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Measuring the Economic and Energy Impacts of Proposals to Regulate Hydraulic Fracturing

Task 1 Report

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Introduction

The American Petroleum Institute (API) has engaged IHS Global Insight to perform an independent study to determine the potential impact on future hydrocarbon production and on U.S. economic performance of proposed policy changes pertaining to hydraulic stimulation or fracturing of oil and gas wells. The study was prepared by IHS Global Insight using its own data, information and analysis. IHS Inc., IHS Global Insight's parent company, holds an extensive well and production database that provided the basis for assessing national and state-level oil and gas production under different scenarios. IHS Global Insight prepared the economic assessment using its U.S. Macroeconomic and state economic models.

The study investigated three scenarios:

- Implementation of regulations similar to those used by EPA to regulate the UIC program.
- Restrictions on the use of certain fluids that are being highlighted by policymakers as having the potential to impact underground aquifers, and
- Elimination of hydraulic fracturing.

This report highlights and summarizes key observations and conclusions and also documents the methodologies and assumptions used to produce the forecast scenarios.

Measuring the Impact on Oil and Gas Production

Part 1 – Study Results

This study determines the effects of regulating hydraulic fracturing on future hydrocarbon production by generating production forecasts for **three** policy scenarios. The results from these three scenarios are compared with production levels in a reference case, which is based on existing regulations, and with the production levels that would come from existing wells alone ("no drilling"). The results show that the effects of any policy will be substantial in the short-term and will increase in the long-term due to the increasing importance of unconventional plays in natural gas production. These effects will generally be negative, particularly for natural gas, with the potential for higher prices, more imports and negative economic impacts from reduced domestic drilling.

The results of the analysis are summarized below.

- **Elimination of Hydraulic Fracturing (No Frac) Scenario:** In five years, if fracturing were eliminated, there would be a decrease of nearly 79% in wells completed. As a result, the country would experience by 2014, a 17% reduction in oil production and a 45% reduction in natural gas production, relative to the reference case, with declines continuing during the forecast period resulting in a 23% reduction in oil production and a 57% decrease in gas production from the reference case by 2018. Due to the country's increasing reliance on unconventional resources, where over 95% of wells are routinely treated using fracturing, the impact on production would be permanent and severe.

- **Fluid Restrictions Scenario:** By 2014, a change in fluid options for hydraulic fracturing operations would reduce natural gas production by 4.4 tcf or 22%, falling from 20.4 tcf in the reference case to 16 tcf. Similarly, crude oil production would decrease by 0.4 million barrels per day or 8% while wellhead revenue would decrease by 48 billion dollars or 15%.

- **UIC Compliance Scenario**. Implementation of these regulations on oil and gas drilling would result in a 20.5% reduction of new wells drilled over a five year period and a 10% loss of natural gas production within five years. Given the tenuous balance between supply and demand, a loss of 2.1 tcf (6 bcf/day) would result in more imports of pipeline natural gas and LNG.

The No Drilling or PDP Scenario. In addition to comparing the three sets of policy-scenario results with the reference case, an additional point of comparison is provided, on the low side, by the volumes that would be produced only from remaining proved reserves from currently producing wells over their lifetime. This is referred to as the "No Drilling or PDP"scenario.

Figure 1. *Natural Gas Production Decrease from Restrictions on Hydraulic Fracturing*

Change in Natural Gas Production
(Trillion Cubic Feet)

	2008	2014	Change From Reference Change	Percent Change
Global Insight Reference	20.9	20.4		
UIC Compliance		18.3	-2.1	-10%
Fluid Change		16	-4.4	-22%
No Fracturing		11.3	-9.1	-45%
No Drilling		7.2	-13.2	-65%

Figure 2. *Crude Oil Production Decrease from Restrictions on Hydraulic Fracturing*

Change in Crude Oil Production
(Million Barrels per Day)

	2008	2014	Change From Reference Change	Percent Change
Global Insight Reference	4.91	4.87		
UIC Compliance		4.66	-0.21	-4%
Fluid Change		4.48	-0.39	-8%
No Fracturing		4.02	-0.85	-17%
No Drilling		2.05	-2.82	-58%

Figure 3. *Wellhead Revenue Decrease from Restrictions on Hydraulic Fracturing*

Change in Wellhead Revenue
(Billion dollars)

	2008	2014	Change From Reference Change	Percent Change
Global Insight Reference	349	330		
UIC Compliance		302	-28	-8%
Fluid Change		282	-48	-15%
No Fracturing*		306	-24	-7%
No Drilling		128	-202	-61%

*** Natural Gas Prices Increase to the Level of Crude Oil Prices**

Figure 4. Gas Production Forecast by Scenario

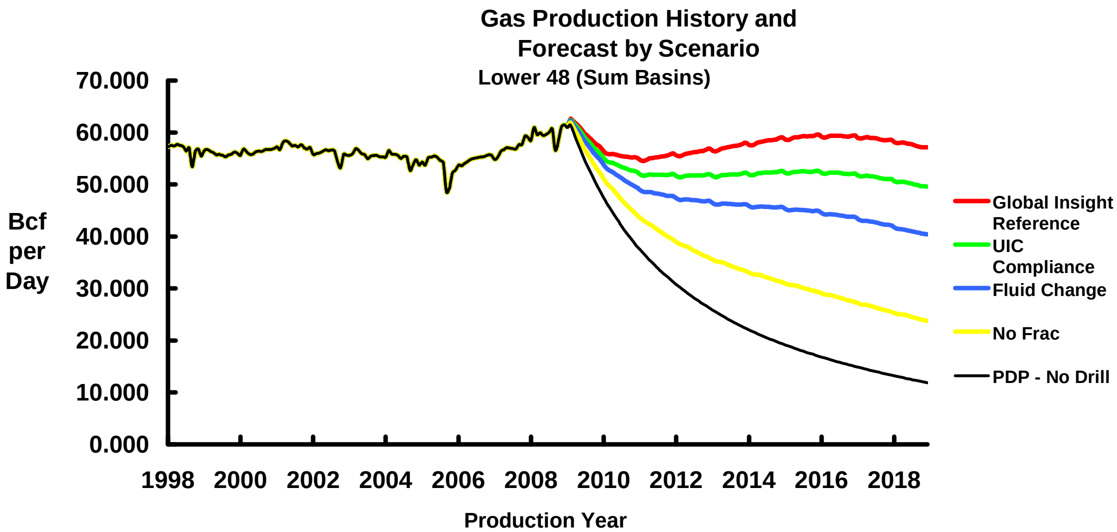
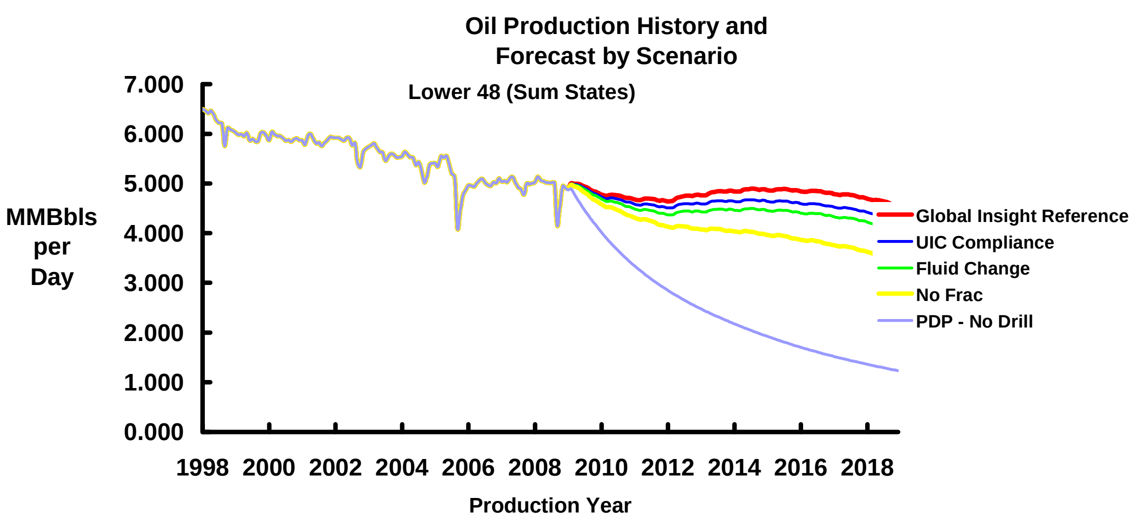


Figure 5. Oil Production Forecast by Scenario



Part 2 – Methods and Assumptions

The primary source of data for this study is the IHS U.S. well and production database, supplemented by internal and publicly available reports, collaboration with other parties and general industry intelligence. IHS has also developed tools and methodologies to use this data to build the forecast scenarios. The IHS U.S. well and production database is a well-known petroleum industry database that has provided detailed well and production data and information for many years. It is based on a combination of databases and services that were originally owned by Petroleum Information Corp. and Dwights EnergyData Inc., which were acquired and further developed by IHS. IHS regularly uses the database to provide consulting services to clients; the methodologies used to project volumes at given price and policy levels are well-established methodologies within IHS.

