the schematic.

Using the materials balance presented in Figure 1.1, a general equation for the water intensity, the ratio of the net water consumption and net energy recovered can be developed (Eq-1 and Eq-2).

$$\text{Water Intensity} = \frac{\left[\text{Volume of Drilling Water} + \text{Volume of Hydraulic Fracturing Water}\right] - \left[\text{Volume of Flowback Water} + \text{Volume of Produced Water} - \text{Volume of Injected Water} - \text{Volume of Evaporated Water}\right]}{\left[\text{Energy from Oil} + \text{Energy from Natural Gas}\right] - \text{Energy Used for Drilling} - \text{Energy Used for Hydraulic Fracturing} - \text{Energy Used for Water Treatment}} \qquad \text{Eq-1}$$

Equation 1 is reduced to:

$$\text{Water Intensity} = \frac{[V_{drill} - V_{frac}] - [V_{flowback} + V_{produced} - V_{injection} - V_{evap}]}{E_{recovered} - E_{drilling} - E_{drilling} - E_{treatment}} \Rightarrow \text{Water Intensity} = \frac{[V_{in}] - [V_{out}]}{E_{net}} \qquad \text{Eq-2}$$

Several scenarios can be developed from this general framework. For example, the materials balance of an entire region can be assessed for the complete lifecycle of the wells to quantitatively determine the long-term impact on water resources. A material balance of individual wells can also be assessed to better understand water reuse logistics and optimized treatment strategies. The degree of treatment of flowback and produced water will determine the amount of water available for reuse, additional energy requirements required for treatment, and best practices for life-cycle water management and disposal. Future work can be performed to determine the amount of treatment required to optimize water intensity for individual wells and entire regions.

In consideration of the potential volumes of produced water and treatment requirements, it is possible that the net water consumption and water intensity can be driven to nearly zero (i.e. lifecycle production of non-appropriated, non-tributary water is greater than or equal to the volume consumed). Further work needs to be completed to estimate the amount of water produced over the lifetime of the well, as well as treatment scenarios and associated energy requirements but the goal of this work is to assist the industry toward water neutrality (no net life-cycle consumption of water).

For the current project, the water intensity assessment scenario incorporates only water consumed and energy produced. The general materials balance framework for this scenario is shown and explained in Figure 1.2. This simplified water intensity approach will establish a baseline estimate that can be compared with future water management approaches that may involve treatment and recycling.

For this water intensity scenario, it is assumed that the amount of energy required for drilling is negligible when compared with the amount of energy recovered over the 30-year lifetime of the well. It is also assumed that all the flowback and produced water is presently disposed of through evaporation or deep well injection and the water used for drilling and hydraulic fracturing is the same as the net water consumed, in other other words no water is reused. Based on these assumptions, the materials balance equation can be simplified as shown in Eq-3 and Eq-4.

$$\text{Water Intensity} = \frac{\left[\begin{matrix}\text{Volume of}\\ \text{Drilling}\\ \text{Water}\end{matrix} + \begin{matrix}\text{Volume of}\\ \text{Hydraulic}\\ \text{Fracturing Water}\end{matrix}\right] - \left[\cancelto{0}{\begin{matrix}\text{Volume of}\\ \text{Flowback}\\ \text{Water}\end{matrix}} + \cancelto{0}{\begin{matrix}\text{Volume of}\\ \text{Produced}\\ \text{Water}\end{matrix}} - \cancelto{0}{\begin{matrix}\text{Volume of}\\ \text{Diposed}\\ \text{Water}\end{matrix}}\right]}{\left[\begin{matrix}\text{Energy}\\ \text{from Oil}\end{matrix} + \begin{matrix}\text{Energy from}\\ \text{Natural Gas}\end{matrix}\right] - \cancelto{0}{\begin{matrix}\text{Energy Used}\\ \text{for Drilling}\end{matrix}} - \cancelto{0}{\begin{matrix}\text{Energy Used for}\\ \text{Hydraulic Fracturing}\end{matrix}} - \cancelto{0}{\begin{matrix}\text{Energy Used for}\\ \text{Water Treatment}\end{matrix}}} \qquad \text{Eq-3}$$

Equation 3 is reduced to:

$$\text{Water Intensity} = \frac{[V_{drill} - V_{frac}]}{E_{recovered}} \Rightarrow \text{Water Intensity} = \frac{V_{in}}{E_{recovered}} \qquad \text{Eq-4}$$

This scenario simplifies the water intensity to a ratio of the water used for drilling and hydraulic fracturing and estimated ultimate oil and gas recovery (EUR). This scenario is likely to overestimate the water intensity because the large volumes of produced water from the 30-year lifespan of the well are not accounted for in the ratio.

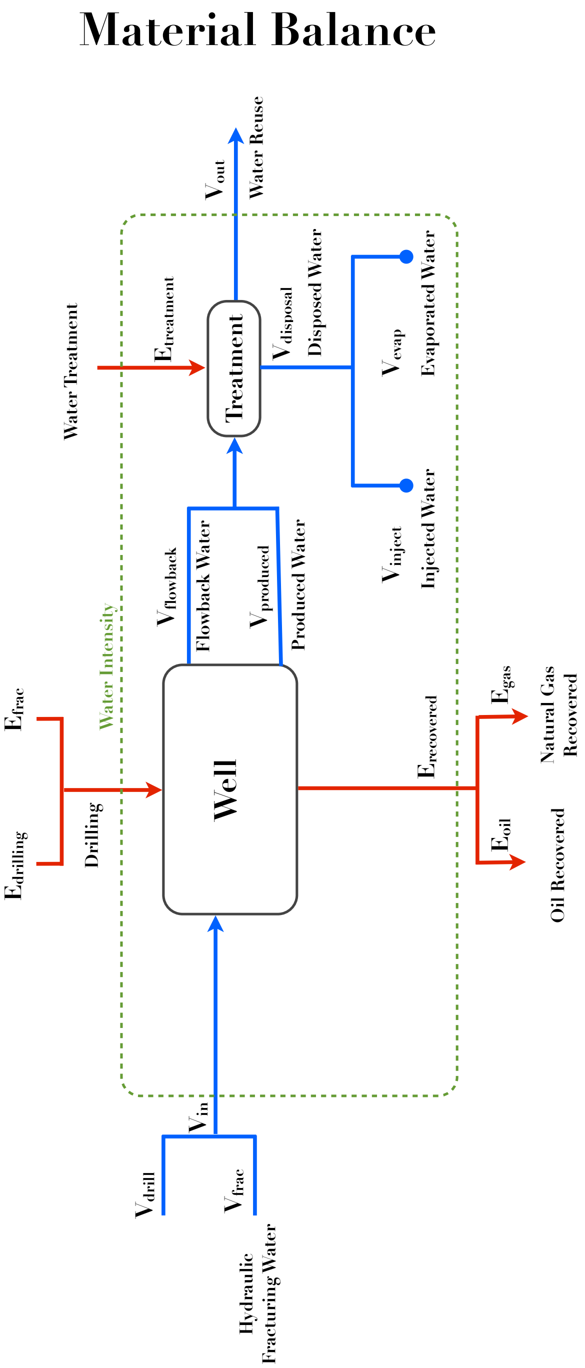

Figure 1.1: Material balance defining the water intensity assessment. The red and blue lines represent the flow of energy and water, respectively.

Material Balance Used to Define Water Intensity Assessment

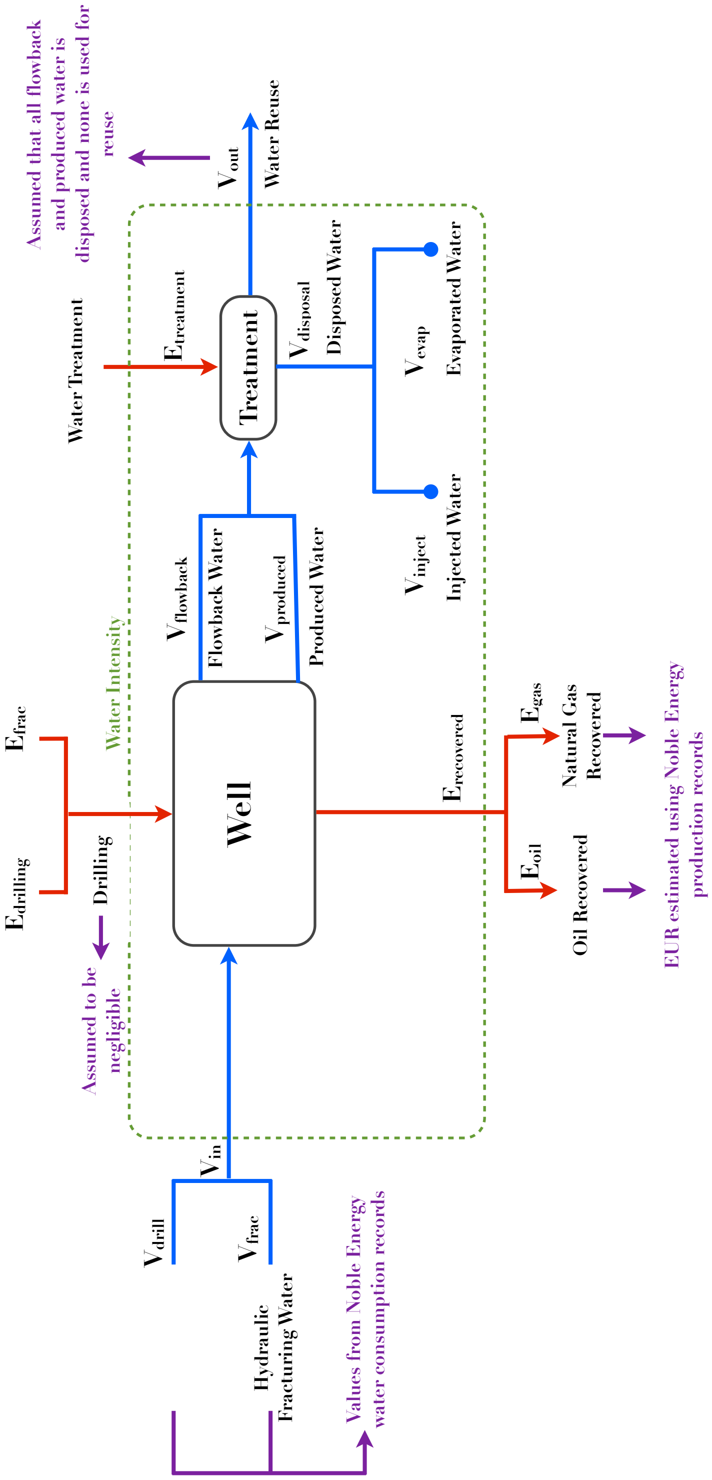

Figure 1.2: Material balance used to defying the water intensity assessment of Noble Energy oil and gas wells in the Wattenberg field.

Chapter 2

Scope and Methods

2.1 Scope of Analysis

The study is divided into two sections: an assessment of the current water intensity of Noble Energy wells, and a water intensity comparison and discussion of other energy sources, such as coal and renewables. To determine the water intensity of current Noble Energy wells, the water consumption and EUR need to be determined, as shown in Figure 2.1. This ratio is used as a basis for a discussion and comparison of water intensity. Unlike other water and energy studies, which often provide broad estimates from literature, both water consumption and EUR were determined from field data representing 445 Noble Energy wells in the Wattenberg. A complete compilation of the results is contained in Appendix G-K.

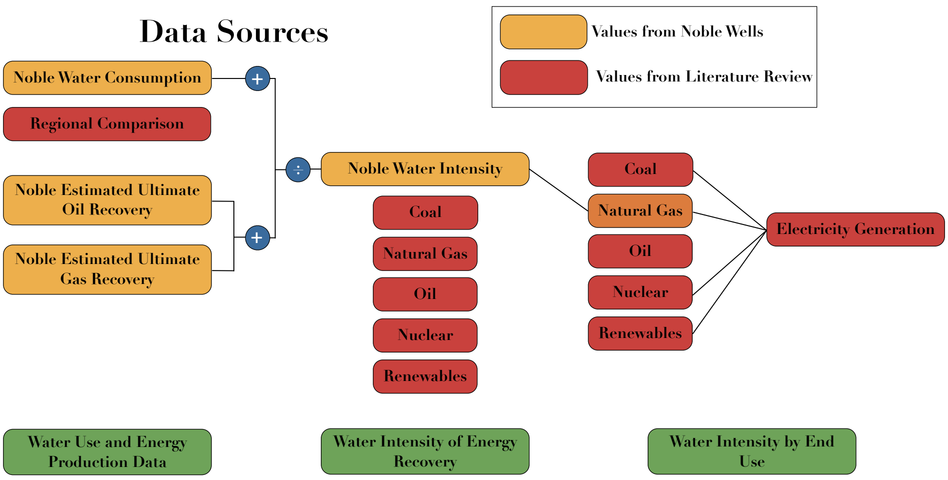

Figure 2.1: The scope of analysis and the source of the information, where the blue boxes represent data directly from Noble Energy and the red boxes represent data collected from a review of literature.

2.2 Data Collection

To best assess current water use and predict future water needs, sampled wells were limited to wells that have been completed in 2010 and 2011 by Noble Energy in the Wattenberg field. Older wells that have been refractured to stimulate recovery were not included in the assessment of wells since this circumstance is not equivalent to fracturing a newly drilled well. The issue of re-fracturing wells and the associated water consumption and water intensity should be included in future studies. Water consumption and energy production data were collected and separated by well type and water use, as shown in Figure 2.2. The final sample includes 445 wells: 386 vertical wells and 59 horizontal wells. This dataset represents all of the wells in 2010 and 2011 with complete water consumption and energy production records. A total of 883 wells were drilled in 2010 and 2011. Wells were omitted for a variety of reasons, most did not have water consumption or production data readily available.

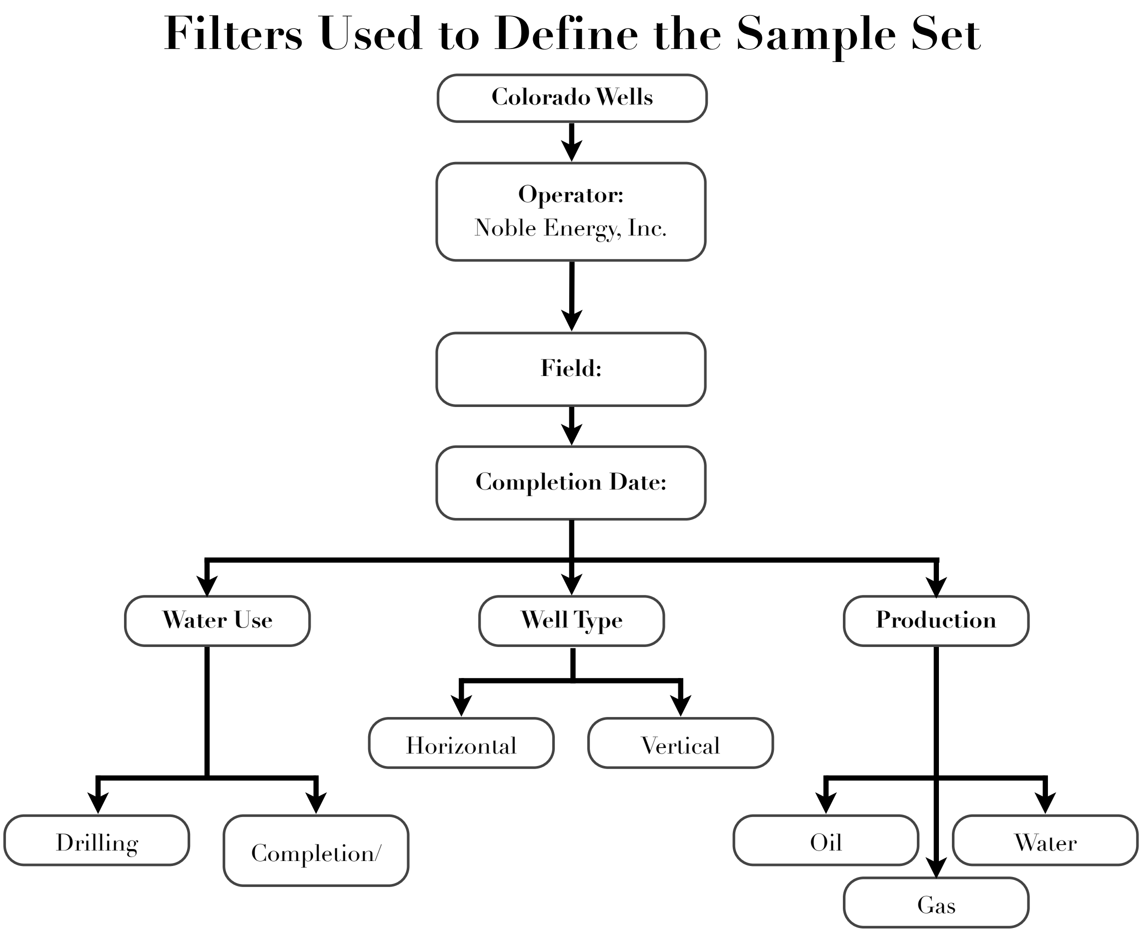

Figure 2.2: Filters and classifications used to define the sample data set.

2.3 Water Consumption Data

Water consumption values were collected using Noble Energy's WellView® program (Peloton Computer Enterprises Ltd., Houston, TX). WellView is part of the Peloton suite of software used for collecting and organizing oil field data. Drilling and hydraulic fracturing reports are added to WellView® by a Noble Energy employee that is on-site at each drilling and hydraulic fracturing site. The water consumption totals are verified by Noble Energy's accounting department and any conflict of values between the field operations and the accounting department are reconciled in WellView®. All of the water consumption data was accessed in November of 2011.

Wells were classified as either horizontally or vertically drilled. Directional and deviated wells are classified as vertical wells, as this is a standard distinction in industry. Horizontal wells are much less common than vertical wells since the technology has only recently been adapted to the Wattenberg field. The final water consumption data set includes water consumed and energy recovered from 386 vertical wells and 59 horizontal wells.

Water use is categorized as either drilling water or completion water. Drilling water is used, with a mixture of clay, to carry cuttings to the surface and to cool and lubricate the drill bit to create the bore hole. Once a bore hole is drilled and perforated, the well is hydraulically fractured. Water used during the hydraulic fracturing phase to expand fractures in the formation and carry proppant down the borehole to hold fractures open when pressure is released.

2.4 Oil and Gas Production Data Collection

Daily oil and gas production from the same 445 wells were collected using Noble Energy's Carte® program. Carte® is part of the Merrick Systems Software (Merrick Systems Oil and Gas Technology Solutions, Houston, TX) used to track daily operations of each individual well. Data is added to Carte® remotely by the lease operator of the well, who is at each well every day. Daily oil production is measured in the tanks and verified when oil is sold to a third-party and removed from the drill site. Gas production is measured at each well using a total flow meter and reconciled by a third party when sold, due to the use of field gas on drill sites. Gas meters are calibrated every quarter and are equipped with a data logger to track historical data.

Estimates of future production for each well was made using decline curves based on the empirical Arps equation. [31] Decline curve analysis are frequently used for naturally-fractured reservoirs, developed unconventional decline curves have not been well established. An exponential decline curve was used to predict a low production scenario and a harmonic decline curve was used to predict a high production scenario, as shown in Eq-6 and Eq-7. An exponential decline curve assumes constant pressure and the production rate approaches zero. A harmonic decline curve approaches a specific value. For this reason exponential and harmonic decline curves often under and over estimate production values, respectively. The two curves were used to bound possible production scenarios.

$$q(t) = \frac{q_i}{(1+D_i t)^{1/b}} \quad \text{where} \qquad \text{Eq-5}$$

q(t) = Future production rate
qi = Initial production rate
Di = Initial decline rate
t = Time
b = Degree of curvature

$$\text{When } b = 0 \Rightarrow \quad q(t) = q_i e^{D_i t} \qquad \text{Eq-6}$$

(Exponential Decline Curve)
(Low Production Scenario)

$$\text{When } b = 1 \Rightarrow \quad q(t) = \frac{q_i}{1+D_i t} \qquad \text{Eq-7}$$

(Harmonic Decline Curve)
(High Production Scenario)

For this analysis, it was assumed that each well would be economically productive for a 30-year period. The decline curves are extrapolated to estimate future oil and gas production over the expected 30-year lifespan of the well. The EUR is estimated by integrating each decline curve using a trapezoidal integration method with a daily step size. The entire analysis was done using MATLAB (2007a, The MathWorks, Natick, MA) and the MATLAB code and an example well can be found in Appendix A.

2.5 Limitations of the Study

For this study water use is reported as average, direct water consumption. Only water quantities are reported and water quality concerns are not addressed for the processes included in this report. Although water quality is a critical factor in the planning, use, and management of water resources this parameter warrants independent analysis that is beyond the scope of this investigation. No comments are made about the source of the water consumed or the transportation requirements.

Water use is typically separated into water withdrawal and water consumption. Withdrawn water is, "water removed from the ground or diverted from a surface-water source for use," and consumed water is, "the part of water withdrawn that is evaporated, transpired, incorporated into products or crops, consumed by humans or livestock, or otherwise removed from the immediate water environment." [32] This study primarily focuses on water consumption; although, some processes (e.g. thermoelectric power generation with once-through cooling) consume only a fraction of the large volumes of water withdrawn. For these types of processes both water consumption and withdrawals are reported.

Water use can also be categorized as direct or indirect water use. Direct water use includes water used directly by the industry (e.g. drilling and hydraulic fracturing water) and indirect water use includes increased water use by an increased population the industry brings. Only direct water use is addressed in this study, but as drilling in Northern Colorado increases a complete assessment of water requirements needs to address indirect and direct water use.

Similarly, upstream or embedded water consumption (e.g. the water required for drill rig fabrication) is not included in the study. Fthenakis [5] attempts to assess the upstream water consumption and provides a good summary of upstream water consumption analysis.

Similar to water consumption, energy recovery is reported as average, direct energy recovery. Embedded or upstream energy is not addressed. Environmental impacts beyond water quantities, such as water quality, air emissions, erosion, land impacts, noise, etc., are also not addressed in this study.

The quality or composition of the energy recovered is not included in the study. Every barrel of oil is assumed to contain 5.78 MMBtu of energy and every thousand standard cubic feet of gas is assumed to contain 1.025 MMBtu of energy. [33] No distinctions are made about the quality of oil or gas recovered.

Chapter 3

Water Consumption

3.1 Noble Energy Water Use

Water consumption data, collected using Noble Energy's WellView®, was collected from 445 wells in the Wattenberg Field. The water consumption for each well was categorized as either drilling water or hydraulic fracturing water. The wells were separated as either vertical or horizontal wells. Each well, represented by an individual vertical bar in Figure 3.1, is ordered from least to greatest. Figure 3.2 gives an example of four wells from Figure 3.1, to illustrate how the figure is developed.

On average, vertical and horizontal wells used 380,000 and 2,800,000 gallons of water. Vertical wells used 77,000 gallons to drill the well and an additional 310,000 gallons to hydraulically fracture the well, on average. Horizontal wells used 130,000 gallons to drill the well and 2,700,000 gallons for hydraulic fracturing.

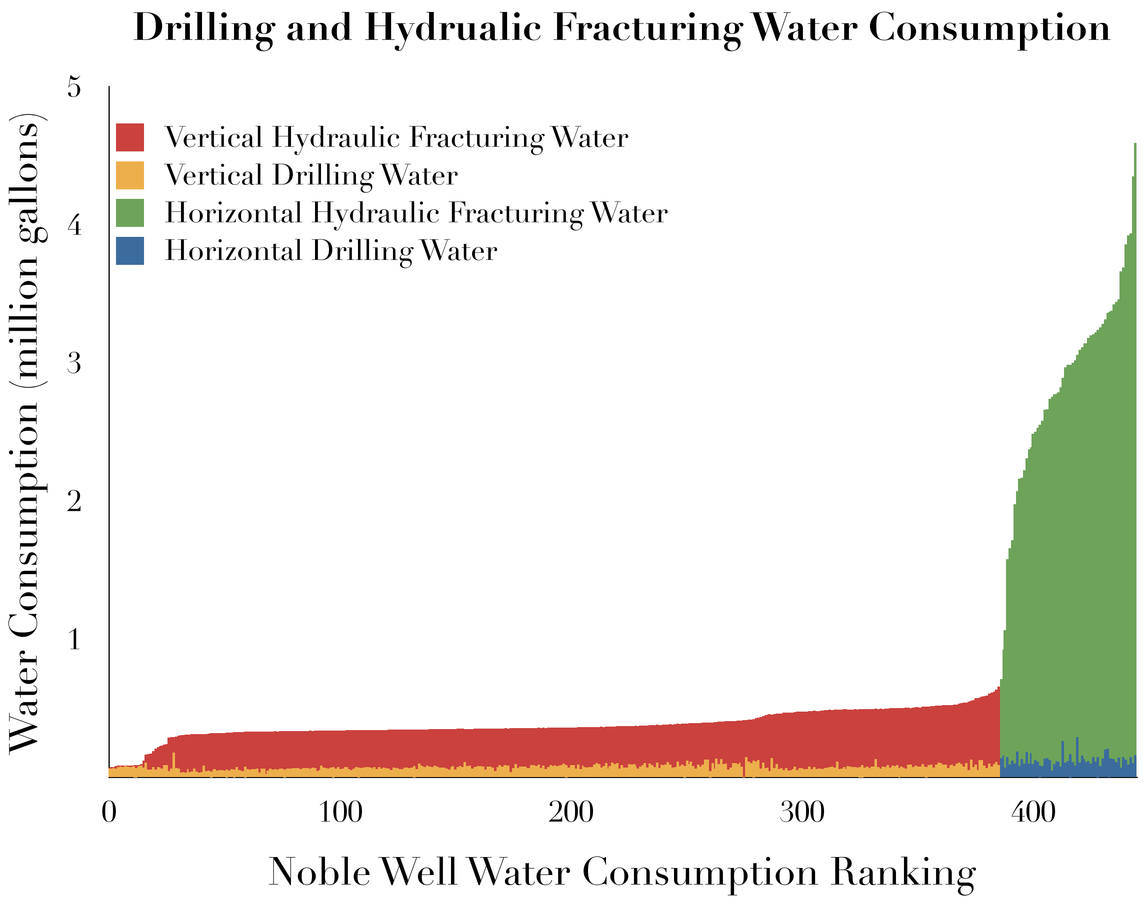

Figure 3.1: The total water consumed per well, represented as individual bars, and separated by water use.

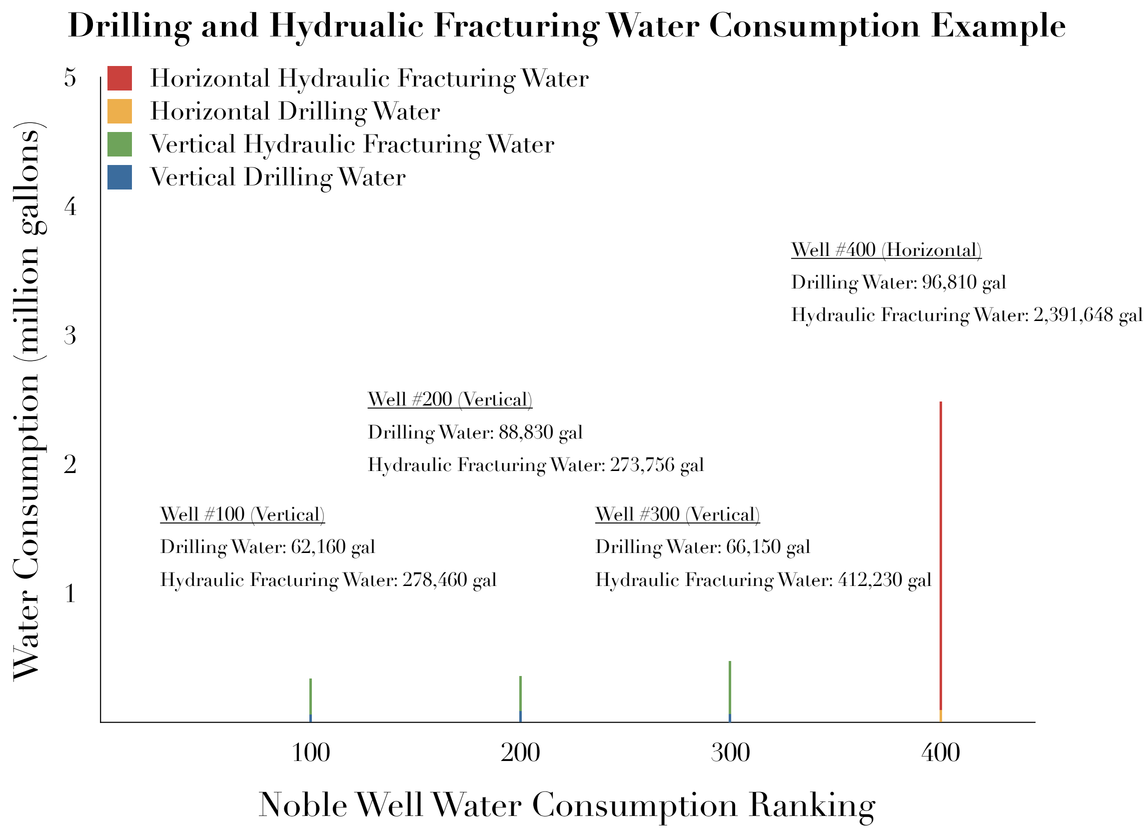

Figure 3.2: An example of the water consumption of four wells to illustrate how Figure 3.1 is constructed.

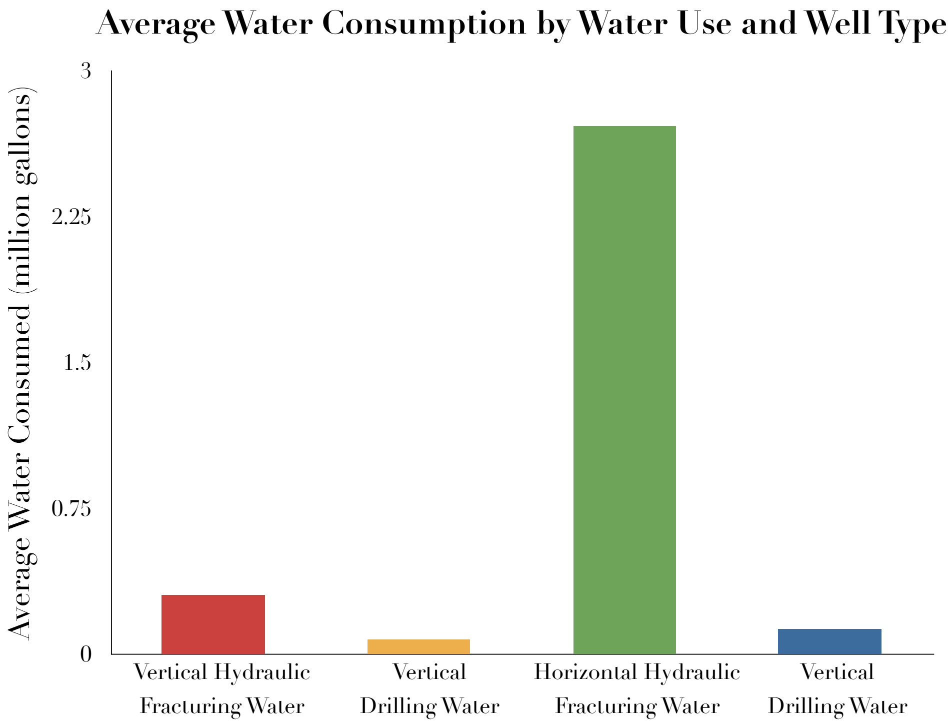

Figure 3.3: Average water consumption of 2010 and 2011 Noble Energy wells in the Wattenberg Field.

The water consumption for each well type and water use are summarized in Table 3.1.

Table 3.1: Average water consumption of 2010 and 2011 Noble Energy wells in the Wattenberg Field

	Drilling Water	Hydraulic Fracturing Water	Total Water
(thousand gallons)			
Horizontal Well	130	2,700	2,800
Vertical Well	77	310	380

Water consumption of horizontal wells appears to be significantly higher for horizontal wells; however, significantly fewer horizontal wells have been drilled. As the number of horizontal wells drilled increases the water requirements may change. An increased drilling distance and number of frac stages was thought to contribute to increased water requirements. To explore this, a subset of wells was chosen to determine if the additional water consumption was a result of the increased drilling distance, or measured distance. The water consumed was plotted as a function of measured wellbore depth. The measured wellbore depth is the length of the wellbore, as if determined by a measuring stick. Figure 3.4 shows that horizontal wells have much longer measured wellbore depths, but no clear correlation with water consumption. A scatter plot of the true vertical depth and water consumption is also shown in Figure 3.5. True vertical depth is the vertical distance from the bottom of the well to the surface. Vertical and horizontal wells had similar true vertical depths, but also showed no clear correlation with the water consumption.

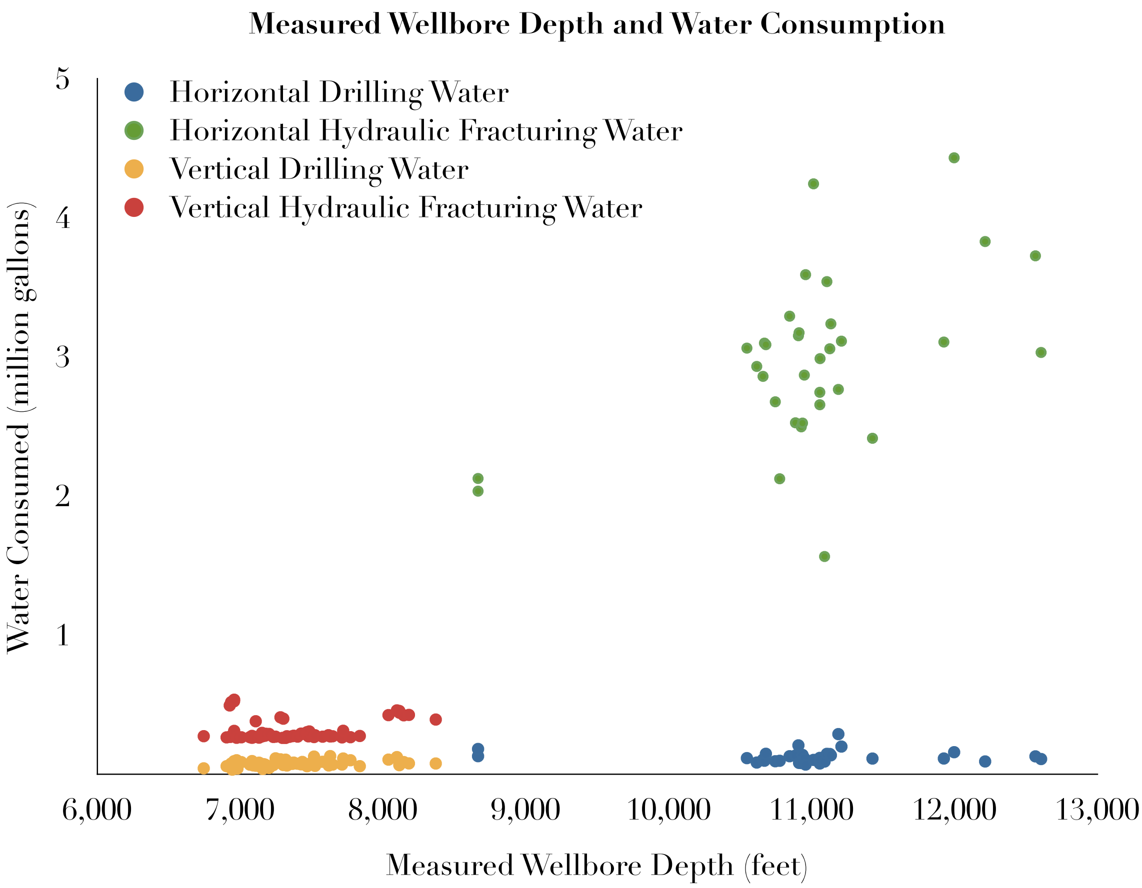

Figure 3.4: Water consumption as a function of the measured well bore depth for a subset of the sampled wells.

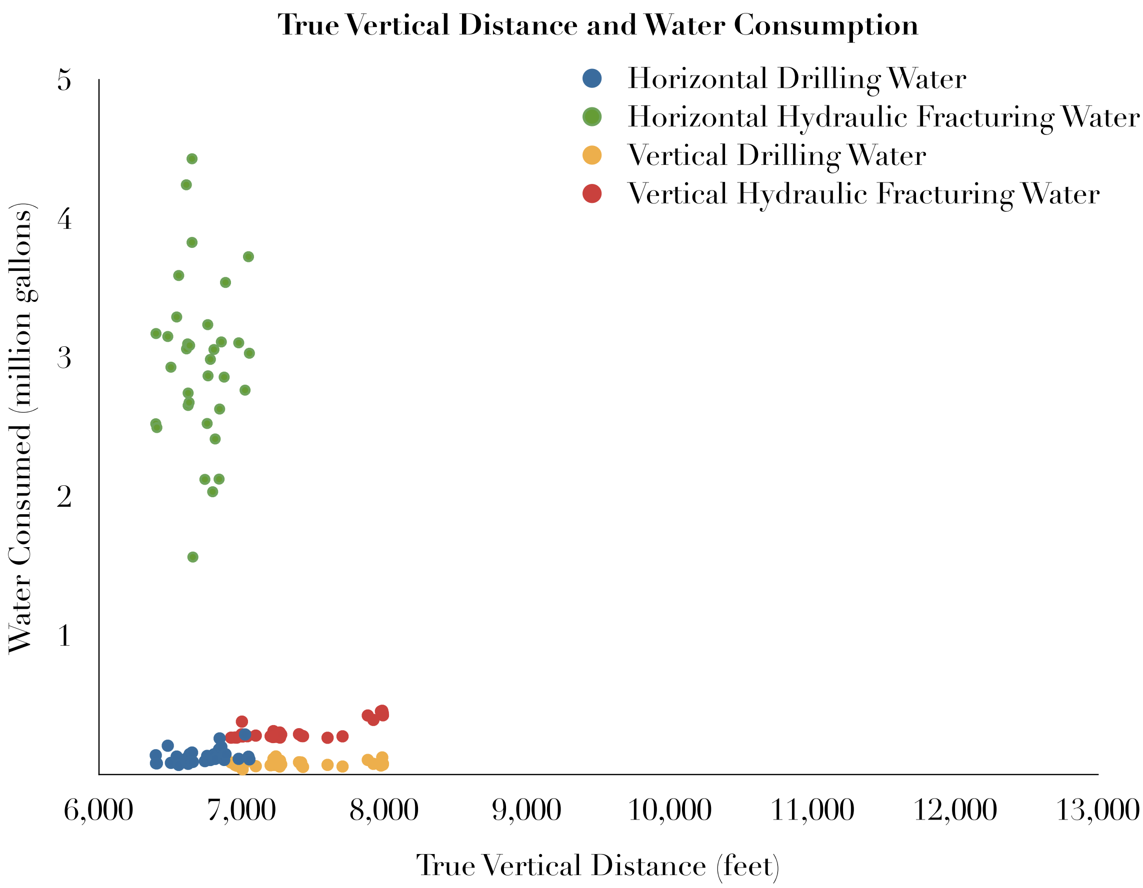

Figure 3.5: Water consumption as a function of the true vertical distance for a subset of the sampled wells.

Chapter 4

Ultimate Energy Recovery

4.1 EUR for Noble Energy Wells

Daily oil and gas production data was collected for the same set of 445 wells using Noble Energy's Carte® program, in the Wattenberg field. Future production was estimated using hyperbolic decline curves and integrated to determine the EUR. The total energy recovered for each well is ordered from least to greatest in Figures 4.1 and 4.2. The low (exponential decline curve) and high (harmonic decline curve) production scenarios are shown in Figure 4.1. The two curves were used to bound possible production scenarios and provide a basic sensitivity analysis. An average of the two production scenarios is shown in Figure 4.2. Each well is represented by an individual vertical bar as described in Chapter 3. The EUR categorized by estimated ultimate oil and gas recovery and well type is shown in Figure 4.3

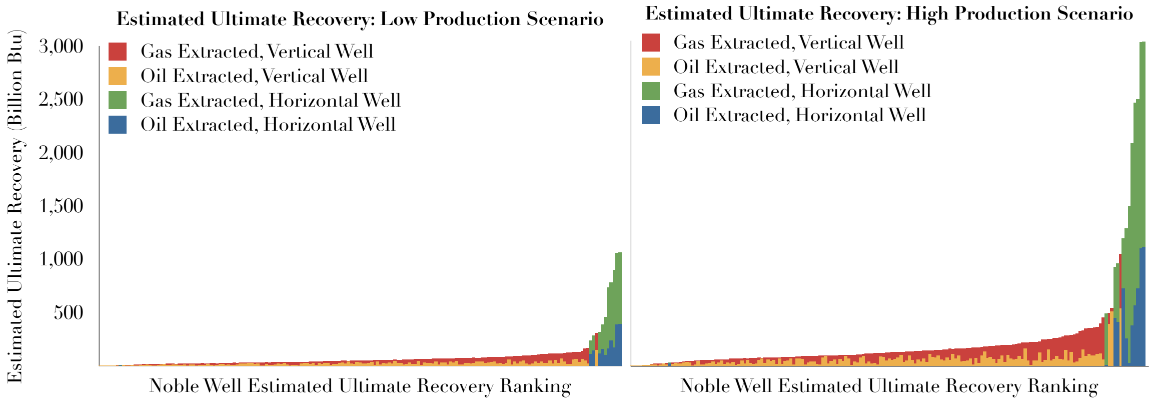

Figure 4.1: The estimated ultimate recovery for each well, represented by each vertical bar, for the low and high production scenarios and separated by energy source recovered and well type.

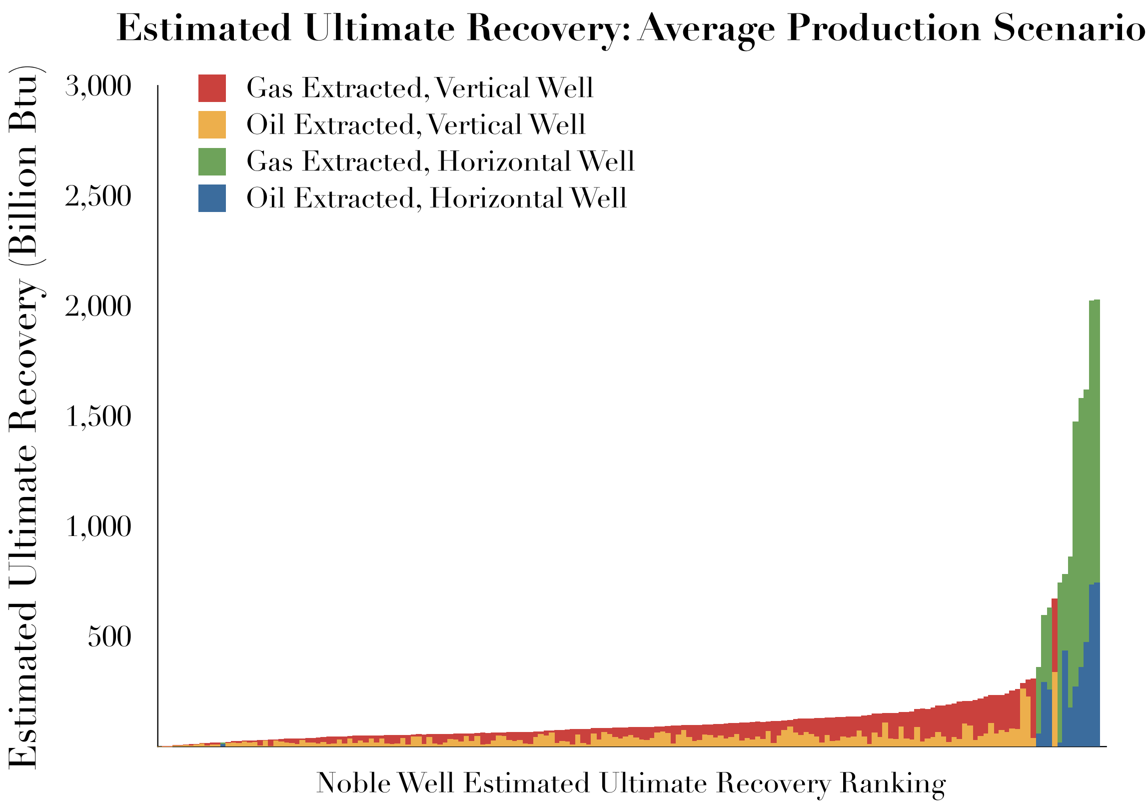

Figure 4.2: The estimated ultimate recovery for each well for the average production scenario.

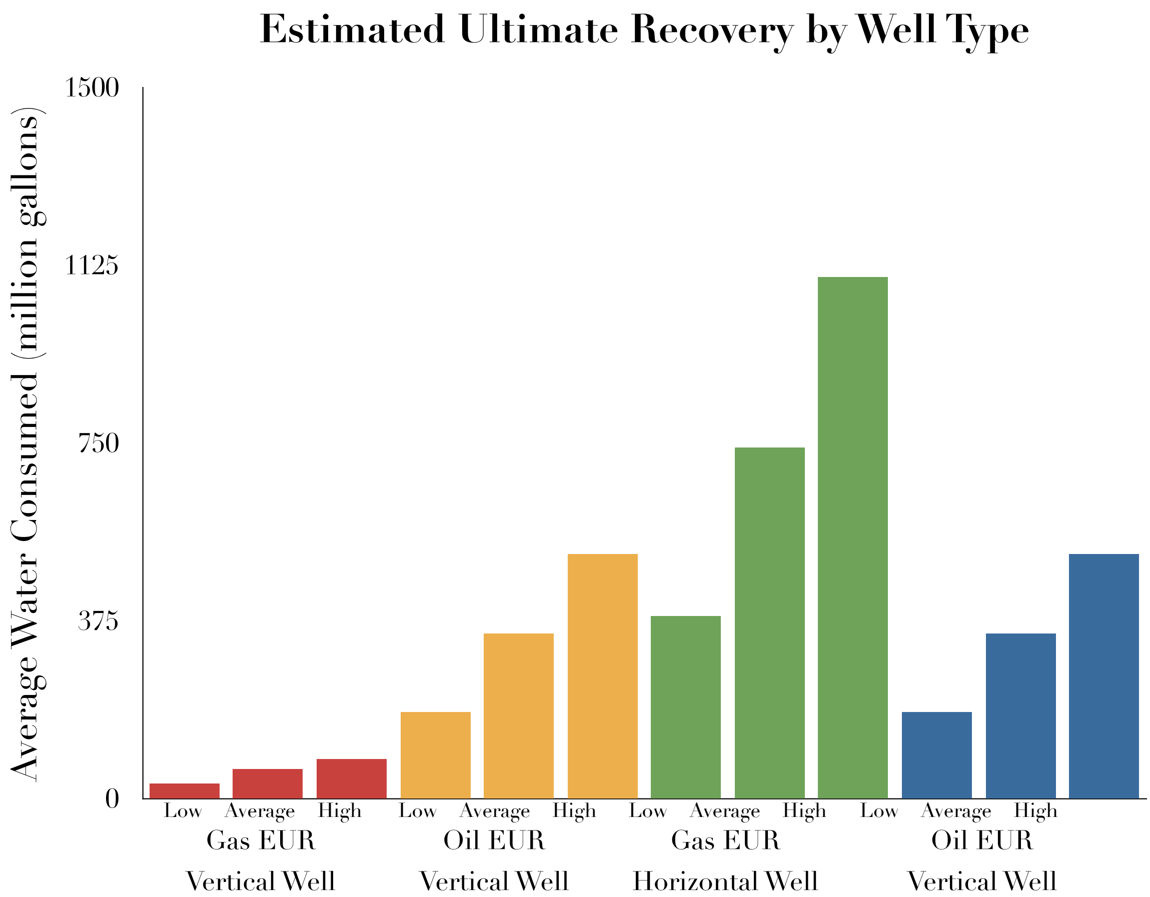

Figure 4.3: The average estimated ultimate recovered at each well separated by well type.

A summary of the estimated ultimate recovery for each production scenario and well type is shown in Table 4.1 and 4.2 for vertical and horizontal wells, respectively.

Table 4.1: Ultimate recovery estimates for vertical wells

(Vertical Wells: Estimated Ultimate Recovery (Billion Btu)			
	Low Production Scenario	Average Production Scenario	High Production Scenario
Oil	24	42	60
Gas	32	62	84
Total	56	100	150

Table 4.2: Ultimate recovery estimates for horizontal wells

(Horizontal Wells: Estimated Ultimate Recovery (Billion Btu)			
	Low Production Scenario	Average Production Scenario	High Production Scenario
Oil	180	350	520
Gas	390	740	1,100
Total	570	1,100	1,600

The estimated recovery from horizontal wells is nearly ten times higher than vertical wells. The ratio of oil and gas is similar for both vertical and horizontal wells.

Chapter 5

Water Intensity

5.1 Noble Well Water Intensity

A ratio of the total water consumed and the total estimated energy recovered is used to determine the water intensity, as described in Eq-4 of Chapter 1, for Noble Energy oil and gas production in the Wattenberg. The low, average, and high production scenarios are used to calculate the three separate water intensity values for each individual well. The water intensities are ordered from least to greatest and represented by each individual vertical bar in the chart. The high and low production scenarios are presented in Figure 5.1 and the average production scenario is presented in Figure 5.2.

The water intensity for Noble Energy wells in the Wattenberg is summarized in Table 5.1. The average values are presented along with a one standard deviation error.

Table 5.1: Water Intensity Estimate (gal/MMBtu)

	Low Production Scenario	Average Production Scenario	High Production Scenario
Horizontal	9.7	4.3	2.9
Vertical	14	6.9	5.4

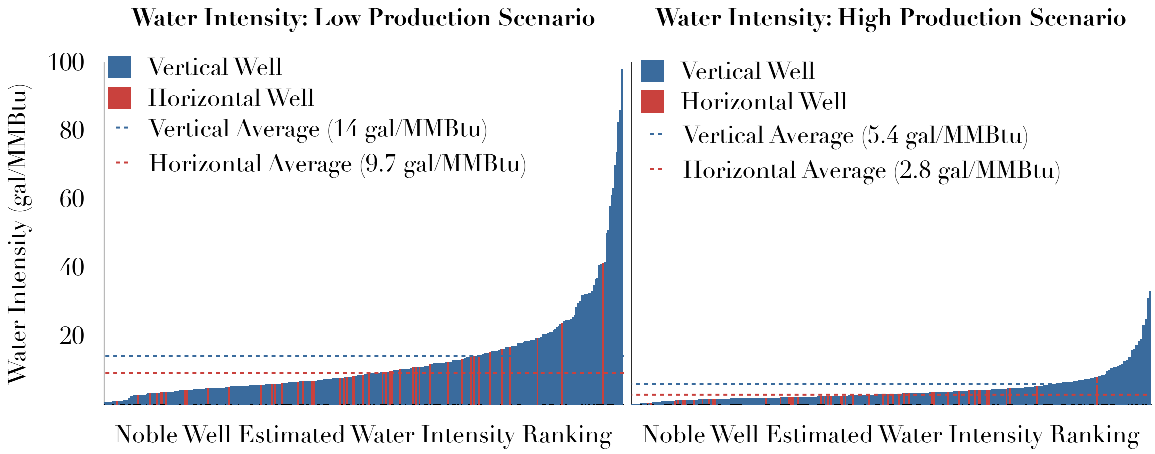

Figure 5.1: Water Intensity estimate for low and high production scenarios.

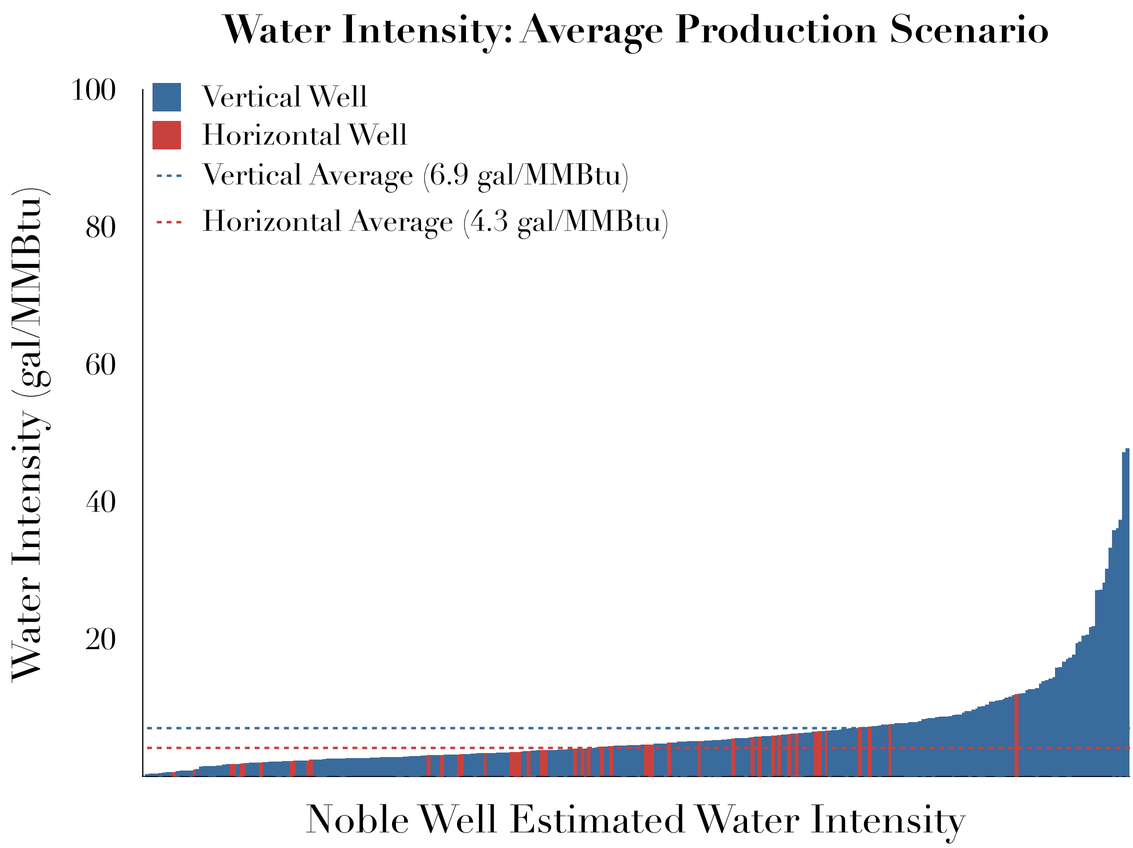

Figure 5.2: Water Intensity estimate for average production scenarios.

Chapter 6

Water Intensity Comparison by Fuel Source

A literature review was performed to compare the water intensities of a variety of fuel sources, including coal, oil, natural gas, uranium, solar, wind, biofuels, and geothermal. The water intensities are categorized by life-cycle stages (extraction, processing, transport, etc.) and end-use (electricity generation). Consumptive, withdrawn, and embedded water intensities are also presented for each life-cycle stage, if the data is available.The values and literature sources are presented in Appendices B-F.

6.1 Extraction and Processing

Water requirements for extraction and processing can vary by fuel source, as shown in Figure 6.1. An abbreviated table of consumptive water values is also shown in Table 6.1In general, water requirements for fossil fuel extraction and processing is relatively low, when compared with the water required for electricity generation from fossil fuels. Biofuels use the most water for extraction and processing, particularly when irrigation is required. Most of the water input to biofuels (71 percent) is consumed via evapotranspiration from crops and is lost to surface run-off and groundwater recharge. [15] Other renewables, such as solar and wind, do not require water in the extraction and processing life-cycle stages and are not included in Figure 6.1.

The range of consumptive water intensities required for coal, oil and natural gas is shown in Figure 6.1. The range of values is represented by the height of the box and the most commonly accepted value is represented by the point where the two boxes come together.

The water required for coal mining varies throughout the country and depends on local geology, mining methods, and water resources. The type of coal and extraction process determine the amount of water required to process the coal. Typically underground mining (approximately 65 percent of Appalachian coal mining) re-

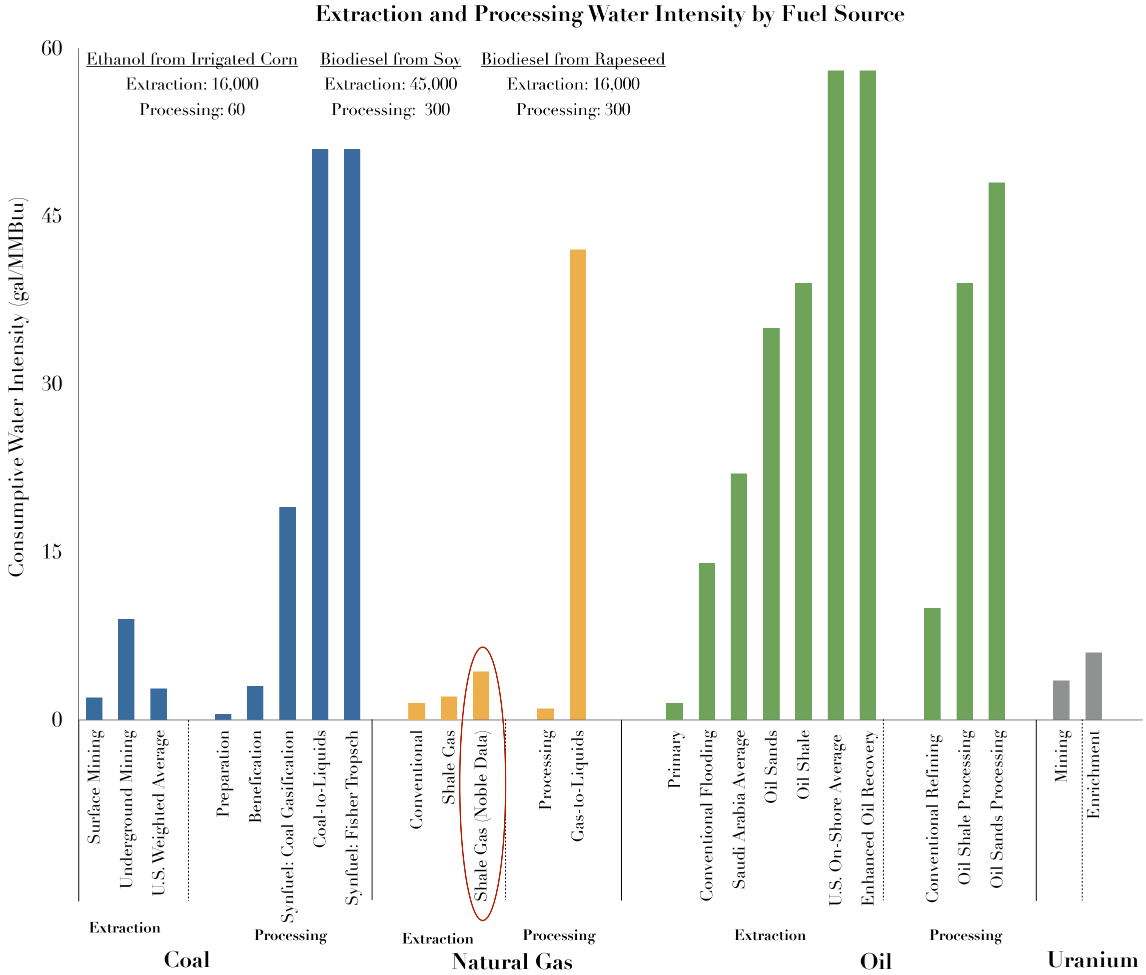

Figure 6.1: Consumptive water intensity for extraction and processing by fuel source.

quires more water than surface mining (approximately 90 percent of western coal mining). Underground mining requires one to 16 gal/MMBtu and surface mining requires one to four gal/MMBtu of consumptive water. [11] Water is required for dust suppression and hauling activities, as well as coal cutting in underground mines. [6] Water is also required for reclamation and revegetation after a mine is closed and to wash the coal to improve impurities. Removing impurities increases the heating value of the coal and reduces harmful emissions, particularly sulfur, during coal combustion. Appalachian coal generally requires additional washing to remove sulfur. Western coal requires little to no additional processing.

