Gas Supply Potential and Development Costs of Rocky Mountain Gas and LNG Delivered to the Pacific NW

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1 EXECUTIVE SUMMARY

A key issue in evaluating the proposed Jordan Cove LNG import facility is the cost to gas customers in the region of natural gas from imported LNG versus the cost of bringing in gas supplies via pipeline. Since the Pacific Northwest has very little gas production and scant potential to develop additional regional supplies of gas, potential future gas production from North American sources would come from the Rockies or Western Canada. Thus it is important to evaluate the costs of potentially transporting future gas supplies from such North American sources as compared with the cost of importing LNG.

This report evaluates the cost of supply and future potential of gas production coming from the U.S. Rocky Mountain region and compares it to that of imported LNG.

The Rockies is a potential source of future domestic gas supplies via pipeline to the Pacific Northwest. Rockies production has been increasing rapidly over the past decade and continues to increase. New pipeline capacity has been built and additional capacity is planned. Several pipelines have also been proposed to move Rockies gas to the Pacific Northwest.

Production from Western Canada has been relatively flat in recent years. Production from that region does have the potential to grow over the long term, but most growth will likely be consumed within Canada rather than being exported, especially with the greatly increased forecast demand for gas for the development of Western Canada oil sands.

Gas production from the Rockies currently moves by pipeline directly to Midwest and East Coast markets, toward the southeast to connections with other pipelines moving gas to the northeast, toward the southwest to California, and toward the northwestern U.S. Should an LNG import facility not be constructed in the Pacific Northwest, a large amount of new pipeline capacity would have to be built to that region.

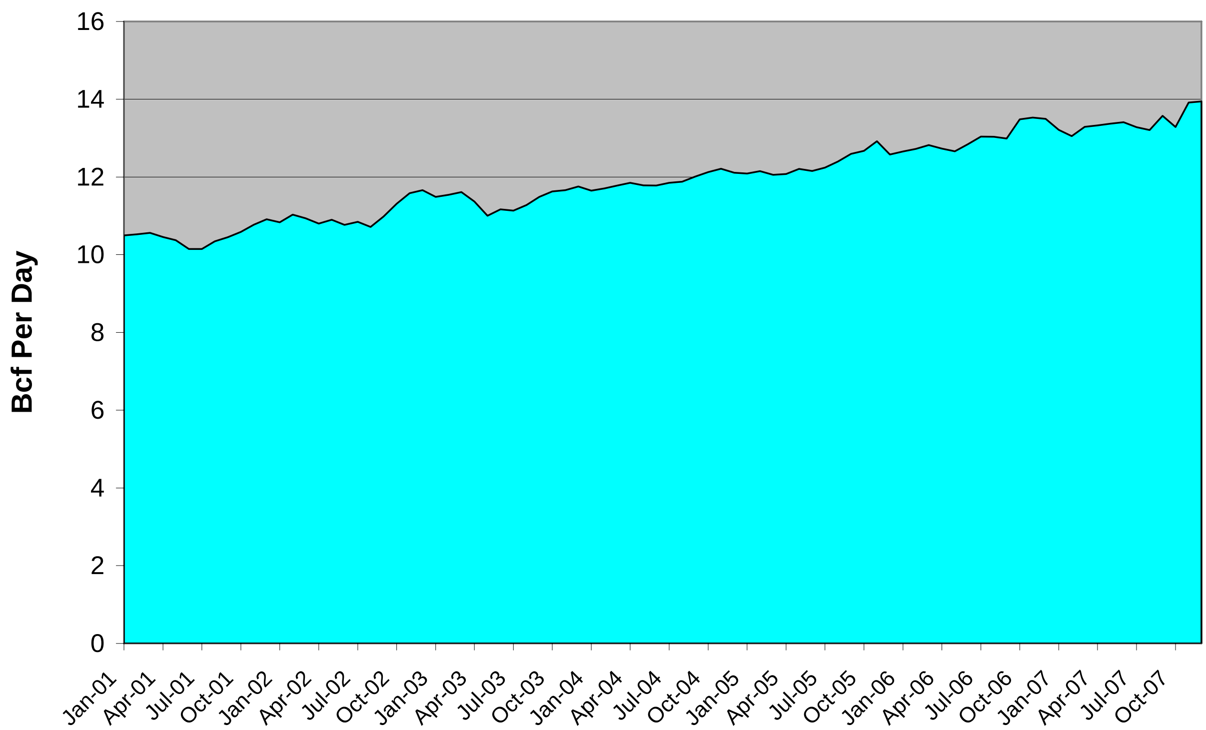
Rockies Production and Activity

The Rocky Mountain region, encompassing portions of Wyoming, Colorado, Utah, and Montana is the most prolific gas producing region of the Lower-48, and contains very large volumes of undeveloped natural gas. Drilling and completion technologies developed over the past twenty years are unlocking an expanding supply of gas from low permeability formations and coal seams. Expansion of activity and production has been so rapid during the past decade that pipeline transportation from the region has represented a major bottleneck. Despite great strides in expansion of the transportation system, the region remains affected by transportation constraints.

Rockies gas production is increasing rapidly, as shown in Figure 1. Production growth has come from two sources: coalbed methane and tight (low permeability) gas deposits. Throughout the 1990s most of the growth was from coalbed methane in areas such as the Powder River Basin of eastern Wyoming. More recently the growth has come from tight gas deposits in southwestern Wyoming, northwestern Colorado, and northeastern Utah. ICF believes that while coalbed methane production continues to increase, the rate of growth has slowed. On the other hand, tight gas production continues to ramp up.

From a resource base and technology standpoint, Rockies production is expected to continue to grow in coming decades, especially if wellhead prices stay above $6 to $7 per MMBtu. Most of the new production will come from the aforementioned tri-state area of Wyoming, Colorado, and Utah.

Figure 1. Rocky Mountain Raw Wellhead Gas Production



Land access to development of Rockies gas has long been a major issue. Much of the area is controlled by the Bureau of Land Management, and some areas are under the jurisdiction of the Forest Service. Recent industry studies have shown that very significant portions of the undeveloped resource base are either off limits or have much higher than average costs due to regulatory issues. Despite these problems, ICF believes that, at least through 2020, industry will have sufficient access to greatly expand production without any reduction in regulations or restrictions. An ominous recent trend for industry is the effort by some states, such as recently in Colorado, to restrict drilling in some of the key areas, and to possibly increase severance taxes as well.

Rockies Wellhead Resource Costs and Delivered Costs

ICF has evaluated wellhead gas resource development costs at the play level for the Rocky Mountain region. Figure 2 shows the supply cost curves for wells drilled annually since 1999. The development costs for wells drilled in 2007 is shown in light blue with open squares. The chart shows that while more reserves have been added in recent years, a substantial amount of those reserves are relatively high cost.

In order to estimate the marginal cost of Rockies reserve additions, ICF based the evaluation on the 90^{th} percentile of reserves added in 2007. At the 90^{th} percentile of reserves added in 2007, the wellhead price needed is $5.73. Table 1 shows the analysis for recent years.

This analysis indicates that industry activity in the region will remain robust as long as wellhead prices are a minimum of about $5.00 dollars per MMBtu, but a price of $5.70 is needed for economic development consistent with what occurred in 2007. Should wellhead prices drop lower than $5.00, the majority of current activity in the region would not be economically sustainable.

Rockies Supply Cost Delivered to the Pacific Northwest

The above analysis applies to wellhead costs only. To estimate the total cost of delivering Rockies gas to the Pacific NW, it is necessary to add additional cost components. These include gathering, transport to a regional hub, and transport to the Pacific Northwest.

Table 2 summarizes the cost components to transport Rockies gas to the Pacific Northwest assuming a starting point in the Piceance Basin of northwestern Colorado. The total transport cost is $2.06 per MMBtu.

If one adds a typical wellhead resource cost of $5.73 per MMBtu, the total delivered cost of Rockies gas is approximately $7.79 per MMBtu.

Table 1. Estimation of Rockies Marginal Cost of Reserves Using 90th Percentile of Reserves Added

Selected Region: Rockies

	1999	2000	2001	2002	2003	2004	2005	2006	2007
Max Quantity	1,809	2,739	3,421	2,790	2,630	3,586	4,860	5,100	4,984
Q @ X Percentile	1,628	2,465	3,079	2,511	2,367	3,227	4,374	4,590	4,486
Rockies Marginal Cost	**$3.15**	**$3.59**	**$5.17**	**$3.81**	**$4.31**	**$4.24**	**$4.96**	**$5.76**	**$5.73**

US Wellhead Price (EIA)	**$2.19**	**$3.68**	**$4.00**	**$2.95**	**$4.88**	**$5.46**	**$7.33**	**$6.40**	**$6.39**

Figure 2. Rockies Wellhead Gas Resource Costs

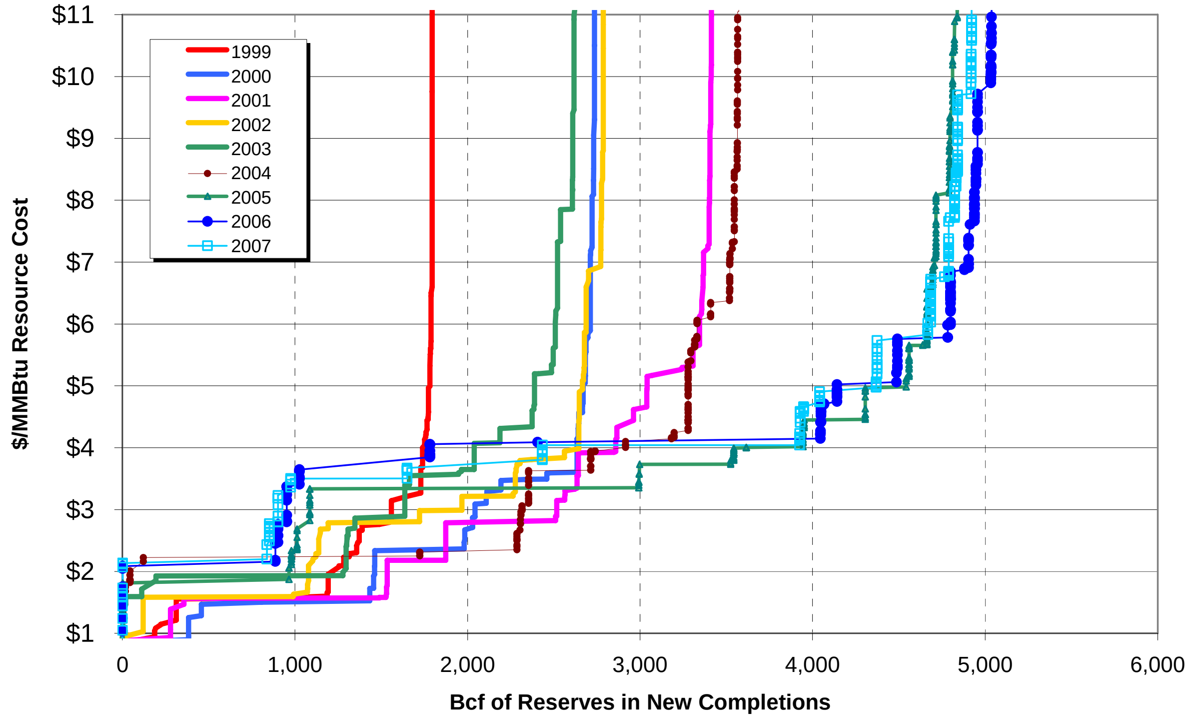


Table 2. Cost of Transporting Rockies Gas

Pipeline	From / to	Full Transport Cost ($'s per MMBtu)
Wellhead Gathering	Basin to Pipeline	$0.500
Wyoming Interstate Company	Piceance to Opal	$0.290
Ruby Pipeline (proposed)	Opal to Malin	$0.700
Gas Transmission Northwest	Malin to Stanfield	$0.155
Northwest Pipeline Company	Stanfield to Oregon Markets	$0.410
Total		$2.055

LNG Supply and Resource Costs

ICF has evaluated the economics of importing LNG to the Pacific Northwest. The analysis includes an evaluation of the cost of liquefaction, transport, and receipt terminals. The results of the study are shown in Table 3. The first example represents a 1 bcfd project in the Russian Far East with upstream development costs of $1.00 per Mcfe of net gas reserves or $7.3 billion for the project. The second example represents a 582 MMcfd project in Peru with upstream costs of $0.75 per net Mcfe or a $3.2 billion total. The third example is a 824 MMcfd project in Papua New Guinea that has an upstream investment cost of $0.75 per Mcfe or a total of $4.5 billion upstream investment.