Forecasts are developed at the play level and are then aggregated to the basin level. Basin level forecasts are allocated to their state or states based on the basin level historical production within each state. State level forecasts are rolled up to the national level. A description of the methods and assumptions used to create the forecast scenarios is set forth below:

Forecast Methodology

Play determination: Each producing well in the U.S. well and production databases is assigned to a geologic basin, field and producing formation. Using industry intelligence and expertise within the company, wells are assigned to plays based on producing formation, resource type and where applicable, basin and county of location. Other well-level attributes also include monthly and cumulative production values of produced gas and liquids, drilling and completion information including treatment fluids and types, and test data. Well level production is summed to the play level and applicable treatment attributes are summed or averaged to the play level as well.

Production Forecasts: Reserves at the play level are classified as follows: Developed (PDP) - Remaining proved reserves from currently producing wells; and Yet to Develop or Probable Undeveloped (PUD) – Remaining reserves which are projected to be produced from wells to be drilled or zones to be completed from existing fields. Production values reflect wellhead gas or wet gas. Since PDP production does not require the drilling of new wells, this portion of future production is included unchanged in each of the forecast scenarios. In other words, capital investments are already sunk, and there is no reason for production from PDP sources to be impacted. Each scenario has its own variation of forecasted PUD production.

Production from currently producing wells: Using monthly oil and gas production volumes, remaining developed reserves are determined by projecting separate declines through the year 2018 for each vintage year of production wells dating between 1995 and 2008. A single decline is also generated for all pre-1995 vintage wells. For each vintage year, the data show that the initial declines are much steeper and thereafter decrease with time; therefore, hyperbolic to exponential decline rates are generated for each vintage year to determine the remaining reserve for that year. The historical and forecasted production for each vintage year is summed to produce the final forecast. Historical production data ends at the end of 2008 and the forecast begins at the beginning of 2009.

Production from projected wells: The production data from recent years (2007-2008) is used to create a type curve which is then multiplied by the number of wells projected to be drilled each year in order to forecast future production. This type curve represents well performance which may either trend up or down in the future by using a productivity trend factor based on increases or decreases in recent type curve performance. Also factored into the forecasted production are changes in performance described within each forecast scenario. The assumptions used to determine the number of new wells are also described within each scenario below.

IHS Reference Baseline Forecast

In order to generate a play-level forecast, IHS uses the type curve to generate a per-well estimated ultimate reserve (EUR). Methods and tools developed by IHS integrate this EUR with drilling costs and other data to calculate a marginal cost of supply or unit cost expressed in dollars per thousand cubic feet ($/mcf) or dollars per barrel ($/bbl). Components of unit cost include capital expenditures, operating costs, royalty and severance and an additional amount needed to generate a 10% rate of return. Mid-2008 costs are used to determine the unit costs. Using the unit costs and a distribution of performance for wells drilled within the past two years, the number of wells that can be drilled economically at a given forecast price can be determined. The forecast number of wells at a given price generates the production forecast.

The price assumptions used in this study were provided by IHS Global Insight and are shown below. (IHS Global Insight publishes long-term U.S. oil and gas price projections twice per year in its U.S. Energy Outlook publications and short-term prices monthly in its Global Petroleum Monthly and Natural Gas Monthly. The semi-annual long-term prices are merged with the updated monthly price projections when needed for such applications as inputs into IHS Global Insight's U.S. economic forecasts and for consulting engagements.)

Figure 6. IHS Global Insight's Assumptions of Crude Oil and Natural Gas Prices (real and nominal dollars)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Real Prices in 2008 dollars											
Crude Oil Price ($2008/bbl)	99.54	44.75	53.58	59.26	70.93	80.33	83.32	85.44	87.40	89.39	91.38
Henry Hub Price($2008/mcf)	9.03	4.41	6.11	6.87	7.29	7.78	8.33	8.53	8.67	8.63	8.64
Nominal Prices											
Crude Oil Price ($/bbl)	99.54	45.12	54.46	61.00	74.00	85.38	90.46	94.72	98.95	103.25	107.64
Henry Hub Price($/mcf)	9.03	4.45	6.21	7.07	7.61	8.27	9.05	9.46	9.82	9.97	10.18

The actual natural gas price assumptions used to forecast production for each play are adjusted to reflect the differential to the Henry Hub. For example prices used for plays in the Appalachian Basin are 4.7% higher than those in North Louisiana, reflecting the recent differential. Oil prices were adjusted slightly to reflect historical differentials to West Texas Intermediate. The intent is to reflect average differences in the oil quality, such as gravity. All price assumptions used to generate the production scenarios are contained in "Appendix 1 – Price Assumptions." No escalation has been applied to unit costs such as drilling or operating expense – which are therefore expressed in real terms. However, price assumptions are also expressed in real terms in the assessment of production.

Most plays have enough historical data to constrain or limit variation in the production scenarios; however, lack of historical data in the Haynesville and Marcellus Shales require some interpretative license to project a credible production scenario. Time will tell the exact contribution of these plays so current interpretations can be quite broad. While optimism remains high, neither play has an established core area. Thus, ultimate production performance is still in question, and infrastructure questions still remain. Production projections are therefore somewhat conservative for these geological areas. However, given that these plays require extensive amounts of hydraulic fracturing, more aggressive production forecasts here would only amplify the effect of any fracturing restrictions.

It is the view of IHS that overall U.S. production will remain at less than 60 billion cubic feet per day (bcf/day), given the long-term natural gas price assumptions. A significant increase in domestic production would not be consistent with the price assumptions. Imports are assumed to fill any gap between production and demand.

UIC Compliance Scenario

UIC compliance regulations are summarized in a report titled "Potential Economic and Energy Supply Impacts of Proposals to Modify Federal Environmental Laws and Applicable to the U.S. Oil and Gas Exploration and Production Industry" prepared for the U.S. Department of Energy Office of Fossil Energy in 2009 by Advanced Resources International, Incorporated. Contained in that report, the table – Estimated Compliance Costs for Regulation of Hydraulic Fracturing Compliance Cost Calculations – was used as a starting point for determining the overall cost increases for UIC compliance. The data used are for 1999.

IHS has updated these costs to reflect the landscape of 2008 by applying cost increase factors and taking into account changes in fracture monitoring that have been implemented since 1999,. The original table from the EIA report and our updated revisions are attached as "Appendix 3: UIC compliance costs."

The effect of UIC compliance is two-fold, namely to increase cost and to delay well completion. Added costs per well of $109,833 for non-shale plays and $47,333 per well for shale plays have been calculated. These added costs raise the economic threshold or EUR at which a play can be developed, thus lowering the number of wells that can be drilled economically. Experience suggests that there will be a reduction in the number of wells completed each year due to increased regulation and its impact on the additional time needed to file permits, push-back of drilling schedules due to higher costs, increased chance of litigation, injunction or other delay tactics used by opposing groups and availability of fracturing monitoring services.

Coal-bed methane development in the Powder River Basin serves as a historical analogue which illustrates a large reduction in well counts due to increased regulation regarding water disposal. As shown in Figure 7, development progressed at a rapid rate until this issue and other related environmental issues caused a severe delay in the permitting process. Permit totals which were 4905 for 2001, dropped to 2060 the following year. Consequently, the number of completed wells which had been rising steadily was suddenly reduced from 3442 in 2002 to 2157 the following year, a decrease of nearly 38%, an even larger reduction than the 20% assumed in this study. Thereafter, drilling remained essentially flat at the reduced levels with a slight up-tick to 2723 completed wells in 2006. The figure also shows production flattening out the following year due to the diminished drilling.

The results of this scenario are shown in Figure 8.

