Cook Inlet Gas Study - An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers

prepared for

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Due to the uncertainties of drilling and producing activities of operating and exploration companies and what Alaska state agencies do and do not do in influencing those activities, this study should be considered a best estimate based on current data. It was prepared using generally accepted engineering and geological predictive methods. As such, Petrotechnical Resources of Alaska can make no warranty as to actual future Cook Inlet gas drilling and production.

Executive Summary prepared by Cook Inlet Utilities

ENSTAR Natural Gas Company, Chugach Electric Association, and Anchorage Municipal Light and Power (Cook Inlet Utilities) commissioned Petrotechnical Resources of Alaska (PRA) to study Cook Inlet natural gas reserves and forecast annual natural gas production. We asked PRA to estimate the cost of the development necessary to meet the immediate needs of Cook Inlet utility customers from 2010 to 2020. The PRA study includes a review of estimated reserves and deliverability of Cook Inlet gas wells drilled between 2001 and 2009, scenarios for potential development activity, a review of a December 2009 Alaska Department of Natural Resources (DNR) reserves analysis, and an analysis of when it might be necessary to rely on non-Cook Inlet natural gas sources, such as liquefied natural gas (LNG) imports or other in-state resources.

In the future, Cook Inlet utility customers should expect to pay more for the gas used by Cook Inlet Utilities to generate heat and electricity. PRA examined results from all of the gas wells drilled in Cook Inlet between 2001 and 2009 and determined that producers spent approximately $1.0 to $1.2 billion in development costs to add reserves of approximately 519 billion cubic feet (Bcf) of natural gas. If the current trends for well success rates and costs continue, producers will need to spend two to three times that amount, an estimated $1.9 to $2.8 billion, to meet projected Cook Inlet utility demand from 2010 to 2020. Producers will invest the necessary capital in future drilling activity only if they have a reasonable expectation of a return that is competitive with other investment opportunities. In order to assure continued drilling activities, increased development costs must be reflected in the market price utilities pay for the gas and ultimately pass onto their customers. Cook Inlet Utilities will also require storage services to deliver gas to their customers on the coldest days and enable producers to optimize gas production rates. The estimated cost of a storage facility is $150 to $200 million[1]. These storage costs will also be borne by utility customers.

[1] Storage cost estimates based on ENSTAR's development assessment.

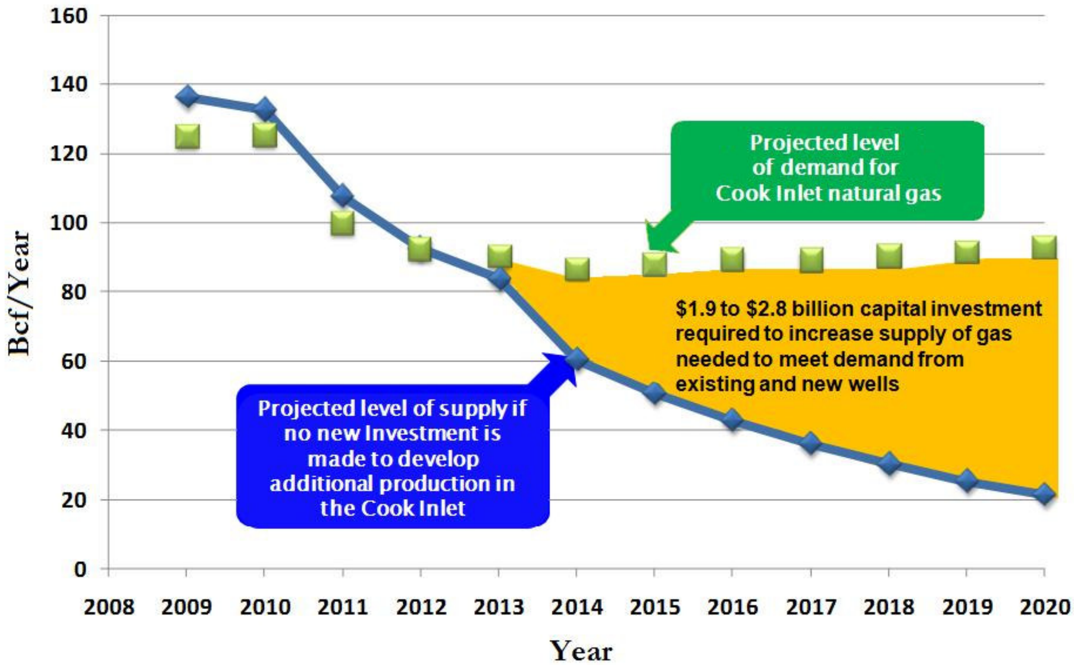


Figure 1 – Cook Inlet Supply & Demand

PRA used a decline curve analysis to review the same underlying data analyzed in the 2009 DNR reserves study and reached a similar conclusion regarding when the supply of gas from existing wells will not meet demand[2]. The PRA study took the next step, estimating the cost of bringing the undeveloped gas resources to market[3]. PRA determined that if significant efforts are undertaken to develop gas from the resources identified by DNR and if the current trends in drilling success rates continue, gas might be available through 2020. However, even if an aggressive development effort were undertaken immediately, that effort may fail to bring new gas to market quickly enough to provide needed gas when demand is projected to exceed supply as soon as 2013. Utilities need to plan for an alternative supply to meet their customers' needs. Having undeveloped gas resources in the ground will not enable Cook Inlet Utilities to provide heat and power to their customers. The gas resources will only be developed and brought to market at prices that incentivize the producers to justify their investment. Contracts with these higher prices will require RCA approval.

Cook Inlet Utilities need a viable option if additional Cook Inlet development does not materialize. To provide a stable gas supply, non-Cook Inlet sources such as gas delivered from the North Slope or LNG imports, are alternatives that must be pursued. The "easy" gas has been found in the challenging geology of Cook Inlet. The future costs of developing additional reserves will be substantial. As the cost of continued Cook Inlet gas production increases, alternative gas supply sources may become more economically attractive. Regulatory uncertainty has also discouraged Cook Inlet producers from

[2] PRA's study estimates remaining reserves of 729 Bcf from existing wells, compared with DNR's forecast of 863 Bcf of Proven Developed Producing reserves.

[3] The DNR study did not address the cost of bringing undeveloped resources to the market. (see DNR Study Figure 14 Description)

exploring for and developing Cook Inlet reserves[4]. In the current regulatory environment, two of the three major Cook Inlet producers have publicly stated that they intend to drill only to meet current contract obligations. Future development depends on a change in the regulatory climate to one where consistent standards are applied to approve negotiated utility gas supply agreements, even if those agreements reflect the increased costs of resource development.

The Cook Inlet market is in transition. Current gas fields are in decline and the loss of industrial customers has reduced the producers' incentives to do anything but meet existing contractual obligations. In order for utilities to be able to continue to supply current customers and to accommodate future growth, Cook Inlet Utilities and others must take action.

Immediate Actions Needed:

- New gas supply agreements between Cook Inlet Utilities and Producers must be signed to ensure continued development of Cook Inlet reserves.

- There must be predictable timelines and standards for regulatory approval of gas supply agreements. The Regulatory Commission of Alaska must be willing to approve gas supply contracts negotiated at arm's length, even if prices under those contracts increase.

- Cook Inlet Utilities must develop gas storage to assure deliverability on the coldest days and optimize gas production throughout the year.

- Cook Inlet Utilities should continue raising customer awareness, conservation efforts, and curtailment plans, to prepare for potential shortfalls.

- Additional well-capitalized exploration and development companies must commit to develop Cook Inlet and other Alaska gas reserves.

- To assure certainty of supply, Cook Inlet Utilities must determine how they will bring gas into Cook Inlet within the next five years to ensure the needs of their customers are met. Alternative gas supply sources include LNG imports and North Slope gas delivered by pipeline to south central Alaska.

- Additional regional industrial gas demand must be found to encourage the development of Cook Inlet reserves and spread the increased costs of production.

- Land management processes must be streamlined to encourage and accelerate reserve and infrastructure development.

[4] Recent favorable regulatory decisions on utility gas supply agreements may be a positive sign.

Technical Summary

ENSTAR Natural Gas Company, Chugach Electric Association, and Anchorage Municipal Light and Power (Cook Inlet Utilities) hired Petrotechnical Resources of Alaska (PRA) to perform a study of Cook Inlet reserves and deliverability. The components of the study included:

- Review the deliverability of Cook Inlet gas wells drilled between 2001 and 2009
- Forecast potential deliverability of future drilled gas wells
- Review Alaska Department of Natural Resources (DNR) reserves analysis
- Analyze timing of demand for a delivery of potential non-Cook Inlet gas sources, such as liquefied natural gas (LNG) imports or other in-state resources

High level findings of the study are:

Cook Inlet Well Drilling Results – 2001 to 2009

- Drivers for Cook Inlet well drilling between 2001 and 2009 included:
    - Newly executed gas contracts
    - Reserves development associated with negotiated gas contracts rejected by the RCA
    - LNG Exports and License Extensions
    - Increasing Regional Natural Gas Prices
    - Industrial Fertilizer Operations
- Results for Cook Inlet well drilling between 2001 and 2009:
    - 128 gas wells were drilled between 2001 and 2009, of which, 105 were completed with an average rate of 3.6 MMSCF/D for the first 12 months of production
        - 97 wells were permitted and drilled as Gas Development wells; 88 of these were completed as gas wells, for a 90.7% success rate
        - 31 wells were permitted and drilled as Gas Exploration wells; 18 were completed as gas wells, for a 58.1% success rate
        - An estimated 519 BCF of gas was developed by these wells
        - Ninilchik, Kenai and Deep Creek Units had the most drilling activity during this period; Ninilchik was very successful; Kenai wells were average and Deep Creek wells were marginal
        - The estimated costs for drilling and facilities of these 128 gas wells are between $1.0 and $1.2 billion

Review of DNR Analysis of Available Reserves

- The DNR completed a Cook Inlet Gas Reserves Study in December 2009
- In the DNR study, reserves and resources are systematically estimated, but as stated in the report, the timing of the development of undeveloped reserves is only an estimate as shown in DNR's Figure 14, a "Hypothetical production forecast for Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analysis discussed in text."

- In the DNR study, the only firm deliverabilities are for reserves estimated by decline curve analysis and material balance. The material balance resources would be realized through the spending of additional capital for development (Beaver Creek) or for compression (Ninilchik). Timing is determined by economic drivers.
- The DNR study forecasted 863 BCF of Proven Developed Producing reserves compared to the decline curve analysis performed by PRA forecasting 729 BCF[5] of reserves.
  - A major difference in decline curve analysis performed by PRA was apparent at Beluga River Field where the DNR study estimated 377 BCF remaining reserves and PRA estimated 207 BCF.
  - The predicted production from decline curve analysis was similar in both studies; both DNR and PRA showed decline curve analysis predictions from existing wells falling below projected demand in the 2012-2013 timeframe.
- The DNR study forecasted Additional Probable Reserves of 279 BCF based on material balance calculations, while PRA did not perform material balance calculations.
- In both studies, the four (4) Fields identified as having greatest remaining potential and selected for detailed geological analysis were: Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands. Reported were:
  - Potential gas resources (from geologic analysis of 4 fields above) estimated to be 353 BCF
  - Possible gas resources of 643 BCF (50% Risked case) estimated from lower confidence pay intervals

<u>Potential of Future Gas Wells in Cook Inlet:</u>

- Drivers required for future Cook Inlet reserve development include:
  - Execution and RCA approval of gas contracts
  - Predictable timeline and standard for regulatory approval of negotiated gas pricing structures
  - Additional regional industrial gas demand, including LNG exports.
  - Additional well-capitalized exploration and development companies committed to develop Alaskan resources
  - Government action to facilitate and accelerate development of necessary infrastructure and permitting
- Challenges facing future Cook Inlet development include:
  - Possible discontinuation of LNG exports from the region
  - Reduced industrial demand (e.g., regional fertilizer manufacturing)
  - Success rates in exploration and development
  - Higher relative regional costs for exploration, development, and production
  - High level of activity in reserve development needed to meet demand

[5] 762 BCF in Report included 33.7 BCF estimated for 4 remaining 2009 Wells

- Probable decline in production rates from future wells in existing fields
- Minimum requirements to meet demand in Cook Inlet gas market until 2020:
  - A new source of gas, such as imported LNG or other in-state reserves, could be required as early as 2013, if ongoing drilling or drilling success does not continue at the 2007-2009 pace.
  - Gas storage will maximize Cook Inlet gas deliverability potential and more closely match local demand curves and production rates.
  - To meet projected demand for the next decade, 185 new wells will be needed, which is a 45% increase over the number of wells drilled in the 2001-2009 period
  - Development costs for this time period are estimated at $1.85 to $2.8 billion, an increase in total capital investment of 54-180%
  - To incent this substantive increase in investment levels, or to bring a new source of gas to Cook Inlet, utility customers should expect to pay significantly higher gas prices

Figure 2 shows recent history and future wells estimated to meet CI gas demands through 2020. The well count assumes average well performance of 2007-2009 wells, with initial rates and developed reserves degraded by 4.3% per year.

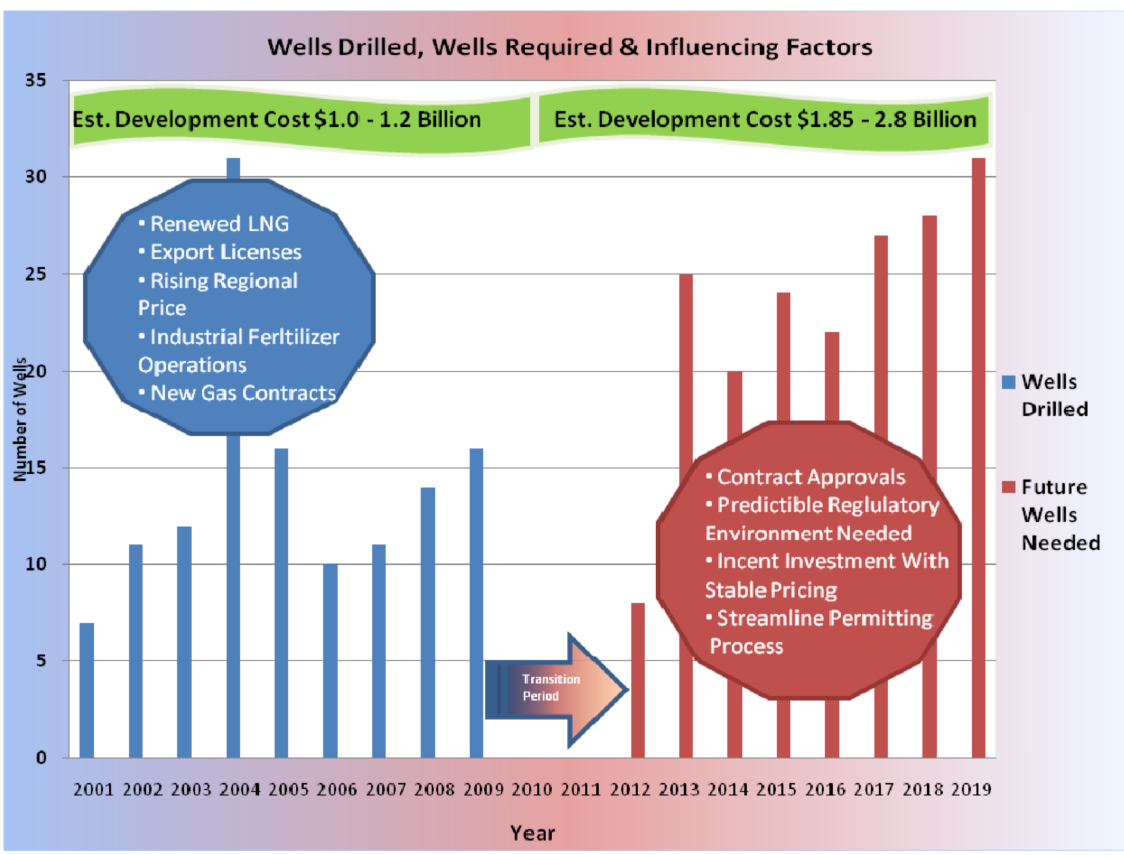


Figure 2:Wells Drilled, Future Wells Required & Influencing Factors

Table of Contents

Table of Figures **Page**

Table of Tables **Page**

I. Introduction

Over the last 10 years, the deliverability profile of gas supply in Cook Inlet has changed. Historically Cook Inlet utilities were not impacted by deliverability shortages. However, in recent years, deliverability shortages have occurred on the coldest winter days. Cook Inlet gas production has declined and if the trend continues, average annual gas production will be less than annual average gas demand before 2020. To meet demand, new sources of gas must be identified. New gas must either come from undeveloped or undiscovered Cook Inlet reserves or from non-Cook Inlet sources, such as the importation of Liquefied Natural Gas (LNG) or other in-state resources.

Development of new or undiscovered reserves in Cook Inlet is hindered by significant challenges that are all likely to increase the prices consumers will pay for gas:

- The most likely undiscovered reserves will be in the offshore, and it takes a large financial commitment to bring in an offshore jack-up rig to explore for gas and expensive infrastructure to develop offshore discoveries. Mobilization costs for an offshore jack-up drilling rig have been estimated to be $156 million for a 3 year contract (Petroleum News 4/20/08)
- The Cook Inlet region is a small market with few customers and few suppliers. Offshore exploration and development investments require high risk, large capital commitments dependent on contracts.
- In recent years, the RCA has rejected several new contracts based on their pricing structures. These rulings create additional risk for producers who are required to invest capital looking for new gas, thus further increasing the cost of production.
- Existing onshore fields have been developed and most of the economical gas has been developed. Other potential onshore resources are on land where development is not permitted.
- Future offshore developments may be restricted, or costs significantly increased if Beluga whales are classified as endangered under federal law[6].

Alaska Department of Natural Resources Division of Oil and Gas (DNR) are land owners that approve Plans of Exploration on Exploration Units and Plans of Development on producing properties (leases or units), but they have little immediate control over timing and actual finding of new reserves. Exploration incentives, capital tax credits, and favorable tax treatment for Cook Inlet Gas have all helped to spur exploration, but the economic drivers are still very challenging for development of new gas reserves.

DNR presented a supply demand curve (Figure 3) to the House Energy Committee in March, 2009 that showed that gas demands in Cook Inlet could be met until 2018 with existing and new developments. This was anecdotally based on the Netherland, Sewell & Assoc. reserves study prepared for ConocoPhillips Alaska (CPAI) and Marathon for the LNG export license extension.

[6] Drilling may be precluded in some areas of Cook Inlet and the additional permitting and environmental costs may be substantial.

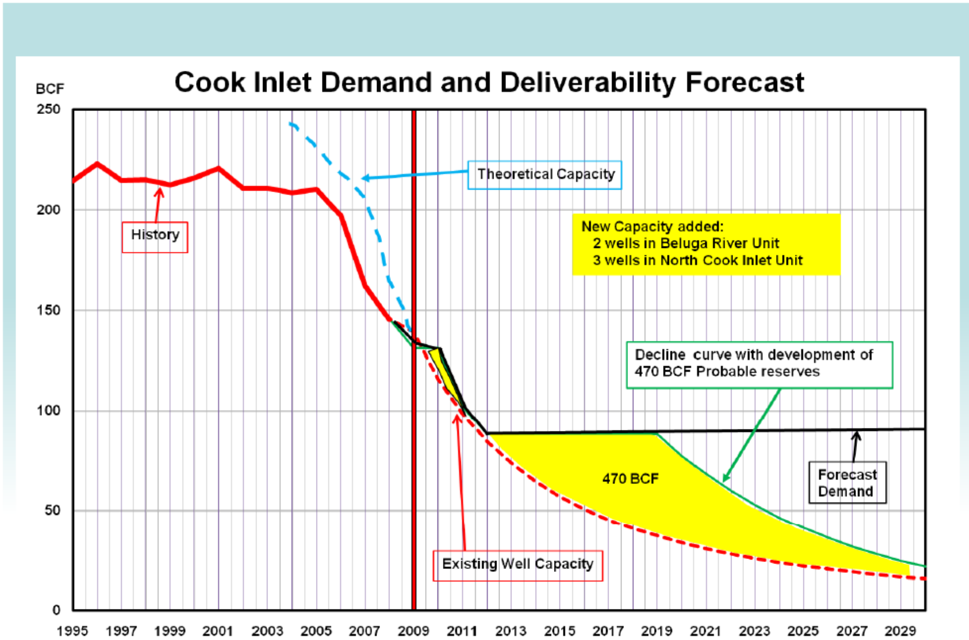


Figure 3: Supply Demand Curve presented by the DNR to the House Energy Committee March 2009

A new study was released by the DNR in December, 2009 that reviews gas reserves in the Cook Inlet basin. The preliminary findings of the new study include the prediction that the average supply from existing wells, assumed from decline curve analysis, will not meet the average annual South Central Alaska demand as early as 2013 as shown in Figure 4.

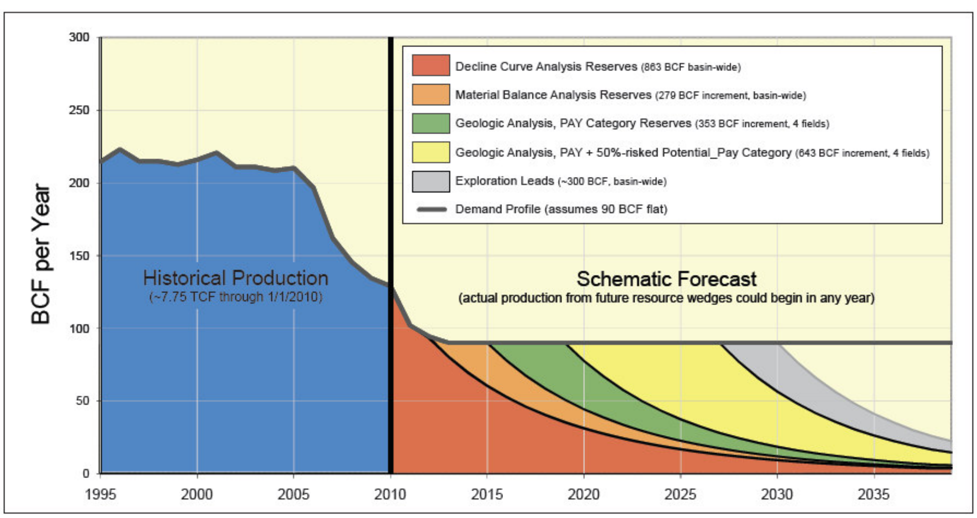


Figure 4: Supply Demand Curve from DNR December 2009 CI Gas Study

The DNR study addressed the question of what gas reserves were physically present, but did not evaluate the economic factors that would result in production of those reserves.

PRA was engaged by the Cook Inlet Utilities to compare the existing supply with current and future demand for gas in the Cook Inlet region and to identify the potential and economic drivers for future reserves development. This study concludes that meeting future utility demand will require a significant level of investment and appropriate price incentives.

Table 1 shows the comparison between the DNR and PRA decline curve analysis estimate. The biggest difference is in the Beluga River Field, where DNR estimates 171 BCF or 45% more reserves than PRA. There are no details in the DNR study showing how decline curve analysis was calculated so differences could not be explained.

Field	DNR Decline Forecast Production, BCF	PRA, BCF	DNR minus PRA, BCF	DNR % Greater than PRA
Kenai	90	74	16	18%
North Cook Inlet	145	129	17	11%
Beluga River	377	207	171	**45%**
McArthur River (Grayling gas sands)	113	163	-50	**-44%**
Ninilchik	62	38	24	39%
Other Fields	76	118	-42	-56%
Total	**863**	**729**	**135**	16%

Table 1: Comparison of DNR Decline Curve Analysis reserves to PRA prediction

Figure 5 shows the comparison of the annualized production potential of DNR's forecast and PRA's. There does not appear to be a large difference, although PRA predicts higher deliverability in 2010-2012 and lower in years after 2013. It is important to distinguish between annual production potential and daily deliverability. Utilities need deliverability to meet their customers' needs. The planned storage facility will improve utility's ability to manage their loads when it is completed. As of the date of this report, however, there are no firm plans to construct a storage facility.

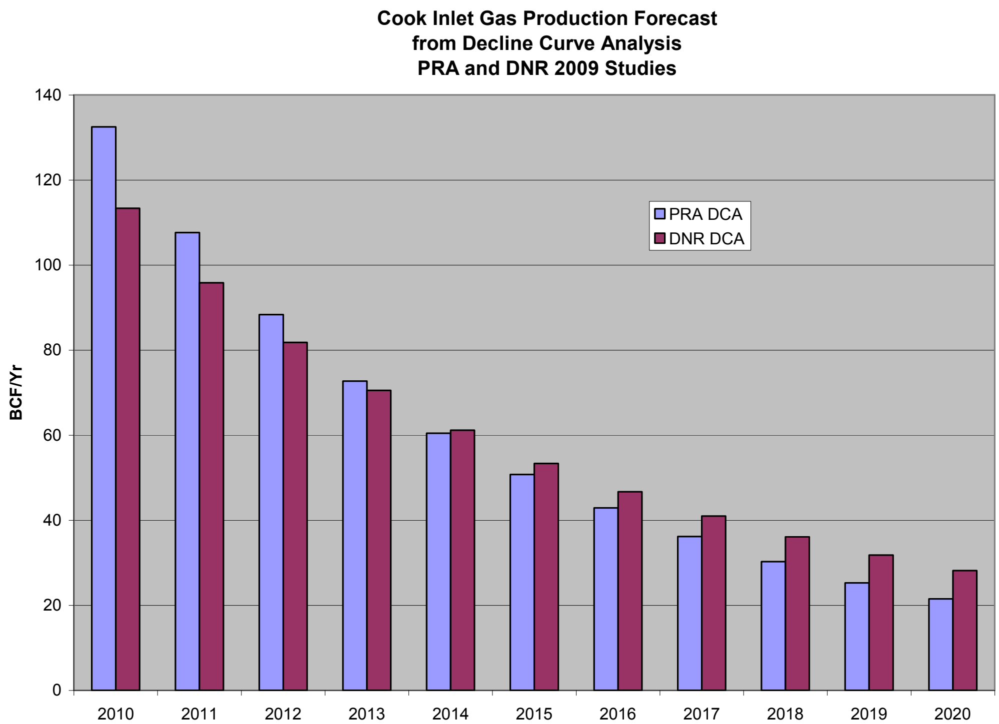


Figure 5: Comparison of DNR decline curve annual production forecast to PRA

II. History of Cook Inlet Gas Development

Twenty nine gas fields have been discovered in Upper Cook Inlet and a total of 7 TCF of non-associated gas has been produced from these fields through December of 2008. Existing Cook Inlet developments are shown in Figure 6. The gas is biogenic methane generated from extensive coal beds in the Tertiary non-marine stratigraphic section. Solution gas production associated with Cook Inlet oil fields is not included in these totals. The four largest gas fields, Beluga River, Kenai, McArthur River and North Cook Inlet have yielded 6.35 TCF or 90% of the produced gas. Appendix A, Table 1 lists the 29 fields in order of discovery and includes other details about the fields. This information is publicly available through the AOGCC and the ADNR Division of Oil and Gas. The following summary of information was largely drawn from the South Central Alaska Natural Gas Study by Thomas, et al. (2004) and the Cook Inlet Oil and Gas power point slides prepared by Director of the Division of Oil and Gas, Kevin Banks (2009).

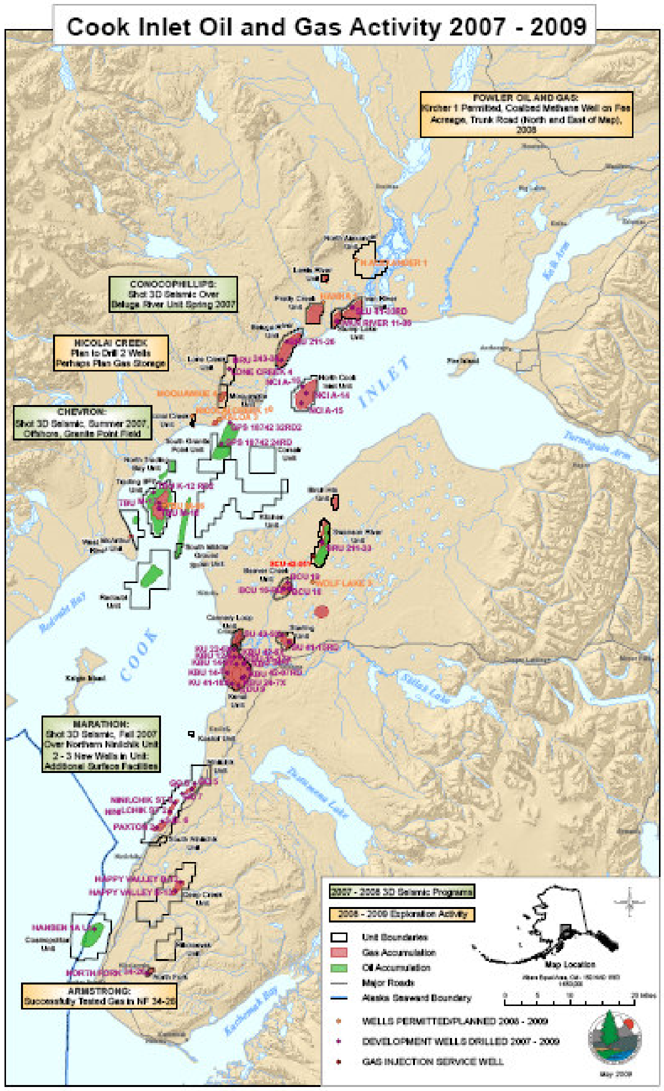


Figure 6: Oil and Gas Fields in Cook Inlet (DNR website)

Exploration History

Aggressive exploration for oil in Upper Cook Inlet began in 1955 and continued to 1968, at which time the discovery of oil at Prudhoe Bay shifted the focus of oil exploration to the North Slope, where it is still concentrated today. Twenty of the twenty-nine gas fields in Upper Cook Inlet were discovered during this initial 13 year period. The exploration, however, was focused on oil, not gas, and all the gas fields discovered were incidental to the oil drilling. Since 1968, the exploration effort in Cook Inlet has been modest, resulting in the basin being under-explored. Most of this exploration was directed toward oil, and only in the late 1990's did gas-first exploration begin in the Cook Inlet. During this aggressive phase of oil exploration, 94% of the current gas reserves were discovered. Because the focus was on oil, some wells drilled early in the exploration history were plugged and abandoned and later re-examined and found to contain ‘by-passed’ or ‘missed’ gas or gas that was purposely left un-tested because gas was not an economic objective.

There is a trimodal distribution of gas field sizes in the Cook Inlet. The estimated ultimate recoverable reserves for the largest four fields range from 1.1 to 2.3 TCF, six fields range from 100 to 250 BCF and the remaining fields range from 3 to 90 BCF. This gap in field sizes suggests there should be more mid-sized fields yet to be discovered. Exploring, discovering, producing and developing new fields is a multi –year process. Even if an aggressive exploration effort were undertaken immediately, it would not bring new gas to market quickly enough to provide the gas that will be needed when demand exceeds supply, even in the most optimistic forecasts.

As discussed in the 2003 Cook Inlet Gas Study, recognized gas reserve volumes increase as a result of continued evaluation and development of the fields. In early 1980 the proved reserves in Cook Inlet were considered to be 3,544 BCF. In January of 1998 the proved reserves were 6,730 BCF, an increase of over 3 TCF. Such increases are accomplished through enhanced recovery techniques, new seismic acquisition and reprocessing, and infill and extension drilling. Additional reserve growth will probably continue to occur in the Cook Inlet fields as development continues (although continued development depends on economic factors), but these cannot be quantified and considered proven for supply/demand assessment purposes.

Geology

Cook Inlet is a forearc basin formed by subduction of the Pacific tectonic plate beneath the North American plate. The basin is filled with Mesozoic dominantly marine and Tertiary non-marine rocks. The Upper Cook Inlet basin sedimentary rocks are separated from the igneous arc rocks to the west by the Bruin Bay fault, the sediments in the Susitna Basin to the north by the Castle Mountain fault, the metamorphic rocks of the Chugach Terrane to the east by the Border Ranges fault and the Lower Cook Inlet sediments to the south by the Augustine-Seldovia arch.

Stratigraphy. Figure 7 shows the Mesozoic and Cenozoic stratigraphy of Cook Inlet. The Mesozoic section was penetrated by some of the deeper wells in Upper Cook Inlet and was a primary objective during the early basin exploration in the 1950’s and 1960’s. The section contains oil prone source rocks but poor reservoirs. No oil or gas has been produced from the Mesozoic section.

The Upper Cook Inlet Tertiary locally exceeds 25,000’ in thickness and consists of five non-marine formations, the West Foreland, Hemlock, Tyonek, Beluga and Sterling. The type sections for these formations are defined in 5 different wells in the basin. The section is thickest in the north central part of the basin and thins to both the east and west sides. The formations overlap in age and do not form a simple layer-cake stratigraphy.

The Eocene and Oligocene aged West Foreland is the basal formation and has generally poor reservoir quality but does locally contain some oil. The Oligocene aged Hemlock Conglomerate is the main oil reservoir and ranges in thickness from 570' in the Swanson River Field to 750' at Middle Ground Shoal. It consists dominantly of sandstone and conglomerate with good reservoir quality. The Oligocene and Miocene aged Tyonek is 7,650' thick in the type section well and consists of thick sandstone beds and thick (30-40' up to 80') bituminous and sub-bituminous coal beds separated by siltstone and claystone interbeds. Because of their thickness, the coals tend to be laterally continuous over tens of miles. The Tyonek sandstones are both oil and gas bearing with oil in the lower and gas in the upper part of the formation. The Miocene aged Beluga formation is 4150' thick in the type section well and is removed by pre-Sterling erosion on the east and west sides of the basin. It consists predominantly of siltstones interbedded with channelized sandstones and lignitic to sub-lignitic thin (5'thick) coal beds and tuffs. The Upper Beluga channel sands are gas reservoirs. The Miocene and Pliocene aged Sterling Formation is 4,490' thick in the type section well and consists of massive sandstones and conglomeratic sandstones interbedded with siltstone and thin coals. The sandstones are stacked fluvial channels that are excellent gas reservoirs.