Water required for oil extraction and processing varies substantially depending on region, geology, recovery method, and reservoir depletion. [6] Enhanced oil recovery methods are the most water intensive methods for oil extraction and account for nearly 80 percent of the total U.S. oil production. [15]

Steam injection and CO_2 injection are the most commonly used enhanced oil recovery methods and have consumptive water intensities of 39 gal/MMBtu and 94 gal/MMBtu, respectively. The water requirements for oil sands mining ranges from 14 to 33 gal/MMBtu, depending on the solvent used to separate the bitumen

Table 6.1: An abbreviated comparison of the average consumptive water intensity for the recovery of various energy sources and the water intensity of Noble Energy wells. For a more complete summary see Appendix B-F.

Coal (gal/MMBtu)	
Surface Mining	2
Underground Mining	9
Natural Gas (gal/MMBtu)	
Conventional	1.5
Noble Data Natural Gas (gal/MMBtu)	
Vertical: Low	5.4
Vertical: Average	6.9
Vertical: High	13.6
Horizontal: Low	2.9
Horizontal: Average	4.3
Horizontal: High	9.7
Oil (gal/MMBtu)	
Primary	1.5
Conventional Flooding	14
Oil Sand	35
Oil Shale	39
Enhanced Recovery	58
Solar (gal/MMBtu)	
Photovoltaic	4
Wind (gal/MMBtu)	
Turbine	0
Biofuels (gal/MMBtu)	
Biodiesel from soy	45,000
Ethanol from irrigated corn	16,000
Biodiesel from rapeseed	16,000

from the sands. [15] Most U.S refineries have water intensities between 7.2 and 13 gal/MMBtu, depending on the refinery configuration. [15]

Conventional natural gas wells consume small amounts of water (zero to three gal/MMBtu) for drilling during the extraction phase. [6] Water consumption for shale gas extraction is front-loaded, requiring large amounts of water for drilling (70 to 800 thousand gallons) and hydraulic fracturing (1 to 6 million gallons) for extraction. However, the water intensity for the lifetime of the well is relatively low (0.8 to 9.7 gal/MMBtu). Coal bed methane has a negligible water intensity; however, production can result in substantial volumes of produced water. [15]

Uranium mining water requirements are very similar to coal mining and depend mostly on geography and mining methods. Underground mining requires approximately six gal/MMBtu and surface mining requires one gal/MMBtu. [3] Refining and enriching uranium in the U.S. has consumptive water intensities of four to eight gal/MMBtu, depending on the enrichment process. [3]

Biofuels require the largest amounts of water for extraction and processing with significant variation in water intensities depending on geography and associated irrigation requirements. [34] For example, in one study [34] corn ethanol grown in Indiana was reported to have a water intensity of 83 gal/MMBtu and corn ethanol grown in Kansas was reported to have a water intensity of 3,805 gal/MMBtu. [15] However, a more detailed study estimated that the water intensity of biofuels has a range of 2,500 to 29,000 gal/MMBtu. [6]

6.2 Electricity Generation

Electricity generation is the single largest energy sector in the U.S. [35] Water is required to carry heat from the condenser. In 2005, thermoelectric power plants accounted for 45 percent of the freshwater withdrawals in the United States, but only three percent of the freshwater consumed. [32] As shown in Figure 6.2 and Figure 6.3, a wide range of withdrawn and consumed water intensities for electricity generation exist depending on the cooling configurations.

The cooling requirements can be divided by once-through and recirculation configurations. Once-through cooling uses withdrawn water to transfer heat and condense steam from the turbine. The water is returned to the source approximately 20^{o}F warmer. [15] Evaporation accounts for all of the consumed water in this configuration. Once-through cooling has low capital and operating costs, but can impact downstream ecosystems due to the increased temperature and is uncommon for new power plants today. [36]

Recirculating cooling configurations include closed loop or wet cooling (e.g. cooling ponds, wet tower) and dry cooling (e.g. dry cooling tower). These configurations have much lower water withdrawals than once-through cooling, as shown in Figure 6.3, but have often higher consumptive water requirements as shown in Figure 6.2. Dry cooling is the least water intensive, but it is also the most expensive. One study estimates dry cooling to be nearly ten times more expensive than once-through cooling. [36] Closed-loop cooling has become the most common configuration for modern power plants. Low water withdrawals are required, but more water is consumed than a once-through configuration.

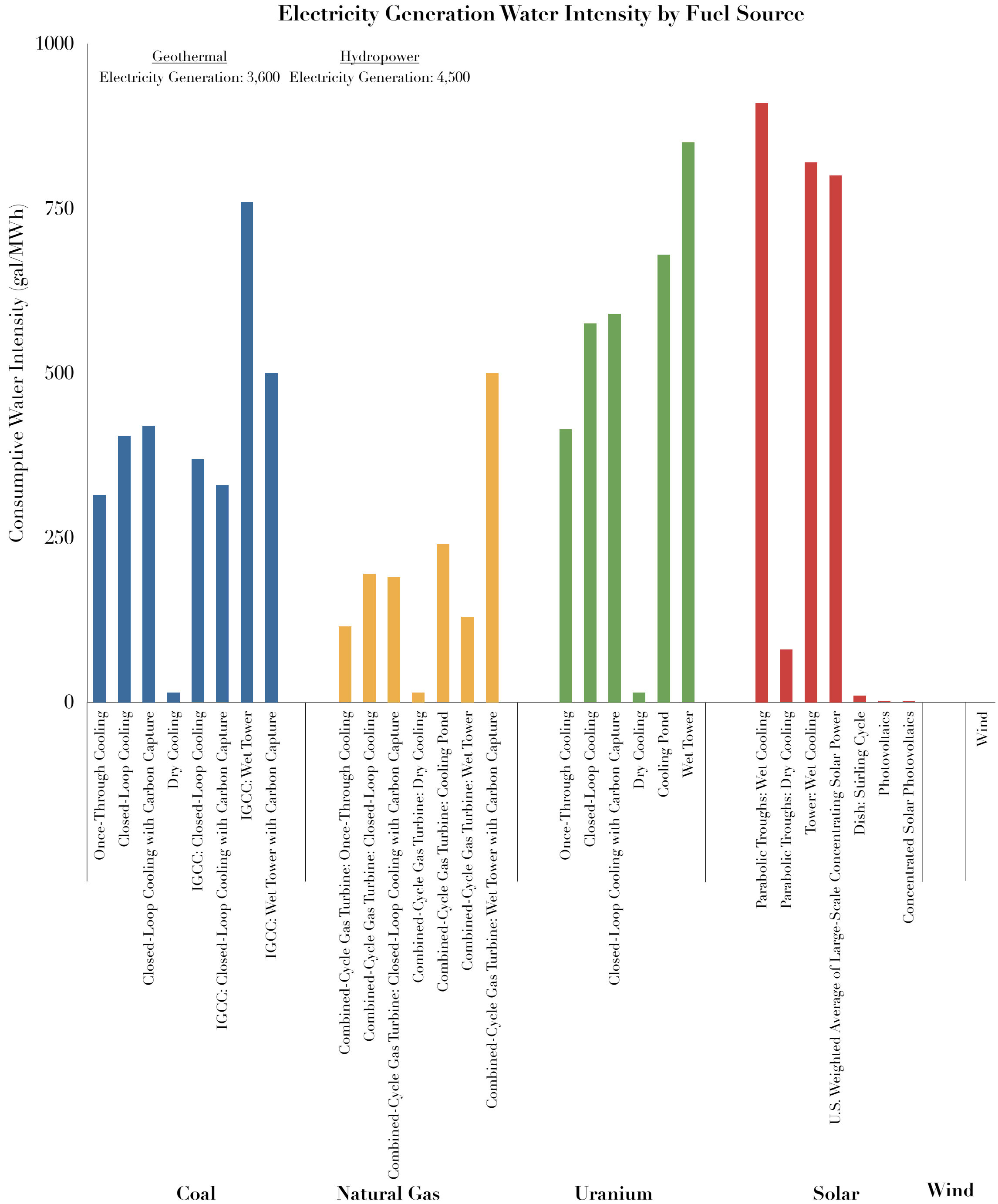

Figure 6.2: Consumptive water intensity for electricity generation separated by fuel source.

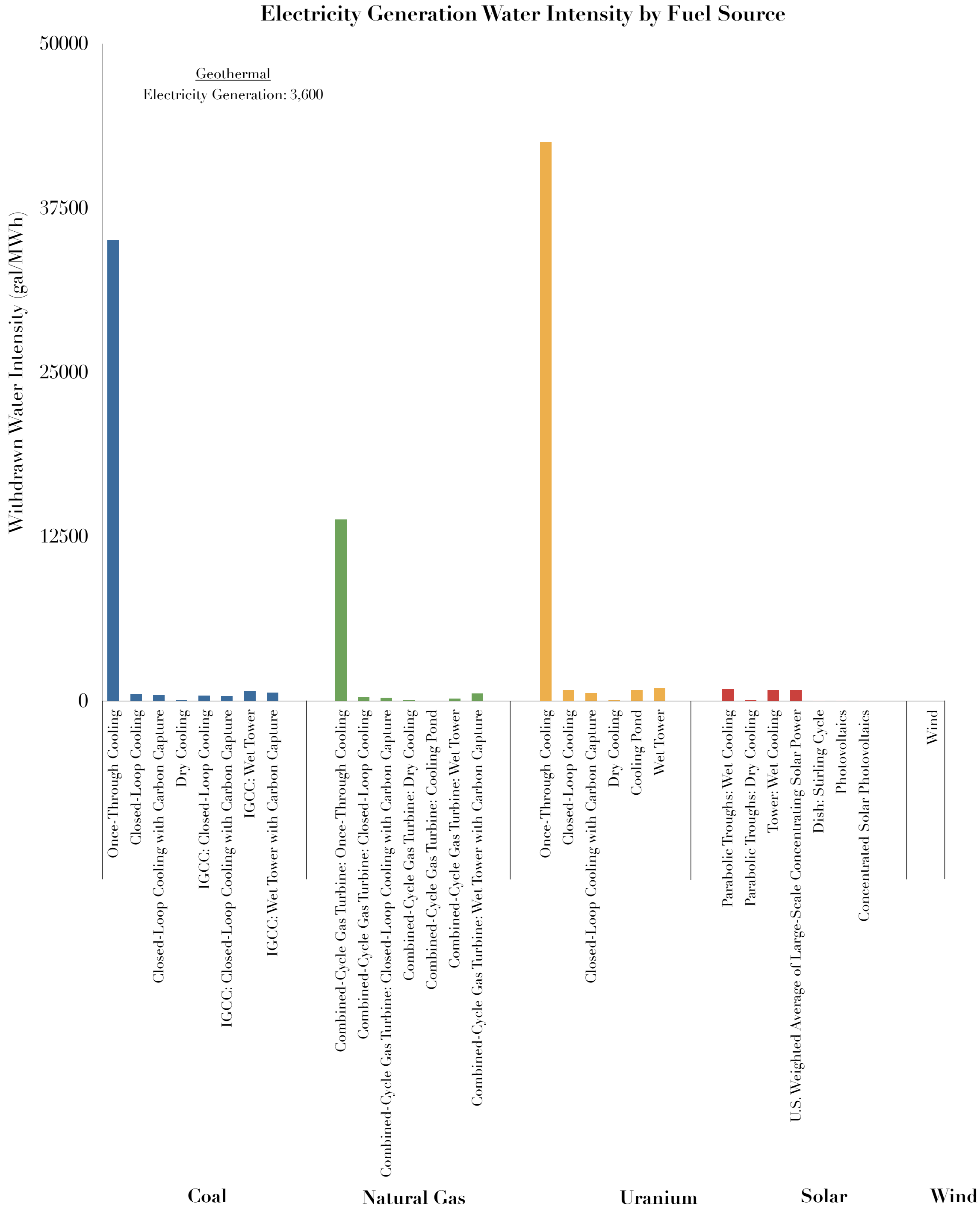

Figure 6.3: Withdrawn water intensity for electricity generation separated by fuel source.

Chapter 7

Conclusion

Efficient use of water, particularly in the Western U.S., is an increasingly important aspect of many activities including agriculture, urban and industry. As population continues to increase and agriculture and energy needs continue to increase, the pressure on water and other natural resources is expected to intensify. Recent technological advances have stimulated growth in oil and gas development and operations, as well as increasing the industry's need for water resources.

This study has provided an analysis of how efficiently water resources are used for unconventional shale gas and shale oil development and compared the efficiency with other energy sources including coal, natural gas, oil, and renewable energy sources. A general materials balance was used to assess the lifecycle of water and energy resources of Noble Energy assets in the Wattenberg field. Water use data as well as oil and gas production data was collected from Noble Energy wells and separated by well type (horizontal or vertical) and water use (drilling and hydraulic fracturing). The sample set included 445 wells operated by Noble Energy and drilled in 2010 and 2011.

Vertical and horizontal wells operated by Noble Energy in the Wattenberg during 2010 and 2011 consumed an average 380,000 and 2,800,00 gallons of water. On average, vertical wells used 77,000 gallons to drill and an additional 310,000 gallons to hydraulically fracture the well. Horizontal wells used 130,000 gallons to drill and 2,700,000 gallons to hydraulically fracture the well.

A decline curve analysis was used to estimate the ultimate recovery from each individual well. Exponential and harmonic decline curves were fit to the production data to project low and high production scenarios, respectively. Vertical wells are expected to have an estimated ultimate recovery between 24 and 60 BBtu for oil and between 32 and 84 BBtu for gas. Horizontal wells are expected to have an estimated ultimate recovery between 390 and 1,100 for gas and between 180 and 520 BBtu for oil.

A ratio of the water consumed and the estimate ultimate recovery for each well was used to estimate the water intensity of each well. Vertical and horizontal wells operated by Noble Energy in the Wattenberg during 2010 and 2011 are expected to have an average water intensity of 6.9 and 4.3 gal/MMBtu, respectively. Vertical wells have an expected water intensity ranging between 5.4 and 14 gal/MMBtu and horizontal wells have an expected water intensity between 2.9 and 9.7 gal/MMBtu.

When the water intensity of shale gas extraction was compared other energy sources it was found to be one of the lowest. Only wind (0 gal/MMBtu), solar (4 gal/MMBtu), primary oil recovery (1.5 gal/MMBtu), and conventional natural gas (1.5 gal/MMBtu) had slightly lower water intensities. Essentially all of the water required for shale gas extraction is needed to drill and hydraulically fracture the well. Horizontal wells require much more water for hydraulic fracturing than vertical wells, on average. However, the water intensity is estimated to still be slightly lower for horizontal wells because the water is used in a more efficient manner.

7.1 Future work

The general materials balance approach developed for this project is useful to understand the full life cycle of water in oil and gas development. The volume of water consumed during well drilling and completion is considered the input and will be compared to the output of produced water over the lifetime of the well. A GIS application will be developed that includes water input and a temporal relationship of water output (produced water). Water quality spatial relationships will be included in the GIS application to provide a basis for determining the potential for returning produced water to the water cycle (e.g. reused for fracturing, surface discharge, agricultural reuse).

Part of this future work will consider the energy inputs and outputs of the materials balance. The degree of water reuse and discharge for frac flowback and produced water is dependent on the water quality and level of treatment required. As quality deteriorates, the energy required to treat the water for anything more than pit evaporation or deep well injection increases. Using the general materials balance, energy and cost estimates will be developed for different levels of treatment in the Wattenberg field.

The goal of the of the GIS application is to provide a tool that can be used to estimate the cost, energy requirements and timeframe for returning an amount of water equal to that consumed to the water cycle, thus achieving full water neutrality in oil and gas operations. The value of adopting a water neutrality position in terms of public perception of water stewardship is considered to be high. Since it is possible to exceed water neutrality, produce more water for the hydrosphere than consumed, Noble Energy could be in the unique position to document a plan to positively impact the water balance in the region.

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Appendix A

Decline Curve Analysis

The Arps Equation used for the decline curves is shown below:

$$q(t) = \frac{q_i}{(1+D_i t)^{1/b}} \quad \text{where} \qquad \text{Eq-5}$$

q(t) = Future production rate
qi = Initial production rate
Di = Initial decline rate
t = Time
b = Degree of curvature

$$\text{When } b = 0 \Rightarrow \quad q(t) = q_i e^{D_i t} \qquad \text{Eq-6}$$

(Exponential Decline Curve)
(Low Production Scenario)

$$\text{When } b = 1 \Rightarrow \quad q(t) = \frac{q_i}{1+D_i t} \qquad \text{Eq-7}$$

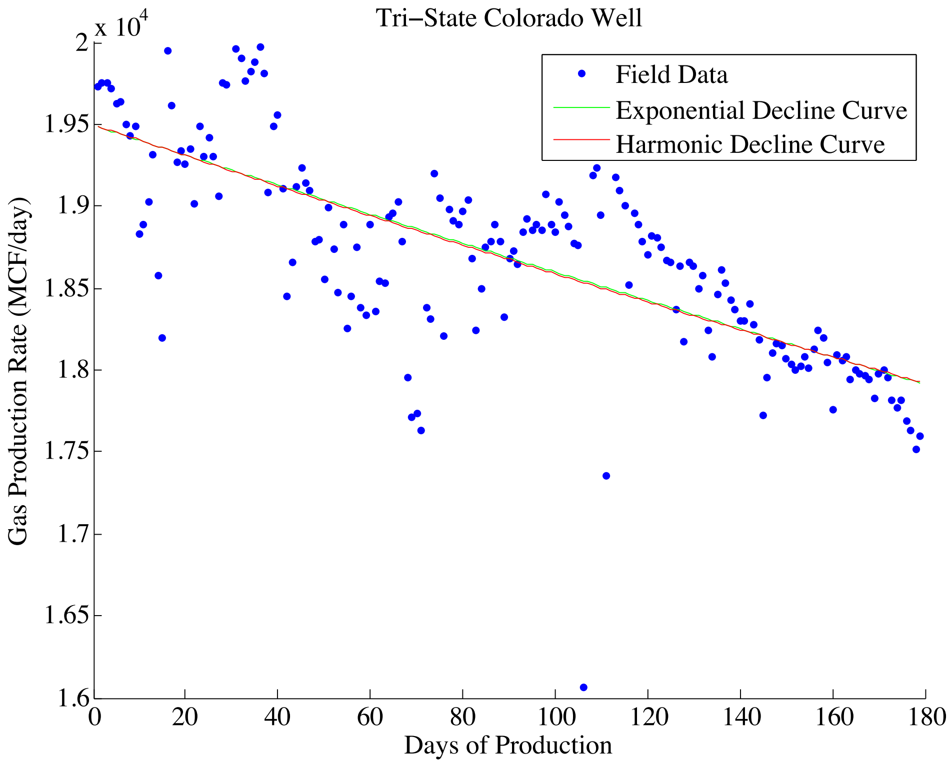
(Harmonic Decline Curve)
(High Production Scenario)

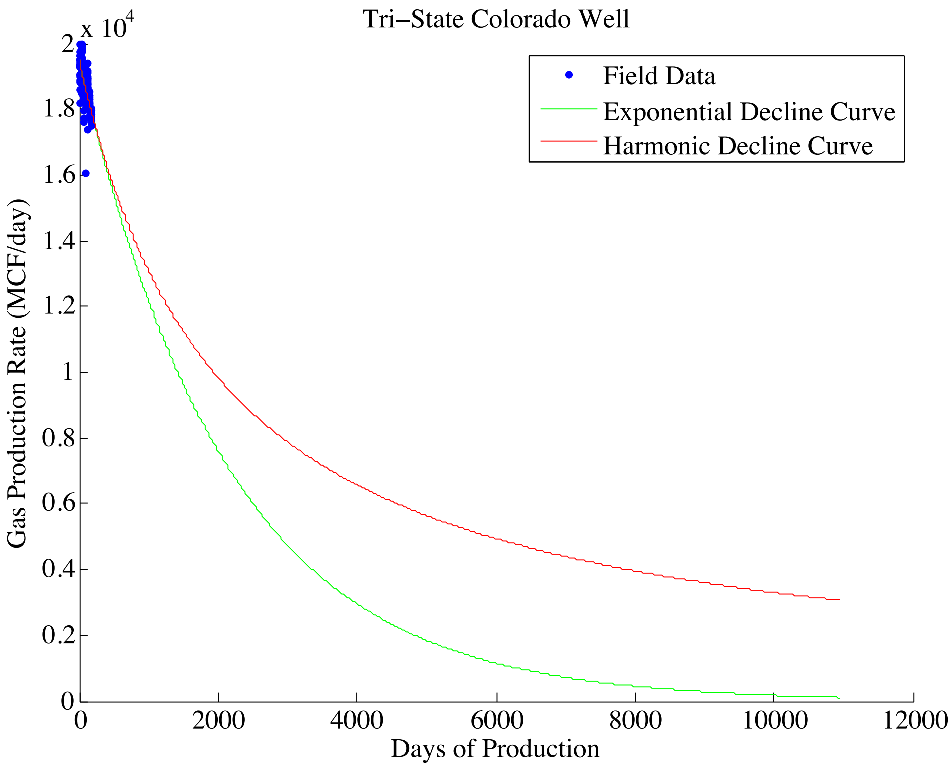
A least-squares method was used to generate the decline curves for each well. The MATLAB code used to generate, plot and integrate the decline curves is shown:

The Arps Equation used for the decline curves is shown below:

```
clear
close all
clc

clear
close all
clc

%Oil Gas and Water Production
|

X=1:length(Y);
x=X';

%z=z';

%Least squares method to estimate exponential decay
%Y is an array of the oil or gas production each day
%x is an array of the number of days since the well was first productive.

%Plots actual data
hold on
plot(x,Y,'.')
xlabel('Days of Production')
ylabel('Gas Production Rate (MCF/day)')
title('Tri-State Colorado Well')

% %Plots exponential decline curve
z=log(Y);

a0=(sum(x.^2)*sum(z)-x'*z*sum(x))/(length(x)*sum(x.^2)-sum(x)^2);
a1=(length(x)*x'*z-sum(x)*sum(z))/(length(x)*sum(x.^2)-sum(x)^2);

b=exp(a0);
a=a1;
x=1:10950;
x=x';
pe=b*exp(a*x);
plot(x,pe,'green')

X=1:length(Y);
x=X';

%Plots projected harmonic decline curve
z=1./(Y);

a0=(sum(x.^2)*sum(z)-x'*z*sum(x))/(length(x)*sum(x.^2)-sum(x)^2);
a1=(length(x)*x'*z-sum(x)*sum(z))/(length(x)*sum(x.^2)-sum(x)^2);

b=1/a0;
a=a1/a0;
x=1:10950;
x=x';
ph=b./(1+a*x);
plot(x,ph,'red')
legend('Field Data','Exponential Decline Curve','Harmonic Decline Curve')
%
% %Uses trapezoidal integration to estimate ultiamate recovery
EUR_exp=trapz(x,pe)
%BOE_exp=EUR_exp*10^3/6000

EUR_har=trapz(x,ph)
%BOE_har=EUR_har*10^3/6000
```

Decline Curve Analysis





Appendix B

Coal Water Intensity

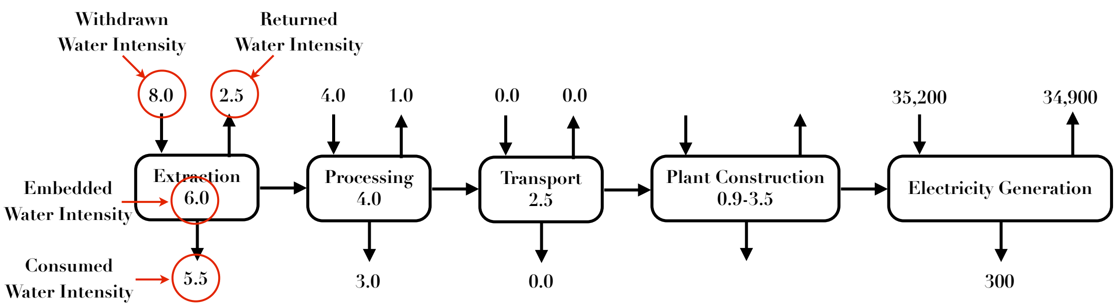


Figure B.1: Water intensity associated with each stage of electricity generation from coal.

Table B.1: Consumptive water intensity of coal extraction

Coal Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Reclamation	0.014	[29]
Dust Suppression	0.46	[29]
Underground Appalachian Mining	1	[6, 15]
Surface Mining: Low	1	[3, 5, 37]
Western Surface Mining	2	[6, 15]
Surface Mining: Average	2	[3, 5, 37]
Underground Mining: Low	1	[3, 5, 37]
U.S. Mining Weighted Average	2	[6, 15]
Surface Mining: High	4	[3, 5, 37]
Underground Mining: Average	9	[3, 5, 37]
Underground Mining: High	16	[3, 5, 37]

Table B.2: Withdrawn water intensity of coal extraction

Coal Extraction	Withdrawn Water Intensity (gal/MMBtu)	Source
Eastern Surface Mining	3	[5, 37]
U.S. Coal Mining	8	[3, 5, 35]
Eastern Underground Mining	15	[5, 37]

Table B.3: Embedded water intensity of coal extraction

Coal Extraction	Embedded Water Intensity (gal/MMBtu)	Source
Western Surface Mining	1	[5]
Eastern Surface Mining	11	[5]
Eastern Underground Mining	39	[5]

Table B.4: Consumptive water intensity of coal processing

Coal Processing	Consumptive Water Intensity (gal/MMBtu)	Source
Coal Preparation	0.26	[29]
Washing: Low	2.3	[5, 11]
Benefication: Low	3.3	[5, 37]
Benefication: Average	3.4	[5, 37]
Benefication: High	3.5	[5, 37]
Washing: Average	3.6	[5, 37]
Washing: High	5.0	[5, 37]
Coal Gasification or Liquefacation	10	[29]
Synfuel Coal Gasification: Low	11	[6, 30]
Synfuel Coal Gasification: Average	19	[6, 30]
Synfuel Coal Gasification: High	26	[6, 30]
Coal-to-Liquids:Low	41	[6, 30]
Coal-to-Liquids:Average	51	[6, 30]
Coal-to-Liquids: High	60	[6, 30]

Table B.5: Withdrawn water intensity of coal processing

Coal Processing	Withdrawn Water Intensity (gal/MMBtu)	Source
Benefication	>3.5	[5, 37]

Table B.6: Embedded water intensity of coal processing

Coal Processing	Embedded Water Intensity (gal/MMBtu)	Source
Benefication	4.1	[5]

Table B.7: Consumptive water intensity of coal transport

Coal Transport	Consumptive Water Intensity (gal/MMBtu)	Source
Slurry Pipeline, 70 Percent Recycling: Low	3.3	[6, 15]
Slurry Pipeline, 70 Percent Recycling: Average	5.5	[6, 15]
Slurry Pipeline, 70 Percent Recycling: High	7.2	[6, 15]
Slurry Pipeline, No Recycling: Low	11	[6, 15, 30]
Slurry Pipeline, No Recycling: Average	18	[6, 15, 30]
Slurry Pipeline, No Recycling: High	24	[6, 15, 30]
Slurry Pipeline: Low	33	[3, 5, 37]
Slurry Pipeline: Average	50	[3, 5, 37]
Slurry Pipeline: High	67	[3, 5, 37]

Table B.8: Withdrawn water intensity of coal transport

Coal Transport	Withdrawn Water Intensity (gal/MMBtu)	Source
Slurry Pipeline	35	[3, 5, 37]

Table B.9: Embedded water intensity of coal transport

Coal Transport	Embedded Water Intensity (gal/MMBtu)	Source
Train: Low	2	[5]
Train: Average	2.5	[5]
Train: High	3	[5]
Slurry Pipeline	240	[5]

Table B.10: Embedded water intensity of coal-fired power plant construction

Coal Plant Construction	Embedded Water Intensity (gal/MMBtu)	Source
Low	0.9	[5]
Average	2.2	[5]
High	3.5	[5]

Table B.11: Consumptive water intensity of coal-fired power plant electricity generation

Coal Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	0	[6, 15, 20]
Dry: Average	15	[6, 15, 20]
Dry: High	30	[6, 15, 20]
Cooling Pond, Supercritical	64	[5, 10]
Once-Through, Supercritical	120	[5, 10]
Once-Through, Subcritical	140	[5, 10]
Once-Through, Fluidized Bed	250	[5, 10]
Wet Tower, Supercritical	250	[3, 5]
Cooling Pond: Low	260	[5, 10]
Once-Through: Low	300	[6, 15, 20]
Closed-Loop: Low	300	[6, 15, 20]
Once-Through: Low	300	[5, 36]
Once-Through: Average	300	[5, 36]
Once-Through: High	300	[5, 36]
Once-Through: Average	315	[6, 15, 20, 21, 30, 38]
Once-Through	320	[3, 5]
Once-Through: High	330	[6, 15, 20]
Wet Tower, Retrofitted with Carbon Capture	340	[5, 39]
Cooling Pond: Average	380	[5, 36]
Closed-Loop: Average	405	[6, 15, 20, 21, 30, 38]
Closed-Loop with Carbon Capture	420	[21, 30]
Wet Tower: Low	450	[5, 36]
Wet Tower, Subcritical	460	[5, 10]
Wet Tower: Average	480	[5, 36]
Cooling Pond: High	500	[5, 36]
Wet Tower: High	500	[5, 36]
Wet Tower, Western U.S.	500	[5, 37]
Closed-Loop: High	510	[6, 15, 20]
Wet Tower, Supercritical	600	[5, 40]
Wet Tower, Subcritical	680	[5, 40]
Wet Tower, Eastern U.S.	740	[5, 37]
Cooling Pond, Subcritical	800	[5, 10]
Wet Tower	820	[3, 5]
Wet Tower, Supercritical	1000	[5, 41]
Wet Tower, Subcritical	1200	[5, 41]
Wet Tower, Supercritical with Carbon Capture	1200	[5, 40]
Wet Tower, Subcritical with Carbon Capture	1330	[5, 40]

Table B.12: Withdrawn water intensity of coal-fired power plant electricity generation

Coal Electricity Generation	Withdrawn Water Intensity (gal/MWh)	Source
Dry: Average	30	[6, 15, 20]
Dry: High	30	[6, 15, 20]
Dry: Low	30	[6, 15, 20]
Wet Tower, Subcritical	230	[5, 10]
Cooling Pond: Low	290	[5, 36]
Closed-Loop: Low	330	[6, 15, 20]
Cooling Pond: Average	450	[5, 36]
Closed-Loop: Average	480	[6, 15, 20, 21, 30, 38]
Wet Tower: Low	5000	[5, 36]
Wet Tower: Average	5600	[5, 36]
Closed-Loop with Carbon Capture	563	[21, 30]
Wet Tower, Supercritical	600	[5, 40]
Cooling Pond: High	610	[5, 40]
Wet Tower: High	610	[5, 40]
Closed-Loop: High	630	[6, 15, 20]
Wet Tower, Supercritical	660	[5, 10]
Wet Tower, Subcritical	690	[5, 40]
Wet Tower, Supercritical	1000	[5, 41]
Wet Tower, Subcritical	1200	[5, 41]
Wet Tower, Supercritical with Carbon Capture	1300	[5, 40]
Wet Tower, Subcritical with Carbon Capture	1500	[5, 40]
Wet Tower, Retrofitted with Carbon Capture	9500	[5, 39]
Cooling Pond, Supercritical	15100	[5, 10]
Cooling Pond, Subcritical	17900	[5, 10]
Once-Through: Low	20030	[6, 15, 20]
Once-Through: Low	20100	[5, 36]
Once-Through, Supercritical	22700	[5, 10]
Once-Through, Subcritical	27300	[5, 10]
Once-Through: Average	35030	[6, 15, 20, 21, 30, 38]
Once-Through: Average	35200	[5, 36]
Once-Through: High	50030	[6, 15, 20]
Once-Through: High	50300	[5, 36]

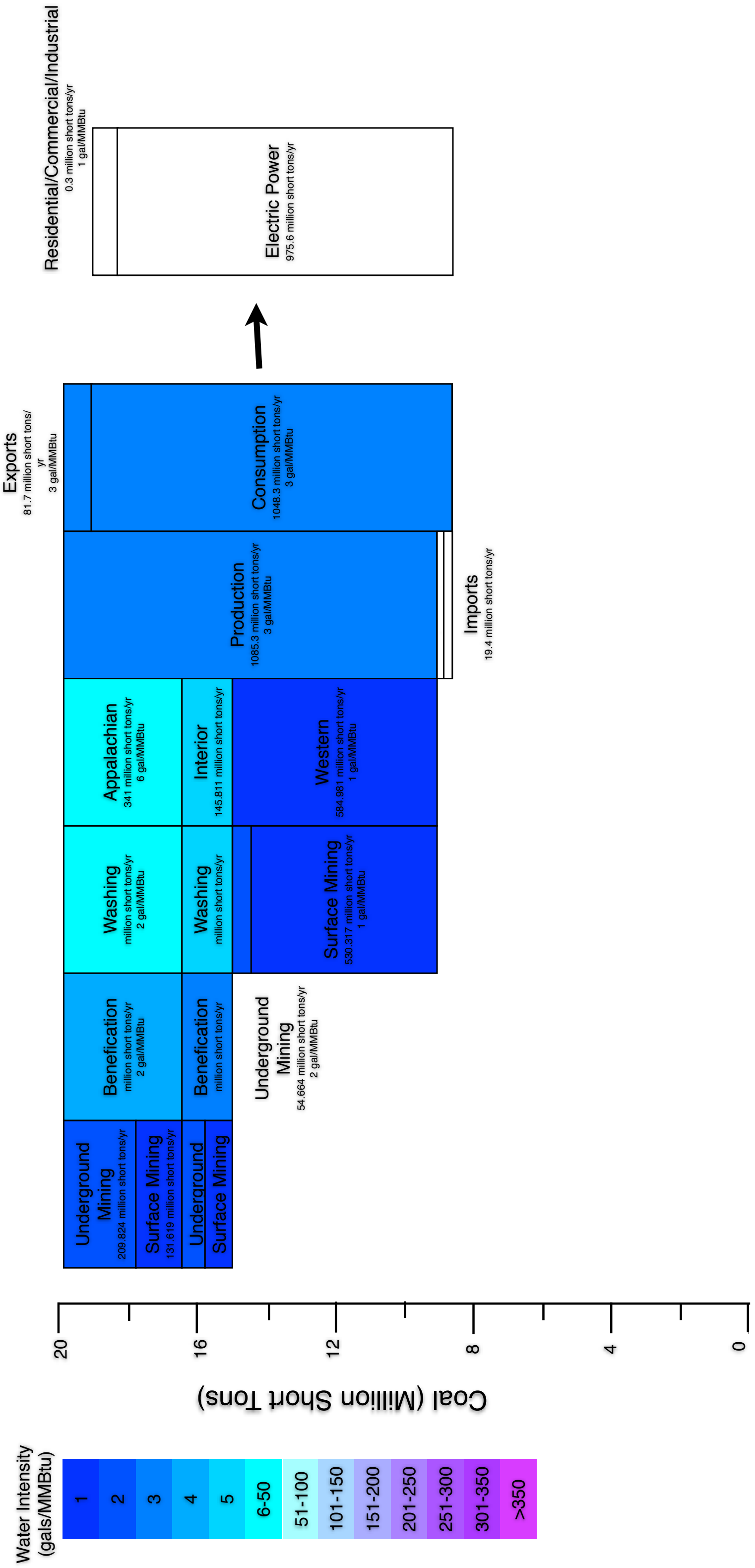


Figure B.2: Water intensity and U.S. consumption associated with each stage of electricity generation from coal.

APPENDIX C

Oil Water Intensity

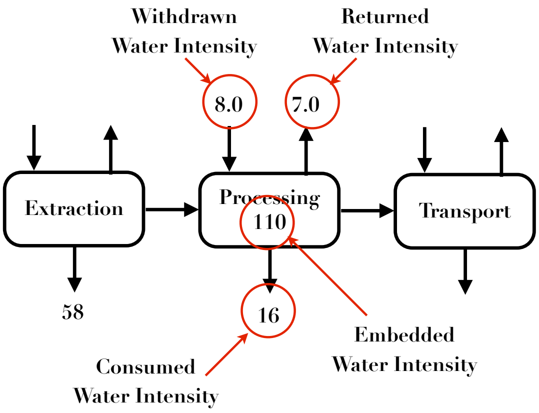


Figure C.1: Water intensity associated with each stage of crude oil production.

Table C.1: Consumptive water intensity of oil extraction

Oil Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Primary	1.4	[15, 34]
Primary	1.5	[3]
PADD II	2	[34]
PADD III	2.2	[34]
Steam-Assisted Gravity Drainage	2.2	[15, 34]
Steam Stimulation	2.5	[42]
Steam Drive	5	[42]
PADD V	5.1	[34]
In-Situ Comustion	5.5	[42]
Oil Sands: Low	7	[34]

Oil Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Upgrading to Syncrude	7.2	[15, 34]
Oil Shale: Low	7.96	[43]
Conventional: Low	8	[6, 30]
PADD I	8	[44]
PADD IV	8	[44]
Cyclic Steam Stimulation	8.7	[15, 34]
SAGD with Upgrade	9.4	[15, 34]
Saudi Arabia: Low	10	[15, 34]
Saudi Arabia: Ghawar Field	10	[34, 45]
Micellar Polymer Injection	11	[42]
CO2 Miscible Flooding	13	[42]
Oil Shale: Average	13.61	[43]
Conventional: Average	14	[6, 30]
Forward Combustion/Air Injection	14	[3, 15, 34]
Oil Sands: Low	14	[15, 34]
CSS with Upgrade	164	[15, 34]
Bitumen Oil Sands via Surface Mining	16	[34, 46]
Oil Shale: High	19.25	[43]
Conventional: High	20	[6, 30]
Oil Sands: Average	20	[34]
Enhanced Oil Recovery: Low	21	[6, 30]
Saudi Arabia: Average	22	[34]
Oil Shale: Low	22	[30]
Oil Sands: Average	24	[15, 34]
Oil Sands: Low	27	[30]
Caustic Injection	28	[15, 34]
Surface Mining (Athabasca)	28	[34]
Bitumen Oil Sands via Surface Mining	29	[34, 47]
Upgrading	29	[34, 47]
Caustic Flooding	30	[42]
CO2 Injection	31	[3, 34]
Saudi Arabia: High	33	[15, 34]
Saudi Arabia: North ÔAin Dar Field, 2005	33	[34]
Oil Sands: High	33	[15, 34]
Oil Sands: High	34	[34]
Bitumen Oil Sands via Surface Mining	35	[3, 34]
CSS (Cold Lake)	35	[34]
Steam Injection	39	[15, 34]
Oil Shale: Average	39	[30]
Polymer Assisted Water Flooding	40	[42]
Saudi Arabia: North ÔAin Dar Field, 1999	43	[34]

Oil Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Multi-Scheme (Peace River)	47	[34]
Oil Sands: Average	48	[15, 34, 48]
Oil Shale: High	56	[30]
2005 U.S. On-Shore Average Recovery	58	[34]
Secondary Conventional	62	[15, 34]
Enhanced Oil Recovery	62	[34]
Other	63	[15, 34]
Oil Sands: High	68	[15, 42, 48]
CO2 Injection	94	[15, 34, 42]
SAGD (Athabasca)	155	[34]
CO2 Injection	178	[42]
Micellar Polymer Injection	2485	[15, 34]
Enhanced Oil Recovery: High	2500	[6, 30]

Table C.2: Consumptive water intensity of oil processing

Oil Processing	Consumptive Water Intensity (gal/MMBtu)	Source
U.S. Refineries: Low	7.2	[3, 15, 34]
U.S. Refineries: Average	10	[15, 34]
U.S. Refineries: High	13	[15, 34]
Oil Shale Petroleum: Low	22	[30]
Oil Sands: Low	27	[30]
Oil Shale Petroleum: Average	39	[30]
Oil Sands: Average	48	[30]
Oil Shale Petroleum: High	56	[30]
Oil Sands: High	68	[30]

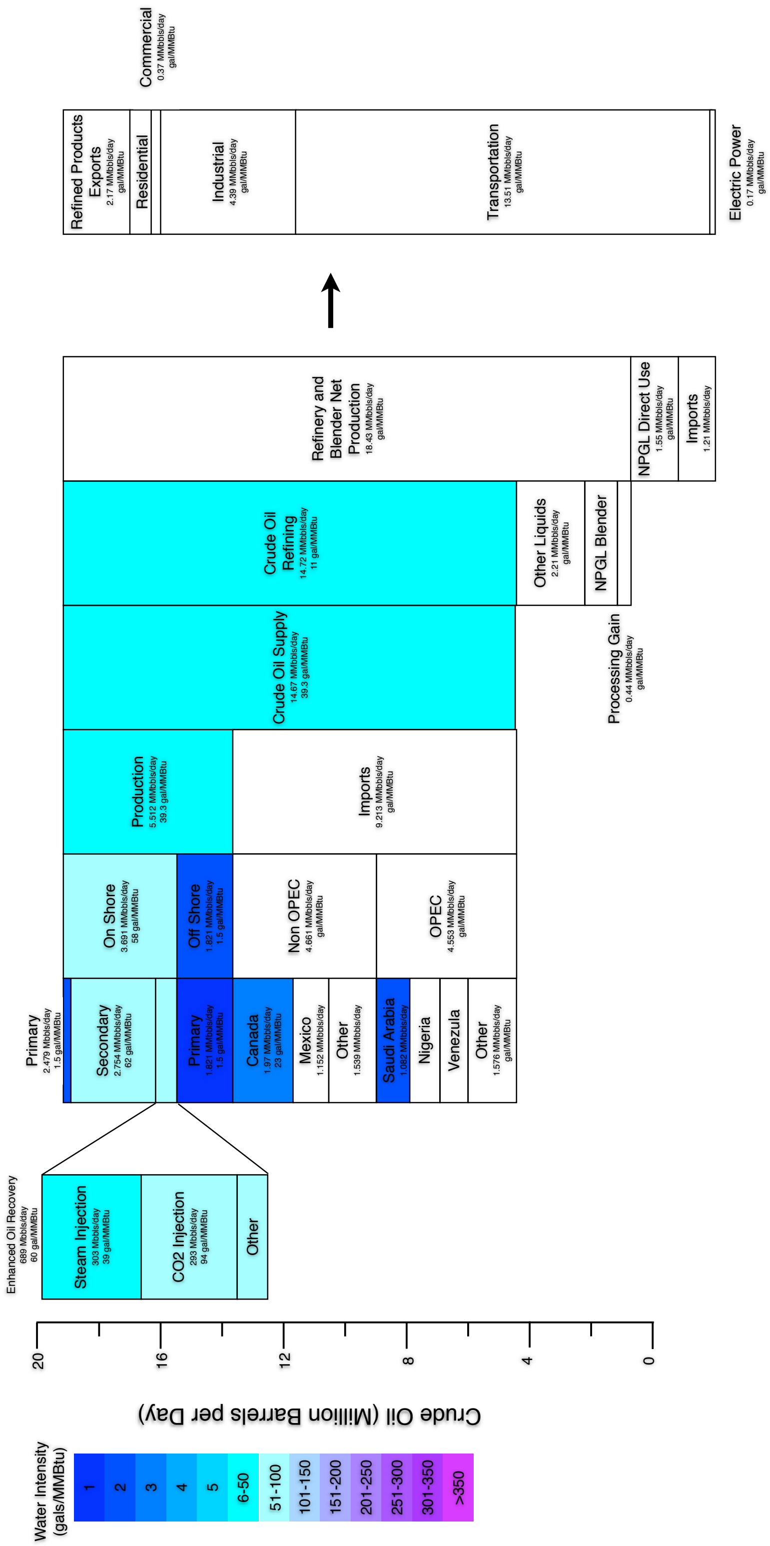


Figure C.2: Water intensity and U.S. consumption associated with each stage of U.S. crude oil production.

Appendix D

Natural Gas Water Intensity

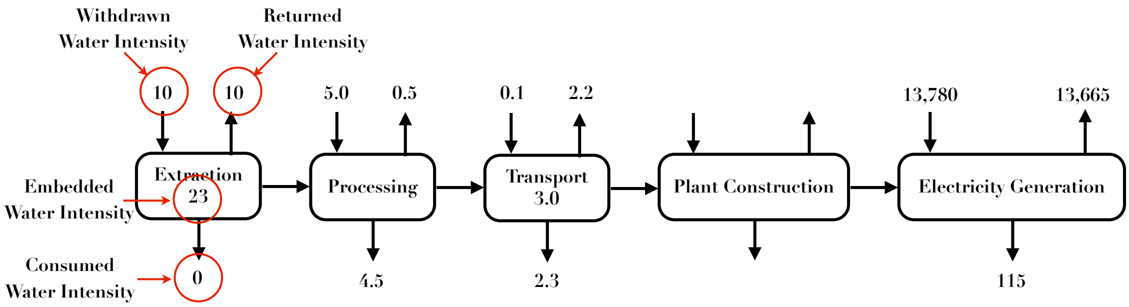


Figure D.1: Water intensity associated with each stage of electricity generation from conventional natural gas.

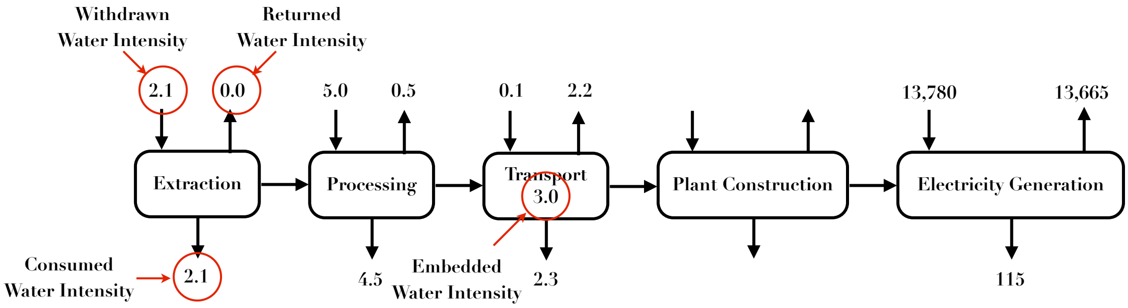


Figure D.2: Water intensity associated with each stage of electricity generation from shale natural gas.

Table D.1: Consumptive water intensity of natural gas extraction

Gas Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Conventional	0	[6, 15]
On-Shore	0	[5]
Off-Shore	0	[5]
Shale Gas: Low	0.6	[15]
Typical Minimum	0.6	[15, 30]
Haynesville	0.8	[15, 30]
Shale Gas: Low	0.84	[30]
Conventional: Low	1	[30]
Marcellus	1.2	[15]
Barnett, Vertical Wells	1.2	[15]
Marcellus	1.3	[15, 30]
Typical Maximum	1.3	[15, 30]
Barnett	1.5	[15, 30]
Fayetteville	1.7	[15, 30]
Typical Average	1.8	[15, 30]
Conventional: Average	2	[30]
Shale Gas: Average	2.08	[30]
Shale Gas: Average	2.2	[15]
Shale Gas: High	2.4	[15]
Conventional: High	3	[30]
Barnett, Horizontal Wells	3.1	[15]
Shale Gas: High	3.32	[30]

Table D.2: Withdrawn water intensity of natural gas extraction

Gas Extraction	Withdrawn Water Intensity (gal/MMBtu)	Source
On-Shore	10	[5]
Off-Shore	0	[5]

Table D.3: Embedded water intensity of natural gas extraction

Gas Extraction	Embedded Water Intensity (gal/MMBtu)	Source
On-Shore	23	[5]
Off-Shore	0	[5]

Table D.4: Consumptive water intensity of natural gas processing

Gas Processing	Consumptive Water Intensity (gal/MMBtu)	Source
Processing and Transport: Low	0	[15, 30]
Processing and Transport: Average	1	[15, 30]
Processing and Transport	2	[3, 15]
Processing and Transport: High	2	[15, 30]
Gas-to-Liquids: Low	19	[15, 49]
Gas-to-Liquids: Average	42	[15, 49]
Gas-to-Liquids: High	86	[15, 49]

Table D.5: Consumptive water intensity of natural gas transport

Gas Transport	Consumptive Water Intensity (gal/MMBtu)	Source
Transport: Low	0	[30]
Transport: Average	1	[30]
Transport: High	2	[30]
Pipeline	2.3	[5]

Table D.6: Withdrawn water intensity of natural gas transport

Gas Transport	Withdrawn Water Intensity (gal/MMBtu)	Source
Pipeline	0.1	[5]

Table D.7: Embedded water intensity of natural gas transport

Gas Transport	Embedded Water Intensity (gal/MMBtu)	Source
Pipeline	3	[5]

Table D.8: Consumptive water intensity of natural gas power plant electricity generation.

Gas Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	0	[6, 15, 20]
Combined-Cycle Gas Dry: Low	0	[6, 15, 20]
Dry: Average	15	[6, 15, 20]
Combined-Cycle Gas Dry: Average	15	[6, 15, 20]
Combined-Cycle Once-Through	20	[5, 10]
Dry: High	30	[6, 15, 20]
Combined-Cycle Gas Dry: High	30	[6, 15, 20]
Once-Through	90	[5, 10]
Combined-Cycle Gas Once-Through: Low	100	[5, 10]
Combined-Cycle Gas Once-Through: Low	100	[5, 40]
Combined-Cycle Gas Once-Through: Average	100	[5, 40]
Combined-Cycle Gas Once-Through: High	100	[5, 40]
Cooling Pond	110	[5, 10]
Combined-Cycle Gas Once-Through: Average	115	[5, 10]
Combined-Cycle Gas Once-Through: High	130	[5, 10]
Combined-Cycle Wet Tower	130	[5, 10]
Wet Tower	160	[5, 10]
Combined-Cycle Gas Closed-Loop: Low	180	[5, 10]
Combined-Cycle Wet Tower	180	[5, 40]
Combined-Cycle Gas Closed-Loop with Carbon Capture	190	[5**?**]
Combined-Cycle Gas Closed-Loop: Average	195	[5, 40]
Combined-Cycle Gas Closed-Loop: High	210	[5, 40]
Combined-Cycle Gas Cooling Pond	240	[5, 10]
Once-Throug	250	[5, 37]
Combined-Cycle Wet Tower	270	[5, 40]
Once-Through	290	[3, 5]
Once-Through: Low	300	[6, 15, 20]
Closed-Loop: Low	300	[6, 15, 20]
Once-Through: Average	315	[6, 15, 20, 21, 30]
Once-Through: High	330	[6, 15, 20]
Closed-Loop: Average	405	[6, 15, 20, 21, 30]
Closed-Loop with Carbon Capture	420	[21]
Combined-Cycle Wet Tower	500	[5, 41]
Combined-Cycle Wet Tower with Carbon Capture	500	[5, 40]
Closed-Loop: High	510	[6, 15, 20]
Wet Tower	820	[3, 5]

Gas Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	30	[6, 15, 20]
Dry: Average	30	[6, 15, 20]
Dry: High	30	[6, 15, 20]
Combined-Cycle Gas Dry: Low	30	[6, 15, 20]
Combined-Cycle Gas Dry: Average	30	[6, 15, 20]
Combined-Cycle Gas Dry: High	30	[6, 15, 20]
Combined-Cycle Wet Tower	150	[5, 10]
Combined-Cycle Gas Closed-Loop with Carbon Capture	217	[5, 40]
Combined-Cycle Wet Tower	230	[5, 40]
Wet Tower	250	[5, 10]
Combined-Cycle Gas Closed-Loop: Low	260	[5, 40]
Combined-Cycle Gas Closed-Loop: Average	260	[5, 40]
Combined-Cycle Gas Closed-Loop: High	260	[5, 40]
Combined-Cycle Wet Tower	270	[5, 40]
Closed-Loop: Low	330	[6, 15, 20]
Closed-Loop: Average	480	[6, 15, 20, 21, 30]
Combined-Cycle Wet Tower	500	[5, 41]
Combined-Cycle Wet Tower with Carbon Capture	560	[5, 40]
Closed-Loop with Carbon Capture	563	[21**?**]
Closed-Loop: High	630	[6, 15, 20]
Combined-Cycle Gas Once-Through: Low	7400	[5, 40]
Combined-Cycle Gas Once-Through: Low	7530	[5, 10]
Cooling Pond	7900	[5, 10]
Combined-Cycle Once-Through	9020	[5, 10]
Combined-Cycle Gas Once-Through: Average	13780	[5, 10]
Combined-Cycle Gas Once-Through: Average	13800	[5, 40]
Once-Through: Low	20030	[6, 15, 20]
Combined-Cycle Gas Once-Through: High	20030	[5, 10]
Combined-Cycle Gas Once-Through: High	20100	[5, 40]
Once-Through	22700	[5, 10]
Once-Through: Average	35030	[6, 15, 20, 21, 30]
Once-Through: High	50030	[6, 15, 20]

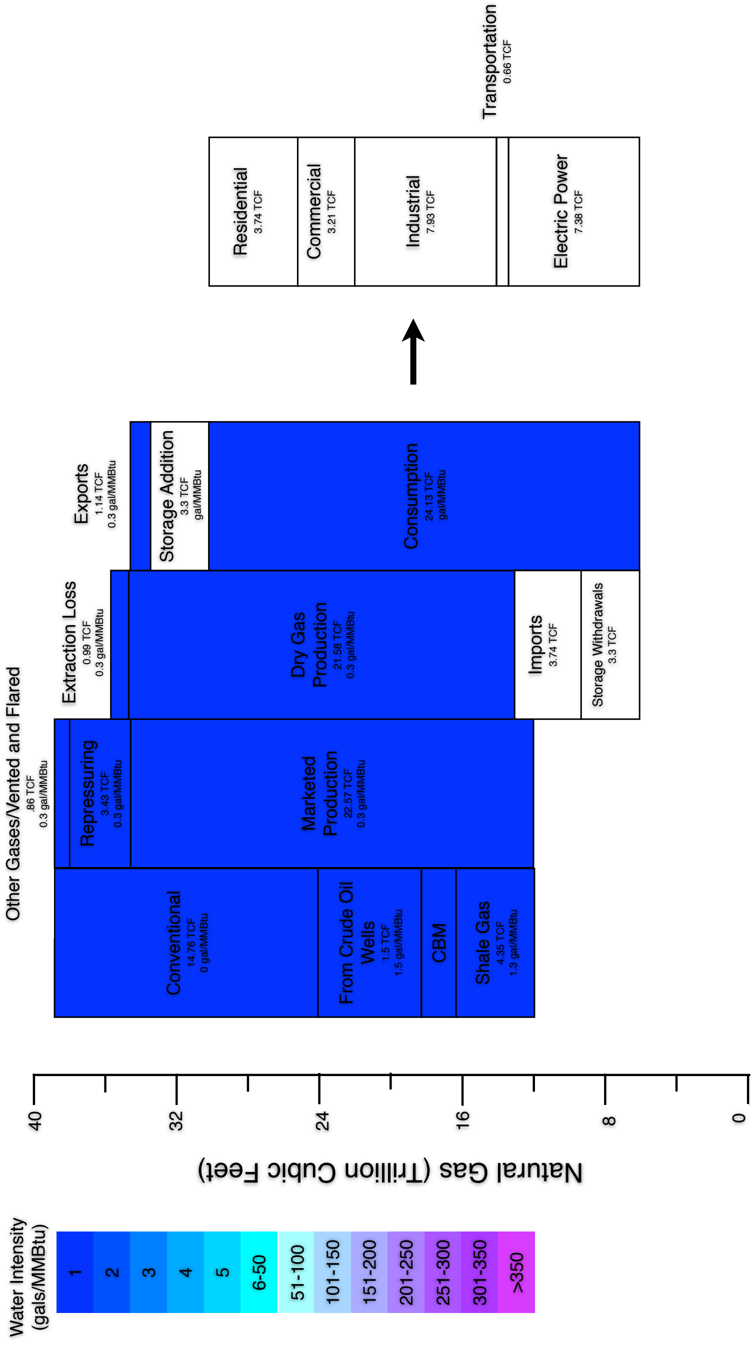


Figure D.3: Water intensity and U.S. consumption of natural gas associated with each stage of electricity generation.