The total costs for the three project examples range from $6.43 to $6.71 per MMBtu (last row of table). Actual project cost will vary from these examples depending on cost for materials and services for facility and ship construction, host country tax and royalty rates, energy prices and the method and cost of project financing.

Thus the total delivered cost of LNG to the Pacific Northwest is about $6.50 per MMBtu. This can be compared to an expected cost of developing and transporting Rocky Mountain gas of $7.79 per MMBtu.

Table 3. Delivered Cost of LNG to North American West Coast

Estimated Costs for LNG Projects
(million 2008 dollars)

	Russia Far East	Peru	Papua New Guinea
Project Size (MMcfd)	1,000	582	824
Project Size (million metric tonnes per year)	7.65	4.45	6.30
Upstream Investment ($/Mcfe)	$1.00	$0.75	$0.75
Upstream Capital Investment	7,300	3,186	4,511
Annualized Upstream Capital Costs	786	343	486
Annual Upstream O&M	292	127	180
Total Annual Cost	1,078	471	666
Upstream Cost Recovery ($/Mcf)	*$2.95*	*$2.22*	*$2.22*
Source-Country Prod. Royalties & Taxes ($/Mcf)	*$1.00*	*$1.00*	*$1.00*
Total Upstream Cost ($/Mcf)	*$3.95*	*$3.22*	*$3.22*
Liquefaction Plant Cost ($/tonne/year)	675	773	708
Liquefaction Plant Capital Investment	5,156	3,436	4,459
Annualized Liquefaction Capital Cost	555	370	480
Annual Liquefaction O&M	206	137	178
Total Annual Cost	762	508	659
Total Liquefaction Cost ($/Mcf)	*$2.09*	*$2.39*	*$2.19*
Ship Size (cubic meters)	135,000	135,000	135,000
Ship Cost ($million/ship)	202	202	202
Travel Distance (one-way nautical miles)	3,805	4,480	5,995
Required Number of Ships	8	6	10
Capital Investment in Ship	1,616	1,212	2,020
Annualized Capital Cost of Ships	172	115	213
Annual Fuel Costs	85	58	112
Annual Non-fuel Ship O&M	68	45	79
Total Annual Shipping Cost	325	218	404
Total Shipping Cost ($/Mcf)	*$0.89*	*$1.03*	*$1.34*
Receipt Terminal Capital Investment (1 bcfd)	675	675	675
Annualized Regas Capital Cost	73	73	73
Annual Fuel Costs	38	38	38
Annual Non-fuel Regas O&M	27	27	27
Total Annual Cost	138	138	138
Total Regas Cost ($/Mcf)	*$0.38*	*$0.38*	*$0.38*
All Capital Investment	14,747	8,509	11,665
All Cost Components ($/Mcf)	*$7.31*	*$7.01*	*$7.13*
Btu per standard cubic foot of gas	1,090	1,090	1,090
All Cost Components ($/MMBtu)	*$6.71*	*$6.43*	*$6.54*

2 ROCKY MOUNTAIN GAS PRODUCTION, POTENTIAL, AND COST OF SUPPLY

Introduction and Discussion of Issues Affecting Rocky Mountain Gas Supply and Economics

The Rocky Mountain region, encompassing portions of Wyoming, Colorado, Utah, and Montana is the most prolific gas producing region of the Lower-48, and contains very large volumes of undeveloped natural gas. Drilling and completion technologies developed over the past twenty years are unlocking an expanding supply of gas from low permeability formations and coal seams. Expansion of activity and production has been so rapid during the past decade that pipeline transportation from the region has represented a major bottleneck. Despite great strides in expansion of the transportation system, the region remains affected by constraints.

The region under consideration is shown in Figures 1 and 2. These maps show the boundaries of the geological basins within the region. The basin boundaries are those of the American Association of Petroleum Geologists, which are aggregations of counties.

Historically, land access has been considered a major impediment to resource development, especially in terms of drilling for large regional unconventional deposits such as the coalbed methane of the Powder River Basin. Industry is concerned about the impact on access and operating costs resulting from what they consider excessive environmental and regulatory restrictions. These costs and restrictions were a major focus of the most recent natural gas studies of the National Petroleum Council. Access issues involve habitat protection, water production and disposal (primarily with coalbed methane), air emissions, seasonal drilling restrictions, and opposition from environmental groups and landowners.

Drilling and completion technology is an important issue in the Rockies, where a very high percentage of the resource base is only accessible through the types of advanced technologies that were not available 20 to 30 years ago. For this region as well, the economics of future production will be heavily dependent upon the availability and cost of such technologies and the availability of experienced hands to implement them.

Figure 3. Rockies Basins – Northern Area

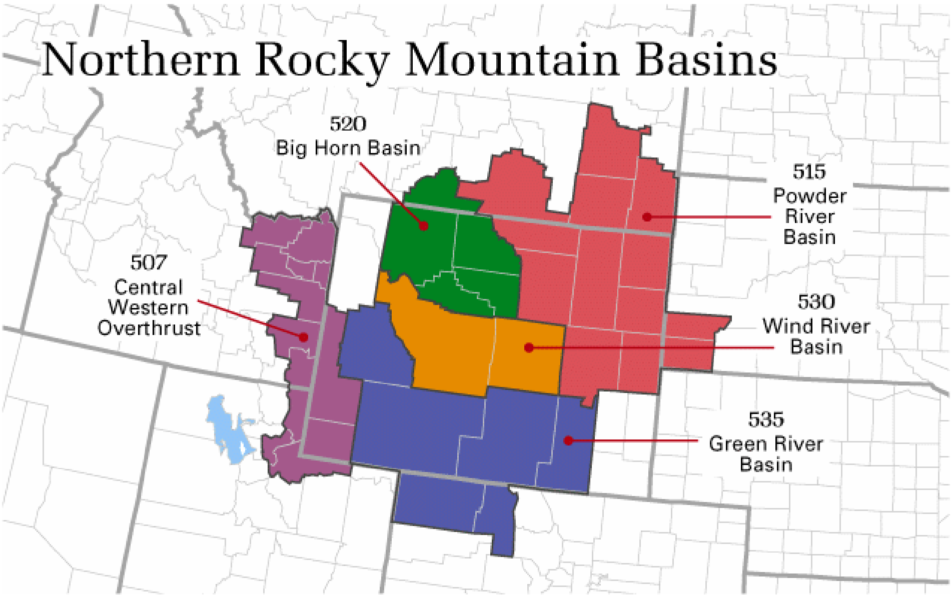
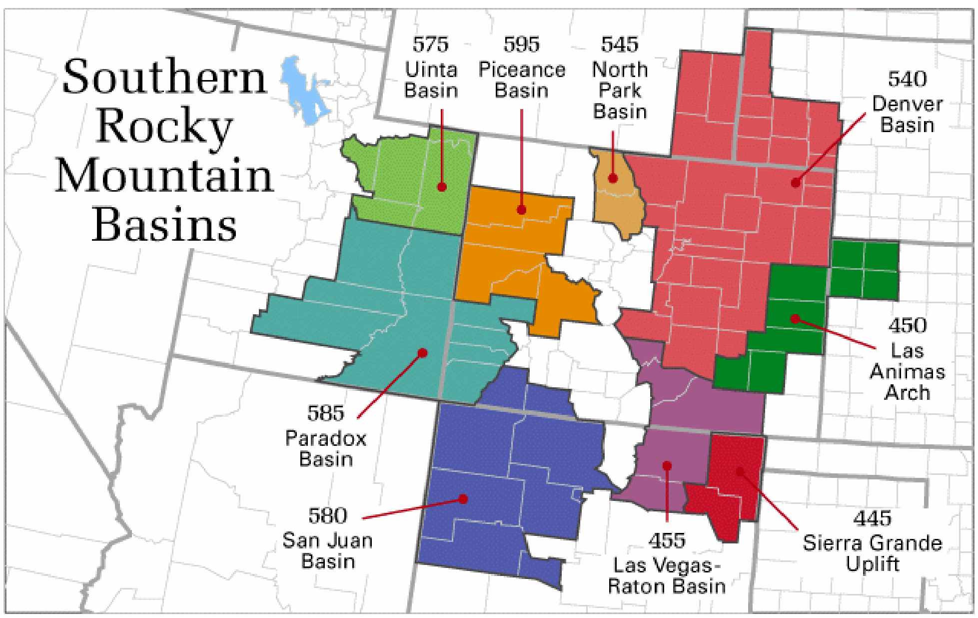


Figure 4. Rockies Basins – Southern Area



ICF has worked with industry to assess the remaining potential of the Rockies, both in terms of the amount of technically recoverable gas resource that will be available to develop, and in terms of the cost of developing that resource. Our costing models include play level details that include estimates of well recovery, drilling costs, operating costs, and other factors that affect supply economics, and the result of our current analysis will be presented here. This analysis shows the volumes of natural gas that can be expected to be developed at a given wellhead gas price.

This chapter addresses natural gas supply from the following AAPG basins:

- Green River Basin of Southwestern Wyoming
- Powder River Basin of Northeastern Wyoming and Southeastern Montana
- Wind River Basin in Wyoming
- Piceance Basin of Northwestern Colorado
- Uinta Basin of Northeastern Utah
- Western Overthrust Belt in Western Wyoming
- Denver Basin of Eastern Colorado

Overview of Rockies Gas Production

The region of interest includes Wyoming and parts of Colorado, Utah, and Montana. This is a prolific region for gas production, especially with the growth in production that has taken place in the past 10 to 15 years and continues in 2008. While the region has been known to have tremendous volumes of gas in place for decades, this resource went largely undeveloped because of low wellhead prices and a shortage of adequate transportation. In the 1990s, development picked up due to technological advance and improved national gas prices, but transportation bottlenecks from the region were severe. This had a major impact on regional wellhead prices and basis differentials.