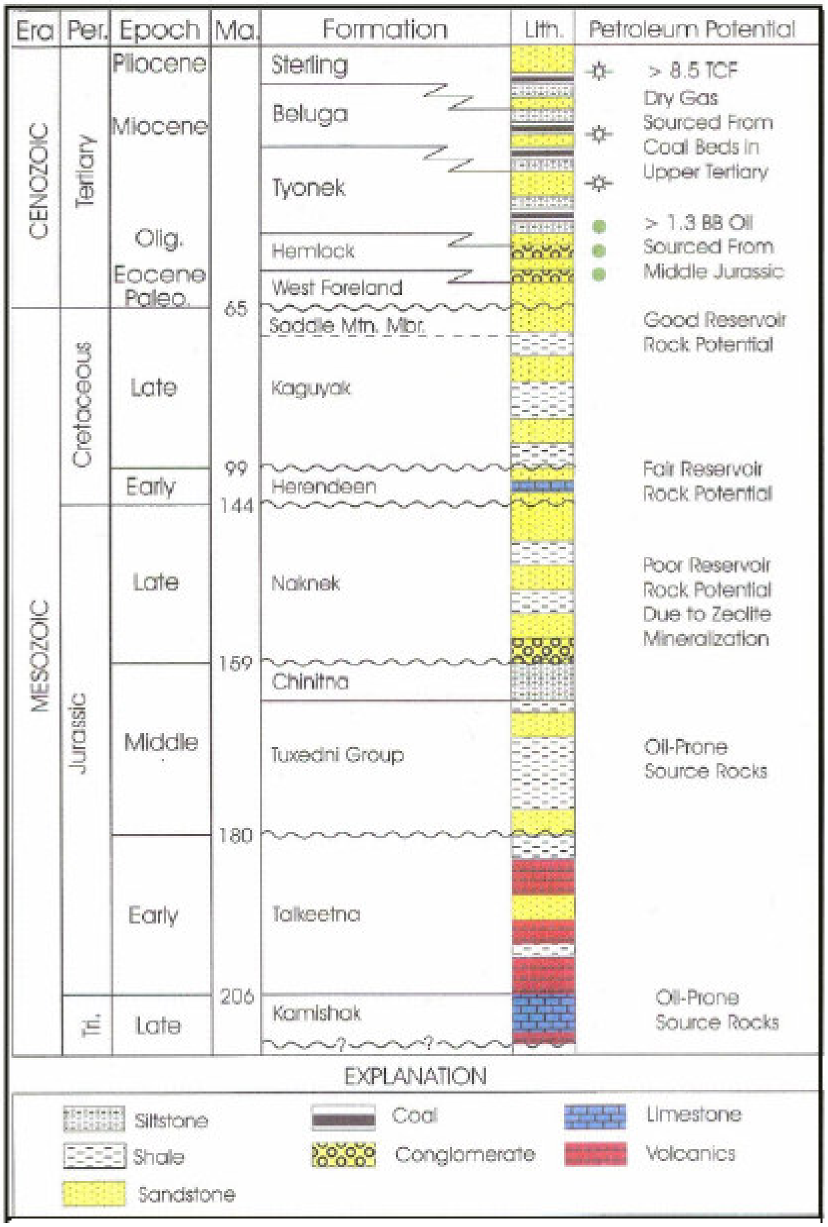


Figure 7: Cook Inlet Stratigraphic Column. FromThomas, et.al., 2004

Hydrocarbon Source Rocks. There are two independent hydrocarbon systems in Upper Cook Inlet. The oil and associated gas produced from the Hemlock and lower Tyonek reservoirs is thermogenic in origin and is sourced from the Middle Jurassic Chinitna member of the Tuxedni Group. All the oil fields are undersaturated with gas so all associated gas is dissolved in the oil and comes out of solution when produced. This associated gas produced with the oil is not included in the proven gas reserves. The gas produced from the upper Tyonek, Beluga and Sterling formations isn't associated with the oil and is biogenically derived from the coals and carbonaceous siltstones.

Reservoirs. Reservoir data are presented in Appendix A, Tables 2 and 3 for the 29 gas fields. Reservoir sandstones are predominantly fluvial, consisting of channels and channel belt deposits of both meandering and braided types of the axial fluvial system and alluvial fan deposits nearer the basin margins. Deposit types include point bar, meandering and braided channel fill, crevasse splay, channel lag, levee, and flood plain deposits as shown in Figure 8. The sands are encased in the overbank flood-plain interbedded siltstones and mudstones which form good seals for trapping hydrocarbons.

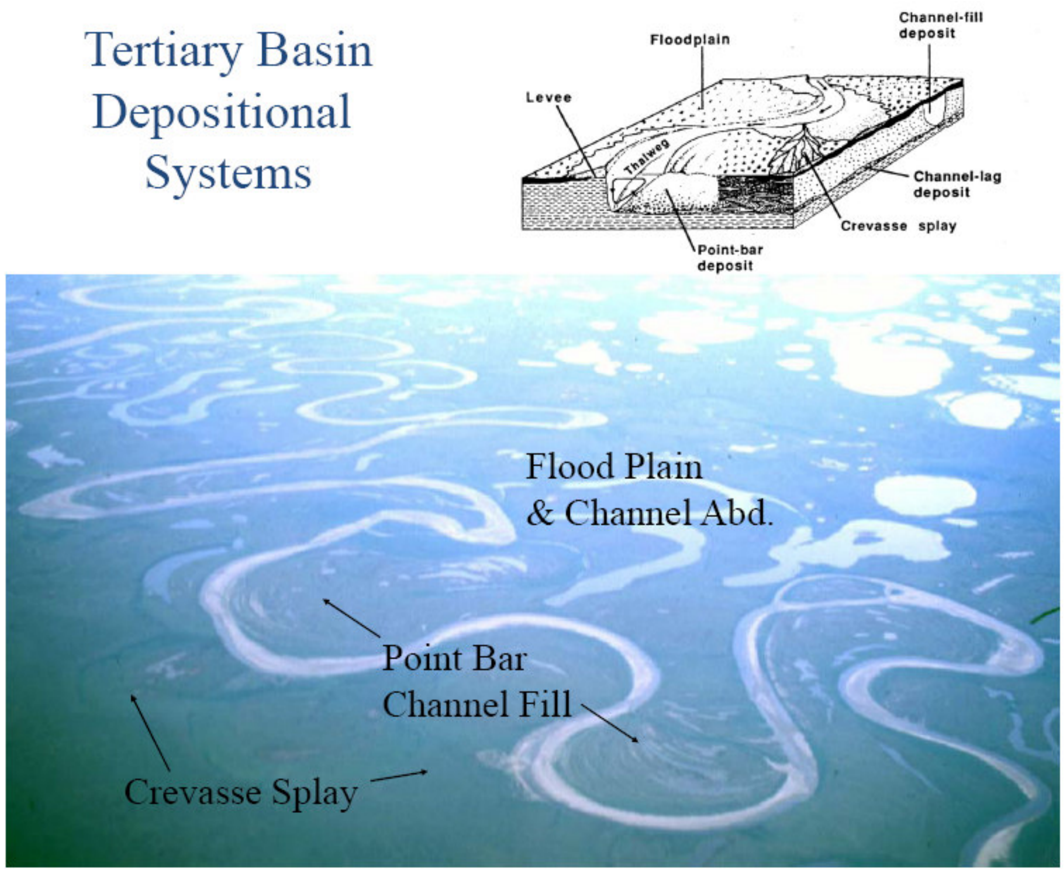


Figure 8: Tertiary Basin Depositional Systems (DNR)

Individual sand packages tend to have limited lateral extent but often overlap or are stacked and may or may not have connectivity over the areal extent of the gas fields or between the spacing of the wells. Sterling and to a lesser extent Tyonek reservoir sands tend to be thicker and more well connected. Beluga reservoir sands are thinner, less well connected and more frequently isolated. The lateral discontinuity of sands can lead to erroneous correlations between wells. New, untested reserves can be found within established fields because of the discontinuous and laterally heterogeneous nature of the reservoir sands. Figure 9 from a DNR presentation shows a stratigraphic cross section over the Beluga River Gas field. The upper portion of the section represents the Sterling Formation and the lower portion represents the Beluga Formation. The section shows the lateral thickness changes and discontinuous nature of the sands and the difficulty in correlating between wells. This is representative of these formations throughout the Inlet.

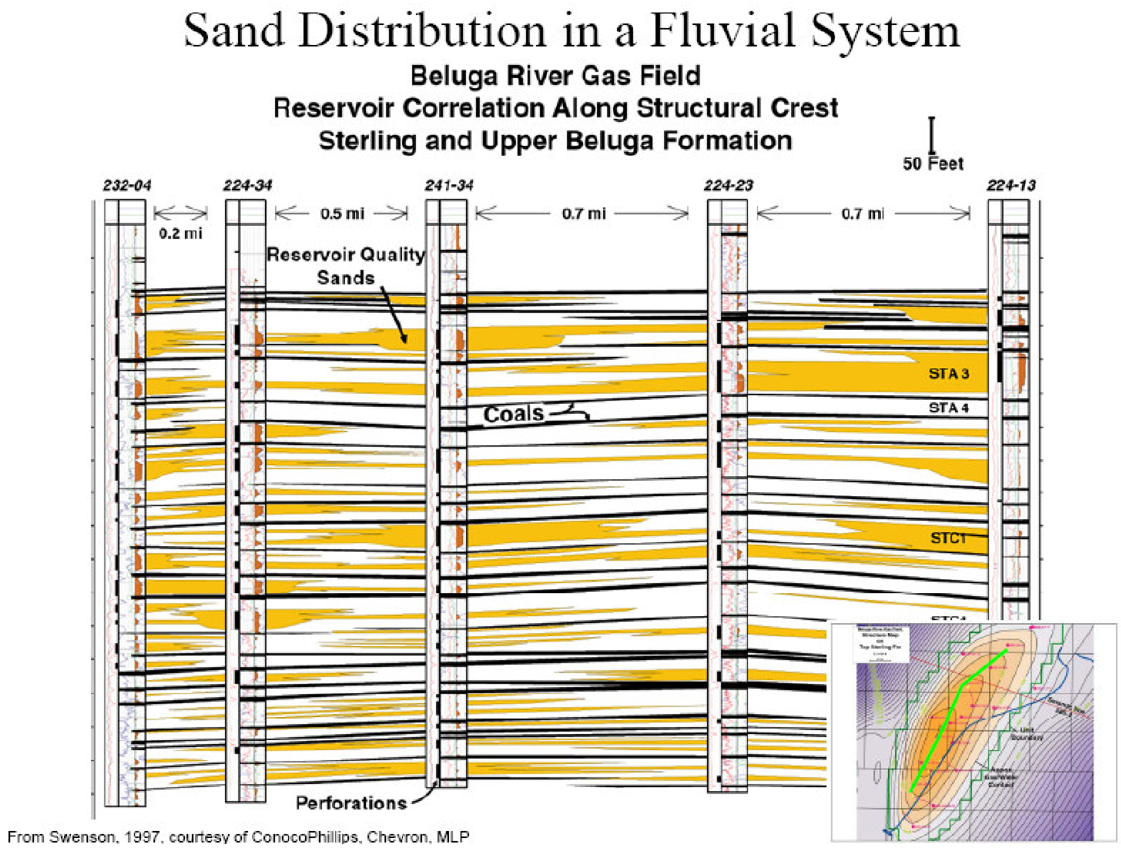


Figure 9: Beluga River Stratigraphic Section

Porosity, permeability and net pay thicknesses from the AOGCC annual report are shown in Appendix A, Tables 2 and 3. Porosity generally decreases with the depth of the reservoirs. Identification of pay on wire line logs can be difficult. Tight gas sands have been productive with effective porosities greater than 10% and less than 1md permeability (Figure 10). Also, low resistivity sands, 10 ohms, can be productive. Detailed petrophysical analysis can identify these possible types of pay.

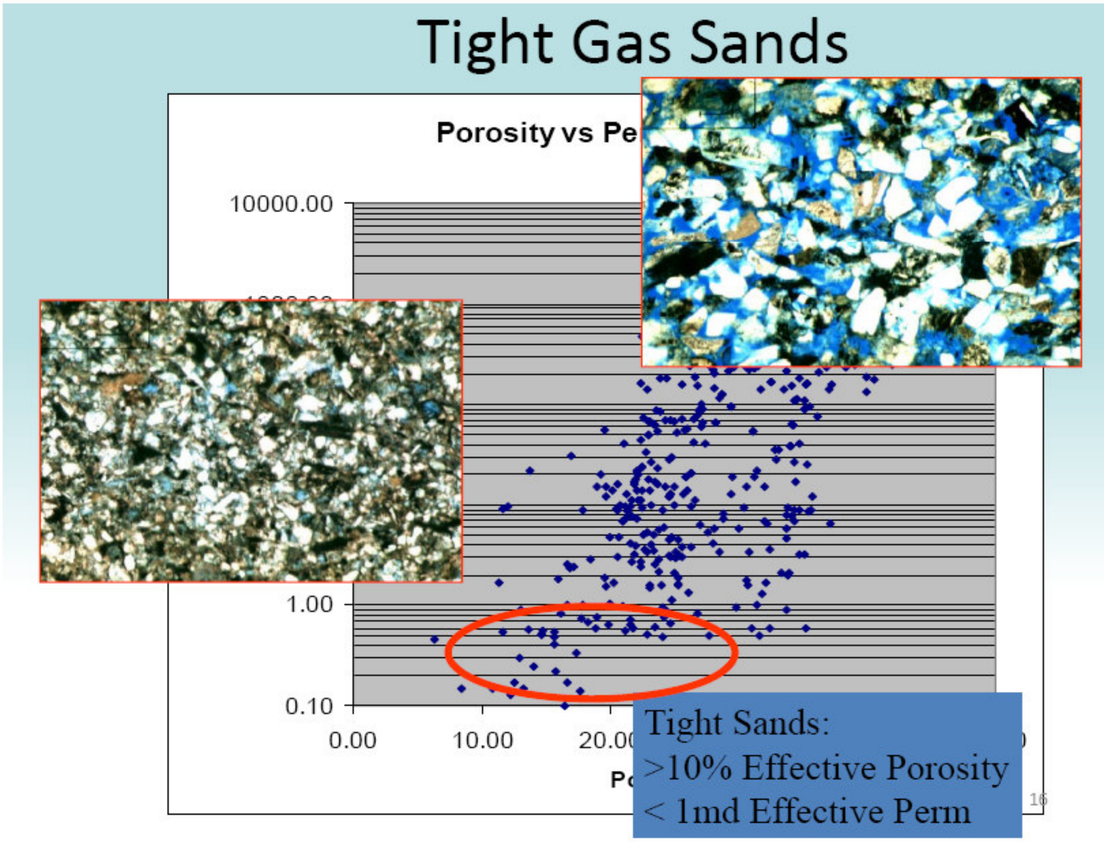


Figure 10: Tight Gas Sands in Cook Inlet (DNR 031709)

Structure. Structures in Cook Inlet are asymmetrical anticlines oriented in northeast-southwest direction due to the northwest-southeast compression of the basin. The folds range from broad and gentle to very tight with some having vertical to overturned limbs. The tighter folds are typically mapped with a high angle reverse fault on their steeper flank. These high angle reverse faults are typically interpreted on seismic data which often cannot image the steep dips that are present and such faults may actually be zones of poor data caused by steep dip. Because the gas reservoirs are in the upper part of the stratigraphic section they are not as affected by steep dips as the oil reservoirs in the deeper cores of the folds. Some of the structures are cross-cut by systems of normal or reverse faults which can be seals to hydrocarbon migration resulting in isolated pay zones. This compartmentalization of the structures by secondary fault systems can lead to the discovery of new untested reserves in old established fields. All of the gas fields were originally mapped using 2D seismic data. Some fields have been re-mapped using 3D seismic techniques which can better image the structural complexity and possible cross-cutting fault systems and potentially identify untested fault blocks.

Traps. All the gas fields in the basin are structural traps and none are filled to spill point. Most of the traps are four-way dip closures that range from <100' to >1000' of structural closure. Some fields such as Swanson River, Granite Point, Middle Ground Shoal and McArthur River have systems of small normal and reverse faults that cross cut the structures and act as seals to migration of gas and form isolated fault traps within the larger structures. Most four way dip structures in the basin have some gas trapped in them no matter how subtle the dip.

<u>Challenges facing Cook Inlet gas business</u>

- Formation damage due to sensitive clay cements
- Drilling and seismic costs are very high
- Fines migration and unconsolidated sands cause production problems in some reservoirs
- Gas is difficult to identify on wire line logs (difficult petrophysical analysis) R_{wa} & S_w varies throughout the stratigraphic section.
- Low resistivity pay can be overlooked or by-passed. Careful petrophysical analysis and re-examination of mud logs and wire line logs can identify such missed pay.
- Tight gas sands can be overlooked on the initial drilling.
- Sands are discontinuous and disconnected (especially Beluga & some Tyonek). Pay can be mis-characterized without additional infill drilling, especially in Beluga reservoirs.
- Correlations are difficult.
- Structures are difficult to image seismically due to steep dips.
- Coal beds in the Sterling, Beluga and upper Tyonek form prominent reflectors on seismic data, absorbing seismic energy, and causing poor imaging of the deeper formations with the only prominent deep reflector often being the unconformity at the Tertiary/Mesozoic boundary.
- 3D seismic improves interpretation of structural complexity significantly over 2-D data.
- Dominance of coals and poorly consolidated sands cause drilling problems.
- Seasonal drilling and seismic acquisition limitations
- Permitting and land access issues are limiting
- Dipmeter data in older wells is suspect due to steep dips – the correlation angle was often insufficient to see true dip.

Specific Field Descriptions, including maps and production forecasts are shown in Appendix B.

III. Analysis of the "gap" between supply and demand

a. Review of Drilling during 2001 to 2009

According to AOGCC records, a total of 128 wells were drilled in the Cook Inlet basin in the period 2001 to 2009. The results, shown in the table below, are that 105 wells were completed.

The wells with the highest 12 month average production were drilled at Beluga River, Cannery Loop, Ninilchik and Trading Bay Unit.

Well-level reserve analysis was made for the wells and the reserves developed per well are shown in Table 2.

As observed, the average reserves developed per well in this period is 4.4 BCF/well.

Summary of Cook Inlet Gas Wells Drilled 2001-2009

Field	Number of Gas Wells Drilled	Number Currently Producing	Average 12 Month Rate MMSCF/D	Cum Production BCF	Estimate of Reserves BCF	Reserves per Producing Well, BCF	Reserves per all Wells, BCF
Beaver Creek	9	7	2.5	15.6	29.1	4.2	3.2
Beluga River	3	3	3.6	4.4	32.3	10.8	10.8
Cannery Loop	7	6	6.9	45.3	70.0	11.7	10.0
Happy Valley	12	12	1.0	13.6	18.4	1.5	1.5
Kenai	28	25	3.1	59.6	108.5	4.3	3.9
No. Cook Inlet	4	4	4.2	14.5	36.2	9.1	9.1
Ninilchik	19	18	5.0	84.1	119.9	6.7	6.3
Sterling Unit	2	2	1.6	1.0	2.7	1.3	1.3
Swanson River Unit	3	2	3.6	3.6	4.2	2.1	1.4
Trading Bay Unit	6	6	8.0	45.6	98.1	16.4	16.4
Other*	35	20	2.6	25.8	43.3	2.2	1.2
Total	**128**	**105**	**3.6**	**313.0**	**562.7**	**5.4**	**4.4**

Table 2: Drilling of Gas Wells in Cook Inlet 2001 to 2009

Table 3 shows the wells that were drilled in the period 2007 to mid-2009. An average of 13.6 wells per year were drilled and completed in the period 2007-09 group of wells and the average well forecast of production will be used as a proxy for the various supply forecasts.

Summary of Cook Inlet Gas Wells Completed 2007-2009

Field	Number of Gas Wells Completed	Number Currently Producing	Average 12 Month Rate MMSCF/D	Cum Production BCF	Estimate of Reserves BCF	Reserves per Producing Well, BCF	Reserves per all Wells, BCF
Beaver Creek	3	3	2.3	3.4	12.0	4.0	4.0
Beluga River	3	3	3.6	4.4	32.3	10.8	10.8
Cannery Loop	0	0	0.0	0.0	0.0		
Happy Valley	2	2	0.7	0.2	0.9	0.4	0.4
Kenai	9	9	3.0	10.2	36.1	4.0	4.0
No. Cook Inlet	3	3	3.5	2.0	20.3	6.8	6.8
Ninilchik	5	5	3.2	6.3	16.9	3.4	3.4
Sterling Unit	2	2	1.6	1.0	2.7	1.3	1.3
Swanson River Unit	0	0	0.0	0.0	0.0		
Trading Bay Unit	3	3	8.4	4.4	30.6	10.2	10.2
Other	4	4	1.7	0.7	9.2	2.3	2.3
Total	**34**	**34**	**3.1**	**32.6**	**161.0**	**4.7**	**4.7**

Table 3: Drilling of Gas Wells in Cook Inlet 2007 to 2009

Table 4 shows the number of net wells (company share of wells) drilled by the most active producer/explorers during the 2001-09 and 2007-09 periods.

Summary of Cook Inlet Gas Wells Drilled 2001-2009

Field	Number of Gas Wells Drilled	Marathon Net Wells	Chevron Net Wells	Conoco Net Wells	MOA Net Wells	Aurora Net Wells	Forest/PERL Net Wells	Other Co. Net Wells
Beaver Creek	9	9.0						
Beluga River	3		1.0	1.0	1.0			
Cannery Loop	7	7.0						
Happy Valley	12		12.0					
Kenai	28	28.0						
No. Cook Inlet	4			4.0				
Ninilchik	19	11.4	7.6					
Sterling Unit	2	2.0						
Swanson River Unit	3		3.0					
Trading Bay Unit	6	3.1	2.9					
Other	35	5.0	10.0			15.0	2.0	3.0
Total	**128**	**65.5**	**36.5**	**5.0**	**1.0**	**15.0**	**2.0**	**3.0**

Summary of Cook Inlet Gas Wells Completed 2007-2009

Field	Number of Gas Wells Completed	Marathon Net Wells	Chevron Net Wells	Conoco Net Wells	MOA Net Wells	Aurora Net Wells	Forest/PERL Net Wells	Other Co. Net Wells
Beaver Creek	3	3.0						
Beluga River	3		1.0	1.0	1.0			
Cannery Loop	0	0.0						
Happy Valley	2		2.0					
Kenai	9	9.0						
No. Cook Inlet	3			3.0				
Ninilchik	5	3.0	2.0					
Sterling Unit	2	2.0						
Swanson River Unit	0		0.0					
Trading Bay Unit	3	1.5	1.5					
Other	4	1.0	1.0			1.0		1.0
Total	**34**	**19.5**	**7.5**	**4.0**	**1.0**	**1.0**	**0.0**	**1.0**

Table 4: Wells drilled 2001-09 and 2007-09 by Company

Figures 11 and 12 show the drilling levels for 2001-2009 for development wells and exploration wells as permitted with AOGCC, respectively. As can be seen the success rate for development was 90.7% and the success rate for gas exploration wells was 58.1%. Appendix E lists the wells with permit numbers and completion status.

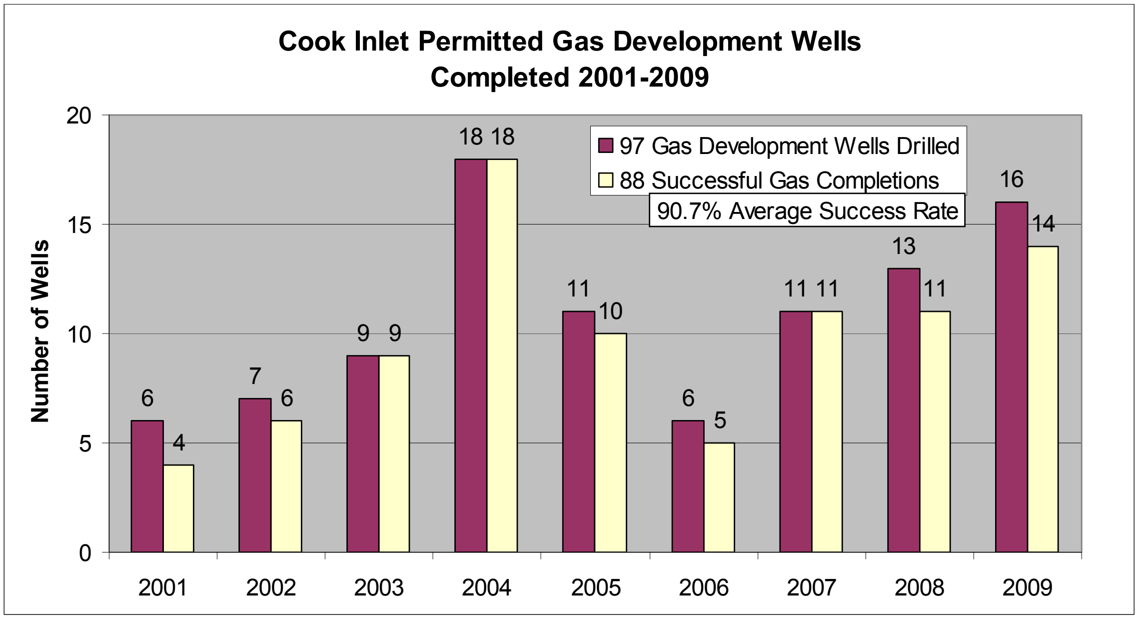


Figure 11: Gas wells drilled 2001-09 permitted as Development wells (AOGCC well database)

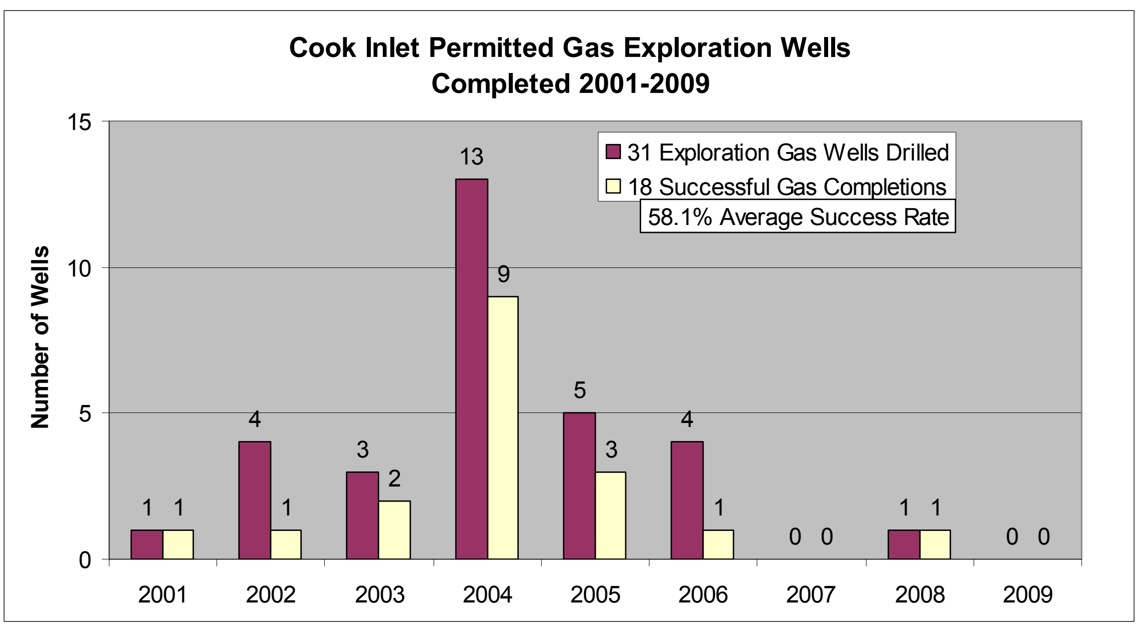
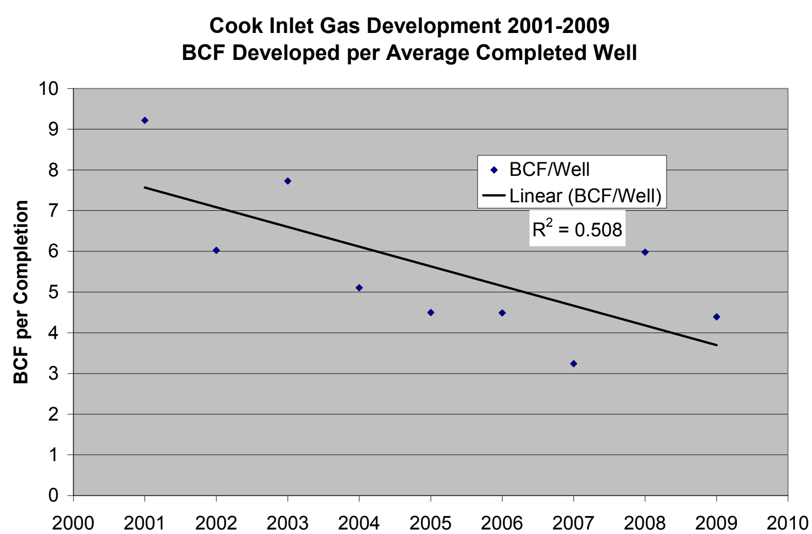


Figure 12: Gas wells drilled 2001-09 permitted as Exploration wells (AOGCC well database)

Factors that have contributed to drilling activity during this time period include the LNG export license renewal extending the license from 2004 to 2009, and again from 2009 to 2011, a new gas contract with Unocal/Chevron was approved in 2001 and Chevron drilled to meet their contractual obligation, Marathon Oil performed activities in conjunction with the potential ENSTAR/APL-5 contract, and the Kenai-Kachemak Pipeline (KKPL) was constructed. It may also be worth noting that regional gas prices climbed more than 140% from 2001 to 2004 and climbed more than 120% from 2004 to 2007.

Figure 13 is shows an estimate of gas developed per well 2001-2009, with a decreasing trend in ultimate recoverable gas.



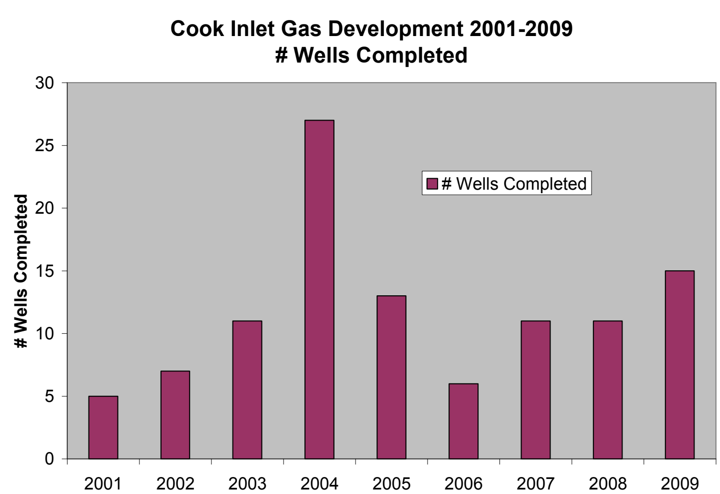


Figure 13: Cook Inlet gas development 2001-2009

i. Recent Well Costs

While there are no public sources for well costs, the bullets below summarize information that has been shared publicly.

- Chevron
  - Spent $250 million in capital on gas projects from 1999-2007
  - Had working interests in 52 wells, 14 were exploratory and 38 were development
  - Had disappointing results at Happy Valley and in exploration further south
  - Elected to decrease annual volumes to ENSTAR from 19.5 Bcf to 13.5 Bcf.
- Marathon
  - Has spent >$450 million on gas projects from 2002-2008
  - Drilled 65 producing wells
  - Extended the LNG export License to 2011
- Conoco-Phillips
  - Recent well at Beluga River Field cost $23 million, which included fracture stimulation and gravel packed completion
  - Extended the LNG export license to 2011
  - Chugach contract recently approved by RCA

Table 5 is an estimate of 2001-2009 gas well and facility costs from published information and estimates where information was not available.

It is estimated that $1.0 to 1.2 billion was spent between 2001 and 2009 to develop an estimated 563 BCF of gas in Cook Inlet, or a capital cost of $1.78 to $2.06 per MCF. Estimates of future capital costs are estimated to range from $2.50 to $4.30 for wells drilled 2010 to 2019.

Estimate of Cook Inlet Gas Development Costs 2001 to 2009

Net Wells Drilled from AOGCC Records

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Marathon	3.6	5.2	6.1	13.8	8.8	6.2	8.9	6.8	6	
Chevron/Unocal	3.4	4.8	2.9	13.2	1.2	0.8	2.1	3.9	4.3	
ConocoPhillips			1					0.7	3.3	
MOA								0.7	0.3	
Aurora		1	2	2	5	2			3	
Armstrong								1		
Others				2	1	1				**Total**
Total	7	11	12	31	16	10	11	13.1	16.9	**128**

Average Cost Per Well Capital and Facilities Estimate, million*

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009
Marathon	$ 5.0	$ 5.1	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 8.9	$ 9.1
Chevron/Unocal	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.3	$ 8.4	$ 8.6
ConocoPhillips			$ 5.0					$ 23.0	$ 23.0
MOA								$ 23.0	$ 23.0
Aurora		$ 3.0	$ 3.1	$ 3.1	$ 3.2	$ 3.2			$ 3.3
Armstrong								$ 8.0	
Others				$ 6.8	$ 6.8	$ 6.8			

** - Assumes 2% Inflation, $5,000,000 per initial well, except for Aurora at $3,000,000 per well, "Others" use yearly average cost*
Chevron/Unocal 2001-2007 and Marathon 2003-2008 are estimates from publically discussed expenditures.
MOA & ConocoPhillips are from publically discussed well costs for Beluga River Unit.

Baseline Annual Cost Per Well Estimate, million

Company	2001	2002	2003	2004	2005	2006	2007	2008	2009	
Marathon	$ 18	$ 27	$ 54	$ 123	$ 78	$ 55	$ 79	$ 60	$ 54	
Chevron/Unocal	$ 28	$ 40	$ 24	$ 109	$ 10	$ 7	$ 17	$ 33	$ 37	
ConocoPhillips	$ -	$ -	$ 5	$ -	$ -	$ -	$ -	$ 16	$ 76	
MOA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16	$ 7	
Aurora	$ -	$ 3	$ 6	$ 6	$ 16	$ 6	$ -	$ -	$ 10	
Armstrong	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8	$ -	
Others	$ -	$ -	$ -	$ 14	$ 7	$ 7	$ -	$ -	$ -	**Total**
Total Baseline	$ 46	$ 69	$ 89	$ 252	$ 111	$ 75	$ 97	$ 134	$ 184	**$ 1,057**
High Estimate 110% of Baseline	**50.7**	**76.2**	**98.3**	**276.9**	**122.0**	**82.6**	**106.2**	**146.9**	**202.6**	**1162.4**
Low Estimate 95% of Baseline	**43.8**	**65.8**	**84.9**	**239.1**	**105.3**	**71.3**	**91.7**	**126.9**	**175.0**	**1003.9**

Table 5: Cost estimate of Cook Inlet gas development 2001-2009.

