

Winter 2008-09 U.S. Natural Gas Production and Supply Outlook

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Summary

The U.S. natural gas supply outlook for this winter is very favorable. Gas production this winter is forecast to be approximately 4.2 Bcf per day or 7.9 percent higher than last winter. The increased production is the result of large-scale development of unconventional gas, especially shale gas and tight gas. Several exciting new shale gas plays were announced earlier this year, with significant implications for the U.S. gas resource base and future production potential. Eastern Gulf of Mexico gas production has also increased.

Other components of gas supply evaluated here include pipeline imports from Canada, LNG imports, and gas storage. Pipeline imports are forecast to be down about 500 MMcf per day, and LNG imports this winter are forecast to be approximately 1 Bcf per day, which is slightly higher than last winter. Natural gas storage inventories as of November 1 are forecast to be approximately 3.45 Tcf, which is about 100 Bcf lower than last year, but still higher than the five year average.

Introduction

This report presents ICF's current view of trends and forecasts of upstream industry activity, production and imports for the upcoming winter heating season. It also discusses regional production trends and exploration plays that will be important in the longer-term.

Rig counts and gas completion activity in the U.S. continue at a high pace, and are a measure of the huge investments being made by both majors and independents to sustain and increase U.S. gas production both onshore and offshore. Onshore, tight gas and shale gas activity dominate and production is surging in several basins.

The most significant developments in North American gas supply since our last report in the fall of 2007 are:

- continued strong production increases from the Barnett, Fayetteville, and Woodford shales,
- the announcement of several new horizontal drilling shale plays in both the U.S. and Canada,
- continued production increases from tight gas in the Rockies and East Texas,
- increased gas production from Independence Hub in the Eastern Gulf of Mexico, and
- lower LNG and pipeline imports for 2008 as a whole.

It now appears certain that horizontal drilling and artificial stimulation of shale gas formations will extend beyond the Barnett, Fayetteville, Woodford, Appalachian, and Michigan shales. In addition, production will not be limited to these Devonian and Mississippian-age organic shales, but will include shales that are younger geologically such as the Haynesville in Louisiana and the Montney in British Columbia. Prior to 2008, almost all activity had been in the Devonian/Mississippian shales and it was assumed by many analysts that these formations had unique characteristics for gas production. The implications for future U.S. gas production of expanding the list of potential shale targets are very significant.

ICF forecasts that 2008 Lower-48 gas production will be 20.3 Tcf, about 7.2 percent higher than in 2007. Going forward into next year we are forecasting a 6.5 percent increase, reflecting high rig counts in tight gas and shale gas plays, and the startup of significant shale gas production in several new areas.

The production analysis presented here is based upon analysis of data from state agencies, the Energy Information Administration (EIA) and the Minerals Management Service (MMS). It incorporates a procedure to estimate recent production where reported production is not yet complete due to a reporting lag. Historic gas production at the individual play level is based upon ICF analysis of state agency and commercial well level production data, as well as individual company reports. The gas production forecast presented here is consistent with the ICF Natural Gas Update, which is a summary of the results of our ongoing North American gas market modeling. The forecasts of gas storage, pipeline imports, and LNG imports presented here are derived from that forecast.

Drilling and Permitting Activity

U.S. rig activity (Baker-Hughes series) in August 2008 averaged 1,987 rigs, 183 rigs or 10 percent higher than in August of 2007 (**Exhibit 1**). The gas rig portion of the total count was 1,581 as compared with 1,492 rigs last year. The rate of increase in gas rig activity in the first half of 2008 was lower than in 2007, but activity picked up again in the summer of 2008.

Most of the activity increase in recent years has been onshore, concentrated in areas of non-conventional natural gas production – tight gas, coalbed methane, and shale gas. Offshore rig activity, dominated by shelf drilling, has generally declined, although industry activity and capital expenditures in the Gulf of Mexico deep water remain very high.

Exhibit 1

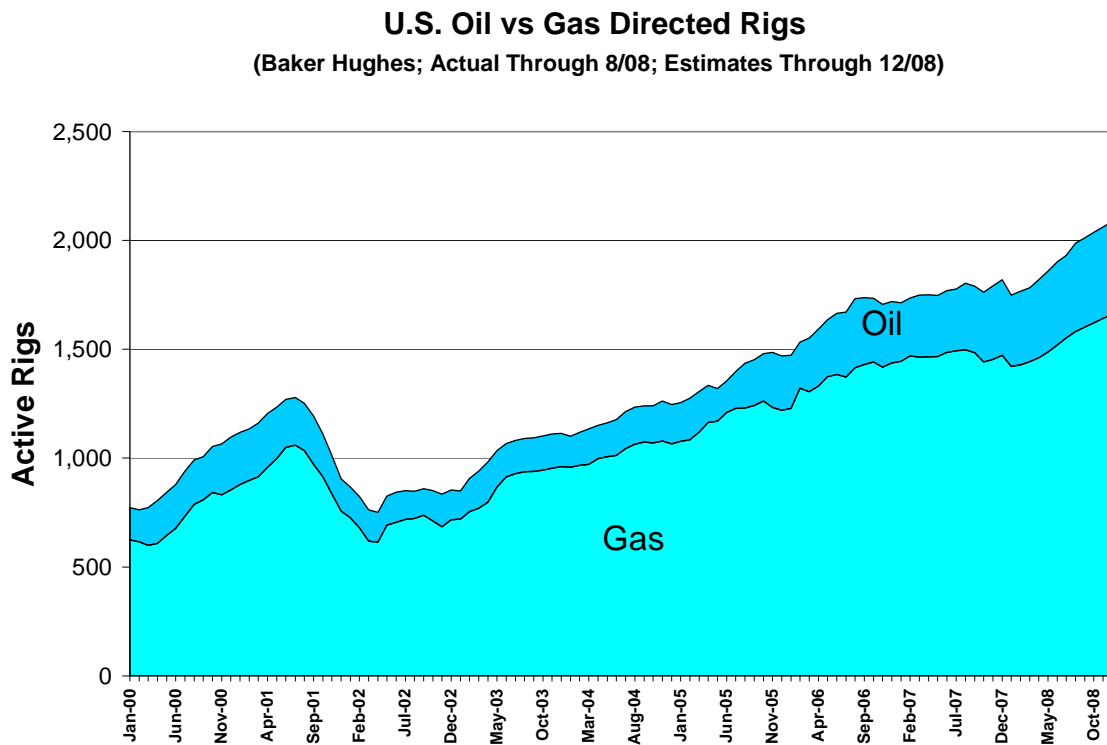


Exhibit 2 shows the relationship between monthly gas rigs and oil and natural gas prices through August. Gas rig counts are shown as columns on the chart, and Henry Hub (Louisiana) natural gas prices are shown as a solid line. Oil prices are also shown. The chart shows that there was a 6-month lag in 2001 and 2003 before the rig count peaked after the gas price peak. Since 2003, rig counts have increased steadily, despite wellhead price fluctuation. This illustrates that development is focused on long-term supply rather than short-term price fluctuations.