Appendix E

Uranium Water Intensity

Table E.1: Consumptive water intensity of uranium extraction

Uranium Extraction	Consumptive Water Intensity (gal/MMBtu)	Source
Underground Mining	1	[3, 6, 15]
Underground Mining	1	[5, 37]
Surface Mining	6	[3, 6, 15]
Surface Mining	16	[5, 37]

Table E.2: Withdrawn water intensity of uranium extraction

Uranium Extraction	Withdrawn Water Intensity (gal/MMBtu)	Source
Underground Mining	3	[5, 37]
Surface Mining	3	[5, 37]

Table E.3: Embedded water intensity of uranium extraction

Embedded Extraction	Embedded Water Intensity (gal/MMBtu)	Source
Underground Mining	1	[5, 37]
Surface Mining	1	[5, 37]

Table E.4: Consumptive water intensity of uranium processing

Uranium Processing	Consumptive Water Intensity (gal/MMBtu)	Source
Uranium Ore Milling	0	[29]
Enrichment with Centrifuge: Low	0.1	[5, 37]
Fuel Fabrication	0.9	[5, 37]
Enrichment with Centrifuge: Average	1	[5, 37]
Enrichment with Centrifuge: High	1.5	[5, 37]
Conversion	3	[5, 37]
Enrichment with Diffusion: Low	3	[5, 37]
Enrichment with Centrifuge: Low	4	[3, 6, 15]
Enrichment with Centrifuge: Average	5	[3, 6, 15]
Enrichment with Centrifuge: High	5	[3, 6, 15]
Milling: Low	6	[5, 37]
Enrichment with Diffusion: Low	7	[3, 6, 15]
Milling: Average	7	[5, 37]
Enrichment with Diffusion: Average	7	[5, 37]
Enrichment with Diffusion: Average	8	[3, 6, 15]
Enrichment with Diffusion: High	8	[3, 6, 15]
Milling: High	8	[5, 37]
Mining and Processing: Low	8	[5, 37]
Enrichment with Diffusion: High	10	[5, 37]
Mining and Processing: Average	11	[5, 37]
Mining and Processing: High	14	[5, 37]

Table E.5: Withdrawn water intensity of uranium processing

Uranium Processing	Withdrawn Water Intensity (gal/MMBtu)	Source
Spent Fuel Disposal	0	[5]
Fuel Fabrication	0.2	[5, 37]
Enrichment with Centrifuge: Low	1	[5, 37]
Enrichment with Centrifuge: Average	1	[5, 37]
Enrichment with Centrifuge: High	1	[5, 37]
Conversion	1.2	[5, 37]
Milling: Low	1.5	[5, 37]
Milling: Average	1.5	[5, 37]
Milling: High	1.5	[5, 37]
Enrichment with Diffusion: Low	6	[5, 37]
Enrichment with Diffusion: Average	6	[5, 37]
Enrichment with Diffusion: High	6	[5, 37]

Table E.6: Embedded water intensity of uranium processing

Uranium Processing	Embedded Water Intensity (gal/MMBtu)	Source
Fuel Fabrication	0	[5, 37]
Conversion	1	[5, 37]
Spent Fuel Disposal	1.5	[5]
Milling: Low	5	[5, 37]
Milling: Average	5	[5, 37]
Milling: High	5	[5, 37]
Enrichment with Centrifuge: Low	8	[5, 37]
Enrichment with Centrifuge: Average	8	[5, 37]
Enrichment with Centrifuge: High	8	[5, 37]
Enrichment with Diffusion: Low	89	[5, 37]
Enrichment with Diffusion: Average	89	[5, 37]
Enrichment with Diffusion: High	89	[5, 37]

Table E.7: Consumptive water intensity of uranium electricity generation

Electricity Generation	Consumptive Water Intensity (gal/MWh)	Source
Dry: Low	0	[6, 15, 20]
Dry: Average	15	[6, 15, 20]
Dry: High	30	[6, 15, 20]
Wet Tower (HTGR)	60	[3, 5]
Once-Through	140	[5, 10]
Once-Through: Low	400	[6, 15, 20]
Closed-Loop: Low	400	[6, 15, 20]
Once-Through: Low	400	[5, 36]
Once-Through: Average	400	[5, 36]
Once-Through: High	400	[5, 36]
Once-Through: Average	415	[6, 15, 20, 21, 30, 38]
Once-Through: High	430	[6, 15, 20]
Cooling Pond: Low	450	[5, 36]
Closed-Loop: Average	575	[6, 15, 20]
Closed-Loop with Carbon Capture	590	[21, 30]
Wet Tower	610	[5, 10]
Cooling Pond: Average	680	[5, 36]
Wet Tower: Low	740	[5, 36]
Closed-Loop: High	750	[6, 15, 20]
Wet Tower: Average	820	[5, 36]
Wet Tower (PWR)	820	[5, 37]
Wet Tower (LWR)	850	[3, 5]
Cooling Pond: High	900	[5, 36]
Wet Tower: High	900	[5, 36]
Wet Tower (BWR)	900	[5, 37]

Table E.8: Withdrawn water intensity of uranium electricity generation

Electricity Generation	Withdrawn Water Intensity (gal/MWh)	Source
Dry: Low	30	[6, 15, 20]
Dry: Average	30	[6, 15, 20]
Dry: High	30	[6, 15, 20]
Cooling Pond: Low	500	[5, 36]
Closed-Loop: Low	530	[6, 15, 20]
Closed-Loop with Carbon Capture	590	[21, 30]
Cooling Pond: Average	800	[5, 36]
Wet Tower: Low	800	[5, 36]
Closed-Loop: Average	830	[6, 15, 20]
Wet Tower: Average	950	[5, 36]
Cooling Pond: High	1100	[5, 36]
Wet Tower	1100	[5, 10]
Wet Tower: High	1100	[5, 36]
Closed-Loop: High	1130	[6, 15, 20]
Once-Through: Low	25030	[6, 15, 20]
Once-Through: Low	25100	[5, 36]
Once-Through	31500	[5, 10]
Once-Through: Average	42530	[6, 15, 20]
Once-Through: Average	43000	[5, 36]
Once-Through: High	60030	[6, 15, 20]

Appendix F

Renewables Water Intensity

Table F.1: Consumptive water intensity of large-scale concentrating solar power

Large-Scale CSP	Consumptive Water Intensity (gal/MWh)	Source
Dish, Stirling	4	[5]
Dish/Engine	20	[6, 15]
Parabolic Troughs	78	[6, 15]
Parabolic Troughs, Dry Cooling	80	[5]
Power Tower	90	[6, 15]
Power Tower	500	[6, 15]
Trough	550	[5]
Concentrating Solar	750	[21, 30]
Tower	770	[5]
Parabolic Troughs	800	[15]
U.S. Weighted Average for CSP	800	[15]
: Tower, Wet Cooling	820	[5]
Parabolic Troughs, Wet Cooling	820	[5]
Parabolic Troughs, Wet Cooling: Low	820	[5]
Tower	850	[5]
Parabolic Troughs, Wet Cooling Average	910	[5]
: Parabolic Troughs, Wet Cooling	980	[5]
Fresnal	1000	[6, 15]
Parabolic Troughs, Wet Cooling: High	1000	[5]

Table F.2: Withdrawn water intensity of large-scale concentrating solar power

Large-Scale CSP	Withdrawn Water Intensity (gal/MWh)	Source
Dish, Stirling	4	[5]
Parabolic Troughs, Dry Cooling	8	[5]
Trough	550	[5]
Concentrating Solar	760	[21, 30]
Tower	770	[5]
Tower, Wet Cooling	820	[5]
Parabolic Troughs, Wet Cooling	820	[5]
Parabolic Troughs, Wet Cooling: Low	820	[5]
Tower	850	[5]
Parabolic Troughs, Wet Cooling: Average	910	[5]
Parabolic Troughs, Wet Cooling	980	[5]
Parabolic Troughs, Wet Cooling: High	1000	[5]

Table F.3: Consumptive water intensity of photovoltaic solar power

Photovolatics	Consumptive Water Intensity (gal/MWh)	Source
Solar Photovoltaics	0	[6, 15]
Photovoltaic	0	[5]
Concentrated Solar Photovoltaics	0	[5]
Concentrated Solar Photovoltaics	4	[15, 50, 51]
Photovoltaic	4	[5]
Concentrated Solar Photovoltaics	4	[5]

Table F.4: Withdrawn water intensity of photovoltaic solar power

Photovolatics	Withdrawn Water Intensity (gal/MWh)	Source
Frame	0	[5]
CdTe	0	[5]
Photovoltaic	0	[5]
Concentrated Solar Photovoltaics	0	[5]
BOS	0.1	[5]
Photovoltaic	4	[5]
Concentrated Solar Photovoltaics	4	[5]
Mono-Si	15	[5]
Multi-Si	16	[5]

Table F.5: Consumptive water intensity of wind power

Wind	Consumptive Water Intensity (gal/MWh)	Source
Wind Power	0	[6, 15]
Wind	0	[5]
Wind	1	[5]

Table F.6: Withdrawn water intensity of wind power

Wind	Withdrawn Water Intensity (gal/MWh)	Source
Wind	0	[5]

Table F.7: Embedded water intensity of wind power

Wind	Embedded Water Intensity (gal/MWh)	Source
Denmark, On Land	130	[5]
Denmark, Off Shore	130	[5]
Spain, On Land	160	[5]
Denmark, Off Shore	180	[5]
Italy, On Land	190	[5]
Denmark, On Land	250	[5]

Table F.8: Consumptive water intensity of geothermal power

Geothermal	Consumptive Water Intensity (gal/MWh)	Source
Geothermal	1400	[6, 15, 20, 30]
Geothermal: Low	2700	[15, 52]
Geothermal: Average	3600	[15, 52]
Geothermal: High	4500	[15, 52]

Table F.9: Consumptive water intensity of hydropower

Hydropower	Consumptive Water Intensity (gal/MWh)	Source
Hydropower	4500	[6, 15, 20, 30]

Appendix G

Noble Water Use Data

Table G.1: Consumptive water use for 2010 and 2011 Noble Energy Wells in the Wattenberg Field

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
70 RANCH BB21-63HN	HOR	140,868	2,526,090	2,666,958
70 RANCH BB21-65HN	HOR	83,454	3,175,368	3,258,822
70 RANCH BB21-67HN	HOR	82,530	2,499,000	2,581,530
70 RANCH USX BB09-63HN	HOR	124,740	2,617,188	2,741,928
ABBEY D01-23	VER	41,580	273,126	314,706
ABBEY D01-27	VER	78,540	8,400	86,940
ABBEY D01-29	VER	70,980	274,470	345,450
ADAMS D30-27D	VER	64,680	427,812	492,492
ALOYSIUS C34-18	VER	87,360	8,820	96,180
ALOYSIUS C34-20D	VER	83,160	7,560	90,720
ALOYSIUS C34-21D	VER	75,180	11,760	86,940
ALOYSIUS C34-22D	VER	65,520	8,400	73,920
ALOYSIUS C34-24	VER	76,440	8,400	84,840
ALOYSIUS C34-27D	VER	139,860	318,150	458,010
ALOYSIUS C34-28D	VER	47,838	350,742	398,580
ALOYSIUS C34-30D	VER	81,060	5,880	86,940
ALOYSIUS C34-31	VER	65,520	6,720	72,240
ALOYSIUS C34-32D	VER	77,280	8,820	86,100
ALOYSIUS C34-33D	VER	74,340	13,020	87,360
ALOYSIUS C34-99HZ	HOR	141,960	3,228,750	3,370,710
ANNIE B03-23	VER	55,440	276,654	332,094

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
ARISTOCRAT PC H11-07	VER	180,600	114,030	294,630
ARISTOCRAT PC H11-18D	VER	79,800	278,208	358,008
ARISTOCRAT PC H11-19D	VER	78,540	419,496	498,036
ARISTOCRAT PC H11-27D	VER	76,440	275,730	352,170
ARISTOCRAT PC H11-29D	VER	66,360	410,340	476,700
ARISTOCRAT PC H11-30D	VER	63,000	441,462	504,462
ARISTOCRAT PC H11-32D	VER	59,640	402,654	462,294
BADDING USX W25-07D	VER	78,540	430,080	508,620
BASHOR PC AA09-08	VER	56,280	277,872	334,152
BASHOR PC AA09-14	VER	74,550	253,806	328,356
BASHOR PC AA09-22	VER	90,930	271,488	362,418
BASHOR PC AA09-23	VER	82,320	270,312	352,632
BASHOR PC AA09-24	VER	85,050	263,676	348,726
BASHOR PC AA17-02D	VER	89,040	267,498	356,538
BASHOR PC AA17-17	VER	75,600	305,466	381,066
BASHOR PC AA17-21	VER	90,090	271,110	361,200
BASHOR PC AA17-22	VER	63,000	307,776	370,776
BASHOR PC AA17-23	VER	102,270	316,218	418,488
BASHOR PC AA17-24	VER	47,040	308,868	355,908
BERNHARDT STATE PC N36-17	VER	60,270	300,048	360,318
BERRY P08-18D	VER	71,820	275,604	347,424
BERRY P08-28D	VER	81,900	411,726	493,626
BERRY P08-29D	VER	65,520	166,908	232,428
BETZ PC G09-19	VER	65,520	270,732	336,252
BETZ PC G09-23	VER	68,880	269,556	338,436
BETZ PC G09-31D	VER	75,180	289,926	365,106
BETZ PC G10-33D	VER	70,140	268,968	339,108
BICKLING PC E02-33D	VER	108,990	272,160	381,150
BICKLING PC E03-22D	VER	71,400	293,832	365,232
BOOTH N25-18D	VER	59,850	277,116	336,966
BOOTH N25-20D	VER	91,560	293,538	385,098
BOOTH N25-21D	VER	71,400	313,782	385,182
BOOTH N25-22D	VER	94,710	294,084	388,794
BOOTH N25-24D	VER	63,000	279,930	342,930
BOOTH N25-31D	VER	74,970	269,220	344,190
BOOTH N25-33D	VER	71,652	266,700	338,352
BOULTER PC G14-29D	VER	77,700	270,606	348,306
BOULTER PC G14-30D	VER	89,040	571,242	660,282
BROWN PC E02-31D	VER	58,800	268,716	327,516
BROWN PC E02-32	VER	63,000	287,952	350,952
BURGHART D04-22	VER	58,800	276,906	335,706
CALVARY USX EE29-04D	VER	57,540	264,138	321,678
CAMP H30-29D	VER	116,340	375,396	491,736
CAMP H30-32	VER	54,600	421,638	476,238
CAMP H30-33	VER	60,480	418,782	479,262

Noble Water Use Data

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
CANNON H35-20	VER	51,240	418,488	469,728
CANNON H35-21	VER	73,500	419,958	493,458
CANNON H35-22	VER	3,108	412,734	415,842
CANNON H35-24	VER	57,540	151,620	209,160
CANNON W15-18D	VER	86,100	252,840	338,940
CANNON W15-19	VER	72,240	271,740	343,980
CANNON W15-21D	VER	91,350	403,410	494,760
CARLSON A18-17	VER	60,060	286,944	347,004
CARLSON K23-18D	VER	94,500	410,466	504,966
CARLSON K23-22D	VER	35,700	271,614	307,314
CARMIN USX CC05-10D	VER	62,580	421,176	483,756
CARMIN USX CC05-16D	VER	76,860	436,548	513,408
CARMIN USX CC05-17D	VER	73,920	486,108	560,028
CODY D03-20	VER	60,900	287,028	347,928
CODY D03-28	VER	71,400	276,234	347,634
COLEMAN C22-17	VER	62,580	270,060	332,640
COLEMAN C22-18	VER	65,520	267,918	333,438
COLEMAN C22-21D	VER	64,260	269,682	333,942
COLEMAN C22-27	VER	54,600	268,254	322,854
CONNELL C04-31D	VER	69,090	228,060	297,150
COX PC GK35-99HZ	HOR	186,900	1,886,556	2,073,456
CRICKET C22-30D	VER	67,620	269,346	336,966
CROISSANT USX WW11-02D	VER	76,440	406,476	482,916
CROISSANT USX WW11-08D	VER	97,020	444,318	541,338
CROISSANT USX WW11-17D	VER	100,590	427,140	527,730
DECHANT 07-15	VER	67,410	526,260	593,670
DECHANT 7-1-17	VER	74,550	278,586	353,136
DECHANT D18-27D	VER	81,900	271,782	353,682
DECHANT D18-30D	VER	79,800	275,436	355,236
DECHANT D31-18D	VER	86,100	415,968	502,068
DECHANT D31-21D	VER	69,300	278,208	347,508
DECHANT D31-22D	VER	93,450	411,642	505,092
DECHANT D31-24D	VER	59,430	251,202	310,632
DECHANT STATE H36-11	VER	77,700	426,426	504,126
DECHANT STATE H36-18D	VER	52,080	416,220	468,300
DECHANT STATE H36-19	VER	75,600	424,284	499,884
DECHANT STATE H36-20D	VER	83,580	419,622	503,202
DECHANT STATE H36-21D	VER	79,380	433,230	512,610
DECHANT STATE H36-31D	VER	94,500	425,208	519,708
DECHANT STATE H36-32D	VER	69,300	426,132	495,432
DECHANT X01-02	VER	72,240	305,424	377,664
DECHANT X01-03	VER	76,440	417,816	494,256
DECHANT X01-04	VER	97,440	364,476	461,916
DECHANT X01-06	VER	85,260	267,414	352,674
DECHANT X01-07	VER	76,440	265,146	341,586

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
DECHANT X01-08	VER	75,180	418,950	494,130
DECHANT X08-09	VER	60,900	422,142	483,042
DECHANT X08-10X	VER	62,160	431,382	493,542
DECHANT X08-15	VER	94,710	427,308	522,018
DECHANT X08-24D	VER	63,420	434,490	497,910
DECHANT Y06-27D	VER	94,500	427,980	522,480
DECHANT Y06-28D	VER	70,140	420,756	490,896
DEGENHART STATE AE16-63HN	HOR	119,490	2,657,928	2,777,418
DEGENHART USX AE17-63HN	HOR	79,170	2,747,262	2,826,432
DF RANCH PC GK09-99HZ	HOR	135,240	3,147,480	3,282,720
DILLARD 10-44	VER	72,870	270,690	343,560
DILLARD KG34-13	VER	110,250	274,848	385,098
DINNEL C27-28D	VER	72,240	382,872	455,112
DINNEL C27-29D	VER	68,040	384,888	452,928
DINNER 01-01-19	VER	33,600	275,940	309,540
DINNER 13-35	VER	49,140	274,848	323,988
DINNER PC G01-22	VER	68,040	278,712	346,752
DONALDSON USX EE29-06D	VER	82,530	271,110	353,640
DRAKE PC MM14-08D	VER	75,180	115,920	191,100
DRAKE PC MM14-15D	VER	55,860	116,550	172,410
EASTON G12-20D	VER	46,620	284,172	330,792
EASTON G12-32D	VER	73,500	278,964	352,464
EGGE USX A03-11D	VER	61,320	271,236	332,556
EHRLICH STATE PC F36-31D	VER	68,880	268,506	337,386
EHRLICH STATE PC F36-32D	VER	135,660	267,540	403,200
EHRLICH STATE PC F36-33D	VER	79,380	278,628	358,008
ERICKSON PC G15-27D	VER	75,180	422,100	497,280
FEIT E23-97HZ	HOR	262,080	2,632,056	2,894,136
FEIT E23-98HZ	HOR	200,970	3,115,014	3,315,984
FEIT E23-99HZ	HOR	107,100	2,861,838	2,968,938
FIVE RIVERS K03-33D	VER	63,000	331,422	394,422
FIVE RIVERS K04-20D	VER	111,174	241,416	352,590
FIVE RIVERS K04-21D	VER	75,600	290,472	366,072
FIVE RIVERS K04-25	VER	103,950	295,050	399,000
FIVE RIVERS K04-32D	VER	79,380	415,968	495,348
FIVE RIVERS K08-07D	VER	68,040	394,842	462,882
FIVE RIVERS K08-17D	VER	81,060	271,320	352,380
FIVE RIVERS K08-22D	VER	64,680	418,446	483,126
FIVE RIVERS K08-23	VER	77,700	401,730	479,430
FIVE RIVERS K08-24D	VER	83,580	442,386	525,966
FIVE RIVERS K09-29D	VER	55,650	352,296	407,946
FIVE RIVERS K09-30D	VER	105,000	272,328	377,328
FIVE RIVERS K09-33D	VER	59,640	287,616	347,256
FIVE RIVERS K10-30D	VER	63,000	278,040	341,040
FIVE RIVERS K15-30D	VER	76,020	267,750	343,770

Noble Water Use Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
FIVE RIVERS K15-31D	VER	85,680	230,202	315,882
FIVE RIVERS K16-17	VER	90,300	265,860	356,160
FIVE RIVERS K16-30D	VER	76,860	262,752	339,612
FIVE RIVERS USX K09-01D	VER	83,580	290,976	374,556
FIVE RIVERS USX K09-08D	VER	69,510	19,320	88,830
FIVE RIVERS USX K09-17D	VER	95,760	274,050	369,810
FIVE RIVERS USX K09-22D	VER	61,740	408,744	470,484
FOOSE A18-23	VER	65,520	272,286	337,806
FOSS 06-35	VER	97,734	308,616	406,350
FOSS USX AA05-03	VER	105,000	304,920	409,920
FRANK PC H22-20D	VER	57,120	112,476	169,596
FRANKLIN C08-62HN	HOR	183,540	2,127,888	2,311,428
FRANKLIN C17-69HN	HOR	99,540	1,878,156	1,977,696
FRANKLIN C18-27D	VER	62,160	260,400	322,560
FRAZIER 33-15	VER	68,250	401,310	469,560
FRICK C17-79HN	HOR	131,880	2,036,916	2,168,796
FRICK PC C17-65HN	HOR	114,660	2,416,806	2,531,466
GABEL USX AB21-14	VER	85,890	270,942	356,832
GITTLEIN D04-33	VER	48,510	277,872	326,382
GREEN USX XX07-07	VER	99,540	508,368	607,908
GREEN USX XX07-08	VER	92,190	424,578	516,768
GULLEY 17-13	VER	98,280	306,306	404,586
GULLEY 17-15	VER	67,200	292,950	360,150
GULLEY 17-25	VER	55,650	299,166	354,816
GUNNER STATE AA16-99HZ	HOR	148,680	3,789,954	3,938,634
GURTLER H24-99HZ	HOR	170,940	2,817,066	2,988,006
GUTTERSEN D02-32D	VER	73,920	270,648	344,568
GUTTERSEN D02-75HN	HOR	95,340	2,679,096	2,774,436
GUTTERSEN D03-33D	VER	91,140	265,692	356,832
GUTTERSEN D04-32	VER	65,520	17,220	82,740
GUTTERSEN D09-27D	VER	70,560	292,026	362,586
GUTTERSEN D10-30D	VER	69,720	51,492	121,212
GUTTERSEN D22-27	VER	75,600	274,386	349,986
GUTTERSEN D23-20	VER	71,400	278,922	350,322
GUTTERSEN D25-17	VER	71,820	156,156	227,976
GUTTERSEN D29-33D	VER	92,820	288,792	381,612
GUTTERSEN D29-65HN	HOR	116,760	2,871,078	2,987,838
GUTTERSEN D29-99HZ	HOR	147,420	3,060,288	3,207,708
GUTTERSEN STATE CC20-30D	VER	79,800	296,982	376,782
GUTTERSEN STATE CC20-31D	VER	67,200	314,244	381,444
GUTTERSEN STATE CC20-32D	VER	75,600	290,346	365,946
GUTTERSEN STATE CC20-33D	VER	89,040	270,228	359,268
GUTTERSEN STATE D22-18	VER	76,440	263,592	340,032
GUTTERSEN STATE D22-22	VER	71,820	418,110	489,930
GUTTERSEN STATE D22-24	VER	46,620	411,306	457,926

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
GUTTERSEN STATE D28-79HN	HOR	106,680	2,989,392	3,096,072
HANSCOME G12-31	VER	116,340	272,076	388,416
HARPER USX EE27-02D	VER	134,400	362,796	497,196
HARPER USX EE27-07D	VER	93,870	288,708	382,578
HARPER USX EE27-15D	VER	80,430	251,286	331,716
HARPER USX EE27-23D	VER	78,540	277,662	356,202
HAYTHORN 04-21	VER	88,830	272,706	361,536
HAYTHORN 04-24	VER	128,940	269,304	398,244
HBR PC G11-32D	VER	61,740	417,018	478,758
HEATH PC GK02-07	VER	106,680	338,646	445,326
HERBST C22-22D	VER	70,980	268,422	339,402
HERBST C22-24	VER	49,980	267,834	317,814
HERBST C22-25	VER	60,690	281,862	342,552
HIPPO D27-24D	VER	67,200	269,514	336,714
HIPPO D34-29D	VER	81,900	269,514	351,414
HOFF PC D06-21	VER	52,920	270,186	323,106
HOFF PC D06-27	VER	62,160	269,640	331,800
HOFFMAN B33-19	VER	88,830	273,924	362,754
HORTON D18-20D	VER	62,160	417,900	480,060
HOUNDSKEEPER PC H01-21D	VER	78,540	417,144	495,684
HOWARD A27-17D	VER	70,980	276,444	347,424
HOWARD USX A09-02D	VER	67,200	289,884	357,084
HOWARD USX A09-06D	VER	52,500	290,304	342,804
HOWARD USX A09-09D	VER	38,220	273,924	312,144
HOWARD USX A09-12D	VER	63,630	289,128	352,758
HOWARD USX A09-14D	VER	78,750	279,300	358,050
HOWARD USX A09-15D	VER	82,110	285,264	367,374
HOWARD USX A09-23	VER	54,600	284,214	338,814
HP FARMS D32-24D	VER	90,090	148,218	238,308
HP Y07-09	VER	59,430	433,062	492,492
HP Y07-10D	VER	102,900	440,202	543,102
HUDSON STATE X36-07D	VER	129,150	427,098	556,248
IGO FARMS J28-19D	VER	61,110	271,068	332,178
IGO FARMS J28-20D	VER	59,010	276,066	335,076
IGO FARMS J28-31D	VER	94,500	271,698	366,198
IGO FARMS J28-32D	VER	72,240	278,502	350,742
JOHNSON PC EE33-09D	VER	56,700	295,428	352,128
JOHNSON PC EE33-10D	VER	71,400	284,340	355,740
JOHNSON PC EE33-15D	VER	94,290	279,720	374,010
JOHNSON PC EE33-16D	VER	96,390	261,240	357,630
JOHNSON PC EE33-23D	VER	77,700	317,730	395,430
KARCH STATE D10-22	VER	49,560	273,000	322,560
KERBS USX A15-12D	VER	96,600	276,528	373,128
KLEIN B15-13D	VER	74,760	266,532	341,292
KLEIN B16-98HZ	HOR	160,440	4,432,974	4,593,414
KLEIN B16-99HZ	HOR	93,870	3,831,030	3,924,900

Noble Water Use Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
LAND USX Y31-01	HOR	159,600	2,954,616	3,114,216
LANG C22-28D	VER	66,150	412,230	478,380
LARSON A32-17	VER	36,750	296,016	332,766
LDS D17-18	VER	65,520	227,724	293,244
LDS D17-22	VER	91,980	268,044	360,024
LDS D17-31D	VER	51,660	418,152	469,812
LDS D17-32D	VER	76,440	413,742	490,182
LDS E25-32	VER	54,600	291,270	345,870
LDS E25-33D	VER	93,240	301,644	394,884
LETTERLY USX AB23-68HN	HOR	147,630	1,432,830	1,580,460
LIND 23-15	VER	58,548	292,446	350,994
LINDBLAD 17-34	VER	73,290	269,724	343,014
LINDBLAD 20-25	VER	123,060	267,876	390,936
LOWER LATHAM PC G11-69HN	HOR	87,570	2,467,080	2,554,650
LOWER LATHAM PC G12-69HN	HOR	131,880	3,011,526	3,143,406
LOYD PC GD33-13	VER	146,370	270,774	417,144
LYSTER E26-22D	VER	123,900	298,326	422,226
LYSTER E26-23	VER	39,480	317,562	357,042
MARIE D04-20	VER	101,640	277,830	379,470
MARLEY C01-18D	VER	78,960	276,696	355,656
MARLEY C01-28D	VER	63,000	276,192	339,192
MARLEY C01-30D	VER	63,000	273,336	336,336
MARLEY C01-31D	VER	67,200	276,066	343,266
MCCLELLAN PC LG04-15	VER	46,200	244,734	290,934
MCWILLIAMS 15-3-17	VER	25,200	308,280	333,480
MEGAN H16-99HZ	HOR	290,430	2,767,968	3,058,398
MILLAGE C11-18	VER	82,320	277,242	359,562
MILLER X31-03	VER	91,560	482,958	574,518
MILLER X31-04	VER	71,400	997,962	1,069,362
MILLER X31-06	VER	60,480	424,074	484,554
MILLER X31-10	VER	76,650	429,996	506,646
MOJACK USX AB21-15	VER	114,240	278,712	392,952
MOSER PC H22-21D	VER	71,400	422,940	494,340
MOSER PC H22-24	VER	78,120	418,236	496,356
MOSER PC H22-33	VER	71,400	433,020	504,420
MOSIER K23-20D	VER	76,020	275,016	351,036
MOSIER K23-21D	VER	67,620	391,272	458,892
MOSIER K23-33D	VER	76,860	417,858	494,718
NCLP PC AA04-04	VER	92,400	304,920	397,320
NCLP PC AA04-05	VER	95,970	314,832	410,802
NCLP PC AA04-06	VER	82,950	305,676	388,626
NCLP PC AA04-11	VER	71,820	300,762	372,582
NCLP PC AA04-12	VER	84,000	304,878	388,878
NCLP PC AA04-13	VER	113,400	304,584	417,984

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
NCLP PC AA04-14	VER	103,110	306,726	409,836
NCLP PC AA04-19	VER	125,160	308,154	433,314
NCLP PC AA04-20	VER	99,120	308,784	407,904
NCLP PC AA04-25	VER	106,470	307,440	413,910
NCLP PC AA08-02D	VER	89,082	288,162	377,244
NCLP PC AA08-03D	VER	78,540	335,790	414,330
NCLP PC AA08-07D	VER	89,250	291,606	380,856
NCLP PC AA08-08D	VER	88,830	155,022	243,852
NCLP PC AA08-18D	VER	63,000	241,458	304,458
NCLP PC AA08-19	VER	63,000	375,396	438,396
NELSON K27-63HN	HOR	130,410	3,728,340	3,858,750
NOFFSINGER 35-13	VER	70,560	280,266	350,826
NOFFSINGER 35-15	VER	50,400	283,122	333,522
OJEDA USX XX07-09D	VER	126,000	451,500	577,500
ORR USX A03-15D	VER	98,700	263,760	362,460
OWENS K17-15	VER	89,880	269,346	359,226
OWENS K17-23D	VER	37,380	270,312	307,692
PEDRO STATE C31-79HN	HOR	148,470	3,542,910	3,691,380
PEPPLER PC AA17-20	VER	97,860	268,884	366,744
PEPPLER PC AA17-25	VER	75,180	147,042	222,222
PETERSON B10-24D	VER	48,300	280,980	329,280
PETERSON PC LG19-06	VER	98,280	294,042	392,322
PHILLIPS 23-1-17	VER	64,260	281,022	345,282
PHILLIPS 23-1-20	VER	71,400	300,342	371,742
PHILLIPS 23-1-21	VER	68,460	289,590	358,050
PHILLIPS 24-2-20D	VER	85,680	276,318	361,998
PHILLIPS 24-3-17	VER	83,370	278,082	361,452
PHILLIPS 24-3-21	VER	81,690	280,308	361,998
PHILLIPS 24-3-23	VER	64,260	299,040	363,300
PHILLIPS PC N24-25	VER	84,000	4,200	88,200
PHILLIPS PC N24-29D	VER	105,210	263,172	368,382
PHILLIPS PC N24-31D	VER	64,260	304,500	368,760
PIONEER USX Y07-08D	VER	92,820	432,096	524,916
PIONEER Y07-07D	VER	67,830	277,662	345,492
POWERS X22-02	VER	84,210	506,142	590,352
POWERS X22-04	VER	84,840	423,360	508,200
POWERS X22-31	VER	70,140	431,760	501,900
PURCELL PC GK11-10	VER	108,570	57,456	166,026
PVA X31-16	VER	69,510	434,196	503,706
QC A32-19	VER	63,840	310,968	374,808
RAY H12-24D	VER	78,960	414,750	493,710
REI H08-13D	VER	73,500	287,070	360,570
REI H08-15D	VER	68,460	418,362	486,822
REI H08-21D	VER	95,970	416,304	512,274
REI H08-24D	VER	88,620	412,230	500,850

Noble Water Use Data

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
RHINO D27-18D	VER	63,000	272,412	335,412
RHINO D27-19D	VER	76,440	267,456	343,896
RHINO D27-20D	VER	86,520	273,714	360,234
RHINO D27-21	VER	65,520	270,480	336,000
RHINO D27-22D	VER	70,980	337,008	407,988
RHINO D27-27D	VER	65,520	337,008	402,528
RHINO D27-28D	VER	88,620	435,666	524,286
RICHTER USX AB27-03	VER	91,350	271,194	362,544
RICHTER USX AB27-05	VER	88,830	273,756	362,586
RICHTER USX AB27-13	VER	106,680	263,004	369,684
RICHTER USX AB27-25	VER	85,050	263,130	348,180
RICHTER USX AB27-65HN	HOR	98,910	2,276,022	2,374,932
RITCHEY USX WW27-19D	VER	103,110	417,732	520,842
ROGERS USX A03-09D	VER	63,000	282,660	345,660
ROHN PC LD04-03	VER	73,500	269,514	343,014
ROHN PC LD09-01	VER	67,200	269,514	336,714
ROHN PC LD16-96HN	HOR	80,640	2,083,452	2,164,092
ROHR A28-25	VER	84,000	263,886	347,886
ROTH USX A30-17	VER	63,000	270,186	333,186
ROTHE BB30-23	VER	44,310	275,478	319,788
SATER C12-21	VER	59,850	266,994	326,844
SATER CC18-14	VER	68,880	270,228	339,108
SATER CC18-23	VER	65,520	269,976	335,496
SCHMIDT K23-24D	VER	62,160	282,282	344,442
SCHOLFIELD STATE A36-69HN	HOR	149,100	3,089,730	3,238,830
SCHOLFIELD STATE A36-79HN	HOR	99,120	3,100,902	3,200,022
SEKICH P19-18D	VER	89,040	282,576	371,616
SEKICH P19-21D	VER	90,300	292,194	382,494
SEKICH P19-24D	VER	65,100	279,048	344,148
SEKICH P19-27D	VER	107,100	426,930	534,030
SEKICH P19-28D	VER	77,700	463,680	541,380
SHELTON G25-22	VER	54,600	273,966	328,566
SHELTON PC D06-32D	VER	115,080	314,496	429,576
SHERWOOD L30-29D	VER	125,160	460,908	586,068
SHERWOOD L30-30D	VER	73,080	444,192	517,272
SHERWOOD L30-31D	VER	67,200	456,624	523,824
SHERWOOD L30-32D	VER	79,170	395,136	474,306
SMITH PC D06-20D	VER	68,880	278,040	346,920
SOONER STATE B36-63HN	HOR	114,240	2,675,694	2,789,934
SPIKE STATE D10-21D	VER	72,450	422,646	495,096
SPIKE STATE D16-99HZ	HOR	138,180	3,239,376	3,377,556
STATE C24-99HZ	HOR	131,460	3,294,480	3,425,940
STATE C36-32D	VER	39,690	275,898	315,588
STATE C36-33D	VER	96,600	277,662	374,262
STATE C36-99HZ	HOR	117,768	3,064,908	3,182,676

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
STATE D01-30D	VER	62,160	278,460	340,620
STEWARDSON USX WW33-01D	VER	89,040	414,372	503,412
STEWARDSON USX WW33-03D	VER	110,880	525,924	636,804
STOCKLEY C15-79HN	HOR	142,170	3,318,000	3,460,170
STOCKLEY C22-79HN	HOR	175,140	2,216,844	2,391,984
STREAR V03-73HN	HOR	123,270	1,593,312	1,716,582
STREAR V06-63HN	HOR	126,840	2,377,452	2,504,292
STROH H12-32	VER	78,960	8,400	87,360
STROHAUER F32-21D	VER	73,080	294,000	367,080
STROHAUER F32-22D	VER	59,640	304,500	364,140
STROHAUER F32-23	VER	109,200	411,180	520,380
STROHAUER F32-24	VER	68,460	289,968	358,428
TANIA D11-27D	VER	47,040	291,522	338,562
TANIA D11-28	VER	42,840	271,026	313,866
TANNER K33-65HN	HOR	111,300	3,033,660	3,144,960
THOMPSON C28-79HN	HOR	136,290	2,528,106	2,664,396
THOMPSON C33-30D	VER	64,260	250,194	314,454
THOMPSON C33-69HN	HOR	98,700	2,125,872	2,224,572
TYE USX A15-03D	VER	66,150	270,690	336,840
TYE USX A15-04D	VER	79,800	273,546	353,346
UPRC G07-99HZ	HOR	115,080	3,108,588	3,223,668
UPRC H17-99HZ	HOR	112,560	3,331,986	3,444,546
WACKER B01-79HN	HOR	110,250	2,890,986	3,001,236
WACKER B10-20D	VER	73,920	282,030	355,950
WACKER B11-69HN	HOR	96,810	2,391,648	2,488,458
WACKER B12-69HN	HOR	139,020	573,594	712,614
WALCKER 12-23	VER	67,620	270,144	337,764
WALCKER AB12-08	VER	83,580	285,642	369,222
WALCKER AB12-09	VER	127,680	270,732	398,412
WARDELL H19-32D	VER	79,800	428,442	508,242
WARDELL H19-33D	VER	56,700	278,418	335,118
WARDELL PC H20-24	VER	73,920	274,386	348,306
WARNER W13-11	VER	89,460	425,628	515,088
WEIDENKELLER PC G01-20D	VER	71,400	274,932	346,332
WEIDENKELLER PC G01-21D	VER	132,300	273,714	406,014
WEIDENKELLER PC G01-27D	VER	91,560	271,908	363,468
WEIDENKELLER PC G01-28D	VER	85,680	278,796	364,476
WEIDENKELLER PC G01-29D	VER	77,700	272,412	350,112
WEIDENKELLER PC G01-30D	VER	102,480	268,170	370,650
WEIDENKELLER PC G01-31D	VER	66,780	7,980	74,760
WELLS RANCH AA12-08	VER	46,200	270,312	316,512
WELLS RANCH AA12-09	VER	58,800	267,456	326,256
WELLS RANCH AE05-12	VER	98,700	249,312	348,012
WELLS RANCH AE18-17	VER	102,480	264,054	366,534
WELLS RANCH AE20-16	VER	78,120	275,730	353,850

Noble Water Use Data

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
WELLS RANCH AE30-68HN	HOR	71,400	3,592,974	3,664,374
WELLS RANCH PC AA22-01	VER	53,130	496,398	549,528
WELLS RANCH PC AA22-02	VER	54,180	520,422	574,602
WELLS RANCH PC AA22-03	VER	77,280	537,726	615,006
WELLS RANCH PC AA22-04	VER	35,070	279,720	314,790
WELLS RANCH PC AA22-07	VER	80,640	313,698	394,338
WELLS RANCH PC AA22-08	VER	95,550	526,554	622,104
WELLS RANCH PC AA22-13	VER	49,980	2,706,858	2,756,838
WELLS RANCH USX AA11-65HN	HOR	105,000	4,245,822	4,350,822
WELLS RANCH USX AA11-67HN	HOR	93,240	1,567,062	1,660,302
WELLS RANCH USX AE29-68HN	HOR	157,920	766,920	924,840
WELLS RANCH USX BB15-65HN	HOR	209,580	3,154,074	3,363,654
WELLS RANCH USX BB15-67HN	HOR	86,100	2,933,196	3,019,296
WEST IRRIGATION USX AB33-23	VER	64,680	274,974	339,654
WILLIAMS F15-17D	VER	77,700	271,740	349,440
WILLIAMS F15-22D	VER	69,300	288,372	357,672
WILSON 35-25	VER	76,440	309,582	386,022
WILSON PC AC20-10	VER	85,050	264,936	349,986
WYSCAVER USX CC05-25	VER	78,750	411,936	490,686

Appendix H

Noble Wells Measured Distance and True Vertical Distance Data

Table H.1: Measured distance and true vertical distance for 2010 and 2011 Noble Energy wells in the Wattenberg Field

Well Name	Well Type	Measured Distance	True Vertical Distance
Distances Measured in Feet			
70 RANCH BB21-63HN	HOR	10933.9	6396.4
70 RANCH BB21-65HN	HOR	10909.8	6398
70 RANCH BB21-67HN	HOR	10925.1	6404
ARISTOCRAT PC H11-27D	VER	7363	7252
BASHOR PC AA17-02D	VER	7006.4	6924
BETZ PC G09-31D	VER	7497	7275
BOOTH N25-18D	VER	7835.3	7705
BOOTH N25-33D	VER	7711	7600
COLEMAN C22-18D	VER	7089.4	6964
DEGENHART STATE AE16-63HN	HOR	11055	6623.1
DEGENHART USX AE17-63HN	HOR	11055	6623.1
DINNEL C27-28D	VER	7107	7000
EHRLICH STATE PC F36-33D	VER	7374	7241
FEIT E23-97HZ	HOR	1191.08	6843.82
FEIT E23-98HZ	HOR	11206.25	6855.76
FEIT E23-99HZ	HOR	10657.48	6875.52
FRANKLIN C08-62HN	HOR	8663	6840
FRAZIER 33-15	VER	7300	
FRICK C17-79HN	HOR	8663	6795
FRICK PC C17-65HN	HOR	11423.57	6812.66

Noble Wells Measured Distance and True Vertical Distance Data

Well Name	Well Type	Measured Distance	True Vertical Distance
Distances Measured in Feet			
GABEL USX AB21-14	VER	7342	
GULLEY 17-15	VER	7177	
GULLEY 17-25	VER	7151	
GUTTERSEN D02-75HN	HOR	10743.44	6629.87
GUTTERSEN D04-32	VER	7110	
GUTTERSEN D22-27	VER	7150	
GUTTERSEN D23-20	VER	7172	
GUTTERSEN D29-65HN	HOR	10946.65	6762.56
GUTTERSEN D29-99HZ	HOR	11124.85	6804
GUTTERSEN STATE D28-79HN	HOR	11056.74	6779.04
HANSCOME G12-31	VER	7246	
HAYTHORN 04-24	VER	7515	
HERBST C22-22D	VER	7066	6952
KLEIN B16-98HZ	HOR	11995.2	6650.5
KLEIN B16-99HZ	HOR	12212.21	6650.5
MEGAN H16-99HZ	HOR	11184.9	7022
NELSON K27-63HN	HOR	12564.2	7046
PEDRO STATE C31-79HN	HOR	11104.5	6885
RICHTER USX AB27-13	VER	7316	
RICHTER USX AB27-25	VER	7294	
ROHR A28-25	VER	7081	
ROTH USX A30-17	VER	7108	
ROTHE BB30-23	VER	6743	
SATER C12-21	VER	6903	
SATER CC18-14	VER	6929	
SCHMIDT K23-24D	VER	7522	7097
SCHOLFIELD STATE A36-69HN	HOR	10677.52	6633.7
SCHOLFIELD STATE A36-79HN	HOR	10667.41	6619.65
SEKICH P19-18D	VER	7616	7415
SEKICH P19-21D	VER	7433	7400
SEKICH P19-24D	VER	7618	7420
SEKICH P19-27D	VER	8036	7882
SHELTON PC D06-32D	VER	7719	7221
SHERWOOD L30-29D	VER	8095	7983
SHERWOOD L30-30D	VER	8113	7987
SHERWOOD L30-31D	VER	8112	7974
SHERWOOD L30-32D	VER	8367	7921
SMITH PC D06-20D	VER	7325	7201
SPIKE STATE D16-99HZ	HOR	11132.35	6760.55
STATE C24-99HZ	HOR	10843.69	6543.01
STATE C36-32D	VER	7156	7005
STATE C36-33D	VER	7081	7038
STATE C36-99HZ	HOR	10544.68	6611.86

Noble Wells Measured Distance and True Vertical Distance Data

Well Name	Well Type	Measured Distance	True Vertical Distance
Distances Measured in Feet			
STROH H12-32	VER	7790	
STROHAUER F32-21D	VER	7424	7256
STROHAUER F32-22D	VER	7466	7265
STROHAUER F32-23	VER	7280	
TANIA D11-27D	VER	7200	6998
TANIA D11-28	VER	6979	
TANNER K33-65HN	HOR	12603.8	7052.4
THOMPSON C28-79HN	HOR	10884.5	6756.4
THOMPSON C33-69HN	HOR	10774.1	6740.5
UPRC G07-99HZ	HOR	11923.25	6977.54
UPRC H17-99HZ	HOR	7453	
WACKER B10-20D	VER	7164	6992
WALCKER 12-23	VER	7230	
WARDELL H19-32D	VER	8179	7988
WARDELL H19-33D	VER	13049	7428
WARDELL PC H20-24	VER	7476	
WARNER W13-11	VER	8143	
WEIDENKELLER PC G01-20D	VER	7645	7225
WEIDENKELLER PC G01-21D	VER	7628	7238
WEIDENKELLER PC G01-27D	VER	7575	7217
WEIDENKELLER PC G01-28D	VER	7373	7256
WEIDENKELLER PC G01-29D	VER	7400	7254
WEIDENKELLER PC G01-30D	VER	7770	7267
WELLS RANCH AE18-17	VER	6973	
WELLS RANCH AE20-16	VER	6934	
WELLS RANCH AE30-68HN	HOR	10955.5	6557
WELLS RANCH PC AA22-01	VER	6925	
WELLS RANCH PC AA22-02	VER	6935	
WELLS RANCH PC AA22-03	VER	6956	
WELLS RANCH PC AA22-04	VER	6943	
WELLS RANCH PC AA22-07	VER	6956	
WELLS RANCH PC AA22-08	VER	6955	
WELLS RANCH PC AA22-13	VER	6995	
WELLS RANCH USX AA11-65HN	HOR	11011.1	6610.5
WELLS RANCH USX AA11-67HN	HOR	11088.3	6656.3
WELLS RANCH USX BB15-65HN	HOR	10905.26	6480.54
WELLS RANCH USX BB15-67HN	HOR	10613.61	6502.47
WEST IRRIGATION USX AB33-23	VER	7325	
WILSON 35-25	VER	7482	
WILSON PC AC20-10	VER	7130	

Noble Wells Measured Distance and True Vertical Distance Data

Appendix I

Noble Estimated Ultimate Gas Recovery Data

Table I.1: Estimated ultimate gas recovery for 2010 and 2011 Noble Energy wells in the Wattenberg Field

Well Name	Well Type	Low	Average	High
Estimated Ultimate Recovery per Well (MMBtu)				
70 RANCH BB21-63HN	HOR			
70 RANCH BB21-65HN	HOR	78,960	166,040	253,120
70 RANCH BB21-67HN	HOR	111,440	59,220	7,000
70 RANCH USX BB09-63HN	HOR	141,120	285,880	430,640
ABBEY D01-23	VER	31,472	57,736	84,000
ABBEY D01-27	VER	32,480	89,040	145,600
ABBEY D01-29	VER	17,864	32,508	47,152
ADAMS D30-27D	VER	20,384	15,092	9,800
ALOYSIUS C34-18	VER	39,928	63,644	87,360
ALOYSIUS C34-20D	VER	64,400	103,040	141,680
ALOYSIUS C34-21D	VER	41,720	54,180	66,640
ALOYSIUS C34-22D	VER	39,032	65,156	91,280
ALOYSIUS C34-24	VER	32,872	52,276	71,680
ALOYSIUS C34-27D	VER	30,016	29,232	28,448
ALOYSIUS C34-28D	VER	37,072	38,192	39,312
ALOYSIUS C34-30D	VER	24,808	29,596	34,384
ALOYSIUS C34-31	VER	28,560	43,680	58,800
ALOYSIUS C34-32D	VER	64,400	105,840	147,280
ALOYSIUS C34-33D	VER	58,240	92,680	127,120
ALOYSIUS C34-99HZ	HOR	155,120	424,760	694,400
ANNIE B03-23	VER	15,176	11,256	7,336

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
ARISTOCRAT PC H11-07	VER			
ARISTOCRAT PC H11-18D	VER	8,176	10,892	13,608
ARISTOCRAT PC H11-19D	VER	12,376	22,204	32,032
ARISTOCRAT PC H11-27D	VER	9,800	16,268	22,736
ARISTOCRAT PC H11-29D	VER	21,784	58,212	94,640
ARISTOCRAT PC H11-30D	VER			
ARISTOCRAT PC H11-32D	VER			
BADDING USX W25-07D	VER	7,952	5,176.5	2,401
BASHOR PC AA09-08	VER	20,328	36,820	53,312
BASHOR PC AA09-14	VER	17,304	31,164	45,024
BASHOR PC AA09-22	VER	34,944	63,952	92,960
BASHOR PC AA09-23	VER	25,592	50,036	74,480
BASHOR PC AA09-24	VER	25,032	45,556	66,080
BASHOR PC AA17-02D	VER	26,264	19,656	13,048
BASHOR PC AA17-17	VER	44,408	54,404	64,400
BASHOR PC AA17-21	VER	43,232	71,176	99,120
BASHOR PC AA17-22	VER	41,664	28,560	15,456
BASHOR PC AA17-23	VER	43,064	55,412	67,760
BASHOR PC AA17-24	VER	49,840	52,640	55,440
BERNHARDT STATE PC N36-17	VER	8,064	14,616	21,168
BERRY P08-18D	VER			
BERRY P08-28D	VER			
BERRY P08-29D	VER			
BETZ PC G09-19	VER	20,832	38,976	57,120
BETZ PC G09-23	VER	7,504	13,944	20,384
BETZ PC G09-31D	VER	18,816	33,740	48,664
BETZ PC G10-33D	VER	12,992	23,632	34,272
BICKLING PC E02-33D	VER	3,048	8,496	13,944
BICKLING PC E03-22D	VER	4,041	9,468.5	14,896
BOOTH N25-18D	VER	23,576	40,628	57,680
BOOTH N25-20D	VER	5,768	5,852	5,936
BOOTH N25-21D	VER	4,856	9,260	13,664
BOOTH N25-22D	VER	8,512	12,208	15,904
BOOTH N25-24D	VER	8,120	16,184	24,248
BOOTH N25-31D	VER	21,616	36,036	50,456
BOOTH N25-33D	VER	19,600	33,740	47,880
BOULTER PC G14-29D	VER	5,768	11,928	18,088
BOULTER PC G14-30D	VER	11,088	25,816	40,544
BROWN PC E02-31D	VER	7,280	14,924	22,568
BROWN PC E02-32	VER	8,344	17,388	26,432
BURGHART D04-22	VER	30,464	54,992	79,520
CALVARY USX EE29-04D	VER	249	1,440.5	2,632
CAMP H30-29D	VER	37,072	64,456	91,840
CAMP H30-32	VER	28,448	59,024	89,600
CAMP H30-33	VER	19,488	43,344	67,200

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
CANNON H35-20	VER	12,320	18,676	25,032
CANNON H35-21	VER	9,464	21,560	33,656
CANNON H35-22	VER	7,616	18,424	29,232
CANNON H35-24	VER	9,744	19,488	29,232
CANNON W15-18D	VER	11,368	25,760	40,152
CANNON W15-19	VER	11,536	25,536	39,536
CANNON W15-21D	VER	15,008	32,116	49,224
CARLSON A18-17	VER	30,520	56,140	81,760
CARLSON K23-18D	VER	5,824	10,304	14,784
CARLSON K23-22D	VER	5,936	11,704	17,472
CARMIN USX CC05-10D	VER	46,872	89,236	131,600
CARMIN USX CC05-16D	VER	38,808	73,444	108,080
CARMIN USX CC05-17D	VER	25,704	47,012	68,320
CODY D03-20	VER	25,816	50,148	74,480
CODY D03-28	VER	24,080	44,800	65,520
COLEMAN C22-17	VER	5,265	9,268.5	13,272
COLEMAN C22-18	VER	25,424	42,392	59,360
COLEMAN C22-21D	VER	21,448	36,260	51,072
COLEMAN C22-27	VER	23,464	43,652	63,840
CONNELL C04-31D	VER			
COX PC GK35-99HZ	HOR			
CRICKET C22-30D	VER	22,680	41,020	59,360
CROISSANT USX WW11-02D	VER	6,328	10,500	14,672
CROISSANT USX WW11-08D	VER	2,819	6,197.5	9,576
CROISSANT USX WW11-17D	VER	2,634	6,413	10,192
DECHANT 07-15	VER			
DECHANT 7-1-17	VER	19,208	33,404	47,600
DECHANT D18-27D	VER	8,680	19,012	29,344
DECHANT D18-30D	VER			
DECHANT D31-18D	VER			
DECHANT D31-21D	VER			
DECHANT D31-22D	VER			
DECHANT D31-24D	VER			
DECHANT STATE H36-11	VER			
DECHANT STATE H36-18D	VER			
DECHANT STATE H36-19	VER			
DECHANT STATE H36-20D	VER			
DECHANT STATE H36-21D	VER			
DECHANT STATE H36-31D	VER			
DECHANT STATE H36-32D	VER			
DECHANT X01-02	VER			
DECHANT X01-03	VER			
DECHANT X01-04	VER			
DECHANT X01-06	VER			
DECHANT X01-07	VER			

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
DECHANT X01-08	VER	24,640	42,280	59,920
DECHANT X08-09	VER	8,344	16,352	24,360
DECHANT X08-10X	VER	11,816	22,736	33,656
DECHANT X08-15	VER	10,136	19,740	29,344
DECHANT X08-24D	VER	20,104	38,892	57,680
DECHANT Y06-27D	VER	18,200	35,840	53,480
DECHANT Y06-28D	VER	20,888	46,284	71,680
DEGENHART STATE AE16-63HN	HOR	100,240	211,680	323,120
DEGENHART USX AE17-63HN	HOR	114,240	238,560	362,880
DF RANCH PC GK09-99HZ	HOR			
DILLARD 10-44	VER	31,192	58,156	85,120
DILLARD KG34-13	VER	4,805	8,114.5	11,424
DINNEL C27-28D	VER	39,368	65,604	91,840
DINNEL C27-29D	VER	31,640	52,220	72,800
DINNER 01-01-19	VER	21,560	35,952	50,344
DINNER 13-35	VER	22,624	36,540	50,456
DINNER PC G01-22	VER	22,624	37,632	52,640
DONALDSON USX EE29-06D	VER	170	536.5	903
DRAKE PC MM14-08D	VER			
DRAKE PC MM14-15D	VER			
EASTON G12-20D	VER	15,176	30,604	46,032
EASTON G12-32D	VER	18,928	35,560	52,192
EGGE USX A03-11D	VER	6,496	16,716	26,936
EHRLICH STATE PC F36-31D	VER	19,488	32,116	44,744
EHRLICH STATE PC F36-32D	VER	12,824	22,008	31,192
EHRLICH STATE PC F36-33D	VER	18,872	31,948	45,024
ERICKSON PC G15-27D	VER	11,312	27,384	43,456
FEIT E23-97HZ	HOR	259,280	454,440	649,600
FEIT E23-98HZ	HOR	271,600	485,800	700,000
FEIT E23-99HZ	HOR	309,680	555,240	800,800
FIVE RIVERS K03-33D	VER	5,442	12,213	18,984
FIVE RIVERS K04-20D	VER			
FIVE RIVERS K04-21D	VER			
FIVE RIVERS K04-25	VER			
FIVE RIVERS K04-32D	VER			
FIVE RIVERS K08-07D	VER	14,168	31,052	47,936
FIVE RIVERS K08-17D	VER	3,641	9,380.5	15,120
FIVE RIVERS K08-22D	VER	5,127	10,067.5	15,008
FIVE RIVERS K08-23	VER	15,960	28,756	41,552
FIVE RIVERS K08-24D	VER	10,248	18,956	27,664
FIVE RIVERS K09-29D	VER			
FIVE RIVERS K09-30D	VER			
FIVE RIVERS K09-33D	VER	13,048	22,680	32,312
FIVE RIVERS K10-30D	VER	3,484	6,670	9,856
FIVE RIVERS K15-30D	VER	14,056	27,412	40,768

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
FIVE RIVERS K15-31D	VER	10,024	18,060	26,096
FIVE RIVERS K16-17	VER	6,216	11,312	16,408
FIVE RIVERS K16-30D	VER			
FIVE RIVERS USX K09-01D	VER			
FIVE RIVERS USX K09-08D	VER			
FIVE RIVERS USX K09-17D	VER			
FIVE RIVERS USX K09-22D	VER			
FOOSE A18-23	VER			
FOSS 06-35	VER			
FOSS USX AA05-03	VER			
FRANK PC H22-20D	VER			
FRANKLIN C08-62HN	HOR	57,120	138,880	220,640
FRANKLIN C17-69HN	HOR	71,680	176,680	281,680
FRANKLIN C18-27D	VER	7,224	15,008	22,792
FRAZIER 33-15	VER	12,992	22,876	32,760
FRICK C17-79HN	HOR	84,560	194,600	304,640
FRICK PC C17-65HN	HOR	114,240	240,520	366,800
GABEL USX AB21-14	VER			
GITTLEIN D04-33	VER	17,416	31,360	45,304
GREEN USX XX07-07	VER	5,050	12,101	19,152
GREEN USX XX07-08	VER	5,426	11,421	17,416
GULLEY 17-13	VER	15,288	25,928	36,568
GULLEY 17-15	VER	38,304	66,192	94,080
GULLEY 17-25	VER	36,288	66,024	95,760
GUNNER STATE AA16-99HZ	HOR			
GURTLER H24-99HZ	HOR	129,360	208,880	288,400
GUTTERSEN D02-32D	VER	8,904	24,780	40,656
GUTTERSEN D02-75HN	HOR	109,200	206,360	303,520
GUTTERSEN D03-33D	VER	14,504	26,768	39,032
GUTTERSEN D04-32	VER	36,008	56,084	76,160
GUTTERSEN D09-27D	VER	7,392	16,940	26,488
GUTTERSEN D10-30D	VER	3,043	8,325.5	13,608
GUTTERSEN D22-27	VER	25,144	44,212	63,280
GUTTERSEN D23-20	VER	21,784	38,500	55,216
GUTTERSEN D25-17	VER	4,117	9,506.5	14,896
GUTTERSEN D29-33D	VER	12,264	22,176	32,088
GUTTERSEN D29-65HN	HOR	157,360	273,840	390,320
GUTTERSEN D29-99HZ	HOR	137,760	230,720	323,680
GUTTERSEN STATE CC20-30D	VER			
GUTTERSEN STATE CC20-31D	VER			
GUTTERSEN STATE CC20-32D	VER			
GUTTERSEN STATE CC20-33D	VER			
GUTTERSEN STATE D22-18	VER	11,088	21,504	31,920
GUTTERSEN STATE D22-22	VER			
GUTTERSEN STATE D22-24	VER			

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
GUTTERSEN STATE D28-79HN	HOR	151,200	265,440	379,680
HANSCOME G12-31	VER	30,632	51,156	71,680
HARPER USX EE27-02D	VER	10,640	21,000	31,360
HARPER USX EE27-07D	VER	7,952	17,164	26,376
HARPER USX EE27-15D	VER	20,776	40,908	61,040
HARPER USX EE27-23D	VER	11,088	22,344	33,600
HAYTHORN 04-21	VER			
HAYTHORN 04-24	VER			
HBR PC G11-32D	VER			
HEATH PC GK02-07	VER			
HERBST C22-22D	VER			
HERBST C22-24	VER			
HERBST C22-25	VER			
HIPPO D27-24D	VER			
HIPPO D34-29D	VER			
HOFF PC D06-21	VER			
HOFF PC D06-27	VER			
HOFFMAN B33-19	VER			
HORTON D18-20D	VER			
HOUNDSKEEPER PC H01-21D	VER			
HOWARD A27-17D	VER			
HOWARD USX A09-02D	VER			
HOWARD USX A09-06D	VER			
HOWARD USX A09-09D	VER			
HOWARD USX A09-12D	VER			
HOWARD USX A09-14D	VER			
HOWARD USX A09-15D	VER			
HOWARD USX A09-23	VER			
HP FARMS D32-24D	VER			
HP Y07-09	VER	21,896	41,748	61,600
HP Y07-10D	VER			
HUDSON STATE X36-07D	VER	2,333	3,282	4,231
IGO FARMS J28-19D	VER	8,624	15,484	22,344
IGO FARMS J28-20D	VER	26,376	42,868	59,360
IGO FARMS J28-31D	VER	8,344	14,000	19,656
IGO FARMS J28-32D	VER	8,736	15,008	21,280
JOHNSON PC EE33-09D	VER	15,176	16,044	16,912
JOHNSON PC EE33-10D	VER	21,616	55,608	89,600
JOHNSON PC EE33-15D	VER	19,600	35,896	52,192
JOHNSON PC EE33-16D	VER	13,944	18,004	22,064
JOHNSON PC EE33-23D	VER	24,752	39,872	54,992
KARCH STATE D10-22	VER			
KERBS USX A15-12D	VER	10,192	24,500	38,808
KLEIN B15-13D	VER	29,008	62,384	95,760
KLEIN B16-98HZ	HOR	378,000	712,600	1,047,200