The current cost for onshore wells is typically $5-10 million; offshore wells can be $10-20 million. Costs vary based on remoteness of location and how exotic a completion is required for the well.

ii. <u>Drivers for future gas Exploration and Development</u>
Based on conversations with current gas producers and public data, the following are required drivers to explore for and develop gas in Cook Inlet:

- Marathon needs certainty in contract approvals & larger markets to enable growth
    - Market is too small to support 10-15 wells in Cook Inlet (Peninsula Clarion 1/17/10)

- Chevron needs better exploration success
    - Had recent success on TBU Grayling Gas sands, but poor results at Deep Creek
    - Concerned about meeting future winter deliverabilities
    - No future exploration planned (Peninsula Clarion 1/17/10)
- Conoco Phillips does not view the market as large enough to commit major capital to new reserves exploration and development costs.
    - Not looking to explore or develop other than to service LNG and Chugach contracts.

b. Decline curve analysis

Base Case: Current Producing Wells

PRA evaluated existing decline and made a future forecast for the major units in the Cook Inlet Basin. The decline analysis for a unit total was used for the following units:

	2010 Avg. Rate, MMSCF/D	Annual Decline, %	Remaining BCF 1/1/10
Beaver Creek Unit	10.9	10%	35.8
Cannery Loop Unit	13.5	22%	21.8
Deep Creek Unit	5.0	17%	9.0
Sterling Unit	2.4	14%	4.4
Swanson River Unit	2.4	15%	5.5
Other Cook Inlet Fields	14.4	12%	41.8

Units that had recent drilling activity showed decline rates that reflected the new wells. Using production declines on a unit that had recent activity overstates future production as declines are lower due to activity. To predict the current production capacity of each of these units, a well by well decline analysis was made for the following units:

	2010 Avg. Rate, MMSCF/D	Annual Decline, %	Remaining BCF 1/1/10
Beluga River Unit	99.1	17%	206.5
Kenai Unit	39.6	21%	74.4
Ninilchik Unit	36.0	35%	38.0
North Cook Inlet Unit	58.1	16%	128.7
Trading Bay Unit	65.7	15%	162.7
2009 Wells to be Drilled	16.6		33.7
Cook Inlet Total	**363.7**		**762.3**

Production curves and forecasts for each of the units above are shown in the field descriptions in Appendix B. The individual well decline curves for Beluga River, Kenai, Ninilchik, North Cook Inlet and Trading Bay units are shown in Appendix D. For the purposes of this study, individual wells were determined to have reached an economic limit at 250 mscf/d.

Figure 14 shows the estimate of annual supply from the existing wells in the current units. It is an estimate from decline curve analysis and may be conservative as the data showed seasonal variation. It also includes 4 wells recently permitted to be drilled in 2009 and forecasts production based on the average for the wells drilled in their respective field during the period 2001 to 2009.

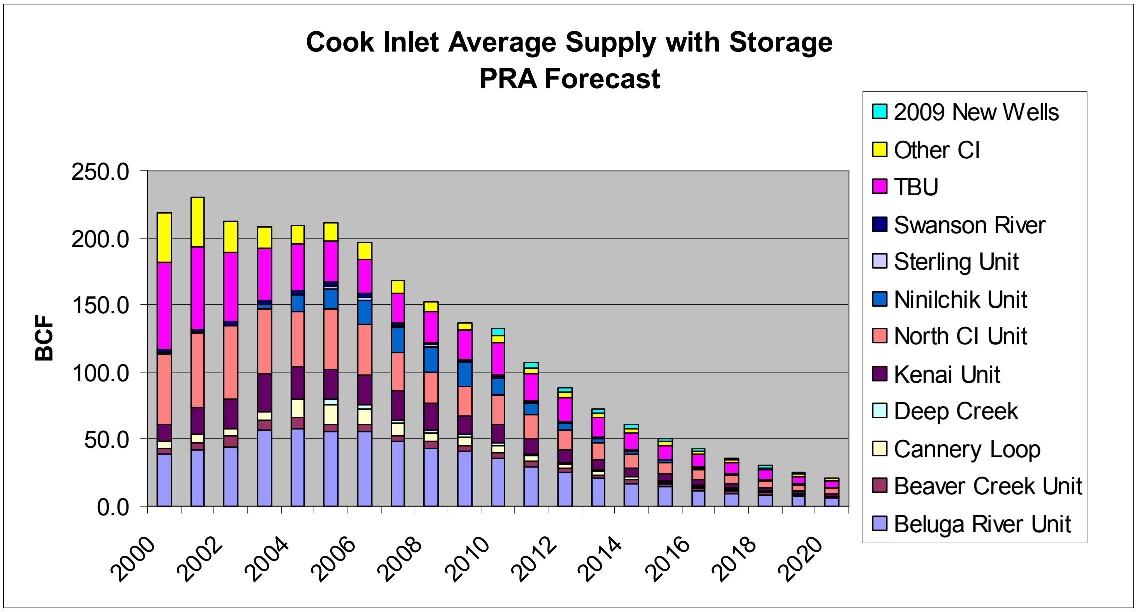


Figure 14: Cook Inlet Gas Production 2000-2009 and 2010-2020 Forecast

The 4 undrilled wells permitted in 2009 and their expected reserves are as follows:

Well	Estimate of Reserves, BCF
Trading Bay Unit M-08	15.7
Moquawkie 5	1.0
Nicolai Creek 11	1.3
Trading Bay Unit M-20	15.7
Total	**33.7**

Reserve estimates are based on the average of wells drilled in 2001-2009 in the respective unit, degraded by 4.3%.

c. Well Flowing Pressures in Major CI Units

Well flowing pressures were reviewed in the following major Cook Inlet units:

- Beluga River Unit
- Kenai Unit
- Ninilchik Unit
- North Cook Inlet
- Trading Bay Unit - Grayling Gas Sand Wells

The well flowing histories of each well in the above units are displayed on the production decline curves in Appendix D. Table 6 summarize the flowing tubing pressures of the wells, by productivity of the well using June 2009 production rates and pressures.

Beluga River Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
300-400	5	33.25
400-500	7	42.89
500-600	3	24.08

Kenai Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
<100	3	0.83
100-300	12	12.02
300-500	8	13.18
500-700	3	7.77
700-900	1	0.87
>900	1	0.81

Ninilchik Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
300-600	8	14.94
600-900	3	8.65
900-1200	3	20.14

TBU Grayling Gas Sand Wells		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
100-200	7	29.61
200-300	1	6.56
300-400	0	0.00
400-500	2	5.00

North Cook Inlet Unit		
Tubing Pressure, Psi	# of Wells	June 09 Production of Wells, MMSCF/D
100-200	9	22.39
200-300	4	15.64
300-400	2	6.28

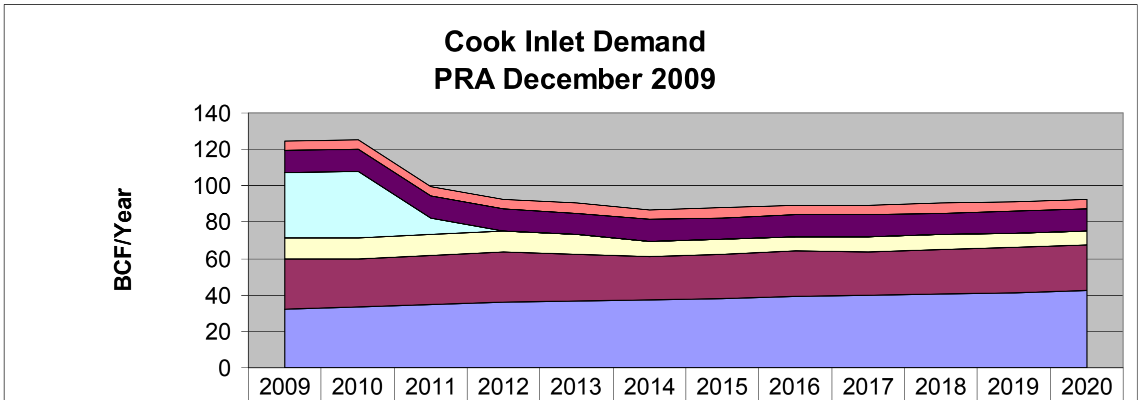
Table 6: Tubing Pressures for Major Cook Inlet Units

As can be observed, there may be potential for increasing production significantly on high pressure wells in Beluga River and Ninilchik Units through the installation of compression. This analysis is preliminary, as each well should be considered separately for its ability to increase production by lowering tubing pressure and whether there is the potential for damaging the well due to higher production rates.

IV. When gas from outside Cook Inlet may be needed

Scenarios have been developed to show when gas will need to be imported to Cook Inlet. Imports could be in the form of gas from other areas of the state or imported LNG.

a. Demand Curve



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tesoro	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Field Operations	12	12	12	12	12	12	12	12	12	12	12	12
LNG	36.4	36.4	9.1									
ML&P	11.54	11.56	11.58	11.62	11.07	8.05	8.06	8.09	8.11	8.14	8.20	8.20
CEA/Railbelt	27.5	26.3	26.9	27.7	25.4	23.8	24.2	25	23.9	24.2	24.5	25
ENSTAR	32.1	33.7	34.9	35.8	36.6	37.4	38.2	39.0	39.8	40.6	41.4	42.2

Figure 15: Forecasted Annual Demand for Cook Inlet Gas

Figure 15 shows the current forecasted demand for the users of Cook Inlet gas. Sources of the data are as follows:

- ENSTAR – M. Slaughter (08/27/09)
- Chugach Electric – M. Fouts (09/24/09)
- ML&P – B. Davies (09/11/09)
- LNG is from projection of Jan-Jun 2009 average shipments through the end of the export license 3/31/11
  (EIA website: http://tonto.eia.doe.gov/dnav/ng/ng_move_expc_s1_m.htm)
- Tesoro is from testimony against the LNG license extension (Tesoro FERC 4/9/07)
- Fuel, Shrinkage and Flare is from the AOGCC records using 2007-08 averages.

b. Supply vs. Demand

This study evaluated Cook Inlet Supply and Demand for three supply cases:

1) Base Case: Normal Decline of existing wells.

2) Case A: Assume same annual drilling activity as the average activity for 2007-2009, which averaged 11.2 wells per year.
3) Case B: Additional wells to meet demand from 2010-2020.
4) Case C: Additional wells to meet demand from 2010-2015.
5) Case D: Additional wells to meet contracted demand 2010-2020

i. Base Case: Current Producing Wells

Figure 16 shows PRA's estimate of current supply vs. demand for Cook Inlet Gas.

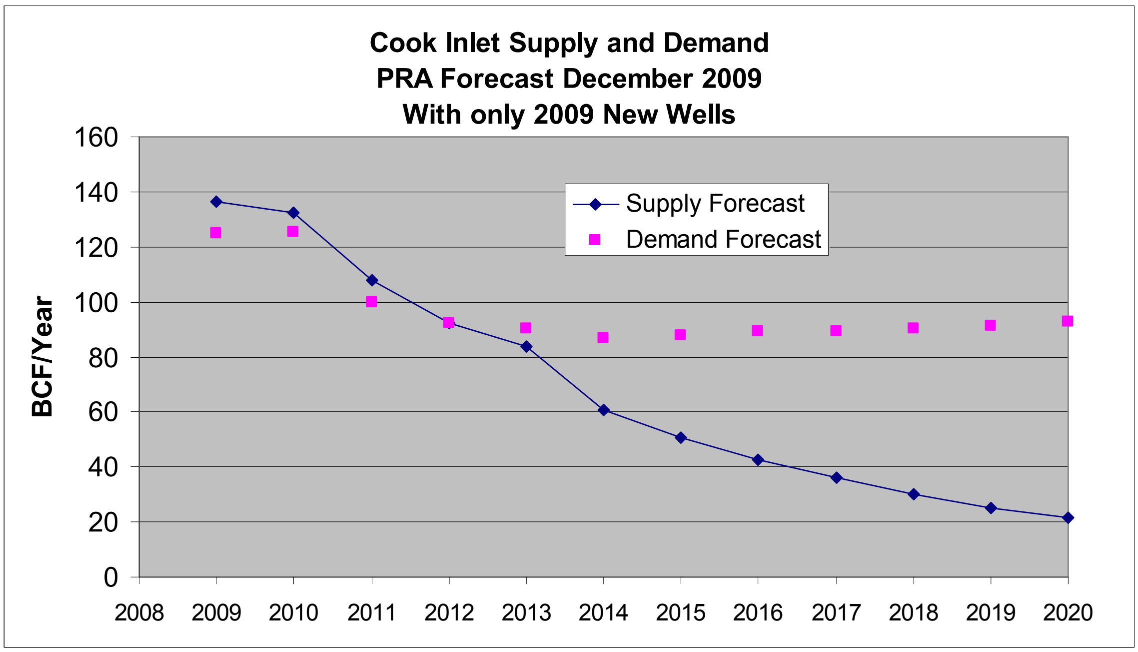


Figure 16: Supply vs. Demand for Cook Inlet Gas – Base Case

Analysis of the base case (production from existing wells) indicates that if no additional wells are drilled by 2013, South Central Alaska will not have enough natural gas supply to meet demand. The current wells are adequate to meet current contract obligations. Therefore, if no new contracts are approved or new customers enter the market, the base case is the likely future scenario.

During 2010 and 2011, analysis indicates equal supply and demand; there will likely be enough cushions (with wells not at peak capacity and the LNG plant being able to divert gas in the coldest periods) to meet the demands in winter. 2012 will be a year with no LNG plant operation and most of the "peaking capacity" of existing wells will be exhausted.

If no additional wells are drilled there should be plans to bring new gas into Cook Inlet by 2012 or 2013. This can be in the form of LNG imports or additional development of existing reserves, if available.

ii. Case A: Current Producing Wells plus Continued 2007-09 Activity Level

This case assumes that the drilling activity during 2007 to mid 2009, averaging 13.6 wells completed per year, will continue through 2019. This number of wells would be in excess of current contract demand and, therefore, inconsistent with public statements made by Chevron and ConocoPhillips.

There were 34 wells drilled and completed in the 2 ½ years from 2007 to mid 2009, an average of 13.6 wells per year. The wells used to model the production are shown in Table 3.

The estimated first year of production from the 13.6 wells was 13.0 BCF/year and the production declined at average of 21% per year. In the forecast, the initial rate is degraded by 4.3% per year for future drilling, based on the trend of average initial rate degradation shown in Appendix D.

Figure 17 shows Cook Inlet (CI) Supply vs. Demand with an assumed 2007-09 average drilling activity level, for a total of 136 wells completed 2010 to 2019.

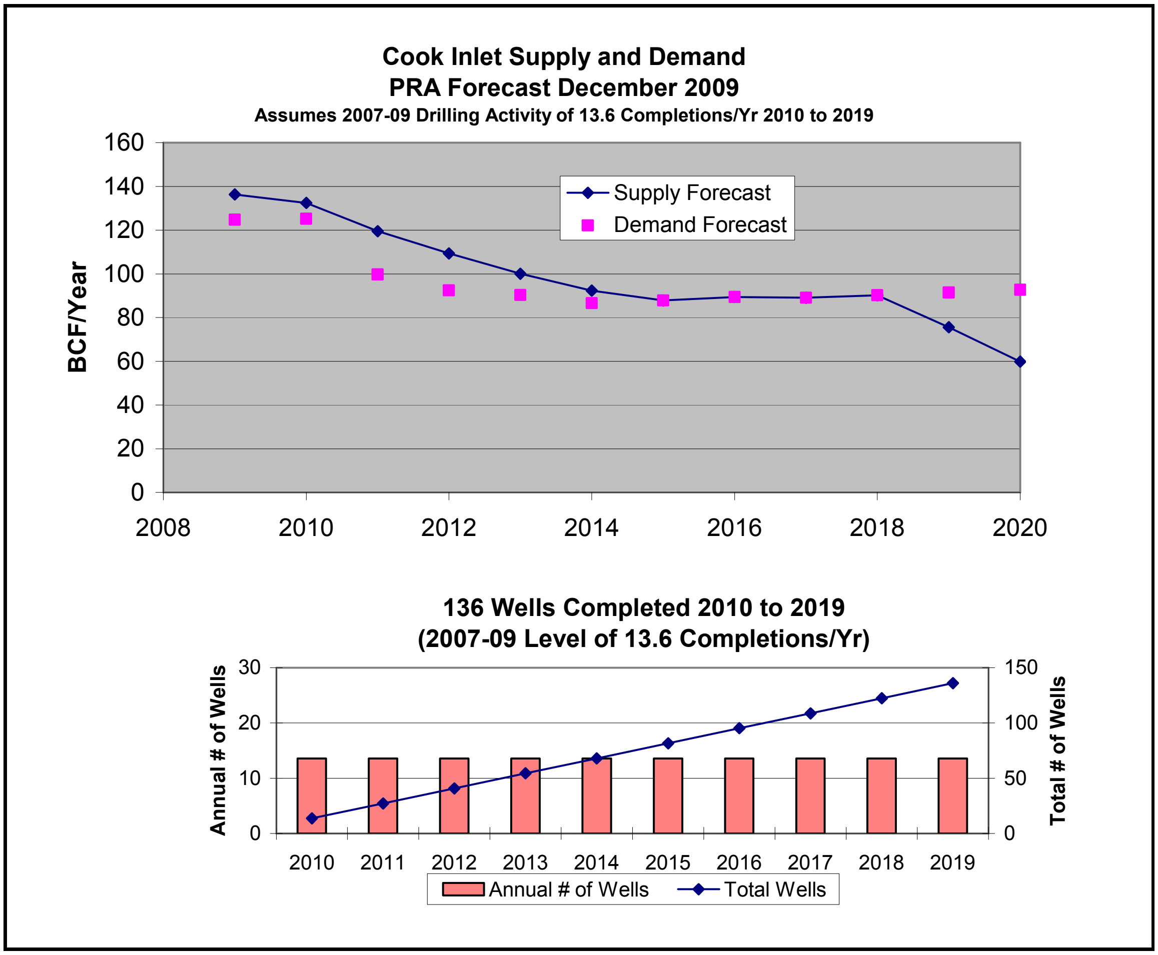


Figure 17: CI Supply-Demand assuming 2007-09 drilling of 13.6 completions per year 2010-2019

For the case of 2007-09 activity levels projected into the future, the demand exceeds supply in 2019.

Assuming \$10-15MM per well, this would require \$1.4 to 2.1 Billion in unrisked capital to drill these wells, resulting in capital costs of \$2.67 to \$4.00 per MCF, as compared to an estimated \$1.78 to \$2.06 /MCF capital cost for 2001-2009.

iii. Case B: Drilling to Meet Demand through 2020

Case B assumes that wells will be drilled and completed from 2010 to 2019 to fully meet demand through 2020. This example is inconsistent with current leaseholders' public statements and is offered for illustrative purposes. It assumes the 2007-09 wells are a proxy for the production rates of future wells, with a degradation of initial production of 4.3% per year for future drilling, based on the trend of average initial rate degradation shown in Appendix F.

Figure 18 shows CI Supply vs. Demand with an assumed drilling level to meet demand through 2020.

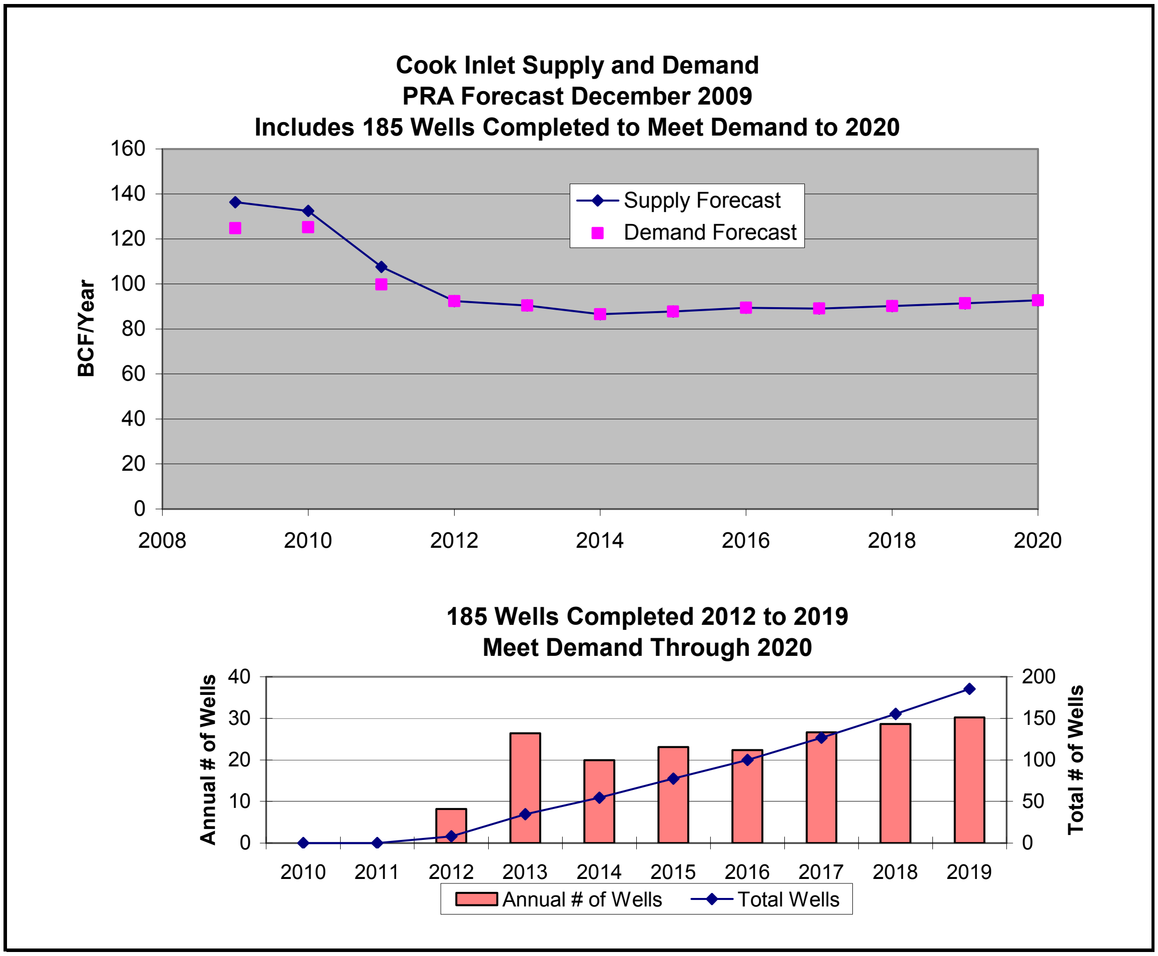


Figure 18: CI Supply-Demand assuming drilling activity to meet Demand 2010-2020

There are a total of 185 completed wells required to fully meet demand through 2020, which will develop 648 BCF of gas.

Assuming $10-15MM per well, this would require $1.85 to 2.8 Billion in unrisked capital to drill these wells resulting in capital costs of $2.86 to $4.29 per MCF, as compared to an estimated $1.78 to $2.06 /MCF capital cost for 2001-2009. Actual costs to customers would include a risk premium and deliverability cost; making the potential contract price upwards of two to three times the development cost.

<u>iv. Case C: Drilling to Meet Demand through 2015</u>

Case C assumes that wells will be drilled and completed from 2010 to 2014 to fully meet demand through 2015. It assumes the 2007-09 wells are a proxy for the production rates of future wells, with a degradation of initial production of 4.3% per year for future drilling, based on the trend of average initial rate degradation shown in Appendix D.

Figure 19 shows CI Supply vs. Demand with an assumed drilling level to meet demand through 2015.

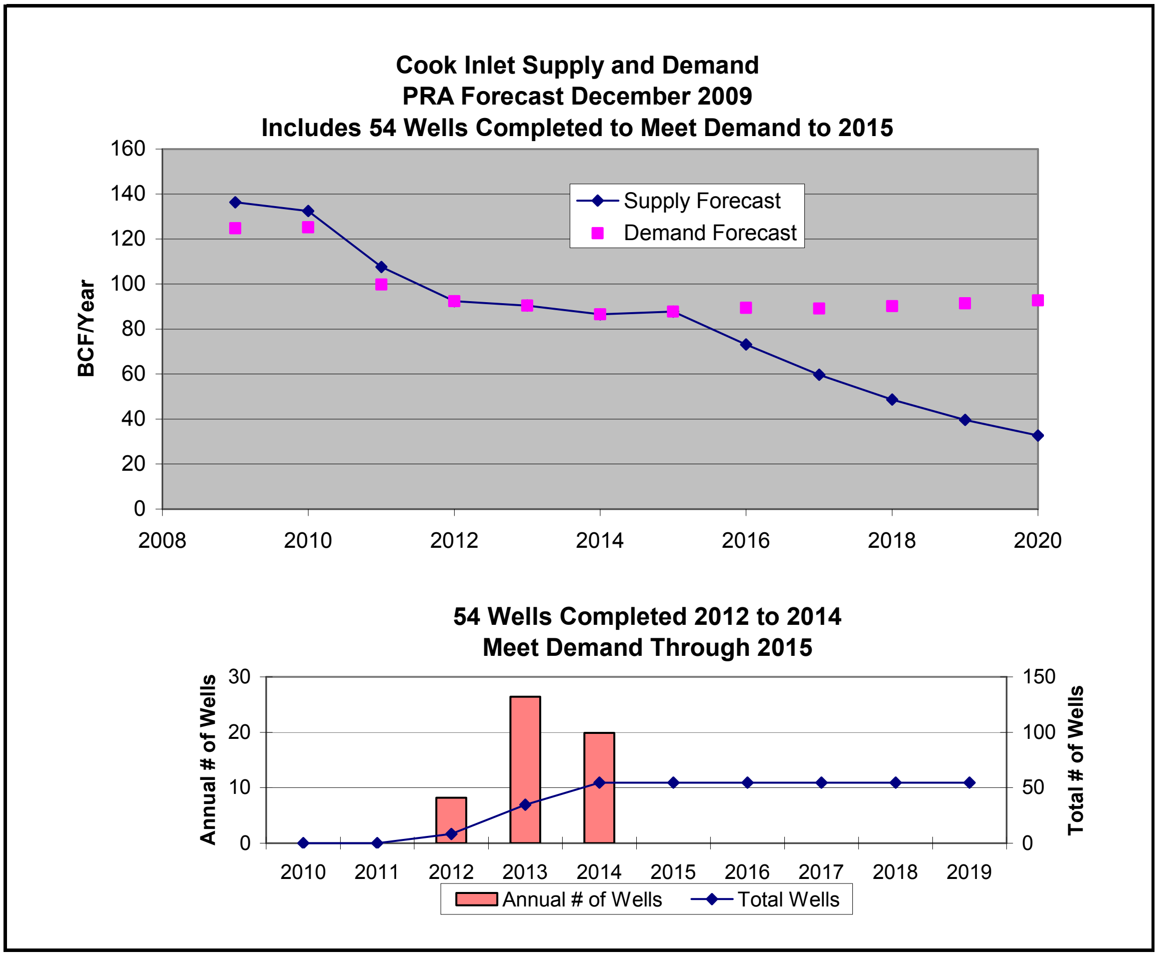


Figure 19: CI Supply-Demand assuming drilling activity to meet Demand 2010-2015

There are a total of 54 completed wells required to fully meet demand through 2015.

Assuming $10-15MM per well, this would require $0.5 to 0.8 Billion in unrisked capital to drill these wells, resulting in capital costs of $2.54 to $3.81 per MCF, as compared to an estimated $1.78 to $2.06 /MCF capital cost for 2001-2009.

v. Case D: Drilling to meet existing contracts through 2020

Case D assumes that wells will be drilled and completed from 2010 to 2014 to fully meet existing contracts through 2020. As can be seen in Figure 20, on average for Cook Inlet, there appears to be sufficient supply to meet existing contracts through 2020. This average analysis is obviously not appropriate to understand the situation of each producer or individual contracts.

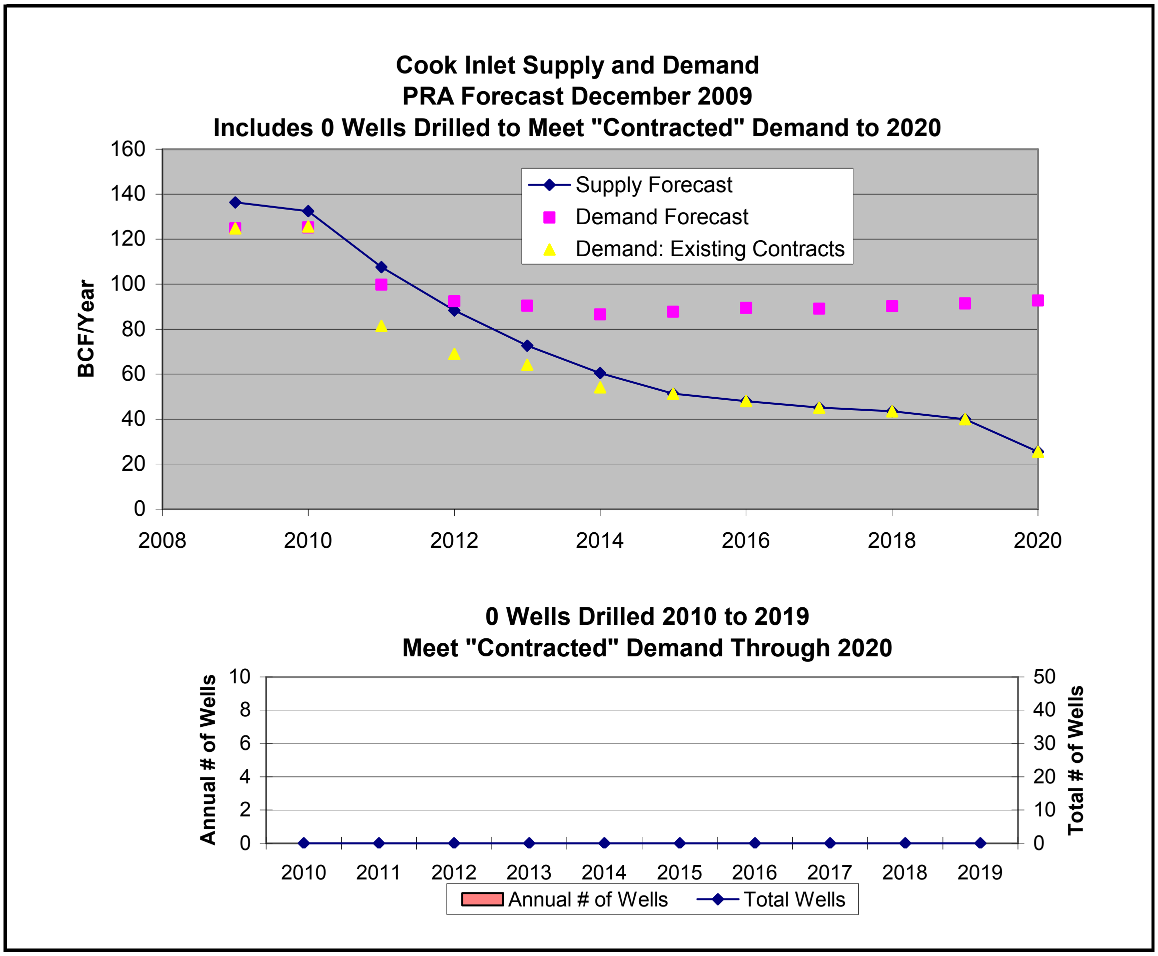


Figure 20: CI Supply-Demand assuming drilling activity to meet Existing Contracts 2010-2020

c. Review of Current Unit Plan of Developments

To understand future activity planned for Cook Inlet gas development, the Unit Plan of Developments (PODs) of the five units with the highest recent drilling activity were reviewed. Drilling and completions planned in the current POD's are as follows:

- Beluga River Unit – ConocoPhillips: 47th POD (6/18/09 to 6/17/10) for BRU approved by BLM on 5/29/09. Two new wells, 211-26 and 243-34 are planned.
- Kenai Unit – Marathon: 51st POD (2/8/09 to 2/7/10) for KU approved by BLM on 1/27/09. Four wells, KBU 11-17X, KBU 23-08, KBU 42-06X and KU 31-06 are planned to be drilled and completed.
- Ninilchik Unit – Marathon submitted 6th POD (1/1/10 to 12/31/10) to AK DNR/DOG on 10/12/09; approval pending. Plans are to drill Paxson #3 and if successful, Paxson #4. Compression will be installed on the Paxson pad.

- North Cook Inlet Unit – ConocoPhillips submitted 2010 POD (1/1/10 to 12/31/10) to AK DNR/DOG on 10/1/09; approval pending. No wells planned, will evaluate feasibility of lowering wellhead pressures.
- Trading Bay Unit (Grayling Gas Sands) – Chevron: 44th POD (8/26/09 to 8/25/10) for TBU was approved by AK DNR/DOG on 7/17/09. One new well, M-20, will be completed, one new well, M-10 will be drilled and completed and two workovers will be undertaken, M-1 and M-5.

In summary, there will be the following new wells or workovers in the major CI gas units, according to current POD's:

Beluga River Unit	2
Kenai Unit	4
Ninilchik Unit	2
No Cook Inlet Unit	0
TBU Gas Sands	4
Total	12

This is at a comparable activity level as the 34 wells drilled in the 2007 to mid 2009 period., although recent statements at a Kenai forum have indicated that this pace is not likely to continue (Peninsula Clarion 1/17/10). Appendix F reviews POD's for the last 3 annual periods for the units shown above.

d. DNR Reserves/Deliverability Study

In December 2009, the DNR published a preliminary study looking at total remaining reserve potential in the major fields in Cook Inlet as well as the deliverability of current wells. Their deliverability study is similar to the PRA findings in that with existing wells DNR shows supply from existing wells will not meet demand in 2015. The DNR estimated reserve potential shows that there is an abundance of undeveloped reserves in Cook Inlet, but in the conclusion of the report it is stated "In order to engage in drilling and development projects in Cook Inlet, local producers must internally justify doing so as an alternative to other projects worldwide." While there may be large undiscovered gas reserves in Cook Inlet as the DNR concludes, it is unlikely that these reserves will be developed soon enough to avoid the necessity of importing gas into south-central Alaska.

The DNR study approaches are discussed in Appendix C.

V. Summary

With existing producing fields in Cook Inlet and the current forecasted demand, there will be a critical shortage of natural gas supply starting in 2013.

If drilling activity remains at the 13.6 wells completed per year level that occurred during 2007-mid 2009, the shortage of gas will occur after 2018. The most recent unit POD's showed 12 wells to be drilled in the POD period, although statements by gas producers at recent Cook Inlet oil and gas industry forum would indicate that continuation at this level of activity is not likely.

To meet demand through 2020, a total of 185 wells will be required to be drilled at an estimated total cost of $1.8 to $2.8 billion.

Given the limited remaining development reserves in Cook Inlet and the long timeframe required to bring new discoveries on-line, further combined with the paucity of true gas exploration in recent years, it is likely that a source of gas outside of the Cook Inlet, such as LNG importation or other in-state reserves, will be required starting between 2013 and 2016.