Exhibit 2

U.S. Gas Directed Drilling Activity and Crude Oil and Gas Prices (Through 8/08)

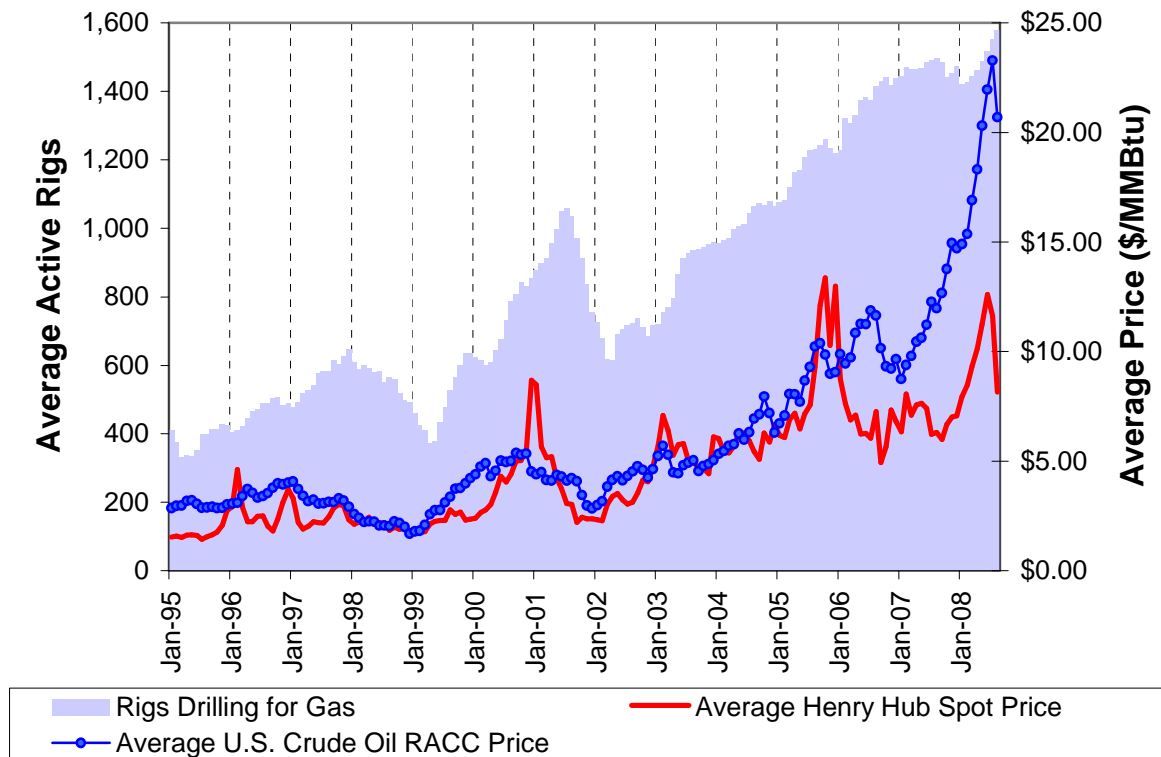


Exhibit 3 presents 2008 trends in drilling activity by region. All major areas experienced increases with the exception of the Gulf of Mexico. Increased activity was observed in Texas, Northern Louisiana, and the Mid-Continent. Appalachian activity is also increasing. Canadian rig activity is predominantly in the Western Canadian Sedimentary Basin, and is down this year due to the impact of development costs and other factors. However, western Canada coalbed methane activity continues at a strong pace.

Exhibit 3

U.S. and Canadian Drilling Trends

August Data - Total Rigs

Source: Baker Hughes

	Aug. 2007	Aug. 2008	Change (%)
Regional U.S. Rig Trends			
Rockies	240	252	5%
Midcontinent	256	278	9%
Texas	844	934	11%
Louisiana	178	188	6%
Gulf of Mexico	70	64	-9%
Appalachia	65	70	8%
Other	151	201	33%
Lower-48	1,804	1,987	10%

Horizontal and directional drilling continues to increase and its proportion of total drilling is increasing. Horizontal drilling has met with great success in shale gas plays and directional drilling is increasing because of the reduced surface impact as multiple wellbores are drilled from a single drilling pad. In July, 2008, approximately 30 percent of active rigs were horizontal rigs and 21 percent were directional. Vertical drilling represented only 49 percent of the total. In July of last year, 23 percent was horizontal, 21 percent was directional, and 56 percent was vertical. Thus, there is a continued trend toward more horizontal drilling, predominantly in shales.

Exhibit 4 summarizes the gas rig comparison between 2007 and 2008. Looking at the U.S. rig counts for the first eight months of 2008, the average was 1,486 rigs. This can be compared to an average of 1,473 gas rigs during the same months last year, an increase of about 1 percent. On a calendar year basis, ICF is forecasting an average of 1,535 gas rigs this year, an increase of 4 percent. Rig activity this year picked up significantly in June and July relative to the first months of the year, and this trend is expected to continue, driven by shale plays.

Exhibit 4

Historical and Forecast Gas Rigs			
	2007	2008	change
January through August (actual)	1,473	1,486	+0.9%
Annual average (2008 forecast)	1,470	1,535	+4.4%

Drilling Cost Trends

In addition to other market factors impacting gas prices, much of the current pressure on natural gas prices has been generated by increases in the costs of upstream activity, including drilling, stimulation, and completion. There are many factors behind this, but the primary ones have been increased demand for quality drilling rigs, limited availability of quality personnel, and increased commodity costs.

There have been steep increases in the cost of materials and labor used in the construction of all types of energy infrastructure, including power plants, pipelines and oil and gas wells following the general pattern of commodity price increases that has occurred since the fall of 2001.

Exhibit 5 shows the recent history of cost per ton of carbon steel plate (used in line pipe, casing, pressure vessels, etc.) Historically, prices for basic commodities such as steel have exhibited cycles with periods of decline following “price booms” such as the current increases.

Exhibit 5

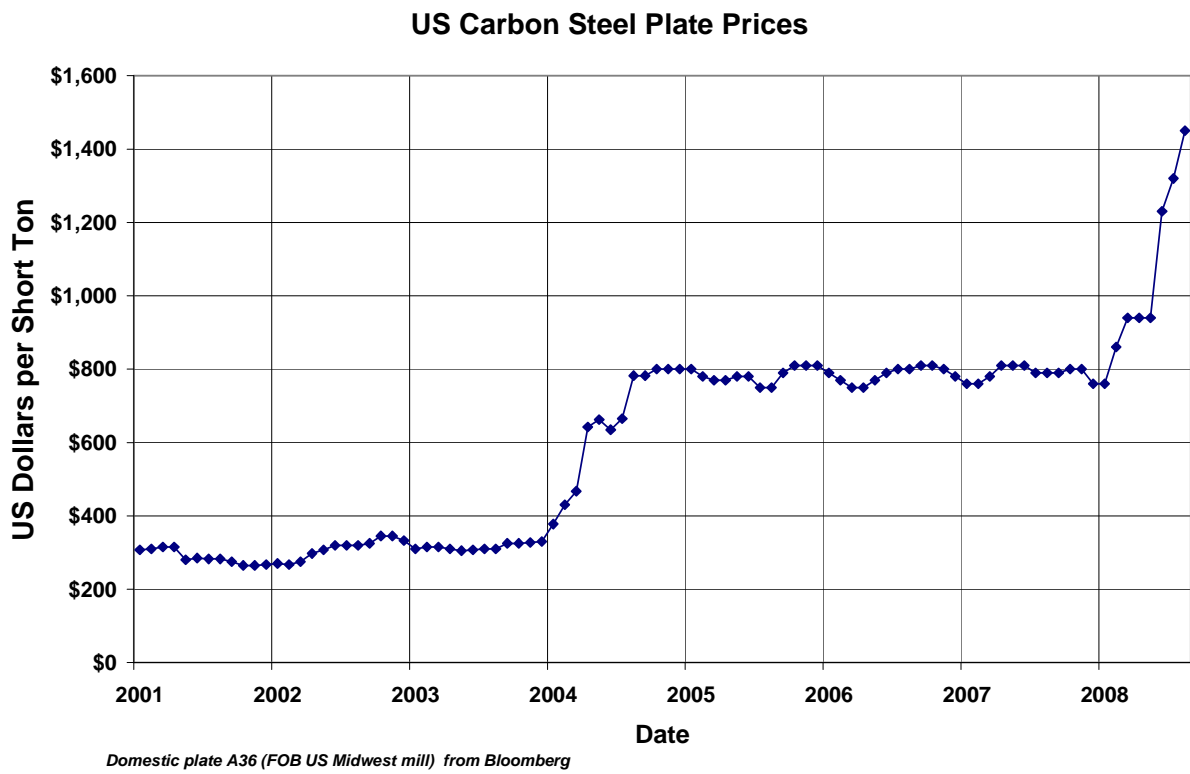
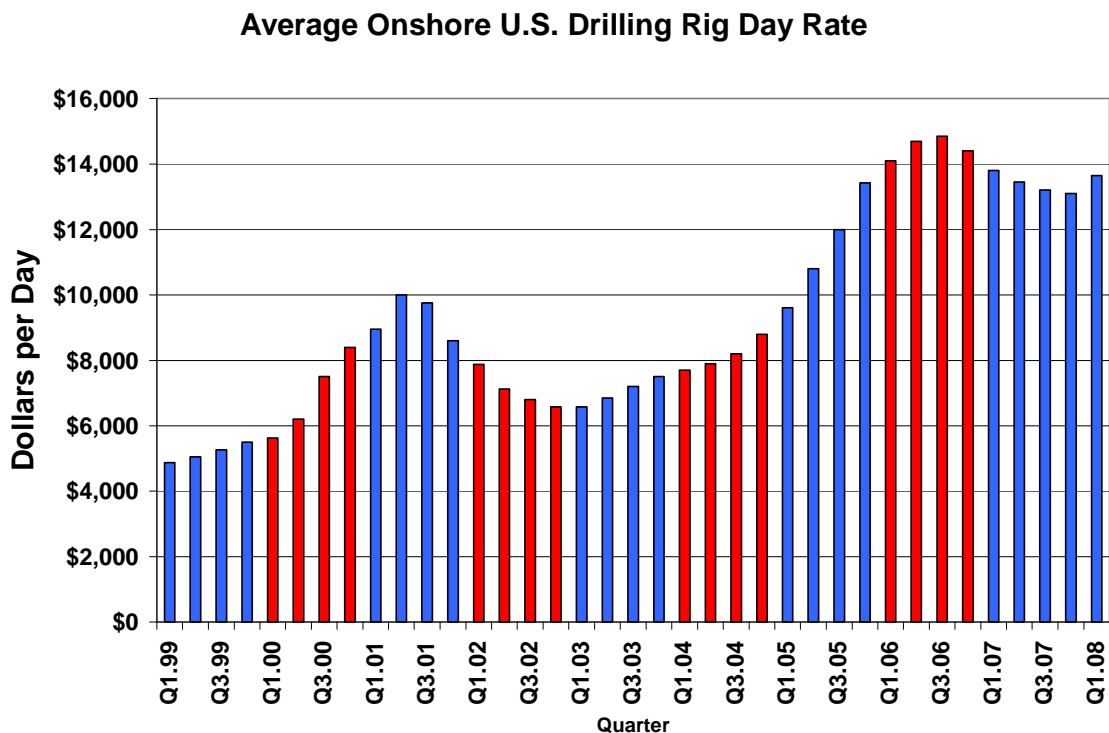