Numerous new pipelines and expansions have resulted in much greater capacity from the region. Capacity has expanded to markets both east and west of the region. Pipeline capacity remains a major issue, however, even with the addition of the 1.8 Bcfd Rockies Express. Numerous pipeline projects are on the boards, and capacity is expected to expand significantly, especially beyond 2011-12 when some of this is operational.

Gas production in the region is growing as a result of tight gas and coalbed methane development. From the mid- 1990s to the early 2000s, the Powder River Basin coalbed play in northeastern Wyoming was a major focus of activity. More recently, tight gas exploration has dominated in areas such as the Piceance Basin of northwestern Colorado and the Green River Basin of southwestern Wyoming. The region has the greatest volume of unproven recoverable tight gas resource of any region in the U.S.

While coalbed methane (CBM) production is very significant in the Rockies, growth in CBM has generally flattened out. Tight gas production continues to increase however, largely in the area of Jonah-Pinedale and other areas in southwestern Wyoming, northwestern Colorado, and northeastern Utah. To date, there is no significant shale gas production in the region, although it appears that this resource will likely emerge to some extent within the next few years.

Figure 5 summarizes recent total gas production in the region. It is shown in units of Bcf per day of raw wellhead gas and includes both non-associated and associated/dissolved production. Figure 6 shows the same data plotted to show the detail of each basin. The charts illustrate the large increase in Rockies gas production over the past seven years. Most of the increase over this period has come from the Green River, Piceance, Uinta, and Powder River Basins, as is discussed below.

Figure 5. Rockies Gas Production: 2001 Through 2007

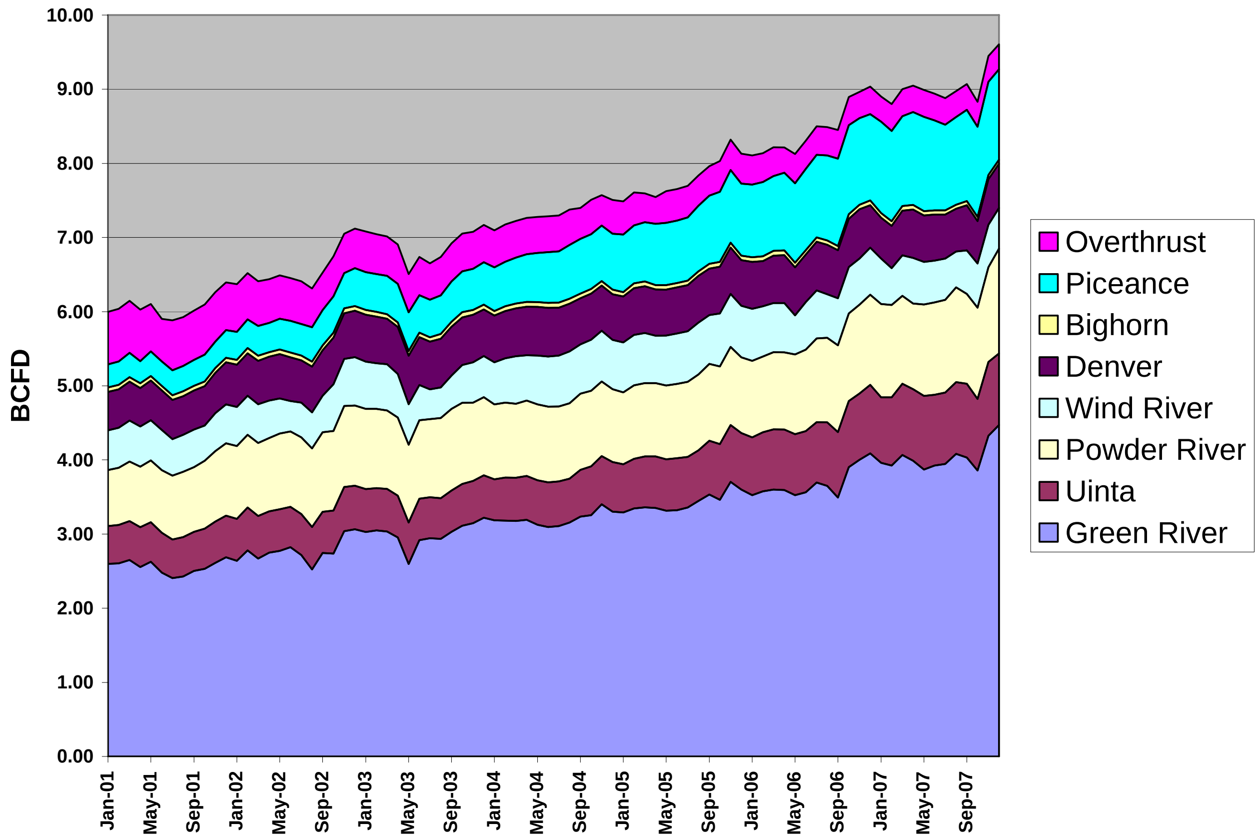
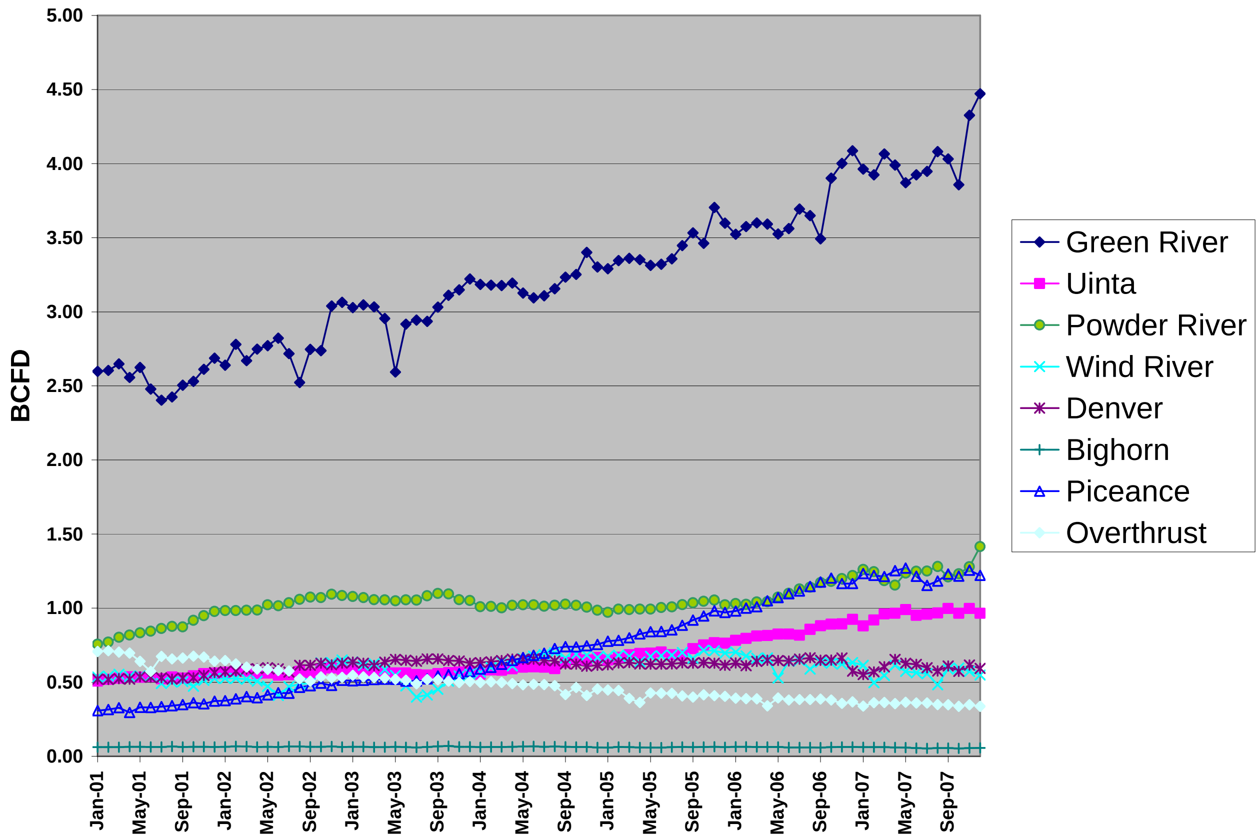


Figure 6. Production Trends for Individual Rocky Mountain Basins: 2001-2007



Gas Resource Base

The Rocky Mountain region is the location of a large percentage of remaining proved and unproved Lower-48 natural gas resources. ICF participated in a 2003 National Petroleum Council gas study, the most recent comprehensive assessment of remaining U.S. gas resources. [1] In addition, we have developed our own assessments of key basins and plays, including the major tight gas and coalbed plays in the Rockies. The results of this analysis are presented in Table 4. The table shows the recoverable gas resources assuming current technology.

The last column of the table shows the assessed total remaining unproved potential for each basin and for the region. The total is 206 Tcf. Of this total 24 Tcf is remaining potential in existing conventional fields, 33 Tcf is in undiscovered conventional fields, 45 Tcf is coalbed

[1] National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," Washington, D.C., http://www.npc.org.

methane, and 90 Tcf is tight gas. There is an additional 15 Tcf in low-Btu gas resources in Wyoming.

The 206 Tcf of remaining unproved resource can be compared to the Lower-48 total of about 1,200 Tcf. At the current rate of Rockies production of 14 bcf per day or 5.1 Tcf per year, the undeveloped resource base represents about 40 years of production. This shows that the resource assessments for the region are still conservative. In addition, the volumes shown are for currently available technologies. ICF also models the likely impact of future technologies on resources and well recoveries.

In the current assessment, there are no assessed shale gas resources included in the Rockies. To date, the shale formations that are productive in the U.S. are Devonian shales that are either not present or not productive in the Rockies. Some shale formations are being drilled in the Rockies, such as in the Baxter Formation in northwestern Colorado and the Pierre Shale in the Raton Basin, but these are not considered nearly as prospective as organic shales such as the Barnett Shale in Texas. Some of the resources of these formations are considered to have been included in the tight gas category.