Noble Estimated Ultimate Gas Recovery Data

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
KLEIN B16-99HZ	HOR	383,040	723,520	1,064,000
LAND USX Y31-01	HOR	4,852	12,674	20,496
LANG C22-28D	VER	22,456	38,528	54,600
LARSON A32-17	VER	16,800	33,180	49,560
LDS D17-18	VER	12,824	28,756	44,688
LDS D17-22	VER	12,320	27,552	42,784
LDS D17-31D	VER	13,720	32,648	51,576
LDS D17-32D	VER	9,688	18,452	27,216
LDS E25-32	VER	26,432	45,696	64,960
LDS E25-33D	VER	26,488	45,724	64,960
LETTERLY USX AB23-68HN	HOR			
LIND 23-15	VER	26,376	45,948	65,520
LINDBLAD 17-34	VER	5,528	14,496	23,464
LINDBLAD 20-25	VER	13,776	23,184	32,592
LOWER LATHAM PC G11-69HN	HOR	112,000	252,280	392,560
LOWER LATHAM PC G12-69HN	HOR			
LOYD PC GD33-13	VER			
LYSTER E26-22D	VER	25,312	44,296	63,280
LYSTER E26-23	VER	39,032	74,116	109,200
MARIE D04-20	VER	28,392	51,436	74,480
MARLEY C01-18D	VER	28,280	50,820	73,360
MARLEY C01-28D	VER	8,064	9,968	11,872
MARLEY C01-30D	VER	4,616	12,108	19,600
MARLEY C01-31D	VER	16,016	29,848	43,680
MCCLELLAN PC LG04-15	VER			
MCWILLIAMS 15-3-17	VER	18,816	30,492	42,168
MEGAN H16-99HZ	HOR	99,120	173,040	246,960
MILLAGE C11-18	VER	27,384	46,452	65,520
MILLER X31-03	VER	9,632	15,792	21,952
MILLER X31-04	VER	14,672	25,676	36,680
MILLER X31-06	VER	11,032	13,748	16,464
MILLER X31-10	VER	8,456	17,360	26,264
MOJACK USX AB21-15	VER	3,496	6,396	9,296
MOSER PC H22-21D	VER	25,424	48,552	71,680
MOSER PC H22-24	VER	21,448	36,232	51,016
MOSER PC H22-33	VER	25,088	43,344	61,600
MOSIER K23-20D	VER	4,664	9,416	14,168
MOSIER K23-21D	VER	5,992	12,068	18,144
MOSIER K23-33D	VER	6,216	11,928	17,640
NCLP PC AA04-04	VER			
NCLP PC AA04-05	VER			
NCLP PC AA04-06	VER			
NCLP PC AA04-11	VER			
NCLP PC AA04-12	VER			
NCLP PC AA04-13	VER			

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
NCLP PC AA04-14	VER			
NCLP PC AA04-19	VER			
NCLP PC AA04-20	VER			
NCLP PC AA04-25	VER			
NCLP PC AA08-02D	VER			
NCLP PC AA08-03D	VER			
NCLP PC AA08-07D	VER			
NCLP PC AA08-08D	VER			
NCLP PC AA08-18D	VER			
NCLP PC AA08-19	VER			
NELSON K27-63HN	HOR	160,160	351,120	542,080
NOFFSINGER 35-13	VER	19,040	35,280	51,520
NOFFSINGER 35-15	VER	31,976	56,308	80,640
OJEDA USX XX07-09D	VER	3,825	6,056.5	8,288
ORR USX A03-15D	VER	14,840	19,404	23,968
OWENS K17-15	VER	14,056	24,724	35,392
OWENS K17-23D	VER	10,136	17,528	24,920
PEDRO STATE C31-79HN	HOR	231,840	460,320	688,800
PEPPLER PC AA17-20	VER	19,040	30,660	42,280
PEPPLER PC AA17-25	VER			
PETERSON B10-24D	VER			
PETERSON PC LG19-06	VER			
PHILLIPS 23-1-17	VER			
PHILLIPS 23-1-20	VER			
PHILLIPS 23-1-21	VER			
PHILLIPS 24-2-20D	VER			
PHILLIPS 24-3-17	VER			
PHILLIPS 24-3-21	VER			
PHILLIPS 24-3-23	VER			
PHILLIPS PC N24-25	VER			
PHILLIPS PC N24-29D	VER			
PHILLIPS PC N24-31D	VER			
PIONEER USX Y07-08D	VER			
PIONEER Y07-07D	VER			
POWERS X22-02	VER			
POWERS X22-04	VER			
POWERS X22-31	VER			
PURCELL PC GK11-10	VER			
PVA X31-16	VER			
QC A32-19	VER			
RAY H12-24D	VER			
REI H08-13D	VER			
REI H08-15D	VER			
REI H08-21D	VER			
REI H08-24D	VER			

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
RHINO D27-18D	VER			
RHINO D27-19D	VER			
RHINO D27-20D	VER	4,202	9,105	14,008
RHINO D27-21	VER	4,748	10,614	16,480
RHINO D27-22D	VER	4,707	10,542	16,377
RHINO D27-27D	VER	6,335	15,115.5	23,896
RHINO D27-28D	VER	5,789	12,731	19,673
RICHTER USX AB27-03	VER			
RICHTER USX AB27-05	VER			
RICHTER USX AB27-13	VER	4,604	7,915.5	11,227
RICHTER USX AB27-25	VER	3,214	5,763	8,312
RICHTER USX AB27-65HN	HOR	11,948	24,926	37,904
RITCHEY USX WW27-19D	VER	822	1,698.5	2,575
ROGERS USX A03-09D	VER	2,688	6,375.5	10,063
ROHN PC LD04-03	VER			
ROHN PC LD09-01	VER			
ROHN PC LD16-96HN	HOR			
ROHR A28-25	VER	36,359	62,006	87,653
ROTH USX A30-17	VER	30,797	55,517	80,237
ROTHE BB30-23	VER	44,908	80,649	116,390
SATER C12-21	VER	16,171	29,406.5	42,642
SATER CC18-14	VER	32,445	56,083.5	79,722
SATER CC18-23	VER	8,374	15,980.5	23,587
SCHMIDT K23-24D	VER	96,202	179,426	262,650
SCHOLFIELD STATE A36-69HN	HOR	297,670	563,410	829,150
SCHOLFIELD STATE A36-79HN	HOR	304,880	583,495	862,110
SEKICH P19-18D	VER	11,845	21,063.5	30,282
SEKICH P19-21D	VER	43,157	79,773.5	116,390
SEKICH P19-24D	VER	37,286	70,040	102,794
SEKICH P19-27D	VER	61,079	103,669.5	146,260
SEKICH P19-28D	VER	79,928	137,299	194,670
SHELTON G25-22	VER	17,510	43,466	69,422
SHELTON PC D06-32D	VER	49,543	83,996.5	118,450
SHERWOOD L30-29D	VER	123,600	201,365	279,130
SHERWOOD L30-30D	VER	139,050	252,350	365,650
SHERWOOD L30-31D	VER	54,693	104,081.5	153,470
SHERWOOD L30-32D	VER	59,122	105,266	151,410
SMITH PC D06-20D	VER	76,735	140,852.5	204,970
SOONER STATE B36-63HN	HOR	118,450	288,400	458,350
SPIKE STATE D10-21D	VER			
SPIKE STATE D16-99HZ	HOR			
STATE C24-99HZ	HOR	216,300	410,455	604,610
STATE C36-32D	VER	42,539	73,284.5	104,030
STATE C36-33D	VER	24,926	48,719	72,512
STATE C36-99HZ	HOR	184,370	360,500	536,630

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
STATE D01-30D	VER	22,866	43,569	64,272
STEWARDSON USX WW33-01D	VER	269	609.5	950
STEWARDSON USX WW33-03D	VER	266	560.5	855
STOCKLEY C15-79HN	HOR	127,720	247,200	366,680
STOCKLEY C22-79HN	HOR	128,750	279,130	429,510
STREAR V03-73HN	HOR	90,022	193,846	297,670
STREAR V06-63HN	HOR	47,071	96,665.5	146,260
STROH H12-32	VER	97,747	165,263.5	232,780
STROHAUER F32-21D	VER	87,756	130,913	174,070
STROHAUER F32-22D	VER	86,314	146,672	207,030
STROHAUER F32-23	VER	52,118	83,739	115,360
STROHAUER F32-24	VER			
TANIA D11-27D	VER	36	87.5	139
TANIA D11-28	VER	9,744	26,399	43,054
TANNER K33-65HN	HOR	672,590	1,340,545	2,008,500
THOMPSON C28-79HN	HOR	179,220	354,320	529,420
THOMPSON C33-30D	VER	8,219	16,057.5	23,896
THOMPSON C33-69HN	HOR	95,893	216,351.5	336,810
TYE USX A15-03D	VER	9,167	18,179.5	27,192
TYE USX A15-04D	VER	4,614	9,517	14,420
UPRC G07-99HZ	HOR	770,440	1,420,370	2,070,300
UPRC H17-99HZ	HOR	388,310	719,455	1,050,600
WACKER B01-79HN	HOR	48,307	124,063.5	199,820
WACKER B10-20D	VER	38,522	86,211	133,900
WACKER B11-69HN	HOR	46,659	113,454.5	180,250
WACKER B12-69HN	HOR	32,342	93,421	154,500
WALCKER 12-23	VER	9,847	22,176	34,505
WALCKER AB12-08	VER	4	14	24
WALCKER AB12-09	VER			
WARDELL H19-32D	VER	55,620	119,995	184,370
WARDELL H19-33D	VER	50,676	84,048	117,420
WARDELL PC H20-24	VER	42,951	88,425.5	133,900
WARNER W13-11	VER	28,325	53,663	79,001
WEIDENKELLER PC G01-20D	VER	70,555	115,617.5	160,680
WEIDENKELLER PC G01-21D	VER	57,268	106,399	155,530
WEIDENKELLER PC G01-27D	VER	29,046	52,015	74,984
WEIDENKELLER PC G01-28D	VER	43,466	80,958	118,450
WEIDENKELLER PC G01-29D	VER	47,071	96,150.5	145,230
WEIDENKELLER PC G01-30D	VER	30,488	52,839	75,190
WEIDENKELLER PC G01-31D	VER	38,831	68,340.5	97,850
WELLS RANCH AA12-08	VER			
WELLS RANCH AA12-09	VER			
WELLS RANCH AE05-12	VER			
WELLS RANCH AE18-17	VER	5,109	12,185	19,261
WELLS RANCH AE20-16	VER	15,759	33,114.5	50,470

Noble Estimated Ultimate Gas Recovery Data

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
WELLS RANCH AE30-68HN	HOR	87,653	189,571.5	291,490
WELLS RANCH PC AA22-01	VER	17,922	36,822.5	55,723
WELLS RANCH PC AA22-02	VER	5,480	123,087,740	246,170,000
WELLS RANCH PC AA22-03	VER	27,913	50,779	73,645
WELLS RANCH PC AA22-04	VER	10,506	19,106.5	27,707
WELLS RANCH PC AA22-07	VER	1,133	3,270.5	5,408
WELLS RANCH PC AA22-08	VER	20,600	35,947	51,294
WELLS RANCH PC AA22-13	VER	35,226	59,122	83,018
WELLS RANCH USX AA11-65HN	HOR			
WELLS RANCH USX AA11-67HN	HOR			
WELLS RANCH USX AE29-68HN	HOR	184,370	308,485	432,600
WELLS RANCH USX BB15-65HN	HOR	313,120	597,400	881,680
WELLS RANCH USX BB15-67HN	HOR	219,390	436,205	653,020
WEST IRRIGATION USX AB33-23	VER	6,448	16,614	26,780
WILLIAMS F15-17D	VER	17,613	33,990	50,367
WILLIAMS F15-22D	VER	10,609	29,252	47,895
WILSON 35-25	VER	38,522	75,396	112,270
WILSON PC AC20-10	VER	818	2,350.5	3,883
WYSCAVER USX CC05-25	VER			

Appendix J

Noble Estimated Ultimate Gas Recovery Data

Table J.1: Estimated ultimate oil recovery for 2010 and 2011 Noble Energy wells in the Wattenberg Field

Well Name	Well Type	Low	Average	High
Estimated Ultimate Recovery per Well (MMBtu)				
70 RANCH BB21-63HN	HOR			
70 RANCH BB21-65HN	HOR			1,411,100
70 RANCH BB21-67HN	HOR	123,600	299,730	475,860
70 RANCH USX BB09-63HN	HOR	138,020	303,335	468,650
ABBEY D01-23	VER	15,450	25,029	34,608
ABBEY D01-27	VER	36,462	66,898.5	97,335
ABBEY D01-29	VER	15,141	13,287	11,433
ADAMS D30-27D	VER	23,072	41,818	60,564
ALOYSIUS C34-18	VER	50,161	84,305.5	118,450
ALOYSIUS C34-20D	VER	64,375	100,682.5	136,990
ALOYSIUS C34-21D	VER	48,925	41,303	33,681
ALOYSIUS C34-22D	VER	28,119	18,262	8,405
ALOYSIUS C34-24	VER	47,586	77,353	107,120
ALOYSIUS C34-27D	VER	30,282	60,255	90,228
ALOYSIUS C34-28D	VER	43,569	71,688	99,807
ALOYSIUS C34-30D	VER	42,333	69,473.5	96,614
ALOYSIUS C34-31	VER	44,908	41,251.5	37,595
ALOYSIUS C34-32D	VER	71,894	125,042	178,190
ALOYSIUS C34-33D	VER	69,113	111,806.5	154,500
ALOYSIUS C34-99HZ	HOR	229,690	345,050	460,410
ANNIE B03-23	VER	42,436	69,113	95,790

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
ARISTOCRAT PC H11-07	VER	622	1,099	1,576
ARISTOCRAT PC H11-18D	VER	33,887	69,988.5	106,090
ARISTOCRAT PC H11-19D	VER	77,971	168,250.5	258,530
ARISTOCRAT PC H11-27D	VER	36,977	64,117.5	91,258
ARISTOCRAT PC H11-29D	VER	91,773	174,636.5	257,500
ARISTOCRAT PC H11-30D	VER			
ARISTOCRAT PC H11-32D	VER			
BADDING USX W25-07D	VER	16,583	8,414	245
BASHOR PC AA09-08	VER	5,521	11,412.5	17,304
BASHOR PC AA09-14	VER	7,643	6,468.5	5,294
BASHOR PC AA09-22	VER	13,184	25,132	37,080
BASHOR PC AA09-23	VER	12,257	21,166.5	30,076
BASHOR PC AA09-24	VER	9,867	9,213	8,559
BASHOR PC AA17-02D	VER	20,703	31,106	41,509
BASHOR PC AA17-17	VER	26,368	24,720	23,072
BASHOR PC AA17-21	VER	38,625	65,044.5	91,464
BASHOR PC AA17-22	VER	57,371	104,905.5	152,440
BASHOR PC AA17-23	VER	32,136	52,118	72,100
BASHOR PC AA17-24	VER	44,084	72,821	101,558
BERNHARDT STATE PC N36-17	VER	15,862	31,466.5	47,071
BERRY P08-18D	VER			
BERRY P08-28D	VER			
BERRY P08-29D	VER			
BETZ PC G09-19	VER	148,320	269,860	391,400
BETZ PC G09-23	VER	45,835	82,142.5	118,450
BETZ PC G09-31D	VER	105,060	169,950	234,840
BETZ PC G10-33D	VER	85,181	148,165.5	211,150
BICKLING PC E02-33D	VER	1,566	2,050	2,534
BICKLING PC E03-22D	VER	1,936	3,991	6,046
BOOTH N25-18D	VER	51,191	95,635.5	140,080
BOOTH N25-20D	VER	6,118	11,865.5	17,613
BOOTH N25-21D	VER	8,601	9,502	10,403
BOOTH N25-22D	VER	12,154	33,269	54,384
BOOTH N25-24D	VER	12,257	21,836	31,415
BOOTH N25-31D	VER	61,285	116,132.5	170,980
BOOTH N25-33D	VER	41,406	78,898	116,390
BOULTER PC G14-29D	VER	18,231	41,303	64,375
BOULTER PC G14-30D	VER	25,853	50,058	74,263
BROWN PC E02-31D	VER	772	1,745.5	2,719
BROWN PC E02-32	VER	1,730	3,584	5,438
BURGHART D04-22	VER	25,132	44,032.5	62,933
CALVARY USX EE29-04D	VER	10	22	34
CAMP H30-29D	VER	93,421	175,460.5	257,500
CAMP H30-32	VER	78,692	167,066	255,440
CAMP H30-33	VER	27,604	63,499.5	99,395

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
CANNON H35-20	VER	9,795	20,244.5	30,694
CANNON H35-21	VER	9,826	22,114	34,402
CANNON H35-22	VER	16,480	39,191.5	61,903
CANNON H35-24	VER	9,610	19,997.5	30,385
CANNON W15-18D	VER	16,377	33,990	51,603
CANNON W15-19	VER	17,304	40,633.5	63,963
CANNON W15-21D	VER	55,002	126,381	197,760
CARLSON A18-17	VER	39,861	70,606.5	101,352
CARLSON K23-18D	VER	30,488	53,096.5	75,705
CARLSON K23-22D	VER	27,192	44,856.5	62,521
CARMIN USX CC05-10D	VER	15,038	28,891.5	42,745
CARMIN USX CC05-16D	VER	12,257	22,454	32,651
CARMIN USX CC05-17D	VER	5,150	11,639	18,128
CODY D03-20	VER	25,441	51,654.5	77,868
CODY D03-28	VER	24,308	42,127	59,946
COLEMAN C22-17	VER			
COLEMAN C22-18	VER	31,415	54,899	78,383
COLEMAN C22-21D	VER	28,428	49,285.5	70,143
COLEMAN C22-27	VER	13,699	23,741.5	33,784
CONNELL C04-31D	VER			
COX PC GK35-99HZ	HOR			
CRICKET C22-30D	VER	32,239	60,461	88,683
CROISSANT USX WW11-02D	VER	3,162	7,246	11,330
CROISSANT USX WW11-08D	VER			
CROISSANT USX WW11-17D	VER			
DECHANT 07-15	VER			
DECHANT 7-1-17	VER	64,478	119,274	174,070
DECHANT D18-27D	VER	7,643	18,190	28,737
DECHANT D18-30D	VER			
DECHANT D31-18D	VER			
DECHANT D31-21D	VER			
DECHANT D31-22D	VER			
DECHANT D31-24D	VER			
DECHANT STATE H36-11	VER			
DECHANT STATE H36-18D	VER			
DECHANT STATE H36-19	VER			
DECHANT STATE H36-20D	VER			
DECHANT STATE H36-21D	VER			
DECHANT STATE H36-31D	VER			
DECHANT STATE H36-32D	VER			
DECHANT X01-02	VER			
DECHANT X01-03	VER			
DECHANT X01-04	VER			
DECHANT X01-06	VER			
DECHANT X01-07	VER			

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
DECHANT X01-08	VER	39,140	65,147.5	91,155
DECHANT X08-09	VER	13,596	27,192	40,788
DECHANT X08-10X	VER	19,261	40,788	62,315
DECHANT X08-15	VER	10,918	24,256.5	37,595
DECHANT X08-24D	VER	58,195	132,612.5	207,030
DECHANT Y06-27D	VER	20,188	37,852.5	55,517
DECHANT Y06-28D	VER	31,209	61,800	92,391
DEGENHART STATE AE16-63HN	HOR	71,482	169,126	266,770
DEGENHART USX AE17-63HN	HOR	81,576	182,928	284,280
DF RANCH PC GK09-99HZ	HOR			
DILLARD 10-44	VER	9,126	16,820	24,514
DILLARD KG34-13	VER	1,844	3,445.5	5,047
DINNEL C27-28D	VER	56,856	93,318	129,780
DINNEL C27-29D	VER	45,629	81,009.5	116,390
DINNER 01-01-19	VER	59,122	105,266	151,410
DINNER 13-35	VER	44,599	84,099.5	123,600
DINNER PC G01-22	VER	56,238	95,584	134,930
DONALDSON USX EE29-06D	VER	70	227	384
DRAKE PC MM14-08D	VER			
DRAKE PC MM14-15D	VER			
EASTON G12-20D	VER	38,419	78,434.5	118,450
EASTON G12-32D	VER	43,672	88,786	133,900
EGGE USX A03-11D	VER	2,575	7,261.5	11,948
EHRLICH STATE PC F36-31D	VER	49,234	87,962	126,690
EHRLICH STATE PC F36-32D	VER	29,355	54,538.5	79,722
EHRLICH STATE PC F36-33D	VER	53,251	101,300.5	149,350
ERICKSON PC G15-27D	VER	36,256	80,443	124,630
FEIT E23-97HZ	HOR	512,940	951,720	1,390,500
FEIT E23-98HZ	HOR	503,670	936,785	1,369,900
FEIT E23-99HZ	HOR	573,710	1,090,255	1,606,800
FIVE RIVERS K03-33D	VER	32,445	69,267.5	106,090
FIVE RIVERS K04-20D	VER			
FIVE RIVERS K04-21D	VER			
FIVE RIVERS K04-25	VER			
FIVE RIVERS K04-32D	VER			
FIVE RIVERS K08-07D	VER	43,775	88,837.5	133,900
FIVE RIVERS K08-17D	VER	15,038	29,818.5	44,599
FIVE RIVERS K08-22D	VER	29,561	61,903	94,245
FIVE RIVERS K08-23	VER	73,851	140,955.5	208,060
FIVE RIVERS K08-24D	VER	57,989	118,089.5	178,190
FIVE RIVERS K09-29D	VER			
FIVE RIVERS K09-30D	VER			
FIVE RIVERS K09-33D	VER	72,203	138,586.5	204,970
FIVE RIVERS K10-30D	VER	15,553	30,024.5	44,496
FIVE RIVERS K15-30D	VER	100,528	187,769	275,010

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
FIVE RIVERS K15-31D	VER	66,435	124,372.5	182,310
FIVE RIVERS K16-17	VER	14,420	33,475	52,530
FIVE RIVERS K16-30D	VER			
FIVE RIVERS USX K09-01D	VER			
FIVE RIVERS USX K09-08D	VER			
FIVE RIVERS USX K09-17D	VER			
FIVE RIVERS USX K09-22D	VER			
FOOSE A18-23	VER			
FOSS 06-35	VER			
FOSS USX AA05-03	VER			
FRANK PC H22-20D	VER			
FRANKLIN C08-62HN	HOR	106,090	262,135	418,180
FRANKLIN C17-69HN	HOR	120,510	302,305	484,100
FRANKLIN C18-27D	VER	11,536	27,655.5	43,775
FRAZIER 33-15	VER	80,649	153,109.5	225,570
FRICK C17-79HN	HOR	134,930	339,385	543,840
FRICK PC C17-65HN	HOR	184,370	417,665	650,960
GABEL USX AB21-14	VER	327	580.5	834
GITTLEIN D04-33	VER	20,394	40,324.5	60,255
GREEN USX XX07-07	VER	3,193	9,424.5	15,656
GREEN USX XX07-08	VER	1,947	5,649.5	9,352
GULLEY 17-13	VER	23,072	42,590.5	62,109
GULLEY 17-15	VER	37,492	73,336	109,180
GULLEY 17-25	VER	64,169	125,814.5	187,460
GUNNER STATE AA16-99HZ	HOR	941	2,582	4,223
GURTLER H24-99HZ	HOR	183,340	293,035	402,730
GUTTERSEN D02-32D	VER	7,601	16,212	24,823
GUTTERSEN D02-75HN	HOR	180,250	294,065	407,880
GUTTERSEN D03-33D	VER	8,395	17,484.5	26,574
GUTTERSEN D04-32	VER	62,109	95,944.5	129,780
GUTTERSEN D09-27D	VER	3,687	11,165	18,643
GUTTERSEN D10-30D	VER	3,440	8,827	14,214
GUTTERSEN D22-27	VER	38,007	63,242	88,477
GUTTERSEN D23-20	VER	31,930	63,963	95,996
GUTTERSEN D25-17	VER	419	905	1,391
GUTTERSEN D29-33D	VER	17,098	33,835.5	50,573
GUTTERSEN D29-65HN	HOR	269,860	558,775	847,690
GUTTERSEN D29-99HZ	HOR	275,010	492,855	710,700
GUTTERSEN STATE CC20-30D	VER			
GUTTERSEN STATE CC20-31D	VER			
GUTTERSEN STATE CC20-32D	VER			
GUTTERSEN STATE CC20-33D	VER			
GUTTERSEN STATE D22-18	VER	18,849	42,230	65,611
GUTTERSEN STATE D22-22	VER			
GUTTERSEN STATE D22-24	VER			

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
GUTTERSEN STATE D28-79HN	HOR	222,480	393,460	564,440
HANSCOME G12-31	VER	121,540	217,845	314,150
HARPER USX EE27-02D	VER	1,504	3,064.5	4,625
HARPER USX EE27-07D	VER	1,236	2,518.5	3,801
HARPER USX EE27-15D	VER	4,614	9,156.5	13,699
HARPER USX EE27-23D	VER			
HAYTHORN 04-21	VER			
HAYTHORN 04-24	VER			
HBR PC G11-32D	VER			
HEATH PC GK02-07	VER			
HERBST C22-22D	VER			
HERBST C22-24	VER			
HERBST C22-25	VER			
HIPPO D27-24D	VER			
HIPPO D34-29D	VER			
HOFF PC D06-21	VER			
HOFF PC D06-27	VER			
HOFFMAN B33-19	VER			
HORTON D18-20D	VER			
HOUNDSKEEPER PC H01-21D	VER			
HOWARD A27-17D	VER			
HOWARD USX A09-02D	VER			
HOWARD USX A09-06D	VER			
HOWARD USX A09-09D	VER			
HOWARD USX A09-12D	VER			
HOWARD USX A09-14D	VER			
HOWARD USX A09-15D	VER			
HOWARD USX A09-23	VER			
HP FARMS D32-24D	VER			
HP Y07-09	VER	25,544	45,680.5	65,817
HP Y07-10D	VER			
HUDSON STATE X36-07D	VER	14,935	28,788.5	42,642
IGO FARMS J28-19D	VER	28,222	51,345.5	74,469
IGO FARMS J28-20D	VER	90,640	151,925	213,210
IGO FARMS J28-31D	VER	15,965	27,964.5	39,964
IGO FARMS J28-32D	VER	20,085	36,719.5	53,354
JOHNSON PC EE33-09D	VER	5,315	10,022	14,729
JOHNSON PC EE33-10D	VER	7,478	13,524	19,570
JOHNSON PC EE33-15D	VER	4,161	15,161.5	26,162
JOHNSON PC EE33-16D	VER	5,366	10,099	14,832
JOHNSON PC EE33-23D	VER	7,138	13,251	19,364
KARCH STATE D10-22	VER			
KERBS USX A15-12D	VER	5,129	11,216.5	17,304
KLEIN B15-13D	VER	27,810	60,924.5	94,039
KLEIN B16-98HZ	HOR	670,530	1,288,015	1,905,500

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
KLEIN B16-99HZ	HOR	670,530	1,282,865	1,895,200
LAND USX Y31-01	HOR	2,966	6,525	10,084
LANG C22-28D	VER	28,737	50,727.5	72,718
LARSON A32-17	VER	30,385	55,877.5	81,370
LDS D17-18	VER	14,111	34,505	54,899
LDS D17-22	VER	9,661	22,289	34,917
LDS D17-31D	VER	21,321	51,448.5	81,576
LDS D17-32D	VER	14,214	31,981.5	49,749
LDS E25-32	VER	47,380	83,430	119,480
LDS E25-33D	VER	39,037	66,280.5	93,524
LETTERLY USX AB23-68HN	HOR			
LIND 23-15	VER	5,212	9,301	13,390
LINDBLAD 17-34	VER	16,377	32,084.5	47,792
LINDBLAD 20-25	VER	2,009	3,765	5,521
LOWER LATHAM PC G11-69HN	HOR	203,940	372,345	540,750
LOWER LATHAM PC G12-69HN	HOR			
LOYD PC GD33-13	VER			
LYSTER E26-22D	VER	53,045	95,532.5	138,020
LYSTER E26-23	VER	81,885	158,877.5	235,870
MARIE D04-20	VER	26,059	47,740.5	69,422
MARLEY C01-18D	VER	36,462	65,611	94,760
MARLEY C01-28D	VER	10,403	47,380	84,357
MARLEY C01-30D	VER	13,390	26,110.5	38,831
MARLEY C01-31D	VER	19,776	36,462	53,148
MCCLELLAN PC LG04-15	VER			
MCWILLIAMS 15-3-17	VER	107,120	180,765	254,410
MEGAN H16-99HZ	HOR	355,350	684,435	1,013,520
MILLAGE C11-18	VER	47,895	87,292.5	126,690
MILLER X31-03	VER	24,617	59,379.5	94,142
MILLER X31-04	VER	39,861	72,460.5	105,060
MILLER X31-06	VER	22,660	40,015.5	57,371
MILLER X31-10	VER	18,231	32,239	46,247
MOJACK USX AB21-15	VER	1,071	1,818	2,565
MOSER PC H22-21D	VER	85,799	168,044.5	250,290
MOSER PC H22-24	VER	34,814	67,722.5	100,631
MOSER PC H22-33	VER	65,817	132,818.5	199,820
MOSIER K23-20D	VER	19,879	45,371.5	70,864
MOSIER K23-21D	VER	31,312	55,723	80,134
MOSIER K23-33D	VER	26,986	51,551.5	76,117
NCLP PC AA04-04	VER			
NCLP PC AA04-05	VER			
NCLP PC AA04-06	VER			
NCLP PC AA04-11	VER			
NCLP PC AA04-12	VER			
NCLP PC AA04-13	VER			

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
NCLP PC AA04-14	VER			
NCLP PC AA04-19	VER			
NCLP PC AA04-20	VER			
NCLP PC AA04-25	VER			
NCLP PC AA08-02D	VER			
NCLP PC AA08-03D	VER			
NCLP PC AA08-07D	VER			
NCLP PC AA08-08D	VER			
NCLP PC AA08-18D	VER			
NCLP PC AA08-19	VER			
NELSON K27-63HN	HOR	571,650	1,223,125	1,874,600
NOFFSINGER 35-13	VER	12,875	21,784.5	30,694
NOFFSINGER 35-15	VER	16,583	28,016	39,449
OJEDA USX XX07-09D	VER	1,277	1,612	1,947
ORR USX A03-15D	VER	3,780	5,994.5	8,209
OWENS K17-15	VER	58,916	108,253	157,590
OWENS K17-23D	VER	53,766	99,498	145,230
PEDRO STATE C31-79HN	HOR	545,900	1,143,300	1,740,700
PEPPLER PC AA17-20	VER	20,291	34,865.5	49,440
PEPPLER PC AA17-25	VER			
PETERSON B10-24D	VER			
PETERSON PC LG19-06	VER			
PHILLIPS 23-1-17	VER			
PHILLIPS 23-1-20	VER			
PHILLIPS 23-1-21	VER			
PHILLIPS 24-2-20D	VER			
PHILLIPS 24-3-17	VER			
PHILLIPS 24-3-21	VER			
PHILLIPS 24-3-23	VER			
PHILLIPS PC N24-25	VER			
PHILLIPS PC N24-29D	VER			
PHILLIPS PC N24-31D	VER			
PIONEER USX Y07-08D	VER			
PIONEER Y07-07D	VER			
POWERS X22-02	VER			
POWERS X22-04	VER			
POWERS X22-31	VER			
PURCELL PC GK11-10	VER			
PVA X31-16	VER			
QC A32-19	VER			
RAY H12-24D	VER			
REI H08-13D	VER			
REI H08-15D	VER			
REI H08-21D	VER			
REI H08-24D	VER			

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
RHINO D27-18D	VER			
RHINO D27-19D	VER			
RHINO D27-20D	VER	11,536	23,156	34,776
RHINO D27-21	VER	22,848	49,504	76,160
RHINO D27-22D	VER	12,600	26,880	41,160
RHINO D27-27D	VER	9,688	19,908	30,128
RHINO D27-28D	VER	10,640	20,272	29,904
RICHTER USX AB27-03	VER			
RICHTER USX AB27-05	VER			
RICHTER USX AB27-13	VER	23,968	44,464	64,960
RICHTER USX AB27-25	VER	18,928	35,504	52,080
RICHTER USX AB27-65HN	HOR	109,200	286,440	463,680
RITCHEY USX WW27-19D	VER	2,991	6,507.5	10,024
ROGERS USX A03-09D	VER	7,952	18,228	28,504
ROHN PC LD04-03	VER			
ROHN PC LD09-01	VER			
ROHN PC LD16-96HN	HOR			
ROHR A28-25	VER	24,528	41,384	58,240
ROTH USX A30-17	VER	28,280	48,020	67,760
ROTHE BB30-23	VER	23,352	39,956	56,560
SATER C12-21	VER	16,240	34,636	53,032
SATER CC18-14	VER	24,416	41,048	57,680
SATER CC18-23	VER	5,123	10,401.5	15,680
SCHMIDT K23-24D	VER	21,112	39,956	58,800
SCHOLFIELD STATE A36-69HN	HOR	255,920	435,960	616,000
SCHOLFIELD STATE A36-79HN	HOR	225,680	432,040	638,400
SEKICH P19-18D	VER	12,600	22,624	32,648
SEKICH P19-21D	VER	31,192	62,356	93,520
SEKICH P19-24D	VER	40,544	67,872	95,200
SEKICH P19-27D	VER	13,552	22,036	30,520
SEKICH P19-28D	VER	17,248	29,764	42,280
SHELTON G25-22	VER	5,656	11,704	17,752
SHELTON PC D06-32D	VER	15,568	26,208	36,848
SHERWOOD L30-29D	VER	49,672	79,436	109,200
SHERWOOD L30-30D	VER	50,960	84,280	117,600
SHERWOOD L30-31D	VER	37,856	60,088	82,320
SHERWOOD L30-32D	VER	21,224	40,012	58,800
SMITH PC D06-20D	VER	50,624	83,272	115,920
SOONER STATE B36-63HN	HOR	104,720	249,760	394,800
SPIKE STATE D10-21D	VER			
SPIKE STATE D16-99HZ	HOR			
STATE C24-99HZ	HOR	94,080	158,760	223,440
STATE C36-32D	VER	37,016	63,588	90,160
STATE C36-33D	VER	25,816	45,388	64,960
STATE C36-99HZ	HOR	83,440	144,760	206,080

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
STATE D01-30D	VER	25,368	43,484	61,600
STEWARDSON USX WW33-01D	VER	4,867	10,049.5	15,232
STEWARDSON USX WW33-03D	VER	2,710	5,611	8,512
STOCKLEY C15-79HN	HOR	131,600	277,760	423,920
STOCKLEY C22-79HN	HOR	175,840	423,920	672,000
STREAR V03-73HN	HOR	67,760	154,280	240,800
STREAR V06-63HN	HOR	57,680	111,440	165,200
STROH H12-32	VER	26,040	42,980	59,920
STROHAUER F32-21D	VER	21,952	34,832	47,712
STROHAUER F32-22D	VER	20,328	32,844	45,360
STROHAUER F32-23	VER	11,256	17,892	24,528
STROHAUER F32-24	VER			
TANIA D11-27D	VER	10,136	19,684	29,232
TANIA D11-28	VER	18,424	33,740	49,056
TANNER K33-65HN	HOR	174,160	389,480	604,800
THOMPSON C28-79HN	HOR	115,920	215,320	314,720
THOMPSON C33-30D	VER	5,593	11,000.5	16,408
THOMPSON C33-69HN	HOR	59,920	123,480	187,040
TYE USX A15-03D	VER	17,752	36,820	55,888
TYE USX A15-04D	VER	8,848	18,564	28,280
UPRC G07-99HZ	HOR	154,000	264,040	374,080
UPRC H17-99HZ	HOR	104,720	177,800	250,880
WACKER B01-79HN	HOR	128,800	361,200	593,600
WACKER B10-20D	VER	12,768	27,972	43,176
WACKER B11-69HN	HOR	113,680	312,480	511,280
WACKER B12-69HN	HOR	217,280	601,440	985,600
WALCKER 12-23	VER	18,200	30,660	43,120
WALCKER AB12-08	VER	941	3,382.5	5,824
WALCKER AB12-09	VER	2,131	4,677.5	7,224
WARDELL H19-32D	VER	22,512	48,496	74,480
WARDELL H19-33D	VER	23,296	43,568	63,840
WARDELL PC H20-24	VER	21,336	35,504	49,672
WARNER W13-11	VER	14,392	34,832	55,272
WEIDENKELLER PC G01-20D	VER	21,560	34,468	47,376
WEIDENKELLER PC G01-21D	VER	14,000	34,468	54,936
WEIDENKELLER PC G01-27D	VER	15,792	27,636	39,480
WEIDENKELLER PC G01-28D	VER	10,248	23,016	35,784
WEIDENKELLER PC G01-29D	VER	7,952	15,008	22,064
WEIDENKELLER PC G01-30D	VER	9,968	19,264	28,560
WEIDENKELLER PC G01-31D	VER	12,152	21,000	29,848
WELLS RANCH AA12-08	VER			
WELLS RANCH AA12-09	VER			
WELLS RANCH AE05-12	VER			
WELLS RANCH AE18-17	VER	17,640	33,936	50,232
WELLS RANCH AE20-16	VER	15,456	26,880	38,304

Noble Estimated Ultimate Gas Recovery Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
WELLS RANCH AE30-68HN	HOR	451,360	830,480	1,209,600
WELLS RANCH PC AA22-01	VER	61,040	133,000	204,960
WELLS RANCH PC AA22-02	VER	13,440	36,400	59,360
WELLS RANCH PC AA22-03	VER	51,744	94,192	136,640
WELLS RANCH PC AA22-04	VER	23,968	39,536	55,104
WELLS RANCH PC AA22-07	VER	9,520	29,148	48,776
WELLS RANCH PC AA22-08	VER	59,920	102,200	144,480
WELLS RANCH PC AA22-13	VER	57,680	96,040	134,400
WELLS RANCH USX AA11-65HN	HOR			
WELLS RANCH USX AA11-67HN	HOR			
WELLS RANCH USX AE29-68HN	HOR	705,600	1,044,400	1,383,200
WELLS RANCH USX BB15-65HN	HOR	245,280	486,640	728,000
WELLS RANCH USX BB15-67HN	HOR	265,440	493,920	722,400
WEST IRRIGATION USX AB33-23	VER	20,608	37,408	54,208
WILLIAMS F15-17D	VER			
WILLIAMS F15-22D	VER	6,216	16,772	27,328
WILSON 35-25	VER	45,248	79,184	113,120
WILSON PC AC20-10	VER	16,128	33,124	50,120
WYSCAVER USX CC05-25	VER			

Appendix K

Noble Estimated Water Intensity Data

Table K.1: Estimated water intensity for 2010 and 2011 Noble Energy Wells in the Wattenberg Field

Well Name	Well Type	Low	Average	High
Estimated Water Intensity per Well (gal/MMBtu)				
70 RANCH BB21-63HN	HOR			
70 RANCH BB21-65HN	HOR	1.96	3.74	41.27
70 RANCH BB21-67HN	HOR	5.35	7.19	10.98
70 RANCH USX BB09-63HN	HOR	3.05	4.65	9.82
ABBEY D01-23	VER	2.65	3.80	6.71
ABBEY D01-27	VER	0.36	0.56	1.26
ABBEY D01-29	VER	5.90	7.54	10.47
ADAMS D30-27D	VER	7.00	8.65	11.33
ALOYSIUS C34-18	VER	0.47	0.65	1.07
ALOYSIUS C34-20D	VER	0.33	0.45	0.70
ALOYSIUS C34-21D	VER	0.87	0.91	0.96
ALOYSIUS C34-22D	VER	0.74	0.89	1.10
ALOYSIUS C34-24	VER	0.47	0.65	1.05
ALOYSIUS C34-27D	VER	3.86	5.12	7.60
ALOYSIUS C34-28D	VER	2.87	3.63	4.94
ALOYSIUS C34-30D	VER	0.66	0.88	1.29
ALOYSIUS C34-31	VER	0.75	0.85	0.98
ALOYSIUS C34-32D	VER	0.26	0.37	0.63
ALOYSIUS C34-33D	VER	0.31	0.43	0.69
ALOYSIUS C34-99HZ	HOR	2.92	4.38	8.76
ANNIE B03-23	VER	3.22	4.13	5.76

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
ARISTOCRAT PC H11-07	VER	186.96	268.13	473.88
ARISTOCRAT PC H11-18D	VER	2.99	4.43	8.51
ARISTOCRAT PC H11-19D	VER	1.71	2.61	5.51
ARISTOCRAT PC H11-27D	VER	3.09	4.38	7.53
ARISTOCRAT PC H11-29D	VER	1.35	2.05	4.20
ARISTOCRAT PC H11-30D	VER			
ARISTOCRAT PC H11-32D	VER			
BADDING USX W25-07D	VER	192.17	37.42	20.73
BASHOR PC AA09-08	VER	4.73	6.93	12.93
BASHOR PC AA09-14	VER	6.53	8.73	13.16
BASHOR PC AA09-22	VER	2.79	4.07	7.53
BASHOR PC AA09-23	VER	3.37	4.95	9.32
BASHOR PC AA09-24	VER	4.67	6.37	9.99
BASHOR PC AA17-02D	VER	6.54	7.02	7.59
BASHOR PC AA17-17	VER	4.36	4.82	5.38
BASHOR PC AA17-21	VER	1.90	2.65	4.41
BASHOR PC AA17-22	VER	2.21	2.78	3.74
BASHOR PC AA17-23	VER	2.99	3.89	5.57
BASHOR PC AA17-24	VER	2.27	2.84	3.79
BERNHARDT STATE PC N36-17	VER	5.28	7.82	15.06
BERRY P08-18D	VER			
BERRY P08-28D	VER			
BERRY P08-29D	VER			
BETZ PC G09-19	VER	0.75	1.09	1.99
BETZ PC G09-23	VER	2.44	3.52	6.35
BETZ PC G09-31D	VER	1.29	1.79	2.95
BETZ PC G10-33D	VER	1.38	1.97	3.45
BICKLING PC E02-33D	VER	23.13	36.14	82.62
BICKLING PC E03-22D	VER	17.44	27.13	61.10
BOOTH N25-18D	VER	1.70	2.47	4.51
BOOTH N25-20D	VER	16.35	21.74	32.40
BOOTH N25-21D	VER	16.00	20.53	28.62
BOOTH N25-22D	VER	5.53	8.55	18.81
BOOTH N25-24D	VER	6.16	9.02	16.83
BOOTH N25-31D	VER	1.55	2.26	4.15
BOOTH N25-33D	VER	2.06	3.00	5.55
BOULTER PC G14-29D	VER	4.22	6.54	14.51
BOULTER PC G14-30D	VER	5.75	8.70	17.87
BROWN PC E02-31D	VER	12.95	19.65	40.68
BROWN PC E02-32	VER	11.01	16.73	34.84
BURGHART D04-22	VER	2.36	3.39	6.04
CALVARY USX EE29-04D	VER	120.67	220.02	1,244.99
CAMP H30-29D	VER	1.41	2.05	3.77
CAMP H30-32	VER	1.38	2.11	4.45
CAMP H30-33	VER	2.88	4.49	10.18

Noble Estimated Water Intensity Data

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
CANNON H35-20	VER	8.43	12.07	21.24
CANNON H35-21	VER	7.25	11.30	25.58
CANNON H35-22	VER	4.56	7.22	17.26
CANNON H35-24	VER	3.51	5.30	10.81
CANNON W15-18D	VER	3.69	5.67	12.22
CANNON W15-19	VER	3.32	5.20	11.93
CANNON W15-21D	VER	2.00	3.12	7.07
CARLSON A18-17	VER	1.90	2.74	4.93
CARLSON K23-18D	VER	5.58	7.96	13.91
CARLSON K23-22D	VER	3.84	5.43	9.28
CARMIN USX CC05-10D	VER	2.77	4.10	7.81
CARMIN USX CC05-16D	VER	3.65	5.35	10.05
CARMIN USX CC05-17D	VER	6.48	9.55	18.15
CODY D03-20	VER	2.28	3.42	6.79
CODY D03-28	VER	2.77	4.00	7.18
COLEMAN C22-17	VER	25.06	35.89	63.18
COLEMAN C22-18	VER	2.42	3.43	5.87
COLEMAN C22-21D	VER	2.75	3.90	6.70
COLEMAN C22-27	VER	3.31	4.79	8.69
CONNELL C04-31D	VER			
COX PC GK35-99HZ	HOR			
CRICKET C22-30D	VER	2.28	3.32	6.14
CROISSANT USX WW11-02D	VER	18.57	27.21	50.89
CROISSANT USX WW11-08D	VER	56.53	87.34	192.00
CROISSANT USX WW11-17D	VER	51.78	82.29	200.35
DECHANT 07-15	VER			
DECHANT 7-1-17	VER	1.59	2.31	4.22
DECHANT D18-27D	VER	6.09	9.51	21.67
DECHANT D18-30D	VER			
DECHANT D31-18D	VER			
DECHANT D31-21D	VER			
DECHANT D31-22D	VER			
DECHANT D31-24D	VER			
DECHANT STATE H36-11	VER			
DECHANT STATE H36-18D	VER			
DECHANT STATE H36-19	VER			
DECHANT STATE H36-20D	VER			
DECHANT STATE H36-21D	VER			
DECHANT STATE H36-31D	VER			
DECHANT STATE H36-32D	VER			
DECHANT X01-02	VER			
DECHANT X01-03	VER			
DECHANT X01-04	VER			
DECHANT X01-06	VER			
DECHANT X01-07	VER			

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
DECHANT X01-08	VER	3.27	4.60	7.75
DECHANT X08-09	VER	7.41	11.09	22.02
DECHANT X08-10X	VER	5.14	7.77	15.88
DECHANT X08-15	VER	7.80	11.86	24.79
DECHANT X08-24D	VER	1.88	2.90	6.36
DECHANT Y06-27D	VER	4.79	7.09	13.61
DECHANT Y06-28D	VER	2.99	4.54	9.42
DEGENHART STATE AE16-63HN	HOR	4.71	7.29	16.17
DEGENHART USX AE17-63HN	HOR	4.37	6.71	14.43
DF RANCH PC GK09-99HZ	HOR			
DILLARD 10-44	VER	3.13	4.58	8.52
DILLARD KG34-13	VER	23.38	33.31	57.92
DINNEL C27-28D	VER	2.05	2.86	4.73
DINNEL C27-29D	VER	2.39	3.40	5.86
DINNER 01-01-19	VER	1.53	2.19	3.84
DINNER 13-35	VER	1.86	2.69	4.82
DINNER PC G01-22	VER	1.85	2.60	4.40
DONALDSON USX EE29-06D	VER	274.68	462.98	1,472.14
DRAKE PC MM14-08D	VER			
DRAKE PC MM14-15D	VER			
EASTON G12-20D	VER	2.01	3.03	6.17
EASTON G12-32D	VER	1.89	2.83	5.63
EGGE USX A03-11D	VER	8.55	13.87	36.66
EHRLICH STATE PC F36-31D	VER	1.97	2.81	4.91
EHRLICH STATE PC F36-32D	VER	3.64	5.27	9.56
EHRLICH STATE PC F36-33D	VER	1.84	2.69	4.96
ERICKSON PC G15-27D	VER	2.96	4.61	10.45
FEIT E23-97HZ	HOR	1.42	2.06	3.75
FEIT E23-98HZ	HOR	1.60	2.33	4.28
FEIT E23-99HZ	HOR	1.23	1.80	3.36
FIVE RIVERS K03-33D	VER	3.15	4.84	10.41
FIVE RIVERS K04-20D	VER			
FIVE RIVERS K04-21D	VER			
FIVE RIVERS K04-25	VER			
FIVE RIVERS K04-32D	VER			
FIVE RIVERS K08-07D	VER	2.55	3.86	7.99
FIVE RIVERS K08-17D	VER	5.90	8.99	18.86
FIVE RIVERS K08-22D	VER	4.42	6.71	13.93
FIVE RIVERS K08-23	VER	1.92	2.82	5.34
FIVE RIVERS K08-24D	VER	2.56	3.84	7.71
FIVE RIVERS K09-29D	VER			
FIVE RIVERS K09-30D	VER			
FIVE RIVERS K09-33D	VER	1.46	2.15	4.07
FIVE RIVERS K10-30D	VER	6.27	9.29	17.91
FIVE RIVERS K15-30D	VER	1.09	1.60	3.00

Noble Estimated Water Intensity Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
FIVE RIVERS K15-31D	VER	1.52	2.22	4.13
FIVE RIVERS K16-17	VER	5.17	7.95	17.26
FIVE RIVERS K16-30D	VER			
FIVE RIVERS USX K09-01D	VER			
FIVE RIVERS USX K09-08D	VER			
FIVE RIVERS USX K09-17D	VER			
FIVE RIVERS USX K09-22D	VER			
FOOSE A18-23	VER			
FOSS 06-35	VER			
FOSS USX AA05-03	VER			
FRANK PC H22-20D	VER			
FRANKLIN C08-62HN	HOR	3.62	5.76	14.16
FRANKLIN C17-69HN	HOR	2.58	4.13	10.29
FRANKLIN C18-27D	VER	4.85	7.56	17.19
FRAZIER 33-15	VER	1.82	2.67	5.01
FRICK C17-79HN	HOR	2.56	4.06	9.88
FRICK PC C17-65HN	HOR	2.49	3.85	8.48
GABEL USX AB21-14	VER	427.94	614.86	1,091.72
GITTLEIN D04-33	VER	3.09	4.55	8.63
GREEN USX XX07-07	VER	17.46	28.24	73.75
GREEN USX XX07-08	VER	19.31	30.27	70.09
GULLEY 17-13	VER	4.10	5.90	10.55
GULLEY 17-15	VER	1.77	2.58	4.75
GULLEY 17-25	VER	1.25	1.85	3.53
GUNNER STATE AA16-99HZ	HOR	932.66	1,525.45	4,186.06
GURTLER H24-99HZ	HOR	4.32	5.95	9.56
GUTTERSEN D02-32D	VER	5.26	8.41	20.88
GUTTERSEN D02-75HN	HOR	3.90	5.54	9.59
GUTTERSEN D03-33D	VER	5.44	8.06	15.58
GUTTERSEN D04-32	VER	0.40	0.54	0.84
GUTTERSEN D09-27D	VER	8.03	12.90	32.73
GUTTERSEN D10-30D	VER	4.36	7.07	18.70
GUTTERSEN D22-27	VER	2.31	3.26	5.54
GUTTERSEN D23-20	VER	2.32	3.42	6.52
GUTTERSEN D25-17	VER	14.00	21.90	50.25
GUTTERSEN D29-33D	VER	4.62	6.81	13.00
GUTTERSEN D29-65HN	HOR	2.41	3.59	6.99
GUTTERSEN D29-99HZ	HOR	3.10	4.43	7.77
GUTTERSEN STATE CC20-30D	VER			
GUTTERSEN STATE CC20-31D	VER			
GUTTERSEN STATE CC20-32D	VER			
GUTTERSEN STATE CC20-33D	VER			
GUTTERSEN STATE D22-18	VER	3.49	5.34	11.36
GUTTERSEN STATE D22-22	VER			
GUTTERSEN STATE D22-24	VER			

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
GUTTERSEN STATE D28-79HN	HOR	3.28	4.70	8.29
HANSCOME G12-31	VER	1.01	1.44	2.55
HARPER USX EE27-02D	VER	13.82	20.66	40.94
HARPER USX EE27-07D	VER	12.68	19.44	41.64
HARPER USX EE27-15D	VER	4.44	6.63	13.06
HARPER USX EE27-23D	VER	10.60	15.94	32.13
HAYTHORN 04-21	VER			
HAYTHORN 04-24	VER			
HBR PC G11-32D	VER			
HEATH PC GK02-07	VER			
HERBST C22-22D	VER			
HERBST C22-24	VER			
HERBST C22-25	VER			
HIPPO D27-24D	VER			
HIPPO D34-29D	VER			
HOFF PC D06-21	VER			
HOFF PC D06-27	VER			
HOFFMAN B33-19	VER			
HORTON D18-20D	VER			
HOUNDSKEEPER PC H01-21D	VER			
HOWARD A27-17D	VER			
HOWARD USX A09-02D	VER			
HOWARD USX A09-06D	VER			
HOWARD USX A09-09D	VER			
HOWARD USX A09-12D	VER			
HOWARD USX A09-14D	VER			
HOWARD USX A09-15D	VER			
HOWARD USX A09-23	VER			
HP FARMS D32-24D	VER			
HP Y07-09	VER	3.87	5.63	10.38
HP Y07-10D	VER			
HUDSON STATE X36-07D	VER	11.87	17.34	32.21
IGO FARMS J28-19D	VER	3.43	4.97	9.02
IGO FARMS J28-20D	VER	1.23	1.72	2.86
IGO FARMS J28-31D	VER	6.14	8.73	15.06
IGO FARMS J28-32D	VER	4.70	6.78	12.17
JOHNSON PC EE33-09D	VER	11.13	13.51	17.18
JOHNSON PC EE33-10D	VER	3.26	5.15	12.23
JOHNSON PC EE33-15D	VER	4.77	7.33	15.74
JOHNSON PC EE33-16D	VER	9.69	12.73	18.52
JOHNSON PC EE33-23D	VER	5.32	7.44	12.40
KARCH STATE D10-22	VER			
KERBS USX A15-12D	VER	6.65	10.45	24.35
KLEIN B15-13D	VER	1.80	2.77	6.01
KLEIN B16-98HZ	HOR	1.56	2.30	4.38

Noble Estimated Water Intensity Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
KLEIN B16-99HZ	HOR	1.33	1.96	3.73
LAND USX Y31-01	HOR	101.84	162.21	398.31
LANG C22-28D	VER	3.76	5.36	9.34
LARSON A32-17	VER	2.54	3.74	7.05
LDS D17-18	VER	2.94	4.64	10.89
LDS D17-22	VER	4.63	7.22	16.38
LDS D17-31D	VER	3.53	5.59	13.41
LDS D17-32D	VER	6.37	9.72	20.51
LDS E25-32	VER	1.88	2.68	4.69
LDS E25-33D	VER	2.49	3.53	6.03
LETTERLY USX AB23-68HN	HOR			
LIND 23-15	VER	4.45	6.35	11.11
LINDBLAD 17-34	VER	4.81	7.36	15.66
LINDBLAD 20-25	VER	10.26	14.51	24.77
LOWER LATHAM PC G11-69HN	HOR	2.74	4.09	8.09
LOWER LATHAM PC G12-69HN	HOR			
LOYD PC GD33-13	VER			
LYSTER E26-22D	VER	2.10	3.02	5.39
LYSTER E26-23	VER	1.03	1.53	2.95
MARIE D04-20	VER	2.64	3.83	6.97
MARLEY C01-18D	VER	2.12	3.05	5.49
MARLEY C01-28D	VER	3.52	5.91	18.37
MARLEY C01-30D	VER	5.76	8.80	18.68
MARLEY C01-31D	VER	3.55	5.18	9.59
MCCLELLAN PC LG04-15	VER			
MCWILLIAMS 15-3-17	VER	1.12	1.58	2.65
MEGAN H16-99HZ	HOR	2.43	3.57	6.73
MILLAGE C11-18	VER	1.87	2.69	4.78
MILLER X31-03	VER	4.95	7.64	16.77
MILLER X31-04	VER	7.54	10.90	19.61
MILLER X31-06	VER	6.56	9.01	14.38
MILLER X31-10	VER	6.99	10.21	18.98
MOJACK USX AB21-15	VER	33.13	47.84	86.03
MOSER PC H22-21D	VER	1.54	2.28	4.44
MOSER PC H22-24	VER	3.27	4.77	8.82
MOSER PC H22-33	VER	1.93	2.86	5.55
MOSIER K23-20D	VER	4.13	6.41	14.30
MOSIER K23-21D	VER	4.67	6.77	12.30
MOSIER K23-33D	VER	5.28	7.79	14.90
NCLP PC AA04-04	VER			
NCLP PC AA04-05	VER			
NCLP PC AA04-06	VER			
NCLP PC AA04-11	VER			
NCLP PC AA04-12	VER			
NCLP PC AA04-13	VER			

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
NCLP PC AA04-14	VER			
NCLP PC AA04-19	VER			
NCLP PC AA04-20	VER			
NCLP PC AA04-25	VER			
NCLP PC AA08-02D	VER			
NCLP PC AA08-03D	VER			
NCLP PC AA08-07D	VER			
NCLP PC AA08-08D	VER			
NCLP PC AA08-18D	VER			
NCLP PC AA08-19	VER			
NELSON K27-63HN	HOR	1.60	2.45	5.27
NOFFSINGER 35-13	VER	4.27	6.15	10.99
NOFFSINGER 35-15	VER	2.78	3.96	6.87
OJEDA USX XX07-09D	VER	56.43	75.31	113.19
ORR USX A03-15D	VER	11.26	14.27	19.47
OWENS K17-15	VER	1.86	2.70	4.92
OWENS K17-23D	VER	1.81	2.63	4.82
PEDRO STATE C31-79HN	HOR	1.52	2.30	4.75
PEPPLER PC AA17-20	VER	4.00	5.60	9.32
PEPPLER PC AA17-25	VER			
PETERSON B10-24D	VER			
PETERSON PC LG19-06	VER			
PHILLIPS 23-1-17	VER			
PHILLIPS 23-1-20	VER			
PHILLIPS 23-1-21	VER			
PHILLIPS 24-2-20D	VER			
PHILLIPS 24-3-17	VER			
PHILLIPS 24-3-21	VER			
PHILLIPS 24-3-23	VER			
PHILLIPS PC N24-25	VER			
PHILLIPS PC N24-29D	VER			
PHILLIPS PC N24-31D	VER			
PIONEER USX Y07-08D	VER			
PIONEER Y07-07D	VER			
POWERS X22-02	VER			
POWERS X22-04	VER			
POWERS X22-31	VER			
PURCELL PC GK11-10	VER			
PVA X31-16	VER			
QC A32-19	VER			
RAY H12-24D	VER			
REI H08-13D	VER			
REI H08-15D	VER			
REI H08-21D	VER			
REI H08-24D	VER			

Noble Estimated Water Intensity Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
RHINO D27-18D	VER			
RHINO D27-19D	VER			
RHINO D27-20D	VER	7.38	11.17	22.89
RHINO D27-21	VER	3.63	5.59	12.18
RHINO D27-22D	VER	7.09	10.90	23.57
RHINO D27-27D	VER	7.45	11.49	25.12
RHINO D27-28D	VER	10.58	15.89	31.91
RICHTER USX AB27-03	VER			
RICHTER USX AB27-05	VER			
RICHTER USX AB27-13	VER	4.85	7.06	12.94
RICHTER USX AB27-25	VER	5.77	8.44	15.73
RICHTER USX AB27-65HN	HOR	4.73	7.63	19.60
RITCHEY USX WW27-19D	VER	41.34	63.47	136.62
ROGERS USX A03-09D	VER	8.96	14.05	32.49
ROHN PC LD04-03	VER			
ROHN PC LD09-01	VER			
ROHN PC LD16-96HN	HOR			
ROHR A28-25	VER	2.38	3.36	5.71
ROTH USX A30-17	VER	2.25	3.22	5.64
ROTHE BB30-23	VER	1.85	2.65	4.68
SATER C12-21	VER	3.42	5.10	10.08
SATER CC18-14	VER	2.47	3.49	5.96
SATER CC18-23	VER	8.54	12.72	24.86
SCHMIDT K23-24D	VER	1.07	1.57	2.94
SCHOLFIELD STATE A36-69HN	HOR	2.24	3.24	5.85
SCHOLFIELD STATE A36-79HN	HOR	2.13	3.15	6.03
SEKICH P19-18D	VER	5.91	8.51	15.20
SEKICH P19-21D	VER	1.82	2.69	5.14
SEKICH P19-24D	VER	1.74	2.50	4.42
SEKICH P19-27D	VER	3.02	4.25	7.16
SEKICH P19-28D	VER	2.28	3.24	5.57
SHELTON G25-22	VER	3.77	5.96	14.18
SHELTON PC D06-32D	VER	2.77	3.90	6.60
SHERWOOD L30-29D	VER	1.51	2.09	3.38
SHERWOOD L30-30D	VER	1.07	1.54	2.72
SHERWOOD L30-31D	VER	2.22	3.19	5.66
SHERWOOD L30-32D	VER	2.26	3.26	5.90
SMITH PC D06-20D	VER	1.08	1.55	2.72
SOONER STATE B36-63HN	HOR	3.27	5.18	12.50
SPIKE STATE D10-21D	VER			
SPIKE STATE D16-99HZ	HOR			
STATE C24-99HZ	HOR	4.14	6.02	11.04
STATE C36-32D	VER	1.63	2.31	3.97
STATE C36-33D	VER	2.72	3.98	7.38
STATE C36-99HZ	HOR	4.29	6.30	11.88

Well Name	Well Type	Drilling Water	Frac Water	Total
Water Used per Well (gallons)				
STATE D01-30D	VER	2.71	3.91	7.06
STEWARDSON USX WW33-01D	VER	31.11	47.23	98.02
STEWARDSON USX WW33-03D	VER	67.98	103.18	213.97
STOCKLEY C15-79HN	HOR	4.38	6.59	13.34
STOCKLEY C22-79HN	HOR	2.17	3.40	7.85
STREAR V03-73HN	HOR	3.19	4.93	10.88
STREAR V06-63HN	HOR	8.04	12.03	23.91
STROH H12-32	VER	0.30	0.42	0.71
STROHAUER F32-21D	VER	1.66	2.21	3.35
STROHAUER F32-22D	VER	1.44	2.03	3.41
STROHAUER F32-23	VER	3.72	5.12	8.21
STROHAUER F32-24	VER			
TANIA D11-27D	VER	11.53	17.12	33.28
TANIA D11-28	VER	3.41	5.22	11.14
TANNER K33-65HN	HOR	1.20	1.82	3.71
THOMPSON C28-79HN	HOR	3.16	4.68	9.03
THOMPSON C33-30D	VER	7.80	11.62	22.77
THOMPSON C33-69HN	HOR	4.25	6.55	14.28
TYE USX A15-03D	VER	4.05	6.12	12.51
TYE USX A15-04D	VER	8.28	12.58	26.25
UPRC G07-99HZ	HOR	1.32	1.91	3.49
UPRC H17-99HZ	HOR	2.65	3.84	6.99
WACKER B01-79HN	HOR	3.78	6.18	16.95
WACKER B10-20D	VER	2.01	3.12	6.94
WACKER B11-69HN	HOR	3.60	5.84	15.52
WACKER B12-69HN	HOR	0.63	1.03	2.85
WALCKER 12-23	VER	4.35	6.39	12.04
WALCKER AB12-08	VER	63.13	108.71	390.90
WALCKER AB12-09	VER	55.15	85.17	186.94
WARDELL H19-32D	VER	1.96	3.02	6.50
WARDELL H19-33D	VER	1.85	2.63	4.53
WARDELL PC H20-24	VER	1.90	2.81	5.42
WARNER W13-11	VER	3.84	5.82	12.06
WEIDENKELLER PC G01-20D	VER	1.66	2.31	3.76
WEIDENKELLER PC G01-21D	VER	1.93	2.88	5.70
WEIDENKELLER PC G01-27D	VER	3.18	4.56	8.11
WEIDENKELLER PC G01-28D	VER	2.36	3.51	6.79
WEIDENKELLER PC G01-29D	VER	2.09	3.15	6.36
WEIDENKELLER PC G01-30D	VER	3.57	5.14	9.16
WEIDENKELLER PC G01-31D	VER	0.59	0.84	1.47
WELLS RANCH AA12-08	VER			
WELLS RANCH AA12-09	VER			
WELLS RANCH AE05-12	VER			
WELLS RANCH AE18-17	VER	5.27	7.95	16.11
WELLS RANCH AE20-16	VER	3.99	5.90	11.34

Noble Estimated Water Intensity Data

Well Name	**Well Type**	**Drilling Water**	**Frac Water**	**Total**
Water Used per Well (gallons)				
WELLS RANCH AE30-68HN	HOR	2.44	3.59	6.80
WELLS RANCH PC AA22-01	VER	2.11	3.24	6.96
WELLS RANCH PC AA22-02	VER	0.00	0.00	30.37
WELLS RANCH PC AA22-03	VER	2.92	4.24	7.72
WELLS RANCH PC AA22-04	VER	3.80	5.37	9.13
WELLS RANCH PC AA22-07	VER	7.28	12.16	37.02
WELLS RANCH PC AA22-08	VER	3.18	4.50	7.73
WELLS RANCH PC AA22-13	VER	12.68	17.77	29.67
WELLS RANCH USX AA11-65HN	HOR			
WELLS RANCH USX AA11-67HN	HOR			
WELLS RANCH USX AE29-68HN	HOR	0.51	0.68	1.04
WELLS RANCH USX BB15-65HN	HOR	2.09	3.10	6.02
WELLS RANCH USX BB15-67HN	HOR	2.20	3.25	6.23
WEST IRRIGATION USX AB33-23	VER	4.19	6.29	12.55
WILLIAMS F15-17D	VER	6.94	10.28	19.84
WILLIAMS F15-22D	VER	4.75	7.77	21.26
WILSON 35-25	VER	1.71	2.50	4.61
WILSON PC AC20-10	VER	6.48	9.87	20.65
WYSCAVER USX CC05-25	VER			

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EXHIBIT B.3

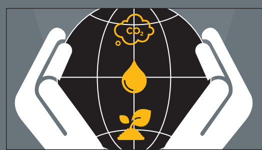
NOBLE ENERGY, INC.