Exhibit 6 shows the average day rate for onshore drilling rigs in the U.S. The day rate for onshore rigs is a key factor in U.S. drilling costs. The average day rate essentially doubled between 2003 and 2007. This had a major impact on overall resource development costs, especially when combined with cost increases for materials. The chart indicates that the day rate appears to have

Exhibit 6



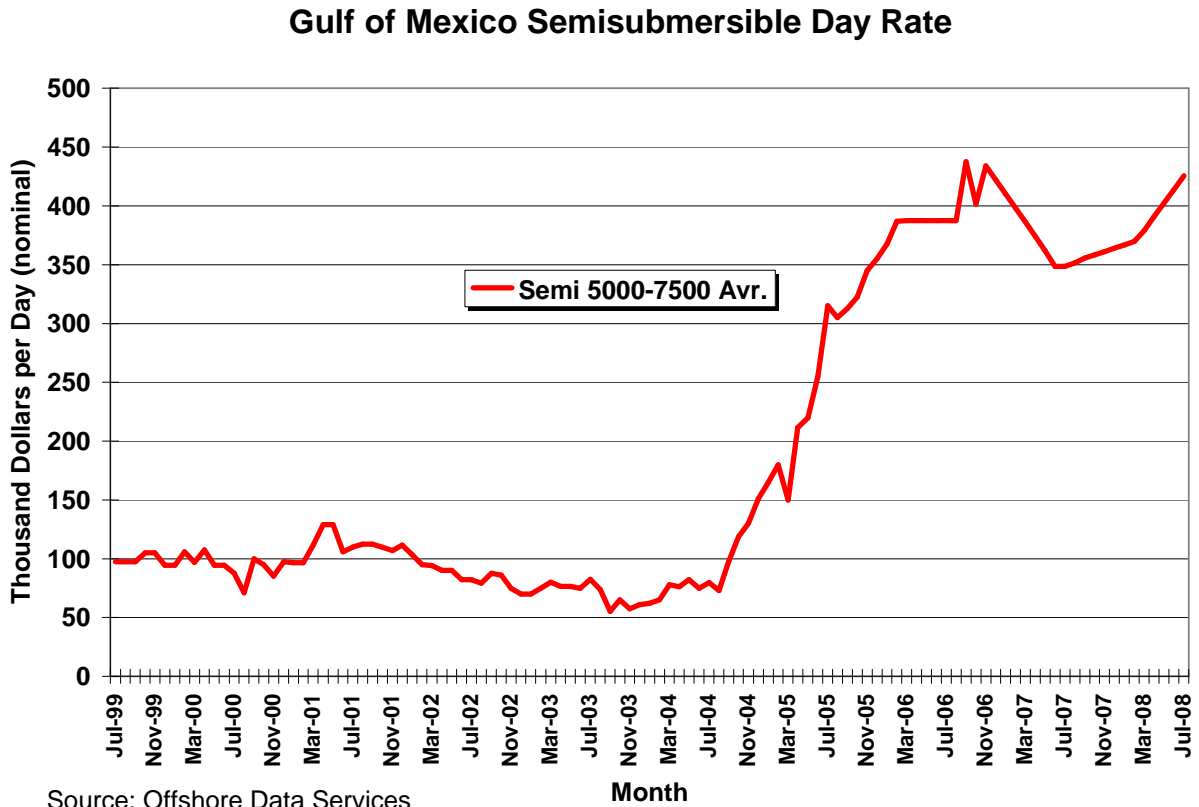
peaked in late 2006. This decline since then in part reflects additions of new rig capacity. The increase in the first quarter of 2008 reflects increased demand caused by the run-up in oil and gas prices in the first part of the year.

Although not included in the day rates another factor driving costs in the non-conventional plays is the reservoir stimulation component, which has increased greatly as operators employ newly developed techniques that can cost hundreds of thousands of dollars per well. Directional tight gas wells such as those at

Jonah-Pinedale are receiving numerous frac treatments, adding greatly to the well costs. With horizontal shale wells, there is the expense of drilling the horizontal component, and the trend has been toward longer laterals and numerous frac stages per lateral.

Exhibit 7 shows the historic rig rates for deepwater semisubmersibles. These day rates have more than quadrupled since 2003.

Exhibit 7



Gas Well Completions

Exhibit 8 shows monthly U.S. gas well completion statistics from the EIA Monthly Energy Review. Activity increased steadily through 2006 and into 2007. However, the rate of increase in completion activity has slowed over the past year or two. During the first half of 2008, monthly gas well completions in this data series were about the same as during this period in 2007. The flattening out of gas completion activity reflects the fact that more wells are now complex horizontal completions with multi-stage fracs and thus take more rig time than some conventional gas completions. However, production per new completion is increasing. For these reasons, new completion activity may not always be a good measure of future gas production.