Table 4. Discovered and Undiscovered Rocky Mountain Gas Resources

Tcf Dry Total Gas	Produced or Discovered			Discovered Undeveloped	Undiscovered Conventional	Undiscovered Unconventional				Remaining
Region	Past Cumulative Production	Remaining Proven Reserves	Proven Ultimate Recovery	Old Field Appreciation	New Fields	Shale	Coalbed	Tight	Low-BTU/ other	Discovered Undeveloped Plus Undiscovered
Uinta-Piceance Basin	4.7	7.2	11.9	3.8	2.1	0.0	5.9	27.5	0.0	39.2
Powder River Basin	2.3	2.4	4.6	1.0	1.5	0.0	26.6	0.8	0.0	29.8
Big Horn Basin	1.9	0.1	2.0	0.5	0.4	0.0	0.0	0.0	0.0	0.9
Wind River Basin	3.2	2.4	5.7	2.0	1.6	0.0	0.4	0.0	0.0	4.0
Southwestern Wyoming (Green River Basin)	12.8	12.7	25.5	7.3	4.7	0.0	2.0	38.8	14.5	67.3
Denver Basin, Park Basins, Las Animas Arch	4.2	2.0	6.2	2.0	1.7	0.0	0.0	2.0	0.0	5.7
Raton Basin-Sierra Grande Uplift	0.2	1.2	1.4	0.0	0.0	0.0	1.9	0.0	0.0	2.0
San Juan and Albuquerque-Santa Fe Rift	29.1	19.6	48.8	5.4	0.7	0.0	8.4	21.0	0.0	35.5
Montana Thrust Belt and SW Montana	0.2	0.0	0.3	0.0	8.3	0.0	0.0	0.0	0.0	8.3
Wyoming Thrust Belt	3.9	0.7	4.6	1.4	12.0	0.0	0.0	0.0	0.0	13.4
total	**62.6**	**48.4**	**111.0**	**23.5**	**32.9**	**0.0**	**45.2**	**90.1**	**14.5**	**206.2**

Basin Level Activity

Powder River Basin

The Powder River Basin is located in northeastern Wyoming and southeastern Montana. Through the early 1990s it had a history of conventional oil and gas production. Beginning in the mid-1990s, significant activity and production started in the coalbed methane play. Production in the basin (including conventional gas) has grown from about 860 MMcfd in 2001 to a 2007 rate of 1.25 Bcfd. Most of the production growth had occurred by about 2001. Since that time, production has been relatively flat, although production was up slightly in 2007. Of the total basin production in 2007 of 1.25 Bcfd, 1.18 Bcfd or 94 percent was coalbed methane.

Initially, activity primarily involved the shallow Tertiary Fort Union Wyodak coals on the eastern flank of the basin. Wells are shallow, about 800 - 1,500 feet in depth, and typically produce around 250 to 300 MMcf over the life of the well. While basin production remains dominated by the shallow Wyodak play, over the past few years the deeper Big George coalbed formation has become increasingly important in terms of both activity and production. Well recoveries are significantly higher than in the Wyodak, and are said by one operator to be two to three times higher than the Wyodak, at approximately 600 MMcf per well. ICF's assessment is that the remaining CBM resource is 26 Tcf. At an average well recovery of 400 MMcf, this would represent 65,000 potential wells. Currently, there are more than 17,000 producing coalbed wells in the basin.

Green River Basin, Southwestern Wyoming

The Green River Basin encompasses portions of southwestern Wyoming and northwestern Colorado. Green River Basin wellhead production has increased from 2.56 Bcfd in 2001 to 4.04 Bcfd in 2007. Over the past few years, gas production as been increasing at a rate of about 100 MMcfd per year. This production increase has been driven almost exclusively by tight gas development.

From a resource base perspective, the Green River basin contains the largest untapped gas resource of any basin in the region. The in-place tight gas resource has been assessed by the U.S. Geological Survey at several thousand Tcf.

The most significant activity in the Green River Basin is in the Jonah-Pinedale field area. This is the area responsible for essentially all of the gas production growth since the late 1990s. It is a structural anticline with multiple stacked tight gas sand reservoirs. A large number of development wells have been drilled on spacing as close as 10 – 20 acres. Ultra Petroleum reports that there are over 350 producing wells in Pinedale Field and 650 wells in Jonah Field. Raw gas production at Pinedale exceeded 1,200 MMcfd at the end of 2007 and raw gas production at Jonah is over 1,100 MMcfd. Gas production from both fields increased substantially in 2007.

At Pinedale, Questar and Ultra Petroleum are developing the multi-Tcf field. Well recoveries are reported to be up to 8 Bcf per well in the Lance Formation, which is the primary formation. At Jonah Field, Encana and Ultra Petroleum are the largest operators. The field contains about 4 Tcf of sweet gas, also in the Cretaceous Lance formation.

The Wamsutter Field in the eastern portion of the basin is experiencing increased tight gas development drilling. This is the location of a large tight gas development by BP. BP is drilling up to 2000 gas wells to increase production by up to 250 MMcfd. To date, they have only achieved 75 MMcfd.

Land access is a major issue in the Green River Basin. In 2003, the National Petroleum Council estimated that 37 percent of the resource is completely off limits to drilling. An additional 26 percent is higher cost due to regulations. ICF's assessment of the remaining tight gas resource base is 39 Tcf.

<u>Uinta Basin, Northeastern Utah</u>

The Uinta Basin is located in northeastern Utah. Gas production from the basin was relatively constant at 200 MMcfd through the mid-1990s. However, over the past decade production has increased to a rate of 960 MMcfd (wellhead).

The Uinta Basin has a large undeveloped tight gas resource base. It also contains coalbed methane resources in the "Ferron" coalbed play of Emery County. Production from coalbed methane is not increasing substantially.

Tight gas resources are being actively developed in the Natural Buttes Field area. ICF assessed this area to have 2 Tcf of infill development potential. Most of the potential is in formations that are somewhat deeper than existing production. Stimulation and completion technology advances have been critical in this play, and well recoveries are reported to be up to 5.5 Bcf per well. The assessment of Natural Buttes is conservative relative to some published assessments of up to 5 Tcf.

<u>Piceance Basin, Northwestern Colorado</u>

The Piceance Basin in northwestern Colorado contains extensive tight gas resources. It is rapidly emerging as one of the key basins in the Rockies, and production growth in the basin is expected to play a major role in future Rockies production. The basin currently produces 1.2 Bcfd (wellhead). This is up from only about 340 MMcfd in 2001. The recent production growth is attributed to a ramp-up in tight gas development activity by Encana, Williams, and Exxon. Encana is drilling several hundred wells per year in the Mamm Creek field. There is the potential for almost 3,000 wells on 10 acre spacing, and each well is expected to recover about 1.5 Bcf. Williams claims it has about 3,000 undrilled tight gas well locations.

Exxon has recently publicized their intentions to develop tight gas resources in the basin. Key to their efforts is a new technology to complete 40 or more zones in each well, and to use directional drilling to minimize surface impacts. They have plans to drill 75 wells or more per year in coming years, and gas production is expected to increase from 55 to 230 MMcfd.

Land access is an issue in the basin. The National Petroleum Council assessed the no-access resource at 19% of the total. Recent industry press has discussed an ongoing conflict between industry and environmental groups regarding the Roan Plateau area, which overlies a significant fraction of the tight gas resource. The Roan Plateau BLM study area encompasses several hundred square miles.

Wind River Basin, Central Wyoming

The Wind River Basin, located in central Wyoming, produced at a rate of about 560 MMcfd in 2007 (wellhead). Production is dominated by the giant Madden Field. Madden field contains sour gas in the Madison formation and sweet gas in shallower intervals. Madden accounts for approximately half of the total production from the basin.

Wind River production almost doubled during the 1990s with the expansion of Madden Field production and processing capacity. In recent years, the operator has increased production from the Madison reservoir through the addition of processing capacity, and has also been active in developing the Fort Union tight sands at a depth of about 9,000 feet. There is significant Tertiary coalbed methane potential and additional tight gas potential in the Frontier at 20,000 feet.

Wyoming-Utah Overthrust, Western Wyoming and Northeastern Utah

The Wyoming-Utah-Idaho Overthrust Belt is a north-south trending structural feature that extends for hundreds of miles. The portion of the Overthrust Belt that is gas productive is located in southwestern Wyoming and northeastern Utah. In Canada, a different segment of the North American Overthrust Belt produces in a similar geologic setting. Production is from conventional carbonate and sandstone reservoirs in discrete structures and there is no large-scale tight gas or coalbed methane potential.

Most of the fields were discovered in the 1970s and 1980s, and the play has been relatively inactive. In the Wyoming and northern Utah part of the play, operators have been unable to extend the productive play area as they had once hoped could be accomplished. Production has declined in recent years from over 600 MMcfd in 2001 to a current rate of about 350 MMcfd.

Denver Basin, Eastern Colorado

The Denver Basin of eastern Colorado produces approximately 600 MMcfd. Production has been flat in recent years. Recent activity has been dominated by extensive tight gas infill drilling, re-stimulation, and recompletion activity in the giant Wattenberg Field, which accounts for most of the basin's production. Kerr McGee is the most active operator and is carrying out hundreds of drilling or completion operations per year.

Spacing rules have been approved to allow 20 acre development in Wattenburg Field, and Kerr-McGee states that they have 1.5 Tcf of unbooked potential in the field. EEA has assessed the tight gas resource in the basin at 2 Tcf.

Land Access

One of the major issues in the upstream gas industry over the past twenty years has been the issue of drilling access. The northern Rockies is subject to more access restrictions than any other onshore region. Access restrictions arise from both legal and regulatory issues. Legal or statutory restrictions include designations such as national parks and wildlife refuges and other areas that are totally off limits. Access is also restricted by regulatory and environmental issues that affect when and where producers can explore or drill.

Table 5 documents the volume of natural gas that is currently estimated to be off limits to industry in the U.S. The analysis relies upon the 2003 National Petroleum Council study. The table indicates approximately 60 Tcf of region resources that were determined to be inaccessible. Another 40 Tcf of resource was considered very high cost due to various regulations, rendering some portion of that resource uneconomic.

Table 5. High Cost and No Access Rockies Resources: National Petroleum Council Study

Tcf
(Resources shown are NPC assessments)

Basin	Standard Lease Terms Tcf	High Cost Tcf	No Access Tcf	Total Resource Tcf
Green River	35	24	35	94
Uinta/ Piceance	14	14	6	34
Powder River	15	1	7	23
Wind River	3	1	0	4
Wyoming Thrust Belt	3	1	10	14
Total of Above Basins	70	41	58	169

In recent years, ICF has developed the view that access restrictions in the Rockies, while very important in some cases, will not prevent growth in future regional production, at least through 2020 or so. One reason is that coalbed methane development will likely not contribute as high of a percentage of future production as previously thought, and the issue of water disposal is very large with Rocky Mountain CBM. Second, in terms of tight gas development, recent trends have indicated that, at least in the more prolific plays, gas development wells are clustered in very small geographic areas, such as Jonah-Pinedale. This can make it easier to drill large volumes of gas without disturbing hundreds of square miles of surface. In addition, the ability to drill numerous wells from one pad has made a great difference.