2011 Sustainability Report

SEE

Our plan for a sustainable future.

CONTENTS



FORWARD-LOOKING STATEMENTS

This Sustainability Report contains forward-looking statements that describe our expectations with respect to future events. These forward-looking statements are based upon management's current plans, estimates, assumptions and beliefs concerning future events as of the date of this report. These statements, by their nature, are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements.

REPORT ANALYSIS

ERM

Environmental Resources Management, Inc. (ERM) reviewed Noble Energy's 2011 Sustainability Report against the *Oil and Gas Industry Guidance on Voluntary Sustainability Reporting* (2nd Edition, 2010), developed by the International Petroleum Industry Environmental Conservation Association (IPIECA), the American Petroleum Institute (API) and International Association of Oil & Gas Producers (OGP); and the *Sustainability Reporting Guidelines* (Version 3.1), developed by Global Reporting Initiative (GRI). ERM found that the report contents address the indicators shown in the index on page 51.

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CHARLES D. DAVIDSON
Chairman and
Chief Executive Officer

LETTER FROM OUR CHAIRMAN AND CHIEF EXECUTIVE OFFICER

NBL2011

We recognize that sustainable, extraordinary performance is about more than operational and financial results. With this in mind, our purpose of *Energizing the World, Bettering People's Lives*® acknowledges our goal of delivering energy through oil and natural gas exploration and production while embracing our responsibility to be a good corporate citizen. In furtherance of our purpose, I am pleased to present our first Sustainability Report.

After a year of tremendous achievement in 2011, Noble Energy's future is NOW. Our business strategy of building a diversified portfolio of growth assets, coupled with an exploration program focused on material opportunities, has provided us with a unique platform for growth. We are committed to using this platform as a springboard to achieve sustainable, extraordinary performance.

After a year of tremendous achievement in 2011, Noble Energy's future is

NOW

– Charles D. Davidson
Chairman and Chief Executive Officer

Each of our five core operating areas – the Denver-Julesburg (DJ) Basin and the Marcellus Shale onshore U.S., the deepwater Gulf of Mexico (GOM), West Africa and the Eastern Mediterranean – continue to deliver extraordinary performance. The extent of our activities in each of these areas illustrates the diversity and scale of our business, as we are now a truly global company.

Sustainability and corporate citizenship are rooted in Noble Energy's history and visible in our efforts to build trust through stakeholder engagement, act on our values, provide a safe work environment, lead our industry, respect our environment and care for our people and the communities where we operate. This report describes our 2011 accomplishments in these areas, as well as a number of ongoing initiatives.

Many of our operational highlights for 2011 include sustainability and corporate citizenship components. For example:

- Our receipt of the first post-moratorium permit for deepwater Gulf of Mexico drilling was the direct result of our work with the government and other industry leaders to implement new practices and deploy new systems designed to enhance safety and improve industry spill response and containment capabilities.
- Our emphasis on safety was also apparent in the early start-up of our Aseng floating production, storage and offloading (FPSO) project offshore Equatorial Guinea, as our contractors recorded more than 10.5 million man hours worked during construction with no major accidents and only 408 man hours lost from minor incidents.
- Our success in developing the Wattenberg field in Colorado's Denver-Julesburg (DJ) Basin in the U.S. was supported by a water management strategy focused on minimizing water used from the tributary system and a separate program to reduce the overall size of our drilling footprint.

Other 2011 Highlights

- We were named by the Houston Chronicle as one of Houston's "Top Workplaces," an honor we have received for two consecutive years.
- We continued to improve the governance structure surrounding our corporate citizenship processes. We formed a management committee to direct our corporate citizenship strategy and initiatives. We also expanded the responsibilities of the Environment, Health and Safety Committee of our Board of Directors to include serving as a forum for review of our strategy and initiatives.
- We provided financial and employee support to more than 100 betterment projects within the communities where we operate (see pages 41–48).
- We continued to participate in the Carbon Disclosure Project by publicly disclosing, on a voluntary basis, information pertaining to our greenhouse gas (GHG) emissions.
- We began participating in FracFocus, a hydraulic fracturing chemical registry website that discloses information regarding chemicals used in hydraulic fracturing.
- Consistent with our Corporate Social Responsibility Policy, we continued our focus on protecting human rights through employee training and enhancing our contractor due diligence processes to address human rights practices.
- Our culture of compliance and ethics was reinforced by hiring a dedicated Chief Compliance Officer. We also saw significant employee participation in our second-annual internal Compliance and Ethics Summit.

We understand that sustainability reporting is a journey. As a company, we are committed to transparency in our interactions with stakeholders and look forward to enhancing the quality and content of our sustainability reporting in the future.

Charles D. Davidson
Chairman and Chief Executive Officer

Our journey began in 1932 with our founder Lloyd Noble. NOW we are ready to share an important part of that journey in our first Sustainability Report.

Journey

2011

Our Approach to Reporting

At Noble Energy, we have been *Energizing the World, Bettering People's Lives®* since our founding in 1932. This is our first Sustainability Report, and it reflects our commitment to reporting our sustainability performance and accomplishments. We understand the importance of demonstrating our commitments and progress in these areas in a manner that distinguishes them from our operational and financial results.

SCOPE OF THIS REPORT

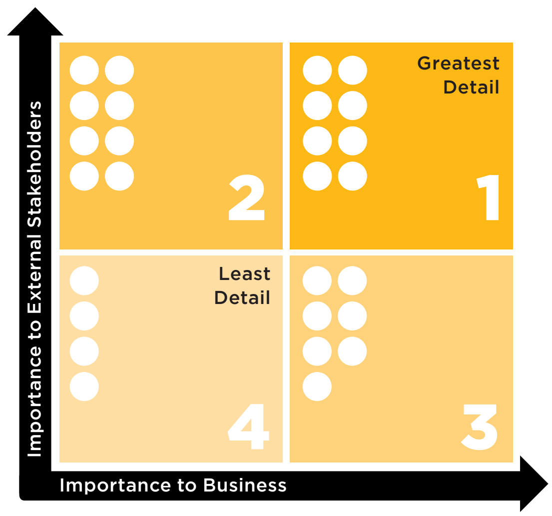
Unless otherwise noted, this report covers the activities under our direct operational control during calendar year 2011. All financial data is reported in U.S. dollars. Information in this report has been subject to internal review and is believed to be correct at the time of reporting. We plan to work towards external assurance of our sustainability reporting in the future.

To develop this report, we utilized the *Oil and Gas Industry Guidance on Voluntary Sustainability Reporting* (2nd Edition, 2010), developed by the International Petroleum Industry Environmental Conservation Association (IPIECA), the American Petroleum Institute (API) and International Association of Oil & Gas Producers (OGP); and the *Sustainability Reporting Guidelines* (Version 3.1), developed by the Global Reporting Initiative (GRI). These guidelines are generally accepted frameworks for reporting economic, environmental and social performance. Our IPIECA/API/OGP and GRI index shows which guideline elements have been reported and where they can be found (see page 51).

OUR MATERIALITY ANALYSIS

The content of this report was determined through a materiality analysis that identified those sustainability related areas that we believe to be of greatest interest to external stakeholders and most relevant to Noble Energy's operations. Areas of potential significance were based on a review of media coverage as a proxy for stakeholder concerns and later validated through a series of stakeholder interviews. We also conducted a series of internal interviews and workshops to discuss issues of potential significance. Stakeholder and business-derived concerns were then analyzed and plotted on a four-quadrant chart based on importance. For this report, we focused on areas of highest business significance – in particular, areas that were ranked priority one and two.

MATERIALITY ANALYSIS MATRIX



In this report, we detail how we are accounting for the EHS and socio-economic impacts of our business while keeping true to our corporate purpose.

STAKEHOLDER FEEDBACK

We believe stakeholder feedback is an important part of the report-development process. Representatives from nongovernmental organizations (NGOs) and analyst groups were interviewed to validate our materiality analysis and better understand what areas they felt should be addressed in the sustainability report of an oil and natural gas company. We were encouraged to find that their key concerns generally matched the areas identified in our own materiality analysis. For instance, interviewed stakeholders were interested in learning about our challenges and our successes at the corporate level through to the project level. Key matching topics included contractor management, water impact, stakeholder engagement and social investment. This information was used to help develop this report.

To provide feedback and comments on this report, please contact: Responsibility@nobleenergyinc.com.

NOBLE ENERGY, INC. TIMELINE

1932
Lloyd Noble forms Samedan Oil Corporation (pronounced sam-ee-dan), named after his children Sam, Ed and Ann

1968
Samedan acquires its first offshore block in the Gulf of Mexico

1969
Noble Affiliates, Inc. is organized combining several companies – the primary two being Noble Drilling Corporation and Samedan

1972
Noble Affiliates begins trading as a public company on NASDAQ

1980
Noble Affiliates moves to the New York Stock Exchange and begins trading under the symbol NBL

1985
Noble Affiliates spins off drilling subsidiary Noble Drilling Corporation

1991
Production commences at Alba field (non-operated working interest) offshore Equatorial Guinea

1996
Noble Affiliates acquires Energy Development Company, adding a diverse group of U.S. and international assets

2000
Noble Affiliates announces Mari-B discovery offshore Israel

2001
Noble Affiliates announces first deepwater Gulf of Mexico discovery

Methanol production commences at Atlantic Methanol Production Company (partially owned subsidiary) plant in Equatorial Guinea

The Noble Energy Story

"... The land must continue to provide for our food, clothing and shelter, long after the oil is gone." – Lloyd Noble

Noble Energy's history begins with the vision and leadership of Lloyd Noble. Lloyd purchased his first drilling rig in 1921 and quickly became one of the most successful and respected onshore drilling contractors in the United States. He demonstrated respect for communities and land, recognizing the importance of protecting our natural resources.

Lloyd's son, Sam Noble, shared this vision for managing the business in a responsible way. Once drilling activities were complete on Sam's own land, he was said to have walked his property with the drilling team and conveyed his gratitude by saying, "You have done a good job taking care of my place; make sure you do that everywhere you go." We continue to embody this vision through our purpose, *Energizing the World, Bettering People's Lives.®*

At Noble Energy, our business is about more than oil and natural gas exploration and production. It's about improving the lives of those around us by helping local communities grow and prosper. Our commitment to *Energizing the World, Bettering People's Lives®* has been with us from our humble beginnings as a regional oil and natural gas producer, through our transformation into the leading global independent exploration and production company that we are today.

We continuously strive to be a better industry partner by providing our employees with opportunities to make positive contributions and by constantly challenging ourselves to find better solutions so we leave a legacy of sustainability wherever possible.

2002

Noble Affiliates changes its name to Noble Energy, Inc.

Operations commence at the Noble Energy integrated gas-to-power project in Ecuador

2004

Mari-B natural gas sales begin in Israel

2005

Noble Energy acquires Patina Oil & Gas Corporation, enhancing its onshore U.S. asset portfolio

2006

Noble Energy establishes significant presence in the deepwater Gulf of Mexico

Noble Energy acquires U.S. Exploration Holdings, Inc., expanding its position in the DJ Basin's Wattenberg field onshore U.S.

2007

Noble Energy announces Benita and Yolanda discoveries in Block I offshore Equatorial Guinea

Production commences at Dumbarton development in the North Sea (non-operated working interest)

2008

Noble Energy discovers hydrocarbon resources in the deepwater Gulf of Mexico at Gunflint

2009

Noble Energy discovers natural gas at Tamar offshore Israel

Noble Energy sanctions Aseng project offshore Equatorial Guinea

2010

Noble Energy discovers natural gas at Leviathan offshore Israel with resource estimates of 16 trillion cubic feet

2011

See Operational Highlights from 2011 on page 9

Our purpose and core values (see page 10) guide our business decisions from our boardroom to our operations. They are the driving force behind our accomplishments and will remain at our core as we continue to search for the right solutions to the world's energy challenges.

Our Corporate Social Responsibility (CSR) Policy outlines our vision for promoting a culture that respects the laws, individuals, environments and sustainability of the communities where we operate. You can view our CSR Policy at: www.nobleenergyinc.com/CSRPolicy.

1980, Noble Energy's first day of NYSE trading. Roy Butler (left center) and Sam Noble (right center).

Noble Energy is a leading independent energy company engaged in worldwide oil and natural gas exploration and production. We are an S&P 500 company with reserves of 1.2 billion barrels of oil equivalent and assets totaling more than $16 billion at year-end 2011. Our broad asset base includes development and exploratory resource opportunities through our five core operating areas:

1. Denver-Julesburg (DJ) Basin
2. Marcellus Shale
3. Deepwater Gulf of Mexico (GOM)
4. West Africa
5. Eastern Mediterranean

CORE

Operational Highlights

We conduct our business according to the following principles:

- Manage a portfolio of superior assets
- Execute major projects with attention to excellence
- Execute a best-in-class exploration program
- Invest in people and technology
- Maintain investment and fiscal discipline
- Demonstrate leadership in EHS, compliance and corporate citizenship

OPERATIONAL HIGHLIGHTS FROM 2011

2011 was another strong year for Noble Energy as we continued to lay the foundation for significant future growth across our five core operating areas. For example:

- We entered into a Marcellus Shale joint venture with CONSOL Energy Inc. that strengthens and rebalances our portfolio and provides a new material growth area that will impact future reserves, production and cash flows.
- We led the way back to work in the deepwater Gulf of Mexico, receiving the first post-moratorium deepwater drilling permit (see page 22), and had exploration success at our Santiago prospect.
- In the Eastern Mediterranean, natural gas production increased as we continued to support the Israeli gas market when it experienced interruptions in Egyptian supplies.
- We continued to improve our operational performance in the DJ Basin and began constructing multi-well horizontal drilling pads and centralized production facilities to minimize our surface rise and allow for more efficient operations (see page 33).
- We made significant progress on the development of our Tamar project offshore Israel.
- We completed appraisal work at the Leviathan discovery offshore Israel and made another significant discovery offshore Cyprus of an estimated 7 trillion cubic feet of natural gas.
- In Equatorial Guinea, we brought our Aseng project online early and under budget (see page 21).
- We continued to make progress on our Alen project in Equatorial Guinea and continued exploration activities offshore Cameroon.
- We transferred our assets in Ecuador to the Ecuadorian government to maintain focus on our core operating areas.

Noble Energy in 2011

Millions	
Total Revenues	$ 3,763
Net Income	$ 453
Total Assets	$ 16,444
Long-term Debt	$ 4,100
Capital Expenditures (cash basis)	$ 3,121
Tax and Royalties to Governments	$ 492
Number of Employees	1,876
Consolidated Crude Oil Sales *(MBbl/d)*	64
Consolidated Natural Gas Sales *(MMcf/d)*	811
Consolidated Natural Gas Liquids Sales *(MBbl/d)*	15
Total Proved Reserves *(MMBoe)*	1,209
Shareholder Ownership *(% institutional)*	94%

See our 2011 Annual Report for more operational highlights.

Core Values

Our core values guide how we do business. They provide the foundation upon which trust can be built and maintained with our stakeholders.

Integrity

Being fair, honest, ethical and transparent in dealing with all stakeholders. One's word is their bond.

Caring

Being genuine and authentic, thinking of the needs of others. Respectful of yourself, others and the environment. Committed to make a positive impact on people and communities we touch.

Creativity

Seeing endless possibilities. Continuously innovating to provide the fuel for sustainable, extraordinary performance.

Wisdom

Joining of knowledge, insight and judgment leading to deliberate, thoughtful decisions that positively impact outcomes today and into the future.

Agility

Always anticipating the need for change. Seizing opportunities by being flexible and responsive.

Excellence

Setting the performance standard through uncompromising demand for being best in class in all we do.

Alignment

Working as one to achieve extraordinary results.

Building Partnerships

Our long-term success depends on our ability to build trust with our stakeholders. We believe that our core values provide the foundation upon which trust can be built.

Communities

Wherever we operate, our goal is to be an active member of the community. We want to be the company that people trust to get the job done right. We aim to earn trust through transparency, open dialogue and treating communities with respect.

Employees

Employees are our ambassadors to the world. We are committed to providing a safe, secure, harassment-free workplace; engaging work; and competitive benefits. We aim to create an inclusive, creative culture where our employees are able to excel and make a difference.

Nongovernmental Organizations

We seek to build partnerships and working relationships with NGOs most relevant to our business, meeting with them to discuss concerns such as human rights and environmental impacts. Sharing who we are and listening to concerns is important to us.

Contractors and Joint Venturers

Our contractors and joint venturers play an important role in the business of Noble Energy. We strive to provide them with the same work environment our employees enjoy, and we hold them to the same standards. We aim to maintain clear lines of communication and exchange best practices at any opportunity.

Governments

Noble Energy engages with governments in the U.S. and abroad for many purposes, ranging from our license to operate to addressing energy policy. We approach this engagement as an opportunity to solve problems and advocate positions to mutually benefit the industry, government and society over the long term.

Shareholders

Noble Energy engages with our shareholders regularly through our Annual Shareholders Meeting, financial reports and other disclosures. Being transparent with our shareholders and other stakeholders is important to us and one of the reasons we are sharing our sustainability story through this report.

Corporate Governance

We are committed to a solid foundation of integrity, reliability and transparency in our disclosures to the public. Our corporate governance structure and practices are designed to ensure that our business is conducted in the best interest of our shareholders and in compliance with our legal and regulatory obligations.

BOARD OF DIRECTORS

Our Board of Directors (Board) underpins our corporate governance structure and represents a broad cross-section of backgrounds and experiences relevant to our business. Eight of our nine directors are non-management and independent under New York Stock Exchange (NYSE) standards.

Leadership Structure

Our Board currently combines the role of chairman of the board with the role of chief executive officer (CEO) and maintains a separate, empowered lead independent director position to strengthen our corporate governance structure. Our Board believes this provides an efficient and effective leadership model for the Company. This approach fosters clear accountability, effective decision making and alignment on corporate strategy. Our lead independent director provides a level of checks and balances within the Board and is responsible for such areas as approving meeting agendas and working with the CEO to prioritize issues.

Corporate Governance Guidelines

We adopted Corporate Governance Guidelines that are available on our website and provide information about our Board and corporate governance structure and practices. These guidelines cover such areas as director qualifications, responsibilities, compensation, orientation, continuing education and access to management and independent advisors; Board committees; evaluation of the Board and its committees; shareholder-director communications; management evaluation, succession and development; and stock ownership guidelines.

Executive Sessions

The non-management directors of our Board hold executive sessions without management at regularly scheduled Board meetings and at such other times as may be set by our lead independent director. These sessions take place outside the presence of our CEO and any other employee. They are presided over by our lead independent director. This allows our non-management directors the opportunity to separately consider management performance and broader matters of strategic significance to the company. During 2011, our non-management directors met five times in executive sessions of the Board.

Communication with our Board

We encourage shareholders and other interested parties to communicate with our Board, any Board committee or committee chair. This may be done by mail, electronically or by calling our independent, toll-free compliance line. Instructions and guidelines for such communications are provided in our Corporate Governance Guidelines.

PUBLIC POLICY ENGAGEMENT

Senior management oversees our public policy efforts, reviewing key issues with our Board that are relevant to risk management and EHS strategies. In 2011, we hired a vice president responsible for communications and government relations to coordinate our engagement efforts and ensure consistency in policy and approach throughout the company.

In 2010, we formed the Noble Energy Political Action Committee (PAC) to promote good citizenship and further business interests that are of concern to our shareholders and employees. Our PAC contributions are publicly reported, as required by law, and totaled $41,287 in 2011.

BOARD COMMITTEES

Our Board has four standing committees. Each of them operates under a charter approved by our Board. These charters, along with information about each committee's composition, are available on our website.

Audit Committee

Our Audit Committee assists our Board in fulfilling its responsibility to oversee the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor's qualifications and independence, and the performance of our internal audit function and independent auditor. In addition to these responsibilities, the Audit Committee plays an important role in risk management by retaining and interacting with our independent auditors of financial statements and oil and gas reserves, and by holding periodic reviews with our management to address financial and related disclosures, key legal and regulatory developments, and possible enhancements to our Code of Business Conduct and Ethics.

Compensation Committee

Our Compensation, Benefits and Stock Option Committee (Compensation Committee) reviews and approves our goals and objectives in the areas of salary and bonus compensation, benefits and equity-based compensation. The Compensation Committee evaluates our CEO's performance based on those goals and objectives and, either as a committee or together with the other independent directors, determines and approves our CEO's compensation level based on that evaluation. It also has certain responsibilities for non-CEO executive officer compensation. It further supports our risk management efforts by reviewing the Compensation Discussion and Analysis contained in our annual proxy statement, discussing disclosures with our management and reviewing our compensation program. This helps ensure that our risk management efforts remain aligned with our compensation objective, and we address potential risks that may have a material adverse effect on the Company.

CORPORATE GOVERNANCE INITIATIVES

2012

Adopted Stock Ownership Guidelines

Joined FracFocus

Expanded EHS Committee roles to address corporate social responsibility

Amended control arrangements to eliminate excise tax gross-up

2011

Adopted Corporate Social Responsibility Policy

2010

We maintain a Political Law Compliance Program to support our continued compliance with U.S. laws and regulations relevant to political activity. This program includes guidelines for such areas as lobbyist registration and reporting, gifts and entertainment, trade associations and retention of political consultants.

We comply with federal regulations to disclose our lobbying expenses, which totaled $1.85 million in 2011. Lobbying expenses included such things as employee time and travel associated with lobbying activity and trade association membership. Federal issues we lobbied in 2011 included matters relating to hydraulic fracturing, Gulf of Mexico offshore liability and permitting, the Dodd-Frank Wall Street Reform and Consumer Protection Act, tax reform and Marcellus Shale operations. The full list of federal issues lobbied is available on the U.S. Senate website at http://www.senate.gov/lobby.

We are involved in multiple industry groups or trade associations that support our legislative and regulatory evaluation process and public policy engagement.

RECENT CORPORATE GOVERNANCE INITIATIVES

We continually strive to enhance our corporate governance structure and practices and undertook several initiatives in 2011. On January 25, 2011, our Board adopted stock ownership guidelines for our officers and non-employee directors. On December 5, 2011, our Compensation Committee and Governance Committee reviewed the holdings of our officers and directors, finding that all of our executive officers and outside directors were in compliance with the guidelines. Effective February 1, 2011, amendments were made to the change of control arrangements for our officers and employees for the purpose of eliminating excise tax gross-up payment obligations of the Company to those individuals.

In 2010, we adopted a Corporate Social Responsibility Policy, which is available on our website. In January 2011, we formed a management committee to direct our corporate citizenship strategy and initiatives. We also expanded the responsibility of our Environment, Health and Safety (EHS) Committee of our Board to include serving as a forum for review of our strategy and initiatives.

We continue to integrate a number of our ongoing initiatives into our corporate social responsibility program. For example, we participate in the Carbon Disclosure Project by publicly disclosing, on a voluntary basis, certain information pertaining to greenhouse gas (GHG) emissions (see page 34). In 2011, we also began participating in FracFocus, a national hydraulic fracturing chemical registry website that discloses information about chemicals used in hydraulic fracturing (see page 27).

Corporate Governance and Nominating Committee

Our Corporate Governance and Nominating Committee (Governance Committee) takes a leadership role in providing a focus on corporate governance to enable and enhance our short- and long-term performance; engages in appropriate identification, selection, retention and development of qualified directors consistent with criteria approved by our Board; advises our Board with respect to the Board's composition, procedures and committees; and oversees the evaluation of our Board and management. It supports our risk management effort by annually reviewing developments in the area of corporate governance and our Corporate Governance Guidelines in order to recommend appropriate actions to our Board. It also reviews director independence, Board membership and committee assignments, and makes adjustments to ensure that we have the appropriate director expertise to oversee the Company's evolving business operations.

Environment, Health and Safety Committee

We maintain an Environment, Health and Safety Committee (EHS Committee) that assists our Board in determining whether we have appropriate policies and management systems in place with respect to EHS matters, and to monitor and review compliance with applicable EHS laws and regulations. This committee also serves as a forum for the review of Company strategy and initiatives in the area of corporate social responsibility. It further supports our risk management efforts by periodically reviewing our EHS performance, annual EHS audit schedule, and key EHS legal and regulatory developments.

Managing our Risks

Our Board, management and external consultants play an important role in identifying, assessing, monitoring and mitigating potential business risks. By proactively managing our top risks, we are better positioned to reduce losses and capitalize on opportunities.

BOARD ROLE

Risk management is a routinely scheduled agenda item for regular Board meetings. Our chairman consults with our lead independent director to determine the topics and scope of each discussion. A number of other Board processes support our risk management efforts, such as those by which our Board reviews and approves our capital budget and certain capital projects; our hedging policy; new country entry; significant acquisitions and divestitures; equity and debt offerings; and the delegation of authority to our management.

MANAGEMENT ROLE

Risk management efforts are overseen by our management team, and we work with outside consultants to identify, evaluate and mitigate key risks affecting our business. We maintain a Disclosure Committee to assist management in evaluating and determining appropriate disclosures, including those regarding risk, in our public filings.

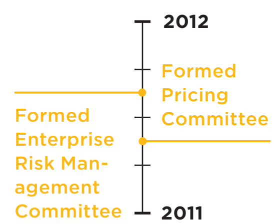
RECENT RISK MANAGEMENT INITIATIVES

We continually strive to enhance our risk management program and undertook several initiatives in 2011.

During the year, we formed an Enterprise Risk Management Committee composed of senior-level personnel from various disciplines to assist our management in identifying, updating and mitigating risks applicable to our business. We continue to enhance our risk identification and mitigation processes in an effort to develop a more integrated and long-term risk-mitigation strategy that focuses on potential risks over the next 10 years.

Also in 2011, our Board appointed a Pricing Committee composed of Board and management representatives to provide oversight of two debt offerings and the renewal of our credit facility. The committee played an important role in enterprise risk management by assessing financial markets and conditions to determine key pricing and other material terms of these transactions.

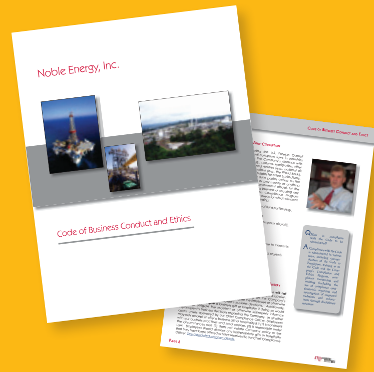
RISK MANAGEMENT INITIATIVES



CODE OF BUSINESS CONDUCT AND ETHICS

Our Code of Business Conduct and Ethics reflects our commitment to conducting business in a manner consistent with the highest ethical standards wherever we operate. Available on our website, our Code of Business Conduct and Ethics and related programs set policies to guide legal and ethical standards of conduct, delineate specific consequences for non-compliance, and provide a mechanism for administering the Code and ensuring compliance. The Code and website also provide a toll-free, 24-hour multi-lingual hotline to report potential incidents of non-compliance. Over the years, the Company has investigated and taken corrective action in response to hotline reports on such matters as abuse or misuse of Company assets, harassment and substance abuse. Our Code has been translated into several languages to ensure its accessibility to every Noble Energy employee and contractor.

Effective November 1, 2011, our Board adopted a revised Company Code of Business Conduct and Ethics that includes several new policies and changes to improve its readability. These changes occurred in conjunction with our annual review of the Code.



COMPLIANCE AND ETHICS

Our commitment to compliance and ethics is an important aspect of our risk management program, and an integral part of our Company culture. We maintain a Compliance and Ethics Program that is grounded by our Code of Business Conduct and Ethics and supported by a number of subject-specific programs.

Compliance and Ethics Program

Our Compliance and Ethics Program provides management commitment, leadership and oversight; education and training; monitoring and auditing; and additional resources. We also maintain a number of subject-specific compliance and ethics programs. Examples include our Antitrust Law Compliance Program, Anti-Boycott and Export Control Law Program, Disclosure Law Compliance Program, Marketing Law Compliance Program and Political Law Compliance Program. Given the global nature of our operations, our Anti-Corruption Compliance Program is discussed in the next section.

In 2005, we formed a Compliance and Ethics Committee, comprised of senior-level personnel from different operational and functional disciplines. It is tasked with assisting our management in identifying, developing and implementing appropriate policies and management systems to support our overall objectives in the areas of compliance and ethics.

Anti-Corruption Compliance Program

Our Policy Regarding Anti-Corruption prohibits employees and third parties acting on behalf of Noble Energy from offering, promising or paying money or anything of value, either directly or indirectly, to a government official or representative for the purpose of improperly obtaining or retaining business or securing any improper advantage. Our Anti-Corruption Compliance Program supplements this policy, providing practical guidance in such areas as identifying "red flags" or warning signs, and governing the receipt or donation of gifts or charitable contributions.

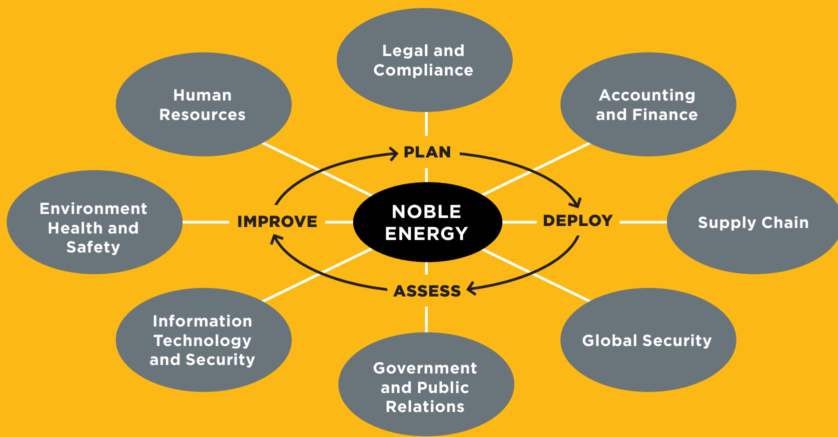
Anti-corruption compliance training is required for Company employees and consultants who travel outside of the U.S. for business; communicate on behalf of Noble Energy with non-U.S. government officials, companies or individuals; are responsible for initiating due diligence; or have other job duties related to compliance with our Anti-Corruption Compliance Program. Our training includes basic and advanced courses, taught both live and online. In 2011, 251 employees or contractors received in-person anti-corruption training, and another 99 employees or contractors took this training online.

Another way we effectively manage anti-corruption risk is by conducting risk-based, anti-corruption due diligence on international contractors according to our Guide to Commercial Due Diligence. During 2011, these practices were expanded to require field-contractor response to human rights and security-related questions.

EXHIBIT B.3

ANNUAL COMPANY COMPLIANCE AND ETHICS SUMMIT

In November 2011, over 90 key compliance and operations leaders participated in our second-annual internal Compliance and Ethics Summit to further integrate and promote compliance awareness and understanding. This diagram emphasizes how effective compliance ties to our business.



The Extractive Industries Transparency Initiative (EITI) supports enhanced governance in resource-rich countries through the disclosure and authentication of company payments and government revenue receipts from oil, gas and mineral development. Noble Energy supports this voluntary initiative to develop good governance in producing countries by improving transparency of payments in the extractive industry. At year-end 2011, Noble Energy was not operating in any EITI-compliant countries.

Recent Compliance and Ethics Initiatives

We continually strive to enhance our compliance and ethics programs. In furtherance of this effort, we hired a dedicated Chief Compliance Officer (CCO) in 2011 to assume compliance responsibilities that previously were held by the Chief Financial Officer.

In June 2011, we revised our Policy Regarding Anti-Corruption to prohibit facilitating payments. While the Foreign Corrupt Practices Act (FCPA) provides an exception for facilitating payments under certain circumstances, our policy now is to prohibit such payments except in emergency situations to avert an imminent threat to the health, safety or welfare of the employee, the employee's family or a co-worker.

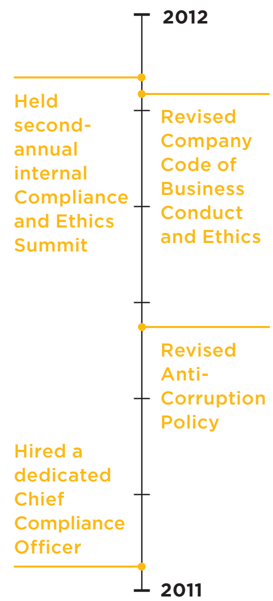
We held our second-annual internal Compliance and Ethics Summit in November 2011. This summit provides a forum for management to reinforce our compliance efforts and an opportunity for employees to hear about and discuss key trends and developments. The program includes presentations by internal and external speakers on a variety of compliance and ethics topics.

ASSESSING BUSINESS OPPORTUNITIES

Our New Ventures team is continually in search of new opportunities around the globe to explore for and develop oil and natural gas resources. This cross-functional group focuses on technical feasibility, commercial attractiveness and above-ground risks when considering entry into a new region. Any new country entry must first undergo this risk assessment, receive Board approval and undergo review again on an annual basis. This process improves our management of above-ground risks in areas such as security, corruption, EHS and corporate social responsibility.

The EHS Strategic Planning and Communications and Government Relations teams are a part of the New Ventures team and work to identify EHS concerns, as well as social and political risks associated with new ventures. They provide recommendations for operations teams to implement to minimize risk of social and environmental impacts, cultivate relationships within local communities, and establish collaborative relationships with governments.

COMPLIANCE AND ETHICS INITIATIVES

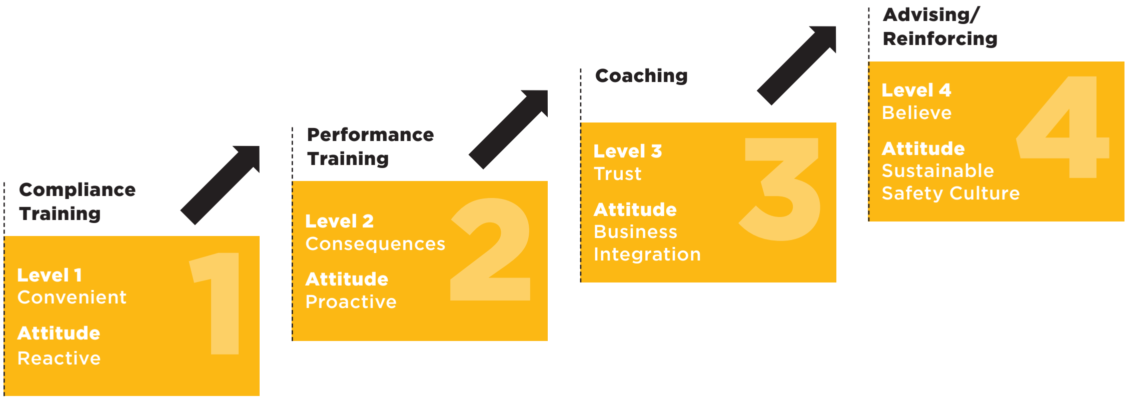


We analyze employee safety performance trends and develop programs to address critical issues. For example, in 2009–2010, we launched a Hands Campaign to address hand-related injuries. In 2010, we launched a Hazard Hunt Campaign to address struck-by/caught-between incidents. Both campaigns provide on-site coaching for hazard awareness, recognition and risk management.

Culture

EXHIBIT B.3

ACHIEVING A SUSTAINABLE SAFETY CULTURE: SAFETY LEVELS OF MATURITY



Providing a Safe Work Environment

Our commitment is to maintain a sustainable safety culture that fosters the development of a safe, efficient and environmentally sound workplace. Our Global Environmental, Health and Safety Management System (GMS) incorporates legal requirements and best practices to protect the environment, health and safety of our employees and communities.

ACHIEVING A SUSTAINABLE SAFETY CULTURE

Following a series of acquisitions in the mid-2000s, we recognized the need to establish a more consistent safety culture across our operations. We conducted a series of site-specific safety analyses for each of our operations, finding sites at different levels of safety maturity. While some sites exhibited excellent safety behavior and commitment, safety culture needed improvement at other sites. As a result, we began conducting a series of training sessions in 2008 to engage in dialogue with our employees about the importance of proactive safety leadership rather than reactive behavior.

GLOBAL ENVIRONMENTAL, HEALTH AND SAFETY MANAGEMENT SYSTEM

Noble Energy depends on our GMS to foster EHS leadership and establish clear and consistent expectations for how we manage EHS risks in operations worldwide. The GMS framework integrates standards from a number of industry and regulatory sources, such as the Occupational Safety and Health Administration (OSHA), the International Labour Organization, the Canadian Standards Association, the Environmental Protection Agency and the World Bank. We review the GMS framework on an annual basis and ensure that it receives a third-party review every other year to maintain consistency with EHS laws and regulations, and industry best practices.

GMS

Global Environmental, Health and Safety Management System

A consistent framework for the management of EHS issues is necessary to protect the environment and the health and safety of our employees and communities. Our GMS incorporates legal requirements and best practices under an umbrella framework consisting of 14 elements:

Prepare

1. Management Commitment and Employee Participation
2. Legal Aspects and Document Control
3. Safe Work and Operating Practices
4. Process Safety and Environmental Information
5. Emergency Preparedness and Community Awareness

Execute

6. Safety and Environmental Training
7. Contractor Safety Management
8. Pre-startup Review
9. Management of Change
10. Risk Assessment and Management

Verify

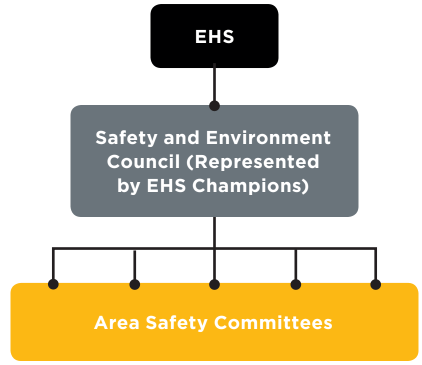
11. Performance Monitoring and Measuring
12. Incident Reporting, Analysis and Corrective Action
13. Management System Compliance Audit

Perform

14. Operational Integrity and Continual Improvement

SAFETY AND ENVIRONMENT COUNCIL

We established a Safety and Environment Council, as well as Area Safety Committees and EHS Champions, to assist employees in meeting their EHS responsibilities and to provide them with opportunities for continual improvement. The council comprises dedicated representatives from various areas of operations who periodically meet to share experiences, issues and concerns. The council fosters a safe, healthy and environmentally responsible workplace. Within each specific area or region, dedicated employees participate in an Area Safety Committee tasked with improving team EHS performance. Representatives from each Area Safety Committee serve on the Safety and Environmental Council. EHS Champions are volunteer posts assumed by area-specific employees who are dedicated to improving EHS initiatives and policy compliance on a daily basis.



Within the GMS, we developed Safe Work and Operation Practices covering Company plans, procedures and strategies for the protection of personnel and the environment. They are periodically reviewed to support continual improvement and include applications such as our Standard Operating Procedures, Job Safety Analysis and Hazardous Communication Program. Our contractors follow their own Safe Work and Operation Practices, but those practices must meet Noble Energy's general requirements.

Under the Emergency Preparedness and Community Awareness element of the GMS framework, incident-management plans are also developed and implemented for each of our operations, as well as at the corporate level. The plans contain provisions for dealing with unanticipated emergencies, and assign authority and duties to ensure that emergency response is timely and effective. Plans cover such areas as:

- Business Continuity
- Incident Management
- Oil Spill Contingency
- Spill Prevention, Control and Countermeasure
- H_2S Contingency
- Hurricane Evacuation
- Coast Guard Emergency Evacuation

EMPLOYEE ENVIRONMENT, HEALTH AND SAFETY PARTICIPATION

We promote a "stop work" culture among our employees and contractors. Any person engaged in operations at one of our facilities has the authority and duty to stop work in response to observed dangers to personnel or the environment, or violations of governmental regulations. Periodic stop work drills are conducted to remind and empower employees and contractors to act on this responsibility whenever they feel it is necessary.

We depend on EHS initiatives that require active participation by employees, such as our management of change, pre-startup review, risk analysis, standard operating procedures and job safety analysis initiatives, as well as near-miss reporting and training. In support of these initiatives, we established a GMS Rewards Program to recognize employees who have been identified as leaders in safety.

Additionally, our North America Northern Region conducts biannual Safety Summits. Each Summit is led by the senior vice president of the Northern Region to reinforce expectations and deliver key messages about EHS leadership. Every district manager in the Northern Region of our U.S. operations is required to present their district's performance, including ongoing challenges and EHS gaps. We plan to extend this program to our other core operating areas in the future.

ENVIRONMENT, HEALTH AND SAFETY TRAINING

A robust training program is essential for supporting a sustainable safety culture. Our training program applies a variety of training methods, such as computer-based training, site-specific training, safety alerts and field-safety orientation. We estimate that operational positions receive at least 25 hours of safety training a year, and office-based employees receive approximately seven hours of safety training a year. We are in the process of integrating our training metrics into a new tracking system.

In 2010, we began providing "Advanced Safety Leadership" training to our field employees and supervisors. This two-day training course focuses on safety communications, encourages employee involvement and engagement, and emphasizes safe operations as a key business objective.

EMPLOYEE SAFETY

Our employees worked over 3.5 million hours and had only four recordable incidents – two of which were lost-time incidents – achieving a total recordable incident rate (TRIR) of 0.22.

CONTRACTOR SAFETY

In 2011, our contractors worked more than 11.6 million man hours and achieved a TRIR of 0.88 with 12 lost-time incidents. In 2010, Noble Energy contractors logged more than 9.8 million man hours and achieved a TRIR of 0.70 with nine lost-time incidents.

EMPLOYEE AND CONTRACTOR SAFETY DATA

	2009	2010	2011
Total Lost-time Incidents	17	10	14
Total Recordable Incidents	37	37	55
Combined (TRIR)	0.67	0.56	0.72
Total Days Away from Work Incident Rate (DWIR)	0.31	0.15	0.18

CONTRACTOR SAFETY STANDARDS

We recognize the role of our contractors in achieving EHS excellence and expect them to operate in accordance with our safety standards. Examples of our efforts in this area include:

- Contractors must disclose their EHS performance as part of the prequalification process.
- Contractor symposiums are held to review policies and expectations.
- Pre-construction meetings are held to address safety issues.
- Safety coordinators are stationed on offshore rigs for ongoing guidance and support.
- A contractor management initiative is underway to standardize the contractor life-cycle for both domestic and international contracts.
- Contractors are expected to complete a Noble Energy safety orientation to access our jobsites. In the U.S., we request contractors complete safety training programs such as Safe Land or Safe Gulf.

SAFETY PERFORMANCE

We set corporate safety goals and objectives that apply to our employees and contractors. Safety metrics are reviewed as part of our compensation program.

Measured metrics include lost-time incidents, total recordable incidents, fatalities, as well as near-misses, first-aid-required incidents, work-related illness, equipment damages, vehicle damages, fire, unintentional discharges and days of restricted duty at work, as defined by OSHA standards for consistent benchmarking.

If a health or safety incident occurs during field activity, it is reported to an internal incident hotline to initiate a response, including any regulatory reporting requirements.

In 2011, an engine fire that occurred during maintenance operations resulted in the death of a contract worker on a supply vessel. In the aftermath of that incident, we worked with the contractor to understand the causes of the accident, and incorporated those learnings into our practices to minimize the risk of a similar incident.

SECURITY

Our growing and diverse asset portfolio presents unique security challenges, which we address on a case-by-case basis to ensure the safety and security of our employees and the communities where we operate. We believe security needs should be integrated into project planning. Our Corporate Social Responsibility Policy reflects our commitment to provide security in a manner consistent with international human rights. We are guided by the Voluntary Principles on Security Standards and Human Rights, a set of principles developed in a multi-stakeholder initiative comprising NGOs, governments and companies.

In 2011, we created a central function that focuses on managing security risk. This group conducts security-risk assessments to help us better understand the sociopolitical environments of the areas in which we operate. We also actively engage with governments, including U.S. officials, to assess and identify potential risks and threats. We created an Information Security Committee within our security group to address the growing risk of cyber threats.

While Noble Energy does not directly employ any public security forces, we may employ private security guards if we determine there are significant security risks, or if mandated to do so by the host government. For example, recognizing security challenges in Israel, we hired a private security firm to secure our assets and safeguard our employees. We have protocols for interacting and maintaining effective communication with Israeli public security forces.

ATLANTIC OCEAN

AFRICA

Aseng is a crude oil development project on Block I offshore Equatorial Guinea. Noble Energy holds a 38 percent working interest and is the technical operator of the project. The Aseng development includes five horizontal wells flowing to a floating production, storage and offloading (FPSO) vessel, where the production stream is separated. The oil is stored on the Aseng FPSO until sold. Natural gas and water are reinjected into the reservoir to maintain pressure and maximize oil recoveries. See our 2011 Annual Report for more details.

Equatorial Guinea

GULF OF GUINEA

Excellence at Aseng

Breakthrough execution and best-in-class safety performance enabled us to achieve first production in November 2011 – seven months ahead of schedule and 13 percent under budget.

Extensive communication, planning and testing were employed to enable early identification and mitigation of potential delays. We ensured peer reviews and third-party assessments of our schedule, budget and engineering plans, and we made our weekly management meetings open to our partners and the government. Transparent communication with all key stakeholders was an important contributor to our success.

A schedule was developed to optimize the movement of drilling rigs, subsea equipment, surface equipment and installation vessels. Each piece of equipment was rigorously tested at key intervals during construction.

Another contributor to our success at Aseng was our commitment to implementing safety-leadership cultures at sites where our contractors work outside of our operational control. Undoubtedly, the single most labor-intensive task at Aseng was the construction of our FPSO. Approximately 2,000 workers were on site to construct our FPSO, along with approximately 8,000 other workers from different countries working on other projects at the shipyard. We worked closely with the shipyard's management to ensure that a commitment to thinking and acting safely was integrated into our project. The motto "safety starts with me, together we care" quickly took hold as each individual embraced his or her responsibility for safety. Safety information was disseminated daily, and monthly award ceremonies were held to recognize the best safety observations and behaviors. These award ceremonies had the added benefit of raising morale, while reinforcing a collective dedication to safety. More than 10.5 million man hours were spent during the construction phase, with no major accidents and only 408 man hours lost for minor incidents.

We are very proud that contractor activity for the construction of the Aseng FPSO was recognized for best-in-class safety performance. During the construction of the FPSO in Singapore, the shipyard builder received an award from the Government of Singapore for its outstanding safety program. This unrivaled dedication to safety kept construction moving safely and efficiently.

Leading the Way Back to the Gulf

The Macondo incident in the Gulf of Mexico affected the entire oil and natural gas industry. The subsequent deepwater drilling moratorium not only halted ongoing deepwater drilling operations in the Gulf, but also stopped the approval process for new drilling permits. We saw the moratorium as an opportunity to take a solutions-based approach in working with the federal government in the face of uncertainty.

The 2010 Macondo spill resulted in a number of fundamental changes to deepwater drilling, including heightened regulatory scrutiny, more stringent operating and safety standards and enhanced engineering requirements. These included additional requirements to subsea blowout preventer testing procedures that required a number of technical changes.

Realizing the industry would require new and innovative equipment and procedures to contain a subsea blowout, Noble Energy collaborated with government officials, energy companies and service providers to assess emergency response systems and determine what enhancements were needed. Noble Energy then brought together a unique consortium of 24 independent deepwater energy companies to see how we could best address the post-spill criteria and comply with the new rules. The Helix Well Containment Group was formed in a shared mission to develop a new approach to deepwater spills. Noble Energy worked with government officials, energy companies and service providers to enhance the overall safety of deepwater drilling operations through third-party certification of well designs and blowout preventer testing. We also made special arrangements during the moratorium to retain our drilling rigs and crews to ensure operational readiness.

Noble Energy experts have since been deployed to train others on these new tools and procedures. Noble Energy also chaired the Helix group's technical committee and volunteered our technical expertise to write a regional Gulf of Mexico well-containment plan and develop a well-containment screening tool.

In February 2011, we secured the first post-moratorium deepwater drilling permit, allowing us to restart our deepwater Gulf of Mexico activities. Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) Director Michael Bromwich stated: "This permit represents a significant milestone. ... [It] was issued for one simple reason: [Noble Energy] successfully demonstrated that it can drill its deepwater well safely and that it is capable of containing a subsea blowout if it were to occur."

Technical breakthroughs and operational readiness were key to the permit approval, but our innovative effort to unite regulators and industry partners behind a common goal was also fundamental to leading the way back to work in the Gulf of Mexico.

In 2011, we conducted a baseline assessment of our current procedures and looked for ways to make improvements in a number of areas. As a result, we strengthened relationships with our emergency response contractors, enabling us to more closely align contract requirements to the specific needs of our operations.

Offshore Operations and Emergency Preparedness

As a result of the lessons learned from the 2010 Gulf oil spill, Noble Energy enhanced its approach to emergency response, particularly in the areas of subsea well containment, oil spill response and shoreline-protection capabilities. We also looked beyond our spill response and planning activities to improve our overall emergency preparedness plans and processes.

We are a member of several international organizations that seek to share equipment and resources in the event of a spill, including the Oil and Gas Operators Emergency Resource Allocation Group in Equatorial Guinea.

Practice and awareness are other essential elements of emergency preparedness. In 2011, we conducted four international response drills in addition to multiple U.S.-based exercises conducted with the Helix Well Containment Group.

One of the most significant and successful improvements to our offshore procedures was the integration of Noble Energy's offshore management systems with the management systems of our drilling contractors. As a result, our internal management system requirements for offshore activities now harmonize global EHS principles into a single methodology, which includes Safety Case Guidelines. We now operate at standards that place stronger emphasis on contractor compliance in developing a project-specific EHS management system, which further reduces risks associated with drilling activities.

On each of our deepwater wells, we conduct a risk-analysis process called "Drill Well on Paper" (DWOP) to ensure shared understanding and alignment among our employees, drilling contractors and service companies. DWOP has proven successful, as it brings multiple groups together behind a single goal. We see this as a critical safety investment.

Over the next three years, we plan to implement an "All Hazard" approach to emergency-response planning. This effort will require a hazard vulnerability assessment, which will be undertaken at the business-unit level. This process will create a comprehensive preparedness, response and recovery architecture that utilizes the National Fire Protection Administration (NFPA) 1600 – Standard on Disaster/Emergency Management and Business Continuity Programs. NFPA 1600 is a broad-based consensus standard developed for the public and private sectors, as well as NGOs. It is designed to be applicable both in the U.S. and internationally.

One of the most significant and successful improvements to our offshore procedures was the integration of Noble Energy's offshore management systems with the management systems of our drilling contractors.

Responsible

As part of the analysis that we conducted to determine the content of this report, we identified three environmental focus areas: onshore oil and natural gas development (including hydraulic fracturing), water management and air emissions.

Respecting our Environment

We are committed to conducting our business in a manner that protects the environment, health and safety of our employees and communities. To achieve this, we work to comply with EHS laws and apply reasonable standards where laws do not exist. By adhering to this approach, we strive to minimize injuries and incidents while protecting the environment.

ENVIRONMENTAL COMPLIANCE

Our EHS Compliance and Risk Group facilitates GMS, EHS and operational integrity audits, utilizing third-party consultants where appropriate to ensure compliance with regulations. Each year, we determine which sites and processes will be audited using a risk-based approach that focuses on identifying specific regulatory or process-related risks.