Exhibit 8

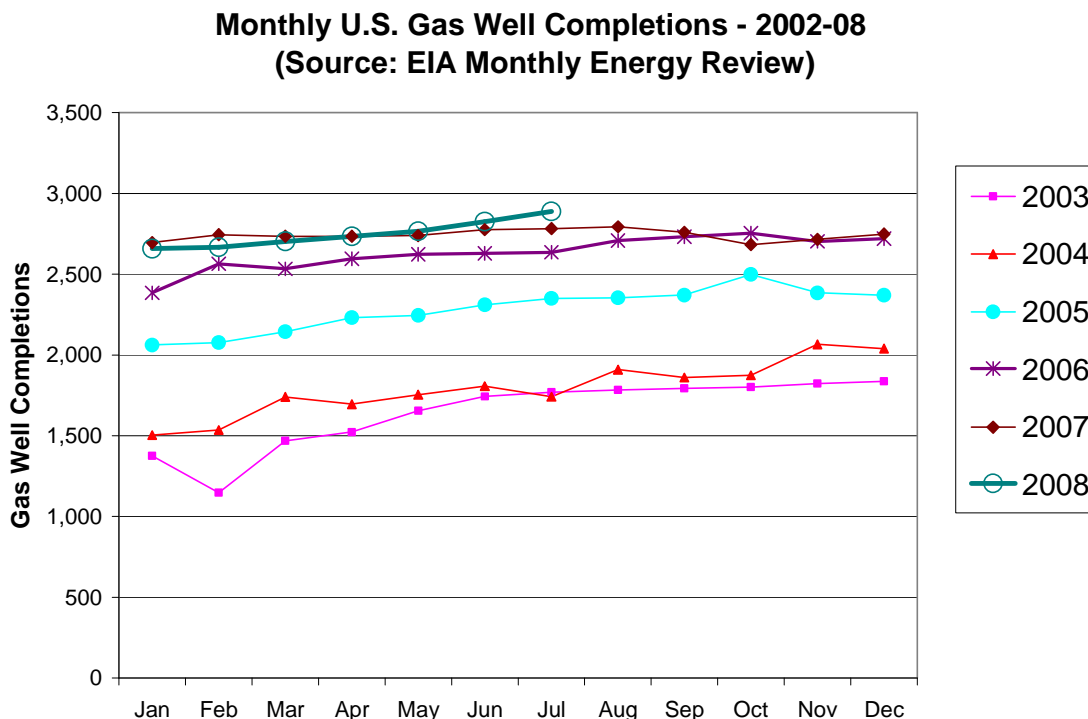


Exhibit 9 presents published data for Lower-48 quarterly gas well completions starting with the first quarter of 2004. The table presents EIA Monthly Energy Review data, API Quarterly Completion Report data, and ICF estimates. Based upon trends in rig activity and available well-completion data for 2008, ICF is forecasting the completion of about 31,500 Lower-48 gas wells in 2008. This represents an increase of 750 or 2.4 percent from the 30,800 wells completed in 2007.

Exhibit 9

Comparison of Quarterly Lower 48 Completion Counts				
Estimated Gas Well Completions				
Sources: EIA Monthly Energy Review and API Completion Report.				
	EIA Monthly Energy Review Estimated	API Quarterly Comp. Report Estimated	ICF Estimated	
2005 Q1	6,283	6,585	6,585	
2005 Q2	6,786	6,935	6,935	
2005 Q3	7,075	7,366	7,366	
2005 Q4	7,253	6,948	6,948	
2006 Q1	7,484	7,067	7,067	
2006 Q2	7,850	7,485	7,485	
2006 Q3	8,076	8,278	8,278	
2006 Q4	8,177	8,335	8,335	
2007 Q1	8,176	7,560	7,560	
2007 Q2	8,251	7,725	7,725	
2007 Q3	8,335	7,842	7,842	
2007 Q4	8,148	7,502	7,650	
2008 Q1	8,028	7,459	7,530	
2008 Q2	8,271		7,800	
2008 Q3	---		8,000	
2008 Q4	---		8,200	
Annual Totals				
				% chg.
2005	27,397	27,834	27,834	
2006	31,587	31,165	31,165	12.0%
2007	32,910	30,629	30,777	-1.2%
2008	---	---	31,530	2.4%

Natural Gas Production

The major trends in Lower-48 gas production since our report last year are the continued increase in gas production from onshore non-conventional gas plays and the strong production performance of the Independence Hub in the Eastern Gulf of Mexico. Shale and tight gas development continues to dominate activity onshore, and unconventional activity is expanding into new areas.

Unconventional drilling and completion activity in the U.S. has been focused on the following plays:

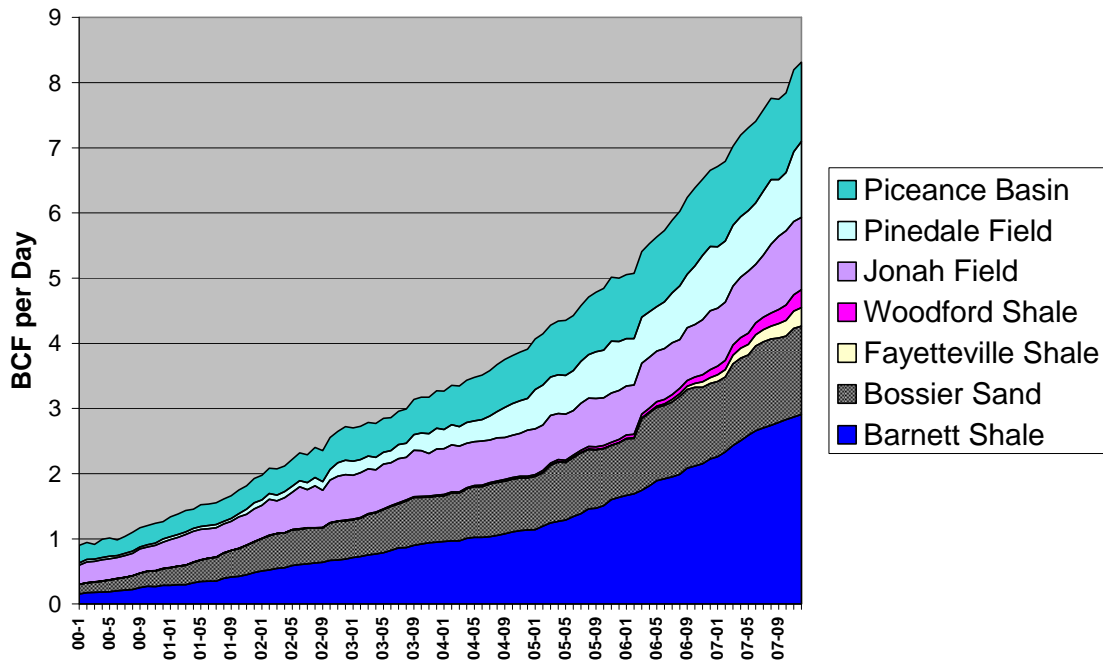
- Barnett Shale in the Fort Worth Basin
- Fayetteville Shale in Arkansas
- Woodford Shale in Oklahoma
- Bossier Sand in East Texas and North Louisiana
- Lance Sand in the Green River Basin (Jonah-Pinedale)
- Mesaverde Sand in the Uinta and Piceance Basins
- Anadarko Basin Cleveland and Granite Wash Sands
- Powder River Basin Coalbed Methane
- Uinta and Raton Basin Coalbed Methane
- Canyon and Morrow Sands in West Texas
- San Juan Basin Coalbed Methane and Tight Gas

Exhibit 10 illustrates the historic gas production trends from several key onshore areas dominated by unconventional gas production. Included in the chart are the Barnett Shale in the Fort Worth Basin, the Bossier Sand in East Texas, the Fayetteville Shale in Arkansas, the Woodford Shale in Eastern Oklahoma, the Jonah and Pinedale Fields in Southwestern Wyoming, and the Piceance Basin in Colorado. These plays have experienced an increase in gas production of over 7 Bcf per day relative to January, 2000. Over the eight year period, their combined average production increase has been 900 MMcf per day per year. During the same period, Lower-48 dry gas production increased slightly from

51.3 Bcf per day in 2000 to 51.6 Bcf per day in 2007. Thus, these few plays have been largely responsible for increasing U.S. gas production.

Exhibit 10

Gas Production Through 2007 From Selected Plays and Basins



This highlights the need to better understand the distribution, economics, and potential of unconventional gas plays. As discussed in another section of this paper, gas production is forecast by ICF to increase substantially in all of these areas. In addition, recently announced shale plays such as the Haynesville Shale in Louisiana and the Marcellus in Appalachia are emerging that are not in the historic data but will soon be making major contributions.