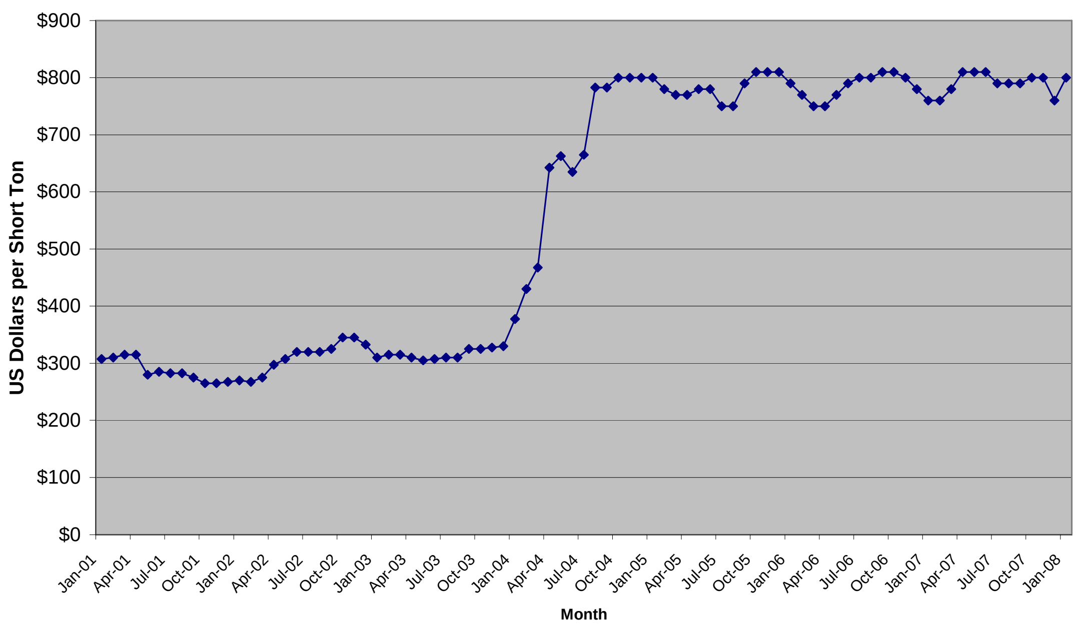
National Upstream Cost Trends

The costs of upstream activity, including drilling, stimulation, and completion, have increased dramatically in recent years. 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 very 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. Figure 7 shows the recent history of cost per ton of carbon steel plate (used in line pipe, casing, pressure vessels, etc.) and Figure 8 shows similar data for nickel (used in corrosion resistant tubing and casing and cryogenic applications such as LNG liquefaction plants and LNG storage tanks). Figure 9 shows the cost of natural gas pipeline construction and Figure 10 shows the average day rate for onshore drilling rigs in the US.

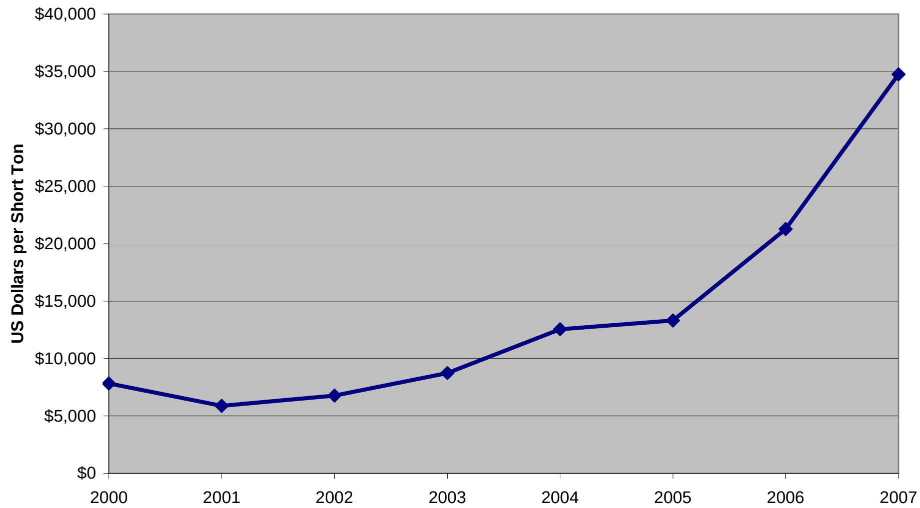
The day rate for onshore rigs is a key factor in U.S. drilling costs. The average day rate essentially doubled between 2003 and 2007. This had a major impact on overall resource development costs, especially when combined with cost increases for materials. The chart indicates that the day rate appears to have peaked last year. This in part reflects decisions to scale back activity in some plays due to increased drilling costs. Another factor driving costs in the non-conventional plays is the reservoir stimulation component, which has increased dramatically as operators employ newly developed techniques that can cost several hundred thousand dollars per frac job, and many wells have multiple fracs.

Figure 7. U.S. Carbon Steel Plate Prices



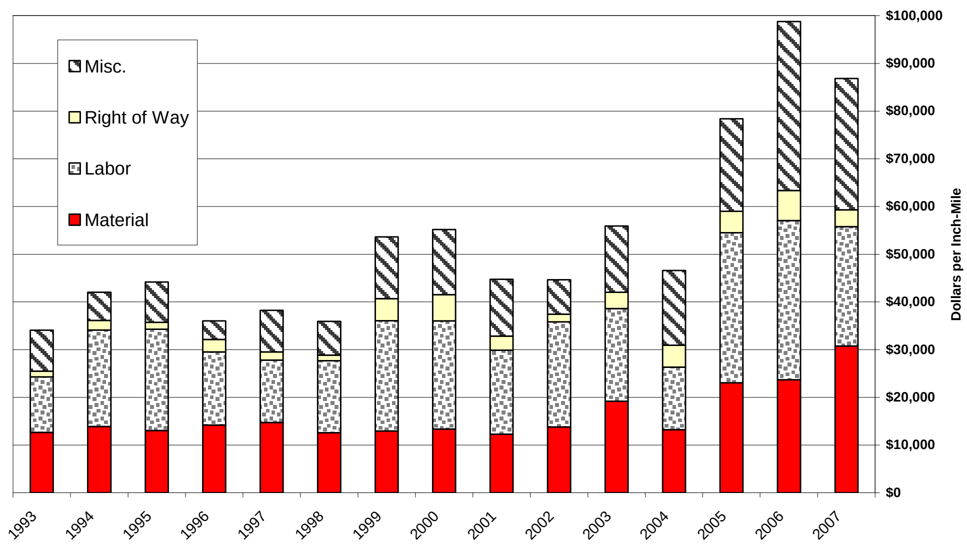
Domestic plate A36 (FOB US Midwest mill) from Bloomberg

Figure 8. Nickel Prices



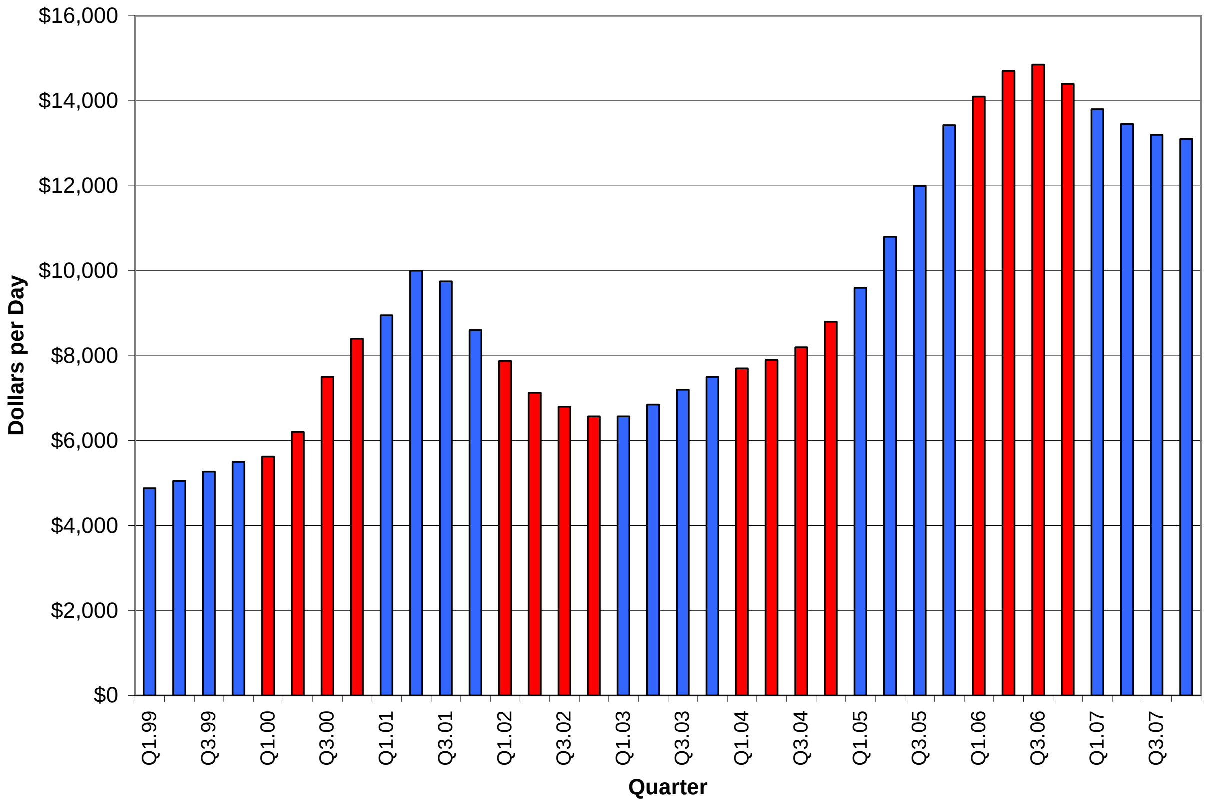
Source: London Metal Exchange

Figure 9. Gas Pipeline Costs by Component



Source: Oil and Gas Journal annual surveys; Average of large-diameter gas pipelines 30 to 36 inches; Miscellaneous category includes surveys, engineering, administration, interest, and overhead.

Figure 10. U.S. Drilling Rig Day Rates



Rockies Supply Costs

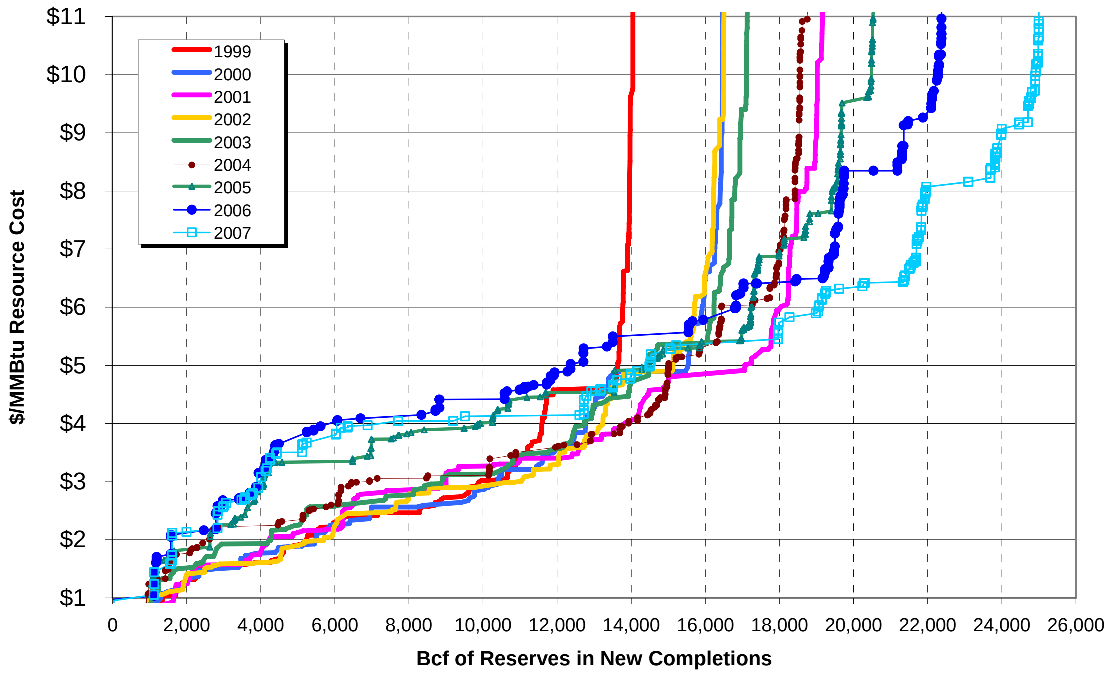
ICF has developed a model to determine cost of gas reserve additions in the U.S. nationally, regionally, and by formation or "play." For the purposes of this study, ICF updated the model and has evaluated the economics and activity of Rocky Mountain gas plays, including conventional and unconventional. The model used is the ICF Play Level Cost Model (PLCM).