In addition, we promptly investigate potential incidents of non-compliance with local, state or federal requirements. In 2011, alleged violations of environmental regulations resulted in the payment of $78,200 in civil fines and penalties.

DEVELOPING ONSHORE OIL AND NATURAL GAS RESOURCES RESPONSIBLY

In the last few years, public concerns have been raised about the possibility of the chemicals used in fracturing fluids reaching ground and surface water supplies. We require our site operators to adhere to strict construction standards and best management practices to avoid potential environmental impacts during onshore natural gas development.

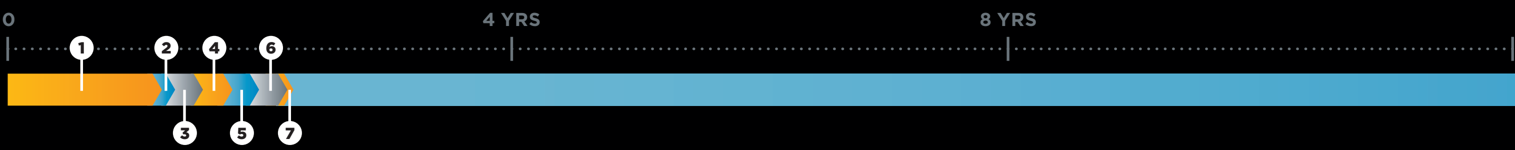
We work to reduce risks to water supplies, the environment and human health. Our practices include managing our water resources (see pages 29–31), ensuring proper installation of our wells (see pages 25–28), and conducting well completion activities, including hydraulic fracturing (see pages 26–28).

Ensuring the Integrity of our Wells

Well integrity is an initial line of defense against water contamination. The pre-drilling subsurface evaluations conducted by our geologists and engineers are used to determine the depths of formations that contain underground drinking water, the proximity of that water to potential oil and natural gas intervals, and the integrity of the confining layers above and below the target completion zone. Our engineers then design a casing and cementing plan that shows how the well will be constructed. This plan is peer reviewed.

In accordance with best management practices, we utilize multiple strings of casing and cement to prevent gas migration or drinking water contamination. We monitor our pump pressures and fluid returns during the cementing process to ensure adequate coverage of cement across the production and groundwater

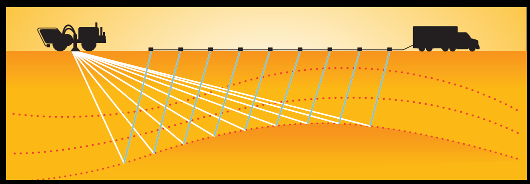
OPERATIONAL PROCESS OF U.S. ONSHORE OIL AND NATURAL GAS EXPLORATION AND DEVELOPMENT



1. Land Acquisition

We acquire a lease or similar rights that allow for oil and natural gas exploration and development. Terms vary and can contain stipulations or mitigation measures to protect various resources. (Duration: one month to a year or more)

2. Seismic



We conduct seismic surveys to determine the location of geologic formations capable of producing oil and natural gas. Seismic testing is done by sending sound waves into the earth that bounce back to the surface and are recorded by geophones or electronic recorders. (Duration: a few weeks to one month)

3. Site Due Diligence

We conduct due diligence by performing on-the-ground surveys to identify existing environmental or social issues to be addressed in our permit applications. (Duration: a few weeks to two months)

4. Site Permitting

APPROVED

We obtain state and federal permits to authorize the drilling and operation of a new well. (Duration: varies by state or U.S. federal property)

5. Site Preparation

Once permits are received, roads are upgraded or constructed to access the site. Well pads are constructed to locate the drill rig and associated equipment. (Duration: weeks to months)

6. Drilling

Our geologists and engineers evaluate subsurface conditions to design the well, which includes an analysis of formations that contain underground drinking water. During the drilling process,

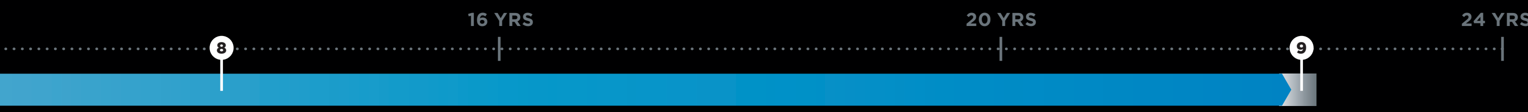
zones. At various stages of the drilling and completion process, mechanical integrity of the casing and cement is tested to ensure proper installation. We also have well control procedures in place to prevent events, such as loss of well control, from occurring.

During the production phase, we continuously monitor flow rates and annular pressures, and we regularly inspect the wellhead assembly and other equipment for leaks, corrosion or damage.

Hydraulic Fracturing

Hydraulic fracturing has been used in the oil and natural gas industry for decades to extract economical amounts of oil and natural gas from reservoirs. Recent technological advances have enabled more efficient well completions within geological formations that were not viable producing zones even a few years ago. This allows for the recovery of oil and natural gas reserves from a number of new areas.

Geologic formations may contain large quantities of oil or natural gas, but have a poor flow rate due to low permeability. Hydraulic fracturing is conducted to create a flow path for hydrocarbons. After a well has been drilled and steel pipe has been cemented

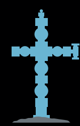


a drilling crew drills down while pumping water and additives (drill mud) to cool the drill bit and flush drill cuttings to the surface. Multiple layers of steel pipe, called casing, are inserted into the full length of the well and cemented in place to protect fresh water formations (see page 28). (Duration: a few days to several months)

7. Well Completion (and Hydraulic Fracturing)

After the well is drilled, the drilling mud is replaced with completion fluid, and an electrical current is sent into the well casing to shoot small holes through the casing and into the geologic formation. Fracturing fluid is prepared on location by sourcing water from a storage pond or tank to a hydration unit and blender that gels the fluid and mixes it with sand and some chemicals. The fluid is then pumped into the well at a high pressure, creating fractures in the rock deep underground. (Duration: a few hours to several days)

8. Production and Partial Site Reclamation



After the drilling and fracturing of the well are complete, the completion crew runs the necessary packers, tubing and production tree to enable commercial production. During production, multiple "workovers" – such as cleaning, repair and maintenance activities to increase or restore declining production – may be performed over the life of the producing well. Once the well is producing oil and/or natural gas, areas of the well site that are no longer needed are reclaimed. Reclamation activities can include reducing the size of the well pad and revegetation. (Duration: 10 to 20 years)

9. Well Plug and Abandonment and Final Reclamation

When the producing well is no longer economically viable, it is plugged by pumping cement into the well. The well heads are removed and the site is abandoned according to regulatory requirements. (Duration: a week to several months)

These steps provide a generic depiction of our operational process for U.S. onshore oil and natural gas exploration and development.

in place, a mixture composed primarily of water, sand and a small amount of chemicals is injected at a high pressure into rock formations to create a flow path (or fracture) for trapped oil and natural gas. The sand keeps fractures open, allowing oil and natural gas to flow into the well. The fracturing fluids are normally recovered during the initial stage of well cleanup and are disposed of according to state or federal regulation. Some water is also produced from returned fracturing fluids or from natural formations. Flowback fluids are managed through a variety of mechanisms, including underground injection, treatment and recycling.

The hydraulic fracturing operation can take a few hours to a day and is performed by personnel trained to monitor pump pressures, fluid volumes and annular pressures with state-of-the-art recording instruments. If, during hydraulic fracturing activity, abnormal pressure responses indicate a potential for mechanical failure or fracture growth outside of the production zone, the job is stopped and corrective action taken.

We have had no impacts to groundwater from hydraulic fracturing. Out of a total 7,479 wells in the DJ Basin Wattenberg field, including 506 wells drilled in 2011, all were successfully hydraulically fractured.

Disclosure of Hydraulic Fracturing Fluids

Noble Energy is an active member and participant in FracFocus, a national hydraulic fracturing chemical registry website. We began voluntarily disclosing the chemicals used at Noble Energy wells through FracFocus in mid-2011, registering 370 of our wells online by the end of the year.

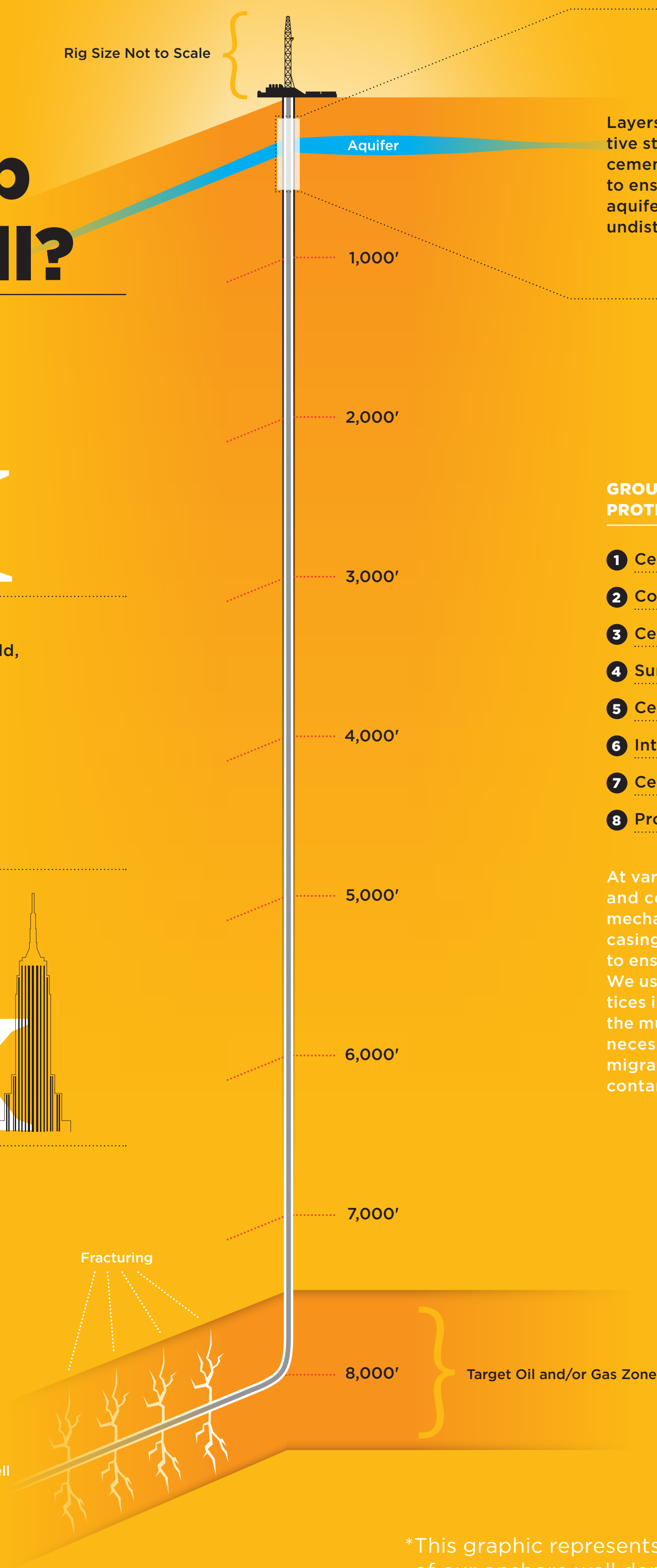
506

Total DJ Basin Wattenberg field wells drilled and successfully fractured in 2011

370

Noble Energy registered wells with FracFocus

How deep is our well?



Deeper than the deepest part of the Grand Canyon (6,000 feet)

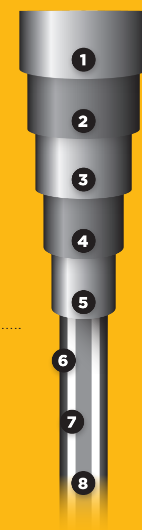
1.3x

The height of the tallest tree in the world, Sequoia Redwood (379.1 feet)

21x

The height of the Empire State building (1,454 feet)

5.5x



Layers of protective steel and cement are used to ensure water aquifers remain undisturbed.

GROUNDWATER PROTECTIVE LAYERS

1. Cement Layer 1
2. Conductor Casing
3. Cement Layer 2
4. Surface Casing
5. Cement Layer 3
6. Intermediate Casing
7. Cement Layer 4
8. Production Casing

At various stages of the drilling and completion process, mechanical integrity of the casing and cement are tested to ensure proper installation. We use best management practices installing and cementing the multiple strings of casing necessary to prevent gas migration or drinking water contamination.

*This graphic represents a generic depiction of our onshore well depth and casing.

EXHIBIT B.3

Two of our core areas: the DJ Basin (left) and the Marcellus Shale (right), along with our other onshore U.S. operations, use hydraulic fracturing for the production of oil and natural gas.

Respecting Water Resources

We recognize the importance of water quality and availability. Developing energy resources can require large volumes of water, and significant energy is needed to access, treat and deliver water. With increasing demand for energy and water, we are actively managing and conserving water resources to minimize the impact of our operations.

Life-Cycle Water Management Strategy

Water is used during many oil and natural gas activities, including drilling and completion of new wells, maintenance and upgrades on existing wells, site construction and sanitary purposes.

In 2011, Noble Energy implemented a Life-Cycle Water Management program for our DJ Basin operations focused on responsible sourcing, transport, use, treatment, recycling and disposal of water resources. This program supplements our ongoing efforts to collaborate with communities as we work to minimize consumption, properly dispose of produced water, and test and implement new water-treatment and -reuse technologies to address potential environmental and community impacts. We employ professionals with expertise in water resources to work with the community to achieve water management objectives. Efforts are underway to implement this strategy globally. The complete range of water management operations addressed by this program is described on page 30.

Our Water Use in 2011

In 2011, our U.S. operations used an estimated 19 million barrels of water – approximately 7 million of these barrels were reused during subsequent drilling and maintenance activities.

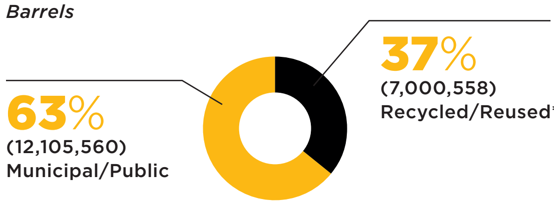
While over 12 million (of the 19 million) barrels of water were obtained from public supplies, we are seeking to reduce our acquisition of municipal or public supplies as part of our water management strategy (see page 30).

We also continue to evaluate the viability of alternative water sources (such as brine aquifers) to minimize our use of public supplies.

In 2012, we participated in the Carbon Disclosure Water Project as we continued to enhance measurement and transparency of our water use.

U.S. Sources of Water

Barrels



*Water is recycled and reused from Noble Energy produced water

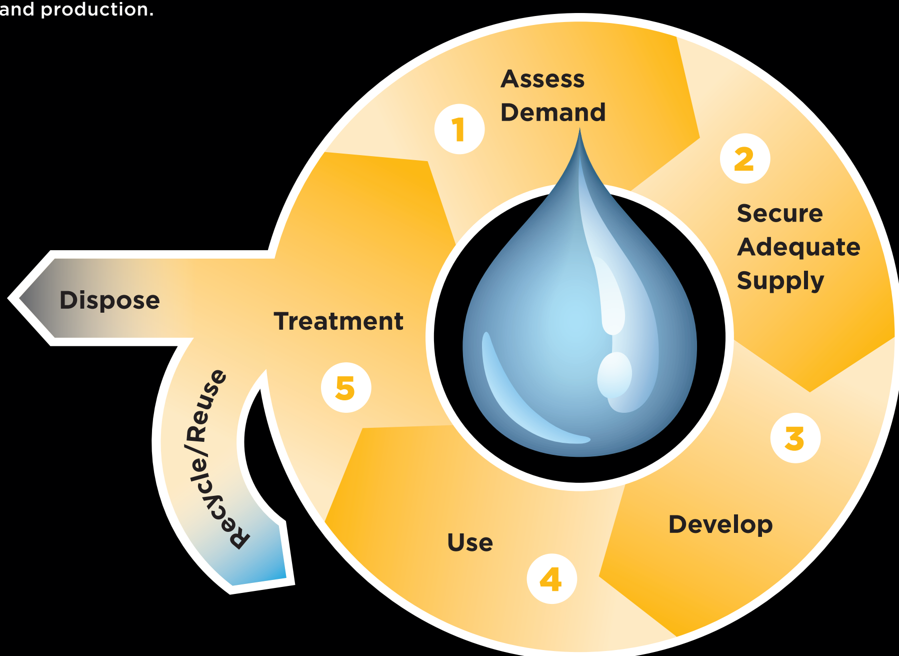
In 2011, Noble Energy implemented a Life-Cycle Water Management program for our DJ Basin operations, reflecting our commitment to responsible sourcing, transport, use, treatment, recycling and disposal of water resources. We plan to expand this program to all of our onshore operations.

2 Secure Adequate Supply

Our approach to securing water rights seeks to strike a balance between effective, long-term and reliable water supply planning to meet our operational demands with the economic, social and environmental needs of landowners and surrounding communities. We work with local landowners to secure necessary water rights and use water resources in compliance with applicable laws and regulations.

1 Assess Demand

Our geologists and engineers identify multi-year water demand for drilling and production.



3 Develop

Once we secure water, we develop water transport and storage infrastructure. Transportation and storage infrastructure – such as pipelines, pumping facilities, tanks and ponds – are designed to meet the specific physical and operational circumstances in each area of operation.

4 Use

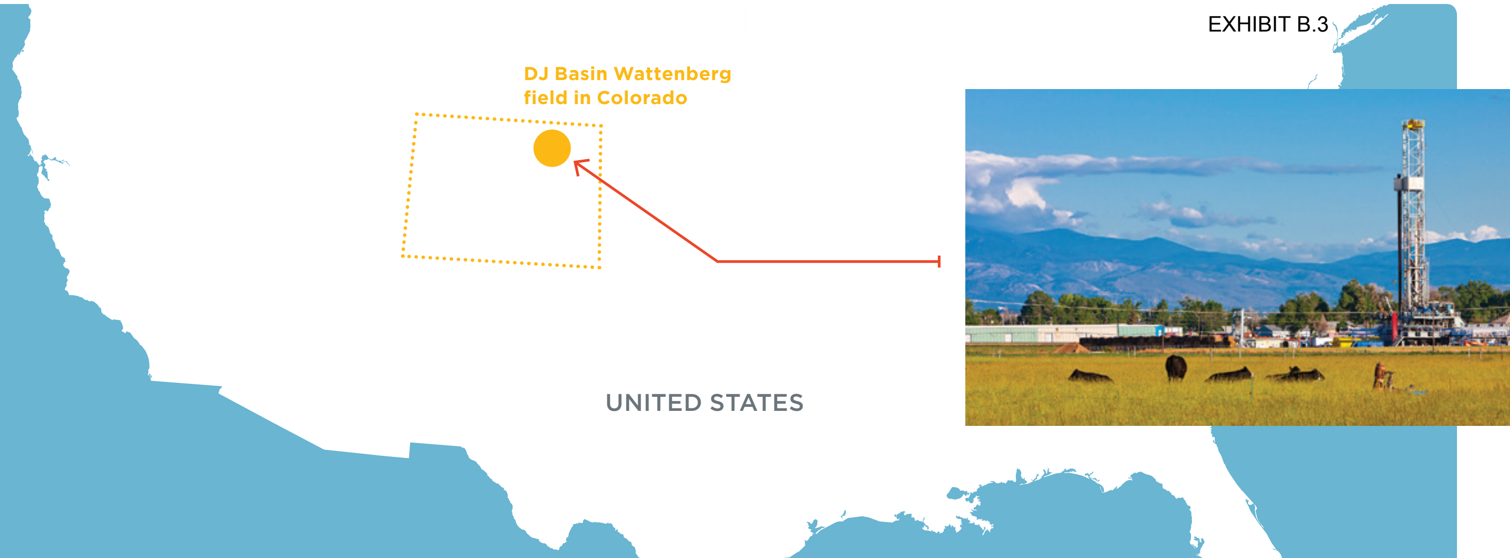
Water is used in drilling, well completion (which includes hydraulic fracturing – see page 26) and workover activity. Site-specific water requirements can fluctuate based on a number of factors and are coordinated with water management teams and field personnel to ensure adequate supply. Effective water management also includes an accurate measurement and reporting system.

5 Treatment, Recycling and Reuse

We apply proven water treatment, recycling and reuse processes to treat wastewater captured as flowback and water produced during operations* to reduce the amount of fresh water we consume and minimize our "hydrologic footprint." These water management efforts optimize capital, water acquisition and transportation costs; minimize the amount of residual wastewater that is typically disposed of in deep injection wells; and contribute to reducing our impact on the environment and community.

* Over the lifetime of an oil or natural gas well, water is regularly brought to the surface in the form of either flowback water or produced water. Flowback: water injected into the well during drilling that returns to the surface. Produced water: naturally occurring, highly saline water that can be produced (come to the surface) during the well's life cycle.

EXHIBIT B.3



Applying our Water Management Strategy in the DJ Basin

Our Wattenberg field in the DJ Basin of Colorado is our largest onshore U.S. asset. This area utilized an estimated 8.5 million barrels of water in 2011. In an effort to secure adequate water and avoid competing with public water supplies, we source water from systems that are unsuitable for drinking purposes. This includes brine aquifers, grey water or produced water.

We also reduce the quantity of water transported by truck to each site by strategically locating storage ponds and tanks, and utilizing pumps and pipelines as alternative means of water delivery. These water-supply facilities help reduce our overall footprint by serving multiple sites and reducing the number of truck trips needed to transport water. In fact, in 2011, we reduced our truck mileage by approximately 5 million miles in the Wattenberg field, yielding an annual reduction of 58,000 tons of carbon dioxide (CO_2) emissions.

Our engineers and operations staff for the DJ Basin are continually identifying and assessing opportunities to conserve water. Enhancements implemented since fourth quarter 2010 resulted in a 10 percent reduction in the volume of water consumed per well in the region.

COLORADO ENERGY WATER CONSORTIUM

In 2011, Noble Energy entered into a collaborative agreement with Colorado State University, the state government, industry partners and environmental NGOs to study the nexus between energy and water-related issues. Our initial $250,000 contribution established the Colorado Energy Water Consortium. Noble Energy experts will participate in each research project, serve on the Consortium's board of directors and coordinate activities with other energy companies. The Consortium will also include engineering corporations, environmental organizations and government agencies. We are seeking ways to expand this multi-stakeholder approach to research water and energy issues in the other regions where we operate.

Initial activities of this group include the implementation of a Water Intensity Study and Geographic Information System (GIS) analysis of water quantity and quality in the Wattenberg field. The Consortium also outlined research projects to analyze water use during horizontal well fracturing activities and associated impacts to the local environment and communities in the Wattenberg field. In addition, they will analyze impacts of other energy and exploration activities on water resources in the field, such as the full life-cycle of water procurement, use, treatment, recycling and disposal.

ONSHORE SPILL PREVENTION AND RESPONSE

Our Spill Prevention, Control and Countermeasure Plans outline necessary mechanical integrity testing, site design, inspections, training and response procedures. If a spill occurs during field activity, personnel are trained to call our incident hotline to initiate an incident response, including any regulatory reporting requirements. If the problem is something that can be fixed safely and immediately, we proceed with this course of action. If the spill is large enough to require remediation, we excavate the soil where the spill occurred, test it, verify that all contaminated soil has been collected and haul it to an approved landfill. We then replace the remediated area with clean soil.

Noble Energy tracks all spills over one barrel and reports any spills that trigger the state reporting threshold, or that extend outside secondary containment and reach water.

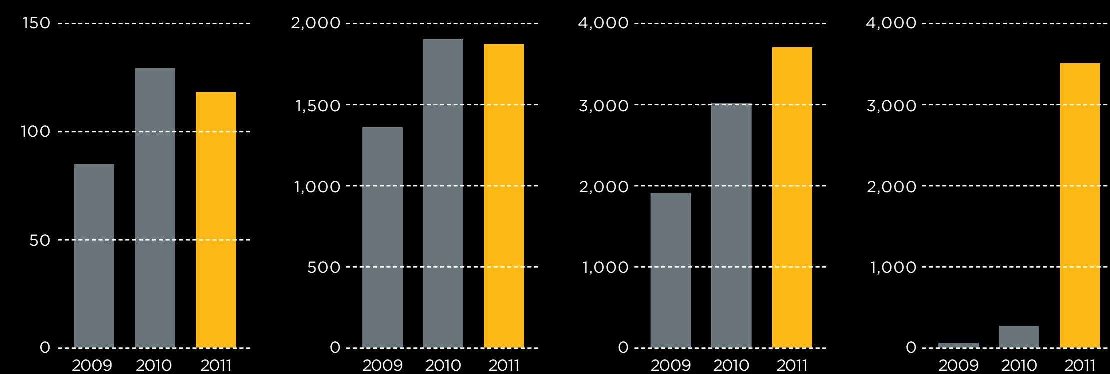
U.S. REPORTABLE SPILLS

Total Number of Releases

Total Volume of Hydrocarbons Released
Barrels

Total Volume of Water Released
Barrels

Total Volume of Other* Released
Barrels



* Other: non-produced fluids on site such as diesel, chemicals and drilling mud.

We are committed to a baseline water sampling program.

Protecting Surface and Groundwater Resources

We utilize secondary spill-containment techniques to protect against contamination in the event of a spill during drilling activity, as well as additional storm water controls to manage runoff. At locations where we are past the drilling phase and are producing, we rely mainly on secondary containments, such as steel rings and liners underneath newer tank batteries, to limit the potential for contamination. To prevent the migration of fracturing fluids, we construct the wellbore with multiple layers of casing (see page 28) to maintain a buffer of more than one foot of steel and cement (total thickness varies based on the geologic conditions of the region) between the wellbore and the surrounding rock. We employ this process to help ensure that onshore natural gas development activities do not pose a meaningful risk to water supplies.

Additionally, prior to drilling selected oil or natural gas wells in the DJ Basin, we hire third-party environmental consultants to assess the baseline water quality at existing water wells. The primary oil and gas constituent we test water for is methane. Methane is the most abundant component of natural gas and, as such, serves as an indicator of potential oil and gas contamination. We also test for a range of water quality parameters, such as total dissolved solids, as well as benzene, toluene, ethylbenzene and xylenes. This information is then shared with landowners to establish a baseline condition for the existing groundwater. If we suspect a risk of impact to groundwater from our activities, we proactively sample nearby water wells.

As we begin operating in the Marcellus Shale in 2012, we will work with our joint venture partner, contractors and service companies to develop community partnerships and initiatives to address local water-related concerns. We also plan to conduct baseline assessments of drinking water quality and quantity to measure domestic and stock water wells within 2,500 feet of our wells. See pages 29–31 to read about our approach to managing water supply and quality.

EXHIBIT B.3

Wildlife Restoration and Management

As part of our commitment to preserving the environment in the Piceance Basin, we partnered with the Colorado Department of Wildlife to develop a regional management solution to minimize and mitigate the impact that our 19,000-acre natural gas development project will have on local wildlife.

The plan includes designing our drilling activities to source multiple wells from one pad, minimizing surface disturbance. We are also committed to educating our employees and contractors on wildlife-friendly practices, and working with landowners to protect wildlife. To support wildlife restoration activities, Noble Energy contributed a total of $150,000 during 2010–2011 to the Battlement Mesa Reservoir Restoration Project to restore the native cutthroat trout habitat. We also contributed $30,000 to the Colorado Mule Deer Association to be used on a six-year project for habitat restoration on the Western Slope of the Rocky Mountains.

In central Wyoming, we partnered with a natural resources consulting firm to analyze the nesting habits of the sage grouse to identify additional ways we could minimize the disruption of its nesting habitat. The study identified factors important for determining sage grouse nest success, including nest site characteristics and weather conditions.

REDUCING OUR DRILLING FOOTPRINT

In late 2011, we initiated the EcoNode Centralized Facilities program at our well sites in the DJ Basin. This allows our engineers to place operational facilities on a central site away from the wells. The program uses advanced engineering and operating designs that provide a highly automated, safe and environmentally protective facility. Water for multiple wells can be pumped from a single location, enabling the efficient collection of produced fluids. Utilizing pipelines to transport fluids significantly reduces surface disturbances for water facilities, while also reducing truck traffic and subsequent air emissions. With up to 32 wells operating on a single EcoNode, our land footprint may be reduced by more than 70 percent. We combined the best in horizontal drilling technology, which by itself has increased efficiency and reduced our environmental footprint, with a level of centralization that consolidates operational activities. In addition to reducing our physical drilling space, the program minimizes air emissions, water consumption and road use. The increased efficiency also raises production yields, while reducing the time and cost of our operations.

By reducing our physical footprint and centralizing our activities, we minimize our impact on the land and cut costs by:

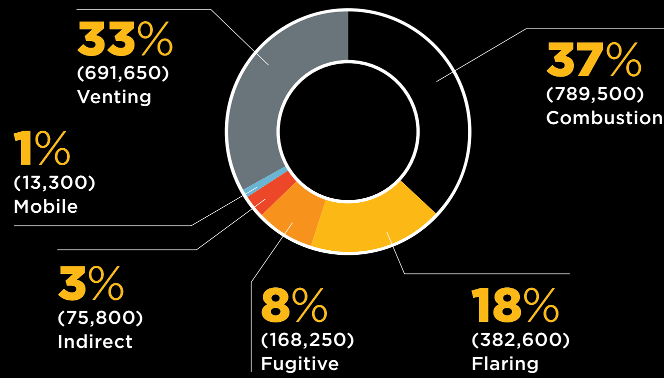
- Collecting oil, water and natural gas in a unique gathering system that maximizes hydrocarbon recovery
- Capturing all the flash gas from the single EcoNode rather than burning it off
- Requiring less equipment and maintenance
- Recovering significantly higher volumes of hydrocarbon fluids through improved pipeline strategies.

EcoNode Centralized Facilities may reduce our land footprint by

70%

2011 NOBLE ENERGY CO_2e EMISSIONS BY SOURCE CATEGORY

Metric tons CO_2e



REDUCING GREENHOUSE GAS EMISSIONS

Noble Energy established a Climate Change Committee composed of company employees to organize, evaluate and advise executive management on climate change and GHG emissions issues.

Our GHG emissions reduction strategy includes emissions inventory, reducing emissions and operation/building reduction initiatives.

THREE FOCUS AREAS FOR REDUCING EMISSIONS

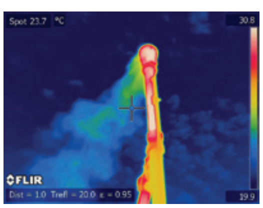
- Reducing flaring
- Preventing leaks
- Converting vehicles and drilling rigs to run on natural gas

Emissions Inventory

Since 2006, we have recorded our annual direct and indirect GHG emissions, and we integrate this data into our Environmental Information Management System to improve its accuracy.

Reducing Emissions

We seek to reduce GHG emissions in our operations through techniques such as green well completions (where gas is separated from the flowback liquid and can be transferred to sales sooner than standard flowback operations), utilizing lift systems to reduce venting, and maintaining a fleet of hybrid and natural gas vehicles.



Infrared cameras capture images like this that show heat, allowing technicians to identify potential leak points (e.g., loose gaskets, etc.) that cannot be ascertained with visual examination alone.

Operation/Building Reduction Initiatives

Designing better emission controls, consolidating wells and making investments in the research and development of new green technologies are a few of the ways we apply our innovative spirit to the task of further reducing our GHG emissions. For example, between 2008 and 2010, Noble Energy replaced 3,200 high-bleed pneumatic valves with more efficient ones. This initiative alone reduced our annual GHG output by more than 220,000 metric tons.

Additionally, since 2009, Noble Energy has participated in the Carbon Disclosure Project (CDP), which seeks to motivate investors, corporations and governments to measure, manage and reduce emissions and mitigate the impacts of climate change. Details of our CDP efforts are available on our website.

In 2012, we will file our first GHG-emissions report according to the standards set forth in the U.S. Environmental Protection Agency's (USEPA) Mandatory Greenhouse Gas Reporting Rule. Although we have been calculating our GHG footprint for the last six years, the USEPA's new calculation methods require additional monitoring, recordkeeping, reporting and data management. We are adjusting our calculations of GHG emissions to align with USEPA requirements.

Flaring Reductions

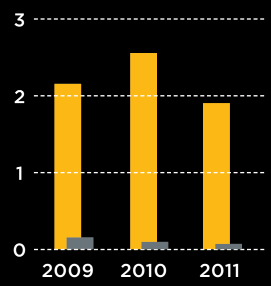
In 2011, flaring accounted for approximately 18 percent of our annual GHG emissions. This 13 percent increase over 2010 was primarily due to expanded activities in the DJ Basin, where the majority of our storage tank emissions are flared.

Flaring, or the burning of natural gas, may be necessary for safety, technical or commercial reasons. In the DJ Basin, we perform green well completions on all of our horizontal wells. This minimizes uncontrolled venting during flowback and maximizes recovery to sales.

Through our Vapor Recovery Unit (VRU) program, we have already made great strides in capturing gas that would otherwise be flared. In 2011, we installed 50 VRUs in the DJ Basin, bringing the total

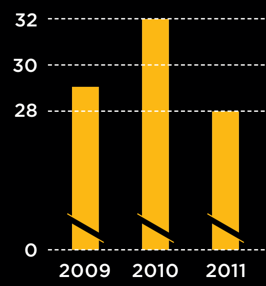
GHG DIRECT AND INDIRECT EMISSIONS

Million metric tons



GHG NORMALIZED EMISSIONS

Metric tons CO_2e/MBOE



GREENHOUSE GAS FOOTPRINT

In 2011, our cumulative (direct and indirect)* CO_2e totaled 2.12 million metric tons,** a 25 percent decrease from 2010. The bulk of this decrease in CO_2e emissions was the result of efforts to streamline our business through operational changes and divestitures. On an intensity basis, we achieved a 13 percent reduction in cumulative emissions per thousand barrels of oil equivalent when compared to 2010. The majority of this decrease can be attributed to operational efficiency gains and emission reductions resulting from upgrading the pneumatic devices in our production equipment.

* The collection of the activity data and the scope one and scope two emissions calculations were completed based on the American Petroleum Institute Compendium of Greenhouse Gas Emissions Estimation Methodology for the Oil and Gas Industry [API 2004].

**Data represents best available information at the time of publication.

number of operational VRUs to 70. These units recovered approximately 926 million cubic feet of gas in 2011, which is equal to a net emissions reduction of 3,000 metric tons of CO_2.*

Proactive Maintenance

Proactively identifying maintenance opportunities can also reduce GHG emissions and costs while increasing the quantity of natural gas available for sale. Since 2005, we have been a member of the USEPA's Natural Gas STAR program, which provides a voluntary framework for oil and natural gas companies to implement technologies and practices to reduce methane emissions (a GHG contributor). Through this framework and our own efforts in this area, we have achieved a cumulative methane emissions reduction of approximately 842.6 million cubic feet since 2008.

We regularly survey our work sites to detect and correct maintenance inefficiencies, often using specially designed infrared cameras to proactively identify maintenance opportunities that cannot be seen with the naked eye. In 2011, we surveyed 275 sites and identified 471 maintenances opportunities, saving 38.405 million cubic feet of gas and reducing GHG emissions by nearly 13,000 metric tons in the process.

Utilizing Natural Gas

When combusting natural gas, emissions of pollutants such as sulfur oxides, nitrogen oxides and carbon compounds are greatly reduced compared to other fuels. With these characteristics, utilizing natural gas can help address climate change by reducing our carbon footprint. Should renewable resources, such as wind or solar power, become more prevalent, natural gas-fired electric plants will provide an alternative backup to maintain consistent energy supply. Natural gas accounted for approximately 61 percent of our total 2011 sales volumes.

Our significant natural gas discoveries offshore Israel are paving the way for meeting energy needs by supplying this affordable, cleaner-burning fuel. Between 2004 and 2011, increased natural gas usage in Israel has resulted in savings of at least $7 billion in energy costs and eliminated an estimated 17 million metric tons of CO_2 emissions. That's the amount produced by an entire year of electricity generated by fossil fuels in Israel, and the equivalent of removing every vehicle from the road in Israel for 15 months.

We seek to employ new, more environmentally friendly technologies to reduce the amount of GHGs emitted. As part of our GHG emissions reduction strategy, we have converted 15 of our fleet trucks in the DJ Basin to run on compressed natural gas (CNG). We also continue to work with industry peers, trade associations, local governments and the public to advocate for the infrastructure necessary to support a move toward natural gas as a transportation fuel by supporting local demand for natural gas fueling stations (see page 43).

Managing Other Air Emissions

In addition to the initiatives outlined above, we do not use, produce or consume any ozone-depleting substances in our operations. Our combined emissions of volatile organic compounds, sulfur dioxide and nitrogen oxides can be found in the data table at the end of this report.

In addition to converting our vehicles to natural gas, we have outfitted two of our drilling rigs to run on liquefied natural gas (LNG), and we plan to have two additional dual-fuel (diesel and LNG) rigs in operation by the end of 2012. Each LNG rig reduces daily fuel costs by between $1,000 and $1,500, and – compared to traditional diesel rigs – significantly reduces toxic and carcinogenic pollutants, reduces particulate matter emissions by as much as half, and reduces nitrogen oxide and volatile organic hydrocarbon emissions by more than 50 percent. We are working with our contractors and suppliers to educate them about the benefits of converting to LNG.

* Inventory GHG emissions do not consider reductions caused by VRUs due to difficulty in quantifying exact emissions reduction.

Team

Our growth and operational success would not be possible without the dedication and technical excellence of our people.

EMPLOYEE SATISFACTION

We are proud to have been rated one of Houston's Top Workplaces by the Houston Chronicle in both 2010 and 2011. In this comprehensive survey, U.S. payrolled employees responded to questions in six areas: direction, execution, conditions, managers, career and pay/benefits. With 97 percent of our Houston-based employees participating in this survey in 2011, Noble Energy outperformed the benchmark top-25 large employers in Houston for employee opinions on confidence in leadership, company direction and company values and ethics.

Caring for our People

We are committed to a sound strategy for employee recruitment and development, and we foster a team-oriented culture that rewards innovation. We recognize that each employee plays an important role in helping us achieve sustainable, extraordinary performance.

RECRUITMENT AND RETENTION

Recruiting and retaining the next generation of energy industry leaders is a vital part of our business strategy. Our employment decisions are based on job-related qualifications, skills and previous work experiences. We do not make any hiring, promotion, termination or other job-related decisions on the basis of age, race, color, sex, religion, national origin, sexual orientation, citizenship status, veteran status, marital status, pregnancy, disability (where the applicant or employee is qualified to perform the essential functions of the job with or without reasonable accommodation), genetic information or any other characteristic protected by law.

We actively recruit from colleges across the nation to attract top talent for career positions and internships. In 2011, we expanded our recruitment efforts by participating in 31 different events on various campuses. We have also begun recruiting former junior military officers to meet future leadership needs.

We seek to provide college interns with challenging positions and the opportunity to learn from experienced mentors, interact with various levels of management and contribute to the Company's success. In addition to project work, our internships may include field trips, formal training and participation in community projects.

We view employee retention rates as a reflection of how well we are meeting our employees' needs. In 2011, our voluntary employee turnover rate was 6.9 percent. Overall, our company-wide turnover has remained in the single digits for the previous three years.

EMPLOYEE BENEFITS

In addition to providing a quality work environment, we pride ourselves on the benefits we offer our employees. We provide a competitive benefits package, which includes healthcare coverage, life insurance, disability pay and retirement plans. We also offer flexible spending accounts for health care or dependent care, as well as health club membership reimbursements and a wellness program.

2011 U.S. GENDER DIVERSITY

Job Categories	Female %	Minority %
Executive/Senior-level Officials and Managers	6.3%	0.0%
First/Mid-level Officials and Managers	13.7%	7.4%
Professionals	36.0%	17.0%
Technicians	70.0%	19.0%
Administrative Support Workers	90.2%	25.2%
Craft Workers	8.3%	8.3%
Operatives	0.0%	9.7%

Our contributions to pension and other post-retirement benefit plans totaled $29 million in 2011. The investment return on plan assets has tended to follow market performance, with the actual return on plan assets totaling a loss of $1 million in 2011. Our qualified defined benefit, or retirement plan, was closed to new participants on May 1, 2006. Employees hired after May 1, 2006, are instead eligible to participate in an enhanced 401k plan. Employment packages vary by country, but our goal is to provide competitive benefits to our employees wherever we operate.

We emphasize continued learning and provide development opportunities. We offer a host of instructor-led internal and external courses to give our employees the tools they need to grow in their careers.

Our Health is Our Energy

We partnered with Provant Health Solutions to offer a comprehensive wellness program, Our Health Is Our Energy, available at no cost to our U.S. employees. This program helps employees understand their health risk factors, provides tools to make positive choices to improve their long-term health, and rewards healthy behaviors through incentives such as discounts on individual health insurance premiums. We are working on initiatives to host wellness activities in Equatorial Guinea and Israel in 2012.

CAREER DEVELOPMENT AND TRAINING

At Noble Energy, we constantly challenge ourselves and our employees to think and act strategically through:

- Breakthrough leadership that achieves the unachievable
- Innovation that changes the world of energy
- Aligning our stakeholder relationships in a manner that positively impacts all

We invest in our people and strive to maximize their personal growth and success while ensuring that we have the capacity and competencies to achieve our business objectives. Our performance-review process is designed to align employee performance objectives with department objectives in order to maintain goals and metrics for performance that are SMART (Specific, Measurable, Attainable, Relevant and Time-bound). Employees meet with their managers to get feedback on their performance and create objectives that align with the Company and their department. During these meetings, employees and their supervisors recognize accomplishments and discuss ways to improve individual performance, including development opportunities.

In addition, we emphasize continued learning. We demonstrate our commitment in this area by offering a host of instructor-led internal and external courses to give our employees the personal development tools they need. In 2011, 1,185 employees (63 percent of total employees) participated in personal development classes sponsored by Noble Energy. Other development opportunities we offer include rotational assignments and on-the-job training. We support continued education and professional certifications, as well as staff participation in industry and professional organizations. See pages 46–47 to read about how we recruited, retained and trained our Equatoguinean employees to make a significant contribution not only to Noble Energy, but also to the skill base of their local communities and the country's workforce as a whole.

EMPLOYEE GENDER DIVERSITY

United States		Equatorial Guinea		Israel	
67%	33%	67%	33%	65%	35%

Leadership Training: Supporting Breakthrough Thinking

We have training and mentorship programs, such as Essentials of Leadership, a five-module training program that focuses on building foundational leadership skills. Additionally, the MANE Event (Managing at Noble Energy) provides managers with tools, techniques and resources that are specific to Noble Energy. These sessions cover topics such as recruiting and managing performance. Given our potential for continued growth as a Company and the corresponding need to fully develop our key talent and leadership, we recently implemented the LEAD (Learn, Excel, Achieve, Develop) program, an accelerated leadership track.

Local Hiring

We recognize the important impact we have on local communities as a source of jobs and economic growth. In both our U.S. and international operations, we strive to hire local workers to support our operations whenever possible. We are committed to seeing our local workforces continue to grow in size, and to strengthen good relationships with communities.

Since opening our offices in Malabo, Equatorial Guinea in 2004, the proportion of jobs held by EG nationals has reached 73 percent, and Equatoguineans hold approximately 23 percent of our management positions. Noble Energy provides its EG national employees with career advancement opportunities such as: on-the-job training; online learning; self-study; overseas training; and work assignments, where appropriate, at our corporate office in Houston.

In 2011, we placed even greater emphasis on local recruitment and the development of existing national employees. This resulted in a 39 percent increase in total national employment over 2010, with Equatoguinean staff in leadership roles. We also launched a local internship program, and announced plans to develop a Leadership and Supervisory Skills program in 2012.

DIVERSITY AND NONDISCRIMINATION

We aim to create an inclusive culture in which our employees are able to excel and express their opinions. In 2011, we launched a special program to broaden the understanding across the Company of the importance of diversification and inclusion. This program also seeks to teach and encourage the use of specific methods for resolving conflicts, increasing effective listening skills, improving communication and motivating and engaging employees from all backgrounds. These tools are becoming increasingly vital given the natural diversification that has come by way of our significant global expansion. Since it was introduced in 2011, more than 1,050 employees (56 percent of total employees) have participated in this program. We will continue to make this training available to our employees in 2012 and beyond, and implement a series of one-day inclusion workshops for managers.

In 2011, women accounted for approximately 33 percent of our total U.S. workforce and 36 percent of our professional employee base. Two of our nine executive team members are women. Outside the U.S., women represent 39 percent of our total international workforce.

Minorities represented about 15 percent of our total U.S. workforce and 17 percent of our U.S. professional employee base.

NATIONAL WORKFORCE

Israel
79%

Equatorial Guinea
73%

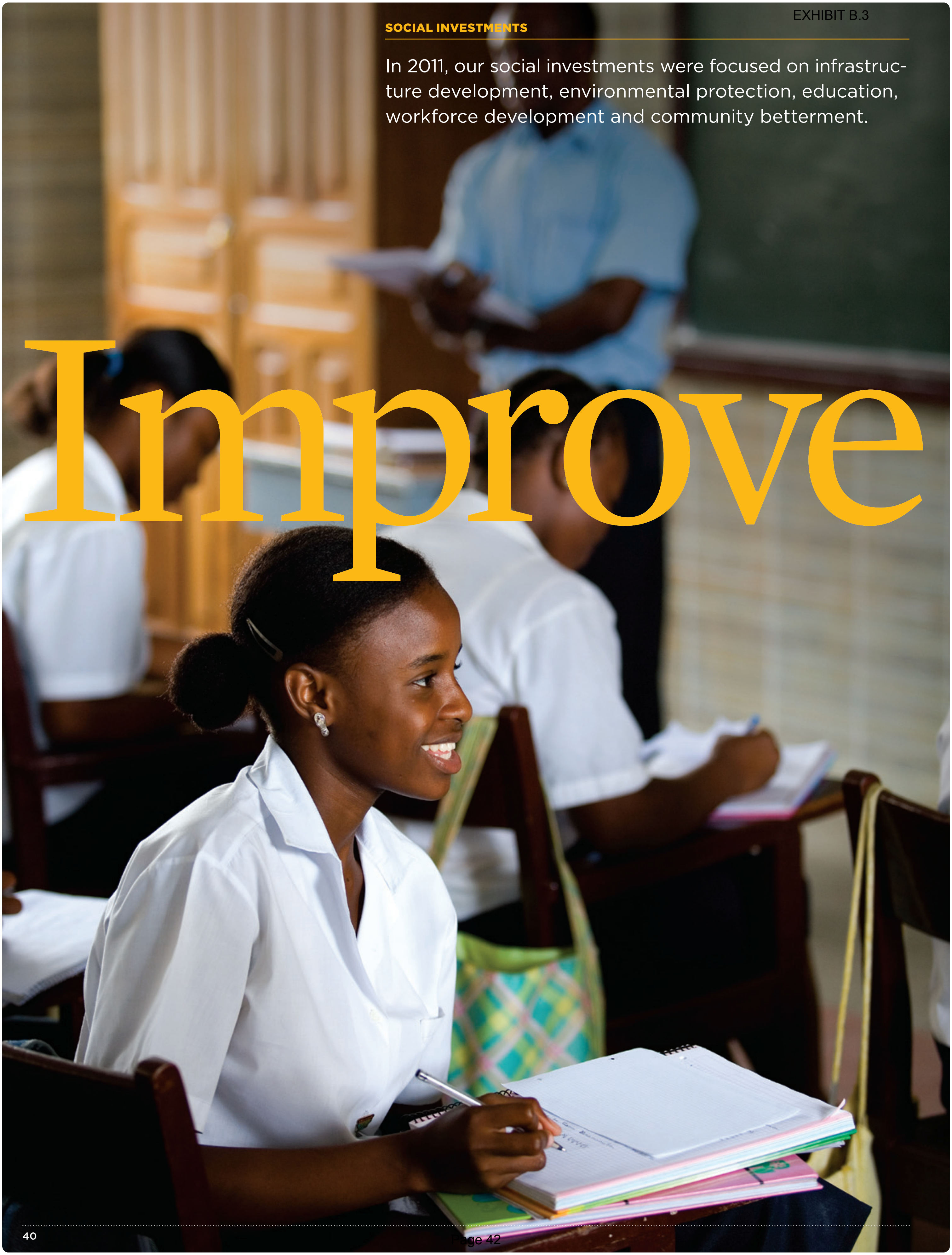
LEAD

The LEAD program (Learn, Excel, Achieve, Develop) provides unique development opportunities on our accelerated leadership track.

SOCIAL INVESTMENTS

In 2011, our social investments were focused on infrastructure development, environmental protection, education, workforce development and community betterment.

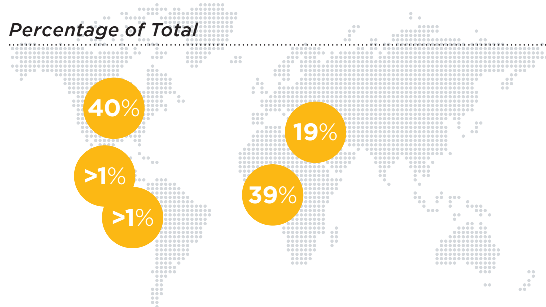
Improve



2011 CONTRIBUTIONS TO SOCIAL INVESTMENTS BY REGION

U.S. Dollars	
Ecuador	$ 13,000
Equatorial Guinea	$ 3,058,000
Israel	$ 1,530,000
Nicaragua	$ 27,000
United States	$ 3,161,000
TOTAL	$ 7,789,000

Percentage of Total



Bettering People's Lives

At Noble Energy, our business is about more than exploration and production. It's about improving the lives of those around us by helping local communities grow and prosper. It's about providing our employees with opportunities to make positive contributions and constantly challenging ourselves to find better solutions. It's about continuously striving to be a better industry partner and leaving behind a legacy of sustainability wherever possible.

INTERNATIONAL HUMAN RIGHTS FRAMEWORKS

All Noble Energy employees are expected to treat community stakeholders with respect and dignity. Our respect for human rights is reflected in this approach, and codified in a number of our policies and procedures. For example, our Corporate Social Responsibility Policy commits Noble Energy to promote the rights set forth in the United Nation's Universal Declaration of Human Rights, abide by the International Labor Organization's Declaration on Fundamental Principles and Rights at Work, and provide security in a manner consistent with international human rights. Additionally, our Code of Business Conduct and Ethics includes policies regarding equal employment opportunity and nondiscrimination, which are applicable everywhere we operate.

In 2010, we began providing our employees with human rights training that includes a review of international human rights frameworks and case study examples. During 2011, three of these training sessions were conducted for Houston employees involved in activities in Equatorial Guinea, and two additional sessions were conducted in Equatorial Guinea for in-country employees and office contractors.

SOCIAL INVESTMENTS

In the U.S., we are a proud supporter of United Way, contributing more than $200,000 in 2011 and consistently ranking among the top donor companies in Houston. We support research, programs and services for people living with multiple sclerosis as a Platinum Sponsor of the MS150, the largest cycling fundraising event in the United States. As part of our commitment to educational advancement, we have a long-standing relationship with Junior Achievement. A partnership among business, community, educators and volunteers, Junior Achievement teaches the key concepts of work readiness, entrepreneurship and financial literacy to young people throughout greater Houston.

In 2011, our Community Activity Committees gave funds to more than 45 organizations such as:

- Food banks
- Shelters
- Hospitals
- Health care centers
- Schools
- Community centers

COMMUNITY ENGAGEMENT IN NICARAGUA

As part of our continued evaluation of an acreage position offshore Nicaragua, we began meeting with local community members prior to conducting any seismic surveys to educate them about offshore oil and natural gas operations. We also supported the refurbishment of 11 schools beginning in 2009, improving the education environment of more than 2,500 students.

11
Refurbished schools

13
Constructed water wells

U.S. employees can submit grant requests to our Community Activity Committees, which give funds to eligible nonprofit organizations that provide education, health or basic life services. Our employees often make these charitable contributions even more meaningful by organizing volunteer events during work and personal time. For example, our Ardmore, Oklahoma, office organized two volunteer-service days in 2011 for employees to spend the workday painting rooms and planting flower beds at the Family Shelter of Southern Oklahoma.

At our corporate headquarters in Houston, the Finance Department has built a special relationship with Aldine Y.O.U.T.H., a grassroots organization that specializes in youth and family development. Employee volunteers helped the group refurbish their resale shop, sort donations, collect holiday gifts and school supplies, and much more. As part of our commitment to Aldine Y.O.U.T.H., Noble Energy also sponsored a two-acre wooded park.

Listening to and working with our stakeholders enables us to understand and respond to their concerns.

Across Weld County and the Denver-Metro area of Colorado, we have provided support for a number of organizations, including Cerebral Palsy of Colorado, Denver Health Foundation, Tennyson Center for Children and Weld Food Bank. Noble Energy is the title sponsor of FORE! Our Kids Golf Classic, the Tennyson Center's largest fundraiser of the year. We also are a platinum sponsor of the Stone Soup, Weld Food Bank's Fundraising event, which encourages cooperation and strength in numbers to address the problem of hunger in the Weld community.

Internationally, we tailor our investments to help local communities address their own development priorities. Investment decisions are typically made at the business unit level, subject to established investment guidelines, and are informed by community engagement. As our operational footprint expands into increasingly complex economic, social and political environments, our investment strategy is maturing accordingly. We are in the process of implementing a community investment strategy that is directly linked to our overall CSR objectives to better align our operations and business objectives with the needs of local communities.

We also contribute time and funds in support of Medical Bridges, an organization that procures medical supplies and equipment for providers of charitable medical care in developing countries. Our volunteers packed shipments that were sent to Sri Lanka, Equatorial Guinea and Ecuador, and we continue to look for sponsorship opportunities in other countries.

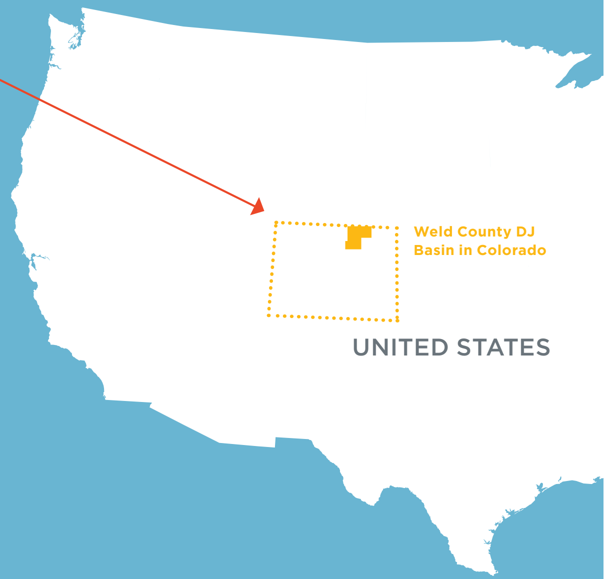
COMMUNITY ENGAGEMENT

We are committed to responsible engagement with local stakeholders. Listening to and working with our stakeholders enables us to understand and respond to their concerns. We seek to engage with communities early in project development. This allows us to assess and respond to community concerns before our operations begin. It also ensures that the long-term social investments we make have the most desirable and meaningful impacts at the local level. Efforts are underway to develop formal guidelines for community engagement that will be applied across our global operations. Of course, one standardized approach will not work in every situation. As a result, we tailor appropriate engagement activities for each situation and aim to enhance our relationships as a result.

See pages 43–48 to read about our engagement and social investment efforts in the DJ Basin, Equatorial Guinea and Israel.

SMART ENERGY PLAN

In the DJ Basin of Colorado, we are proud to be an active member of the Weld County Natural Gas Coalition and support their Smart Energy Plan to promote the use of natural gas as an alternative transportation fuel. By seeding local demand for natural gas fueling stations, we are helping build infrastructure to enhance the ability of cars, trucks and vehicle fleets throughout Colorado to utilize natural gas. In further support of the Smart Energy Plan, we are also converting our truck fleet to run on compressed natural gas (CNG) by introducing CNG pickups as older pickups reach end of service. As of 2011, we had 15 super-duty trucks running on CNG in the DJ Basin. While our remaining truck conversions are wholly dependent on the availability of CNG fueling stations, our goal is to convert all the trucks in our fleet to CNG.



Community Engagement in the DJ Basin

We are a leader in DJ Basin community development, which we have demonstrated through our efforts to enhance local educational, health and business-development opportunities.

In Weld County, located in the DJ Basin, we seek opportunities to contribute to the local economy by participating in the Leadership Council of Upstate Colorado Economic Development, a public/private nonprofit economic development organization that supports the county's retail, service and professional sectors. We participate in meetings to learn how we can better contribute to their vision for a sustainable economy that creates wealth, preserves the quality of life, and improves the standard of living for area residents. In 2010, the group set a goal to create 5,000 new jobs in five years. Noble Energy has since created more than 200 jobs, and we expect to add approximately 250 to 300 jobs to that total. Our commitment is to invest $8 billion in the DJ Basin over the next five years.

We believe that community engagement helps us ensure successful operations at each and every location. It is important to us that we understand the perspectives of our stakeholders and engage in open dialogue with them about our activities.

Because our onshore operations involve heavy trucking activities that can have a negative impact on roads and drivers, we partnered with the Weld County Department of Public Works to provide the county with funds needed to support road maintenance, including a $170,000 donation that helped the county complete a $500,000 project to pave a 1.5-mile road impacted by heavy truck activity. We also discussed with town board members ways to compensate for expected traffic increases in advance of our office opening in Greeley. Local stakeholders applauded our approach as an example of how collaboration between local authorities and energy companies should work.

With more than 7,500 producing wells in the county, planning for emergency situations is a top priority. In 2011, we contributed $25,000, along with training and equipment, to the Mountain View Fire Protection District to ensure they were prepared to respond to potential fires in oil and natural gas fields.

To support and encourage interest in science in education, Noble Energy became a sponsor of the Frontiers of Science Institute in 2011. Several Noble Energy employees also volunteer their time to review student projects and teach them how oil and natural gas is produced. This includes tutorials on geology, drilling, hydraulic fracturing, completions, and job opportunities within the industry.

In 2011, we hosted a tour of a natural gas powered drilling rig for a dozen members of the Weld County Natural Gas Coalition. We conducted several site tours in the DJ Basin to showcase our operations to community groups, media and regulators.