The production for the Fayetteville and Woodford Shales in the Arkoma Basin of Arkansas and Eastern Oklahoma appears relatively minor on the chart. However, in the near future both of these plays will make a large contribution to U.S. gas production. This is based upon factors such as completion activity, well productivity, and resource assessment and economics. Additional information on active shale plays is presented below.

Exhibits 11 through 13 present our natural gas production analysis and forecast. Lower-48 gas production in the third quarter of 2008 is expected in this analysis to average 55.9 Bcf per day, up from 52.0 Bcf/d in the third quarter of last year. These estimates are presented graphically in **Exhibit 12**. The current rate of production is higher than it has been during the entire period evaluated from 2003-08. The highest rate of U.S. gas production in history occurred during the early 1970s, when dry gas production was approximately 60 Bcf per day. It now appears likely that U.S. annual gas production will exceed the all time record within the next year or two.

The lower portion of **Exhibit 11** presents an annual summary and shows the percentage change in Lower-48 production. ICF estimates that 2008 production will average 55.3 Bcf/d (20.3 Tcf), a 7.2 percent increase over 2007. The forecast for 2009 is for an average of 58.9 Bcf/d, a 6.5 percent increase over this year.

Exhibit 13 presents the details of winter monthly natural gas production since November 2006 and the ICF forecast for the upcoming winter. The forecast is for Lower-48 production to average 57.5 Bcf/d this winter through March of 2009. The average monthly production rate for this winter is forecast to be approximately 4.2 Bcf/d higher than last year.

Exhibit 11

ICF Analysis of Lower-48 Quarterly Wellhead Gas Production

Dry marketed total gas - Bcf per day

Quarterly averages		Bcf per day *	Quarterly Bcfd Change	Quarterly Pct. Chg.
2003	1Q03	51.37		
	2Q03	51.49	0.12	0.2%
	3Q03	50.82	-0.67	-1.3%
	4Q03	50.50	-0.32	-0.6%
2004	1Q04	50.94	0.44	0.9%
	2Q04	49.94	-1.00	-2.0%
	3Q04	49.59	-0.35	-0.7%
	4Q04	49.03	-0.56	-1.1%
2005	1Q05	50.17	1.14	2.3%
	2Q05	50.46	0.29	0.6%
	3Q05	47.44	-3.02	-6.0%
	4Q05	46.83	-0.61	-1.3%
2006	1Q06	48.58	1.75	3.7%
	2Q06	49.57	0.99	2.0%
	3Q06	49.90	0.33	0.7%
	4Q06	49.77	-0.13	-0.3%
2007	1Q07	50.26	0.49	1.0%
	2Q07	51.28	1.02	2.0%
	3Q07	51.98	0.70	1.4%
	4Q07	52.95	0.97	1.9%
2008	1Q08	53.99	1.04	2.0%
	2Q08	54.57	0.58	1.1%
	3Q08	55.88	1.31	2.4%
	4Q08	56.87	0.99	1.8%
2009	1Q09	57.87	1.00	1.8%
	2Q09	58.67	0.80	1.4%
	3Q09	59.32	0.65	1.1%
	4Q09	59.82	0.50	0.8%

Annual averages		Bcf per day	Bcfd Change	Annual Pct. Chg.	Annual Production Bcf/Yr.	Annual Change Bcf
	2002	50.65	-1.66	-3.18%	18,487	-606
	2003	51.04	0.39	0.77%	18,630	142
	2004	49.87	-1.17	-2.29%	18,252	-377
	2005	48.66	-1.21	-2.43%	17,761	-492
	2006	49.46	0.80	1.64%	18,053	292
	2007	51.62	2.16	4.37%	18,841	788
	2008	55.33	3.71	7.19%	20,251	1,409
	2009	58.92	3.59	6.49%	21,506	1,255

* Production excludes approximately 1.2 Bcfd of Alaska gas production and 200 MMcfd of supplemental gas production consisting of coal gas and propane-air.

Exhibit 12

ICF Analysis of Lower 48 Dry Gas Production September 2008

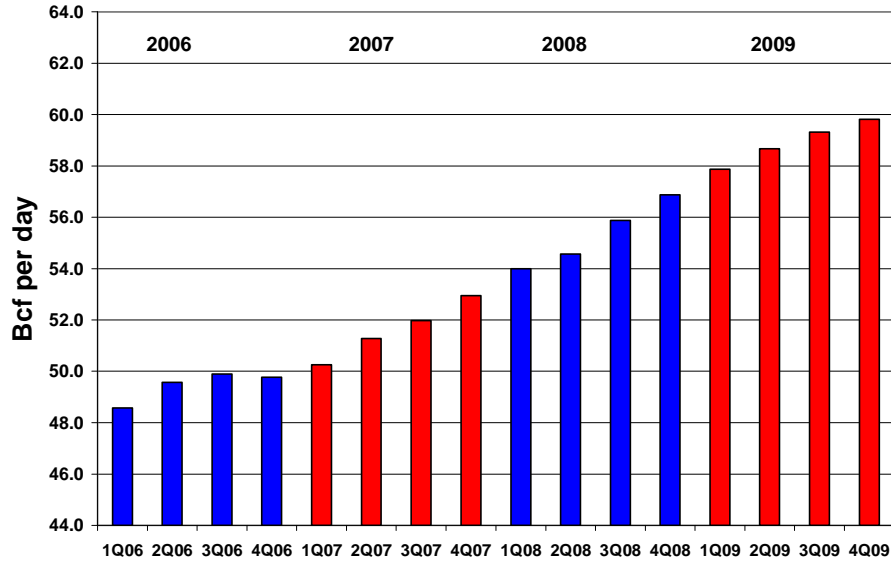


Exhibit 13

Historical and Forecast Winter Monthly Production

November - March

Source: ICF Database and Models

Bcf

Historical 2006-07			Historical 2007-08			ICF Forecast for this winter		
		Bcf			Bcf			Bcf
Nov	2006	1,495	Nov	2007	1,587	Nov	2008	1,706
Dec	2006	1,533	Dec	2007	1,651	Dec	2008	1,775
Jan	2007	1,550	Jan	2008	1,662	Jan	2009	1,785
Feb	2007	1,407	Feb	2008	1,511	Feb	2009	1,620
Mar	2007	1,566	Mar	2008	1,685	Mar	2009	1,803
total		7,551			8,096			8,689

Bcf per day

Historical 2006-07			Historical 2007-08			ICF Forecast for this winter		
		Bcfd			Bcfd			Bcfd
Nov	2006	49.8	Nov	2007	52.9	Nov	2008	56.9
Dec	2006	49.5	Dec	2007	53.3	Dec	2008	57.3
Jan	2007	50.0	Jan	2008	53.6	Jan	2009	57.6
Feb	2007	50.3	Feb	2008	52.1	Feb	2009	57.9
Mar	2007	50.5	Mar	2008	54.4	Mar	2009	58.2
average		50.0			53.3			57.5

Shale Gas Plays

2008 has been one of the most significant years in the history of the U.S. natural gas industry. Gas production from the Barnett, Fayetteville, and Woodford Shales has continued to climb rapidly, and at least five new shale plays were announced in the first half of this year. These include:

- Haynesville Shale in Northern Louisiana
- Marcellus and Huron Shale in Appalachia
- Utica Shale in Eastern Canada
- Muskwa Shale in British Columbia
- Montney Shale in British Columbia

There are now more than 8,000 Barnett Shale gas wells producing in the Newark East gas field. Estimates of recoverable resources range from a USGS estimate of 26 Tcf to the current ICF estimate of 107 Tcf, assuming full 40 acre spacing development with horizontal wells. Some industry analysts expect Barnett Shale production to increase to 7 Bcf per day in coming years.