The PLCM computes the wellhead "resource cost" of each play or formation. An example of a play is the coalbed methane play in the Powder River Basin. The wellhead resource cost is the total required wellhead price needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes and income taxes. In this approach, the cost is applied to actual investments made and reserve additions in a historical year. A supply curve is built by summing all of the volumes added by play according to their resource costs.

The wellhead resource cost excludes the costs required for gathering, compression, and transport to the mainline. In the Rockies, such costs typically range from 12 to over 80 cents per thousand cubic feet. In addition, gas losses in the range of 2 to10 percent can be expected due to gas use for compression. Compression costs are greatest in low pressure plays such as the coalbed methane plays, or older plays with low wellhead pressures.

The annual distributions of wellhead resource costs across Lower-48 plays are shown in the Figure 11 below for the nine years of available data. The figure shows cumulative nonassociated (gas well) gas reserve additions from new gas completions sorted from the cheapest plays to the most expensive. Note that because actual costs are used, all values are in nominal dollars. Since well-level production data are not reported for oil wells throughout the U.S. no similar curve can be created for the approximately 2 Tcf per year of reserve additions coming from associated-dissolved gas.

Figure 11. Annual Lower-48 Non-Associated Wellhead Cost Curves



To take the year 2007 as an example, the total non-associated reserves added were 25,000 Bcf or 25 Tcf. Of that amount, approximately 14 Tcf were added at resource costs below $5.00 per MMBtu, and 4 Tcf was added below $3.00. The curve from the 1999 wells shows that a lot of reserves were added below $3.00 per MMBtu (about 10 Tcf). However, the total reserves added in 1999 were only 14 Tcf. Overall, this shows that operators are adding a lot more reserves, but those reserves are being added at much higher costs.

ICF has also evaluated wellhead gas resource development costs at the play level for the Rocky Mountain region. Figure 12 shows the supply cost curves for wells drilled annually since 1999. The development costs for wells drilled in 2007 is shown in light blue with open squares. The chart shows that while more reserves have been added in recent years, a substantial amount of those reserves are high cost.

In order to estimate the marginal cost of Rockies reserve additions, ICF based our evaluation on the 90th percentile of reserves added in 2007. At the 90th percentile of reserves added in 2007, the wellhead price needed is $5.73. Table 6 shows the analysis for recent years.

This analysis indicates that industry activity in the region will remain robust as long as wellhead prices are a minimum of about $5.00 dollars per MMBtu, but a price of about $5.73 is needed for economic development consistent with recent history. Should wellhead prices drop lower than $5.00, the majority of current activity in the region would not be economically sustainable.

Figure 12. Wellhead Cost Analysis for the Rocky Mountain Region.

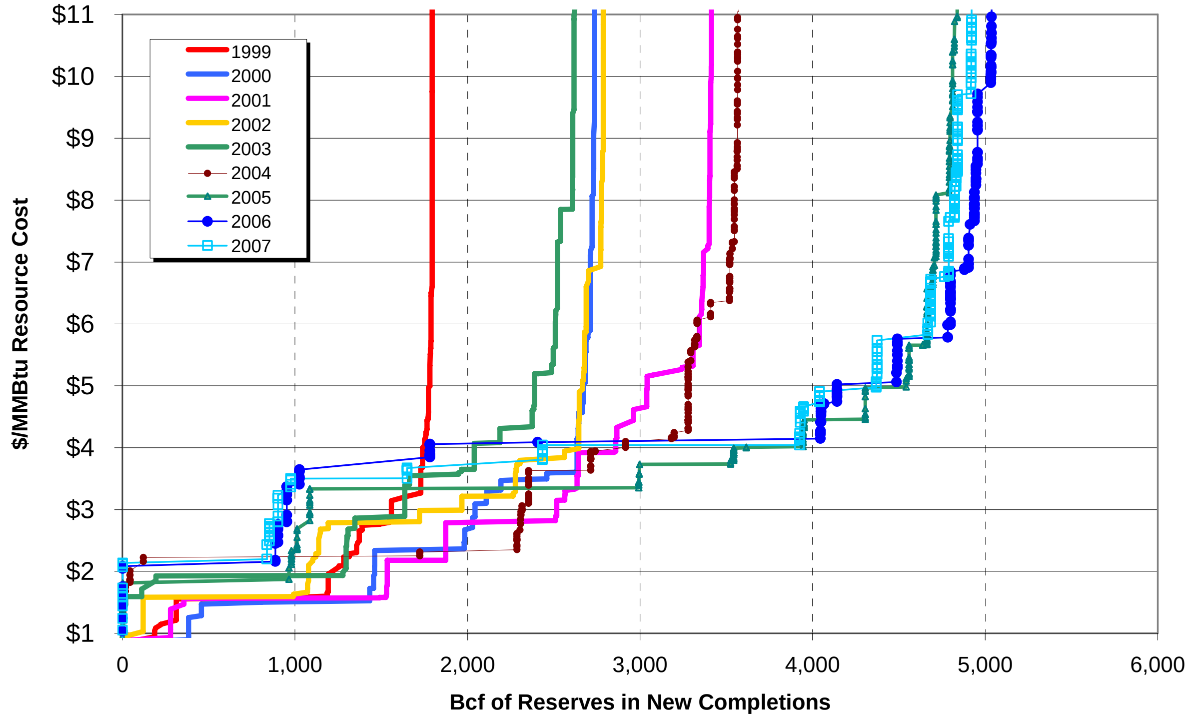


Table 6. Estimation of Rockies Marginal Cost of Reserves Using 90th Percentile of Reserves Added

Selected Region:	Rockies								
	1999	2000	2001	2002	2003	2004	2005	2006	2007
Max Quantity	1,809	2,739	3,421	2,790	2,630	3,586	4,860	5,100	4,984
Q @ X Percentile	1,628	2,465	3,079	2,511	2,367	3,227	4,374	4,590	4,486
Rockies Marginal Cost	**$3.15**	**$3.59**	**$5.17**	**$3.81**	**$4.31**	**$4.24**	**$4.96**	**$5.76**	**$5.73**
US Wellhead Price (EIA)	**$2.19**	**$3.68**	**$4.00**	**$2.95**	**$4.88**	**$5.46**	**$7.33**	**$6.40**	**$6.39**

It should be noted that if a gas play's cost is above the prevailing price, then the desired rate of return is not met with those wells. This can be offset for any given producer with profits from new wells drilled in other plays or from higher prices from old gas wells. This is one reason why there are always some wells drilled in plays with costs above the prevailing price. Another reason why these high cost plays are drilled is that reserves per well are lower than anticipated. Also, producers may invest in a certain play with the expectation that technology and improved information will improve the economics of that play in the future.

Another consideration when evaluating wellhead resource costs is that individual factor costs for the producer, such as day rates, tubulars, and well services, are a function of oil and gas prices. Therefore, resource costs will go up our down with future price fluctuations.

Rockies Supply Cost Delivered to the Pacific Northwest

The above analysis applies to wellhead costs only. To estimate the total cost of delivering Rockies gas to the Pacific NW, it is necessary to add additional cost components. These include gathering, transport to a regional hub, and transport to the Pacific Northwest.

Table 7 summarizes the cost components to transport Rockies gas to the Pacific Northwest assuming a starting point in the Piceance Basin of northwestern Colorado. The total transport cost is $2.06 per MMBtu.

If one adds a typical wellhead resource cost of $5.73 per MMBtu, the total delivered cost or Rockies gas is approximately $7.79 per MMBtu.

Table 7. Cost of Transporting Rockies Gas to Pacific Northwest

Pipeline	From / to	Full Transport Cost ($'s per MMBtu)
Wellhead Gathering	Basin to Pipeline	$0.500
Wyoming Interstate Company	Piceance to Opal	$0.290
Ruby Pipeline (proposed)	Opal to Malin	$0.700
Gas Transmission Northwest	Malin to Stanfield	$0.155
Northwest Pipeline Company	Stanfield to Oregon Markets	$0.410
Total		$2.055

Summary and Implications

Analysis of recent trends in production, activity, and economics of supply for the Rocky Mountain gas production province confirm our expectations that this region will play a major role in North American gas supply for decades to come. Gas production continues to grow rapidly, especially in southwestern Wyoming, northwestern Colorado, and northeastern Utah. Industry is making an intense and expanding effort to focus on low permeability plays such as Jonah-Pinedale in the Green River Basin where well stimulation and infill development is having tremendous success, and where there remain thousands of potential development locations.

Activity in the Powder River Basin coalbed play of eastern Wyoming will continue for decades, with infill drilling and the addition of new zones.

There are vast areas of lower quality tight gas resources in geographic parts of basins such as the Green River and Piceance basins that are not currently being developed. There is also the potential for future horizontal shale gas development, which is just now emerging.

An issue that appears to be on the horizon is the effort to increase severance and production taxes on gas producers in the Rockies. Significant increases in severance taxes could dampen activity substantially. Various groups in opposition to industry activity in the Rockies would not mind if future drilling were substantially reduced, especially if taxes could be raised sufficiently to compensate the loss of production over the near term. Such an approach, however, could leave very large volumes of gas undeveloped due to poor economics.

Our analysis indicates that the delivered cost of Rockies gas to the Pacific Northwest is approximately $7.79 per MMBtu, using an assumed wellhead cost of $5.73 and a transport cost of $2.06.

In terms of resource economics, ICF analysis indicates that industry activity in the region will remain relatively robust as long as wellhead prices are a minimum of $5.00 dollars per MMBtu. Should wellhead prices drop substantially below this, the great majority of current activity in the region would not be economically sustainable.

2 WORLD LNG MARKETS AND COSTS

This section briefly describes the current status of the world LNG market. The amount of global natural gas supply available to North America is provided.

Current World Trade of LNG

LNG is expected to play an increasingly important role in world energy markets. A significant market will develop for global LNG trade over the next two decades due to the growing dependence of many "energy poor" countries such as Japan, on energy supplies from "energy-rich" and developing countries. Imported LNG, in large part, becomes an economically viable energy supply due to the low cost of developing and producing abundant stranded gas reserves located throughout the world (see below). LNG imports are projected to become an increasing portion of the North American gas market. Most of the gas that is likely to be available to the LNG market may be developed and delivered to liquefaction facilities at investment costs under $1.00 per MMBtu, depending on the area.