Figure 7. Comparison of Powder River Basin Drilling and Permitting

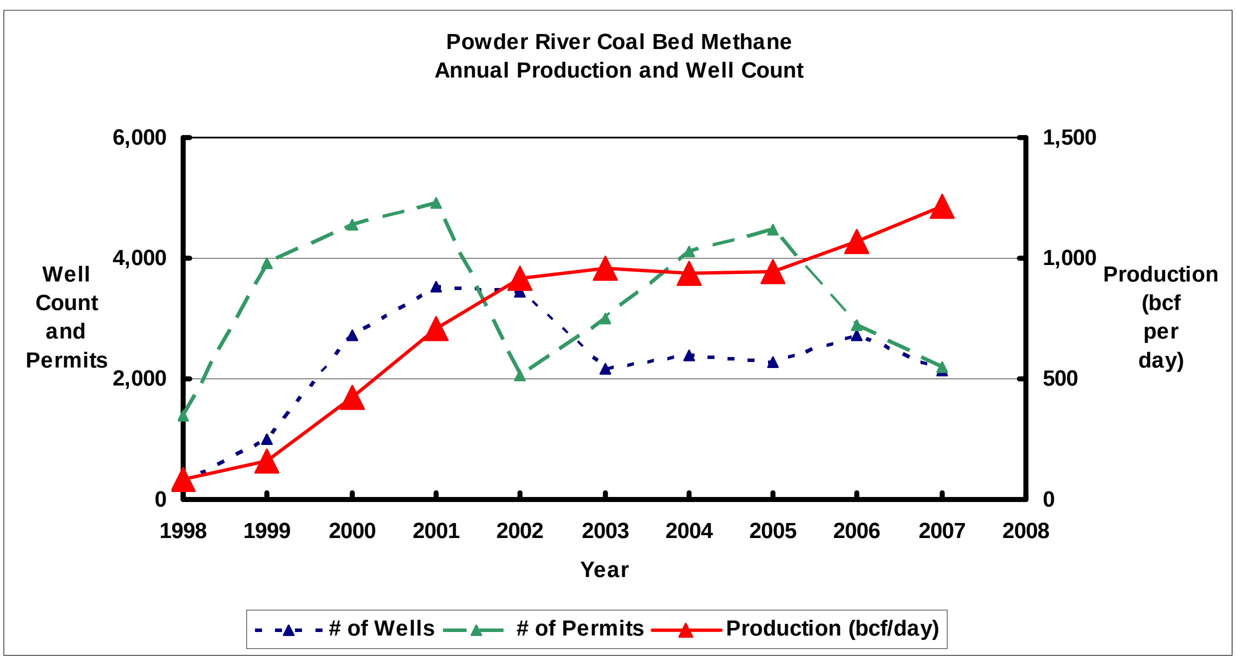


Figure 8. Natural Gas and Crude Oil Production for UIC Compliance

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Natural Gas Production (billion cubic feet)										
Reference	21004	19478	19353	19675	20043	20437	20724	20779	20610	20207
U.I.C. Compliance	20757	18765	18175	18117	18173	18300	18372	18277	18011	17566
Change	-247	-713	-1178	-1557	-1870	-2137	-2352	-2501	-2599	-2641
percent change	-1.2%	-3.7%	-6.1%	-7.9%	-9.3%	-10.5%	-11.3%	-12.0%	-12.6%	-13.1%
Crude Oil Production (million barrels per day)										
Reference	4.92	4.75	4.67	4.72	4.82	4.87	4.87	4.83	4.76	4.63
U.I.C. Compliance	4.90	4.67	4.56	4.57	4.63	4.66	4.63	4.58	4.49	4.35
Change	-0.03	-0.07	-0.11	-0.15	-0.19	-0.22	-0.24	-0.26	-0.27	-0.28
percent change	-0.5%	-1.5%	-2.4%	-3.2%	-3.9%	-4.4%	-4.9%	-5.3%	-5.7%	-6.0%

Fluid Restrictions Scenario

For this analysis, non-restricted fluids include water with additives such as salt and iron control and CO_2 foams and gels. (It should be noted that fracturing, including with water, is currently regulated at state and/or local levels.) Restricted fluids are:

- Water containing surfactants or detergents – These are common in the so-called "slick water fracs" which are becoming the treatment of choice in the emerging shale plays
- Nitrogen foams and gels used to drive in and set proppants and which could interact with water and create ammonia
- Large quantities of acid, mainly hydrochloric, used to regulate the pH

An initial investigation of the IHS database revealed that a very small percentage of wells drilled with fracturing—fewer than 120 in the past two years—still use oil-based fluids for fracturing. Thus, restrictions of these fluids were not evaluated in this study.

Wells with restricted fluids have been segregated from those with non-restricted fluids and the average initial flow rates (mcf/day) of each group calculated. Of the 177 plays (123 natural gas and 54 oil) analyzed, 117 had performance rates which were higher in wells using restricted fluids. Natural gas plays with higher performance in plays using restricted fluids totaled 86 or 70%, while similar oil plays totaled 31 or 58%. This suggests that impact of fluid restrictions would be greatest for natural gas. Only those plays with higher comparative performance using restricted fluids were analyzed, since it would have been extremely difficult to prove any performance increases by not using fluids specifically designed to enhance well productivity. Statistical information input into the forecast models is contained in "Appendix 2 – Fluid and Treatment Statistical Information."

In order to calculate the specific amounts of reduced production, IHS makes the assumption that if non-restricted fluids were to be used in lieu of restricted fluids, well performance would decrease in a manner similar to the differences observed in initial production rates. A performance reduction limit or cut off of 80% is applied for plays with extensive differences in initial flow rates. The play level fluid change percentage is then calculated by multiplying the percent reduction in performance by the percentage of wells that used restricted fluids by the percentage of wells that have been hydraulically fractured. This percentage is then applied to raise the threshold or required EUR at which the play could be economically produced at the forecasted price; this in turn reduces the number of wells that could be drilled.

Example IHS calculation: For the Barnett Shale plays, averaging all of the wells in each play in each category of restricted fluid use and non-restricted fluid use, 4 of the 6 gas plays had significantly lower production from wells using non-restricted fluids. The Fort Worth syncline, Barnett-3 play had a 33.1%

reduction in production for wells using non-restricted fluids compared to those using restricted fluids. With 80% of the wells using restricted fluids and with 96.9% of wells being treated, the resulting reduction for production from the Barnett 3 play is 25.7% or the product of the change to non-restricted fluids times the share using restricted fluids times the share of wells being treated. Numerically, total production is reduced by 25.7% or the product of 33.1% * 80% * 96.9%.

The results of this scenario are shown in Figure 10.

Figure 9. Fluid and Treatment Statistical Information for Barnett Shale Plays

SUB_BASIN	**FORT WORTH SYNCLINE**			**STRAWN SUBBASIN**		
PLAY	**Barnett**	**Barnett - 1**	**Barnett - 3**	**Barnett**	**Barnett - 2**	**Barnett - 3**
PRODUCT (OIL or GAS)	Gas	Gas	Gas	Gas	Gas	Gas
Initial Flow Rate (mcf/month) Restricted fluids used	35,510	51,654	14,395	77,393	61,719	18,546
Initial Flow Rate (mcf/month) Non restricted fluids used	38,009	49,069	9,628	55,206	52,010	24,654
Analyze change in Frac Fluids		Y	Y	Y	Y	Y
Percent Reduction in Production (note 80% limit)		5.0%	**33.1%**	28.7%	15.7%	-32.9%
Initial Flow Rate (mcf/month) Non frac wells	28,461	51,105	15,951		50,271	4,776
Initial Flow Rate (mcf/month) All frac wells	36,343	50,289	13,442	67,308	57,329	20,582
Percent wells with restricted fluid	66.7%	47.2%	**80.0%**	54.5%	54.8%	66.7%
Percent wells treated	50.0%	94.3%	**96.9%**	100.0%	96.2%	97.4%
Final Reduction based restricted fluid		2.2%	**25.7%**	15.6%	8.3%	-21.4%

Figure 10. Natural Gas and Crude Oil Production for Fluid Change

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Natural Gas Production (billion cubic feet)										
Reference	21004	19478	19353	19675	20043	20437	20724	20779	20610	20207
Fluid Change	20509	18014	16908	16467	16199	16010	15786	15445	14960	14375
Change	-494	-1465	-2445	-3207	-3844	-4427	-4938	-5333	-5650	-5832
percent change	-2.4%	-7.5%	-12.6%	-16.3%	-19.2%	-21.7%	-23.8%	-25.7%	-27.4%	-28.9%
Crude Oil Production (million barrels per day)										
Reference	4.92	4.75	4.67	4.72	4.82	4.87	4.87	4.83	4.76	4.63
Fluid Change	4.87	4.60	4.44	4.42	4.46	4.48	4.45	4.38	4.29	4.15
Change	-0.05	-0.14	-0.23	-0.30	-0.35	-0.39	-0.43	-0.45	-0.47	-0.48
percent change	-1.0%	-3.0%	-4.9%	-6.4%	-7.4%	-8.1%	-8.7%	-9.3%	-9.8%	-10.3%

Elimination of Hydraulic Fracturing Scenario

Since hydraulic fracturing is now such an important component of well completion, particularly in the emerging unconventional plays, a scenario with no hydraulic fracturing is included. Since supplies will be constrained, IHS assumes that prices will most likely have to be higher to meet demand requirements. Unlike the UIC and fluid cases, IHS assumes that the price of oil becomes the best reference point for a market balancing price of natural gas. The oil-equivalent natural gas price is calculated by dividing the oil price by six (6) to obtain the price used for the analysis of no fracturing. Since the forecasted oil price is generally higher by a factor of 10, dividing the oil price by 6 results in a higher natural gas price.

Also, if hydraulic fracturing is eliminated, more drilling will have to be done in conventional and offshore plays where many wells are developed without fracturing. At this stage, the higher natural gas prices lower the expected reserves (EUR) threshold so that more wells can be drilled economically.

This new calculated projected well count is then reduced by the percentage of wells that are treated with hydraulic fracturing. For some unconventional gas plays, the amount of drilling reduction is over 90%. "Appendix 2 – Fluid and Treatment Statistical Information," contains the percentage of wells completed in 2007 and 2008 that were hydraulically fractured and used to make the drilling calculations.

The results of this scenario are shown in Figure 11.