In the Midcontinent Region Arkoma Basin, the Fayetteville Shale horizontal gas play in the Arkansas part of the basin and the Woodford Shale horizontal play in the Oklahoma part of the basin are both experiencing rapid increases in production. In 2007, the Fayetteville produced an average of 244 MMcf per day and the Woodford produced an average of 195 MMcf per day. The Fayetteville is now producing over 600 MMcf per day and the Woodford is producing over 350 MMcf per day.

Chesapeake Energy announced the opening of a large new horizontal shale gas play in northern Louisiana – the Jurassic age Haynesville Shale. In early press reports, the company indicated that their acreage has 20 + Tcf of potential. The play is in Caddo, DeSoto, Bienville, Bossier and Red River parishes in northwestern Louisiana, and extends into several counties in East Texas. Depths range from 10,500 to 13,000 feet – somewhat greater than the Barnett -- and the shale is about 200 feet thick. Operators have stated that some wells are as good as or better than Barnett Shale wells in terms of flow rates and recovery per well. One recent report indicated an average of 6.5 Bcf per well could be expected. This is much higher than the average Barnett well. However, based upon public data, it is too early to know how large an area will be represented by such wells.

The Devonian age Marcellus Shale in Appalachia also emerged in early 2008. Operators have been testing both vertical and horizontal drilling across a very wide area representing the full known depositional extent of the Marcellus from West Virginia on the southwest to northeastern Pennsylvania and southern New York on the north. This is a very large area, even in comparison to the Barnett. It is generally thinner than the Barnett, averaging about 50 – 200 feet. Organic content and maturity are favorable and depths are in a range of 5,000 to 8,500 feet. While the play is very well located in terms of eastern population centers, accessibility may be an issue in some areas, at least relative to plays in Texas, Oklahoma, and Arkansas.

Gulf of Mexico Deepwater

In the deepwater Gulf of Mexico (>200 meters water depth), Anadarko's Independence Hub in the Eastern Gulf of Mexico started up last summer and successfully ramped up to its capacity of 1 Bcf per day by late 2007. Production from this group of gas fields now represents a significant percentage of total Gulf of Mexico production.

In October of 2007, BP started production from the Atlantis semi-submersible platform. The facility is located in about 7,000 feet of water and is the deepest moored floating oil and gas production facility in the world. The production capacity for this facility is 200,000 barrels of oil and 180 million cubic feet of gas per day. This rate of production is expected by the end of 2008. BP's Thunder Horse Field had a partial startup in June and is expected to be at full production by the end of 2008. The field is rated at 250,000 bopd and 200 MMcf per day. BHP Billiton started production at the Neptune Field in the Green Canyon area. The field has a capacity of 50,000 bopd and 50 MMcf per day.

EIA statistics on historical deepwater (200 m+) gas production indicate a recent plateau at about 3 Bcf per day through 2006, the latest year of published data. This is down from the peak rate of 4.1 Bcf per day in 2003. However, ICF forecasts that deepwater production will increase in coming years, as plays in the ultra-deep water "Lower Tertiary" oil and associated gas trend come online. Discoveries in this trend represent about 3 billion barrels of oil and up to 3 Tcf of gas, and there is excellent potential for additional discoveries. In addition, new areas of the Eastern Gulf deepwater area have been leased, and this region is gas-prone.

Gulf of Mexico Deep Shelf

The "Deep Shelf" drilling play (different from the "Ultra-Deep Shelf" play, discussed below) has resulted in a number of gas discoveries. The Deep Shelf play lies in less than 200 meters of water with drilling targets between 15,000 and 25,000 feet. Production is approximately 1 Bcf per day. The most active operator is McMoRan, which has a number of discoveries. Two major new fields in the play, named "Dutch" and "Mary Rose" were discovered by Contango Oil and Gas last year. Expected production from just these two fields is 300 MMcf per day, due to very high per-well productivity.

The “Ultra-Deep Shelf” play lies below 30,000 feet across part of the Gulf of Mexico shelf offshore Louisiana. McMoRan Exploration has re-entered the Blackbeard well that was previously drilled to 32,000 feet on the Gulf of Mexico shelf looking for ultra-deep objectives. McMoRan plans to drill the well to a depth of 35,000 feet to test the prospect and the play concept.

Comparison with EIA Short-Term Forecast

EIA publishes a short-term forecast each month with quarterly estimates of U.S. natural gas production and imports. The August 2008 Short Term Energy Outlook was evaluated and compared to the ICF forecast. **Exhibit 14** presents the EIA and ICF quarterly production averages for the Lower-48.

EIA is forecasting a 2008 Lower-48 production increase of 8.5 percent. This compares to an increase of 7.2 percent in the ICF analysis. The EIA forecast for 2009 is for a 3.5 percent increase, compared with our 6.5 percent.

Storage Injection

At the end of August, U.S. inventories of working natural gas in storage stood at about 2.80 Tcf, or 30 Bcf above the five-year average of 2.77 Tcf and 220 Bcf lower than the 3.02 Tcf at the end of late August, 2007. As shown in **Exhibit 15 (a)**, the 2008 storage volumes were below the five year average in June and July but have since recovered. The ICF forecast is for the storage level on November 1 to be approximately 3.45 Tcf. This compares to a level of 3.55 Tcf last year, or approximately 100 Bcf lower. **Exhibit 15 (b)** is a detail of the first eight months of 2008 compared with prior years and the five year average.

One factor that has affected storage injection this year is the reduced volume of LNG imports during the warm weather months compared to recent years. This is presented in the LNG import section of this report.

Exhibit 14

Comparison with EIA Short Term Outlook

Bcf per day; Lower-48 and U.S. Total Dry Gas Production
ICF Current Study vs. EIA Short Term Outlook

	ICF (Lower 48)	EIA (U.S. Total)	EIA (Lower 48)	Lower 48 Difference ICF vs.EIA	
2006					
1Q	48.58				
2Q	49.57				
3Q	49.90				
4Q	49.77				
2007					
1Q	50.26	51.47	50.13	0.13	
2Q	51.28	52.28	51.14	0.14	
3Q	51.98	53.06	51.87	0.11	
4Q	52.95	54.41	53.21	-0.26	
2008					
1Q	53.99	55.83	54.60	-0.61	
2Q	54.57	56.37	55.91	-1.34	
3Q	55.88	57.67	56.56	-0.68	
4Q	56.87	58.16	56.93	-0.06	
2009					
1Q	57.87	58.72	57.45	0.42	
2Q	58.67	59.22	58.16	0.51	
3Q	59.32	59.21	58.11	1.21	
4Q	59.82	59.28	58.07	1.75	
		L48 % chg.		L48 % chg.	
2007	51.62	4.37%	52.81	51.60	4.05%
2008	55.33	7.19%	57.17	56.00	8.53%
2009	58.92	6.49%	59.11	57.95	3.48%

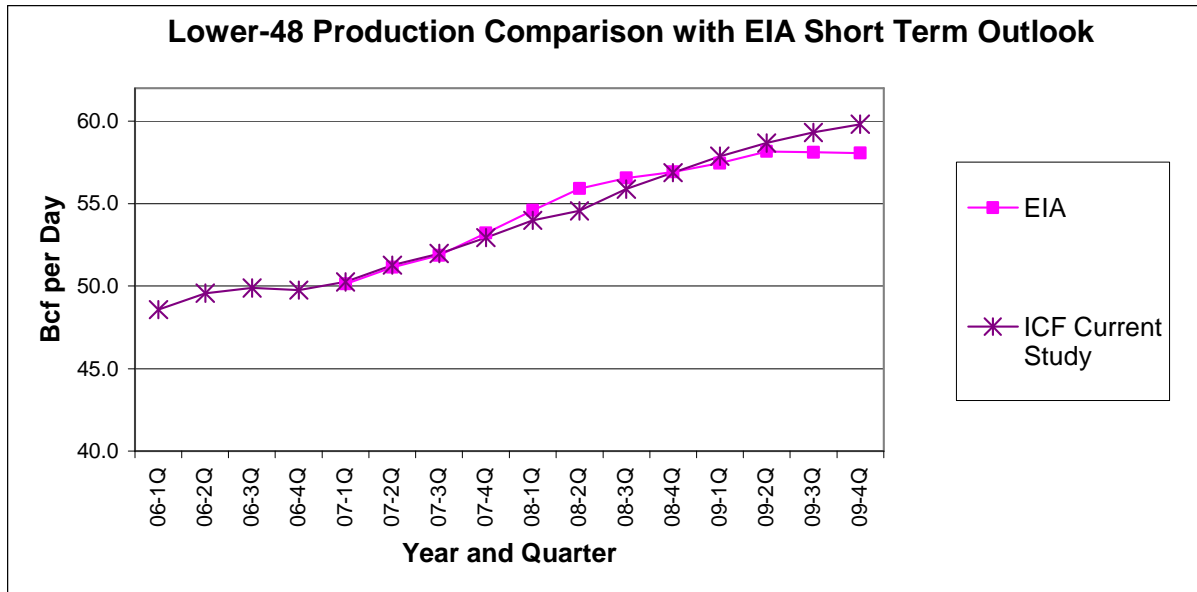


Exhibit 15 (a)