Unlike domestic gas supplies in the U.S. and Canada, North America must compete with the rest of the world for LNG. World market conditions will influence LNG prices. International LNG trade was 7.6 Tcf in 2006, which can be compared to the 3 Tcf level in 1993. In 2006, the U.S. imports of over 584 Bcf accounted for approximately 8 percent of worldwide imports. U.S. exported 61 Bcf of LNG or just under 1 percent of total world LNG exports.

As shown in Table 8, The U.S. currently has eight operating U.S. LNG import terminals and there is one terminal in Mexico. The first four facilities shown in the table were built in the 1970's and early 1980's. The U.S.'s operating export facility is located in Kenai, Alaska built in 1969. A number of LNG facilities in North America, including Mexico and Canada, are under construction as shown in Table 9. Canada does not yet have an operating LNG facility.

In 2006, the U.S. imported approximately 584 Bcf of LNG or a little over 2 percent of total U.S. natural gas supply. This was 48 Bcf less LNG imports than 2005. The decline was more demand related, as a combination of a warm U.S. winter and a cold European winter in early 2006 diverted LNG tankers to Europe.

Table 8. Currently Operating North American LNG Facilities

Source: FERC website:
http://www.ferc.gov/industries/lng.asp

Location	Operator	Listed Capacity Bcf/d
Everett, MA	Suez LNG - DOMAC	1.035
Cove Point, MD	Dominion - Cove Point LNG	1.000
Elba Island, GA	El Paso - Southern LNG	1.200
Lake Charles, LA	Southern Union/ Trunkline LNG	2.100
Gulf of Mexico	Gulf Gateway Energy Bridge; Excelerate Energy	0.500
Offshore Boston	Northeast Gateway Energy Bridge; Excelerate Ener(	0.500
Freeport, TX	Cheniere - Freeport LNG Development	1.500
Sabine, LA	Sabine Pass Cheniere LNG	2.600
Altamira, Mexico	Shell/Total/Mitsui	0.700
Total		11.135

Table 9. North American LNG Facilities Under Construction

Source: FERC website:
http://www.ferc.gov/industries/lng.asp

Region	Facility	Capacity BCFD	Type	Operator
Gulf Coast	Hackberry, LA	1.80	New site	Cameron LNG - Sempra
	Sabine; LA	1.40	Expansion	Sabine Pass Chenier LNG
	Sabine, TX	2.00	New site	Golden Pass - ExxonMobil
	Pascagoula, MS	1.50	New site	Gulf LNG Energy
East Coast US	Elba Island, GA	0.90	Expansion	El Paso - Southern LNG
	Cove Point, MD	0.80	Expansion	Dominion
East Coast Canada	St. John, NB	1.00	New site	Canaport - Irving Oil
Mexico	Baja California, MX	1.00	New site	Sempra
Total		10.40		

There are several key players in the U.S. LNG market, the largest being the BG Group (formally British Gas). The BG Group has interests in three of the four U.S. LNG import terminals. It holds contracts for all of the import terminal capacity at Lake Charles and Elba Island and is one of the main suppliers to the Everett terminal in Massachusetts. In 2006, it was responsible, in one way or another for 53 percent of the LNG imports into the U.S. BP, Shell, and Statoil of Norway hold terminal import capacity at Cove Point. Distrigas Corporation of Boston currently operates the import capacity for the Everett terminal. Operators of terminals include: Distrigas, a division of Tractebel, for Everett, Dominion for Cove Point, Trunkline for Lake Charles, and Southern Natural Gas, a division of the El Paso Corporation, for Elba Island. Other companies include Excelerate Energy and Cheniere.

The current most prominent suppliers of LNG include BP, BG Group, Repsol, Suez LNG, Atlantic LNG of Trinidad, Sonatrach, and NLNG from Nigeria. As new liquefaction supplies become available this list will expand. A terminal on the West coast will allow access from the Pacific Basin suppliers.

Currently, 16 other countries besides the U.S. import LNG, with the largest volumes going to Japan and South Korea (Table 10). A host of other countries may start importing LNG within the next decade. China started importing LNG in 2006 and they represent a potentially huge LNG market with import terminals under construction. India just started imports in 2004 and also has significant growth potential. Mexico started importing LNG in 2006.

In 2006, 13 countries exported LNG: Qatar, United Arab Emirates, and Oman in the Middle East; Algeria, Nigeria, Egypt, and Libya in Africa; Indonesia, Malaysia, Australia, Brunei and the United States (Alaska) in the Pacific; and Trinidad and Tobago off the coast of South America (Table 11). The largest supplies of LNG in 2006 came from the Pacific sources, accounting for 42 percent of the world market supply. Africa and the Middle East supply 27 percent and 24 percent of the world market, respectively. Trinidad and Tobago currently supplies about 8 percent of world LNG.

Table 10. LNG Imports by Country and Region 2006 – Bcf

Source: Energy Information Administration 2007

Billion Cubic Feet Per Year
Source: Energy Information Adminisration 2007

Region	Country	Bcf	Region Total
U.S. and	United States	584	
Caribbean	Mexico	48	
	Puerto Rico	28	9%
	Dominican Republic	11	671
Europe	Spain	862	
	France	490	
	Turkey	185	
	Belgium	151	
	United Kingdom	120	
	Italy	93	
	Portugal	73	26%
	Greece	23	1,997
Asia	Japan	3,135	
	South Korea	1,162	
	Taiwan	372	
	India	254	65%
	China	35	4,958
Total			7,626

Table 11. LNG Exports by Country and Region – 2006

Source: Energy Information Administration 2007

Billion Cubic Feet Per Year
Source: Energy Information Adminisration 2007

Region	Country	Bcf	Region Total
Africa	Algeria	844	
	Nigeria	628	
	Egypt	528	27%
	Libya	25	2,025
Mid-East	Qatar	1,110	
	Oman	436	24%
	United Arab Emirates	263	1,809
Pacific	Indonesia	1,074	
	Malaysia	1,016	
	Australia	702	
	Brunei	355	42%
	United States	61	3,208
			8%
S. America	Trinidad and Tobago	584	584
Total			7,626

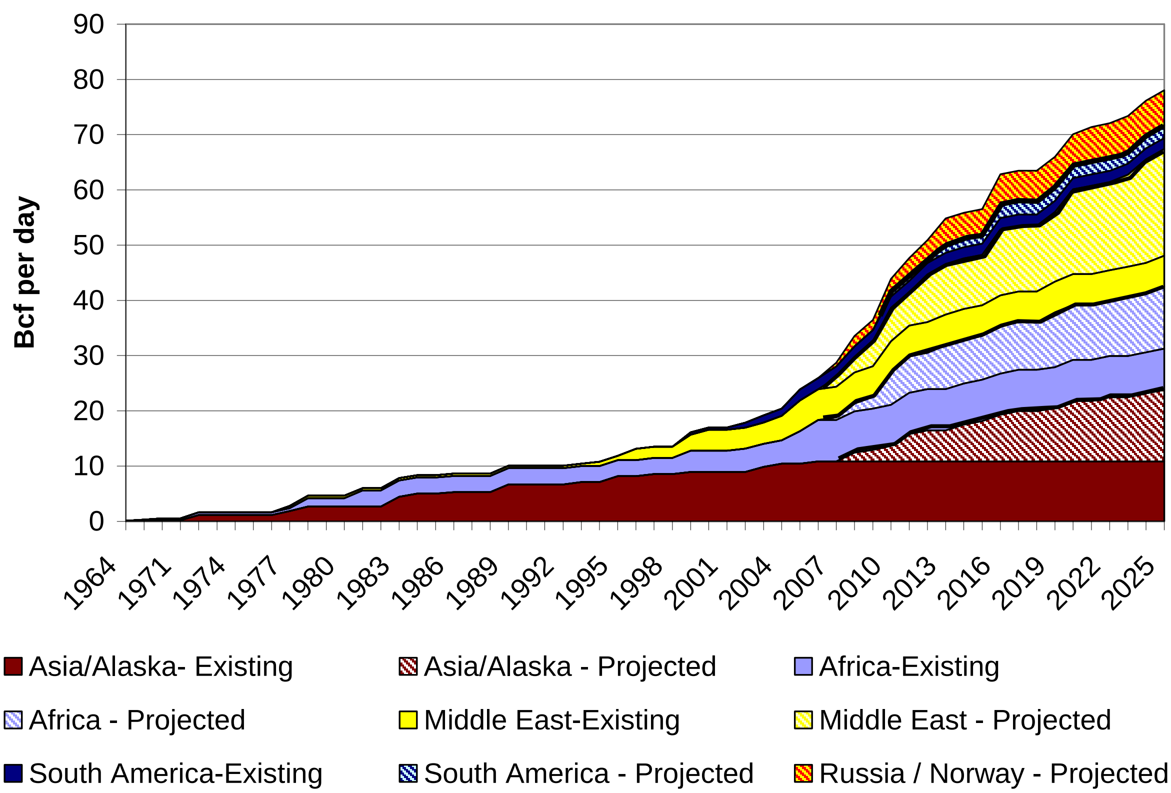
Additional liquefaction and export capability is expected to grow both in existing export countries and new ones. Currently world LNG liquefaction capacity is over 25 Bcf per day. In the early 1990s liquefaction was only about 10 Bcf per day. By 2025 Liquefaction capacity could reach 80 Bcf per day or more.

Current world capacity is produced by 83 liquefaction trains. A new LNG train can produce approximately 150 to 200 Bcf of LNG per year. There are 13 trains or LNG liquefaction facilities currently under construction. Within the next few years, new sources of LNG will come from Angola, Norway, Equatorial Guinea, and Russia. There are over 50 trains in the planning and proposal stage. New countries entering the export business could include Abu Dhabi, Iran, Yemen, Venezuela, Peru, Brazil, and Bolivia.

As shown in Figure 13, liquefaction capacity is poised to grow significantly in the next ten years.

Figure 13. Base Case - Worldwide Liquefaction Capacity (Bcf per day)

Source: Energy and Environmental Analysis, Inc.



Most LNG supply serves markets that are closest in proximity to the source. For example, most Pacific and Middle Eastern supplies serve Asian markets. North African LNG supplies mostly go to Europe. In 2005, the U.S. received over 70 percent of its LNG supply from Trinidad and Tobago. This percentage declined to 66 percent in 2006 as U.S. importers sought other supplies. Nigeria and Egypt have increased imports to the U.S. in 2006 versus 2005 and now account for 30 percent of the U.S. imports. The majority of Algerian LNG in 2006 most likely went to Europe. The source location for North American imports is likely to change in the future. Various U.S. supply contracts totaling nearly 1 Tcf of gas per year from Australia, Equatorial Guinea, and Norway are scheduled for start-up in the next several years. There is another 1 Tcf per year of signed supply contracts from Qatar and Russia scheduled to begin in 2009 or 2010.

Supplies dedicated to the North American markets including Canada and Mexico[2] as new terminals are built are projected to grow significantly. Current firm supplies to U.S. markets are approximately 1.5 Bcf per day. Dedicated LNG supplies to North America could rise to nearly 6 Bcf per day by 2010 and to over 14 Bcf per day by 2025. Flexible or swing LNG volumes that could seek North America when market conditions are attractive, are roughly equal to the firm supplies. Maximum LNG volumes capable of supplying the North American market reach about 28 Bcf per day by 2025. In the Base Case, total regasification capacity for North American LNG terminals is 12.5 Bcf per day in 2010 and 30 Bcf per day in 2026, more than double the firm supplies dedicated to the North American terminals and about 10 percent greater than the maximum limit due to available liquefaction supplies.