Figure 11. Natural Gas and Crude Oil Production for No Fracturing Scenario

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Natural Gas Production (billion cubic feet)										
Reference	21004	19478	19353	19675	20043	20437	20724	20779	20610	20207
No Fracturing	20017	16625	14515	13103	12067	11264	10563	9897	9236	8596
Change	-986	-2853	-4838	-6571	-7976	-9173	-10161	-10882	-11374	-11611
percent change	-4.7%	-14.6%	-25.0%	-33.4%	-39.8%	-44.9%	-49.0%	-52.4%	-55.2%	-57.5%
Crude Oil Production (million barrels per day)										
Reference	4.92	4.75	4.67	4.72	4.82	4.87	4.87	4.83	4.76	4.63
No Fracturing	4.81	4.46	4.24	4.12	4.07	4.02	3.93	3.83	3.71	3.55
Change	-0.11	-0.29	-0.44	-0.60	-0.75	-0.86	-0.94	-1.01	-1.05	-1.08
percent change	-2.2%	-6.0%	-9.4%	-12.8%	-15.5%	-17.6%	-19.3%	-20.8%	-22.1%	-23.4%

LNG Imports Maximized by Elimination of Hydraulic Fracturing Scenario

In the three policy scenarios as well as the reference case, LNG imports meet most of the future gap caused by reduction in U.S. natural gas production. By the end of 2009, there will be 15 bcf/day of LNG terminal capacity available in North America with an additional 9 bcf/day of capacity either under construction or approved for construction. LNG terminal capacity is sufficient to handle the LNG import requirements until 2018. LNG supply is also relatively abundant during 2009. Although current LNG developments indicate adequate supply prospects for most scenarios, in order to meet U.S. demand in the No Fracturing Scenario, the gap that must be filled by LNG would be quite large; almost all of the planned LNG supply projects worldwide would have to be undertaken, and the U.S. would have to pay a price competitive with other LNG consumers in order to obtain LNG imports in the amount required. (This also assumes existing long-term LNG contracts do not interfere with U.S. ability to attract needed supplies.) For this reason, IHS sets the price of natural gas in the No Fracturing Scenario equal to the price of crude oil on a Btu equivalent basis (since this is the way most global LNG is priced).

Figure 12. LNG Imports Compared to LNG Terminal Capacity

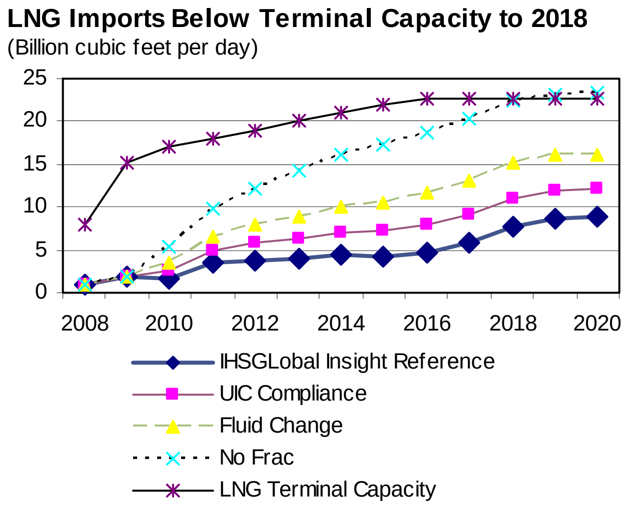
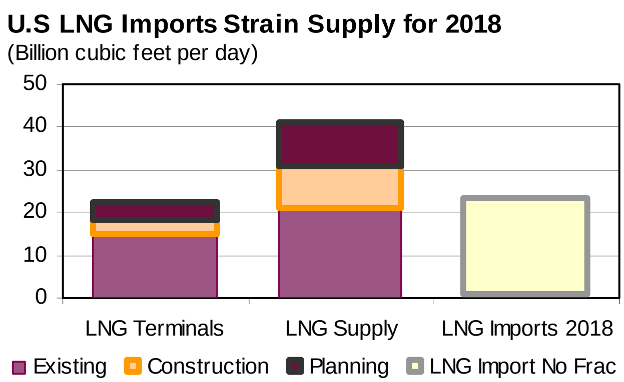


Figure 13. LNG Imports for 2018 in No Fracturing Scenario



Appendix 1 – Price Assumptions

The price assumptions used in this study were provided by IHS Global Insight and are shown below. (IHS Global Insight publishes long-term U.S. oil and gas price projections twice per year in its U.S. Energy Outlook publications and short-term prices monthly in its Global Petroleum Monthly and Natural Gas Monthly. The semi-annual long-term prices are merged with the updated monthly price projections when needed for such applications as inputs into IHS Global Insight's U.S. economic forecasts and for consulting engagements.)

Natural Gas Price Assumptions by Basin *(nominal $/mcf)*

Region	Basin	2007	2008	2009	2010	2014	2018
CALIFORNIA	OREGON - WASHINGTON	6.41	7.93	3.68	5.51	8.54	8.97
	SACRAMENTO BASIN	6.41	7.93	3.68	5.51	8.54	8.97
	SAN JOAQUIN BASIN	6.41	7.93	3.68	5.51	8.54	8.97
	SOUTHERN CALIFORNIA	6.41	7.93	3.68	5.51	8.54	8.97
NORTHERN ROCKIES	BIG HORN BASIN	3.93	6.26	2.62	4.70	7.91	8.34
	MONTANA UPLIFTS	3.93	6.26	2.62	4.70	7.91	8.34
	DENVER BASIN	3.93	6.26	2.62	4.70	7.91	8.34
	POWDER RIVER BASIN	3.93	6.26	2.62	4.70	7.91	8.34
	WILLISTON BASIN	3.93	6.26	2.62	4.70	7.91	8.34
GREATER GREEN RIVER	EASTERN GREEN RIVER	4.11	6.37	2.68	4.69	7.88	8.30
	PICEANCE BASIN	4.11	6.37	2.68	4.69	7.88	8.30
	UINTA BASIN	4.11	6.37	2.68	4.69	7.88	8.30
	WESTERN GREEN RIVER	4.11	6.37	2.68	4.69	7.88	8.30
	WIND RIVER BASIN	4.11	6.37	2.68	4.69	7.88	8.30
SAN JUAN AREA	LAS VEGAS-RATON BASIN	5.99	7.20	3.21	5.04	8.09	8.51
	PARADOX BASIN	5.99	7.20	3.21	5.04	8.09	8.51
	SAN JUAN BASIN	5.99	7.20	3.21	5.04	8.09	8.51
MID CONTINENT	ANADARKO BASIN	6.04	7.13	3.08	5.26	8.23	8.65
	ARKOMA BASIN	6.04	7.13	3.08	5.26	8.23	8.65
	CHAUTAUQUA PLATFORM	6.04	7.13	3.08	5.26	8.23	8.65
	CHEROKEE BASIN	6.04	7.13	3.08	5.26	8.23	8.65
	CENTRAL KANSAS UPLIFT	6.04	7.13	3.08	5.26	8.23	8.65
	SOUTH OKLAHOMA FOLDED BELT	6.15	7.44	3.37	5.45	8.30	8.71
PERMIAN	BEND ARCH	6.15	7.44	3.37	5.45	8.30	8.71
	PALO DURO BASIN	6.15	7.44	3.37	5.45	8.30	8.71
	PERMIAN BASIN	6.15	7.44	3.37	5.45	8.30	8.71
EAST/CENTRAL TEXAS	ARKLA BASIN	6.46	8.51	3.87	5.74	8.61	9.02
	EAST TEXAS BASIN	6.46	8.51	3.87	5.74	8.61	9.02
	FORT WORTH SYNCLINE	6.15	7.44	3.37	5.45	8.30	8.71
	OUACHITA FOLDED BELT	6.15	7.44	3.37	5.45	8.30	8.71
	STRAWN BASIN	6.15	7.44	3.37	5.45	8.30	8.71
GULF COAST	GULF COAST BASIN - LOUISIANA	6.88	9.03	4.45	6.21	9.05	9.46
	GULF COAST BASIN - TEXAS	6.59	8.65	3.89	5.75	8.57	8.98
	MID-GULF COAST BASIN	6.57	8.64	4.04	5.85	8.70	9.11
GULF OF MEXICO	GULF OF MEXICO DEEP WATER	6.48	8.62	4.00	5.81	8.73	9.14
	GULF OF MEXICO LOUISIANA SHELF	6.48	8.62	4.00	5.81	8.73	9.14
	GULF OF MEXICO TEXAS SHELF	6.48	8.62	4.00	5.81	8.73	9.14
EASTERN US	APPALACHIAN BASIN	7.17	9.48	4.79	6.51	9.42	9.82
	BLACK WARRIOR BASIN	7.17	9.48	4.79	6.51	9.42	9.82
	ILLINOIS BASIN	6.83	8.88	4.36	6.09	8.90	9.32
	MICHIGAN BASIN	6.83	8.88	4.36	6.09	8.90	9.32