**Gas Storage - Entire Year With Forecast
U.S. Working Gas Inventories - End of Month Volumes**

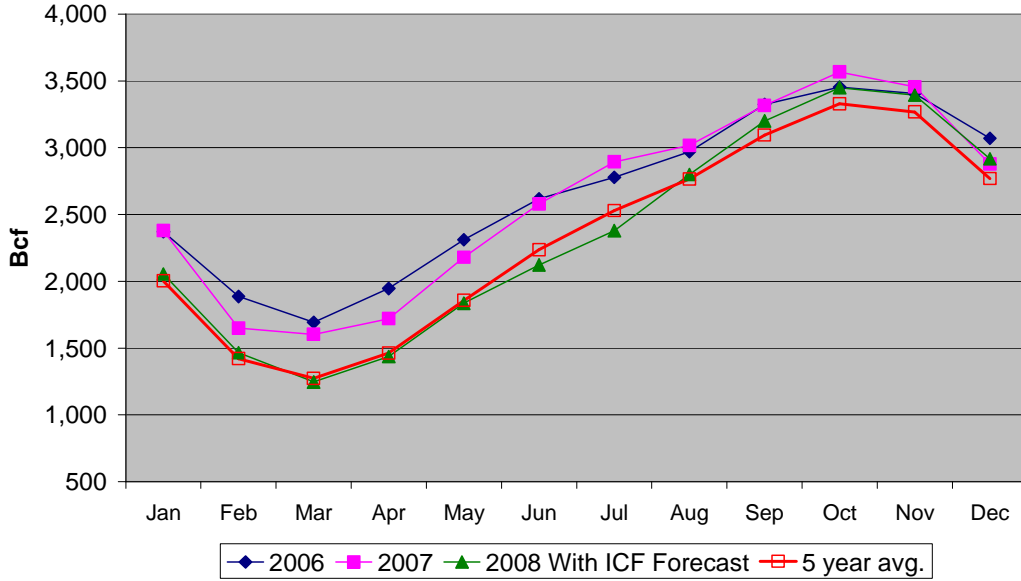
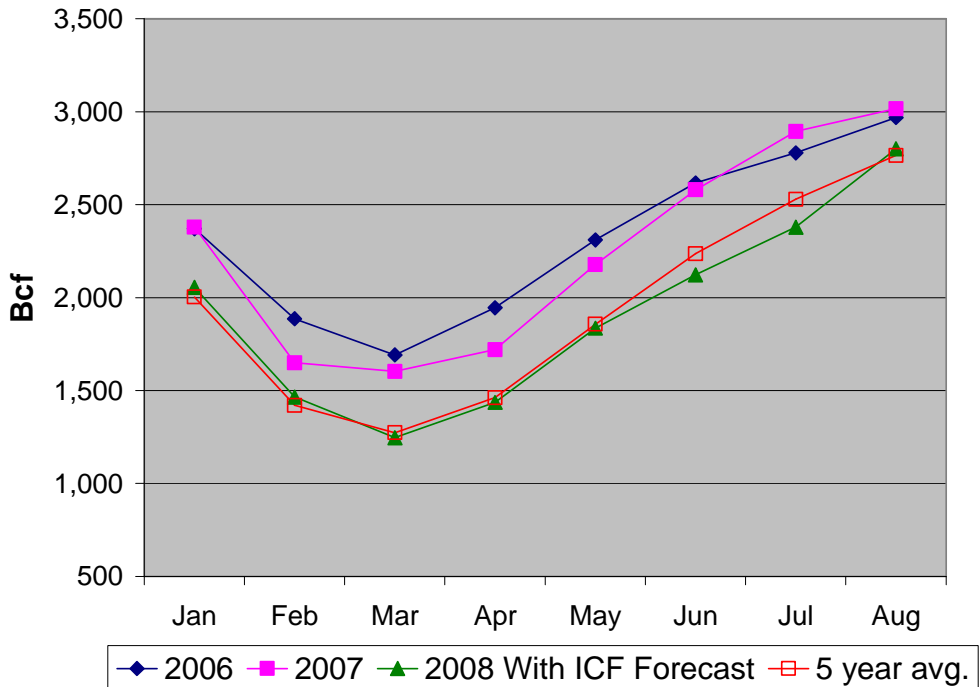


Exhibit 15 (b)

**Gas Storage - January through August
U.S. Working Gas Inventories - End of Month Volumes**



Pipeline Imports and Exports

Exhibit 16 shows the winter pipeline imports from Canada and exports to Mexico, starting with the winter of 2006-07. Import data are net to the U.S. The historical Canadian import data are taken from the ICF Natural Gas Update and are a combination of Stats Canada and pipeline bulletin boards.

Net imports from Canada last winter (2007-08) averaged 8.0 Bcf per day, about 7 percent lower than the previous winter's average of 8.6 Bcf per day.

This winter we forecast that imports from Canada will average 7.5 Bcf per day, a decline of 6 percent or 0.5 Bcf/d relative to last winter. The volume of Canadian pipeline imports depends on WCSB gas production and demand in both Canada and the U.S. Western Canada production is declining, and ICF is forecasting that this will continue in the near-term.

While gas production from the Western Canada coalbed methane play is increasing, these gains have not resulted in an upturn in overall gas production. On the Canadian demand side, an important consideration is the demand for gas from oil sands operations, which is increasing. Another factor in Canadian imports is that the offshore Nova Scotia area production has been relatively flat, and Canadian LNG imports have not yet started, although a 1 Bcf per day facility in New Brunswick is scheduled for startup in late 2008 as discussed below.

Exhibit 16

Pipeline Imports from Canada and Exports to Mexico

November through March

Sources: ICF Monthly Gas Update and EIA Natural Gas Monthly

Net Imports from Canada

Bcf per day

positive = net imports

Historical 2006-07			Historical 2007-08			ICF Forecast for this winter 2008-09		
		Bcf/d			Bcf/d			Bcf/d
Nov	2006	8.10	Nov	2007	7.90	Nov	2008	7.40
Dec	2006	8.20	Dec	2007	8.40	Dec	2008	8.40
Jan	2007	8.10	Jan	2008	7.90	Jan	2009	8.30
Feb	2007	10.00	Feb	2008	7.70	Feb	2009	6.80
Mar	2007	8.50	Mar	2008	8.00	Mar	2009	6.40
average		8.55			7.98			7.47

Net Exports to Mexico

Bcf per day

negative = net exports

Historical 2006-07			Historical 2007-08			ICF Forecast for this winter 2008-09		
		Bcf/d			Bcf/d			Bcf/d
Nov	2006	-0.80	Nov	2007	-0.80	Nov	2008	-1.20
Dec	2006	-0.80	Dec	2007	-0.80	Dec	2008	-1.10
Jan	2007	-0.40	Jan	2008	-0.80	Jan	2009	-0.80
Feb	2007	-0.50	Feb	2008	-0.90	Feb	2009	-0.90
Mar	2007	-0.50	Mar	2008	0.90	Mar	2009	-0.90
average		-0.60			-0.47			-0.98

Winter LNG Imports

The U.S. typically imports 1.0-1.8 Bcf/d of LNG during the winter months. Over the long term, LNG imports are projected to become an increasing portion of the North American gas market. The U.S. currently has eight operating LNG import terminals and there is one terminal in Mexico. Below is a listing of the facilities with their peak import capacity, which currently totals 11.1 Bcf per day.