In order for Cook Inlet gas requirements to be met, either by additional development of Cook Inlet gas or gas imported as LNG or from other areas of the state, adequate gas storage will be required to meet the winter deliverability swings.

Appendices

Appendix A: Cook Inlet Field and Reservoir Data

Table 1: Cook Inlet Gas Fields in order of discovery (AOGCC 2008 Annual Report).

	Gas Field	Discovery Date	Discovery Well	Current Operator	TD MD/TVD	Production (BCF) to 1/1/2009
1	Kenai	10/11/1959	Unocal Kenai Unit #14-6	Marathon	12037/12037	2353
2	Cannery Loop	10/11/1959	Unocal Kenai Unit #14-6	Marathon	12037/12037	171
3	Swanson River	5/18/1960	SOCAL SRU 212-10	Chevron	12029/11566	50
4	West Fork	9/26/1960	Halbouty King Oil, Inc #1-B	Marathon	14019/14019	6
5	Ninilchik-Falls Ck	6/21/1961	SOCAL Falls Creek Unit #1	Marathon	13795/13382	23
6	Sterling -Sterling	8/4/1961	Unocal Sterling Unit #23-15	Marathon	14832/14832	4
7	West Foreland	3/27/1962	Pan Am West Foreland No. 1	Forest	13500/13500	10
8	North Cook Inlet	8/22/1962	Pan Am Cook Inlet St 17589 #1	ConocoPhps	12237/12237	1798
9	Beluga River	12/1/1962	SOCAL BRU # 1 (212-35)	ConocoPhps	16429/16429	1107
10	Birch Hill	6/14/1965	SOCAL Birch Hill Unit #22-25	ConocoPhps	15500/15500	0.1
11	Moquawkie	11/28/1965	Mobil-Atlantic Moquawkie #1	Aurora	11364/11364	4
12	North Fork	12/20/1965	SOCAL North Fork Unit # 41-35	Gas-Pro	12812/12812	0.1
13	Nicolai Creek	5/12/1966	Texaco Nicolai Ck. St. #1-A	Aurora	8338/7979	5
14	Ivan River	10/8/1966	SOCAL Ivan River Unit #44-1	Chevron	15269/15269	79
15	Beaver Creek	2/10/1967	Marathon Beaver Ck. Unit #1	Marathon	13595/12911	199
16	Albert Kaloa	1/4/1968	Pan Am Albert Kaloa #1	Aurora	13600/13600	3
17	McArthur River	12/2/1968	Unocal Trading Bay Unit G-18	Chevron	6390/4510	1095
18	Lewis River	9/2/1975	Cities Lewis River #1	Chevron	9480/9480	12
19	Stump Lake	5/1/1978	Chevron Stump Lake Unit 41-33	Chevron	11660/11660	6
20	Pretty Creek	2/20/1979	Unocal Pretty Ck Unit #2	Chevron	12025/12025	9
21	Trading Bay	10/5/1979	Texaco NTB Unit SPR-3	Marathon	10250/10094	6
22	Middle Ground Shoals	7/14/1982	Amoco MGS 17595 No. 14	Chevron	10445/9031	16
23	Granite Point	6/10/1993	Unocal Granite Pt. St. 17586 9	Chevron	5905/4170	1
24	Lone Creek	10/12/1998	Anadarko Lone Creek #1	Aurora	11487/11269	7
25	Wolf Lake	10/31/1998	Marathon Wolf Lake No. 2	Marathon	14451/14086	0.8
	Sterling - UP Bel	11/9/1998	Unocal Sterling Unit No. 32-09	Marathon	6858/6336	7
	Ninilchik-Oskolkoff	7/31/2001	Marathon Grassim Oskolkoff #1	Marathon	11600/8510	24
	Ninilchik-S.Dionne	7/30/2002	Marathon Susan Dionne #3	Marathon	10255/8102	38
26	Redoubt Shoal	4/23/2003	Forest Redoubt Shoal No. 3	Forest	16940/13016	0.5
27	Deep Creek	7/9/2003	Unocal Happy Valley #1	Chevron	10872/9700	12
28	Kasilof	3/25/2004	Marathon Kasilof South 1	Marathon	17545/9642	3

29	Three Mile Creek	1/23/2005	Aurora Three Mile Creek Unit 1	Aurora	8180/8011	2
	Sterling-LW Beluga/Tyonek	9/12/2007	Marathon Sterling Unit 41-15RD	Marathon	11655/9517	0.6
					TOTAL	**7052**

Table 2: Reservoir Characteristics of 10 Cook Inlet Gas Fields (AOGCC 2008)

Gas Field	Gas Pool	Production Depth (ss)	Production (BCF) to 1/1/2009	Net Pay Thickness (feet)	Por. (%)	Perm. (md)	Swi %
Beaver Creek	Sterling	5000	126	110	30	2000	40
	Beluga	8100	67.4	50	10		
	Tyonek Undef	9847	5.5	45			
Beluga River	Undefined Sterling	3450	1107	107	31	50-199	37
	Beluga	4500		106	24	20-49	42
Cannery Loop	CLU Sterling undef.	4965	21.4	76			40
	CLU Beluga	5175	76.2	33	20	25	45
	CLU U Tyonek	8700	72.0	17	21	250	45
	CLU Tyonek D	10000	1.3	35	23		45
Deep Creek	Beluga/Tyonek	5984	11.9	NA	28	4	40
Kenai	Sterling 3	3700	333	88	31		35
	Sterling 4	3960	452	60	33		35
	Sterling 5.1	4025	485	113	33		35
	Sterling 5.2	4125	44	53	33		35
	Sterling 6	4565	534	110	28		40
	Beluga Undef	4900	0	213	19		45
	U Tyonek Beluga	6600	318	120			45
	Tyonek	9000	189	100	19		45
North Cook Inlet	Tertiary (Ster./Bel.)	4200	1798	130	28	178	40
Ninilchik							
Falls Creek	Tyonek (und)	4690	23.0	189	15-25	6	
G. Oskolkoff	Tyonek (und)	3496	24.2	210	15-21	14	
Susan Dionne	Tyonek (und)	3338	37.6	44	15-20	8	
Sterling	Sterling	5030	3.74	25	26	125	40
	Beluga Undef	8104	0.44	100	10	0.1	
	UP Beluga Undef	5400	6.85				
	LW Bel/Tyonek		0.58				
	Tyonek Undef	9449	0.14	55	12	1.5	
Swanson River	Sterling	2720-3060	30.6		30	650	35
	Beluga	4676	1.3	22	30	110	50
	Tyonek Undefined	5600-7500	18.5	13-40	25-29	5-500	37-55
Trading Bay (McArthur River)	Tyonek	1518-8982	1095	375	12-32	900	36
		TOTAL	**6882**				

Table 3: Reservoir Characteristics of the 19 Other Cook Inlet Gas Fields (AOGCC 2008)

Gas Field	Gas Pool	Production Depth (ss)	Production (BCF) to 1/1/2009	Net Pay Thickness (feet)	Por. (%)	Perm. (md)	Swi %
Albert Kaloa	Undef (Beluga)	3141	3.2	139	20	60	40
Birch Hill	Undef (Tyonek)	7960	0.1	31	25	5 to 6	NA
Granite Point	Undef (Tyonek)	4088	0.9				
Ivan River	Undef (Tyonek)	7800	79.5	37	20	1600	45
Kasilof	Tyonek Undef		3.1				
	Tyonek 2 Undef		0				
Lewis River	Undef (Beluga)	4700	11.8	85	22		45
Lone Creek	Undef (Tyonek)	1958	6.8	53	19	100	30
Middle Ground Shoal	Undef (Tyonek)	3550	16.4				
Moquawkie	Undef (Tyonek)	2250	4.11	106	22	20-50	35-40
Nicolai Creek	Undef North (Tyonek)	1935	2.22	128	17		50
	Undef South (Tyonek)		0.98				
	Beluga		1.48				
North Fork	Undef (Tyonek)	7200	0.1	40	18	3.5	50
Pretty Creek	Undef (Beluga)	3364	9.44	60	22		45
Redoubt Shoal	Tyonek (undefined)		0.45				
Stump Lake	Undef (Beluga)	6740	5.64	91	24	5	45
Three Mile Creek	Beluga Undef		1.7				
Trading Bay	Undef (Tyonek)	9000	5.7	250	13	15	40
West Foreland	L. Tyonek 4.0	4250	7.32				
	L. Tyonek 4.2		3.05				
West Fork	Sterling A	4700	1.23	22	32	200	50
	Sterling B	4700	1.44				
	Undefined	7148	3.12				
Wolf Lake	Undef (Tyonek)	6749	0.82				
		TOTAL	**170.62**				

Appendix B-1: Beaver Creek Unit Gas Field Description

<u>Geological Introduction</u>. The Beaver Creek gas field is located onshore Kenai Peninsula about 50 miles south-southwest of Anchorage and 10 miles east-northeast of Kenai. It was discovered in 1967 by the Marathon Beaver Creek Unit No. 1 well which blew out at a depth of 9,134' and the well was plugged and abandoned. The well discovered gas in the Sterling and Beluga formations. It is currently operated by Marathon. Gas is produced from three pools, the Sterling, Beluga and Tyonek undefined. Production began in 1972 from the Sterling, 1990 from the Beluga and 1996 from the Tyonek. Production depths are at 5,000'ss, 8,100'ss and 9,874'ss, respectively. Table 2 shows reservoir characteristics. Gas production is from 7 of the 14 wells in the field with 2 wells producing oil, 1 used for disposal and 4 abandoned. A cumulative total of 201 BCF has been produced through June 2009.

The structure is a slightly asymmetrical anticline with a high angle reverse fault bounding the eastern side (Figure B1.1). The permeability barrier shown on the Sterling B-3 structure map could be a stratigraphic pinchout, facies change, localized tight streak, small scale fault or some other lateral discontinuity in the reservoir. Such reservoir heterogeneities tend to be more common in the Beluga and Tyonek sands and can isolate pay zones that can be revealed by ongoing field development. 3-D seismic has been shot over the field but no revisions have been made to the publically available structure map.

The 18 and 24 year time gaps between the start of Sterling production and production from the Beluga and Tyonek, respectively, demonstrates that, as field development progresses, reserve growth occurs. Future additional reserve growth potential exists, especially in the Beluga and Tyonek, because of the discontinuous nature, potentially poor connectivity to existing perforations, and often low porosity and permeability of these reservoirs. The low porosity and permeability 'tight-sands' were often over-looked or considered non-economic during the early development of the obvious 'easy' gas in the high porosity and permeability 'good' reservoirs. The 'tight-sands' require fracture stimulation to be productive.

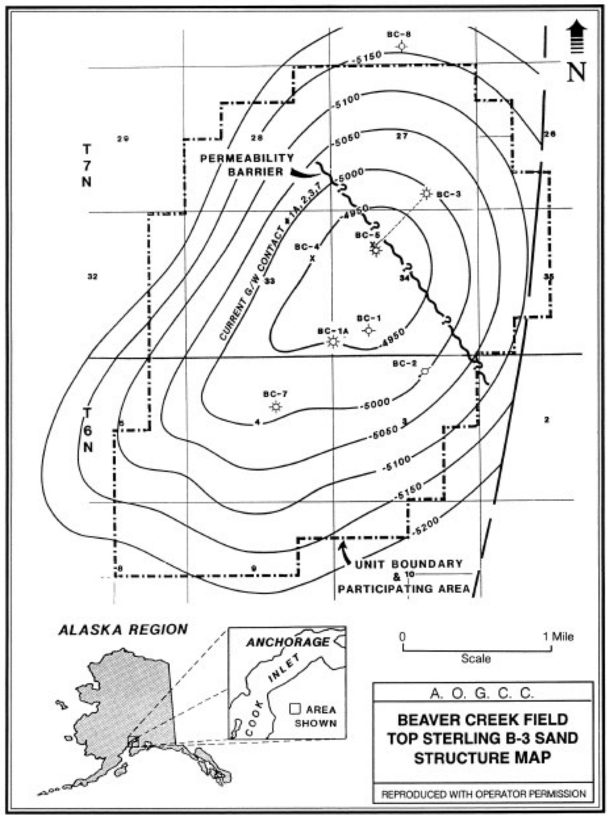


Figure B1.1: Beaver Creek Unit Structure Map (AOGCC)

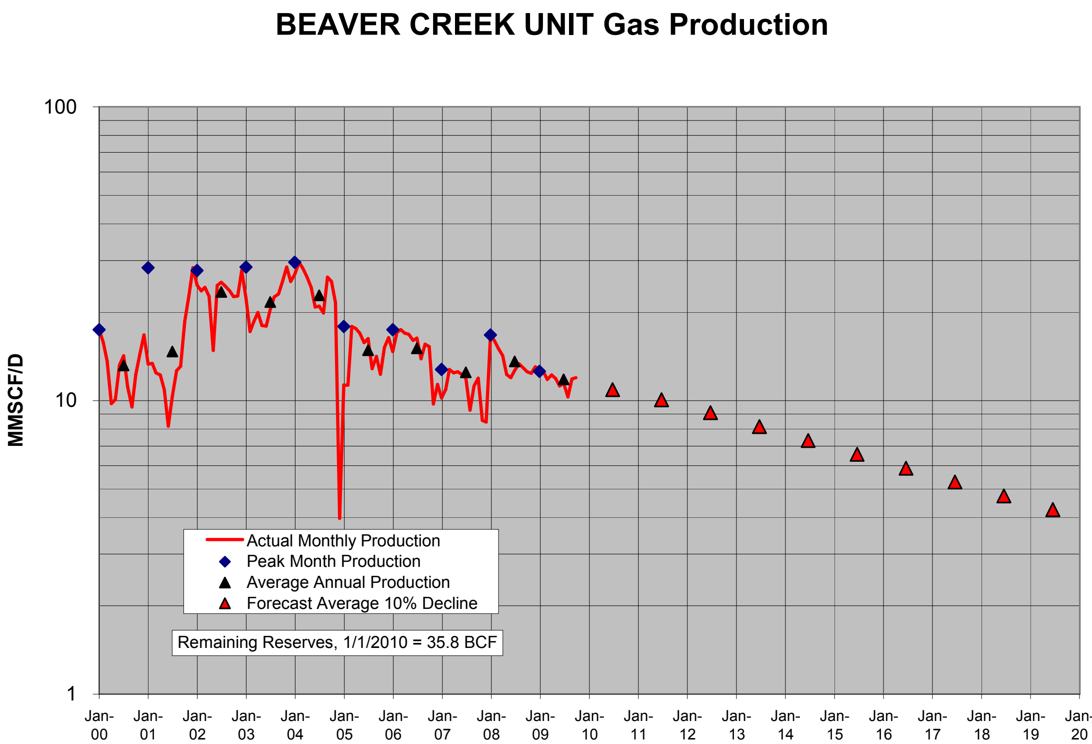


Figure B1.2 Field Production Curve 2000-2009 and Forecast

Appendix B-2: Beluga River Unit Gas Field Description

Geological Introduction. The Beluga River field is located on the coastline of the west side of Cook Inlet, about 40 miles west of Anchorage. It was discovered in 1962 by the Socal Beluga River Unit No. 1 (212-35) well which was drilled to a depth of 16,429' (MD and TVD) to explore for deep oil objectives. It is currently operated by ConocoPhillips. Gas is present in both the Sterling and Beluga formations at average subsea depths of -3,300' and -4,000', respectively. Multiple pay zones are produced in both formations but the gas production from the Sterling and Beluga is comingled. The Sterling is subdivided into three zones, A, B and C and the Beluga is subdivided into 7 zones, D, E, F, G, H, I and J. Total net pay is 107' and 108', respectively. Correlation of sands is difficult because of lateral variability in thickness and sand quality and wide well spacing. Detailed correlation of the laterally more continuous coals is critical to determining sandstone body geometry. Gas production began in 1968. Out of a total of 22 wells in the field, 19 have produced gas, 14 of which are currently producing. The total cumulative production through June 2009 was 1,128 BCF.

The structure shown in figure B2.1 is a relatively broad, asymmetrical fault propagation fold oriented in a northeast-southwest direction with a steeper northwest limb. The structure as mapped is relatively simple, without a system of cross-cutting faults found in some of the other Cook Inlet fields. The structure is about 7 miles long and 3 miles wide. ConocoPhillips conducted a 3D seismic survey over the field in 2007. This was done to improve structural mapping which was problematic using the relatively widely spaced, older 2D data. When I worked the field for ARCO with Blaine Campbell in 1994, our volumetric calculation of reserves was less than the reserves calculated by material balance, indicating probable inaccurate structural mapping. Re-mapping of the field may reveal structural complexities such as small faults or separate structural highs with intervening saddles that could isolate pay from existing well infrastructure.

A reservoir modeling study by Rick Levinson and others at ConocoPhillips was published as an abstract and presented at AAPG in May of 2006. A focus of the study was to identify gas that might not be drained by the existing perforations. They conducted a connectivity analysis and determined that Sterling sands are 99% connected to existing perforations and Beluga sands are 81% connected. Connected OGIP in the model is 28% greater than determined by P/Z analysis suggesting potential for accessing through well work or new drilling isolated pay sands, mainly in the Beluga formation. This was tested in two work over operations (pre May 2006) resulting in new pay sands identified and perforated leading to increased gas production. Two wells drilled in 2008 tapped reservoirs that added 9.7 BCF new production per well. Ongoing field development will likely result in identification of similarly isolated pay sands.

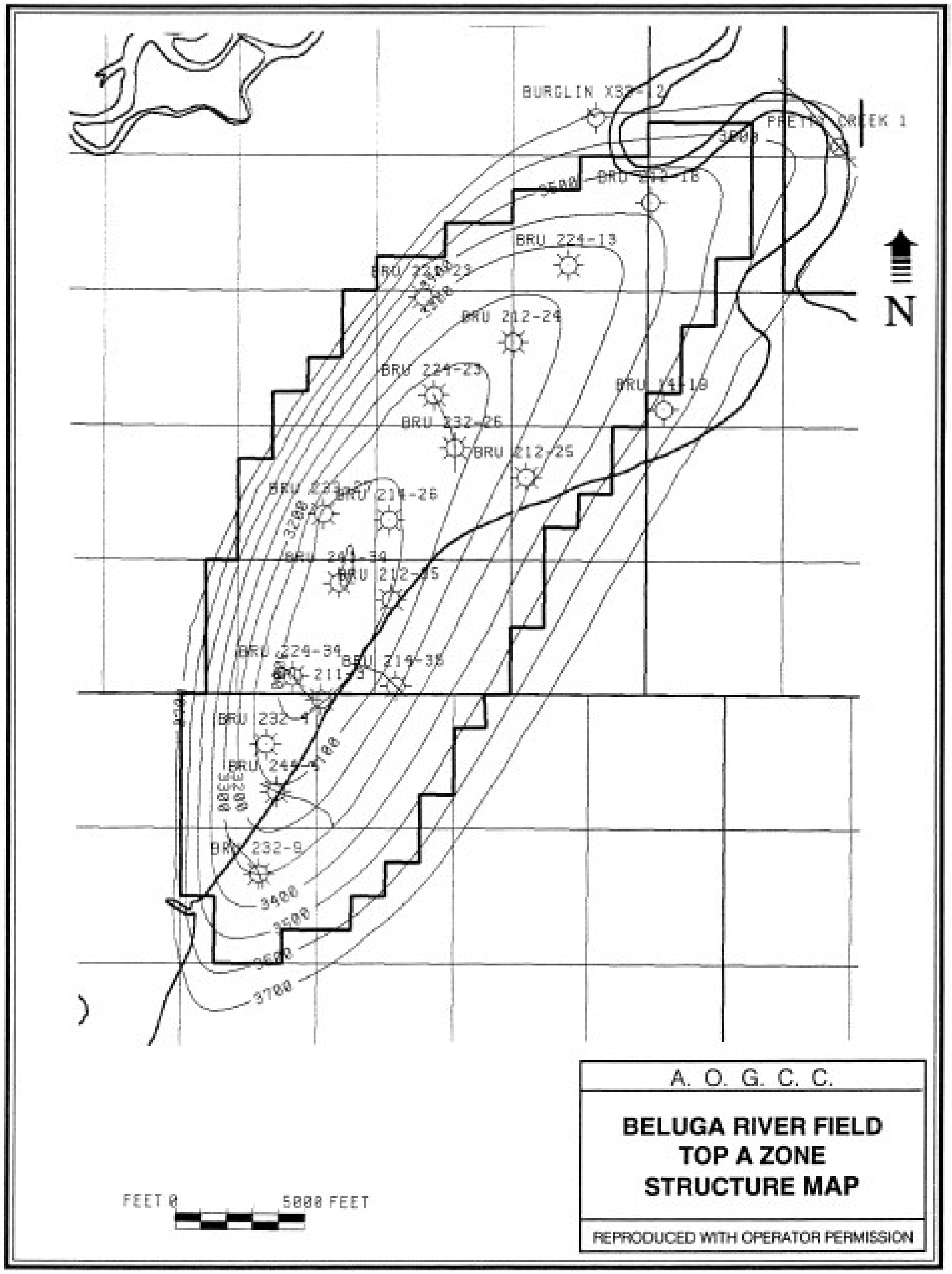


Figure B2.1: Beluga River Field Structure Map (AOGCC)

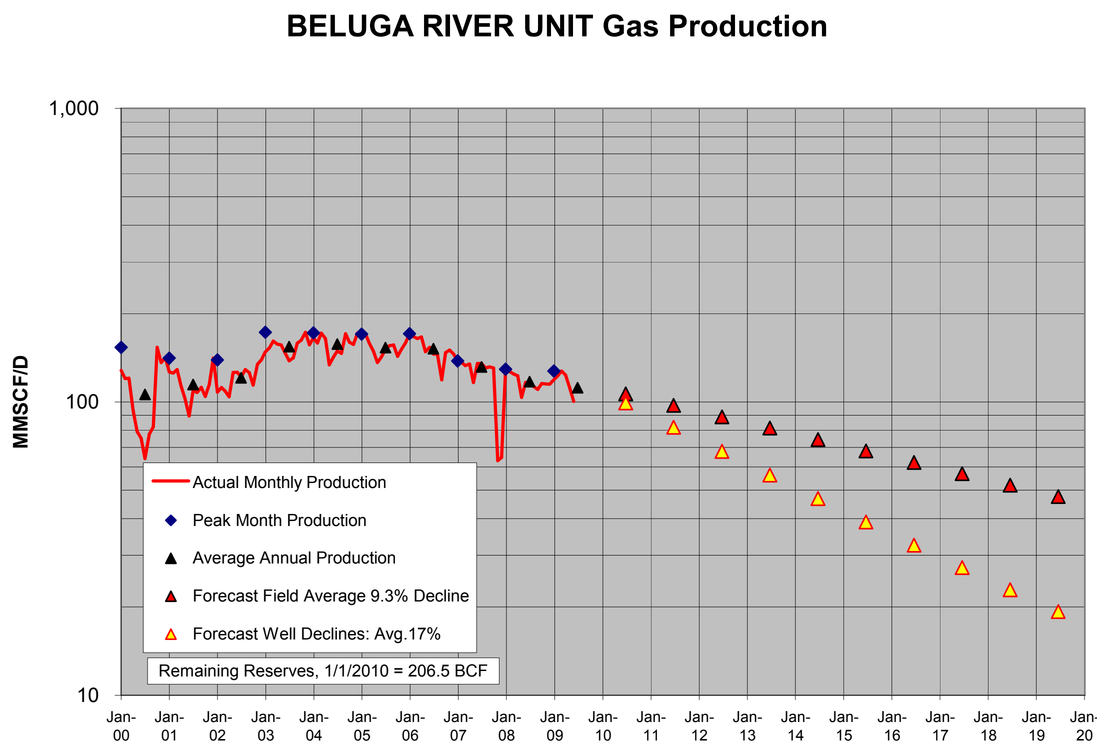


Figure B2.2: Field Production Curve 2000-2009 and Forecast

Appendix B-3 Cannery Loop Unit Gas Field Description

Geological Introduction. Cannery Loop Unit (CLU) is located on the eastern shoreline of the Kenai Peninsula and straddles the mouth of the Kenai River. Its southern unit boundary is adjacent to the northern boundary of the Kenai Unit. Because the AOGCC includes the CLU as part of the Kenai Field the Unocal Kenai Unit 14-6 well is listed as the discovery well for both Units. The Cannery Loop Unit No. 1 well may better be considered the discovery well for the CLU since the CLU anticline is structurally separated from the Kenai anticline. It was directionally drilled by the current operator, Marathon, in 1979 to a depth of 12,010' MD (10,215' TVD. Production is from four gas pools, Sterling undefined, Beluga, Upper Tyonek and Tyonek Deep with pool top depths at 4,965'ss, 5,175'ss, 8,700'ss and 10,000'ss, respectively. Net pay for each pool is 76', 33', 17' and 35' respectively. Reservoir characteristics are shown in Table 2. Gas production began in 1988 in the Beluga and Upper Tyonek Gas pools and in 2000 in the Sterling Undefined pool. Tyonek Deep produced briefly in 1988-1989 but was stopped due to high water production. Production is from 14 completions in 10 wellbores and of the 13 wells in the field two are P&A'd, one is suspended and the other ten are actively producing. A cumulative total of 174 BCF has been produced through June 2009.

The structure is a gentle, slightly asymmetrical anticline separated from the Kenai field anticline by a structural saddle (Figure B3.1). The structure is about 3 miles long and 2 miles wide, trends north-northeasterly and is slightly steeper on the west side.

The relatively thick productive stratigraphic interval, including the Sterling, Beluga and upper to middle Tyonek, provides the potential for new isolated pay discoveries. Reservoir heterogeneities resulting in isolated and disconnected pay and possible 'tight-sands' are likely to be discovered with ongoing field development.

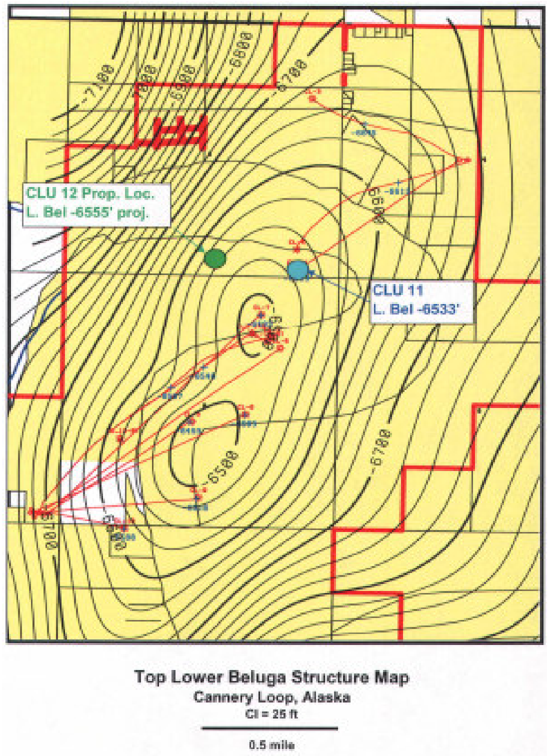


Figure B3.1: Cannery Loop Unit Structure Map (AOGCC)

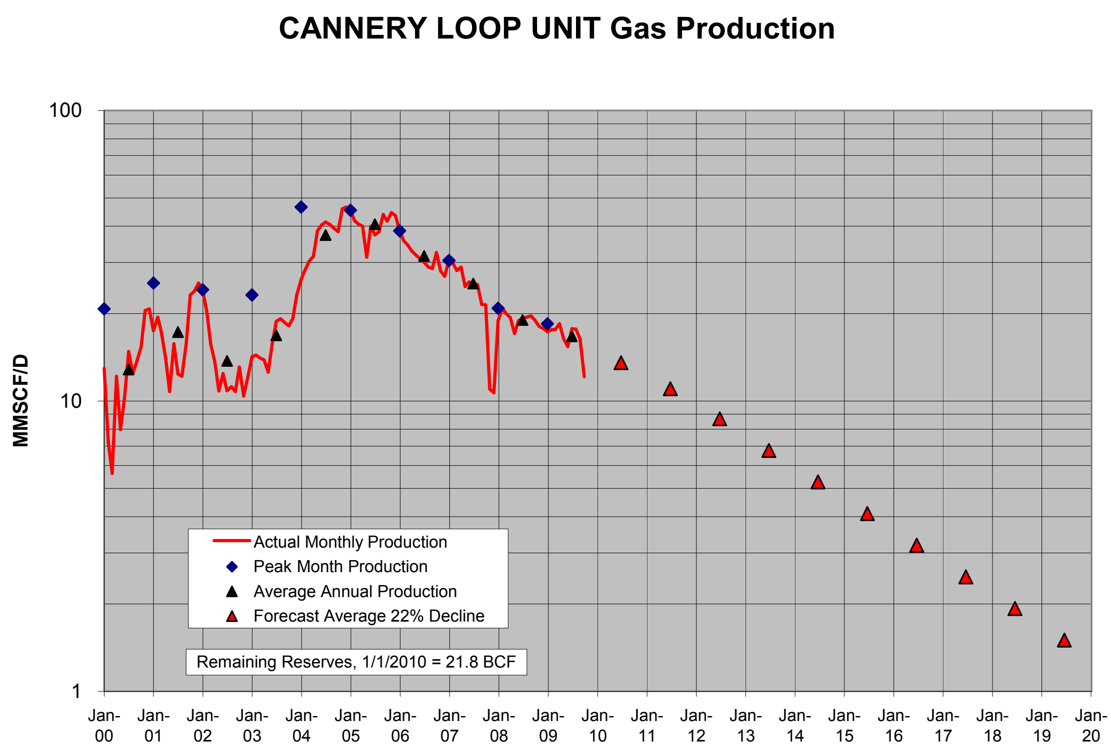


Figure B3.2: Field Production Curve 2000-2009 and Forecast

Appendix B-4: Deep Creek Unit Gas Field Description

Geological Introduction. The Deep Creek Unit gas field is located on the Kenai Peninsula about 8 miles east-southeast of Ninilchik. It was discovered in 2003 by the Unocal Happy Valley 1 well which was drilled to a depth of 10,871' MD (9,700' TVD) in search of gas up dip of sands with gas shows penetrated in the Happy Valley 31-22 well in 1963. The field is currently operated by Chevron and produces from the Beluga/Tyonek gas pool. Both Beluga and Tyonek sands are productive. Production is from low permeability sands, 1-4md. Other reservoir characteristics are shown in Table 2. Production is currently from 6 of 11 wells from an average depth of 6,012'ss. Total cumulative production was 12.9 BCF through June 2009.

The structure is an elongate anticline 13 miles long and 3 to 4 miles wide. No structure maps are publicly available.

Future potential lies in discovery of reservoir discontinuities such as small scale faults or stratigraphic changes and testing of additional low porosity and permeability 'tight-sands'. Fracture stimulation (with resulting additional capital expenditure) will be required to produce future 'tight-sands'.

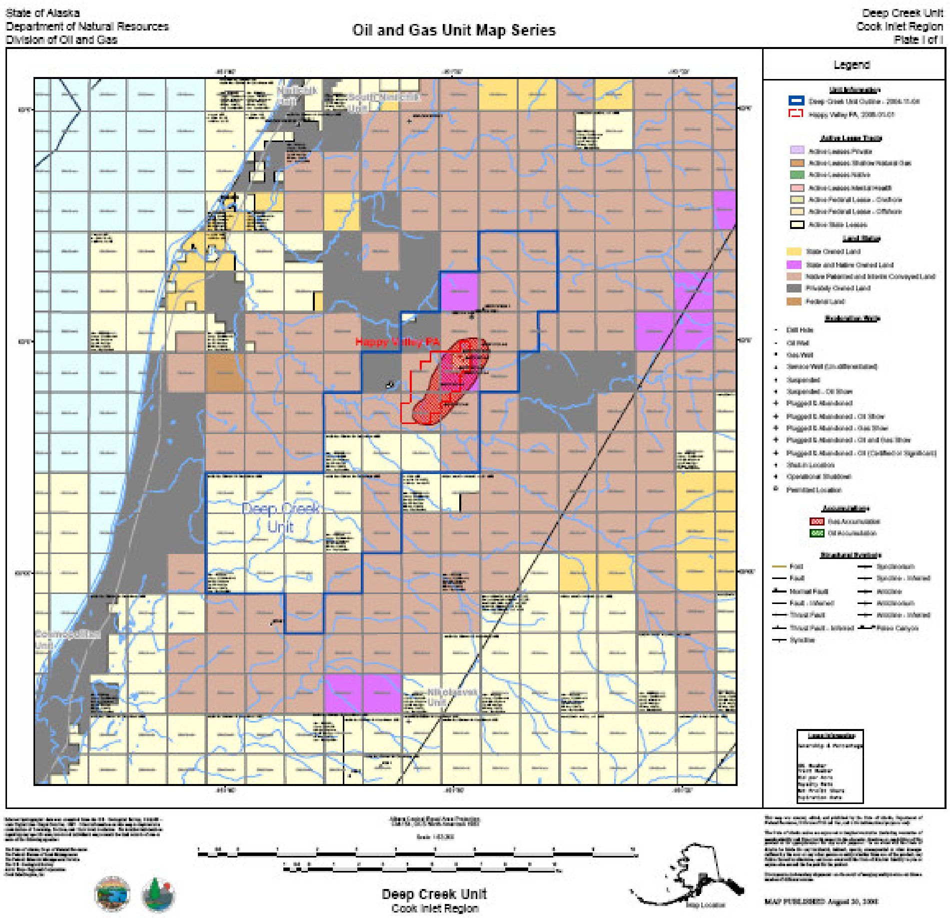


Figure B4.1: Deep Creek Unit Location Map (DNR)

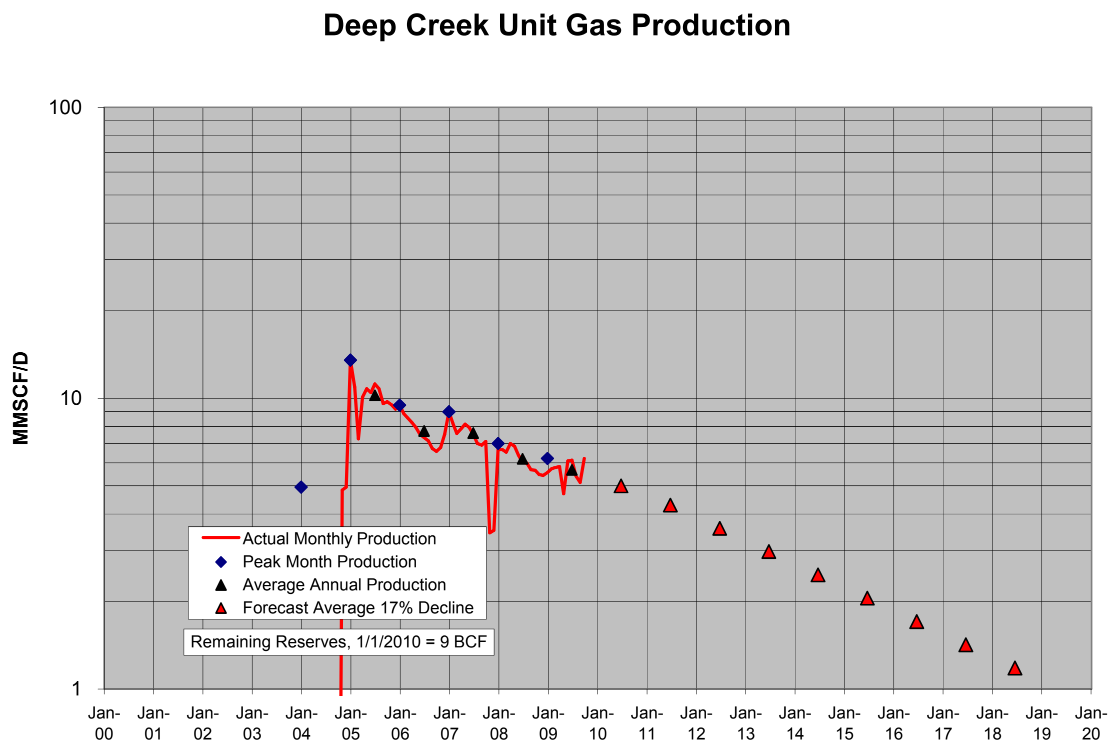


Figure B4.2: Field Production Curve 2000-2009 and Forecast

Appendix B-5: Kenai Unit Gas Field Description

Geological Introduction. The Kenai Gas field and the Cannery Loop Unit are considered part of the same gas field by the AOGCC and Marathon operates them both as part of the same Kenai Field area. The DOG considers them two separate fields and subdivides them into separate Kenai and Cannery Loop Units. They will be separated for purposes of this study. Although both are part of the same anticlinal fold they are separated by a structural saddle.