Crude Oil Price Assumptions by Basin *(nominal $/barrel)*

Region	Basin	2007	2008	2009	2010	2014	2018
CALIFORNIA	OREGON - WASHINGTON	64.67	89.02	40.35	48.71	80.91	96.27
	SACRAMENTO BASIN	64.67	89.02	40.35	48.71	80.91	96.27
	SAN JOAQUIN BASIN	64.67	89.02	40.35	48.71	80.91	96.27
	SOUTHERN CALIFORNIA	64.67	89.02	40.35	48.71	80.91	96.27
NORTHERN ROCKIES	BIG HORN BASIN	63.33	87.17	39.51	47.69	79.23	94.27
	MONTANA UPLIFTS	68.81	94.72	42.93	51.82	86.08	102.43
	DENVER BASIN	72.17	99.35	45.03	54.36	90.30	107.45
	POWDER RIVER BASIN	63.33	87.17	39.51	47.69	79.23	94.27
	WILLISTON BASIN	63.33	87.17	39.51	47.69	79.23	94.27
GREATER GREEN RIVER	EASTERN GREEN RIVER	63.33	87.17	39.51	47.69	79.23	94.27
	PICEANCE BASIN	63.33	87.17	39.51	47.69	79.23	94.27
	UINTA BASIN	63.33	87.17	39.51	47.69	79.23	94.27
	WESTERN GREEN RIVER	63.33	87.17	39.51	47.69	79.23	94.27
	WIND RIVER BASIN	63.33	87.17	39.51	47.69	79.23	94.27
SAN JUAN AREA	LAS VEGAS-RATON BASIN	68.72	94.60	42.88	51.76	85.98	102.30
	PARADOX BASIN	68.72	94.60	42.88	51.76	85.98	102.30
	SAN JUAN BASIN	68.72	94.60	42.88	51.76	85.98	102.30
MID CONTINENT	ANADARKO BASIN	71.01	97.75	44.31	53.48	88.85	105.72
	ARKOMA BASIN	68.55	94.37	42.77	51.63	85.77	102.06
	CHAUTAUQUA PLATFORM	71.01	97.75	44.31	53.48	88.85	105.72
	CHEROKEE BASIN	71.01	97.75	44.31	53.48	88.85	105.72
	CENTRAL KANSAS UPLIFT	67.13	92.41	41.88	50.56	83.99	99.94
	SOUTH OKLAHOMA FOLDED BELT	73.47	101.14	45.84	55.34	91.92	109.38
PERMIAN	BEND ARCH	72.31	99.54	45.12	54.46	90.46	107.64
	PALO DURO BASIN	72.31	99.54	45.12	54.46	90.46	107.64
	PERMIAN BASIN	72.31	99.54	45.12	54.46	90.46	107.64
EAST/CENTRAL TEXAS	ARKLA BASIN	71.96	99.05	44.90	54.19	90.03	107.12
	EAST TEXAS BASIN	72.31	99.54	45.12	54.46	90.46	107.64
	FORT WORTH SYNCLINE	72.31	99.54	45.12	54.46	90.46	107.64
	OUACHITA FOLDED BELT	71.01	97.75	44.31	53.48	88.85	105.72
	STRAWN BASIN	72.31	99.54	45.12	54.46	90.46	107.64
GULF COAST	GULF COAST BASIN - LOUISIANA	75.36	103.74	47.02	56.76	94.28	112.19
	GULF COAST BASIN - TEXAS	72.31	99.54	45.12	54.46	90.46	107.64
	MID-GULF COAST BASIN	72.31	99.54	45.12	54.46	90.46	107.64
GULF OF MEXICO	GULF OF MEXICO DEEP WATER	71.46	98.37	44.59	53.82	89.41	106.38
	GULF OF MEXICO LOUISIANA SHELF	71.46	98.37	44.59	53.82	89.41	106.38
	GULF OF MEXICO TEXAS SHELF	71.46	98.37	44.59	53.82	89.41	106.38
EASTERN US	APPALACHIAN BASIN	72.23	99.44	45.07	54.40	90.37	107.54
	BLACK WARRIOR BASIN	73.48	101.15	45.85	55.34	91.93	109.39
	ILLINOIS BASIN	70.24	96.69	43.82	52.90	87.88	104.56
	MICHIGAN BASIN	71.95	99.05	44.89	54.19	90.02	107.12
ALASKA	ARCTIC COASTAL PLAINS PROVINCE	66.13	91.04	41.26	49.81	82.74	98.45
	COOK INLET BASIN	73.17	100.73	45.66	55.11	91.55	108.93