Invest

ATLANTIC OCEAN

AFRICA

Equatorial Guinea

RECENT PROJECTS IN EQUATORIAL GUINEA

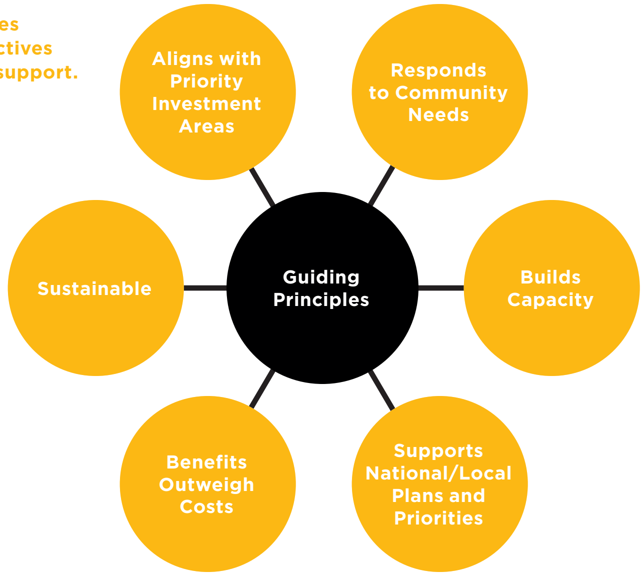
Approximate U.S. Dollars

ASET Scholarship, per year budget	$ 1,500,000
Bitika School	$ 500,000
Bioko Island Malaria Control Project*	$ 10,400,000
El Porvenir and Atepa Water-wells Construction, each	$ 45,000
GEGEO Graduate Scholarships, per year 2008–2011	$ 225,000
Instituto Nacional de Enseñanza Inem Rey Malabo Library	$ 715,000
ITNHGE Scholarship, per year	$ 900,000
Nuestra Señora de Africa	$ 330,000

*Noble Energy's total contribution since 2003

EQUATORIAL GUINEA COMMUNITY INVESTMENT STRATEGY

Our guiding principles outline the key objectives for each project we support.



Strategic Development in Equatorial Guinea

Since 1990, Noble Energy has explored for and produced oil and natural gas offshore the Republic of Equatorial Guinea. The successes of our operations in Equatorial Guinea rely on a strong local workforce and healthy, stable communities. We make strategic community investments to improve quality of life, enhance educational opportunities, protect the environment and support critical national infrastructure priorities.

STRATEGIC COMMUNITY INVESTMENT

Since 2008, Noble Energy, along with our co-venturers (Glencore Exploration, GEPetrol, Atlas Petroleum and Osbourne Resources) have invested $1 million per year in social projects through our Community Investment Program in Equatorial Guinea. This joint fund will increase to $1.5 million in 2012 and $2 million in 2013. These social investments are budgeted and managed by Noble Energy as a part of our contractual obligations with the government.

Proposed social projects are presented to Noble Energy by the Ministry of Mines, Industry and Energy, or through direct correspondence with the project applicant. All proposals are vetted by the national government and Noble Energy's selection committee.

Guiding principles outline the key objectives for each social project we support. In 2011, we took a number of steps to further improve how we select, implement and monitor these projects to maximize sustainability. To increase transparency in the project-selection process and improve the quality of applications that we receive, we developed application guidelines and selection criteria that will be published in 2012. We also established a selection committee to evaluate proposals based on project management capability, positive impact and sustainability.

COMBATING MALARIA

Through an innovative public-private partnership developed locally, we are actively engaged in the Bioko Island Malaria Control Project to combat and reduce the transmission of the malaria parasite. Since 2003, Noble Energy has contributed more than $10.4 million to the overall $44 million program, which has led to:

55%

Reduction in the malaria parasite in children under the age of 15

Providing Clean Drinking Water

In 2008, we completed two community water-well projects to provide clean water to the communities of El Porvenir and Atepa. Prior to the installation of these wells, many lower- and middle-income families relied on their children to travel many miles to secure drinking water. By providing safe access to treated water, this project filled an urgent community need. We continue to monitor and assist with the maintenance of these wells, and plan to complete two more water-well projects by the end of 2012 that will benefit more than 350 people in remote communities.

Enhancing Educational Opportunity

Inadequate infrastructure and an increasing student population have created a pressing need for new educational facilities, particularly within Equatorial Guinea's primary and secondary school system. Since 2008, we have funded and managed the execution of a number of school construction and rehabilitation projects to meet this need and improve the quality of the learning environment for local youth.

Construction of the Instituto Nacional de Enseñanza Inem Rey Malabo library.

Some of these projects include:

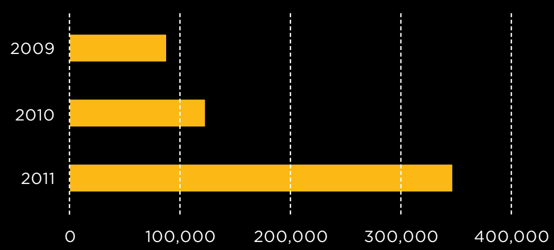
- Six new classrooms at the Nuestra Señora de Africa school in Mongomo, which will accommodate an additional 200 students.
- Six classrooms and an administration room to adequately serve the 200 students at the Cruces School in Riaba.
- A two-story library with a computer lab and study areas that will serve more than 3,000 secondary schoolchildren at the Instituto Nacional de Enseñanza Media Rey Malabo school (expected completion in 2012).
- The design and development of the first public children's park in Malabo – planned in partnership with the City of Malabo and the country's Ministry of Public Works and Infrastructure. The completed park will include a playground, soccer field, picnic areas and green space (expected completion in 2013).

CULTIVATING A STRONG, LOCAL WORKFORCE

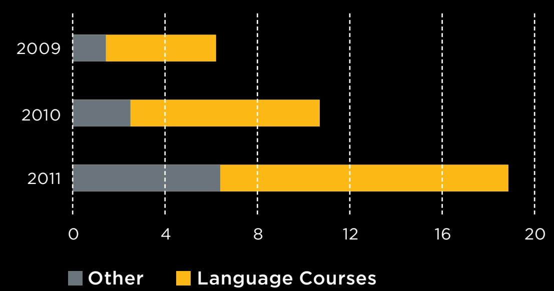
In 2004, the government established the Instituto Tecnológico Nacional en la Industria de Hidrocarburos de la República de Guinea Ecuatorial (ITNHGE) to help train Equatoguineans working within the oil and natural gas industry. Noble Energy is an active participant in ITNHGE programs, having sponsored 25 students who trained to become production operators, mechanical technicians, and instrumentation and electrical technicians during ITNHGE's first three phases beginning in 2008. To help build on ITNHGE's early success, Noble Energy continues to sponsor students in ITNHGE training programs, and is helping finance the construction of a new ITNHGE campus in Mongomo. Additionally, each Noble Energy sponsored graduate of ITNHGE receives an additional 18 months of intensive technician training and hands-on experience at the Aberdeen Skills and Enterprise Training (ASET) College in the United Kingdom. The first group of graduates from the ASET is now working on the Aseng FPSO project and future groups will also work on the FPSO and other projects.

EQUATORIAL GUINEA TRAINING EXPENDITURES

Approximate U.S. Dollars



EQUATORIAL GUINEA AVERAGE NUMBER OF TRAINING DAYS



Noble Energy also provides academic scholarships to Equatoguinean students enrolled in universities in the United States and Malaysia. We are a founding partner of the Equatorial Guinea GEOscience program (GEGEO), a collaborative project between the University of South Carolina and the National University of Equatorial Guinea to provide training and scholarships for students earning their bachelor's degrees in Geology and Engineering at the University of South Carolina. In 2010 alone, 50 GEGEO students successfully completed introductory engineering courses, eight graduated from South Carolina with bachelor's degrees in either geology or engineering, and 20 earned industry internships.

Equatorial Guinea GEOscience program graduates (2008–2011).

In late 2010, following a comprehensive advertisement and selection process in which more than 1,000 applications were received, 10 individuals were selected by the Universiti Teknologi Petronas (UTP) in Malaysia to receive six years of fully sponsored undergraduate-level education in fields such as Petroleum Engineering, Mechanical Engineering, Electrical and Electronic Engineering and Business Information Systems. The program includes two years of intensive English and foundation-skills training, and three to four years of undergraduate-level studies. Two of the 10 scholarship recipients made the Dean's List within their first year of study.

Noble Energy is proud to support higher learning and career advancement opportunities because they contribute to the development of a strong local workforce.

Local Contractor Development

Developing a local contractor base helps Noble Energy ensure the timely and effective delivery of services. Whenever possible, we not only hire local contractors but provide them with training in areas such as defensive driving and, if necessary, English. We plan to develop additional training programs to better enable local companies to compete for contracts, and we are working alongside one of our subcontractors to provide sponsorship of a local contractor-development program. We currently use more than 150 local contractors for services such as security, housekeeping, catering, transportation and logistics, and we are in the process of implementing a system to track local-supplier spending. We also encourage our multinational contractors to support local-supplier development by including local content requirements in requests for proposals and bid evaluations. All of our long-term service contractors must develop a local hiring plan in coordination with the Ministry of Mines, Industry and Energy Director General of National Content.

Graduates of the National Hydrocarbons Institute of Technology in Equatorial Guinea. They go on to pursue studies at the International Oil and Gas Training Academy in Aberdeen, Scotland.

Social Investment in Israel

Our success in offshore exploration activities has contributed to an energy revolution in Israel. Production at Mari-B began in 2004, and the natural gas processed there now fuels a significant portion of Israel's electricity generation. In 2009, we made a major discovery at Tamar, which is estimated to hold enough natural gas to meet Israel's domestic energy needs for decades. In 2010, we made the largest discovery in our history at Leviathan. It has the potential to turn Israel into a leading regional exporter of natural gas. While these discoveries are important for Israel's energy independence and economic growth, we also want our presence there to bring about positive impacts at the community level.

In 2011, we partnered with the Israel National Museum of Science, Technology and Space (MadaTech) – Israel's premier institution of science and technology education – to build a science park at its facility. This engagement with one of Israel's most popular museums creates a connection between our business values and goals and the science and technology we employ every day to achieve those goals. The Noble Energy Science Park opened in Haifa in October 2011, allowing visitors to interact with the very scientific principles and technologies that are shaping the world around us. Between 2012 and 2016, we will invest $4 million in the park's continued development and maintenance.

In February 2011, we became a major private sponsor of the Youth Futures program, a Jewish mentoring program that provides paid mentors to disadvantaged elementary school children to enhance their educational and social development.

Our efforts with Youth Futures have thus far focused on four cities, including Lod, a town with a large Arab and immigrant population where the robust volunteer program we helped start is already strengthening ties across a number of socioeconomic and cultural levels.

MadaTech Science Park

Performance Data

HEALTH AND SAFETY

	2009	2010	2011
Hours Worked			
Employees	2,615,752	3,436,714	3,614,934
Contractors	8,447,991	9,777,675	11,587,249
Total Hours Worked	**11,063,743**	**13,214,389**	**15,202,183**
Lost-time Incidents			
Employees	5	1	2
Contractors	12	9	12
Total Lost-time Incidents	**17**	**10**	**14**
Recordable Incidents			
Employees	7	3	4
Contractors	30	34	51
Total Recordable Incidents	**37**	**37**	**55**
Total Recordable Incident Rate (TRIR)			
Employees	0.54	0.17	0.22
Contractors	0.71	0.70	0.88
Combined TRIR	**0.67**	**0.56**	**0.72**
Days Away from Work Incident Rate (DWIR)			
Employees	0.38	0.06	0.11
Contractors	0.28	0.18	0.21
Total Days Away from Work Incident Rate	**0.31**	**0.15**	**0.18**
Fatalities			
Employees	0	0	0
Contractors	0	0	1
Total Fatalities	**0**	**0**	**1**

PEOPLE

2011 Percentage of National Employees	
Cameroon	78%
Cyprus	57%
Equatorial Guinea	73%
Israel	79%

	FEMALE %	MINORITY %
2011 U.S. Diversity by Job Category		
Executive/Senior-level Officials and Managers	6.3%	0.0%
First/Mid-level Officials and Managers	13.7%	7.4%
Professionals	36.0%	17.0%
Technicians	70.0%	19.0%
Administrative Support Workers	90.2%	25.2%
Craft Workers	8.3%	8.3%
Operatives	0.0%	9.7%

	2009	2010	2011
Total Number of Employees			
Total Employees	**1,630**	**1,772**	**1,876**

We are working to improve and enhance data collection to expand the quality and types of data to share in our future reports.

ENVIRONMENT

2011 U.S. Water Consumption (in barrels)

Recycled and Reused Water*	7,000,558
Water sourced from municipal/public supplies	12,105,560
Total Water Consumed	19,106,118

	2009	2010	2011
GHG Emissions *(metric tons CO_2e)*			
Combustion	1,056,000	1,275,000	789,500
Flaring	254,000	362,500	382,600
Fugitive	145,000	168,200	168,250
Indirect	151,280	99,000	75,800
Mobile	20,450	11,500	13,300
Venting	828,000	691,600	691,650
U.S. Emissions *(in tons)*			
VOC	13,974	–	11,205
NOx	2,194	–	1,915
SOx	16	–	15
CO	2,044	–	2,250
Spills			
Total Number	84	129	118
Hydrocarbons *(in barrels)*	1,374	1,933	1,904
Water *(in barrels)*	1,903	3,010	3,726
Other *(in barrels)*	75	301	3,485

* Water is recycled and reused from Noble Energy produced water in our domestic operations.

COMMUNITY INVESTMENTS

	2009	2010	2011
Spend by Region			
Cyprus	$ 289,000	$ 386,000	$ –
Ecuador	152,650	185,900	13,000
Equatorial Guinea	2,034,700	3,584,950	3,058,000
Israel	2,500	4,000	1,530,000
Nicaragua	36,600	25,050	27,000
U.S.	2,571,550	2,251,450	3,161,000
Other	40,700	1,700	–
Total Spend	**$ 5,127,700**	**$ 6,439,050**	**$ 7,789,000**

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DMA represents the GRI-recommended disclosure on management approach.
IPIECA/API/OGP indicators included in this index address the common reporting elements, at a minimum.
■ Indicates partially reported GRI indicators.

NBL

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noble energy

EXHIBIT C

APRIL 15, 2013 LETTER FROM INDUSTRY

April 15, 2013

George Gerstle
Boulder County Transportation Director
ggestle@bouldercounty.org

Kim Sanchez
Boulder County Planning Division Manager
ksanchez@bouldercounty.org

Ben Doyle
Assistant Boulder County Attorney
bdoyle@bouldercounty.org

Dear George, Ben, and Kim:

This letter outlines the concerns of Encana Oil & Gas (USA), Inc. ("Encana") and Noble Energy, Inc. ("Noble") regarding Boulder County's potential new roadway impact fee for oil and gas development and the Boulder County Oil and Gas Roadway Impact Study prepared by Felsburg Holt & Ullevig and BBC Research and Consulting ("Roadway Impact Study").

In its January 24, 2013 press release, Boulder County indicated that the Roadway Impact Study is part of an effort to "ensure impacts of oil and gas development on the public transportation system are mitigated and the cost of such mitigation is fairly and equitably allocated" and that any resulting fee or mechanism should be "legally defensible." Encana and Noble share these objectives and have previously worked with a number of other Colorado counties and municipalities to ensure that roadway impacts are appropriately mitigated.

The roadway impact fee contemplated by Boulder County reflects a different approach. In addition to identifying specific road maintenance and improvement requirements to mitigate identified impacts from proposed oil and gas development, the County would assess a standard fee on each new pad and well to offset the assumed impact of future oil and gas development on the local road system as a whole. The Roadway Impact Study recommends a fee of $1,200 per pad and $36,800 per well for this purpose. Report at 55-56. Contrary to the County's objectives, such a fee would neither provide fair and equitable mitigation nor be legally defensible.

Fairness and Equity

The contemplated roadway impact fees would not provide fair and equitable mitigation for several reasons.

Property Tax Revenues. To begin with, there is no need for the County to assess a new roadway impact fee because the County's property tax revenues from future oil and gas development will be many times greater than the road system costs associated with such development under any conceivable scenario. Although the Roadway Impact Study does not consider the County tax revenues from future oil and gas development, the authors of the Study addressed this subject in a similar study they prepared last year for Douglas County. In that study, the authors acknowledge that: "Property tax and severance tax are the major revenue sources that will increase as oil and gas wells are drilled and begin to produce. These tax revenues are designed to offset the additional county expense incurred to provide infrastructure and services to the industry." Felsburg Holt & Ullevig & BBC Research & Consulting, Douglas County Oil & Gas Production Transportation Impact Study at ES (Jan. 23, 2012).

Because the Roadway Impact Study does not address the County's oil and gas tax revenues, Encana and Noble commissioned economist Michael Orlando, PhD to analyze this issue regarding property taxes. Dr. Orlando is currently a Lecturer on Global Energy Management at the University of Colorado – Denver and Adjunct Professor of Finance at Tulane University. He previously worked as an Economist, Vice President, and Branch Executive in the Federal Reserve System and has written or co-written numerous refereed journal articles. His analysis is enclosed. *See* Economic Advisors, Inc., Evaluation of Boulder County Property Tax on Oil and Gas Activity (Apr. 12, 2013) ("Property Tax Evaluation").

As Dr. Orlando explains,

- A typical well should provide the County with total tax payments of "approximately $374,000 in the first year of well production," and "over $1 million over the first 10 years of production." Boulder County Government's share of these tax payments will be approximately "$107,000" and "$288,000," respectively.

- Under the various development scenarios set forth in the Roadway Impact Study or modeled by Dr. Orlando, "the total cumulative nominal tax payments to the county are expected to range between $207 million and $1.89 billion." Boulder County Government's share of these tax payments will be "between $59.2 million and $542 million."

- The "real value" of the tax payments received by the Boulder County Government will range from "from 6.2 to 10 times the real value of the Roadway Impact Study cost estimates" depending upon the development scenario.

- If the estimated roadway costs in the Roadway Impact Study are adjusted to reflect more realistic assumptions for the trucking of hydraulic fracturing water, then the "real value of tax revenues to Boulder County Government ranges from 7.7 to 14 times the real value" of the "cost estimates" depending upon the development scenario. If such costs are adjusted to reflect the piping of hydraulic fracturing water, then the "real value of tax revenues to Boulder County Government ranges from 8.6 to 18 times the real value" of the "cost estimates" depending upon the development scenario.

Id. at 3-5.

Thus, the Boulder County Government will receive property tax revenues from future oil and gas development that are about 7 to 18 times greater than the road system costs associated with such development. These are revenues received by the County Government, which should be more than sufficient to cover the road deterioration, safety, and other costs identified in the Roadway Impact Study. *Id.* at 8-12 & 20-24. Indeed, the present value of these revenues is "between 1.5 years and 13 years of the total Boulder County Budget for capital building projects for all highways and streets." *Id.* at 23.

Other possible impacts from oil and gas development, such as impacts to schools, cities and towns, and fire districts, are addressed by 102 other taxing districts. *Id.* at 7 & App. I. These districts too will receive tens of millions to more than a billion dollars in additional property tax revenues. As Dr. Orlando notes, "schools can expect to receive between $109 million and $1 billion; cities and towns . . . can expect to receive between $24 million and $220 million; and the various other tax districts . . . can expect to receive between $14.4 million and $132 million. *Id.* at 3. As with roads, these additional tax revenues will be available to offset any impacts that result.

Dr. Orlando does identify a one-time, three year lag between construction and completion of the initial wells and the point at which the County begins to receive these tax revenues. *Id.* at 5 & 24. He preliminarily identifies several measures, such as financial assurance mechanisms and tax credits for escrow payments, which could address this temporal issue. *Id.* at 24. Although this issue can be resolved on a case-by-case basis during the County land use approval process, Encana and Noble are also willing to work with the County to find an equitable and responsible solution through the current implementation discussions.

Excessive Costs. In addition, the contemplated fee would significantly exceed the road system costs associated with future oil and gas development in the Wattenberg field. The Roadway Impact Study bases these fees upon dated information from other states and regions, Roadway Impact Study at 9-10, which does not reflect current and future practices in the Wattenberg field. In addition, the Study assumes that operators will take no action to reduce or otherwise manage their use of water and the traffic associated with such usage, *id.* at 6-20 & 28-35, which, again, does not reflect current and future practices in the Wattenberg field. Encana and Noble have previously provided information on this subject, which indicates that trucking hydraulic fracturing water generates less traffic than the Roadway Impact Study assumes and that piping hydraulic fracturing water results in significant additional traffic reductions. *See* Encana Oil & Gas (USA), Inc. and Noble Energy, Inc., Boulder County Oil & Gas Roadway Impact Study: Initial Points of Concern (March 1, 2013); Letter from Dave Neslin & Kirk Mueller to George Gerstle, Kim Sanchez, & Ben Doyle (Apr. 5, 2013). Encana and Noble have also provided examples of water management strategies they currently employ and plan to expand in their Niobrara operations. *Id.*

Dr. Orlando provides alternative estimates for truck trips based upon current water trucking and pipeline practices in the Wattenberg field. Property Tax Evaluation at 18-19. With respect to the latter, he notes that Encana's historical experience in the DJ-Niobrara indicates it is technically and commercially feasible to pipe hydraulic fracturing water to most well pad locations, which eliminates water delivery trips for this purpose. *Id.* at 19. He also notes that most water will be produced and removed from the well during the first year of production. *Id.*

Using this information, Dr. Orlando has recalculated the costs in the Roadway Impact Study. As he explains:

- The Study estimates total roadway costs "of $8.07 million under a 'low' development scenario . . . and $27.4 million under a 'steady' . . . or an 'accelerated' development scenario."

- Using more accurate trip generation figures for the assumption that "frac water would be trucked to location" reduces "these total nominal costs" to "$6.27 million" and "$19.17 million," respectively, and "assuming frac water would be piped to location" further reduces these costs to "$5.59 million" and "$16.05 million," respectively.

- "Based on nominal estimates, the per-well cost . . . is between $17,857 and $31,056 – 16 percent to 52 percent below the $37,100" estimated in the Study.

- The "present value of costs estimated" in the Study are "$6.32 million under the 'low' development scenario and $21.1 million under the 'accelerated' development scenario. Thus, failure to account for the time-value of roadway impacts overstates the present value of those costs by 28 percent to 30 percent."

- "Assuming established industry water-trucking practices" reduces "the present value of costs" to "$5.14 million" and "$15.14 million," respectively, and "[i]mplementing established pipeline practices further reduces these costs to "$4.59 million" and "$12.36 million."

Id. at 3-4 & 13-22. Thus, the per-well cost calculated by Dr. Orlando "ranges from $14,818 . . . to $31,811 . . . approximately 14 percent to 60 percent below the $37,100 fee" estimated in the Study. *Id.* at 4.

Limitation to Oil and Gas Development. Finally, the contemplated fee would be limited to oil and gas pads and wells and would not apply to other types of development that can generate significant truck traffic. For example, the proposed expansion of the Gross Reservoir in Boulder County would increase the height of the dam by 125 feet and triple the size of the reservoir. *See, e.g.,* Laura Snider, *Diverting the Colorado: 2 projects with Boulder County ties to bring more water to Front Range*, Boulder Daily Camera, July 9, 2011, *available at* http://www.dailycamera.com/boulder-county-news/ci_18442684. This would be a major, multi-year construction project involving extensive truck traffic on County roads, which is directly comparable to oil and gas development from a roadway impact standpoint. But unlike oil and gas development, water development projects like Gross Reservoir and other types of development projects would be exempt from the roadway impact fee. The County has offered no explanation for this discriminatory treatment, and it is unfair and inequitable.

Legality

For the same reasons that the fee would be unfair and inequitable it would be legally indefensible.

For example, because the fee is not needed to pay for road system costs associated with oil and gas development it would violate the requirement that impact fees must fund "expenditures . . . on capital facilities needed to serve new development." C.R.S. § 29-20-104.5(1). As Dr. Orlando has explained, the tax revenues from future oil and gas development will be many times greater than the associated road system costs under any conceivable scenario. Accordingly, the assessment of an additional and duplicative impact fee is unnecessary to fund such expenditures.

Similarly, because the fee will greatly exceed the road system costs associated with oil and gas development in the Wattenberg field, it would violate the requirement that impact fees must be established "at a level no greater than necessary to defray such impacts directly related to proposed development." C.R.S. § 29-20-104.5(2). Here, the recommended fees do not reflect current water trucking and pipeline practices in the Wattenberg field, which result in significantly less traffic than the Roadway Impact Study estimates. They also do not reflect the present value of the costs in question. Consequently, they greatly exceed the fees necessary to defray the roadway impacts of oil and gas development in violation of Colorado law.

Finally, because the fee will be limited to oil and gas development alone, it would violate the requirement that impact fees must be "[g]enerally applicable to a broad class of property." C.R.S. § 29-20-104.5(1)(b). In addition, the Colorado courts have invalidated as discriminatory taxes and fees whose scope is similarly circumscribed. *See, e.g., K.P. Kaufman v. Town of Frederick*, Case No. 12-ca-0037 (Colo. App. Oct. 25, 2012) (unpublished) (inspection fee invalidated as discriminatory where imposed only on oil and gas operations); *City of Central v. Axton*, 410 P.2d 173, 180 (Colo. 1966) (occupation tax invalidated as discriminatory where imposed only on purveyors of products from outside jurisdiction); *Houston v. Kirschwing*, 184

P.2d 487, 490-92 (Colo. 1947) (license fee invalidated as discriminatory where imposed only on out-of-town businesses).

Suggested Alternative

Boulder County's recently enacted oil and gas regulations already set forth a thorough and site-specific process for identifying and mitigating transportation impacts. As part of this process, the applicant must submit a detailed "transportation plan" identifying traffic routes, volumes, and frequencies as well as mitigation measures for transportation impacts. *See* Articles 12-500(N), 12-602(D), & 12-703(K). The applicant is also responsible for any necessary transportation improvement costs. Articles 12-602(D)(5) & 703(K)(5). To the extent that there is some additional incremental impact on the road system as a whole from oil and gas development, the property taxes paid by the applicant will more than cover the applicant's share of such costs. With respect to the one-time, three year lag between construction and completion of the initial wells and the point at which the County begins to receive these tax revenues, Encana and Noble are willing to work with the County to achieve a responsible and equitable solution.

This is the approach that most other Colorado local governments follow with respect to the roadway impacts associated with oil and gas development. Because it involves specific mitigation measures to address identified roadway impacts from proposed development projects, this approach is much more likely to produce fair, equitable, and legally defensible results than a standard fee that is based upon generalized assumptions. Moreover, unlike the assessment of a standard fee, this approach creates an incentive for operators to continue to work on reducing their roadway impacts because such reductions will reduce the mitigation measures that are required.

*   *   *

Thank you for considering Encana's and Noble's views. If we can answer any questions regarding this letter, please do not hesitate to contact us. We are also available to meet with you at your convenience regarding this subject.

Respectfully,

Jamie Jost
Elizabeth Gallaway

for
Beatty & Wozniak

Counsel for EnCana

Dave Neslin
R. Kirk Mueller
for
Davis Graham & Stubbs LLP

Counsel for Noble

EXHIBIT C.1

ATTACHMENT TO THE APRIL 15 LETTER

ea

Economic Advisors, Inc.
evaluation of
Boulder County
Property Tax
and
Roadway Impacts
from
Oil and Gas Activity

Expert Report

prepared for:

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April 12, 2013

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I. Introduction and Executive Summary

Economic Advisors, Inc. ("EA" or "we") has been retained by Beatty & Wozniak, P.C. ("BW") and Davis Graham & Stubbs LLP ("DGS") to provide opinions and/or testimony regarding the magnitude of oil and gas production property taxes paid to Boulder County, Colorado. Interested parties, Encana Oil & Gas (USA) Inc. and Noble Energy, Inc. ("Encana and Noble"), have indicated that this analysis may provide useful information for current discussions with the Boulder County Colorado Board of County Commissioners (the Commissioners) regarding roadway impacts associated with oil and gas development activity.

This study estimates oil and gas property tax revenue expected to be paid to Boulder County. We obtained the 2012 Summary of Levies for Boulder County Assessor's Office.[1] We obtained the Boulder County Budget Summary, 2012 from the Boulder County Treasurer's Office.[2] We utilize these two sources to determine average oil and gas production property taxes paid to Boulder County and all tax districts within Boulder County. We confirm this average tax rate estimate utilizing records of historical tax payments from Encana to Boulder County. We utilize this tax rate estimate to calculate tax revenues expected from a single well representative of those expected to be drilled in eastern Boulder County. We also summarize total tax revenues expected to be collected from several projected drilling program scenarios.

This study also evaluates roadway impact costs associated with oil and gas development and production activity. We review roadway impact cost estimates calculated in the report entitled "Boulder County Oil and Gas Roadway Impact Study" by Felsburg Holt & Ullevig and BBC Research and Consulting, for Boulder County, dated January 14, 2013 (the Roadway Impact Study). We utilize a cost model approximated from the Roadway Impact Study to estimate the present value of roadway impact costs under a variety of oil and gas development and roadway utilization assumptions.

Key findings include:

- <u>County Property Tax Revenues</u>:
  - Oil and gas production in Boulder County is assessed an average total mill levy of 86.1, of which 24.645 mills is assessed for Boulder County Government. Thus, 28.6 percent of total county property taxes are assessed by Boulder County Government, with the remaining 71.4 percent of property

[1] Obtained via conversations with Boulder County Assessor's Office staff and downloaded on March 14, 2013.
[2] Obtained via conversations with Boulder County Treasurer's Office staff and downloaded on March 15, 2013.

taxes assessed by various tax districts within the county (e.g. schools, fire districts, etc.)

- The current county property tax regime results in a 7.5 percent tax on gross production revenue.

- A typical 300 MBOE DJ-Niobrara well is expected to result in tax payments to the county of approximately $374,000 in the first year of well production. Boulder County Government, schools, and cities and towns are expected to receive $107,000, $198,000, and $43,400 respectively, with the additional $26,200 to be received by other tax districts within the county.

- A typical 300 MBOE DJ-Niobrara well is expected to result in tax payments to the county of over $1 million over the first 10 years of production. Boulder County Government, schools, and cities and town are expected to receive $288,000, $533,000, and $117,000, with the additional $70,300 to be received by other tax districts within the county.

- For the various development scenarios considered herein, the total cumulative nominal tax payments to the county are expected to range between $207 million and $1.89 billion. Boulder County Government can expect to receive between $59.2 million and $542 million; Boulder County schools can expect to receive between $109 million and $1 billion; cities and towns within Boulder County can expect to receive between $24 million and $220 million; and the various other tax districts within the county can expect to receive between $14.4 million and $132 million.

- <u>County Roadway Impacts</u>:

  - The Roadway Impact Study suggests total nominal costs of oil and gas development activity on Boulder County roadways of $8.07 million under a 'low' development scenario (180 wells over 16 years) and $27.4 million under a 'steady' development scenario (824 wells over 16 years) or an 'accelerated' development scenario (824 wells over 8 years.)

  - Assuming frac water would be trucked to location (the practice in approximately 10 percent of an historical sample of DJ Niobrara developments) reduces these total nominal costs to $6.27 million to $19.17 million – a 22 percent to 30 percent reduction from estimates provided in the Roadway Impact Study.

  - Assuming frac water would be piped to location (the practice in approximately 90 percent of an historical sample of DJ Niobrara developments) reduces total nominal costs to $5.59 million to $16.05 million – a 31 percent to 41 percent reduction from estimates provided in the Roadway Impact Study.

  - Based on nominal estimates, the per-well cost indicated by the present analysis is between $17,857 and $31,056 – 16 percent to 52 percent below the $37,100 fee proposed in the Roadway Impact Study.

  - The present value of costs estimated under Roadway Impact Study assumptions are $6.32 million under the 'low' development scenario and $21.1 million under the 'accelerated' development scenario. Thus, failure to account for the time-value of roadway impacts overstates the present value of those costs by 28 percent to 30 percent.

  - Assuming established industry water-trucking practices for well site operations reduces the present value of costs to $5.14 million (low scenario) to $15.14 million (accelerated scenario). Implementing established pipeline practices reduces the present value of costs to $4.59 (low scenario) million to $12.36 million (accelerated scenario).

  - Based on real values, the per-well cost indicated by the present analysis ranges from $14,818 (present value discounting, piping frac water assumption, maximum development activity estimate) to $31,811 (present value discounting, trucking frac water assumption, low development activity estimate), approximately 14 percent to 60 percent below the $37,100 fee proposed in the Roadway Impact Study.

- <u>Comparison of Tax Revenues to Roadway Impacts</u>:

  - The real value of total tax revenues received from the various development scenarios considered in this analysis ranges from 22 times to 35 times the real value of roadway impact costs estimated in the Roadway Impact Study. The real value of tax revenues to Boulder County Government ranges from 6.2 to 10 times the real value of Roadway Impact Study costs estimates.

  - The real value of total tax revenues received from the various development scenarios considered in this analysis ranges from 27 times to 50 times the real value of roadway impact costs estimated under the assumption that frac water would be trucked to location. The real value of tax revenues to Boulder County Government ranges from 7.7 to 14 times the real value of frac-water-trucking assumptions costs estimates.

- The real value of total tax revenues received from the various development scenarios considered in this analysis ranges from 30 times to 62 times the real value of roadway impact costs estimated under the assumption that frac water would be piped to location. The real value of tax revenues to Boulder County Government ranges from 8.6 to 18 times the real value of frac water piping assumptions costs estimates.

- Because actual production is necessarily reported with a lag and taxes are assessed in arrears, the county may receive production property tax payments up to three years after well drilling activity. Thus, in the initial stages of a new development program, roadway impact costs associated with a step-up in oil and gas development activity will precede revenues from oil and gas property taxes. After the first three years of increased development activity, previously drilled and producing wells will generate tax payments contemporaneous with roadway costs attributable to wells then in the development phase.

Section II summarizes the issues evaluated in this report. Section III evaluates property taxes assessed and paid on oil and gas production in Boulder County. Section IV summarizes estimated roadway impact costs. The concluding discussion provides a comparison of public tax receipts and roadway impacts attributable to oil and gas activity in Boulder County.

II. Description of the Issues Addressed in this Report – tax receipts and roadway impacts associated with oil and gas development and production activity in Boulder County

The report considers potential public financial impacts and roadway costs associated with oil and gas development and production activity in Boulder County, Colorado.

Oil and gas development and production activity has a range of economic implications for local communities. It is the means through which mineral rights owners realize the value of their property. It also results in jobs for workers, both directly and indirectly associated with the oil and gas industry. Finally, industry workers' local expenditures induce other forms of employment in the provision of various goods and services seemingly unrelated to the energy industry.

As with all private and commercial activity, oil and gas development and production activity also places demands on local public goods and services. Currently, property taxes are assessed to provide funds commensurate with some portion of shared local public goods and services utilized by the industry. This report evaluates those industry tax payments and compares them to impacts on county roadways.

III. Evaluation of County Property Taxes

This section evaluates property taxes paid on oil and gas production in Boulder County. We also present estimates of tax receipts projected for a single well and for several drill program scenarios.

A: *Average mill levies on oil and gas development and production activity in Boulder County*

The Boulder County government assesses property taxes on oil and gas production within Boulder County. Property tax revenues are combined with revenues from other sources.[3] Total county revenues are used to fund a variety of expenditures, including health and welfare initiatives, conservation and sanitation, public safety, debt service, and county highways and streets.

Boulder County also collects property taxes for all tax districts within the county. There are 102 tax districts within Boulder County,[4] each with the authority to determine their own tax rates. There are four public school tax districts (e.g. Park School District), 10 town or city tax districts (e.g. Lyons), and large number of other tax districts to fund provision of public services such as fire protection, water service, sanitation, libraries, and transportation.

Property taxes on oil and gas production are paid to Boulder County Government and any and all Boulder County tax districts in which a particular well is located. Consequently, there is no single county-wide property tax rate for oil and gas production. However, the Boulder County Budget Summary can be used to infer a county-wide average mill levy.

Boulder County Government assessed a mill levy of 24.645 mills in 2012.[5] Revenues from this levy accounted for approximately 28.6 percent of all property taxes collected in Boulder County.[6] The Boulder County levies imply that approximately 0.861 mills resulted in one percent of total county property taxes levied in 2012. Thus, approximately 86.1 mills accounts for all (100 percent of) taxes levied in Boulder County in 2012.[7]

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[3] See Boulder County Budget Summary, 2012.

[4] See Appendix I, Boulder County 2012 Summary of Levies, Boulder County Assessor.

[5] Ibid.

[6] See Boulder County Budget Summary, 2012.

[7] Alternatively, according to the Boulder County Budget Summary 2012, the total taxable assessed valuation of all properties in Boulder County was $5,602,968,410. Thus, the 24.645 mills levied on that total assessed value basis resulted in $138,085,156 property taxes. Since these taxes represent 28.6 percent of total taxes levied in the county, the same assessed property value was also levied an additional 61.5 mills, on average, in order to raise the remaining 71.4 percent of property tax revenue collected in the county. Consequently, the total average mill levy in Boulder County is estimated at 86.145.

We corroborate this county-wide average mill levy estimate utilizing Encana tax payment records. Table 1 summarizes payments for property taxes levied by Boulder County and paid or payable by Encana in 2010, 2011, 2012, and 2013. The table also presents the assessed value of mineral properties subject to county levies. These records imply that Encana paid a four-year-average mill levy of 90.2. This suggests that aggregate county receipts may provide a relatively conservative estimate (86.1 mills) of actual taxes levied on oil and gas production (90.2 mills) in Boulder County.

Table 1

			Encana, Tax Payments to Boulder County, Summary					
Prod Yr	Tax Yr	Paid Yr	Market Value	Assessed Value	implied assessment ratio	Tax Paid	implied tax rate (=tax/av)	implied tax rate (=tax/mv)
2011	2012	2013	$18,686,881	$16,351,018	0.875	$1,550,234.48	0.0948	0.0830
2010	2011	2012	$18,175,999	$15,903,999	0.875	$1,427,977.38	0.0898	0.0786
2009	2010	2011	$14,902,000	$13,039,250	0.875	$1,180,061.24	0.0905	0.0792
2008	2009	2010	$31,629,943	$27,676,200	0.875	$2,377,022.12	0.0859	0.0752
						average:	0.0902	0.0790

The Boulder County Assessor taxable property class code listing[8] indicates that mineral properties are assessed at of 87.5 percent of actual market value. This suggests that total county levies amount to approximately 7.5 percent of property market values. This effective tax rate also provides a conservative estimate of actual taxes paid on a market basis by Encana (note 7.9 percent average market-price-based county tax rate in table 1.)

Roughly 28.6 percent of total property taxes paid to the county are paid to Boulder County Government, with the remaining 71.4 percent to other tax districts within the county. This implies that approximately 5.36 percentage points of the 7.5 percent of oil and gas property market value paid to all county taxes is allocated to the various tax districts within Boulder County. The remaining 2.14 percentage points are collected for the Boulder County Government account.

B: <u>Estimated tax collections on prospective wells drilled in Boulder County</u>

County property tax collections forecasts are based upon a typical DJ-Niobrara horizontal well with an estimated ultimate recovery of 300 million barrels of oil equivalents and production rates as summarized in Table 2.[9] Annual average daily production rates decline exponentially at a decelerating rate through year 10. The terminal 20 years of production (years 11-30) are modeled at the average annual

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8 See Boulder County Assessor Class Code List, p. 8.

9 EUR (Estimated Ultimate Recovery) assumption may be obtained from a variety of publicly available energy investment analyses. For the present study, see Redden (2012).

rate predicted at year 20. Because the harmonic declines are typically less severe than those estimated using the exponential form, this method provides a conservative estimate of terminal period production.

Table 2
DJ-Niobrara model well production rates

Time period year	Daily production rate (BOEPD)	Exponential decline
1	228	0.94
2	97	0.42
3	65	0.27
4	49	0.21
5	40	0.16
6	34	0.14
7	29	0.12
8	26	0.10
9	24	0.09
10	22	0.09
11-30	8.9	

Revenues are modeled at $60 per BOE. This value represents the production volume weighted average of recent oil and gas prices typical to DJ–Niobrara wells.

Total property taxes paid to Boulder County and all tax districts within Boulder County are modeled at an average rate of 7.5 percent of total revenue. Approximately 28.6 percent of assessed taxes are collected for Boulder County Government, with the remaining 71.4 percent of assessed taxes collected for the various tax districts within Boulder County. In 2012, Boulder County Schools received 52.8 percent of total property taxes collected in the county. Cities and towns received 11.6 percent, and other tax districts received a total of 6.98 percent of county property tax payments.

Table 3 presents county taxes attributable to the first 20 years of production[10] from a single DJ-Niobrara horizontal well, typical of that expected to be drilled in eastern Boulder County. The table summarizes the value of tax accruals. For simplicity, the analysis assumes the well is drilled in the first year and begins production in year two. In practice, however, well production can be expected after six months following the initiation of drilling. The table shows that county tax authorities can expect to receive approximately $374 thousand from the first year of production of a single well. Approximately $107 thousand is expected to be payed to Boulder

[10] We only consider public revenues from the first 20 years of production in order to provide a revenue estimate comparable to the 20-year well operational life assumed in the Roadway Impact Study. Thus, the tax revenues calculated herein are conservative since they exclude the final 10 years of production taxes expected from each well.

County Government, with the remaining $267 thousand paid to various tax districts within Boulder County.[11]

Table 3

			Single Well County Tax - Accruals				nominal	present value
	year:	1	2	3	4	5	cumulative	@ 3% real dr
		(drilling)	(production . . . .)				total	total
Payable to:	County total	$0	$374,490	$159,323	$106,763	$80,483	$1,149,639	$1,005,499
	Boulder Co.	-	107,104	45,566	30,534	23,018	328,797	287,573
Boulder Co. Schools		-	197,731	84,122	56,371	42,495	607,009	530,903
Boulder Co. Cities / Towns		-	43,441	18,481	12,384	9,336	133,358	116,638
Other county tax districts		-	26,214	11,153	7,473	5,634	80,475	70,385

Each well is expected to be assessed a cumulative total of $1.15 million in county taxes.[12] At a relatively modest 3 percent real discount rate, total county tax assessments are equivalent to a present value exceeding $1 million.[13]

Table 4 presents actual cash flows anticipated from county taxes attributable to a single Boulder County DJ-Niobrara horizontal well. Colorado property taxes are paid in arrears. And those tax obligations are assessed on actual historical production records. Thus, in contrast to the tax accruals presented in table 3, actual tax cash flows occur with a two-year lag to production, and a three-year lag to drilling activity. Real values of tax receipts are therefore lower than accrued values, depending upon the discount rate assumed.

Table 4

			Single Well County Tax - Cash Flows				nominal	present value
	year:	1	2	3	4	5	cumulative	@ 3% real dr
		(drilling)	(production . . . .)				total	total
Paid to:	County total	$0	$0	$0	$374,490	$159,323	$1,149,639	$947,779
	Boulder Co.	-	-	-	107,104	45,566	$328,797	$271,065
Boulder Co. Schools		-	-	-	197,731	84,122	$607,009	$500,427
Boulder Co. Cities / Towns		-	-	-	43,441	18,481	$133,358	$109,942
Other county tax districts		-	-	-	26,214	11,153	$80,475	$66,345

[11] According to the Boulder County Budget Summary 2012, approximately 53 percent of total county property taxes are assessed for various school districts, 12 percent are assessed for cities, seven percent are assessed for other tax district types. Thus, each well's first year county tax payments of $374 thousand are expected to provide $198 thousand to schools, $43 thousand to cities, and $26 thousand to other tax district accounts.
[12] An additional $142 thousand in taxes is expected to be generated from the terminal 10 years of production excluded from this analysis. See footnote 10.
[13] Real values were calculated at a relatively low discount rate to reflect the risk averse nature of public financial management. Real values can be recalculated upon request at any desired discount rate.

Total county tax receipts will depend upon the magnitude of development in Boulder County. This study evaluates county tax flows anticipated from the various oil and gas development scenarios summarized in Table 5. The table presents the number of wells drilled in each of the first five years of drilling programs evaluated in the Roadway Impact Study (RIS).[14] The magnitude and pace of each scenario is defined by the total number of wells assumed to be drilled in each scenario, and the total duration of each drilling program scenario. In addition, the present study considers an industry-provided maximum development scenario, which has twice as many wells but the same duration as the Roadway Impact Study steady scenario.

Table 5

		Boulder County Drill Program Scenarios						
	year:	1	2	3	4	5	total wells	total years
	RIS - low	11	11	11	11	11	180	16
	RIS - steady	51	51	51	51	52	824	16
	RIS - accelerated	91	91	92	92	92	824	9
	maximum	103	103	103	103	103	1,648	16

Expected Boulder County tax accruals and cash flows for each of the four oil and gas development program scenarios are presented in tables 6 and 7. County tax flows under each scenario grow over time, as taxes assessed on the production of newly drilled wells is added to the taxes assessed on production from producing wells drilled in previous years.

Table 6

								nominal	present value
				Drill Program County Tax - Accruals				cumulative	@ 3% real dr
		year:	1	2	3	4	5	total	total
	RIS - low	county total	$0	$4,119,390	$5,871,938	$7,046,325	$7,931,633	$206,934,939	$146,323,916
		Boulder Co.	0	1,178,146	1,679,374	2,015,249	2,268,447	59,183,392	41,848,640
	RIS - steady	county total	0	19,098,990	27,224,438	32,669,325	36,773,933	947,302,164	669,922,427
		Boulder Co.	0	5,462,311	7,786,189	9,343,427	10,517,345	270,928,419	191,597,814
	RIS - accelerated	county total	0	34,078,590	48,576,938	58,666,815	66,150,045	947,302,164	738,275,849
		Boulder Co.	0	9,746,477	13,893,004	16,778,709	18,918,913	270,928,419	211,146,893
	maximum	county total	0	38,572,470	54,982,688	65,979,225	74,268,923	1,894,604,328	1,339,935,259
		Boulder Co.	0	11,031,726	15,725,049	18,870,058	21,240,912	541,856,838	383,221,484

Oil and gas development activity is expected to generate a tax cash flow to Boulder County property taxing authorities of $4.12 million to $38.6 million at approximately three years following the initiation of drilling activity, with approximately 28.6 percent of these cash flows paid to Boulder County Government (the county-wide authority). At a 3 percent discount rate, total tax receipts are

[14] See "Boulder County Oil and Gas Roadway Impact Study" by Felsburg Holt & Ullevig and BBC Research and Consulting for total number of wells and duration of drilling program assumed for each scenario. The present study assumes those wells are drilled at a constant pace over the duration of each drilling program scenario.

expected to range between $138 million and $1.26 billion, depending upon the drill program scenario assumption.

Table 7

								nominal	present value
			Drill Program County Tax - Cash Flows					cumulative	@ 3% real dr
		year:	1	2	3	4	5	total	total
	RIS - low	county total	$0	$0	$0	$4,119,390	$5,871,938	$206,934,939	$137,924,324
		Boulder Co.	0	0	0	1,178,146	1,679,374	59,183,392	39,446,357
	RIS - steady	county total	0	0	0	19,098,990	27,224,438	947,302,164	631,466,139
		Boulder Co.	0	0	0	5,462,311	7,786,189	270,928,419	180,599,316
	RIS - accelerated	county total	0	0	0	34,078,590	48,576,938	947,302,164	695,895,795
		Boulder Co.	0	0	0	9,746,477	13,893,004	270,928,419	199,026,197
	maximum	county total	0	0	0	38,572,470	54,982,688	1,894,604,328	1,263,017,493
		Boulder Co.	0	0	0	11,031,726	15,725,049	541,856,838	361,223,003

IV. Assessment of Roadway Impact Study Cost Estimates

The base case for the present analysis is provided in the Roadway Impact Study. The authors estimate roadway impact costs attributable to three energy development scenarios. We identify a cost model that is implied by the Roadway Impact Study results. We then utilize the implied cost model to approximate roadway costs appropriate to alternative development scenario assumptions. Finally, we also utilize the model to estimate the discounted present value of roadway costs associated with oil and gas development in Boulder County.

A: Cost model implied by the Roadway Impact Study

Table 8 presents the road deterioration and safety fees calculated in the Roadway Impact Study.[15]

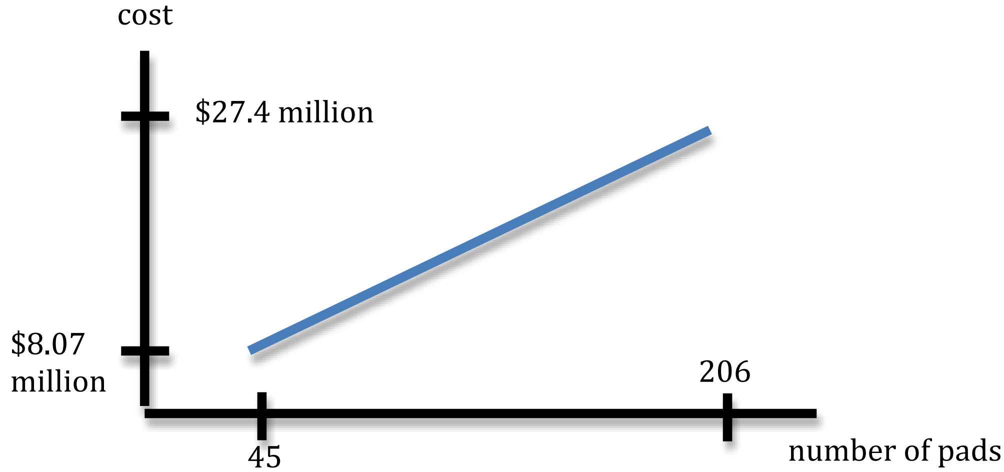
Table 8
Road Deterioration and Safety Costs

	Road Deterioration Cost	Safety Cost	Total Cost
Accelerated Scenario			
Total Cost (16-year period)	$24,393,296	$2,843,980	$27,237,276
Average Cost per 4-Well Pad	$118,414	$13,806	$132,220
Average Cost per Well	$29,604	$3,451	$33,055
Steady Scenario			
Total Cost (16-year period)	$24,661,955	$2,843,220	$27,496,175
Average Cost per 4-Well Pad	$119,718	$13,758	$133,476
Average Cost per Well	$29,929	$3,440	$33,369
Low Scenario			
Total Cost (16-year period)	$5,965,501	$2,105,360	$8,070,861
Average Cost per 4-Well Pad	$132,567	$46,786	$179,353
Average Cost per Well	$33,142	$11,696	$44,838
Scenario Average			
Average Cost per 4-Well Pad	$123,566	$24,783	$148,350
Average Cost per Well	$30,583	$6,196	$36,779
Average Cost per Pad Construction (1% of total cost)	$1,236	-	$1,236
Fee per Pad (rounded)			**$1200**
Fee per Well (rounded)			**$36,800**

[15] This table is presented as Table 15 in the original source report.

We utilize the Roadway Impact Study estimates of total roadway deterioration costs for the low and high well scenarios to approximate a linear model of roadway impacts from oil and gas activity, depicted in figure 1.

Figure 1



The total road deterioration and safety costs for the 'Low Scenario' are estimated at $8.07 million in the Roadway Impact Study. These costs correspond to roadway usage associated with 180 wells,[16] or 45 four-well pads. Alternatively, the 'Steady' and 'Accelerated' scenarios assume development of 824 wells on 206 pads, resulting in a cost of approximately $27.4 million. These two estimates imply that oil and gas development activity has a variable impact on roadways of $120 thousand per drill pad. In addition, oil and gas development activity results in a fixed cost of $2.67 million – an impact independent of the number of drill pads developed.

Assuming that the variable costs to roadways are proportional to truck activity associated with drill pads, the variable impact of $120 thousand per drill pad can be further decomposed into a cost per truck trip.[17]

Table 9 summarizes the preceding derivation of the implied roadway impact cost model, and further decomposes the variable costs to a truck trip basis. The roadway report truck utilization assumptions are presented in Table 10.[18] And a timeline for well pad development is presented in Figure 2.[19]

The truck trip assumptions presented in table 10 indicate that the well development phase is expected to require 7,230 truck trips. Figure 2 indicates that this phase is estimated to conclude within 26 weeks. Assuming that production begins

[16] See table 5.

[17] Cost normalization on a truck trip basis is analogous to the equivalent-single-axle-load normalization utilized by the authors of the Roadway Impact Study to allocate costs between pad construction phase and well drill and production phases. See Felsburg et al. 2013, p55.

[18] This table is presented as Table 7 in the original source report.

[19] This figure is presented as Figure 18 in the original source report.

immediately thereafter, the remaining life of the well pad will require two truck trips per day. Total well production life is assumed to be 20 years, the mid-point of the estimates indicated in the figure from the Roadway Impact Study. These assumptions imply that a well pad will require 14,600 truck trips over the production phase. Thus, a well pad will require a total of 21,830 truck trips over both development and production phases.

Table 9

		Roadway Impact Cost Model			
				Roadway	
				Impact Study	
	development			Cost Estimate	
	scenario	# wells	# pads	($ millions)	
	RIS - low	180	45	8.07	
RIS - steady / accelerated		824	206	27.40	
Implied Roadway Impact Cost model:			fixed costs ($ millions):		2.67
			variable costs -		
				per pad ($ millions):	0.120
				per truck trip ($):	5.50

Recall that the Roadway Impact Study estimates imply a variable impact of each well pad on county roadways of $120 thousand. Because each pad requires 21,830 truck trips over pad development and production phases, Roadway Impact Study estimates imply a per-truck cost to county roadways of $5.50.[20]

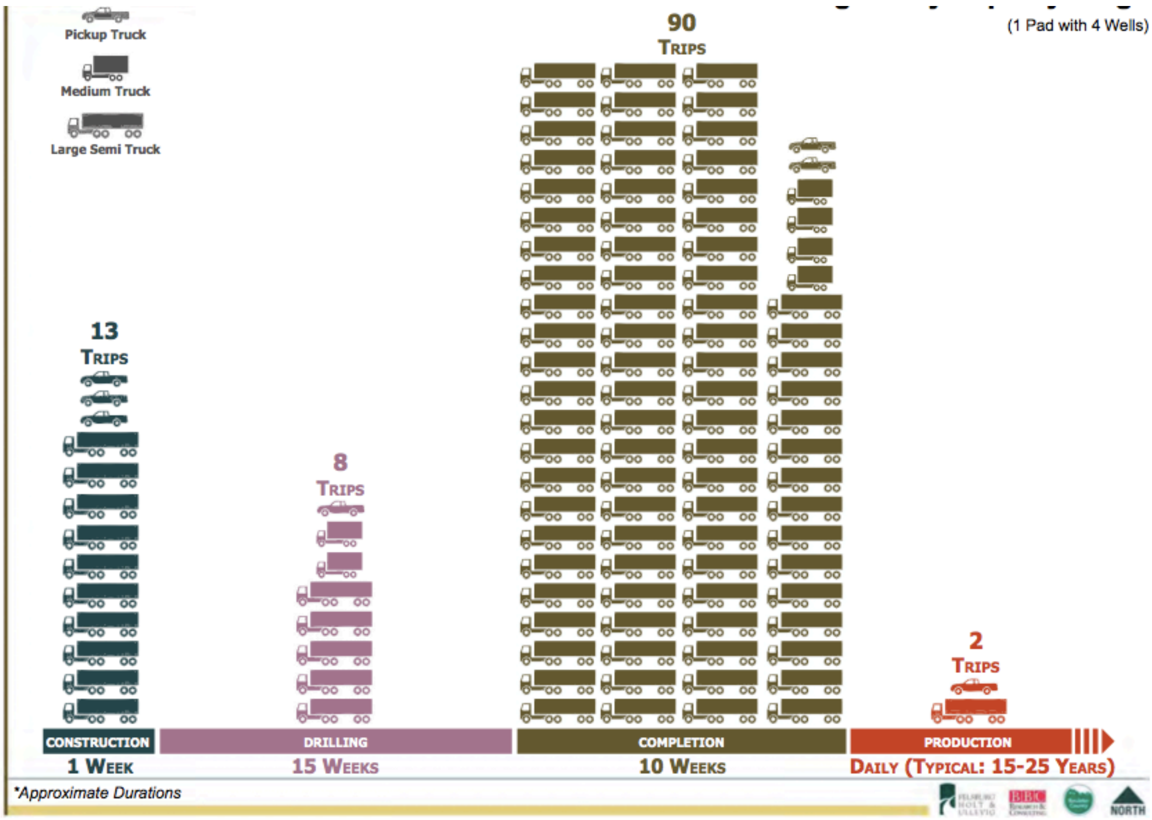
As with the cost estimates computed in the Roadway Impact Study, the estimated cost of the expanded drilling program is also an artifact of the particular assumptions in that study. Thus, the implied cost model allows us to compute roadway impact costs under alternative assumptions for roadway use.

[20] I.e. $120,000 per pad ÷ 21,830 trucks per pad = $5.50 per truck.

Table 10
Trip Generation Estimates

Activity	1 Pad, 4 Wells
Construction Stage	
Pad and Road Construction	90
Drilling Stage	
Drilling Rig	90
Drilling Fluid and Materials	270
Drilling Equipment (casing, drill pipe, etc.)	450
Completion Stage	
Completion Rig	40
Completion Fluid and Materials	170
Completion Equipment (pipe, wellhead, etc.)	10
Fracturing Equipment (pump trucks, tanks, etc.)	320
Fracture Water	4,200
Fracture Sand	190
Flowback Water Disposal	1,400
Total Development Trips	**7,230**
Production Stage	
Oil & Water Removal	580
Operations and Maintenance	150
Total Production Trips (per year)	**730**

Figure 2
Average Daily Trips by Stage of Drill Pad Development



B: <u>Roadway Impact Study cost estimates based on the Roadway Impact Study Cost Model and alternative assumptions for roadway use</u>

Encana and Noble Energy, Inc. prepared on March 1 a list of concerns with several assumptions utilized in the Roadway Impact Study.[21] We use the implied Roadway Impact Study cost model to predict the total roadway costs appropriate to alternative truck trip assumptions.

Recall from table 5 that we introduce a 1,624 maximum drilling program scenario in order to provide an upper bound to possible public financial (tax receipt) outcomes. According, we estimate roadway impact costs or $52.1 million associated with this maximum development scenario. Recall from the implied cost model, the fixed cost of oil and gas development activity on Boulder County Roadways is approximately $2.67 million, regardless of the level of that development activity. In addition, the study suggests that oil and gas development and production activity imposes a cost to Boulder County roadways, on average, of approximately $120 thousand per well

[21] See Appendix II.

pad, or $5.50 per truck trip. These cost estimates suggest that a development program roughly twice as large as that considered in the Roadway Impact Study would result in a total cost to Boulder County roadways of $52.1 million.[22]

Table 11
Trip Generation Estimates (per 4-well pad)

	original FHU RIS	industry practices trucking water	industry practices piping water
Development Phase			
Construction Stage			
Pad and Road Construction	90	90	90
Drilling Stage			
Drill Rig	90	102	102
Drilling Fluid & Materials	270	364	364
Drilling Equip (casing, etc)	450	94	94
Completion Stage			
Completion Rig	40	8	8
Completion Fuid & Material	170	24	24
Completion Equip (pipe, etc)	10	21	21
Frac Equip (pump truck, etc)	320	34	34
Frac Water	4,200	2,764	5
Frac Sand	190	284	284
Flowback Water disposal	1,400	85	85
total development phase (#)	7,230	3,870	1,111
Production Phase (annual)			
Oil & Water Removal (y1)	580	2075	2075
Oil & Water Removal (y2-20)	580	296	296
Operations & Maintenance	150	150	150
yr 1 prod phase (#)	730	2225	2225
yr 2 to yr 20 prod phase (#/yr)	730	446	446

[22] I.e. $120 thousand for each of the 412 pads associated with the 1,648 wells, plus the fixed cost of $2.67 million. This value is included in Table 12, below. Note, however, that this direct application of the implied cost model may overstate true roadway impact costs of a large development scenario if developers can be expected to reduce costs through learning and other economies of scale.