The Kenai Gas field is located on the coast of the Kenai Peninsula just south of the Kenai River and about 70 miles southwest of Anchorage. The Kenai field was discovered in 1959 by the Unocal Kenai Unit No 14-6 well which was drilled to a depth of 15,047' MD to explore for deep oil objectives. Gas production began in 1963 and has been from 7 gas pools, Sterling 3, 4, 5.1, 5.2, 6, Upper Tyonek-Beluga, and Tyonek, however, from 2000 to 2009, only the Sterling 3, 4, 6, Upper Tyonek-Beluga and Tyonek have been produced, with the other pools shut-in. The Sterling 6 pool is used for gas storage. The Sterling gas pools were discovered in 1959 but the Tyonek pool was discovered in November 1967 by the Unocal Kenai Deep Unit #1 well. Production started from the different pools at different times. Initial test production in the Sterling 3, 4 and 6 began July 1965, April 1965 and November 1960 with continuous production beginning in 1966, 1968 and 1961, respectively. Tyonek continuous production began in 1968. Upper Tyonek-Beluga production began in December 1967 and was combined in 2003 for production reporting purposes. Reservoir depths range from about 3,700'ss to 9,000' ss. Field reservoir statistics are shown in Table 2. The field has produced, through June 2009, a cumulative total of 2,361 BCF.

The structure is a broad, gently folded, asymmetrical anticline with a slightly steeper west flank (Figure B5.1). The fold axis is oriented north-south in the Kenai field but curves slightly to the north-northeast in the Cannery Loop unit. No faults are shown on the publicly available maps.

The thick pay section involving multiple pools offers good potential for new reserve discoveries. Additional reserve growth is most likely to come from the Beluga and Tyonek pools through discovery of isolated sands near the edges of the field. Also, testing of 'tight-sands' not previously considered economically viable may lead to new reserves.

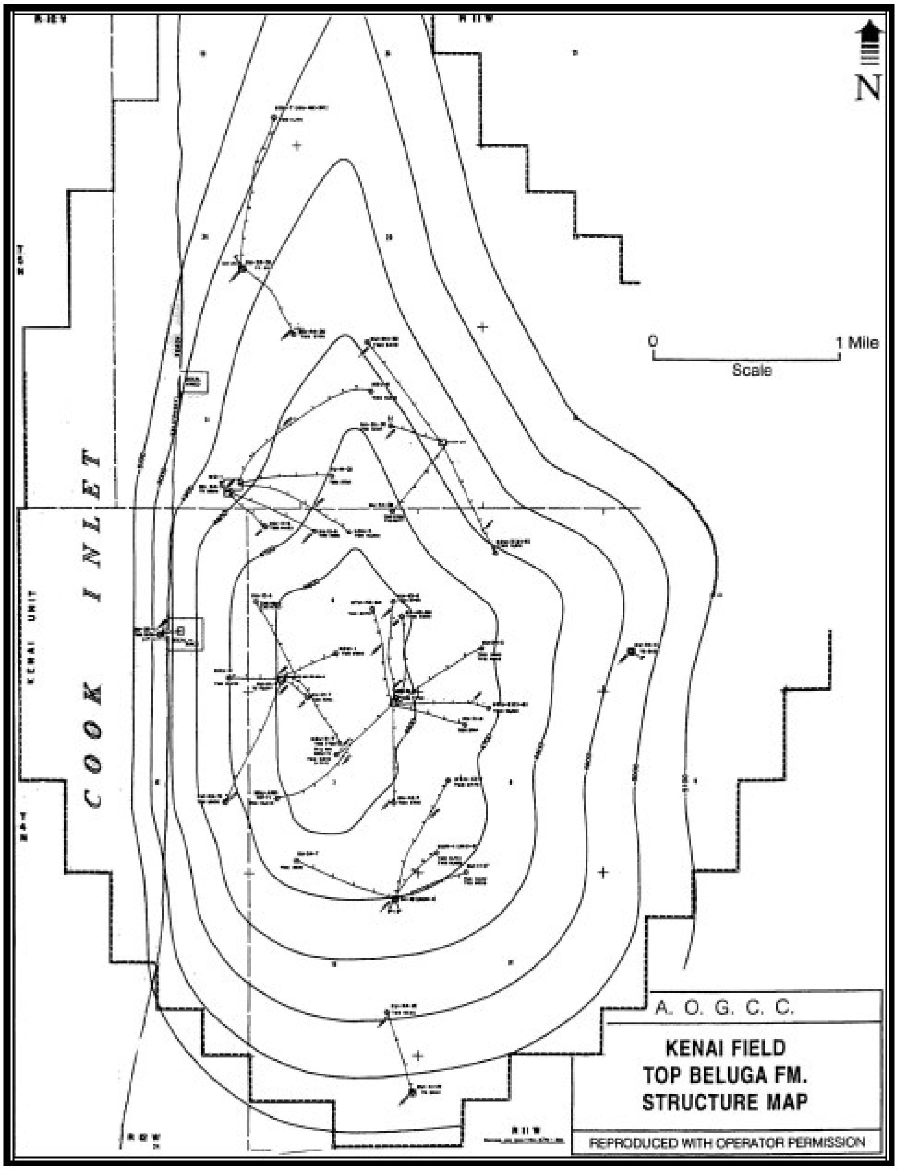


Figure B5.1: Kenai Unit Structure Map (AOGCC)

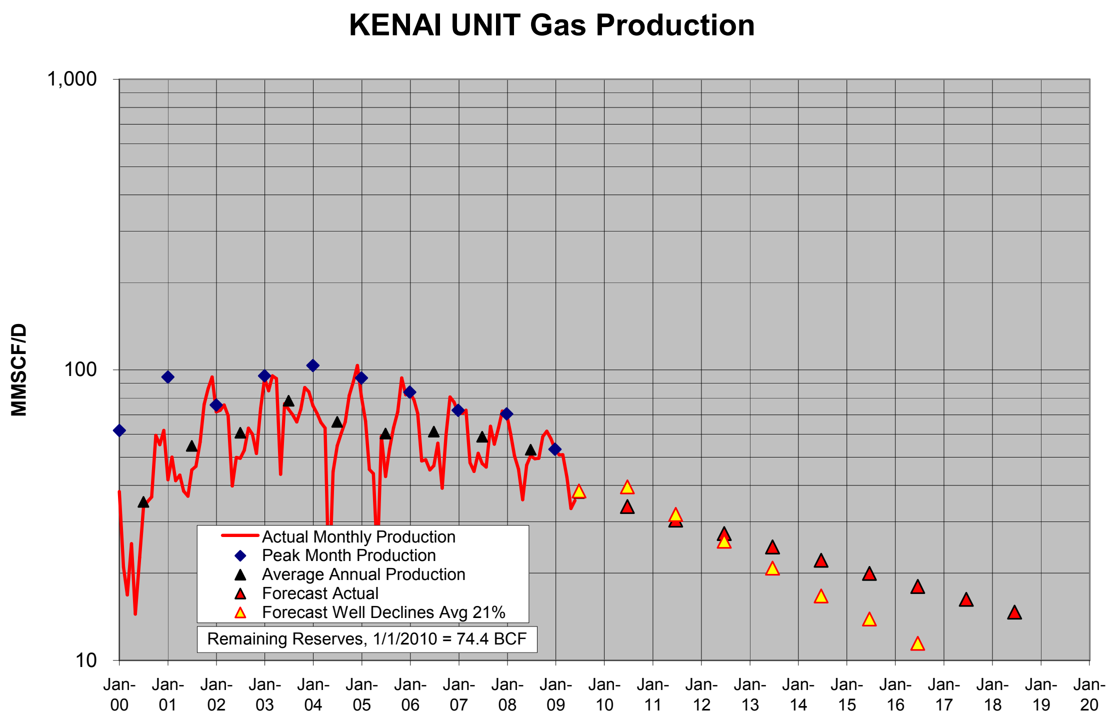


Figure B5.2: Kenai Unit Production Curve 2000-2009 and Forecast

Appendix B-6: North Cook Inlet Unit Gas Field Description

<u>Geological Introduction</u>. The North Cook Inlet gas field is located offshore Cook Inlet about 38 miles southwest of Anchorage and 38 miles north-northeast of Kenai. It was discovered in 1962 by the Pan American Cook Inlet St.17589 No.1well which was drilled to a depth of 12,237' MD to explore for deep oil objectives. The well blew out and was never tested. The field is currently operated by ConocoPhillips. There are 16 total wells in the field, 12 are currently producing and 3 are shut-in. Gas production began in 1969 form both the Sterling and Beluga formations, with the production combined into a single pool. Production depths range from about 3,500'ss to 7,000'ss. Multiple pay zones are produced from both formations. Conoco Phillips subdivides the Sterling into 13 productive zones designated A, B and Cook Inlet 1 through 11 and the Beluga into 21 sands designated A through U for a total of 34 zones. Total net pay is 310 feet. Log derived porosities range from the low 30%'s in the Cook Inlet sands to mid 20%'s in the upper Beluga to the low 20%'s to high teens in the lower Beluga. The total cumulative production through June 2009 was 1,808 BCF.

The structure is a broad, gently folded, slightly asymmetrical anticline with steeper dips on the west side and with the fold axis trending in a north-northeast direction (Figure B6.1). The structure is about 6 miles long and 4 miles wide. No small scale faults are shown on the publicly available structure map.

The multiple pay zones provide good opportunities for future reserve growth similar to the new pay sands discovered at the Beluga gas field. Additional reserves are likely to be found in the Beluga formation at the edges of the field where sands are disconnected from existing perforations due to reservoir heterogeneities.

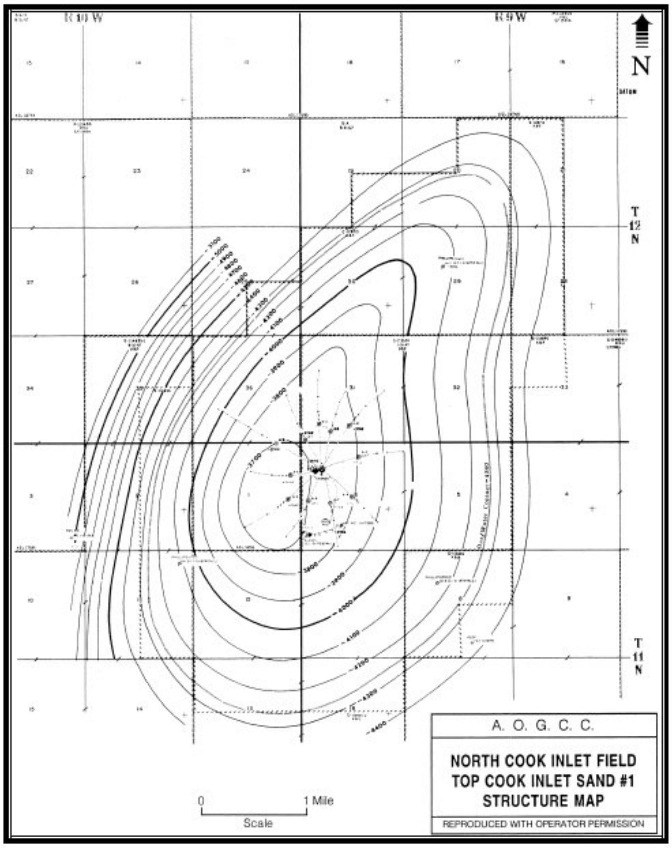


Figure B6.1: North Cook Inlet Field Structure Map (AOGCC)

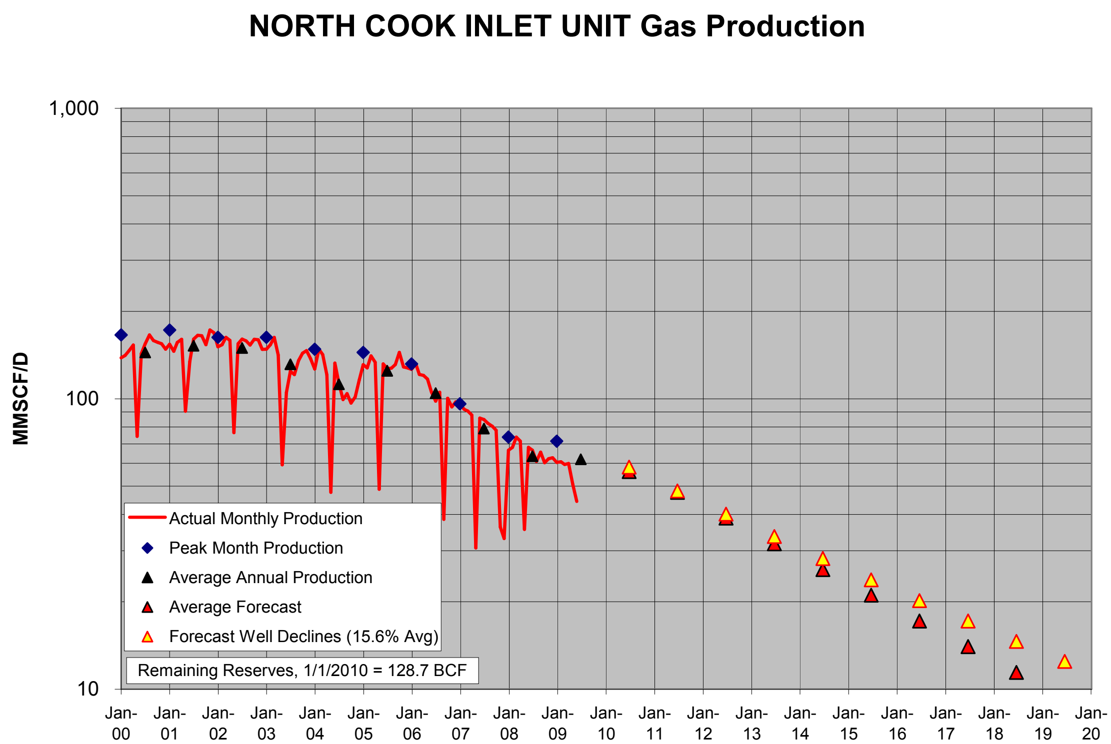


Figure B6.2: North Cook Inlet Unit Production Curve 2000-2009 and Forecast

Appendix B-7: Ninilchik Unit Gas Field Description

Geological Introduction. The Ninilchik gas field is located partly onshore and partly offshore on the Kenai Peninsula between Clam Gulch and Ninilchik. There are three Participatng Areas (PAs) within the Ninilchik Unit: Falls Creek; Grassim Oskolkoff; and Susan Dionne. The Falls Creek part of the field was discovered in 1961 by the Socal Falls Creek No. 1 well which was drilled to a total depth of 13,795' MD (13,382' TVD) in search of deep oil objectives. This was initially called the Falls Creek gas field and the Falls Creek Unit was established. The G. Oskolkoff part of the field was discovered in 2001 by the Marathon Grassim Oskilkoff No. 1 well which was drilled to 11,600' MD (8,510' TVD). The Susan Dionne part of the field was discovered in 2002 by the Marathon Susan Dionne No. 3 well drilled to 10,255' MD (8,102' TVD). The current operator of the unit is Marathon. Production is from three pools in the Tyonek formation, Falls Creek Tyonek undefined gas pool, G. Oskolkoff undefined gas pool and the S. Dionne undefined gas pool from depths of 4,690'ss, 3,496'ss and 3,338'ss, respectively. Production began in September of 2003 in the Falls Creek and G. Oskolkoff pools and in December 2003 in the S. Dionne pool. Reservoir characteristics are shown in Table 2. Gas production is currently form 3 wells at Falls Creek, 5 wells at G. Oskolkoff, and 6 wells at S. Dionne. A cumulative total of 94.8 BCF has been produced through June 2009.

The structure is an anticline 17 miles long and 3 miles wide with the crest about 1 mile offshore and parallel to the shoreline. No structure contour maps are publically available for the field. 3-D seismic was acquired by Marathon over part of the structure. The field straddles the transition zone between onshore and offshore resulting in somewhat difficult seismic acquisition and merger with the onshore and offshore data.

Since the Ninilchik field has been produced for only 6 years, future reserve growth will likely come from additional 'tight-sand' Tyonek reservoirs that are yet to be tested. Also shallow Beluga reservoirs could be new reserve targets. The 3-D seismic should allow detailed mapping of the structure with identification of possible small scale cross-faults forming isolated fault blocks.

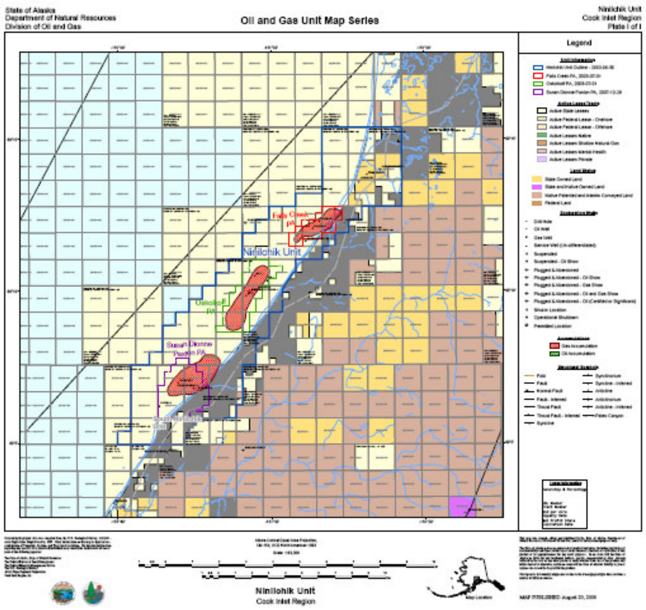


Figure B7.1: Ninilchik Unit Location Map (DNR)

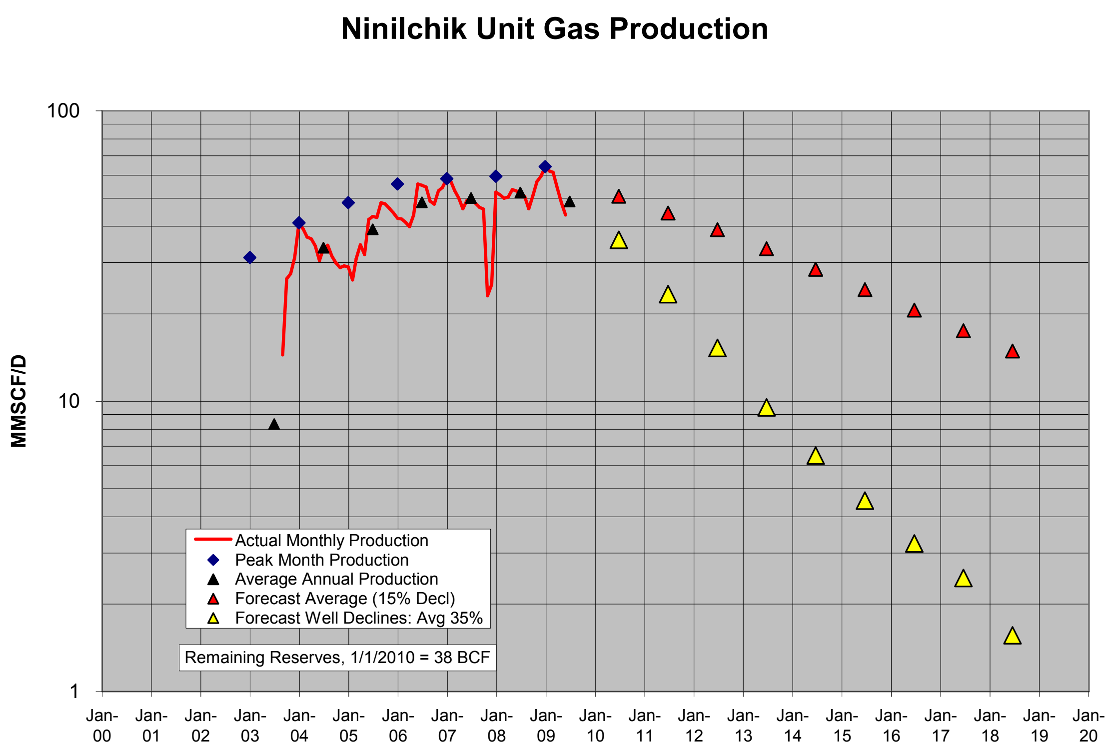


Figure B7.2: Ninilchik Unit Production Curve 2000-2009 and Forecast

Appendix B-8: Sterling Unit Gas Field Description

<u>Geological Introduction</u>. The Sterling gas field is located on the Kenai Peninsula about 60 miles southwest of Anchorage and about 8 miles east of Kenai. It was discovered in 1961 by the Unocal Sterling Unit 23-15 well which was drilled to a depth of 14,832' (MD and TVD) in search of deep oil objectives. From 1962 through 1998 production was from the Sterling undefined gas pool. In 1999 two additional pools were added, Beluga undefined and Tyonek undefined and in 2008, two more, Upper Beluga undefined and Lower Beluga Tyonek undefined, were added and the production volumes were corrected to reflect the re-assignment. These new pools expanded the unit boundary and added new participating areas to the unit. The field was shut in between 1986-1994 and Marathon took over as operator in 1994. The Upper Beluga undefined pool was discovered in 1998 by the Marathon Sterling Unit No. 32-09 which was drilled to a depth of 6,858' MD (6,336' TVD). Production depths are at 5,030' ss, 5,400' ss, 8,104' ss, 9,449'ss for the Sterling, Upper Beluga, Beluga undefined and Tyonek undefined pools. Reservoir characteristics are shown in Table 2. Gas production is currently from three wells. Total cumulative production is 12.3 BCF through June 2009.

The structure is a subtle, low relief, four way dip anticline, about 2.5 miles wide and with only about 100 feet of closure (Figure B8.1). 3-D seismic led to the drilling of the Sterling 32-09 well and the discovery of the Upper Beluga pool.

The addition of the upper Beluga and Lower Beluga Tyonek pools in 2008 demonstrates the kind of reserve growth that occurs through ongoing field development. Additional reserve growth will likely come from the Beluga and Tyonek as more potential 'tight-sands' are tested and additional wells are drilled. Development will likely require fracture stimulation with associated capital expenditure.

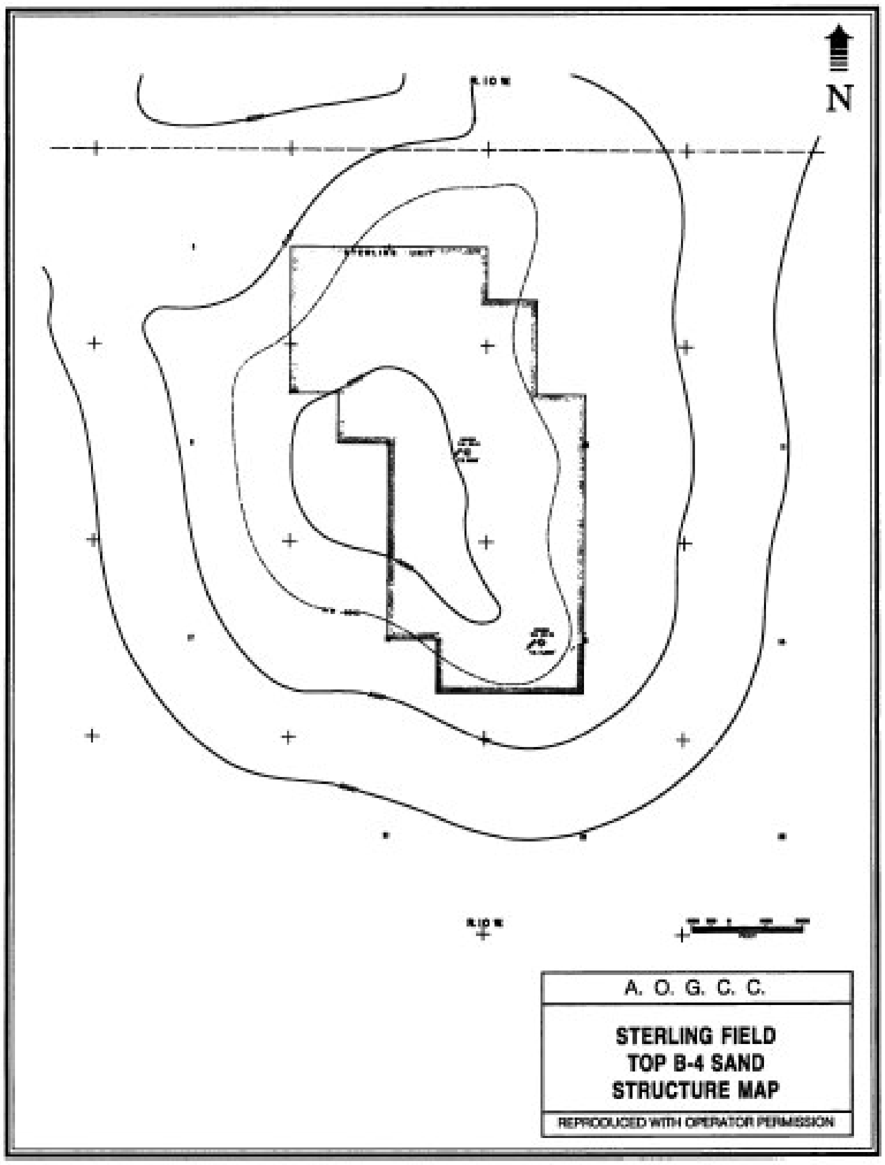


Figure B8.1: Sterling Field Structure Map (AOGCC)

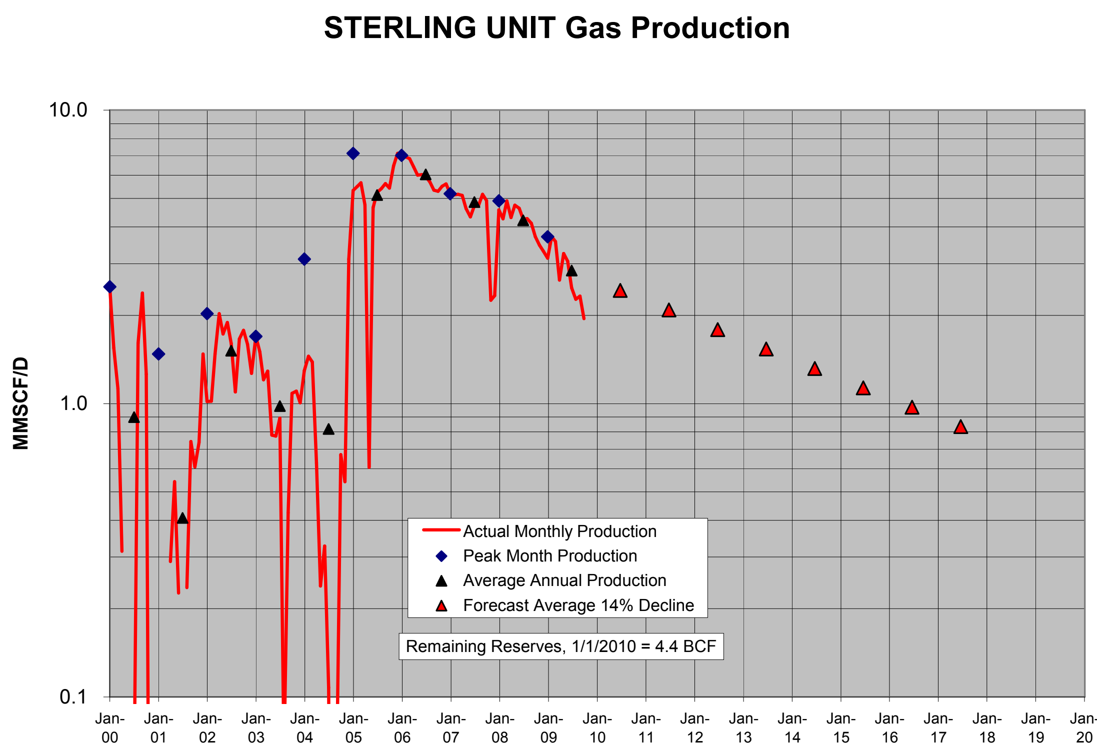


Figure B8.2: Sterling Unit Production Curve 2000-2009 and Forecast

Appendix B-9: Swanson River Unit Gas Field Description

Geological Introduction. The Swanson River gas field is located on the Kenai Peninsula about 45 miles southwest of Anchorage and about 15 mile northeast of Kenai. It is subdivided into a northern Swanson River Unit and a southern Soldotna Creek Unit. The oil field, discovered in 1957, was the first oil field discovered in Cook Inlet and it began producing oil in 1958 from the Hemlock formation. Associated gas produced with the oil was re-injected beginning in 1962 for pressure maintenance. Gas from other fields was also injected. Gas was discovered in the Swanson River field in 1960 by the Unocal Swanson River Unit 212-10 well which was drilled to 12,029' MD (11,526 TVD) as an oil development well. Chevron is the current operator. Intermittent production occurred in 1960, 1962 through 1966, 1979 and continuous production began in 1987. Production from 1960 to 2005 was from the Sterling and Tyonek formations and was assigned to a single undefined gas pool. In 2005 the gas was re-assigned to 3 pools, Sterling undefined, Beluga undefined and Tyonek undefined, producing from sands at 2,720', 2,974' and 3,060' in the Sterling, 4,676' in the Beluga, and 5,600'-7,500' in the Tyonek. Current production is from 2 wells in the Sterling, 1 well in the Beluga and 2 wells in the Tyonek. Individual pool production and reservoir characteristics are shown in Table 2. The Swanson River field is used by Chevron for gas storage. Total cumulative production for all three pools through December 2008 was 50.3 BCF.

The Swanson River structure is a slightly asymmetrical anticline, with the fold axis oriented in a north-south direction. The structure is 8 miles long and 2 to 3 miles wide and is cross-cut by several normal faults, some of which are sealing and subdivide the reservoirs into separate fault blocks. 3-D seismic shot over the structure has allowed more accurate mapping of the cross faults and identification of previously untested fault blocks.

Future reserve growth will likely come from future drilling of untested isolated fault blocks identified on the 3-D seismic data. Also, with the re-assignment of the gas into 3 pools in 2005 and production from the Beluga sands being added, potential exists for additional Beluga sands being tested as well as isolated pay being discovered in the Beluga and Tyonek sands due to stratigraphic isolation.