Appendix 2: Fluid and Treatment Statistical Data by Play

SUB_BASIN	PLAY	Product (Oil or Gas)	Initial Flow Rate (mcf/month) Restricted fluids used	Initial Flow Rate (mcf/month) Non-Restricted fluids used	Analyze change in Frac Fluids	Percent Reduction in Production (note 80% limit)	Initial Flow Rate (mcf/month) Non frac wells	Initial Flow Rate (mcf/month) All frac wells	Percent wells with restricted fluid	Percent wells treated	Final Reduction based on restricted fluid
ARCTIC COASTAL PLAINS PROVINCE	Conv Gas	G	388	-				388	100%	100.0%	
ARCTIC COASTAL PLAINS PROVINCE	Conv Oil	O	-	-			48,036		0%	0.0%	
COOK INLET SUBBASIN	Conv Gas	G	93,900	-	Y	**80.0%**	18,093	93,900	100%	20.0%	**16.0%**
COOK INLET SUBBASIN	Conv Oil	O	-	-			1,814		0%	0.0%	
SACRAMENTO SUBBASIN	Conv Gas	G	33,875	-	Y	**80.0%**	23,000	33,875	100%	1.2%	**1.0%**
SACRAMENTO SUBBASIN	Conv Oil	O	-	-			3,308		0%	0.0%	
SAN JOAQUIN SUBBASIN	Conv Gas	G	-	-			11,133		0%	0.0%	
SAN JOAQUIN SUBBASIN	Conv Oil	O	1,372	1,257	Y	**8.3%**	987	1,362	92%	50.7%	**3.9%**
SAN JOAQUIN SUBBASIN	Heavy Oil	O	1,535	276	Y	**80.0%**	1,486	1,531	100%	33.3%	**26.6%**
SOUTHERN CALIFORNIA	Conv Oil	O	4,582	-	Y	**80.0%**	1,354	4,582	100%	2.0%	**1.6%**
SOUTHERN CALIFORNIA	Heavy Oil	O	1,174	-	Y	**80.0%**	3,327	1,174	100%	10.8%	**8.6%**
ARKLA SUBBASIN	Conv Gas	G	21,699	6,832	Y	**68.5%**	14,779	18,327	77%	49.5%	**26.2%**
ARKLA SUBBASIN	Conv Oil	O	1,244	401	Y	**67.8%**	888	1,027	74%	23.2%	**11.7%**
ARKLA SUBBASIN	Cotton Valley	G	38,843	33,807	Y	**13.0%**	34,406	38,376	91%	80.4%	**9.5%**
ARKLA SUBBASIN	Haynesville-Bossier	G	123,761	6,338	Y	**80.0%**	35,242	102,411	82%	64.7%	**42.4%**
ARKLA SUBBASIN	Hosston	G	35,757	37,353			35,510	35,853	94%	76.7%	
EAST TEXAS SUBBASIN EAST	Conv Gas	G	45,938	34,869	Y	**24.1%**	38,458	44,050	83%	90.7%	**18.1%**
EAST TEXAS SUBBASIN EAST	Conv Oil	O	518	1,183				585	90%	100.0%	
EAST TEXAS SUBBASIN EAST	Cotton Valley	G	30,233	33,316			22,959	30,472	92%	95.0%	
EAST TEXAS SUBBASIN EAST	Haynesville/Bossier	G	36,619	17,305	Y	**52.7%**	7,927	34,688	90%	93.8%	**44.5%**
EAST TEXAS SUBBASIN EAST	Haynesville-Smackover	G	22,183	34,202				26,189	67%	100.0%	
EAST TEXAS SUBBASIN EAST	Travis Peak	G	37,773	41,586			35,215	38,140	90%	93.7%	
EAST TEXAS SUBBASIN WEST	Bossier	G	64,607	123,477			23,956	66,400	97%	98.5%	
EAST TEXAS SUBBASIN WEST	Bossier-Deep	G	369,886	555,415			277,130	393,498	87%	77.5%	
EAST TEXAS SUBBASIN WEST	Conv Gas	G	49,001	21,949	Y	**55.2%**	36,434	44,605	84%	78.4%	**36.3%**
EAST TEXAS SUBBASIN WEST	Conv Oil	O	741	2,525			1,129	1,484	58%	66.7%	
EAST TEXAS SUBBASIN WEST	Cotton Valley	G	58,731	80,895			88,227	59,740	95%	96.8%	
FORT WORTH SYNCLINE	Barnett	G	35,510	38,009			28,461	36,343	67%	50.0%	
FORT WORTH SYNCLINE	Barnett - 1	G	51,654	49,069	Y	**5.0%**	51,105	50,289	47%	94.3%	**2.2%**
FORT WORTH SYNCLINE	Barnett - 3	G	14,395	9,628	Y	**33.1%**	15,951	13,442	80%	96.9%	**25.7%**
FORT WORTH SYNCLINE	Conv Gas	G	12,669	23,723				17,945	52%	100.0%	
FORT WORTH SYNCLINE	Conv Oil	O	258	351			99	276	81%	74.3%	
OUACHITA FOLDED BELT	Conv Gas	G	38,682	34,198	Y	**11.6%**	7,140	37,358	70%	92.5%	**7.6%**
OUACHITA FOLDED BELT	Conv Oil	O	935	1,120			34	961	86%	63.6%	
OUACHITA FOLDED BELT	Woodford - Core	G	12,232	-	Y	**80.0%**		12,232	100%	100.0%	**80.0%**
STRAWN SUBBASIN	Barnett	G	77,393	55,206	Y	**28.7%**		67,308	55%	100.0%	**15.6%**
STRAWN SUBBASIN	Barnett - 2	G	61,719	52,010	Y	**15.7%**	50,271	57,329	55%	96.2%	**8.3%**
STRAWN SUBBASIN	Barnett - 3	G	18,546	24,654	Y	**-32.9%**	4,776	20,582	67%	97.4%	**-21.4%**
STRAWN SUBBASIN	Conv Gas	G	4,722	1,789	Y	**62.1%**	3,827	3,989	75%	66.7%	**31.1%**
STRAWN SUBBASIN	Conv Oil	O	-	-			128		0%	0.0%	
APPALACHIAN SUBBASIN	CBM	G	4,639	1,712	Y	**63.1%**	19,579	4,606	99%	98.5%	**61.5%**
APPALACHIAN SUBBASIN	Conv Gas-North	G	2,178	1,282	Y	**41.2%**	1,517	2,077	89%	97.7%	**35.7%**
APPALACHIAN SUBBASIN	Conv Gas-South	G	4,387	2,420	Y	**44.8%**	31,586	4,263	94%	95.7%	**40.2%**
APPALACHIAN SUBBASIN	Conv Oil	O	248	174	Y	**29.7%**	167	237	85%	98.4%	**24.9%**
APPALACHIAN SUBBASIN	MARCHELLUS SHALE - I	G	2,821	2,513	Y	**50.0%**	583	2,749	77%	98.8%	**37.8%**
APPALACHIAN SUBBASIN	Trenton-Black River	G	2,174	6,728				3,692	67%	100.0%	
APPALACHIAN SUBBASIN	Upper Devonian	G	148	-	Y	**80.0%**	534	148	100%	50.0%	**40.0%**
BLACK WARRIOR SUBBASIN	CBM	G	2,737	5,209			11,518	2,748	100%	90.8%	
BLACK WARRIOR SUBBASIN	Conv Gas	G	2,471	3,639			360	2,909	63%	92.3%	
BLACK WARRIOR SUBBASIN	Conv Oil	O	93	-	Y	**80.0%**		93	100%	100.0%	**80.0%**
BLACK WARRIOR SUBBASIN	Floyd	G	1,517	-	Y	**80.0%**		1,517	100%	100.0%	**80.0%**
ILLINOIS SUBBASIN	Conv Oil	O	230	170	Y	**26.0%**	110	196	44%	84.8%	**9.6%**
MICHIGAN SUBBASIN	Antrim	G	3,674	3,305	Y	**10.0%**	1,812	3,607	82%	96.8%	**8.0%**
MICHIGAN SUBBASIN	Conv Gas	G	29,848	63,450			27,200	42,449	63%	88.9%	
MICHIGAN SUBBASIN	Conv Oil	O	2,203	3,542				3,141	30%	100.0%	
EASTERN GREEN RIVER SUBBASIN	CBM	G	18,876	11,338	Y	**39.9%**	6,614	12,300	13%	61.0%	**3.1%**
EASTERN GREEN RIVER SUBBASIN	Conv Oil	O	6,172	6,846			2,088	6,307	80%	76.9%	
EASTERN GREEN RIVER SUBBASIN	Vermillion	G	13,604	2,794	Y	**79.5%**	36,829	13,077	95%	89.1%	**67.4%**
EASTERN GREEN RIVER SUBBASIN	Wamsutter	G	23,166	21,961	Y	**5.2%**	18,277	23,104	95%	90.9%	**4.5%**
GREEN RIVER SUBBASIN	Conv Oil	O	1,269	-	Y	**80.0%**	273	1,269	100%	85.7%	**68.6%**
GREEN RIVER SUBBASIN	Jonah	G	84,665	111,259			100,891	84,908	99%	96.2%	
GREEN RIVER SUBBASIN	Labarge	G	14,301	16,000			5,803	14,919	64%	97.1%	
GREEN RIVER SUBBASIN	Moxa Arch	G	25,543	22,807	Y	**10.7%**	43,316	24,008	44%	94.7%	**4.5%**
GREEN RIVER SUBBASIN	Overthrust	G	12,880	-	Y	**80.0%**	8,447	12,880	100%	93.5%	**74.8%**
GREEN RIVER SUBBASIN	Pinedale	G	122,347	-	Y	**80.0%**	143,922	122,347	100%	96.1%	**76.9%**
PICEANCE SUBBASIN	CBM	G	6,456	4,561	Y	**29.4%**		6,284	91%	100.0%	**26.7%**
PICEANCE SUBBASIN	Conv Gas	G	14,222	12,085	Y	**15.0%**	11,043	13,244	54%	94.7%	**7.7%**
PICEANCE SUBBASIN	Conv Oil	O	5,401	-	Y	**80.0%**		5,401	100%	100.0%	**80.0%**
PICEANCE SUBBASIN	Mamm Creek	G	29,109	26,335	Y	**9.5%**	25,485	27,539	43%	97.2%	**4.0%**
UINTA SUBBASIN	CBM	G	16,672	16,099	Y	**3.4%**	3,946	16,493	69%	88.9%	**2.1%**
UINTA SUBBASIN	Conv Gas	G	46,166	63,646			46,280	51,640	69%	63.9%	
UINTA SUBBASIN	Conv Oil	O	2,089	3,027			4,981	2,110	98%	93.8%	
UINTA SUBBASIN	Natural Buttes	G	21,963	19,812	Y	**9.8%**	14,875	21,623	84%	91.5%	**7.5%**
WIND RIVER SUBBASIN	Conv Gas	G	40,023	12,163	Y	**69.6%**	14,051	38,225	94%	88.6%	**57.7%**
WIND RIVER SUBBASIN	Conv Oil	O	1,560	760	Y	**51.3%**	2,431	1,293	67%	50.0%	**17.1%**
GULF COAST - LOUISIANA	Conv Oil	O	7,294	4,181	Y	**42.7%**	4,734	5,922	56%	24.5%	**5.9%**
GULF COAST - LOUISIANA	Frio	G	115,686	22,144	Y	**80.0%**	107,440	82,671	65%	20.5%	**10.6%**
GULF COAST - LOUISIANA	Miocene	G	143,629	59,672	Y	**58.5%**	90,176	106,315	56%	27.8%	**9.0%**
GULF COAST - LOUISIANA	Tuscaloosa	G	195,532	107,789	Y	**44.9%**	99,658	161,785	62%	65.0%	**17.9%**
GULF COAST - LOUISIANA	Wilcox-Cretaceous	G	35,766	6,173	Y	**80.0%**	30,049	28,368	75%	20.0%	**12.0%**
Gulf Coast Texas LOWER GULF SUBBA	Austin	G	-	-			571		0%	0.0%	
Gulf Coast Texas LOWER GULF SUBBA	Conv Oil	O	715	364	Y	**49.1%**	1,496	665	86%	71.3%	**30.0%**
Gulf Coast Texas LOWER GULF SUBBA	Cretaceous	G	22,351	10,282	Y	**54.0%**	60,299	17,458	59%	50.7%	**16.3%**
Gulf Coast Texas LOWER GULF SUBBA	Frio-Miocene	G	80,294	19,945	Y	**75.2%**	38,690	77,671	96%	48.4%	**34.8%**
Gulf Coast Texas LOWER GULF SUBBA	Lobo	G	81,602	35,671	Y	**56.3%**	78,357	80,718	98%	86.7%	**47.8%**
Gulf Coast Texas LOWER GULF SUBBA	Olmos	G	10,399	7,675	Y	**26.2%**	10,487	9,626	72%	96.7%	**18.1%**
Gulf Coast Texas LOWER GULF SUBBA	Vicksburg	G	90,675	57,755	Y	**36.3%**	69,028	89,763	97%	83.8%	**29.6%**
Gulf Coast Texas LOWER GULF SUBBA	Wilcox-Yegua-Eocene	G	74,782	41,938	Y	**43.9%**	66,619	74,131	98%	80.2%	**34.5%**
Gulf Coast Texas UPPER GULF SUBBAS	Austin	G	161,214	12,446	Y	**80.0%**	179,662	134,961	82%	25.0%	**16.5%**
Gulf Coast Texas UPPER GULF SUBBAS	Austin	O	2,243	-	Y	**80.0%**		2,243	100%	100.0%	**80.0%**
Gulf Coast Texas UPPER GULF SUBBAS	Conv Oil	O	2,371	419	Y	**80.0%**	1,283	1,549	58%	41.6%	**19.3%**
Gulf Coast Texas UPPER GULF SUBBAS	Cretaceous	G	49,943	11,169	Y	**77.6%**	69,504	40,637	76%	35.7%	**21.1%**
Gulf Coast Texas UPPER GULF SUBBAS	Frio-Miocene	G	60,307	11,042	Y	**80.0%**	36,950	54,197	88%	24.4%	**17.1%**
Gulf Coast Texas UPPER GULF SUBBAS	Wilcox-Yegua-Eocene	G	83,115	27,804	Y	**66.5%**	74,420	80,710	96%	53.5%	**34.0%**