- Everett, MA; 1.04 Bcf/d peak capacity
- Cove Point, MD; 1.00 Bcf/d peak capacity; expansion of 800 MMcf/d planned for 2008

- Elba Island, GA; 1.2 Bcf/d peak capacity; expansion planned for additional 900 MMcf/d
- Lake Charles, LA; 2.1 Bcf/d peak capacity
- Gulf Gateway, Gulf of Mexico, 0.5 Bcf/d capacity
- Northeast Gateway Energy Bridge, Offshore Massachusetts; 0.5 Bcf/d
- Cheniere – Freeport LNG, Freeport, Texas; 1.5 Bcf/d
- Sabine Pass Cheniere LNG, Sabine Pass, LA; 2.6 Bcf/d ; expansion planned for additional 1.4 Bcf/d
- Shell/Total/Mitsui, Altamira, Mexico ; 0.7 Bcf/d

A number of LNG facilities in North America, including Mexico and Canada, are under construction. One Canadian facility is under construction at Saint John, New Brunswick. This is the Canaport-Irving Oil 1.0 Bcf/d facility scheduled for startup in late 2008. Three facilities are under construction in the Gulf Coast region with capacity totaling 5.3 Bcf/d. There is a Mexican facility under construction in Baja California with a capacity of 1.0 Bcf/d. In total, the currently operational and planned North American import capacity is over 21 Bcf/d.

Exhibit 17 shows the recent history of worldwide LNG shipments and world gas production. Total LNG shipments increased from 4.9 Tcf in 2000 to 8.0 Tcf last year. LNG imports to North America increased from 239 Bcf per year in 2000 to 886 Bcf per year in 2007, and now represent about 11 percent of worldwide shipments. The Asia-Pacific region imports about 65 percent of world LNG.

World gas production continues to grow and a significant fraction of production is converted to LNG. In 2007, world gas production was 104 Tcf and LNG production was 8.0 Tcf or 7.7 percent. Since 2000, world gas production has increased by 18 Tcf per year, while LNG shipments have increased by 3.1 Tcf per year.

Exhibit 17

World LNG Imports and Gas Production

EIA data through 2005; BP data for 2006 and 2007

	LNG Imports				Gas Production		
	North America Bcf	Europe Bcf	Asia - Pacific Bcf	Total Bcf	LNG Post-2000 Increase Bcf	World Gas Production Tcf	Post-2000 Increase Tcf
2000	239	1,150	3,544	4,933	0	85.4	0.0
2001	261	1,157	3,776	5,194	261	87.6	2.2
2002	253	1,386	3,671	5,310	377	89.1	3.7
2003	544	1,390	3,978	5,912	979	92.3	6.9
2004	683	1,423	4,347	6,453	1,520	95.4	10.0
2005	664	1,668	4,495	6,827	1,894	98.0	12.6
2006	652	2,028	4,774	7,454	2,521	101.4	16.0
2007	886	1,883	5,225	7,994	3,061	103.8	18.4

Percentage of world LNG imports				
	North America	Europe	Asia - Pacific	Total
2000	4.8%	23.3%	71.8%	100.0%
2001	5.0%	22.3%	72.7%	100.0%
2002	4.8%	26.1%	69.1%	100.0%
2003	9.2%	23.5%	67.3%	100.0%
2004	10.6%	22.1%	67.4%	100.0%
2005	9.7%	24.4%	65.8%	100.0%
2006	8.7%	27.2%	64.0%	100.0%
2007	11.1%	23.6%	65.4%	100.0%

Unlike with domestic gas supplies in the U.S. and Canada, North America must compete with the rest of the world for LNG. World natural gas prices have been higher than those in North America, impacting the economics of importing LNG to the U.S. European countries such as Spain and France rely heavily on LNG in the winter and are purchasing increasingly large volumes and paying higher prices than would be competitive in the U.S. Demand from Asia and South America also continues to climb.

Other factors impacting world LNG markets are the higher price of oil, the linkage of European gas prices to oil, declining North Sea gas production, and an emphasis on gas fired power generation in Europe. Another factor is the delay in previously planned liquefaction capacity.

In recent years, the U.S. has imported most of our annual LNG in the summer months when there is less demand in Europe. However, this summer, LNG imports to the U.S. are much lower than in 2007. In the first half of 2008, LNG imports to the U.S. were down 60 percent compared with last year.

Exhibit 18 shows monthly LNG gross imports for the past two winters and the ICF forecast for this winter. The winter total volume imported for 2006-07 was 283 Bcf, or 1.9 Bcf per day. Last winter, the volume declined to 123 Bcf, or 0.8 Bcf/d. For the upcoming winter, ICF is forecasting a volume of 150 Bcf, or 1.0 Bcf/d -- about 0.2 Bcf per day more than last winter.

Exhibit 18

Historical and Forecast Winter LNG Imports

November - March; Gross Imports - Not Net of Alaska Exports

Source of historical data: EIA Natural Gas Monthly (Data shown through March 2008)

Source of forecast: ICF Monthly Gas Update (Data shown for 2008-09)

Bcf

Historical 2006-07			Historical 2007-08			ICF Forecast for this winter 2008-09		
		Bcf			Bcf			Bcf
Nov	2006	47.2	Nov	2007	26.5	Nov	2008	30
Dec	2006	51.2	Dec	2007	20.8	Dec	2008	31
Jan	2007	53.4	Jan	2008	28.4	Jan	2009	31
Feb	2007	44.1	Feb	2008	23.6	Feb	2009	28
Mar	2007	86.8	Mar	2008	23.7	Mar	2009	30
total		282.7			123.0			150

Bcf per day

Historical 2006-07			Historical 2007-08			ICF Forecast for this winter 2008-09		
		Bcfd			Bcfd			Bcfd
Nov	2006	1.57	Nov	2007	0.88	Nov	2008	1.0
Dec	2006	1.65	Dec	2007	0.67	Dec	2008	1.0
Jan	2007	1.72	Jan	2008	0.92	Jan	2009	1.0
Feb	2007	1.58	Feb	2008	0.81	Feb	2009	1.0
Mar	2007	2.80	Mar	2008	0.76	Mar	2009	1.0
average		1.86			0.81			1.0

Summary

Exhibit 19 summarizes the results of the supply analysis

Exhibit 19

Supply Outlook for Winter 2008-09

	source	2007-08	2008-09	change	percent change
U.S. production vs previous year (trend)	1	---	Up	---	---
Annual well completions (calendar year)	2	30,777	31,530	753	2.4%
Annual rig count (gas rigs Jan. - December)	3	1,470	1,535	65	4.4%
Winter LNG imports (Bcf/d - Nov. - March)	4	0.81	1.00	0.19	23.5%
Winter average gas production (Bcf/d - Lower 48)	5	53.3	57.5	4.20	7.9%
Working gas in storage (Tcf - Nov.1)	6	3.55	3.45	-0.10	-2.8%
Net pipeline imports from Canada (Bcf/d - Nov. - Mar.)	7	7.98	7.47	-0.51	-6.4%

Sources:

1. ICF - Current Study - State and federal data with ICF adjustments and forecast.
2. API Quarterly Completion Report with ICF estimates.
3. Baker Hughes gas rigs with ICF forecast through December.
4. Historical data from EIA Natural Gas Monthly; Forecast from ICF Monthly Gas Update.
5. Historical and forecast from current study. Derived from state and federal data with adjustments and forecast
6. Historical data from EIA; Forecast from Monthly Gas Update.
7. Historical data from StatsCanada and bulletin boards; Forecast from Monthly Gas Update.