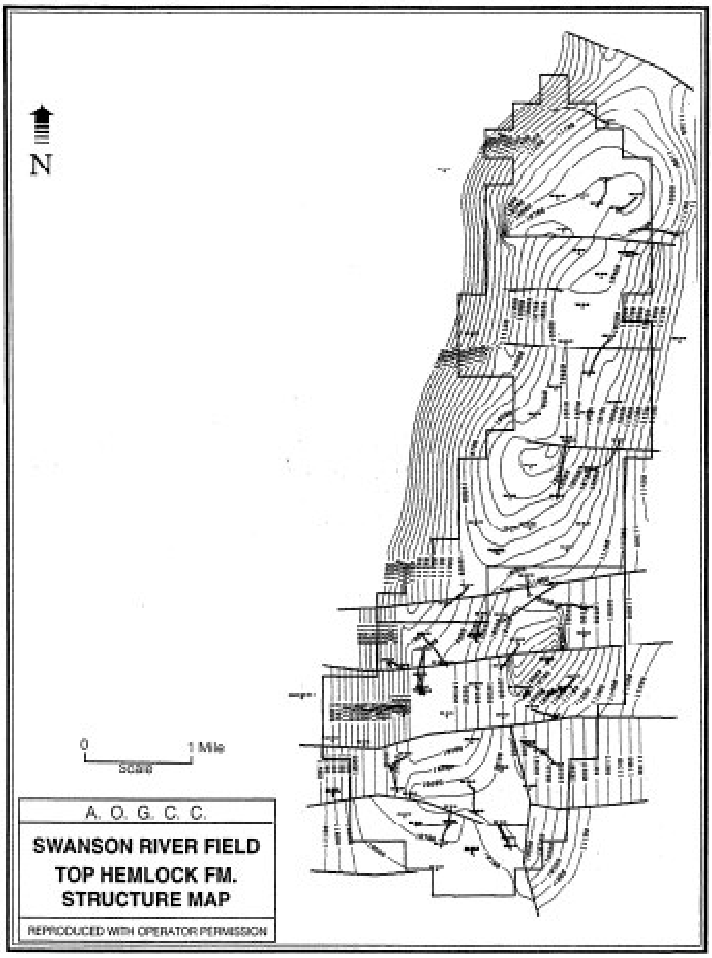


Figure B9.1: Swanson River Field Structure Map (AOGCC)

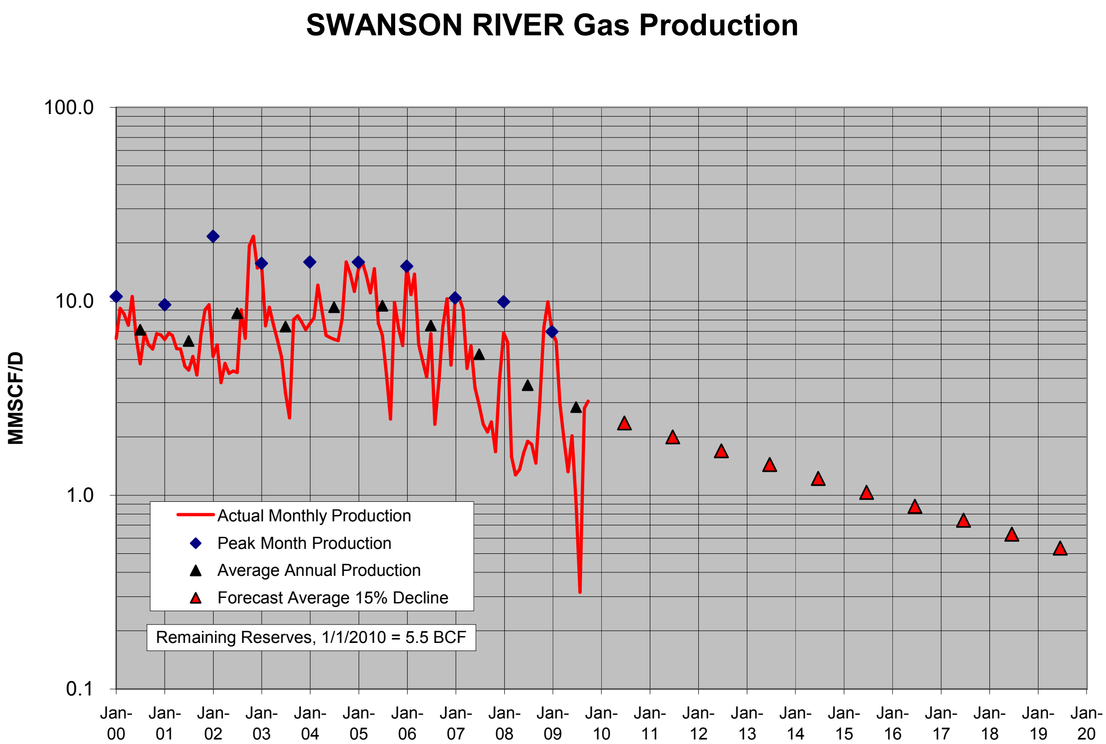


Figure B9.2: Swanson River Unit Production Curve 2000-2009 and Forecast

Appendix B-10: Trading Bay Unit Gas Field Description

Geological Introduction. The McArthur River field is located offshore on the western side of Cook Inlet 64 miles southwest of Anchorage and about 20 miles southwest of Tyonek. The McArthur River oil field was discovered in 1965 by the Unocal Grayling 1A well which found oil in the Lower Tyonek (Middle Kenai G), Hemlock and West Foreland formations. The mid Kenai gas pool was discovered in 1968 by the Unocal Trading Bay Unit G-18 well which was drilled to a depth of 6,930' MD (4,510' TVD). Gas production began in December 1968 from the Grayling platform and soon thereafter from the Dolly Varden and King Salmon platforms. This initial production was "wet" gas associated with the oil produced from the oil pools. Most of this associated gas was not sold commercially but was used for gas lift and field operations. In 1988 the Steelhead platform was constructed to produce the dry (biogenic) gas from the Middle Kenai gas pool also called the Grayling sands. These sands are in the Chuitna and Middle Ground Shoal members of the upper Tyonek formation and are defined as the sands correlative with the interval between a measured depth of 1,518' in the Trading Bay unit M-1 well to 8,982' in the Trading Bay Unit M-14 well. The reservoirs are sandtones labeled zones A through F and G through O above the G zone oil pool and are conglomeratic, thin (20-50') thick and range in porosity from 12 to 32%. The gas is currently produced from 16 wells with about 4% of it used for field operations and the remainder sold commercially. Total cumulative production was 1,105 BCF through June 2009.

The structure is a faulted anticline 4 miles long and 1.5 miles wide oriented north-northeasterly (Figure B10.1). The two normal faults that intersect the structure do not affect the limits of the gas in the reservoir.

The relatively thick stratigraphic interval containing pay sands provides good opportunities for isolated, disconnected pay at the fringes of the field. Also, reserves could be added through future testing of 'tight-sands' in the Tyonek which have not been the target of existing development as well as petrophysical examination of the Beluga section for potential low resistivity pay.

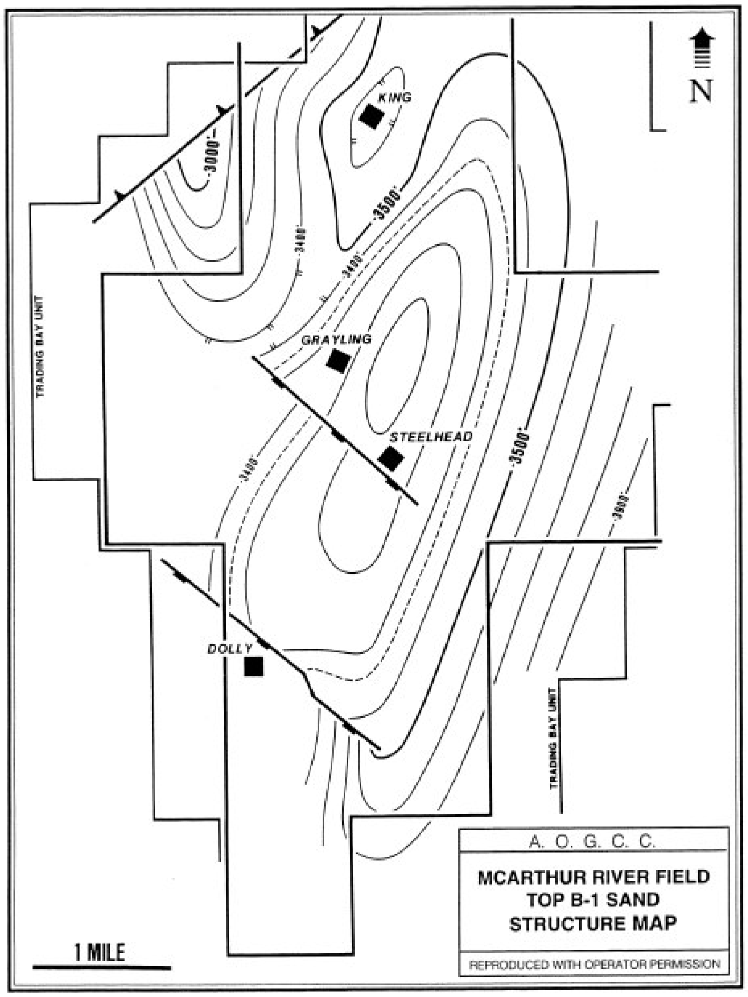


Figure B10.1: Trading Bay Unit Structure Map (AOGCC)

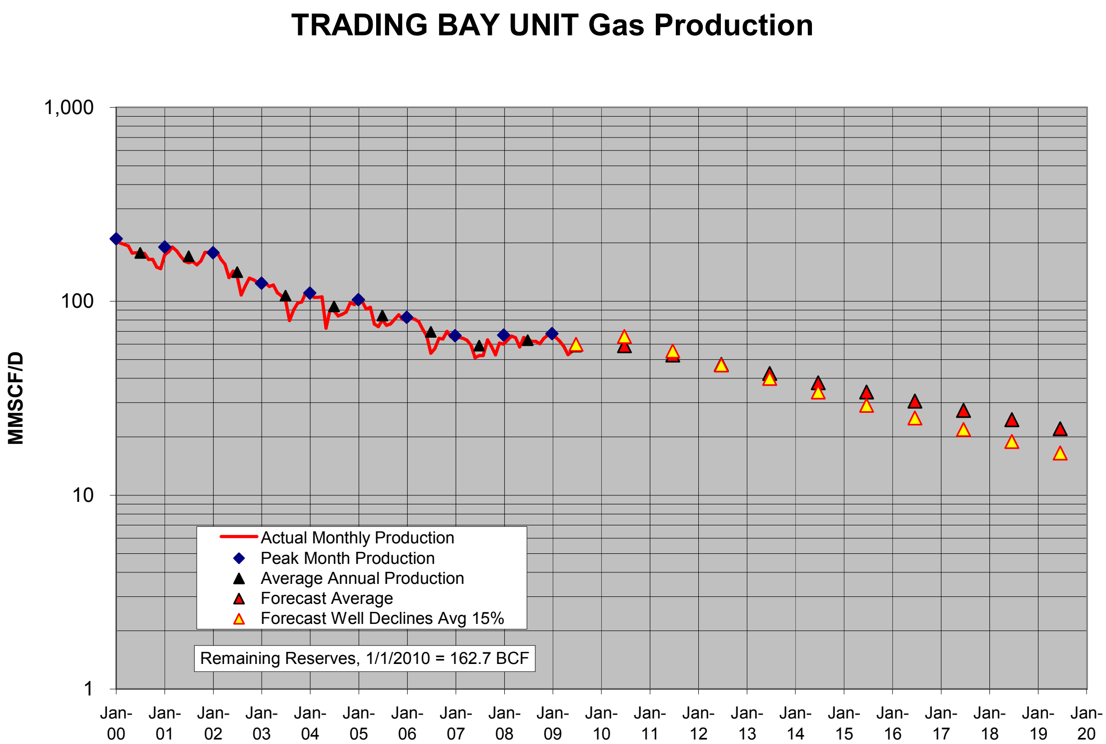


Figure B10.2: Trading Bay Unit Production Curve 2000-2009 and Forecast

Appendix B-11: Other Cook Inlet Gas Fields

The Remaining gas fields are shown in Table 3 with cumulative reserves and reservoir characteristics. Also included in the "Other" category is gas associated with oil production in Cook Inlet.

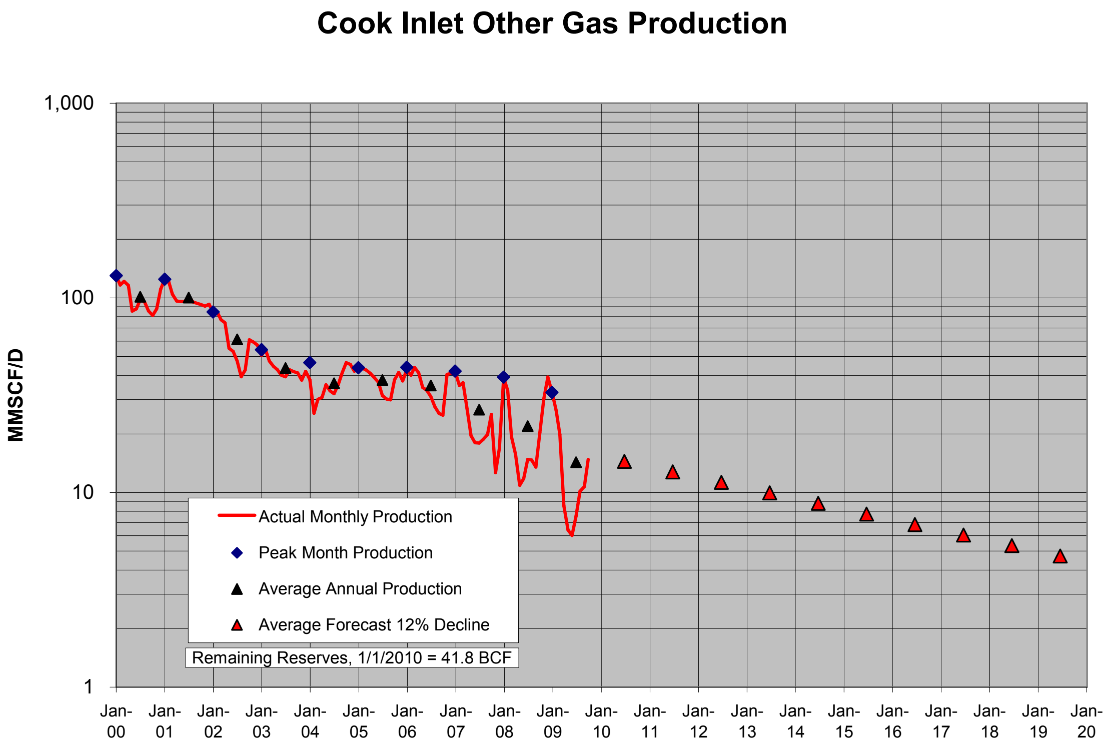


Figure B11.1 "Other" Cook Inlet Production Curve 2000-2009 and Forecast

Appendix C-1 DNR Geologic Reserves Study

The DNR is conducting a detailed volumetric calculation of original gas in place (OGIP) for four Cook Inlet fields, Beluga River (BRU), North Cook Inlet (NCI), (Kenai,) Ninilchik, and Trading Bay (Grayling sands). The work is being done by Meg Kremer (BRU, Ninilchik and Trading Bay), Laura Silliphant (NCI), with Paul Anderson providing geophysical support and Don Kroskoph preparing stratigraphic cross-sections. Trading bay has not been assigned to anyone as yet. Jack Hartz is conducting a detailed decline curve and material balance analysis of all the gas fields in Cook Inlet. The results of the two approaches will be compared and will yield an estimate of the proved reserves remaining in the Cook Inlet gas fields. This work is expected to be published in mid-December.

Following is the process used by Meg Kremer for the Beluga River Field. The same process was used for the other fields as well.

1. Construct cross-sections containing all 23 wells in the field and showing all the wire line curves and perforated intervals. Correlate the sands and coal beds between the wells. (Thicker coals can be correlated over the area of the field and are better in the Sterling than in the Beluga. The coal correlations can help with adjacent sand correlations but sands vary in thickness and can pinch out laterally and disconnected sands can be erroneously correlated as the same sand. Post the log tops and bases provided by ConocoPhillips for all wells in all 10 productive zones, Sterling A, B, C and Beluga D, E, F, G, H, I, and J. Identify two categories of reserves using definitions approved by SPE and WPC:
Pay = Proved (1P) reserves, colored green on the cross sections
Pay Low confidence = Probable (2P) and Possible (3P) reserves, colored yellow.

2. Apply the following criteria to identify pay. Pay consists of all zones that have been perforated or are currently perforated and have produced or are producing gas. Those same zones usually show and elevated resistivity response greater than 10 ohmm (deep resistivity) along with an SP shift off shale baseline, sonic-neutron crossover or neutron-density crossover or a decrease in sonic travel time (slower than the sonic in shales or 'other sandstones'). Some zones are labeled pay that have not been perforated if correlated to sandstones that are now being perforated in newer wells. Some zones are labeled pay that have not been perforated if the log response looks very similar to a perforated interval in the same or offset well. Completion reports available through the AOGCC were examined for production and test information. This analysis does not include production history information or deliverability. Those factors will be addressed when the volumetric analysis is compared to the decline curve/material balance analysis by Jack Hartz. Pay will include cemented off pay that can't be produced without additional capital expenditure. A log analyst in Houston, conducted petrophysical analysis to help with water saturation and porosity estimates as well as pay identification from the log data. His work will be incorporated in the study when complete. Petrophysical identification of pay is difficult in Cook Inlet due to variable clay

cementation in the sandstones which makes Rw vary throughout the section. Standard petrophysical models are not reliable in the Inlet and must be modified on a well-by-well and field-by-field basis.

3. Apply the following criteria to identify low confidence pay. Low confidence pay consists of perforated intervals that flowed minor gas with water; small sandstones in long perforated intervals where gas was present but it is unclear which sandstones produced, generally with some fluid recovery as well; and gas ‘shows’ on logs not as robust as Pay (lower resistivity but still over 10 ohmms, less crossover on porosity logs.

4. Sum the pay for each well and use Geographix to generate pay isopach maps for each of the 10 Sterling and Beluga zones. This essentially stacks the pay in each zone and treats it as a single sand within the zone. Meg Kremer applied a N10E bias to the computer mapping in the Sterling sands because the contouring suggested a N10E channel belt orientation. No bias was used in the Beluga sands. Computer contouring programs tend to produce ‘bullseye’ maps especially where well data points are few and widely spaced. Geologically biasing the contouring can produce more realistic maps.

5. Using formation tops and limited structure maps provided by ConocoPhillips create (in Geographix) additional structure maps for each of the ten zones. Using the top zone structure maps and gas water contact (GWC) depths clip the isopach maps using a polygon formed by the structure map contoured down to the G/W. This clipping method results in excess pay at the edges of the maps because it does not account for the wedge zone at the edges of the reservoir where the GWC causes the pay to taper to zero. Meg chose not to adjust for this wedge area. The Sterling A and B were clipped at a GWC of -3,590’ss and the Sterling C was clipped at GWC of -3,670’ss. The Beluga sands GWC’s, gas-down-to’s (GDT’s) and water-up-to’s (WUT’) were all different, requiring review of DST and completion data to determine where to clip pay. Within some beluga zones there were three or four different possible contacts that could be up to 400’ apart. Often the contact was picked by splitting the difference. Use Geographix to calculate the bulk reservoir volume from the pay isopachs

5. Use the following OGIP equation to calculate reserves.

$$\text{OGIP} = \frac{43560 A h Ø (1-Sw)(N/G)(0.98)}{Bgi}$$

Where	Ah	= bulk reservoir volume (from clipped isopachs)
	Ø	= Porosity (from density logs)
	Sw	= Water saturation (fraction)
	N/G	= Net sand to Gross sand
	0.98	= Adjustment for produced gas being 98% methane
	Bgi	= Initial gas formation volume factor

Porosity. Geographix was used to calculate average porosity of pay in each well and for each zone. These porosities were used to create a grid for each zone over the field. For most zones the creation of the grid resulted in more pore volume than calculations without the grid. This method may be more valid in fields with closer well spacing. North Cook Inlet spacing is less than BRU. Petrophysicist is supposed to provide his input to log derived porosity.

Water Saturation. For Beluga River Field Water Saturations used were .37 for the Sterling and .42 for the Beluga. Meg believes the Sterling should be closer to .25. This may change with petrophysical input.

Net/Gross. This factor was applied after removing tight streaks, etc. on the logs. The factors applied in Beluga River Field were 0.95 for the Sterling and 0.80 for the Beluga.

Bgi. Calculated by averaging the zone tops from all wells in each zone.

Appendix C-2 DNR Engineering Production Prediction

DNR is made a rigorous study of deliverability and reserves from existing producing wells. It has been tied into the DNR geologic study to identify proved and probably reserves with a "Hypothetical Production Forecast" from Figure 14 of the December 2009 report shown below.

The reservoir analysis being performed in the study includes material balance (P over Z plots) and well, pool and field decline curve analysis. As was the case in the PRA analysis, a big issue is how to determine current deliverability due to the seasonal demand.

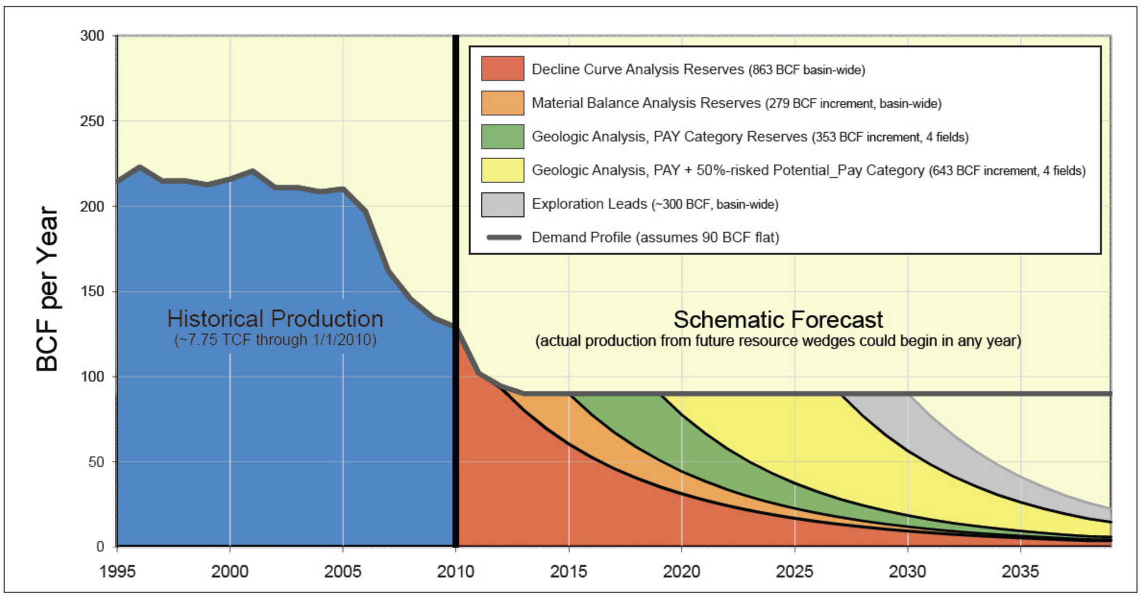
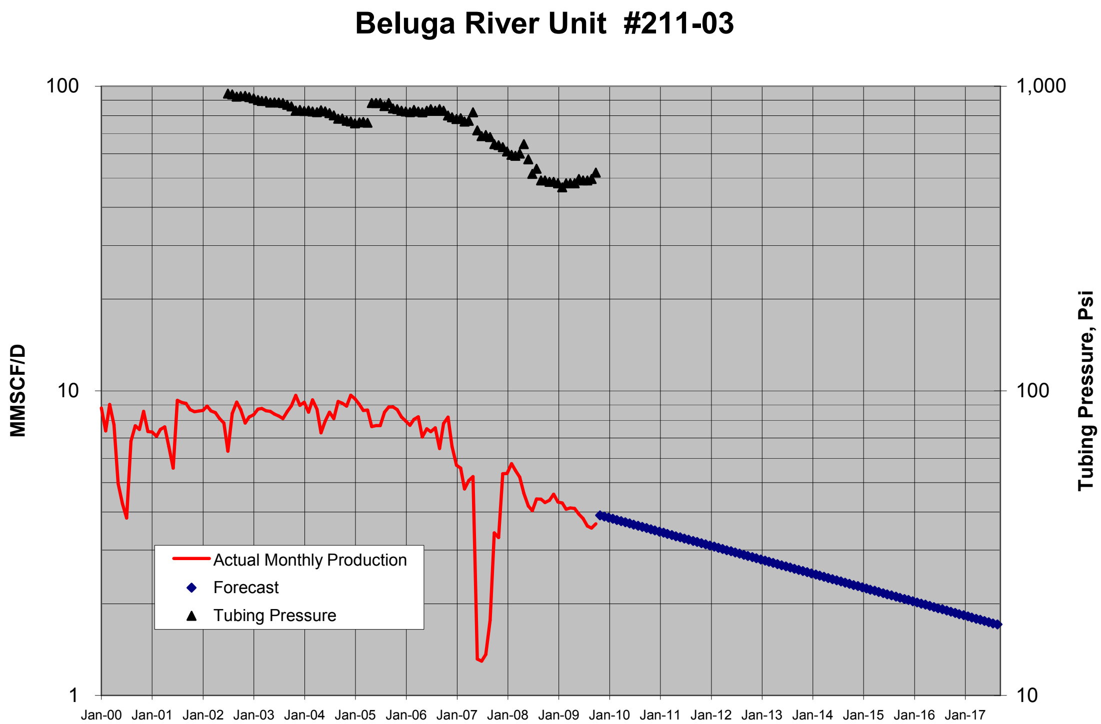
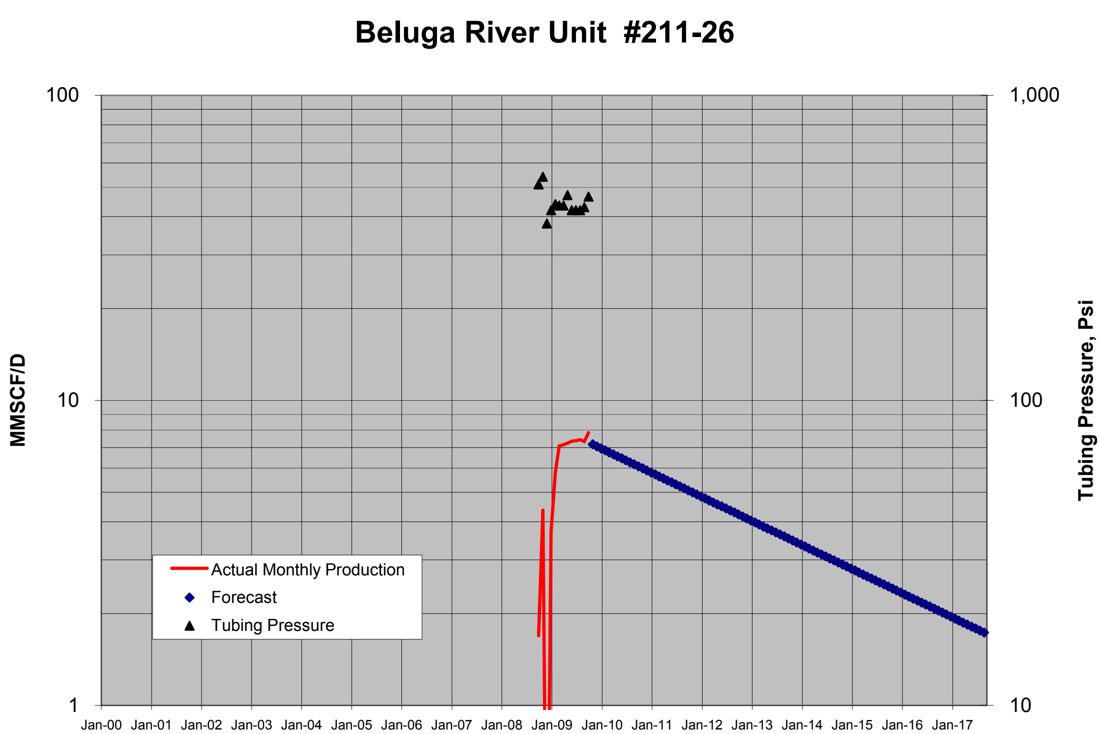


Figure 14. Hypothetical production forecast for the Cook Inlet basin showing increments of reserves and resources identified by engineering and geological analyses discussed in text. This schematic diagram assumes that near-term production will come from gas volumes documented by the most conservative estimation techniques. Successive wedges are introduced with progressively lower certainty regarding commerciality, volume, and timing of first production. Production from future resource wedges could begin in any year, resulting in a more complex forecast, and extending the production lifespan of previous wedges. On the other hand, we are unable to predict the commercial thresholds at which volumes from future wedges become economic to recover. Wedges show gas volume increments from basin-wide decline curve analyses (red), basin-wide material balance analyses (orange), deterministic geologic mapping of PAY (green), and 50 percent-risked Potential_Pay (yellow) in four large gas fields (Beluga River, North Cook Inlet, Ninilchik, and McArthur River Grayling gas sands). The last wedge (gray) is a more speculative estimate of aggregated gas volumes that may be recoverable from the exploration leads discussed in text. See text for additional discussion.

Figure 14 from DNR "Preliminary Engineering and Geological Evaluation of Remaining Cook Inlet Reserves", December 2009.

Appendix D-1 Beluga River Unit Well Decline Curves





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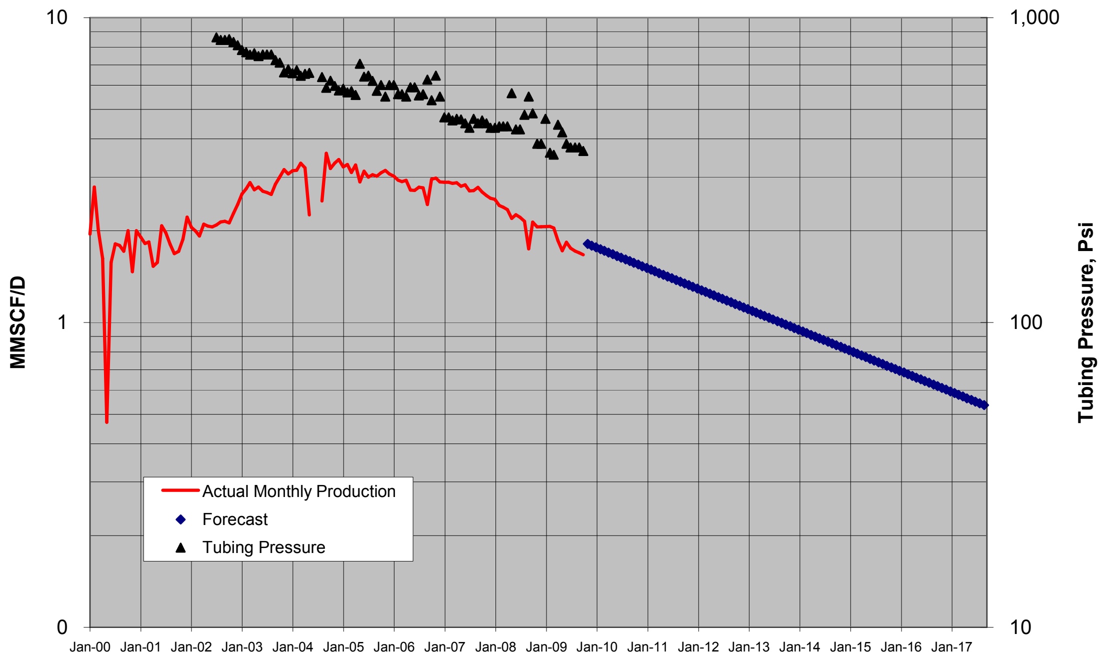
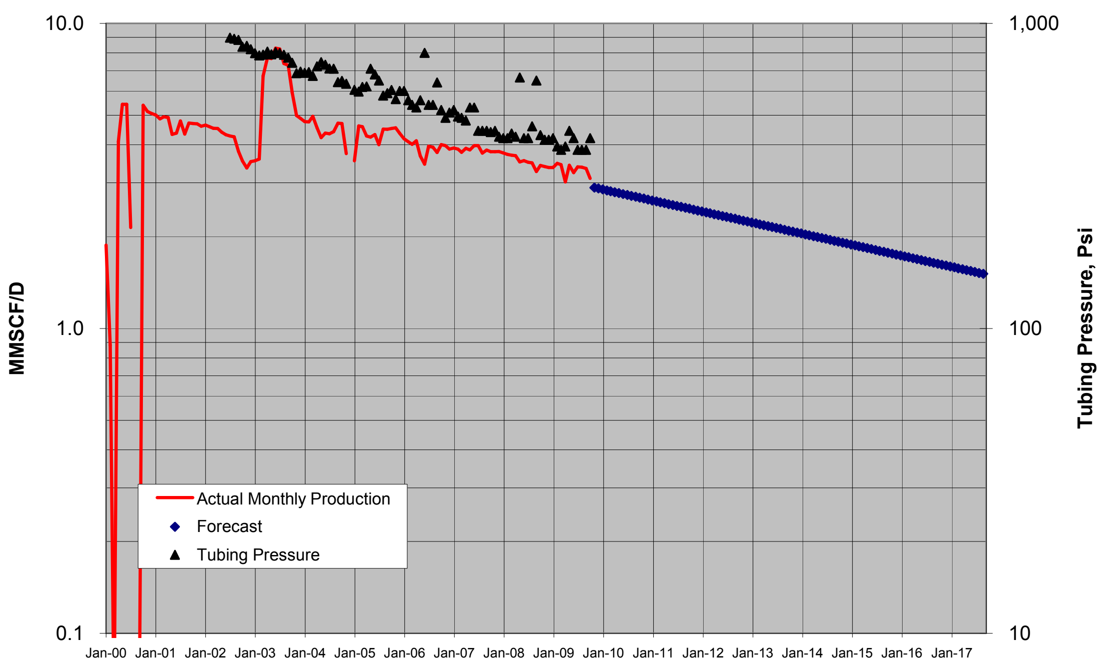
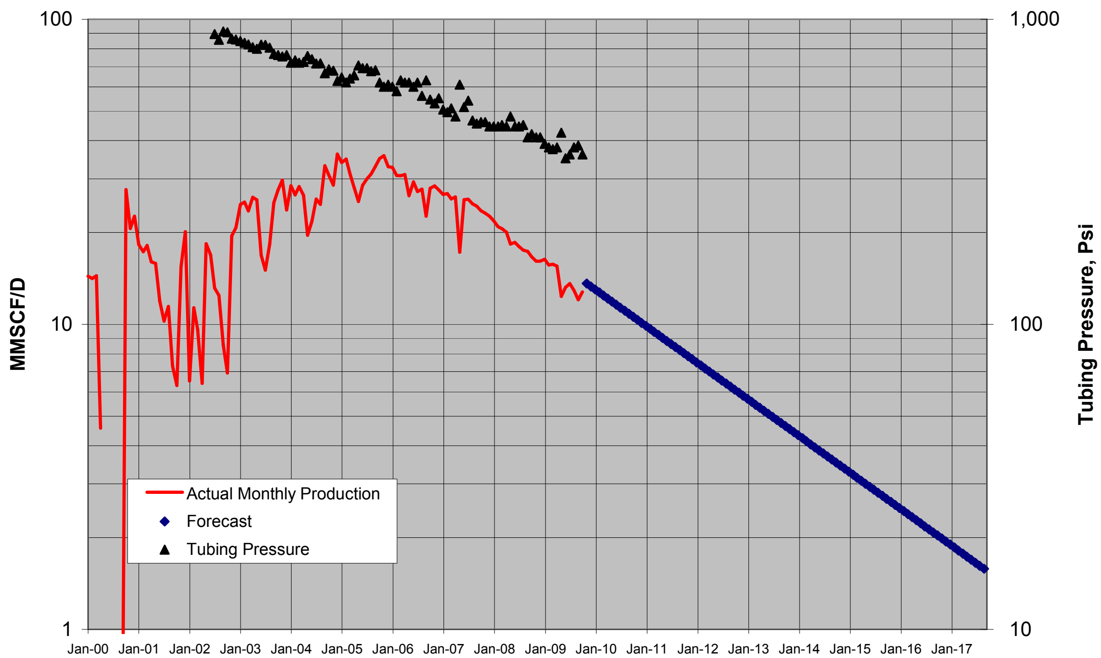