SUB_BASIN	PLAY	Product (Oil or Gas)	Initial Flow Rate (mcf/month) Restricted fluids used	Initial Flow Rate (mcf/month) Non-Restricted fluids used	Analyze change in Frac Fluids	Percent Reduction in Production (note 80% limit)	Initial Flow Rate (mcf/month) Non frac wells	Initial Flow Rate (mcf/month) All frac wells	Percent wells with restricted fluid	Percent wells treated	Final Reduction based on restricted fluid
MID-GULF COAST SUBBASIN	Conv Gas	G	34,031	2,253	Y	**80.0%**	29,673	26,616	77%	68.2%	**41.8%**
MID-GULF COAST SUBBASIN	Conv Oil	O	1,314	5,194			2,961	4,501	18%	38.9%	
GULF OF MEXICO - DEEP WATER	Miocene Conv Gas	G	187,231	-	Y	**80.0%**	1,255,776	187,231	100%	10.2%	**8.2%**
GULF OF MEXICO - DEEP WATER	Miocene Conv Oil	O	-	-			251,553			0.0%	
GULF OF MEXICO - DEEP WATER	Norphlet Conv Gas	G	-	112,919				112,919	0%	100.0%	
GULF OF MEXICO - DEEP WATER	Plio-Pleistocene Conv Ga	G	-	-			587,138		0%	0.0%	
GULF OF MEXICO - DEEP WATER	Plio-Pleistocene Conv Oil	O	-	-			147,745		0%	0.0%	
GULF OF MEXICO - LOUISIANA	Conv Oil	O	-	56,910			13,662	56,910	0%	0.3%	
GULF OF MEXICO - LOUISIANA	Miocene	G	-	27,461			165,214	27,461	0%	0.7%	
GULF OF MEXICO - LOUISIANA	Plio-Pleistocene Conv Ga	G	41,396	72,024			124,995	61,814	33%	1.1%	
GULF OF MEXICO - TEXAS	Conv Oil	O	-	-			9,820		0%	0.0%	
GULF OF MEXICO - TEXAS	Miocene-Frio	G	77,543	-	Y	**80.0%**	114,568	77,543	100%	1.8%	**1.4%**
GULF OF MEXICO - TEXAS	Pliocene	G	-	-			215,410		0%	0.0%	
ANADARKO SUBBASIN	Conv Oil	O	2,080	2,636			1,533	2,330	55%	80.7%	
ANADARKO SUBBASIN	Middle Pennsylvanian	G	37,351	109,193			26,661	51,327	81%	97.3%	
ANADARKO SUBBASIN	Sooner-Ringwood-Cedard	G	19,068	15,450	Y	**19.0%**	18,501	17,755	64%	97.5%	**11.8%**
ANADARKO SUBBASIN	Springer	G	110,013	153,258			5,994	115,857	86%	97.4%	
Anadarko-HUGOTON EMBAYMENT SUE	Cleveland	G	51,789	37,911	Y	**26.8%**	22,496	49,971	87%	97.3%	**22.7%**
Anadarko-HUGOTON EMBAYMENT SUE	Conv Oil	O	2,121	1,333	Y	**37.2%**	2,731	1,765	55%	55.5%	**11.3%**
Anadarko-HUGOTON EMBAYMENT SUE	Granite Wash-Atoka	G	48,495	60,067			64,707	50,298	84%	98.5%	
Anadarko-HUGOTON EMBAYMENT SUE	Hugoton	G	5,085	4,971	Y	**2.2%**	14,075	5,067	84%	72.2%	**1.4%**
Anadarko-HUGOTON EMBAYMENT SUE	Mocane Laverne	G	14,665	12,461	Y	**15.0%**	13,213	14,110	75%	79.9%	**9.0%**
Anadarko-HUGOTON EMBAYMENT SUE	Panhandle	G	24,786	21,206	Y	**14.4%**	30,637	24,149	82%	93.7%	**11.1%**
Arkoma-ARKANSAS SUBBASIN	Conv Gas	G	19,791	6,618	Y	**66.6%**	27,149	19,527	98%	86.5%	**56.4%**
Arkoma-ARKANSAS SUBBASIN	Fayetteville	G	47,038	8,155	Y	**80.0%**	45,180	43,335	90%	84.0%	**60.8%**
Arkoma-ARKANSAS SUBBASIN	Fayetteville Core	G	47,953	54,664			60,149	48,646	90%	82.8%	
Arkoma-OKLAHOMA SUBBASIN	Caney	G	3,658	-	Y	**80.0%**		3,658	100%	100.0%	**80.0%**
Arkoma-OKLAHOMA SUBBASIN	CBM	G	17,446	20,896			11,387	17,632	95%	89.8%	
Arkoma-OKLAHOMA SUBBASIN	Conv Gas	G	26,884	16,071	Y	**40.2%**	35,113	25,397	86%	95.2%	**33.0%**
Arkoma-OKLAHOMA SUBBASIN	Conv Oil	O	1,534	401	Y	**73.9%**	478	813	36%	73.3%	**19.7%**
Arkoma-OKLAHOMA SUBBASIN	Woodford	G	19,995	3,997	Y	**80.0%**	24,712	8,171	26%	92.0%	**19.2%**
Arkoma-OKLAHOMA SUBBASIN	Woodford - Core	G	58,247	45,576	Y	**21.8%**	4,979	56,489	86%	99.7%	**18.7%**
CENTRAL KANSAS UPLIFT	Conv Gas	G	6,214	5,223	Y	**16.0%**	4,817	5,908	69%	61.0%	**6.7%**
CENTRAL KANSAS UPLIFT	Conv Oil	O	1,233	1,042	Y	**15.5%**	950	1,101	31%	55.3%	**2.6%**
CHAUTAUQUA PLATFORM	CBM	G	1,117	845	Y	**24.3%**	1,935	1,025	66%	98.3%	**15.8%**
CHAUTAUQUA PLATFORM	Conv Gas	G	7,753	4,676	Y	**39.7%**	5,577	7,036	77%	93.6%	**28.5%**
CHAUTAUQUA PLATFORM	Conv Oil	O	1,013	866	Y	**14.5%**	526	954	60%	92.8%	**8.1%**
CHEROKEE SUBBASIN	CBM	G	1,084	1,186			1,383	1,098	86%	70.7%	
CHEROKEE SUBBASIN	Conv Gas	G	1,344	1,520			1,257	1,400	68%	64.4%	
CHEROKEE SUBBASIN	Conv Oil	O	485	1,230			1,049	965	36%	54.6%	
SOUTH OKLAHOMA FOLDED BELT	Barnett - 1	G	9,697	-	Y	**80.0%**		9,697	100%	100.0%	**80.0%**
SOUTH OKLAHOMA FOLDED BELT	Conv Gas	G	32,209	30,137	Y	**6.4%**		31,723	77%	100.0%	**4.9%**
SOUTH OKLAHOMA FOLDED BELT	Conv Oil	O	2,179	2,041	Y	**6.3%**	802	2,130	64%	85.1%	**3.5%**
SOUTH OKLAHOMA FOLDED BELT	Woodford - Core	O	3,665	325	Y	**80.0%**		3,248	88%	100.0%	**70.0%**
BIG HORN SUBBASIN	Conv Gas	G	56,150	5,881	Y	**80.0%**	58,564	31,016	50%	66.7%	**26.7%**
BIG HORN SUBBASIN	Conv Oil	O	979	733	Y	**25.1%**	811	874	57%	70.0%	**10.0%**
CENTRAL MONTANA UPLIFT	Conv Gas	G	10,559	4	Y	**80.0%**	3,099	8,800	83%	85.7%	**57.1%**
CENTRAL MONTANA UPLIFT	Conv Oil	O	28	-	Y	**80.0%**	117	28	100%	33.3%	**26.7%**
DENVER SUBBASIN	Conv Gas	G	2,915	3,070			1,875	2,987	54%	46.1%	
DENVER SUBBASIN	Conv Oil	O	928	2,067			1,838	1,435	56%	60.0%	
DENVER SUBBASIN	Niobrara	G	3,293	3,637			2,624	3,414	65%	95.5%	
Denver-WATTENBERG SUBBASIN	Conv Oil	O	973	459	Y	**52.8%**	2,566	894	85%	95.2%	**42.6%**
Denver-WATTENBERG SUBBASIN	Wattenberg	G	4,467	3,982	Y	**10.9%**	4,738	4,450	97%	95.7%	**10.0%**
POWDER RIVER SUBBASIN	CBM	G	2,515	4,970			8,058	4,797	7%	37.0%	
POWDER RIVER SUBBASIN	Conv Gas	G	1,841	1,297	Y	**29.6%**	19,302	1,831	98%	86.7%	**25.1%**
POWDER RIVER SUBBASIN	Conv Oil	O	1,903	797	Y	**58.1%**	1,223	1,754	87%	68.4%	**34.4%**
SWEETGRASS ARCH	Conv Gas	G	3,428	1,084	Y	**68.4%**	3,630	2,451	58%	54.5%	**21.8%**
SWEETGRASS ARCH	Conv Oil	O	630	524	Y	**16.8%**	1,621	574	47%	60.7%	**4.8%**
WILLISTON SUBBASIN	Bakken Conv Oil	O	5,466	4,173	Y	**23.6%**	5,922	5,420	96%	78.5%	**17.9%**
WILLISTON SUBBASIN	Conv Gas	G	5,297	47,476			8,812	12,679	83%	71.4%	
WILLISTON SUBBASIN	Conv Oil	O	1,639	2,600			2,754	2,039	58%	58.5%	
WILLISTON SUBBASIN	Western Bowdoin	G	4,064	-	Y	**80.0%**		4,064	100%	100.0%	**80.0%**
BEND ARCH	Conv Gas	G	7,679	4,076	Y	**46.9%**	11,227	5,579	42%	90.0%	**17.6%**
BEND ARCH	Conv Oil	O	178	562			336	386	46%	80.0%	
PALO DURO SUBBASIN	Conv Gas	G	1,970	1,302	Y	**33.9%**	1,076	1,444	21%	94.3%	**6.8%**
PALO DURO SUBBASIN	Conv Oil	O	360	925			215	430	88%	92.0%	
PERMIAN SUBBASIN	Conv Gas	G	14,038	5,465	Y	**61.1%**	15,666	12,292	80%	91.5%	**44.5%**
PERMIAN SUBBASIN	Conv Oil	O	1,304	1,212	Y	**7.0%**	694	1,282	76%	98.0%	**5.2%**
Permian-DELAWARE SUBBASIN	Barnett-Woodford	G	12,703	8,025	Y	**36.8%**		9,584	33%	100.0%	**12.3%**
Permian-DELAWARE SUBBASIN	Conv Gas	G	36,147	14,740	Y	**59.2%**	41,670	30,562	74%	94.5%	**41.3%**
Permian-DELAWARE SUBBASIN	Conv Oil	O	1,644	1,068	Y	**35.0%**	1,736	1,513	77%	90.9%	**24.5%**
Permian-DELAWARE SUBBASIN	Haley	G	240,041	-	Y	**80.0%**		240,041	100%	100.0%	**80.0%**
Permian-DELAWARE SUBBASIN	Morrow	G	14,331	12,663	Y	**11.6%**	1,304	13,872	73%	100.0%	**8.4%**
Permian-VAL VERDE SUBBASIN	Canyon-Strawn	G	11,427	11,253	Y	**1.5%**	16,247	10,642	84%	99.0%	**1.3%**
Permian-VAL VERDE SUBBASIN	Conv Gas	G	20,490	22,116			32,422	20,623	92%	98.0%	
Permian-VAL VERDE SUBBASIN	Conv Oil	O	1,225	1,465			2,350	1,265	84%	90.9%	
LAS VEGAS-RATON SUBBASIN	CBM	G	4,386	3,049	Y	**30.5%**	3,657	4,380	100%	95.8%	**29.1%**
LAS VEGAS-RATON SUBBASIN	Pierre Shale	G	5,238	-	Y	**80.0%**		5,238	100%	100.0%	**80.0%**
PARADOX SUBBASIN	Conv Gas	G	34,910	28,526	Y	**18.3%**	25,221	33,459	77%	71.0%	**10.0%**
PARADOX SUBBASIN	Conv Oil	O	311	111	Y	**64.4%**	2,351	261	75%	80.0%	**38.6%**
SAN JUAN SUBBASIN	CBM	G	11,373	20,000			18,335	11,501	99%	91.3%	
SAN JUAN SUBBASIN	Conv Gas	G	11,410	11,488			19,285	10,452	94%	97.9%	
SAN JUAN SUBBASIN	Conv Oil	O	465	12	Y	**80.0%**		428	92%	100.0%	**73.3%**
SAN JUAN SUBBASIN	Lewis-Mancos-Mesaverde	G	16,338	12,762	Y	**21.9%**	15,339	15,486	76%	90.3%	**15.1%**