The world LNG tanker fleet, as expected, is growing in unison with increasing global liquefaction and regasification capacity. The world fleet currently stands at 222 vessels with a carrying capacity of over 600 Bcf. A typical new LNG tanker holds a little over 3 Bcf of gas supply. There are an additional 142 vessels with a carrying capacity of 535 Bcf on order from the various shipyards around the world. There is a typical 3-year lag to deliver a tanker once an order is placed. This delivery period may extend somewhat with the recent increase in orders. However, it does not appear that the lack of tanker capacity will be a bottleneck in world trade of LNG. The most significant bottleneck is liquefaction capacity.

Stranded Natural Gas Reserves

Proven world reserves are well over 6,000 Tcf, which is over 250 years of current U.S. consumption (Table 12). Most of those reserves, over 4,500 Tcf, are “stranded” and do not have ready pipeline access to large consumption markets. They must be shipped via LNG tankers or connected via pipeline to be sold. Finding reserves for a growing global LNG market is not a problem. The more relevant questions are whether additional LNG infrastructure will be built quickly enough to meet growing demand, and how much of the LNG supply will be dedicated to the North American market.

[2] Mexico LNG imports will affect import and exports between the U.S. and Mexico.

Table 12. Natural Gas Reserves by Country Through 2007[3]

Source: Oil and Gas Journal Reserves and ICF Analysis.

Source: Oil and Gas Journal Reserves and ICF Production and Reserve Analysis
UAE = United Arab Emirates
FSU = Former USSR

Rank	Country	Total Producing and Stranded Reserves Tcf	Percent of World Reserves	Non-Producing or Stranded Reserves Tcf
1	Russia (FSU)	1,680	27%	1,248
2	Iran	948	15%	874
3	Qatar	905	15%	870
4	Saudi Arabia	253	4%	201
5	United States	211	3%	32
6	UAE	199	3%	181
7	Nigeria	184	3%	164
8	Venezuela	166	3%	146
9	Algeria	159	3%	99
10	Iraq	112	2%	110
11	Kazakhstan (FSU)	100	2%	100
12	Turkmenistan(FSU)	100	2%	56
13	Indonesia	94	2%	42
14	Malaysia	83	1%	40
15	China	80	1%	39
16	Norway	79	1%	0
17	Uzbekistan (FSU)	65	1%	26
18	Egypt	59	1%	27
19	Canada	58	1%	0
20	Kuwait	56	1%	46
	Total Top 20	5,590	90%	4,301
	Rest of world	596	10%	265
	World total	6,186		4,566

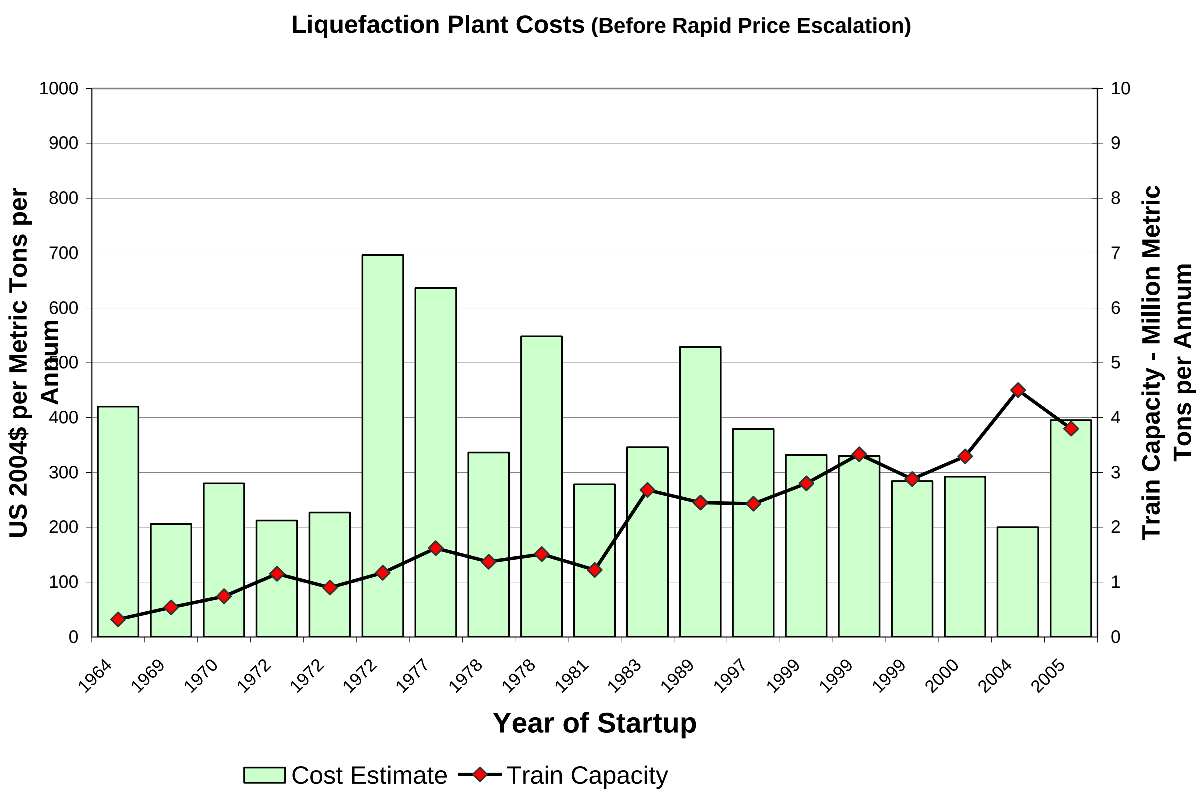
[3] Former Soviet Union includes: Kazakhstan, Turkmenistan, Uzbekistan, Ukraine, Azerbaijan, Georgia, Kyrgyzstan, Tajikistan, and Belarus.

LNG Costs

The cost of marginal LNG supplies reaching the North American market rose recently due to the increase in materials and construction cost for all types of energy-related investments. Figure 7 in a previous section shows the recent history for the price of steel plate and Figure 8 shows data for the cost of nickel, another key material in the construction of cryogenic facilities.

The past history of the cost of building liquefaction plants is shown in Figure 14. The price of these plants trended downward to below $300 per tonne-year through 2004 as the size of liquefaction trains trended upward. Since then, the escalation in prices of materials and services has caused the cost of liquefaction plants to more than double to $650 per tonne-year and more.

Figure 14. Liquifaction Plant Costs



The overall costs of new LNG projects are shown in Table 13 for three example projects intended for delivery of gas to the North American West Coast. The first example represents a 1 bcfd project in the Russian Far East with upstream development costs of $1.00 per Mcfe of net gas reserves or $7.3 billion for the project. The second example represents a 582 MMcfd project in Peru with upstream costs of $0.75 per net Mcfe or a $3.2 billion total. The third example is a 824 MMcfd project in Papua New Guinea that has an upstream investment cost of $0.75 per Mcfe or a total of $4.5 billion upstream investment.

The liquefaction plant cost for each example was assumed to be between $675 and $773 per tonne-year of capacity. The cost of ship construction was $202 million for each ship of 135,000 cubic meters of capacity. Due to the different shipping distances for each example, the number of ships needed for each project varies as does the $/Mcf shipping costs. A one bcfd regasification terminal was assumed to have capital costs of $675 million (including dock facilities and storage).

The annualized cost of capital was computed assuming a 20-year project cost recovery period, a 60/40 debt to equity split, a cost of debt of 6 percent per year, an after-tax cost of capital of 13 percent per year and a tax rate of 35 percent. Fuel cost for ship fuel and regasification at the terminal were based on costs of $7.00 per MMBtu.

The total costs for the three project examples range from $6.43 to $6.71 per MMBtu (last row of table). Actual project cost will vary from these examples depending on cost for materials and services for facility and ship construction, host country tax and royalty takes, energy prices and the method and cost of project financing.

Conclusions

ICF has evaluated the economics of importing LNG to the Pacific Northwest. The analysis includes an evaluation of the cost of liquefaction, transport, and receipt terminals.

The total costs for the three project examples range from $6.43 to $6.71 per MMBtu. Actual project cost will vary from these examples depending on cost for materials and services for facility and ship construction, host country tax and royalty takes, energy prices and the method and cost of project financing.

The total delivered cost of LNG to the Pacific Northwest is about $6.50 per MMBtu. This can be compared to an expected cost of developing and transporting Rocky Mountain gas of $7.79 per MMBtu, of which $5.73 is the wellhead cost and $2.06 is the transport cost.

Table 13. Delivered Cost of LNG to North American West Coast

Estimated Costs for LNG Projects
(million 2008 dollars)

	Russia Far East	Peru	Papua New Guinea
Project Size (MMcfd)	1,000	582	824
Project Size (million metric tonnes per year)	7.65	4.45	6.30
Upstream Investment ($/Mcfe)	$1.00	$0.75	$0.75
Upstream Capital Investment	7,300	3,186	4,511
Annualized Upstream Capital Costs	786	343	486
Annual Upstream O&M	292	127	180
Total Annual Cost	1,078	471	666
Upstream Cost Recovery ($/Mcf)	*$2.95*	*$2.22*	*$2.22*
Source-Country Prod. Royalties & Taxes ($/Mcf)	*$1.00*	*$1.00*	*$1.00*
Total Upstream Cost ($/Mcf)	*$3.95*	*$3.22*	*$3.22*
Liquefaction Plant Cost ($/tonne/year)	675	773	708
Liquefaction Plant Capital Investment	5,156	3,436	4,459
Annualized Liquefaction Capital Cost	555	370	480
Annual Liquefaction O&M	206	137	178
Total Annual Cost	762	508	659
Total Liquefaction Cost ($/Mcf)	*$2.09*	*$2.39*	*$2.19*
Ship Size (cubic meters)	135,000	135,000	135,000
Ship Cost ($million/ship)	202	202	202
Travel Distance (one-way nautical miles)	3,805	4,480	5,995
Required Number of Ships	8	6	10
Capital Investment in Ship	1,616	1,212	2,020
Annualized Capital Cost of Ships	172	115	213
Annual Fuel Costs	85	58	112
Annual Non-fuel Ship O&M	68	45	79
Total Annual Shipping Cost	325	218	404
Total Shipping Cost ($/Mcf)	*$0.89*	*$1.03*	*$1.34*
Receipt Terminal Capital Investment (1 bcfd)	675	675	675
Annualized Regas Capital Cost	73	73	73
Annual Fuel Costs	38	38	38
Annual Non-fuel Regas O&M	27	27	27
Total Annual Cost	138	138	138
Total Regas Cost ($/Mcf)	*$0.38*	*$0.38*	*$0.38*
All Capital Investment	14,747	8,509	11,665
All Cost Components ($/Mcf)	*$7.31*	*$7.01*	*$7.13*
Btu per standard cubic foot of gas	1,090	1,090	1,090
All Cost Components ($/MMBtu)	*$6.71*	*$6.43*	*$6.54*