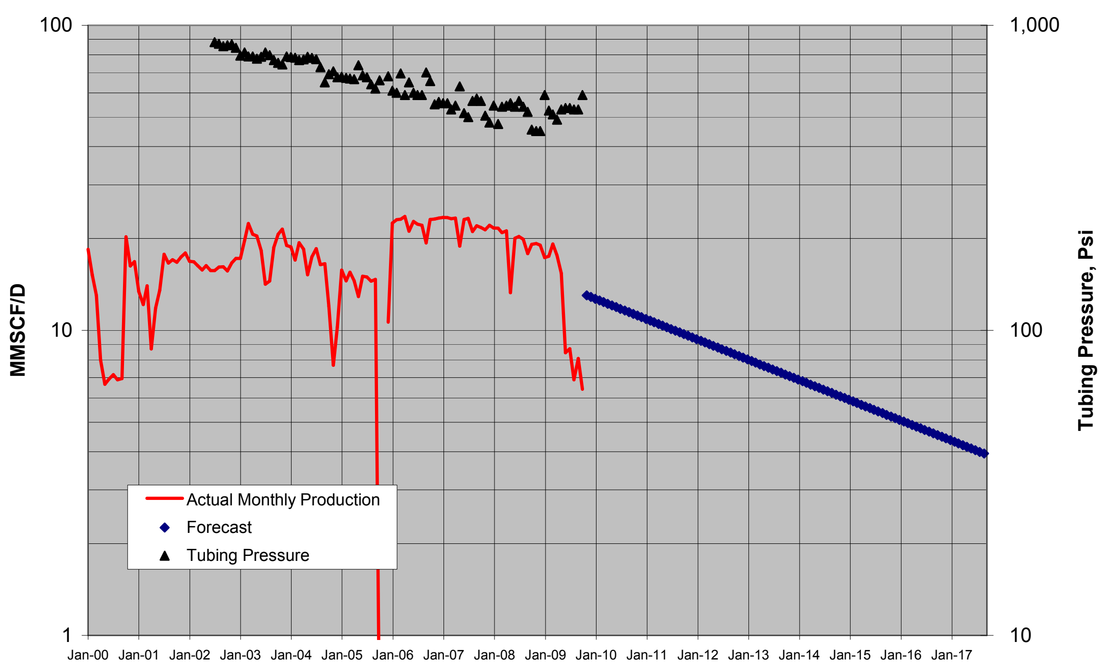
Beluga River Unit #212-35



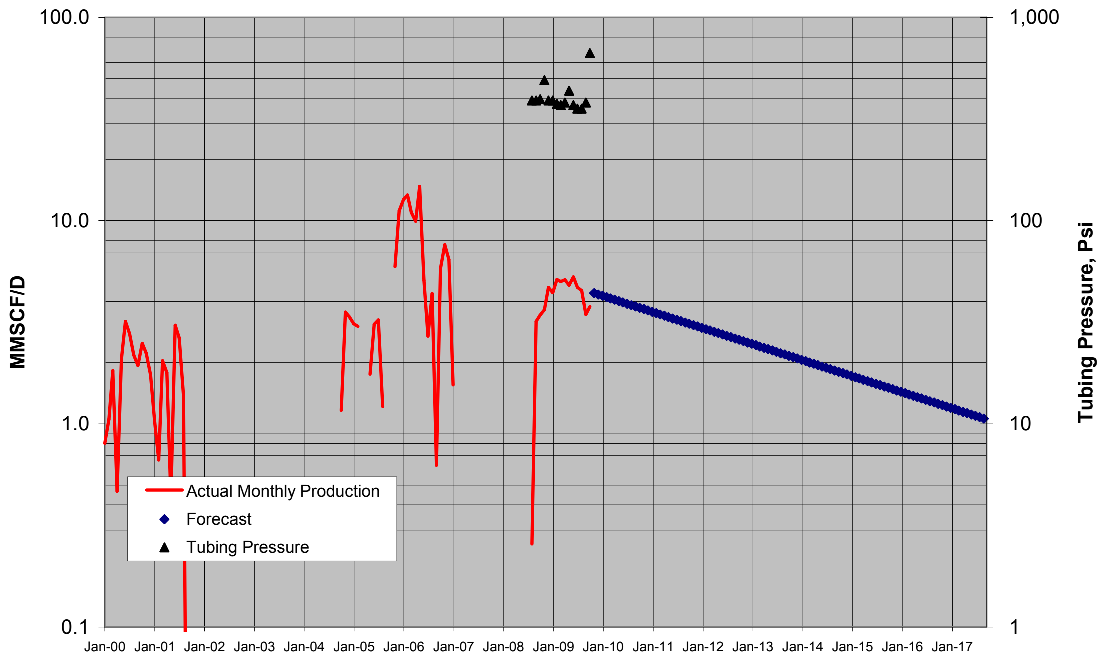
Beluga River Unit #212-35T



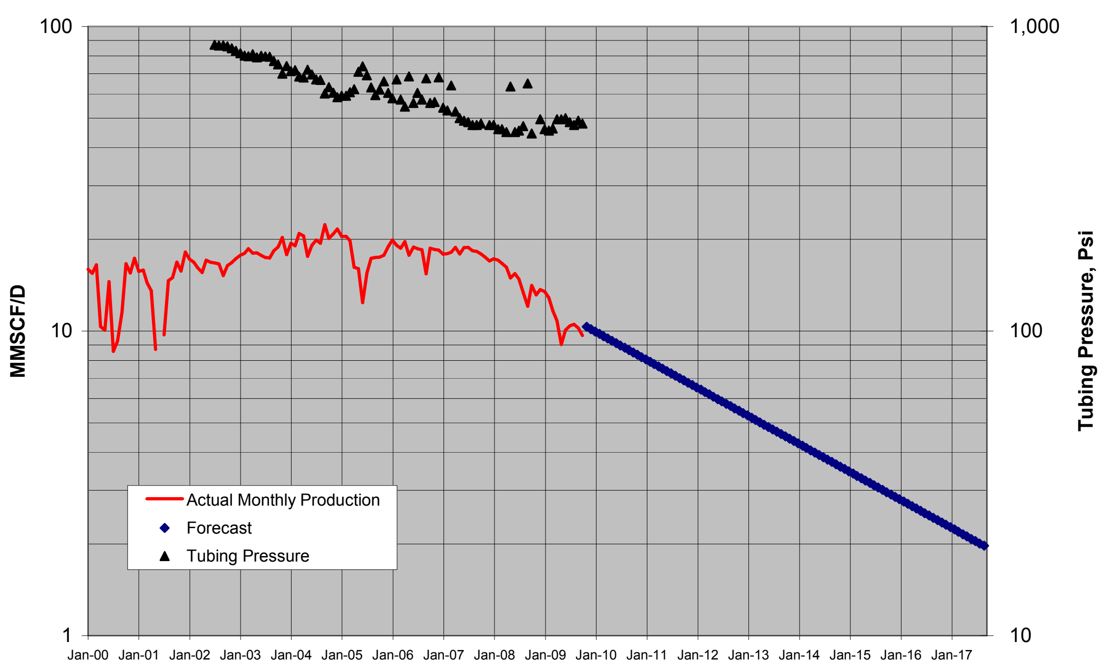
Beluga River Unit #214-26

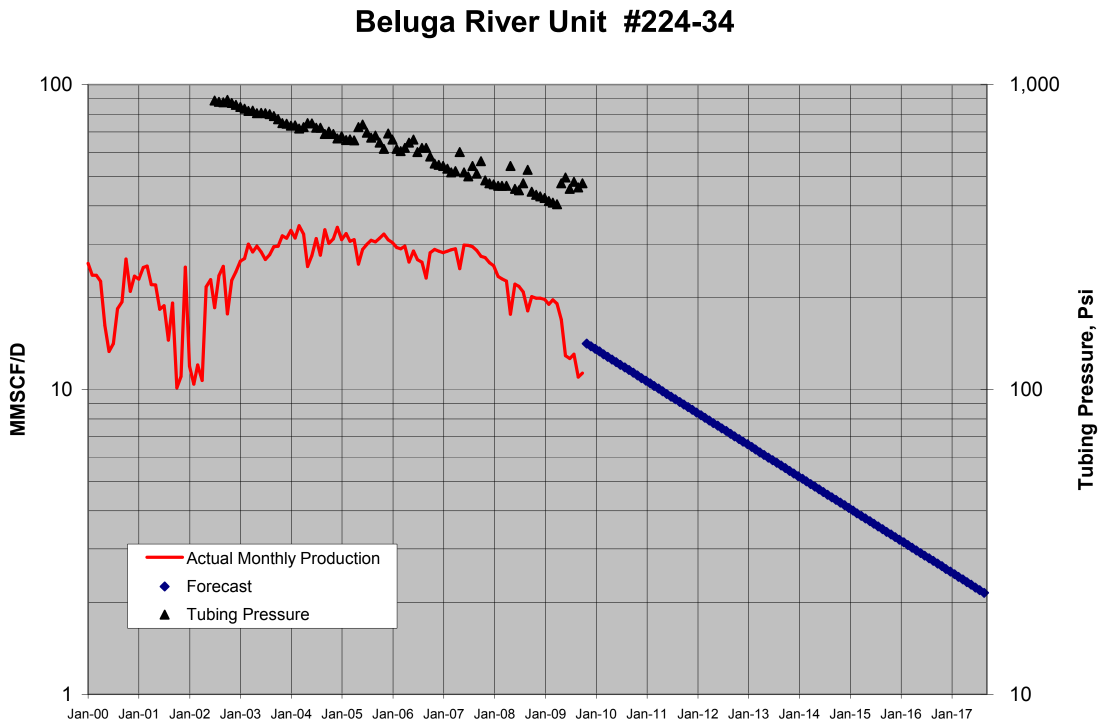


Beluga River Unit #224-13

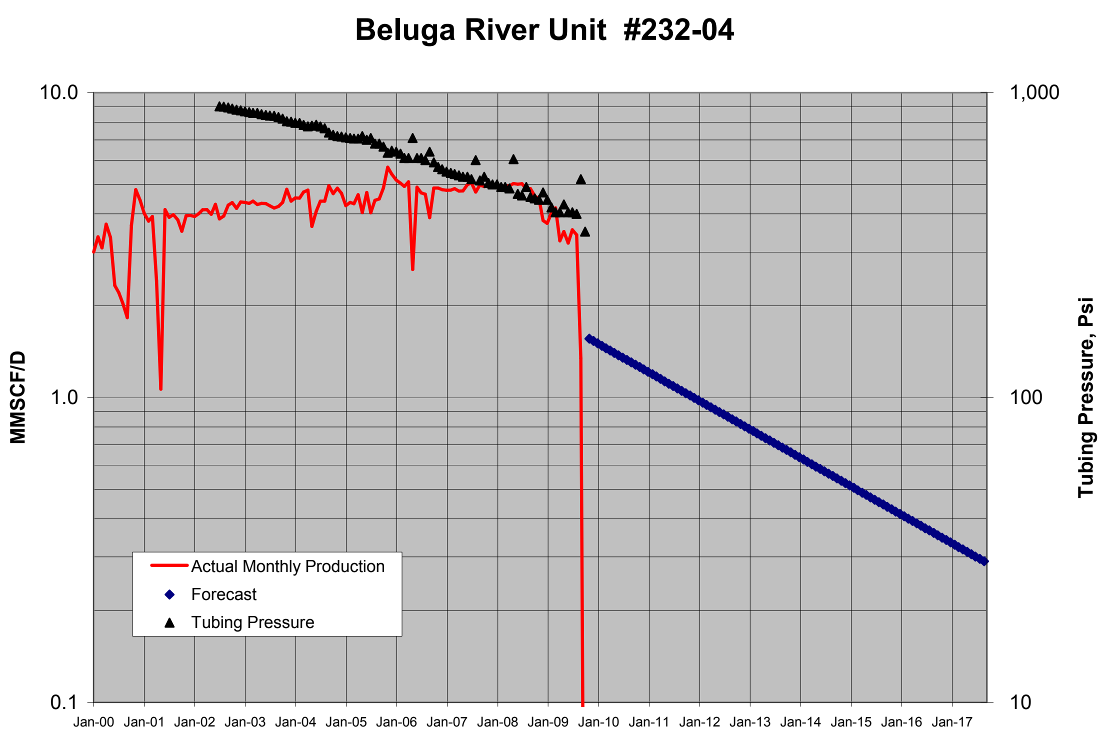


Beluga River Unit #224-23

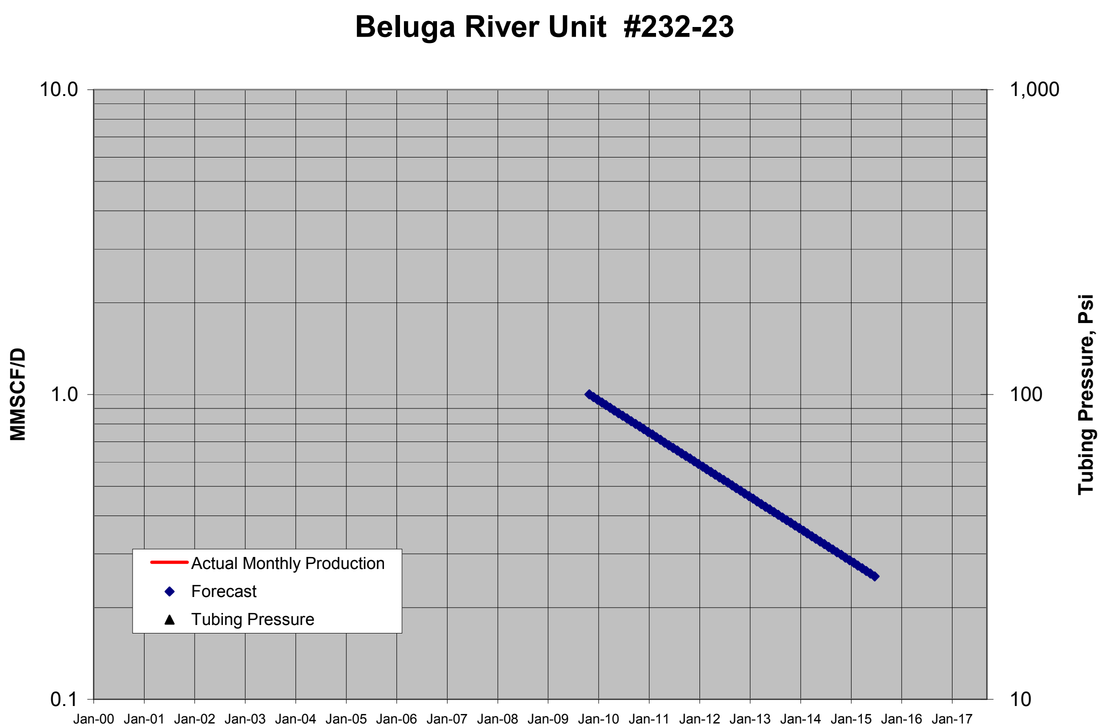


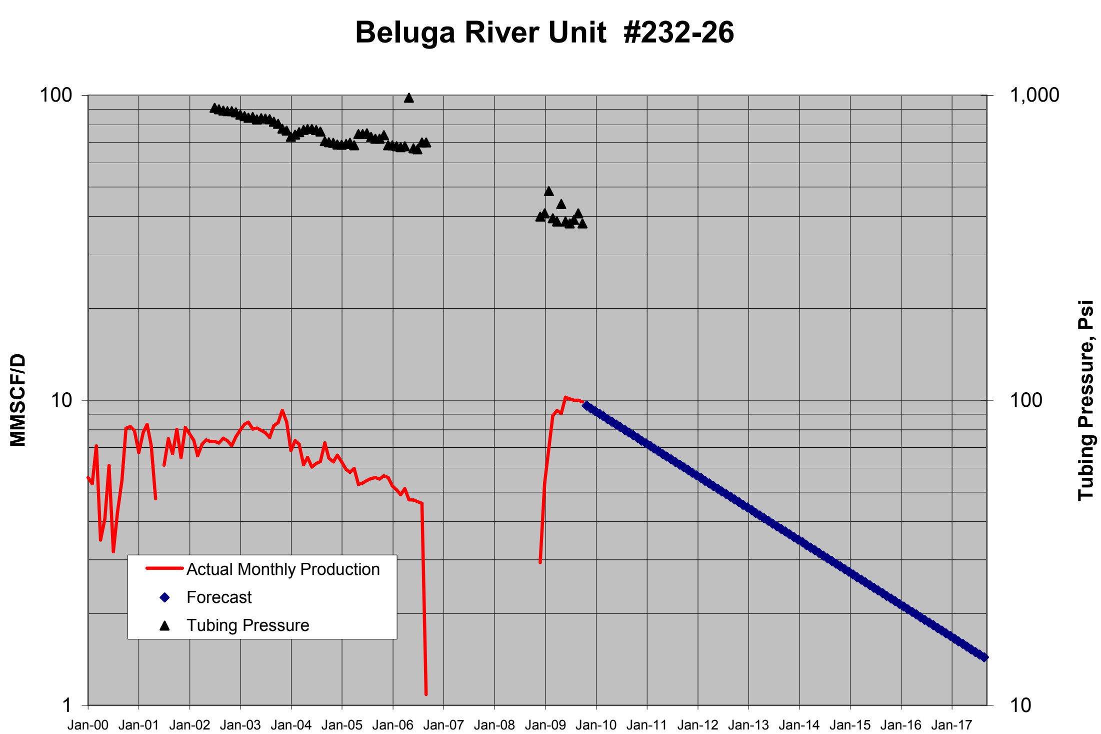


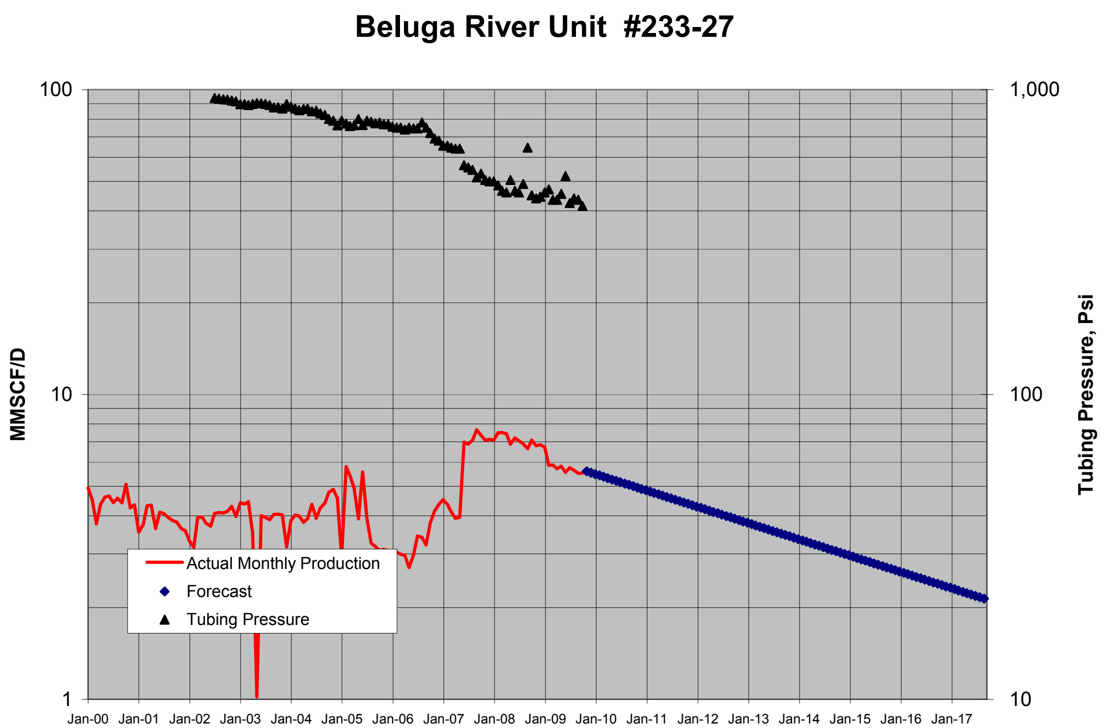
Beluga River Unit #224-34
100
10
1
1,000
100
10
MMSCF/D
Tubing Pressure, Psi
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17
Actual Monthly Production
Forecast
Tubing Pressure



Beluga River Unit #232-04
10.0
1.0
0.1
1,000
100
10
MMSCF/D
Tubing Pressure, Psi
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17
Actual Monthly Production
Forecast
Tubing Pressure


Beluga River Unit #232-23
10.0
1.0
0.1
1,000
100
10
MMSCF/D
Tubing Pressure, Psi
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17
Actual Monthly Production
Forecast
Tubing Pressure


Beluga River Unit #232-26
100
10
1
1,000
100
10
MMSCF/D
Tubing Pressure, Psi
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17
Actual Monthly Production
Forecast
Tubing Pressure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Tubing Pressure, Psi
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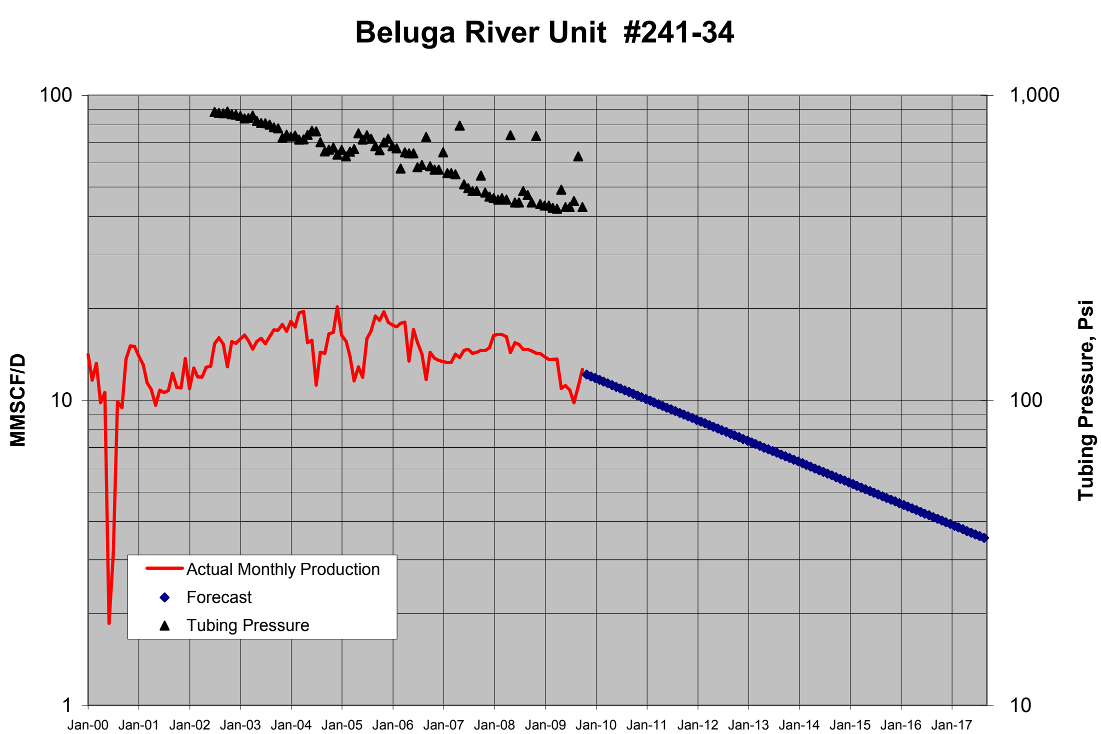
10
1
1,000
100
10
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17


Beluga River Unit #241-34
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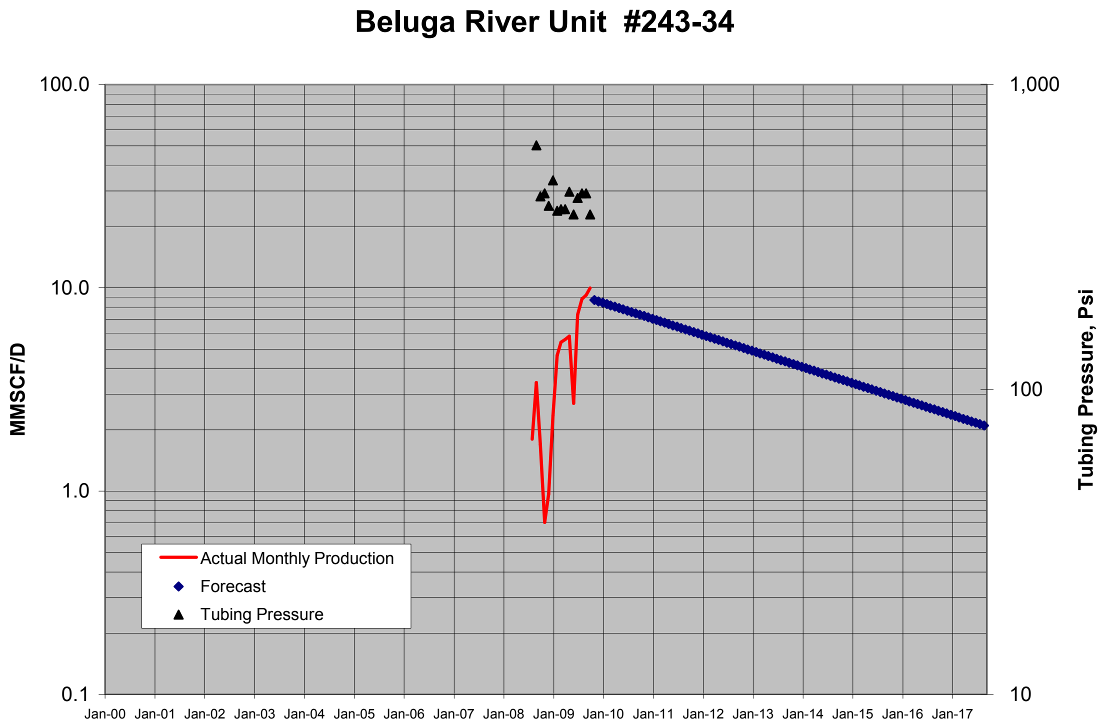
Tubing Pressure, Psi
100
10
1
1,000
100
10
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17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MMSCF/D
Tubing Pressure, Psi
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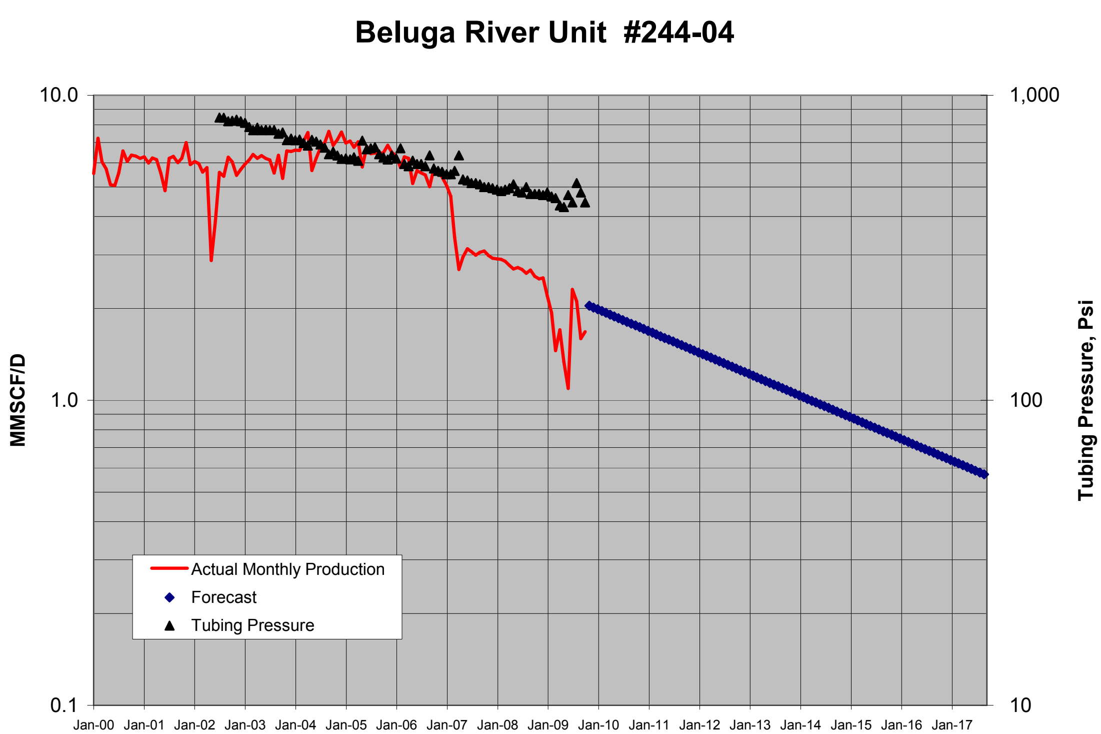
10.0
1.0
0.1
1,000
100
10
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17
Actual Monthly Production
Forecast
Tubing Pressure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Tubing Pressure, Psi
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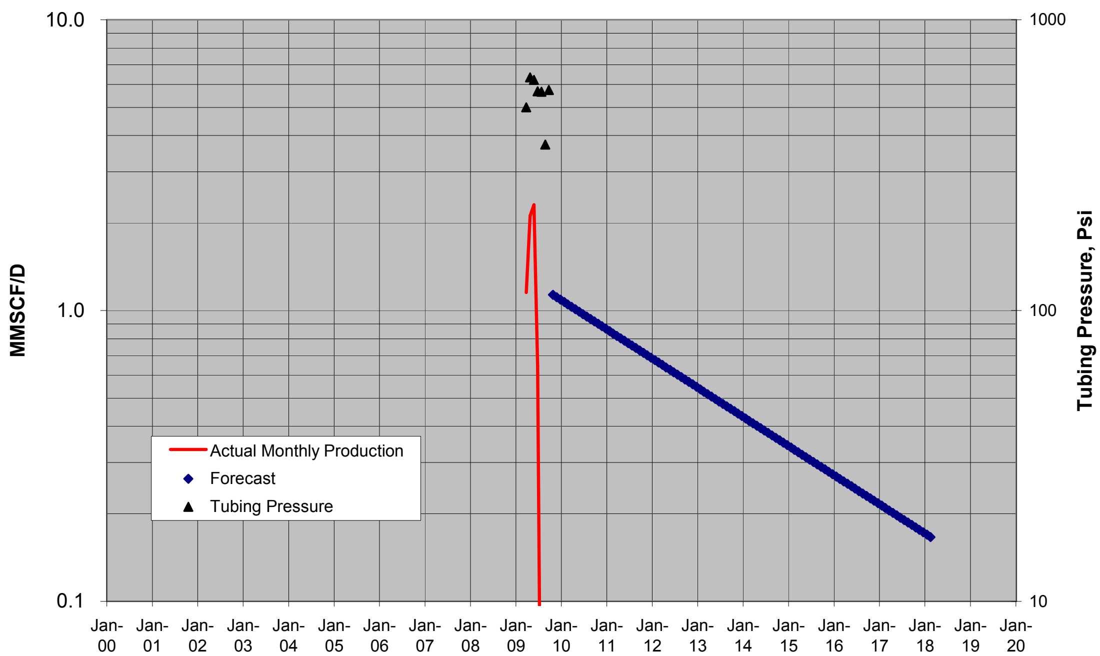
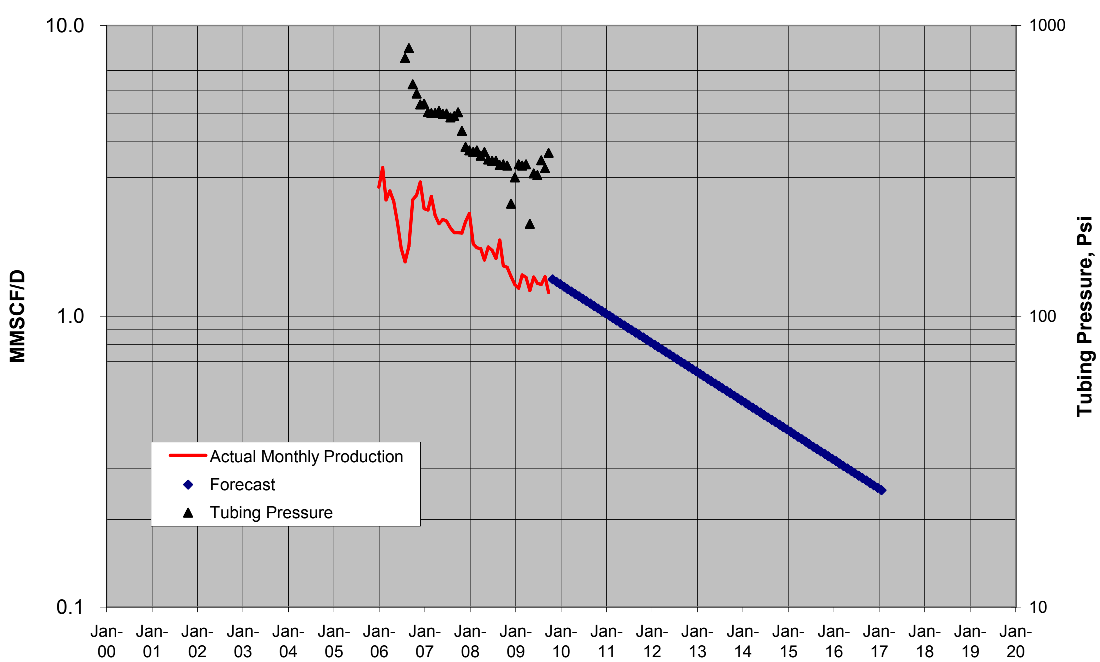
0.1
1,000
100
10
Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17
Actual Monthly Production
Forecast
Tubing Pressure