Appendix 3: UIC Compliance Costs

1999 Estimated Compliance Costs*					2008 Estimated Compliance Cost Assumptions				
Action	Estimated Cost($)	Wells (%)	Total 1999 Est. costs ($)	Comments	Cost Change Factor (1999-2008) (2)	2008 Est. costs ($)	Wells (%)	Total 2008 Est. costs ($)	Comments
Obtain permit	4,500	100	4,500	60 hr/well * $75/hr	1.81	8,145	100	8,145	Same as 1999 assumption
Area of review (amount per AOR)	2,800	100	2,800	Assume all wells will require AOR but no corrective action if potential problems are found; assumes no drill or frac if potential problems found	1.81	5,068	100	5,068	Assume all wells will require AOR, with no corrective action. Will assume an overall 2% no drill/no frac due to possible problems (See comment 2 below)
In-situ stress analysis from accoustic logs (amount per frac per well)	15,000	30	4,500	Assumes 40% of wells already determine stress gradient with acounstic log	1.81	27,150	30	8,145	Assumes 40% of wells already determine stress gradient with acounstic log
In-situ stress analysis from pump in/fall off tests (amount per frac per well)	5,000	30	1,500	Assumes 40% of wells already determine stress gradient with pump in/fall off test	1.81	9,050	30	2,715	Assumes 40% of wells already determine stress gradient with pump in/fall off test
3-D fracture Simulation	10,000	75	7,500	Assumes 3-D model used for frac design in 25% of the cases	1.81	18,100	50	9,050	Fracture simulation software is more available now than in 1999. Assume a 50% use of simulation
Monitor, map fracture or other post frac analysis	10,000	60	6,000	Assumes some frac monitoring or post frac analysis already in 40% of fracs	1.76	17,600	40	7,040	Due to resource plays increase, post frac monitoring to 60% already in place
State of art downhole fracture imaging e.g. microsismic or downhole tiltmeter	375,000	10	37,500	Assumes that state of art downhole fracture imaging requiring observation wells may be required in 10% of fractured wells		500,000	12.5	62,500	A 1-mile square survey typically costs $500K (see additional comments 3 and 4 below)
Total Incremental Hydraulic fracturing cost (1999)			**64,300**		**Total Incremental Hydraulic fracturing cost (2008)**			**102,663**	
Average incremental cost for additional cementing to ensure isolation of the target zone prior to fracture	10,000	30	3,000		2.39	23,900	30	7,170	Assume similarly that 70% of wells being fractured will have adequate cementing prior to fracturing. Note also the cost change factor is higher for materials
Original Report - Fracture treatmant (1999 $)			**67,300**		**Increased Cost 2008 (non shale plays)**			**109,833**	See comments 5 and 6, adjustments to cost
Original Report - Fracture treatmant (2007 $)			**100,505**		**Increased Cost 2008 (shale plays)**			**47,333**	

*Source of 1999 Estimated Compliance Costs is "Potential Economic and Energy Supply Impacts of Proposals to Modify Federal Environmental Laws and Applicable to the U.S. Oil and Gas Exploration and Production Indu prepared by Advanced Resources International, Inc. 1999 for the U.S. Department of Energy Office of Fossil Energy

Notes:

1 - The cost change factor is based on the cost index generated by Cambridge Energy Research Associates, an IHS affiliate (CERA) from 2000 to 2008. An additional 5% is added to account for 1999 - 2000 interval

2 - While no adjustments to cost are made here for remediation, we apply the 2% reduction to projected wells to be drilled in the overall scenario

3 - Micro-seismic imaging is generally performed within the shale plays and included in the overall well cost, thus this cost should not be applied to shale plays. Generally observation wells are ultimately converted into producing wells

4 - The 12.5% assumption is based on the drilling of eight wells within a 640-acre parcel. While there is considerable variability here due to play maturity, well depth, and planned downspacing, we assume that in general the downspacing goal with normally be 40-acres or 16 wells per 640-acres and that overall currently one-half of the wells have been drilled in the non-shale plays

5 - Overall drilling and completion cost is determined at the play level. The 2008 increased cost is added to this total for the UIC scenario, but will be adjusted based on the recent percentage of wells which are actually fractured. For example if the percent of wells fractured in a non-shale play is 60%, a cost of $72,416 is applied to each well (i.e 120,693 x 0.6)

6 - Well depths averaged approximately 7800 feet in 2008. Given that drilling costs are a function of depth, we assume a 20% increase to the cost in plays with an average well depth greater 10,000 and a 20% reduction in cost for plays with average well depths less than 5000 feet as shown below.

Depth Range	Non-shale ($)	Shale ($)
Less than 5,000 feet	91,528	39,444
Between 5000 and 1000 feet	109,833	47,333
Greater than 10,000 feet	131,800	56,800

Appendix 4: Powder River Coalbed Methane Data

Powder River Coalbed Methane Drilling Fell Sharply Under New Regulations

	# of Wells	Production (bcf/day)	# of Permits
1998	288	84	1,396
1999	1,008	157	3,913
2000	2,732	422	4,551
2001	3,519	706	4,905
2002	3,442	917	2,060
2003	2,157	960	2,991
2004	2,387	938	4,114
2005	2,274	946	4,468
2006	2,723	1,066	2,902
2007	2,146	1,215	2,185

Source: Wyoming Oil and Gas Conservation Commission