The implied model can also be used to evaluate the implications of alternative estimates of truck utilization. Table 11 lists the original Roadway Impact Study trip generation estimates along with alternative trip generation assumptions based on established operational practices.

Total drilling stage truck trips are estimated to be approximately 31 percent below Roadway Impact Study assumptions. Based on current practices, the Roadway Impact Study understates the number of trips required to mobilize and demobilize the drill rig and fluid and materials necessary for a four-well pad. However, the number of truck trips necessary to move casing, cement, and other drilling equipment is overstated by approximately 356 trips.

Total completion stage truck trips are estimated to be approximately 49 percent to 93 percent below Roadway Impact Study assumptions. Based on Encana's historical experience in the DJ-Niobrara, it is technically and commercially feasible to deliver frack water to approximately 90 percent of well pad locations. This practice eliminates frac water delivery truck trips, though we include 5 truck trips necessary for piping materials under this scenario. Historically, in the approximately 10 percent of locations where it is not feasible to utilize piped water, frac water delivery is estimated to be 1,436 trips below Roadway Impact Study assumptions.

Flowback water is only partly recovered at the end fracking operations. The majority of this water will be produced and removed in the first year of production. Thus, we model the production phase in two stages, a year-one phase, and years two through 20. Year-one production includes a higher estimate of truck trips to account for flowback water recovery. Years two through 20 are estimated to require approximately 39 percent fewer truck trips than assumed in the Roadway Impact Study.

Table 12

		Roadway Impact Cost Model Estimates				
					industry	industry
				Roadway	practices	practices
				Impact Study	trucking water	piping water
	development			Assumptions	assumption	assumption
	scenario	# wells	# pads	($ millions)	($ millions)	($ millions)
	RIS - low	180	45	8.07	6.27	5.59
RIS - steady / accelerated		824	206	27.40	19.17	16.05
	maximum	1,648	412	52.13	35.68	29.43

Table 12 summarizes roadway impact costs associated with each of the development scenarios under these alternative trucking practice assumptions. The values of approximately $8.07 million for the low development scenario and $27.4

million for the steady and accelerated development scenarios are the values reported in the Roadway Impact Study.[23]

Assuming implementation of established industry practices reduces the total impact to roadways by up to $2.48 million under the low development scenario, and $11.4 million under the steady and accelerated development scenarios. Assuming implementation of advanced industry practices under the maximum development scenario reduces nominal estimates of roadway damages by up to 44 percent below estimates implied by the Roadway Impact Study.[24]

Table 13 summarizes roadway impact costs on a per-well basis. Nominal costs on a per-well basis are projected to be up to 52 percent lower than the $37,100 per-well fee proposed in the Roadway Impact Study.[25] This reduction in per-well costs is attributable to both lower truck utilization under various industry assumptions, and leveraging fixed roadway impact costs over a larger drilling program under industry assumptions.

Table 13

		Roadway Impact Cost Model Estimates			(per-well basis)	
	development scenario	# wells	# pads	Roadway Impact Study Assumptions ($/well)	industry practices trucking water assumption ($/well)	industry practices piping water assumption ($/well)
	RIS - low	180	45	44,833	34,850	31,056
RIS - steady / accelerated		824	206	33,252	23,269	19,475
	maximum	1,648	412	31,634	21,650	17,857

C: Present value of roadway impact cost estimates accounting for the discounted value of future roadway impacts

If roadways are impacted over time in proportion to roadway use over the life of each well pad and regional development scenario, then nominal calculation of roadway costs will overstate the present value of those damages. And although the development phase of a well pad may be the most road-use intensive portion of the well pad life, a significant fraction of total truck trips occurs during the production phase. Indeed, under the Roadway Impact Study assumptions, approximately two

[23] See table 8 in this report, or table 15 in the original source report.

[24] E.g. compare the $52.13 million cost for the industry development scenario under Roadway Impact Study assumptions to the $29.43 million under the piping water assumptions.

[25] I.e. The Roadway Impact Study concludes with a fee design proposal of $36,800 per well plus ¼ of the $1,200 per pad fee; this total value of $37,100 is compared to the value of $17,857 per well.

thirds of all truck trips occur during the 20-year production phase. In addition, because each development scenario is implemented over a number of years, the present value of much of the roadway costs is below nominal estimates.

Table 14 calculates the present value of roadway damages under the assumption that damage is proportional to truck utilization of roadways over the development and production lifetime of a well pad.[26] At a relatively modest discount rate of three percent, the present value roadway impact costs are approximately 22 to 29 percent below the nominal values calculated in the Roadway Impact Study.[27] Factoring in the established practices assumptions for roadway utilization results in a commensurate reduction in roadway impact costs.

Table 14

	Present Value (3%)			Roadway Impact Cost Model Estimates			
						industry	industry
					Roadway	practices	practices
				development	Impact Study	trucking water	piping water
	development			duration	Assumptions	assumption	assumption
	scenario	# wells	# pads	(years)	($ millions)	($ millions)	($ millions)
	RIS - low	180	45	16	6.32	5.14	4.59
	FHU - steady	824	206	16	19.39	13.99	11.46
FHU - accelerated		824	206	9	21.10	15.14	12.36
	maximum	1,648	412	16	36.12	25.31	20.26

Table 15 provides a computation of present-value roadway impact costs on a per-well basis that is comparable to the roadway impact fee proposed in the Roadway Impact Study. It is important to note that because the per-well fee structure currently under consideration for policy implementation would presumably be paid over time contemporaneously with well development, the values reported in Table 15 do not represent a simple normalization of the values presented in table 14. Instead, the values presented in Table 15 are only discounted to the beginning of each well life (i.e. not to the beginning of the entire drill program.) Appropriately, therefore, the estimates in table 15 do not incorporate discounting attributable to the fact that much of the drilling program in each well development scenario would occur over future years. Thus, these values are comparable to the per-well fee proposal of $37,100 based upon the original Roadway Impact Study cost estimates.

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[26] Real values are calculated at a relatively low discount rate of three percent to reflect the risk-averse nature of public financial management. This is the same discount rate utilized for the present value of tax receipts presented in tables 3, 4, 6, and 7. Real values can be recalculated upon request at any desired discount rate.

[27] I.e. $6.32 million, as compared to the $8.07 million calculated in the Roadway Impact Study; or $19.39 million as compared to the $27.4 million calculated in the Roadway Impact Study. At an even more modest discount rate of two percent, present value roadway impact cost estimates are 16 percent below nominal estimates for the low development scenario ($6.8 million, as compared to the original estimate of $8.07 million), and 21 percent below nominal estimates for the steady scenario ($21.6 million, as compared to the original estimate of $27.4 million.)

Table 15

	Present Value (3%)	Roadway Impact Cost Model Estimates				(per-well basis)	
						industry	industry
					Roadway	practices	practices
				development	Impact Study	trucking water	piping water
	development			duration	Assumptions	assumption	assumption
	scenario	# wells	# pads	(years)	($/well)	($/well)	($/well)
	RIS - low	180	45	16	39,918	31,811	28,017
	FHU - steady	824	206	16	28,337	20,230	16,436
	FHU - accelerated	824	206	9	28,337	20,230	16,436
	maximum	1,648	412	16	26,718	18,612	14,818

For the low development scenario, the nominal value of roadway damages of $44,838 per well estimated in the Roadway Impact Study[28] corresponds to a discounted value of $39,918, a reduction of 11 percent. And for the steady and accelerated well development scenarios, the real value of per-well roadway impact costs is at least 14 percent below nominal values. Assuming established industry practices reduces the estimated present value of roadway impact costs to approximately $16,436 per well. Incorporating industry assumptions reduces the estimated roadway impact to $14,818 per well, approximately 60 percent below the original fee proposal of $37,100 per well.[29]

[28] See table 8 in this report and table 15 in the Roadway Impact Study for the original figures, and table 13 in this report for the figures calculated with the implied model used herein (where the estimate is calculated as $44,833.)

[29] The Roadway Impact Study fee proposal of $37,100 is based on $36,800 per well plus ¼ of the $1,200 per pad cost fee.

V. Concluding Discussion

This report examines county tax payments associated with oil and gas activity in Boulder County. We also consider how Roadway Impact Study cost estimates are affected by varying assumptions regarding roadway usage during oil and gas development and the dynamic nature of roadway impacts (i.e. that roadway impacts are realized over the course of time.)

The roadway impacts cost assessment presented in this report suggests that varying roadway use assumptions and discounting to present values can have significant implications for roadway impact cost estimates. Assuming established industry practices, the present value of roadway costs per well for the 'steady' development scenario is estimated at $16,436 per well, approximately 56 percent below per-well fees proposed in the Roadway Impact Study.[30]

And the present value of total roadway impact costs are considerably lower than those calculated in the Roadway Impact Study. For example, steady scenario roadway impact costs assuming current industry practices are estimated at $13.99 million,[31] approximately 49 percent below the nominal cost estimate of $27.4 million obtained under the original assumptions of the Roadway Impact Study.[32],[33]

In comparison, the present value of total oil and gas production property tax cash flows to Boulder County is estimated to range from $138 million under the low development scenario to $1.26 billion under the larger, industry-anticipated development scenario.[34] Assuming the current distribution of mill levies, the 28.6 percent of assessed taxes paid to Boulder County Government is equivalent to $39.4 million to $361 million. These values are equivalent to between 1.5 years and 13 years of the current Boulder County Budget for capital building projects for highways and streets.[35]

It is important to note, however, that the timing of property tax receipts is realized at a three-year lag to some significant fraction of roadway impact costs. Fully one third of truck trips associated with well pads are experienced within the first year of well development, with the remaining two thirds experienced throughout the remaining 20 years of a well's production life. In contrast, because taxes are paid in arrears on actual production (which is necessarily reported with a lag), production property tax receipts do not occur until three years after a well has been drilled.

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[30] I.e. The Roadway Impact Study concludes with a fee design proposal of $36,800 per well plus ¼ of the $1,200 per pad fee; this total value of $37,100 is compared to the value of $15,071 in reported in Table 15.
[31] See Table 14.
[32] See Table 12 of this report, and Table 15 of the Roadway Impact Study.
[33] It may also be useful to consider these values in relation to historical expenditures on roads in Boulder County. According to the Boulder County Budget Summary, 2012, total expenditures on capital building projects for highways and streets in 2012 was $27.1 million.
[34] See Table 7.
[35] See Boulder County Budget Summary, 2012. Also, see footnote 33 in this report.

Thus, roadway impact costs associated with a step-up in oil and gas development activity will precede revenues from oil and gas property taxes during the initial stages of a new development program. After the first three years of increased development activity, however, previously drilled and producing wells will generate tax payments contemporaneous with roadway costs attributable to wells then in the development phase.

A number of mechanisms can be utilized to match the timing of public financial capacity to roadway impacts over this first three years of increased development activity (i.e. in the early stages of increased development, before oil and gas property tax receipts equal to or greater than roadway impact costs.) For example, financial assurance mechanisms such as bonds or trusts are 'pre-funded' and thus provide financial capacity that is contemporaneous with costs. Alternatively, property tax based methods of finance could incorporate tax credits for escrowed payments in order to match the timing of public revenues to costs.

This report is to be used in discussions with the Commissioners and other Boulder County road-use fee stakeholders. This report is not to be used for any other purpose without the prior written consent of EA. We understand that public deliberation over the financing of road-impact costs is ongoing and, therefore, to the extent that new information and/or additional documentation is provided that may affect our opinions subsequent to the issuance of this report, we reserve the right to revise and supplement this report.

Signature: ________________________________

Michael J. Orlando
Economic Advisors, Inc.

Date: _____April 12, 2013_____

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APPENDICIES

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Appendix I

2012 SUMMARY OF LEVIES (December 2012)

		Valuation	Total Levy	Revenue	Temp Tax	Abate	Gen. Fund	Road & Bridge	Health	Cap Exp	Welfare	HS Safety Net	Devel Disab
▸ ▸	**BOULDER COUNTY**	**5,617,089,739**	**24.645**	**139,022,459**	**-0.000**	**0.000**	**19.859**	**0.186**	**0.693**	**0.910**	**1.097**	**0.900**	**1.000**

	Tax District		Valuation	Total Levy	Revenue	Temp Tax Credit	Gen. Fund	Abate Refund	Capital Expend	Overrides	Bond Levy	Other
▸ ✓	St. Vrain Valley School District	RE-1J	1,486,058,110	53.500	79,504,109		24.995	0.311		13.394	14.800	
▸ ✓	Boulder Valley School District	RE-2	4,104,257,195	45.547	186,936,602		25.023	0.354		12.620	6.007	1.543
✓	Thompson School District	LR-2J	3,610,015	40.884	147,592		22.360	0.501		9.969	8.054	
✓	Park School District	LR-P-3J	23,164,420	31.025	718,676		20.549	0.456		5.386	4.634	
▸ +	Boulder	BLDR	2,500,705,976	11.981	29,960,958		8.748		3.233			
✓	Erie	ERIE	96,290,673	17.095	1,646,089		7.288				5.807	4.000
	Jamestown	JAS	3,133,738	18.500	57,974		5.500		5.000			8.000
▸	Lafayette	LAF	356,840,096	14.379	5,131,004		8.184				1.695	4.500
▸	Longmont	LGT	1,020,468,232	13.420	13,694,684		13.420					
▸	Louisville	LSVL	441,537,828	6.710	2,962,719		5.184				1.526	
+	Lyons	LYONS	29,217,565	15.696	458,599	-4.948	20.644					
▸ +	Nederland	NED	21,946,417	16.917	371,268	-0.357	17.274					
+	Superior	SUP	162,671,805	9.430	1,533,995	-4.197	12.127					1.500
	Ward	WARD	1,390,741	3.800	5,285		3.800					
✓	Allenspark Fire	APFD	29,477,640	7.507	221,289		7.507					
	Allenspark Water & Sanitation	APWSD	2,058,427	4.130	8,501		4.130					
	Baseline Water	BWD	6,234,585	1.464	9,127		1.464					
✓	Berthoud Fire	BERFD	9,019,268	15.274	137,760		12.531		1.243		1.500	
▸ +	Boulder Central General Imp	BCGID	205,767,411	5.307	1,092,008	-4.683	9.990					
●	Boulder County Gunbarrel PID	GPID	113,984,871	0.000	0							
	Boulder Junction Access- Parking	BJAGP	2,669,289	10.000	26,693		10.000					
	Boulder Junction Access- Trans	BJAGT	3,590,485	5.000	17,952		5.000					
	Boulder Mountain Fire	BMFPD	56,101,912	8.912	499,980		8.912					
	Boulder Mountain Fire Water Subdistrict	BMFWSD	29,200,523	1.803	52,649		1.803					
	Boulder Rural Fire	BRFD	206,419,277	11.747	2,424,807		11.747					
✓ ●	Boulder Soil	BSD	413,296,381	0.000	0							
	Brownsville Water & Sanitation	BNVWSD	6,215,960	0.780	4,848		0.780					
▸ ●	BURA 9th & Canyon	BURA9th	2,332,278	0.000	0							
◆	BURA Incremental Increase		9,393,325		0							
✓	Coal Creek Canyon Fire	CCFD	14,080,318	8.000	112,643		8.000					
●	Coal Creek Canyon Park & Rec District	CCCPRD	12,230,878	0.000	0							
●	Coalton Metropolitan District	CMD	564,166	0.000	0							
	Colorado Tech Center Metro	CTCMD	75,812,398	16.039	1,215,955		1.089				14.950	
▸ +	Downtown Boulder Business Imp	DBBID	214,190,083	4.730	1,013,119		4.730					
	East Boulder County Water	EBCWD	9,412,280	17.743	167,002						17.743	
●	Erie Farm Metro	EFMD	21,283	0.000	0							
+ ✓	Estes Valley Recreation & Park	EVRPD	6,826,660	2.438	16,643	-0.328	1.781	0.012				0.973
	Exempla GID	EXEMPLA	14,481,762	5.000	72,409		5.000					
	Fairways Metropolitan	FWMD	18,668,856	3.651	68,160		3.651					
	Flatiron Meadows Metro	FMMD	2,631,355	50.000	131,568		50.000					
+	Forest Glen Eco Pass	FGED	7,371,910	1.292	9,525	-1.018	2.310					
	Four Mile Canyon Fire	FMFD	11,004,064	12.000	132,049		11.820					0.180
	Gold Hill Fire	GHFD	4,701,954	7.484	35,189		3.484					4.000
	Gunbarrel Estates Metro Park & Rec	GEMPRD	10,114,252	5.091	51,492		3.591		1.500			
	Harvest Junction Metropolitan Dist	HJMD	19,227,931	30.000	576,838		7.000				17.258	5.742
✓	High Plains Library District	HPLD	96,148,349	3.261	313,540		3.249	0.012				
▸ ●	Highway 42 Revitalization Area	HWY42RURP	29,399,809	0.000	0							
◆	HWY42RURP Incremental Increase		770,519		0							
	Hoover Hill Water & Sanitation	HHSD	10,705,112	5.040	53,954		2.678				2.362	
	Hygiene Fire	HFPD	61,883,121	4.099	253,659		4.099					
	Indian Peaks Fire	IPFD	8,716,828	3.947	34,405		3.947					
	Knollwood Water	KWD	5,125,541	3.996	20,482		3.996					
	Lafayette City Center Gen Imp	LCCGID	2,866,557	31.671	90,787		5.000				26.671	
	Lafayette Corporate Campus	LCRPCGID	10,696,605	22.746	243,305		5.000				17.746	
	Lafayette Rural Fire	LRFD	46,058,569	2.500	115,146		2.500					
	Lafayette Tech Center Gen Imp	LATCGID	2,020,072	80.965	163,555		5.000				75.965	
▸ ●	Lafayette OT Urban Renewal Plan	LAFURP	9,294,421	0.000	0							
◆	LAFURP Incremental Increase		1,654,296		0							
●	Lake Eldora Water	LEWSD	1,800,514	0.000	0							
	Lefthand Fire	LHFD	35,856,759	11.022	395,213		11.022					
●	Lefthand Water	LHWD	340,475,004	0.000	0							
	Lefthand Water & Sanitation	LHWSD	5,686,974	21.716	123,498		16.089					5.627
◆	LGTDDA Incremental Increase		11,007,207		0							
✓ ●	Little Thompson Water	LTWD	7,735,618	0.000	0							
▸ ●	Longmont Business Improvement	LBID	32,920,401	0.000	0							
▸	Longmont Downtown Dev Auth	LGTDDA	27,386,139	3.310	90,648		3.310					
●	Longmont Gateway BID	LGBID	8,936,154	0.000	0							
▸	Longmont General Improvement	LGTGID	5,907,707	6.798	40,161		6.798					
✓ ●	Longmont Soil	LSD	290,836,031	0.000	0							
✓ ●	Longs Peak Water	LPWD	32,954,767	0.000	0							
▸	Louisville Fire	LOFD	461,145,555	6.686	3,083,219		6.686					
+ ✓	Lyons Fire	LYFD	45,207,440	7.680	347,193		4.330				1.350	2.000
▸ ●	Main Street Louisville BID	MSLBID	10,272,360	0.000	0							
✓	Mountain View Fire Protection	MVFD	356,427,517	11.747	4,186,954		11.747					
◆	NEDDDA Incremental Increase		918,718		0							
▸	Nederland Downtown Dev Authority	NEDDDA	3,909,556	5.000	19,548		5.000					
▸	Nederland Fire Protection	NFD	45,436,520	15.406	699,995		11.347	0.046			3.513	0.500
▸	Nederland Community Library District	NLD	58,432,992	6.620	386,826		4.400				2.220	
●	Niwot Sanitation	NSD	124,023,921	0.000	0							
✓	North Metro Fire Rescue	NMFRD	5,315,786	11.375	60,467		9.726	0.249			1.400	
▸ ✓	Northern Colorado Water	NCWD	5,173,950,133	1.000	5,173,950							1.000
	NCWD Allotments				39,317							
●	Olde Stage Water & Sanitation	OSWD	6,070,274	0.000	0							
	Pine Brook Water	PBWD	27,022,590	13.450	363,454						13.450	
▸ ●	Regional Transportation District	RTD	5,617,089,739	0.000	0							
●	Rex Ranch Metro District	RRMD	10,995	45.000	495		45.000					
	Rocky Mountain Fire District	RMFD	348,870,669	17.445	6,086,049		15.325				2.120	
	Shannon Estates Water	SWSD	3,374,730	1.380	4,657		1.380					
	SoLa Metro District - Commercial	SOLAMDC	1,478,723	60.000	88,723		10.000				50.000	
	SoLa Metro District - Institutional	SOLAMDI	312,881	60.000	18,773		10.000					50.000
▸ ●	South Boulder Road Rev URP	SBRRURP	5,014,210	0.000	0							
◆	SBRRURP Incremental Increase		166,768		0							
▸ ✓	St. Vrain Left Hand Water	SVLHD	1,384,790,184	0.184	254,801		0.184					
	Sugarloaf Fire	SLFPD	20,849,878	11.045	230,287		7.000		4.045			
	Sunshine Fire	SFD	6,081,139	12.040	73,217		4.480		4.000			3.560
	Superior Metro No. 2	SMD2	91,041,692	6.200	564,458						6.200	
	Superior Metro No. 3	SMD3	44,702,359	6.200	277,155						6.200	
	Superior/McCaslin Interchange District	SMIMD	23,954,843	28.000	670,736		13.000				15.000	
	Takoda Metro District	TMD	2,777,359	50.000	138,868		5.000				45.000	
✓	Timberline Fire	HCFD	14,508,135	8.342	121,027		5.660		2.682			
+	University Hills General Improvement	UHGID	14,132,223	2.276	32,165	-2.708	4.984					
▸ + ✓	Urban Drainage & Flood Control	UDFC	4,082,869,012	0.599	2,445,639	-0.097	0.696					
	TOTAL REVENUE FROM DISTRICTS				**497,556,544**							
	Late Filing Penalties				65,667							
	Mosquito Control				357,121							
	Senior/Veteran Prop Tax Exemption				44,993							
	TOTAL PROPERTY TAX REVENUE				**497,934,339**							

● Did not levy this year
◆ Valuation for LGTDDA, BURA9th, NEDDDA, LAFURP, SBRRURP & HWY42RURP incremental financing pruposes.
✓ Multi-county district
▸ Total value reduced LGTDDA,BURA9th,NEDDDA,LAFURP,SBRRURP, HWY42RURP
+ Temporary property tax credits or temporary mill levy reductions per 39-1-111.5 C.R.S.

Appendix II

Boulder County Oil & Gas Roadway Impact Study
Initial Points of Concern

Prepared by: Encana Oil & Gas (USA), Inc. and Noble Energy, Inc.
March 1, 2013

- Well Assumptions: A more accurate well count for the roads studies would be 1,648 wells, or 16 wells per section.

- Road Assumptions:
    - Residential streets within developments are included in the Study Area Road Network which would not be used at any time for Oil & Gas operations. Separate access roads would be built to avoid this.
    - There is no mention of the preferential use of the State highways designed for truck traffic. Access to Oil and Gas operations sites would be predominantly from the east and accessing on Highways 7, 287, 52, or 119. Only when near location would travel on Boulder County roads be required. The study report does not mention this.
    - The study report indicates that certain paved segments of the Study Area Road Network are currently in poor condition and that these poor pavement conditions will magnify the impacts of Oil and Gas traffic. How does the study ensure that the proposed impact fee will not remedy these existing roadway deficiencies, which is prohibited by Colo. Rev. Stat. § 29-20-104.5(2)?
    - The safety mitigation costs are predicated on the need to add shoulders for bicyclists and the increased traffic. The roads were not originally designed to accommodate both bicycles and motor traffic. This is not a road repair issue.

- At least some of the paved road mitigation costs are based upon generalized figures generated by CDOT. How do the CDOT cost figures compare to the actual costs that Boulder County has paid for such work? Oil and Gas Traffic Assumptions:
    - Table 7 from the study report (copied below) summarizes the truck trips assumed for a four well pad in the modeling for the study. There is no mention or allowance made in the road use study for sourcing water at or near the well location or pipelines for water. This truck trips required for local municipal or pipelined water would reduce to 5 for the poly pipe and materials, not the 4,200 used in the study for every well drilled.

Table 7. Trip Generation Estimates

Activity	1 Pad, 4 Wells
Construction Stage	
Pad and Road Construction	90
Drilling Stage	
Drilling Rig	90
Drilling Fluid and Materials	270
Drilling Equipment (casing, drill pipe, etc.)	450
Completion Stage	
Completion Rig	40
Completion Fluid and Materials	170
Completion Equipment (pipe, wellhead, etc.)	10
Fracturing Equipment (pump trucks, tanks, etc.)	320
Fracture Water	4,200
Fracture Sand	190
Flowback Water Disposal	1,400
Total Development Trips	**7,230**
Production Stage	
Oil & Water Removal	580
Operations and Maintenance	150
Total Production Trips (per year)	**730**

- The truck trip count for fracturing equipment is assuming that the fracturing equipment includes 500 bbl frac tanks. The use of the new round tanks would reduce these trips to 80, not 320 as stated in the table. The truck trip count for fracture water is a little high and for horizontal wells should be 650 to 850 trips per well for frac water. The truck trip count for frac water, if not sourced locally and or pipelined, should be 3400 for a four well pad (using 850 trips per well) and not 4,200.
- The truck trip counts make no allowance for a variety of other water management strategies that Encana and Noble are already employing and plan to expand in their Niobrara operations. These strategies will significantly reduce the estimated trip counts in the study, which assume that no such mitigation occurs. For example:
  - Noble reused and recycled about 37% of its water in the United States during 2011. As part of this effort, Noble conducted a pilot experiment in the Niobrara to treat flowback from one hydraulic fracture for reuse in a subsequent hydraulic fracture. This successful pilot is intended to be implemented on a larger scale within the Niobrara as well as in additional basins.
  - Noble's hydraulic fracturing operations in the Wattenberg field are using on average 20% less water by reducing slickwater stages and using higher sand concentrations during gel stages.

        - Noble reduced its truck mileage by approximately 5 million miles in the Wattenberg field during 2011 by strategically locating storage ponds and tanks and utilizing pumps and pipelines as alternative means of water delivery.
    - Many of the traffic assumptions appear to rely upon generalized information from Colorado or dated information from other regions, which do not accurately reflect current and future practices in the Wattenberg field. Water management is highly dynamic and rapidly evolving, and current local information is therefore vital.

- Tax Revenues Generated From Oil and Gas Development:
    - The study does not address the substantial tax revenues that Boulder County receives from oil and gas development or explain why such revenues are insufficient to pay the transportation mitigation costs attributable to such development. Given the magnitude of these revenues, no additional impact fee appears necessary for this purpose.
        - Boulder County reportedly received about $985,000 in ad valorem taxes during 2011 attributable to oil and gas development within the County.
        - Boulder County reportedly received another $83,000 from the State during 2011 reflecting its share of severance taxes and federal royalty payments.
        - These ad valorem and severance tax revenues will increase dramatically if significant new oil and gas development occurs in Boulder County as assumed in the study. Indeed, the study predicts that such development will consist of horizontal wells, which are highly productive. A rough calculation is that during the first year of production a typical new horizontal well in the Wattenberg field will generate about $300,000 in local ad valorem taxes at a 6% rate and another $300,000 in state severance taxes at current rates. Just the local ad valorem taxes for that one year would be more than eight times the transportation mitigation costs that the study attributes to the well.

Appendix III

Expert Witness Information

MICHAEL JOSEPH ORLANDO
PHD, MS, MBA, BS

Biographical Summary

Michael J. Orlando is Principal of Economic Advisors, Inc., a consulting firm specializing in financial economics, applied political economy, and industrial strategy. He is also Lecturer of Global Energy Management at the University of Colorado – Denver and Adjunct Professor of Finance at Tulane University.

Michael began his career with Shell Oil Company. He provided reservoir engineering and economic evaluation expertise for oil and gas exploration and development projects in the Gulf of Mexico. He also worked as an environmental engineer, ensuring environmental compliance and managing the Company's relationship to a listed Superfund site. Michael later served as a Research Economist in the Federal Reserve System, and then as Vice President and Branch Executive of the Fed's Denver Branch. He was responsible for regional economic research, energy markets analysis, policy advising, and public communication. Prior to founding Economic Advisors, Michael was Vice President for Research and Product Development with a business analytics and media monitoring start-up.

Michael's research spans a range of topics in applied microeconomics. He has published work on corporate governance, financial regulatory policy, the economics of payments networks, the geography and industrial demography of innovation, and energy and environmental policy. He is also a practiced teacher, and has developed courses in economics, finance, and energy business management and policy, and has co-authored a textbook on money and banking.

Michael holds a Ph.D and an M.A. in economics from Washington University in St. Louis, an M.B.A. from Tulane University, and a B.S. in petroleum and natural gas engineering from The Pennsylvania State University.

For complete bibliographic information and links to Dr. Orlando's publications, see http://home.comcast.net/~michael.j.orlando.

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EDUCATION

- Ph.D., Economics, Washington University in St. Louis, 2000.
- A.M., Economics, Washington University in St. Louis, 1995.
- M.B.A., Business Administration, Tulane University, 1993.
- B.S., Petroleum & Natural Gas Engineering, The Pennsylvania State University, 1988.

EMPLOYMENT

- Economic Advisors, Inc., Denver
  - Principal and Owner, 2008-present. Client projects include:
    - vote theoretic and game theoretic bargaining modeling, negotiations and competitive strategy development for global primary energy producer
    - environmental risk/surety analysis, financial assurance mechanism design, negotiations strategy for multinational strategic minerals mining company
    - bargaining modeling and market research for national regulated electricity generation and transmission corporation
    - financial, economic, and litigation strategy advising for small international energy E&P company
    - market research and advising for private toll road owner/operator
    - rule-making advising for state oil and gas regulatory authority
- University of Colorado – Denver
  - Global Energy Management program, Business School, Lecturer (financial management), 2012-present.
- Tulane University, New Orleans
  - Freeman School of Business, Adjunct Professor of Finance (financial management), 2009-2011.
- The Pennsylvania State University, State College
  - College of Earth and Mineral Sciences, Courseware Consultant (Global Energy Enterprise) 2010-2011.
- Evolve24, LLC, St. Louis
  - Vice President for Research and Product Development, 2007-2008.
- Federal Reserve Bank of Kansas City
  - Denver Branch, Vice President, Branch Executive and Economist, 2006-2007.
  - Economic Research Department, Senior Economist (energy, regional), 2004-2005.
  - Economic Research Department, Economist (energy, regional), 2000-2004.
- Washington University in St. Louis
  - Department of Economics, Instructor (macroeconomics, microeconomics), 1996, 1997, 1999.

    - Graduate School of Arts and Sciences, Instructor ("The Web and the Classroom: Instructional Enhancement through Appropriate Use of Technology"), 1997-1999.
    - Department of Economics, Research/Teaching Assistant (industrial organization, anthropology and economics), 1997-1998.
    - Center for the Study of American Business, Research Assistant, 1995-1997.
- Private Consultancy, St. Louis
    - Economist, 1997.
- Shell Offshore, Inc., New Orleans
    - Reservoir Engineer, 1989-1990, 1992-1994.
    - Environmental Engineer, 1990-1992.
    - Petrophysical Engineer, 1988 - 1989.
- Sohio, Houston
    - Drilling Engineer, 1987.

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CURRENT RESEARCH AND WORKING PAPERS

"Financial assurance for environmental protection: trends and opportunities"

"Universities, population, and regional innovation," with Michael Verba and Stephan Weiler (revise and resubmit, *Regional Studies*).

"The risks of negotiating from a position of strength," with Christopher Douglass

"Pollution exposure and student achievement in New Orleans," with Sammy Zahran.

"The great credit crunch of 2008: a complete history," with Srinivas Thiruvadanthai.

"Mom-and-pops and brand-name shops: a mixed-equilibrium specification" with Courtney LaFountain and Antoine Martin.

"Is Auditor Independence Endogenous? Evidence and Implications for Public Policy," with Dino Falaschetti, *Federal Reserve Bank of Kansas City Research Working Paper 03-13*, June 2004.

"Innovation in disadvantaged places," with Courtney LaFountain and Antoine Martin.

"Population and the skill premium: evidence for knowledge spillovers or matching advantages in thick markets?"

"On learning-by-doing and knowledge spillovers," with Christopher S. Hollenbeak.

"On urbanization and localization: evidence from R&D spillovers."

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Financial assurance for environmental protection: trends and opportunities. The Property and Environmental Research Center, Conference on Financial Contracting, Transactions Costs, and Environmental Amenities, Bozeman, MT, July 2012.

Beyond Our Borders – Natural Gas in a Global Context: How political and economic risks affect investment decisions. Natural Gas Symposium, Colorado State University, Fort Collins, October 2011.

Energizing Society: A collaborative approach to resource management. Graduates of Earth and Mineral Sciences Seminar Series, College of Earth and Mineral Sciences, The Pennsylvania State University, September 2011.

Managing Political, Regulatory, and Legal Risks in Practice. 'Summer in Seattle' Conference on Politics, Law, and Business, Albers School of Business and Economics, Seattle University, August 2011.

QE2: The Politics, Economics, and Business of Easy Money. Gleed Chair Distinguished-Speaker Series, Albers School of Business and Economics, Seattle University, February 2011.

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Universities, population, and regional innovation. North American Meetings of the Regional Science Association International, Brooklyn, November 2008; North American Meetings of the Regional Science Association International, Toronto, Canada, November 2006; Department of Economics, Colorado State University, Fort Collins, May 2006; Conference of the Western Economic Association International, San Francisco, July 2005.

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Reputation and the Federal Reserve. Weidenbaum Center Public Policy Meeting, Washington University in St. Louis, February 2008.

Barriers to network-specific investment. Department of Economics, Colorado State University, Fort Collins, April 2007; Department of Agricultural Economics and

Economics, Montana State University, Bozeman, March 2007; Conference of the Western Economic Association International, San Francisco, July 2005; Midwest Macroeconomics Meetings, University of Iowa, Iowa City, May 2005; Previously titled "Hold-up on a Monopoly-owned Network," Department of Economics, The Pennsylvania State University, State College, September 2004; Missouri Economics Conference, Columbia, April 2004; Conference on the Economics of Payments, Federal Reserve Bank of Atlanta, April 2004.

Commencement Address: The Limits of Intellectual Honesty. Graduate School, University of Northern Colorado, Greeley, December 2006.

Commentary on Economic Conditions. Colorado Association of Commerce and Industry, Denver, October 2006; University of Northern Colorado's 2006-2007 Business Plus Speaker Series, Greeley, Colorado, October 2006; Tower Club Luncheon, Denver, Colorado, October 2006; Pueblo Rotary Club, Pueblo, Colorado, August 2006; St. Joseph Hospital Foundation, Denver, Colorado, August 2006; Denver Association of Business Economists, University of Colorado - Denver, June 2006; Daniels College of Business, University of Denver, April 2006; Federal Reserve Bank of Kansas City Regulatory Forums, Casper Wyoming, Denver, Colorado, Montrose, Colorado, April 2006; Colorado Hedge Fund Roundtable, Denver, April 2006.

Regional Analysis at the Federal Reserve. School of Business, University of Northern Colorado, Greeley, October 2006; The Bard Center for Entrepreneurship, University of Colorado – Denver, May 2006.

Innovation and the Regional Economy. Federal Reserve Bank of Kansas City Economic Forums, Albuquerque, New Mexico, October 2006; Cheyenne and Casper, Wyoming, September 2006.

Where Does Innovation Happen. Rocky Mountain Biowest Conference, Denver, August 2006.

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Creating Knowledge Regions. European Union Association of Regional Development Agencies, Madeira, Portugal, May 2006.

The Importance of Asset Building. United Way National Leadership Conference, Young Americans Bank, Denver, May 2006.

Economic Outlook – Wyoming in Perspective. Wyoming Business Alliance / Wyoming Heritage Foundation, Casper, Wyoming, May 2006.

Technological Maturity and the Location of Innovation: Implications for Colorado. South Metro Denver Chamber of Commerce, December 2005.

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2004; Department of Economics, University of Texas-Arlington, October 2004; Conference of the Western Economic Association International, Vancouver, British Columbia, July 2004.

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On the Nature and Importance of Spillovers from Innovative Activity. Omicron Delta Epsilon Invited Graduate Student Papers Session, Meeting of the Allied Social Sciences Association, New York, January 1999.

PROFESSIONAL SERVICE

Referee:

- *Research Policy*
- *American Economic Review*.
- Bank of England working paper series.
- *Economic and Social Review*.
- *Journal of Regional Science*.
- *Review of Network Economics*.
- *Review of Regional Studies*.
- World Bank, Global Development Network Research Grant Competition.

Discussant:

- North American Meetings of the Regional Science Association International, Toronto, Canada, November 2006; Seattle, November 2004; San Juan, Puerto Rico, November 2002.
- Conference of the Western Economic Association International, San Francisco, July 2005; Vancouver, Canada, July 2004.
- Federal Reserve System Committee on Applied Microeconomics, New York, June 2002.
- Federal Reserve System Committee on Macroeconomic Analysis, Philadelphia, June 2001; Boston, November 2000.
- Omicron Delta Epsilon Invited Graduate Student Papers Session, Meeting of the Allied Social Sciences Association, Boston, January 2000.

OTHER SERVICE ACTIVITY

Chair, Energy Business and Finance Program Industrial and Professional Advisory Council, College of Earth and Mineral Sciences, The Pennsylvania State University, 2012-present.

Member, Renewable Energy and Sustainable Technologies Graduate Program Advisory Board, The Pennsylvania State University, 2011-present.

Member, President's Advisory Council, Denver Museum of Nature and Science, 2006-present.

Director, Graduates of Earth and Mineral Sciences Alumni Society, The Pennsylvania State University, 2004-2010.

Instructor, "Anyone Can Cook!" Steele Elementary School Out-of-the-Box elective program, Denver Public Schools, 2008-2009.

Advisor, The Alliance for Earth Sciences, Engineering, and Development in Africa, College of Earth and Mineral Sciences, The Pennsylvania State University, 2005-present.

Director, Colorado Council on Economic Education, 2006-2007.

Judge, American Royal Open Barbeque Contest, Kansas City, 2005.

Judge, American Royal Barbeque Sauce, Baste, and Rub Contest, Kansas City, 2003.

Junior Achievement Economics Course Consultant and Company Advisor, McMain Magnet High School, New Orleans, 1990, 1993, 1994.

Director, Shell Employees of New Orleans Federal Credit Union, 1991-1993.

EXHIBIT D

MAY 7, 2013 LETTER FROM INDUSTRY

May 7, 2013

George Gerstle
Boulder County Transportation Director
ggestle@bouldercounty.org

Kim Sanchez
Boulder County Planning Division Manager
ksanchez@bouldercounty.org

Ben Doyle
Assistant Boulder County Attorney
bdoyle@bouldercounty.org

Dear George, Ben, and Kim:

This letter supplements our letter of April 15, 2013, and offers additional input from Encana Oil & Gas (USA), Inc. ("Encana") and Noble Energy, Inc. ("Noble") concerning equitable and legally defensible methods to mitigate the potential impact of oil and gas development on the public transportation system in Boulder County.

As Dr. Orlando explained in his April 12, 2013 report, during the first decade of operation each new oil and gas well will generate about $533,000 in property tax revenues to Boulder County schools, about $288,000 in property tax revenues to Boulder County Government, about $117,000 in property tax revenues to Boulder County municipalities, and about $70,300 in property tax revenues to other Boulder County tax districts.

Ben Doyle has explained that C.R.S. § 30-25-106(1) would prohibit Boulder County from using its share of these property tax revenues to fund road improvements and maintenance. But even if Boulder County could not use its additional property tax revenues for this purpose, the substantial increase in such revenues may free up other funds for road projects. We also understand that other local governments use various other funding sources for this purpose, including the road and bridge mill levy, direct distribution of severance taxes, payments in lieu of taxes ("PILT"), and Energy and Mineral Impact Assistance Program grants. Here, the first two of these sources, the road and bridge mill levy and the direct distribution of severance taxes, appear to approximate the projected cost of road improvements and maintenance. In addition, C.R.S. § 39-29-107.5 encourages operators like Encana and Noble to contribute funding for road projects by providing them with a credit against their severance taxes for such contributions; this effectively allows the County and operators to redirect severance taxes to mitigate local road impacts if additional funding for this purpose is necessary. These options are summarized below, together with additional information on the ability of operators to install pipelines within road rights of way and thereby reduce the number of truck trips associated with oil and gas development.

Sources of Funding for Road Improvements

Although Encana and Noble have not sought to identify all sources of funding that would be available for road projects in Boulder County, they have identified several sources that are used by other local governments and would approximate the projected cost of such work with the assumptions set forth in Dr. Orlando's April 12, 2013 report.

Road and Bridge Mill Levy. We understand that Boulder County assesses a special mill levy of 0.186 for road and bridge projects. To determine the amount of such tax revenues per well, Encana and Noble asked Dr. Orlando to analyze this issue. Dr. Orlando determined that the road and bridge mill levy would generate cumulative total tax payments of $2,480 per well and that the present value of these payments would be $2,050 per well. Letter from Michael J. Orlando to Jamie Jost & Dave Neslin at 2 (May 3, 2013) (enclosed). If the well is located within a municipality, then half of this total may need to be shared with the municipality under C.R.S. § 43-2-202(2). Therefore, this source should generate approximately $1,025 to $2,050 in real payments per well.

Direct Distribution of Severance Taxes. In addition to generating additional property tax revenues, each new well will also generate additional state severance tax revenues, and the State will directly distribute a portion of these tax revenues to Boulder County. We understand that a number of local governments use their share of such revenues to fund road and bridge projects. To determine the amount of such revenues that would be available to Boulder County for this purpose, Encana and Noble asked Dr. Orlando to analyze this issue as well.

Dr. Orlando explains that "[b]ecause property taxes are based on prior-year production values, wells in their first year of production do not have a creditable property tax liability with which to offset a severance tax liability." *Id.* at 2. Therefore, during their first year of production, wells "produce a severance tax cash flow commensurate with the state severance tax rate." *Id.* Using conservative assumptions, he calculates that during the first year of production a "typical DJ Niobrara well will generate $125k of severance tax revenue that will not be eligible for property tax credit." *Id.* at 3. Of this amount, "19k" would be "directly distributed" by the State to the County, and "$44k" would be allocated by the State to the "Energy and Mineral Impact Assistance Fund Grant program." *Id.* The $19,000 in direct distribution per well would be available to the County for road and bridge projects and should not be subject to municipal apportionment under C.R.S. § 43-2-202(2). The $44,000 allocated to the Energy and Mineral Impact Assistance Fund Grant Program would be available to the County for road and bridge projects through Program grants issued by the Department of Local Affairs ("DOLA") as discussed below.

PILT. PILT are federal payments to local governments that help to offset losses in property taxes due to nontaxable federal lands within their boundaries. *See* 31 U.S.C. §§ 6901-6907; 43 C.F.R. Part 44. We understand that other local governments in Colorado use PILT payments for road and bridge projects, and that such payments are not considered subject to municipal apportionment under C.R.S. § 43-2-202(2). According to the Department of Interior website, Boulder County has 164,404 acres of federal land and received $345,639 in PILT payments during the 2012 fiscal year. To the extent that any PILT payments are not currently used to fund road and bridge projects, they could be redirected to that purpose and any loss of existing funding for other programs could be offset with the additional property tax revenues generated by each new well.

Energy and Mineral Impact Assistance Program Grants. The Energy and Mineral Impact Assistance Program assists local governments that are impacted by the development of energy and minerals. The Program is funded by part of the state severance tax and by part of the state's share of federal mineral royalties. Local governments may apply to DOLA for grants to mitigate energy and mineral impacts, and such grants may be used for road improvements. Indeed, during the 2012 fiscal year, grants were awarded for an interchange in the Town of Parachute, an overpass in Mesa County, and a bypass around the City of Delta. *See* Colorado Department of Local Affairs, Local Government Energy and Assistance Program Thirty-sixth Annual Report at 13-18 (Jan. 2013), *available at* http://www.colorado.gov/cs/Satellite/DOLA-Main/CBON/1251594722445. DOLA expects to award about $60 million in grants this calendar year. Although the road and bridge mill levy and the direct distribution of severance taxes by themselves should approximate the projected road mitigation costs with the assumptions set forth in Dr. Orlando's report, the Energy and Mineral Impact Assistance Program could provide an additional source of funding for this purpose.

Impact Assistance Contributions

Another approach to mitigating transportation impacts would be through operator contributions. C.R.S. § 39-29-107.5 encourages such contributions by creating a severance tax credit for the contribution amount provided that the contribution is made prior to severance of the minerals, assists in solving local impact problems, is the subject of an agreement with the local government, and is approved by the DOLA Director. It specifically states that such contributions include payments "for use in planning . . . , construction, or expansion of public facilities, including . . . county . . . roads . . . , which are deemed to be necessitated by the initiation of a new operation or increase in production of an existing operation." *Id.* at § 39-29-107.5(2)(a). This could enable Boulder County and the operators to redirect to local transportation needs a portion of the $106,000 in additional severance tax revenues that the State would receive for each new well ($125,000 in revenue less $19,000 in direct distribution).

This statute was originally enacted "to encourage local governments and mineral producers to embark on public improvements early in the mineral project development process." DOLA, Severance Tax Credit Statute: Study Group HB-08-1084 Report at 2 (Jan. 31, 2009). In addition, "the process of developing the credit agreements enables local governments to build partnerships with mineral producers in the planning and financing of needed public infrastructure." *Id.* at 4. Although the statute has not been used in recent years, 40 such agreements were approved during the 1980s and 1990s. *Id.* This could provide another tool for collaboratively addressing potential transportation impacts.

Pipeline Installation

Through the use of existing public rights of way and condemnation authority, oil and gas companies routinely install pipelines and pipeline networks as a means to efficiently service oil and gas production facilities. In the case of water, these pipeline systems can substantially reduce truck traffic by eliminating the need to use trucks to deliver hydraulic fracturing water as discussed in Dr. Orlando's April 12, 2013 report.

Oil and gas companies and other industries routinely install pipelines along public rights of way for transmission purposes, including telephone lines, electric lines, and gas and water pipelines. Weld County, Colorado, for example, has an exhaustive list of standard provisions that govern a right of way permit and routinely approves right of way permits to enable oil and gas development to proceed efficiently and with a minimal environmental footprint. Boulder County also has a right of way permit process that can likewise enable installation of water pipelines to substantially reduce truck traffic in the county.

Oil and gas companies also have authority in Colorado to condemn private land and county-owned property for the installation of pipelines, including water pipelines. *See* C.R.S. §§ 2-4-401(8), 38-2-101, & 38-5-105. While the Colorado Supreme Court limited condemnation authority for the installation of petroleum pipelines, *see Larson v. Sinclair Transp. Co.*, 284 P.3d 42 (Colo. 2012), the decision did not curtail the broad authority of companies to install other types of pipelines, including water pipelines.

The use of existing public rights of way and condemnation authority for the installation of water pipelines help substantiate the assumption in Dr. Orlando's April 12, 2013 report that hydraulic fracturing water can be piped to well sites in many situations. As Dr. Orlando's report explains, Encana's historical experience in the DJ-Niobrara is that it is technically and commercially feasible to use such pipelines for approximately 90 percent of well pad locations. As this experience indicates, however, pipelines may not be feasible for this purpose in certain situations. Furthermore, generally it is infeasible to pipe water from a location to a disposal facility due to the lack of nearby disposal facilities.

*   *   *

Thank you for considering this additional information. If we can answer any questions regarding this letter, please do not hesitate to contact us. We also remain available to meet with you at your convenience regarding this subject.

Respectfully,

Jamie Jost
Elizabeth Gallaway
for
Beatty & Wozniak

Counsel for EnCana

Dave Neslin
R. Kirk Mueller
for
Davis Graham & Stubbs LLP

Counsel for Noble

EXHIBIT D.1

ATTACHMENT TO THE MAY 7 LETTER

ea
Economic Advisors, Inc.
498 S. High St.
Denver CO 80209

Date: May 3, 2013

Jamie Jost
Beatty & Wozniak, P.C.
216 16th St., Suite 1100
Denver CO 80202

Dave Neslin
Davis Graham & Stubbs LLP
1550 Seventeenth St., Suite 500
Denver CO 80202

Subject: Addendum to Boulder County Property Tax and Roadway Impacts from Oil and Gas Activity study dated April 12, 2013

Jamie, Dave;

This memorandum summarizes the expected value of Boulder County Road and Bridge Fund revenue and State severance tax revenue associated with oil and gas well drilling, and the magnitude of that revenue in relation to potential roadway impacts associated with oil and gas development activity in Boulder County.

<u>Background</u>:

Recall that the April 12 Boulder County Property Tax and Roadway Impacts report indicated that each horizontal well drilled in Boulder County is expected to generate $374k of property tax revenue from the first year of production, and total nominal property tax revenue of $1,150k (equivalent to a present value of $948k at a 3 percent discount rate.)[1] Roughly 28.6 percent of these receipts are allocated to Boulder County government, with the remainder of property taxes allocated to schools, cities and towns, and other tax districts within Boulder County. These property tax revenues compare to estimated roadway impact costs per well of $18k to $35k[2] (equivalent to a present value of $15k to $32k at a 3 percent discount rate).[3]

On April 30, 2012, Dave and I discussed concerns raised by Boulder County officials that although per-well property tax payments clearly exceed the magnitude of roadway impact costs estimates, county officials may not have sufficient discretion to allocate those funds

[1] Economic Advisors, Inc. Evaluation of Boulder County Property Tax and Roadway Impacts from Oil and Gas Activity, April 12, 2013, Table 4.
[2] Ibid, Table 13.
[3] Ibid, Table 15.

to roadway-related expenditures. Consequently, Dave requested quantification of those tax revenue streams that may be most administratively appropriate for use to mitigate roadway impact costs. For the purpose of this memorandum, those categories of tax revenue streams include the Road and Bridge Fund portion of Boulder County property taxes, and the share of state severance taxes that flow back to local communities through direct distribution and the Energy and Mineral Impact Assistance Fund.

Property (County) taxes:

Recall that for each well, property tax payments to the county are equivalent to an 86.1 average mill levy.[4] The Boulder County Road and Bridge Fund assesses a mill levy of 0.186.[5] Thus, on average, 0.216 percent of county property tax payments are received by the Road & Bridge Fund. Table 1 summarizes property taxes paid to the Boulder County:

Table 1

Single-well Property Tax Flows to Boulder County

	year 4 payments (first year of payment)	Total cumulative payments	Real (pv 3%) payments
Total to all Boulder County tax districts	$374k	$1,150k	$948k
Portion of total to Road & Bridge Fund	$0.800k	$2.48k	$2.05k

Severance (State) taxes:

Production is assessed a severance tax of approximately 5%, which is eligible for a credit of 87.5 percent of county property tax payments. Because property taxes are based on prior-year production values, wells in their first year of production do not have a creditable property tax liability with which to offset a severance tax liability. Oil and gas wells in their first year of production, therefore, produce a severance tax cash flow commensurate with the state severance tax rate. Subsequent year severance tax cash flows reflect the severance tax liability net of property taxes due in each of those years. Thus, a calculation of each well's first year severance tax liability represents a minimum estimate of total cumulative severance tax payments for each well.

Half of all state severance tax payments are allocated to Local Impact Fund. Of this share, 30 percent are directly distributed to local governments according to a

[4] Ibid, p. 7.

[5] Ibid.

formula intended to allocate funds proportional to severance-tax-generating-industry impacts. The remaining 70 percent of funds are allocated though the Energy and Mineral Impact Assistance Fund Grant Program. Thus, 15 percent[6] of per-well severance tax payments represents an estimate of severance taxes flowing to localities for their discretionary use. In addition, 35 percent of per-well severance tax payments represents an estimate of severance taxes flowing to a pool for which localities are eligible through grant applications.[7]

A typical DJ-Niobrara well is estimated to have an average annual first-year production rate 228 BOEPD, and generate revenue at approximately $60 per BOE.[8] Assuming new wells are in production for, on average, 6 months of their year of completion, and severance rates are 5 percent, then typical DJ Niobrara well will generate $125k of severance tax revenue that will not be eligible for property tax credit. Thus, in the first year of production,

- each well generates $125k x 0.15 = $19k in severance tax payments that are directly distributed back to localities.
- each well generates $125k x 0.35 = $44k in severance tax payments to the state Energy and Mineral Impact Assistance Fund Grant program.

In addition to the Road and Bridge levy estimates provided in Table 1, these discretionary severance tax revenue streams may be compared to the per-well roadway impact cost values presented in Table 15 of the April 12 report entitled "Evaluation of Boulder County Property Tax and Roadway Impacts from Oil and Gas Activity."

Michael J. Orlando

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[6] I.e. Direct Distribution of 30 percent of the 50 percent of funds to the Local Impact Fund implies 15 percent of total severance taxes are directly distributed to local communities, per Colorado Department of Local Affairs.

[7] I.e. Energy and Mineral Impact Assistance Fund Grant Program allocation of the 70 percent of the 50 percent of funds to the Local Impact Fund suggests 35 percent of total severance taxes is a justifiable target value for grant applications from communities host to wells generating this revenue. To be sure, however, well-host communities are not necessarily guaranteed this revenue; however, they may also apply for grants that exceed this revenue.

[8] Economic Advisors, Inc. Evaluation of Boulder County Property Tax and Roadway Impacts from Oil and Gas Activity, April 12, 2013, p. 9.

EXHIBIT E

Amendments to transportation regulations in Boulder County Land Use Code, Article 12

12-500 General Application Submittal Requirements for Expedited DPR and Standard DPR

N. Transportation Plan. The Applicant shall submit a report establishing compliance with the transportation standards in Section 12-602(D) (for expedited DPR applications) or Section 12-703(K) (for standard DPR applications) and which also contains the following information:

1. Map indicating proposed trip routes for all traffic serving the oil and gas operation during all phases of well development and operations.
2. For each segment of the proposed route in Boulder County, the types, sizes, weight, number of axles, volumes, and frequencies (daily, weekly, total) and timing (times of day) of all vehicles to be used for the proposed oil and gas operation must be indicated.
3. Operational measures to minimize impacts to the public including, but not limited to, time of day, time of week, vehicle fuel and emissions reduction technology, noise minimization, and traffic control safety measures.
4. Maintenance practices on the proposed route during pad construction, drilling, and completion activities, including without limitation, grading of unpaved roads, dust suppression, vehicle cleaning necessary to minimize re-entrained dust from adjacent roads, snow and ice management, sweeping of paved roads/shoulders, pothole patching, repaving, crack sealing, and chip sealing necessary to maintain an adequate surface of paved roads along the proposed route.
5. Any physical infrastructure improvements the Applicant believes may be necessitated by the proposed oil and gas operation to ensure public safety for all modes of travel along travel routes to and from the site.

12-602.D and 12-703.K (changes will be same to Expedited and Standard sections)

Transportation, Roads, Access Standards, and Fees.

1. The Applicant's Transportation Plan must be designed and implemented in its entirety to ensure public safety for all modes of travel along travel routes to and from the site and maintain quality of life for other users of the county transportation system, adjacent residents, and affected property owners.

2. The Transportation Department may require the Applicant use a particular route for some or all of the pad construction, drilling, and completion phases of the oil and gas operation.

3. Operational measures included in the Applicant's transportation plan shall be designed to minimize impacts to the public.

4. Maintenance practices on the proposed route during pad construction, drilling, and completion activities must be designed and implemented to adequately minimize impacts of the oil and gas operation by: ensuring public safety for all modes of travel; maintaining quality of life for other users of the county transportation system, adjacent residents, and affected property owners; minimizing impacts on air quality; and protecting the integrity of county transportation infrastructure.

5. Unless traffic safety, visual or noise concerns, or other adverse surface impacts clearly dictate otherwise, existing private roads on or near the site of the proposed oil and gas operation shall be used in order to minimize land disturbance.

6. Access roads on the site and access points to public roads shall be built and maintained in accordance with the engineering specifications and access road standards defined in the Boulder County Multimodal Transportation Standards. With the exception of Article 4 concerning transportation system impact analysis, all of the Boulder County Multimodal Transportation Standards apply to oil and gas development unless the Transportation Director determines a particular section is inapplicable to oil and gas based on the particular facts and circumstances.

7. Prior to issuance of a Development Plan Review Construction Permit, the Transportation Department shall ensure that:

    i. All applicable permits shall be obtained including without limitation:

        1. access permits
        2. oversize/overweight permits
        3. right of way construction permits

    ii. All applicable fees have been paid including without limitation:

        1. access permit, oversize/overweight permit, and right of way construction permit fees
        2. any impact fees adopted by the Board of County Commissioners via separate resolution intended to mitigate the cumulative impacts of oil and gas truck traffic on the county transportation system.

    iii. The Applicant has updated its Transportation Plan in accordance with any conditions of approval placed on the DPR approval.

8. Oil and gas operations must minimize impacts to the physical infrastructure of the county transportation system. In some cases, the addition of or improvements to physical infrastructure may be necessitated by the proposed oil and gas operation. Taking into account the information submitted by the Applicant under 12-500.N.5, the County Transportation Department will make the final determination of the necessary transportation system infrastructure improvements and associated costs. Any such physical infrastructure improvements required by the County Transportation Department must be (a) necessary to ensure public safety for all modes of travel along travel routes to and from the site; (b) directly attributable to the proposed oil and gas operation; and (c) based upon application of the standards defined in the Boulder County Multimodal Transportation Standards. Any costs to improve county transportation system infrastructure necessitated by the proposed oil and gas operation shall be the responsibility of the Applicant. The County shall perform the work or arrange for it to be performed at the Applicant's expense prior to commencement of the applicable phase of oil and gas operations. No Applicant shall be required to provide any site specific dedication or improvement to meet the same need for capital facilities for which an impact fee or other similar development charge is imposed.

9. The Applicant may request the Director place a DPR application on hold in order to discuss alternate routes, alternate approaches to impact mitigation, or provide additional information to the Transportation Department. The Applicant may also request the Director reclassify an Expedited DPR application as a Standard DPR application in accordance with 12-400.F.

10. Should an Applicant's oil and gas operations result in any damage to the county transportation system that requires immediate repair to ensure public safety, the Applicant must immediately report such damage to the Transportation Department. Necessary repairs and associated costs shall be determined by the Transportation Department, and such repair costs shall be the responsibility of the Applicant. The County shall perform the work or arrange for it to be performed as soon as possible. By way of example only, repairs might include replacing signage or traffic control devices damaged by a large truck attempting to navigate a tight corner, replacing failing culverts, sweeping tracked mud from the road, or fixing potholes.