Appendix D-2: Kenai Unit Well Decline Curves

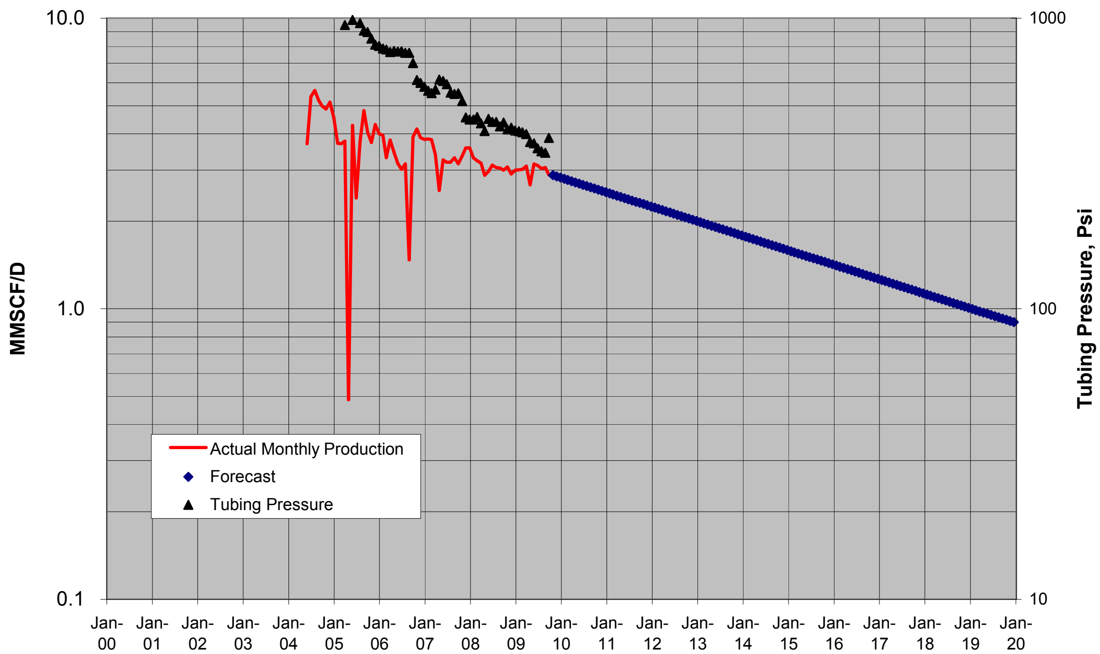
KENAI BELUGA UNIT 11-17X



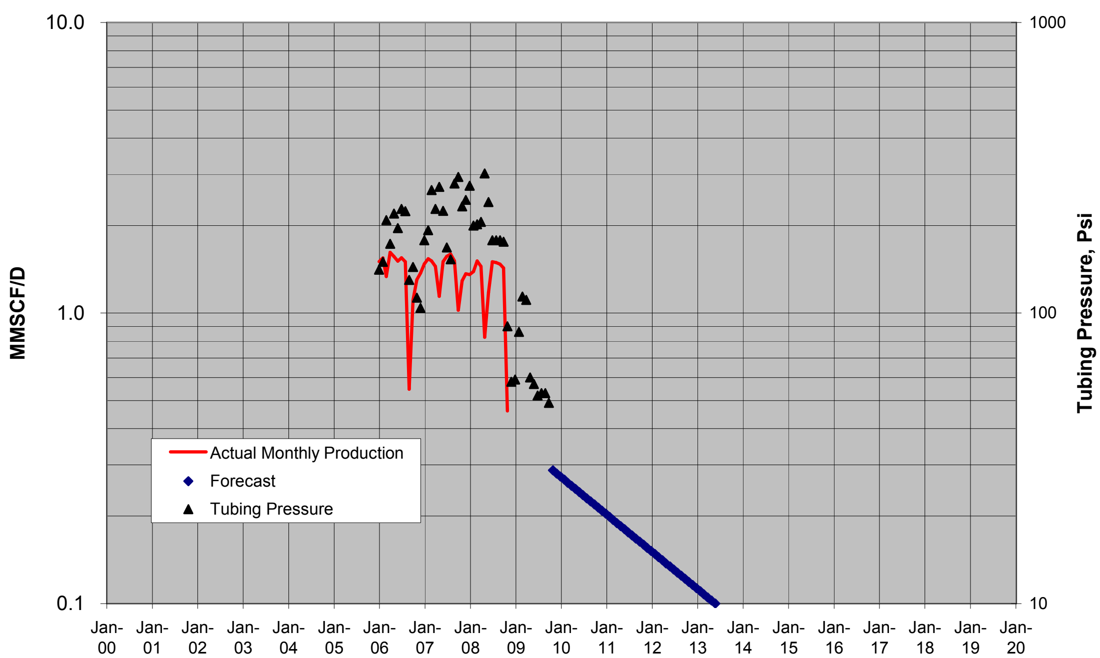
KENAI BELUGA UNIT 11-7



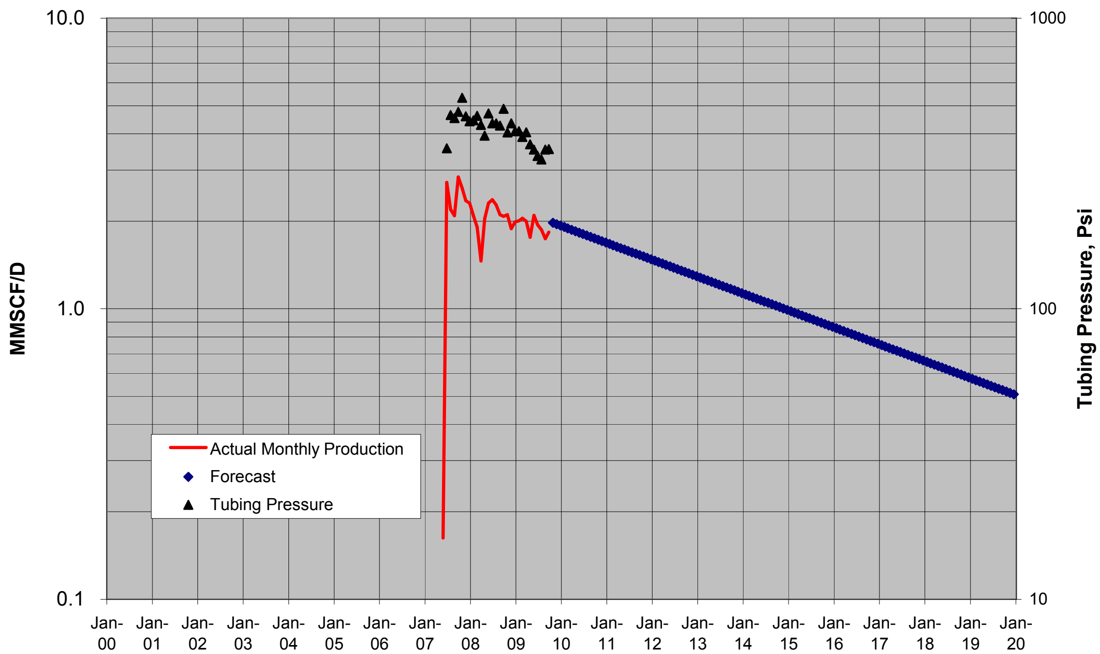
KENAI BELUGA UNIT 11-8X



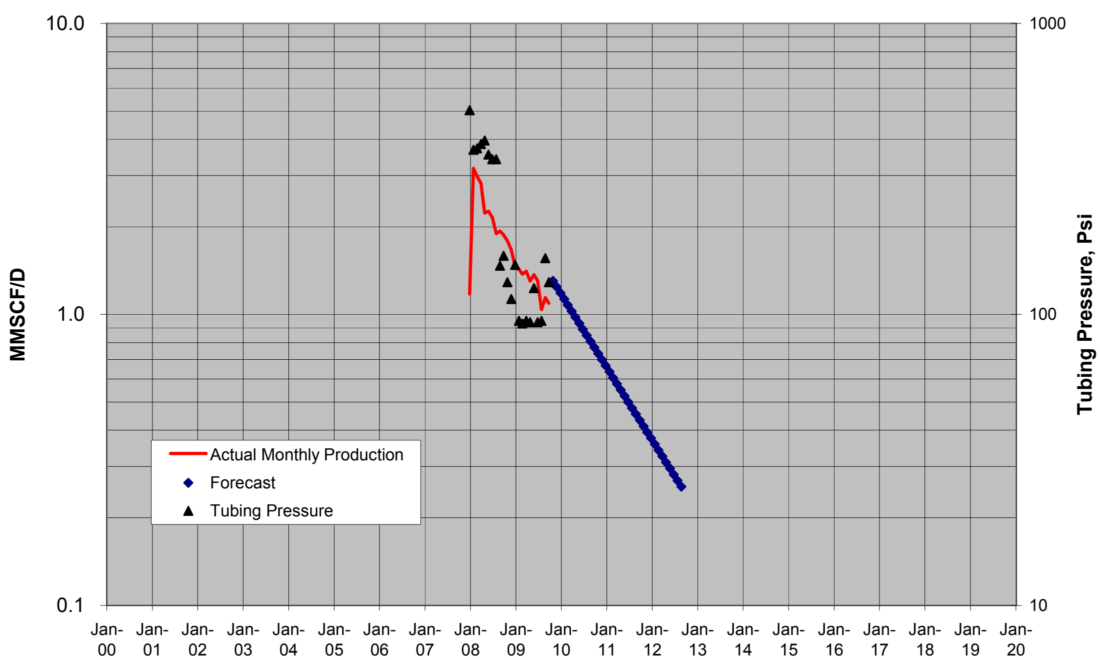
KENAI BELUGA UNIT 11-8Y



KENAI BELUGA UNIT 12-5



KENAI BELUGA UNIT 14-6Y



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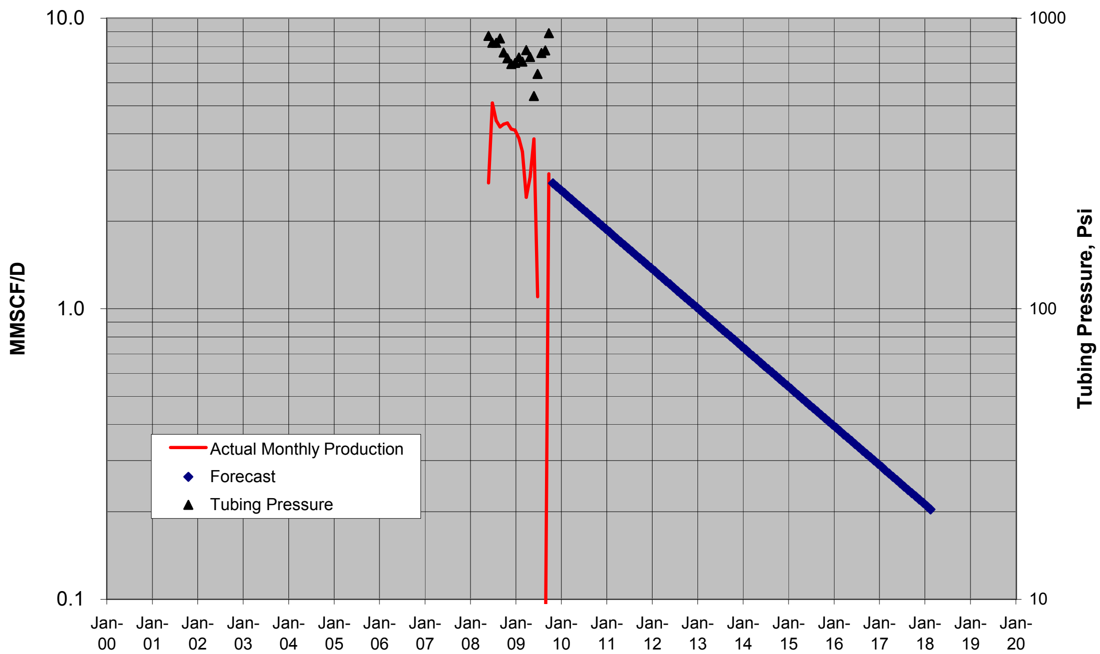

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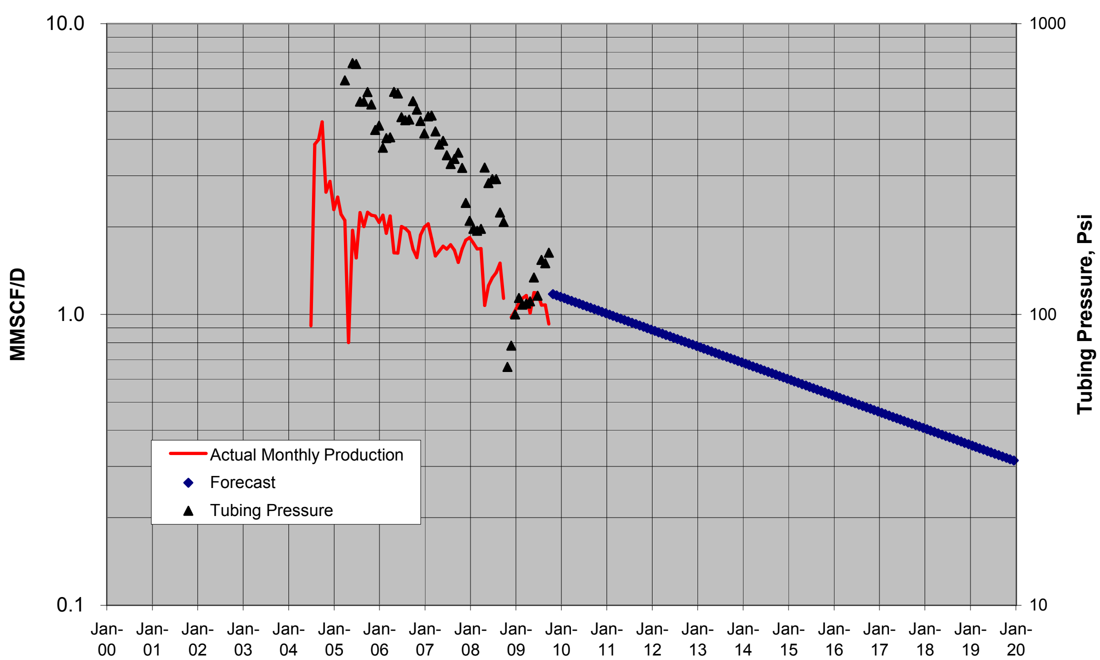

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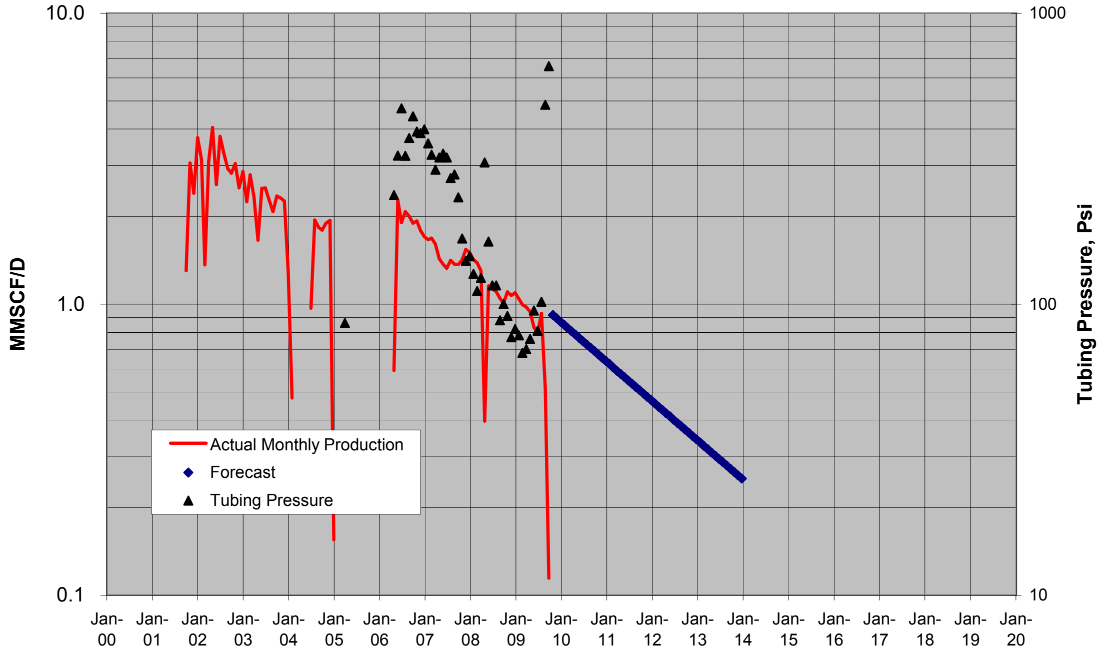
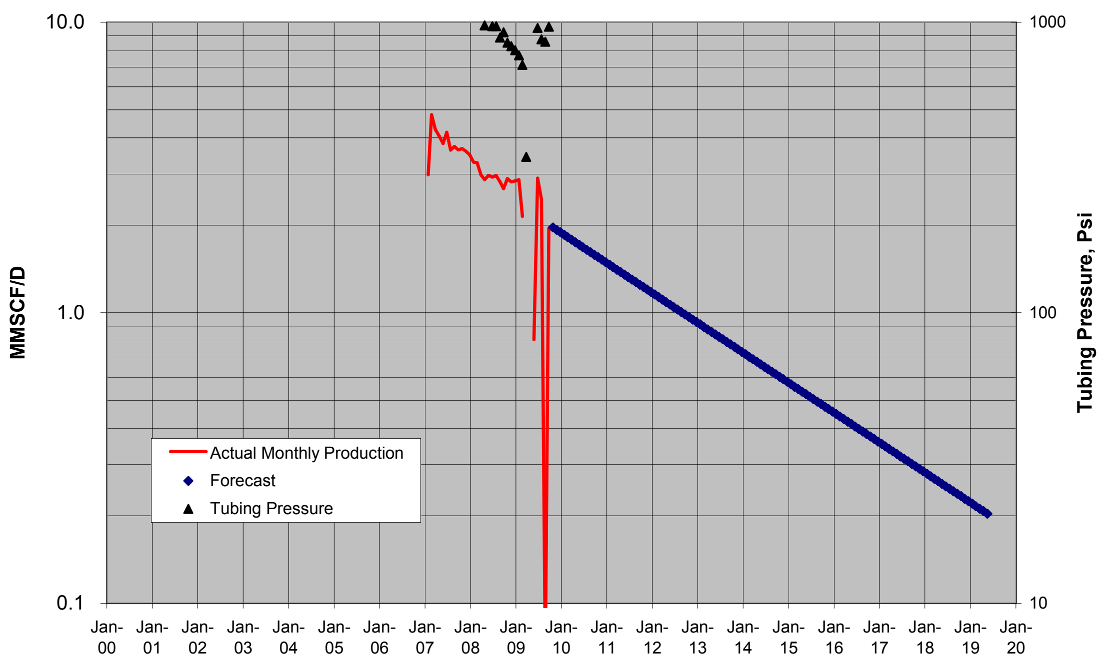
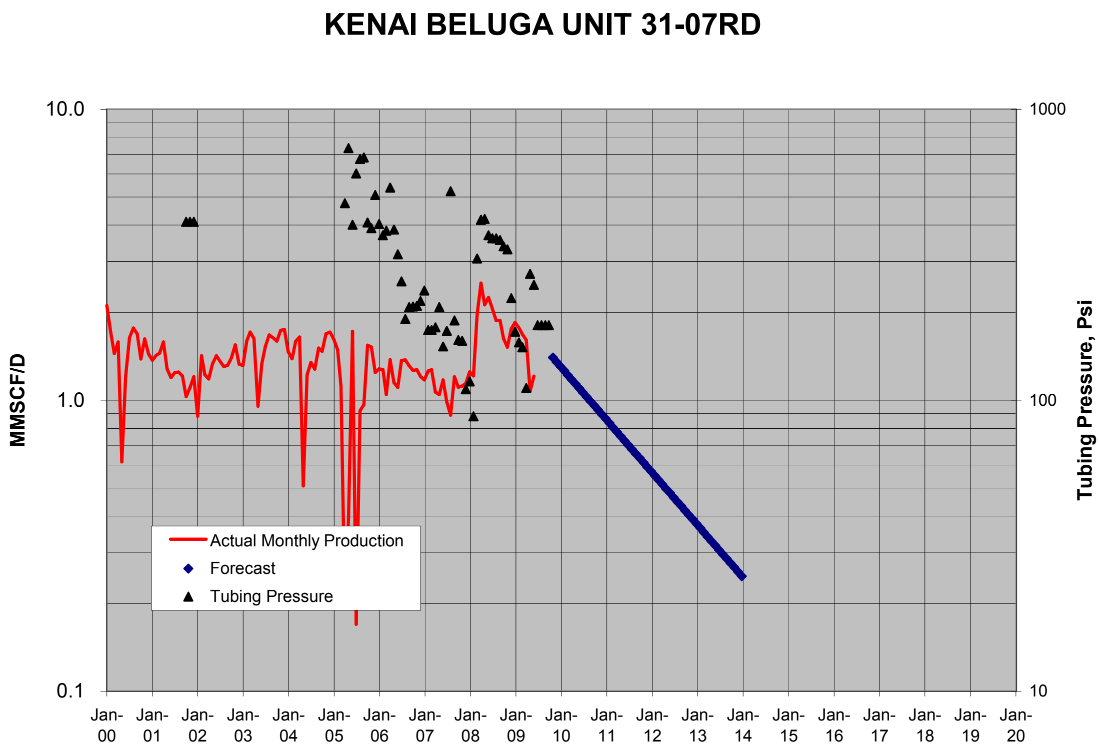
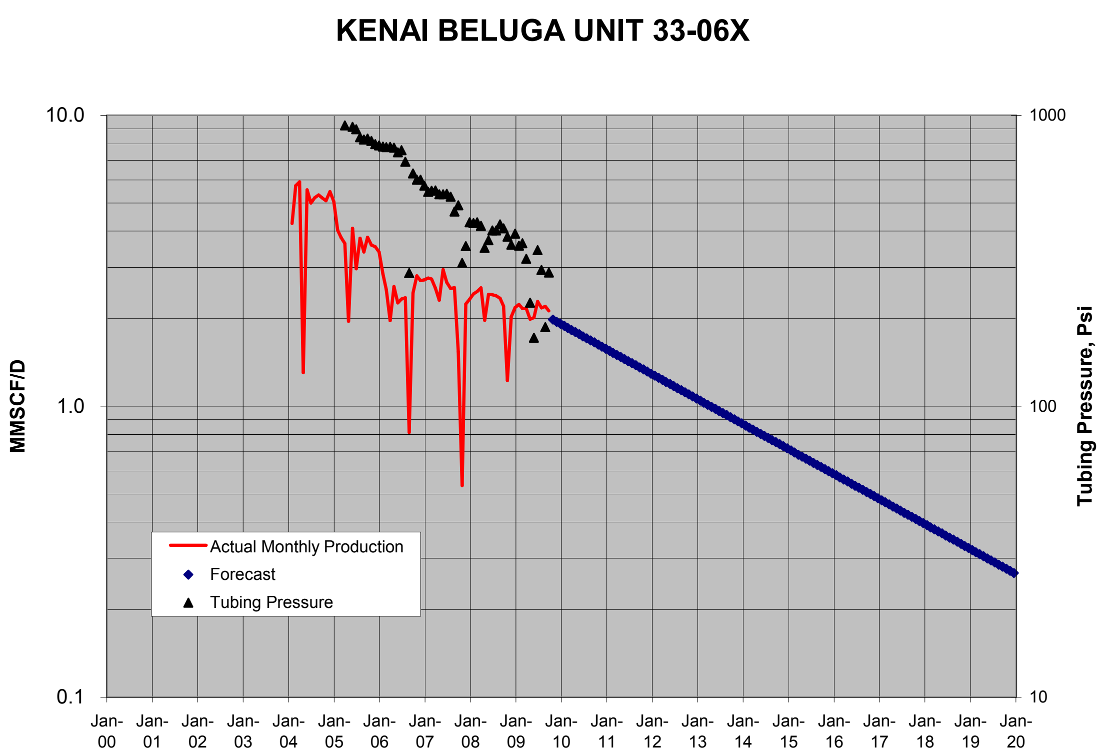


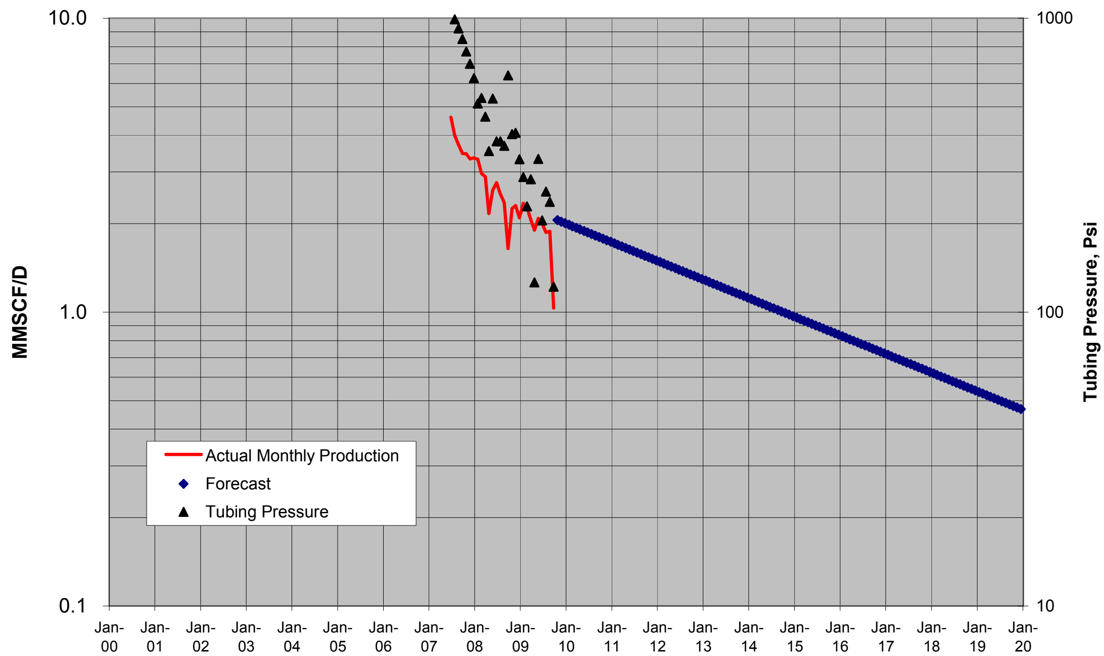
KENAI BELUGA UNIT 24-7X



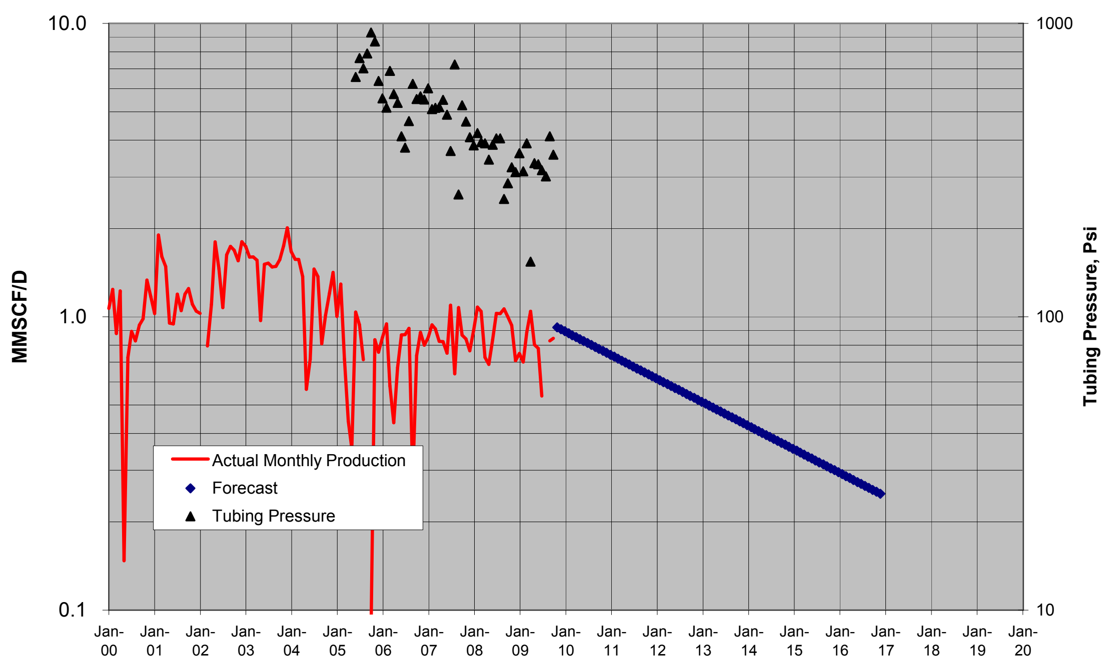

KENAI BELUGA UNIT 31-07RD
MMSCF/D
Tubing Pressure, Psi
10.0
1.0
0.1
1000
100
10
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20
Actual Monthly Production
Forecast
Tubing Pressure


KENAI BELUGA UNIT 33-06X
MMSCF/D
Tubing Pressure, Psi
10.0
1.0
0.1
1000
100
10
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20
Actual Monthly Production
Forecast
Tubing Pressure

KENAI BELUGA UNIT 34-6



KENAI BELUGA UNIT 41-07



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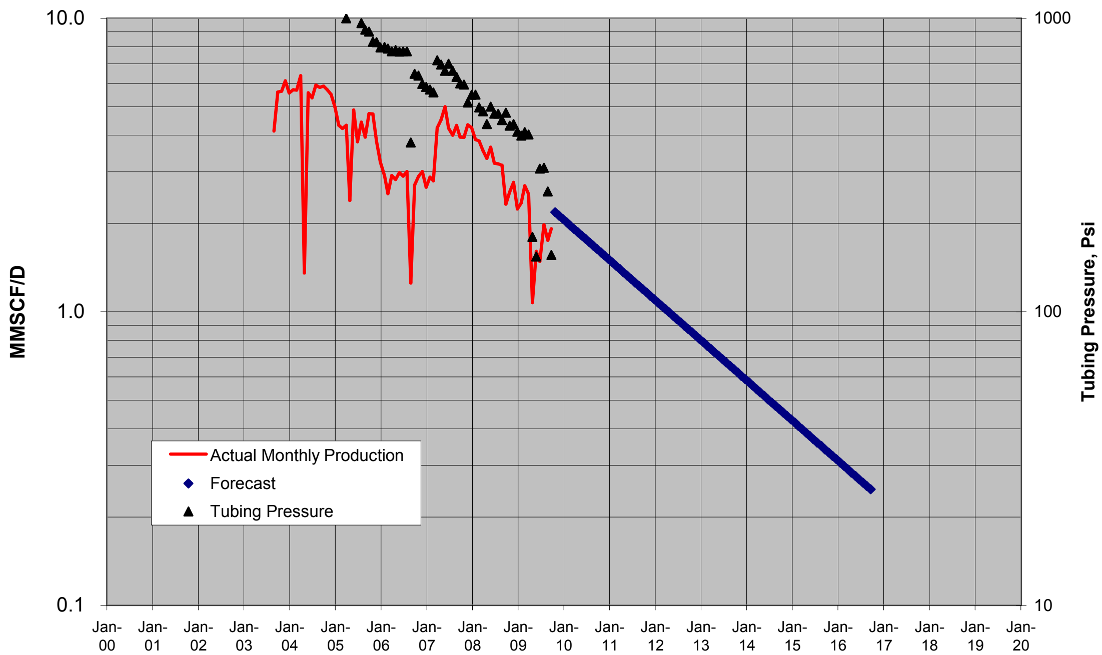
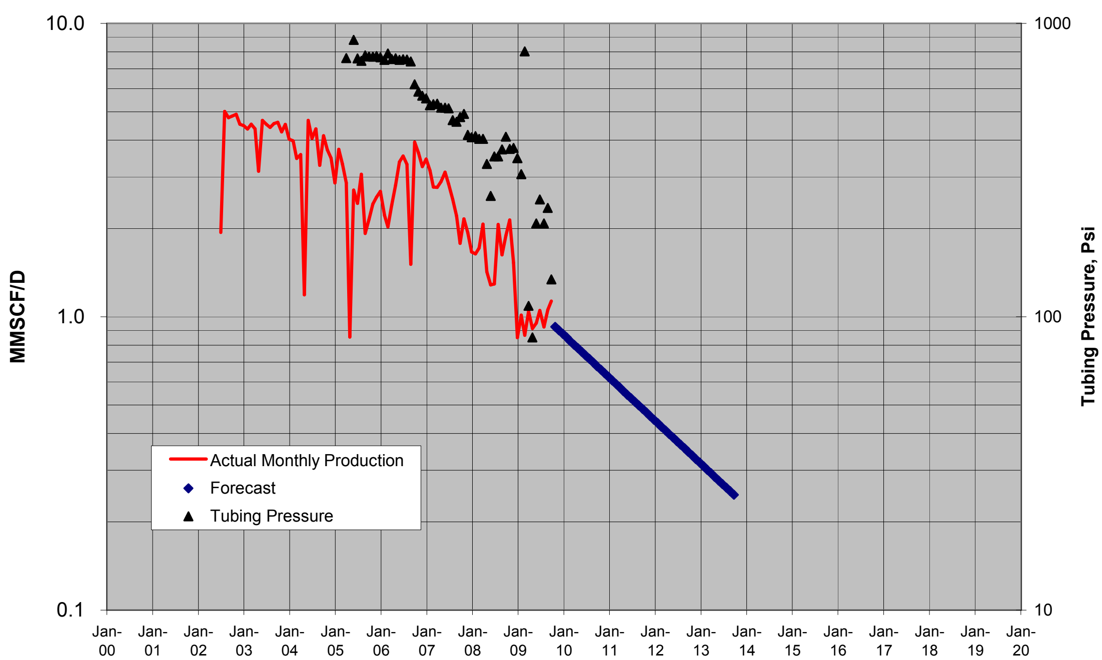
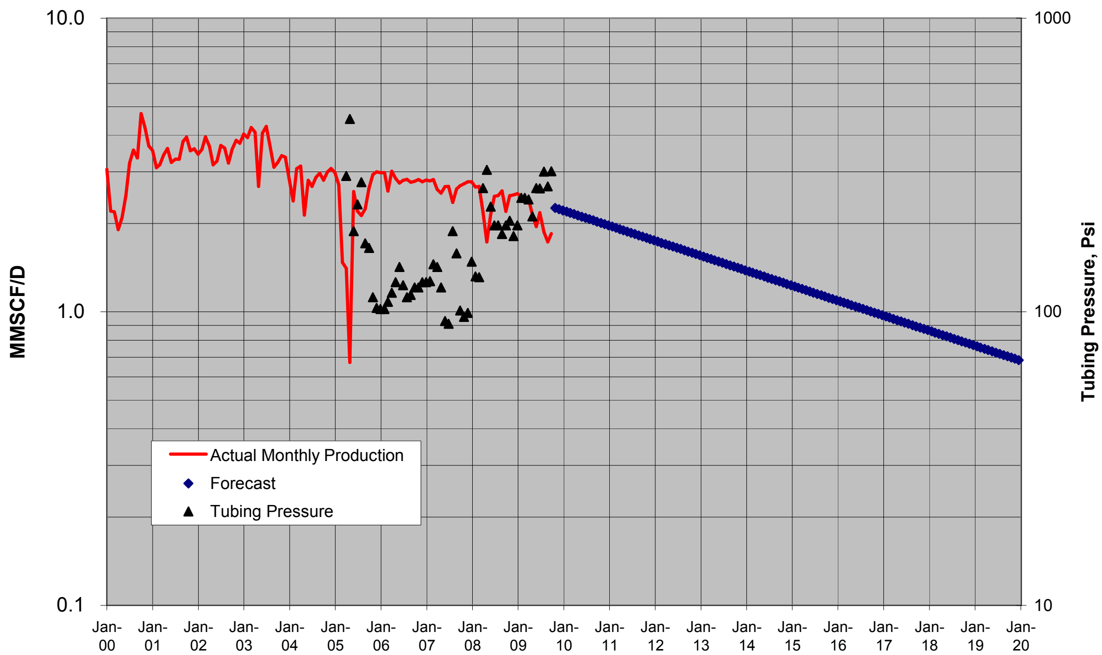


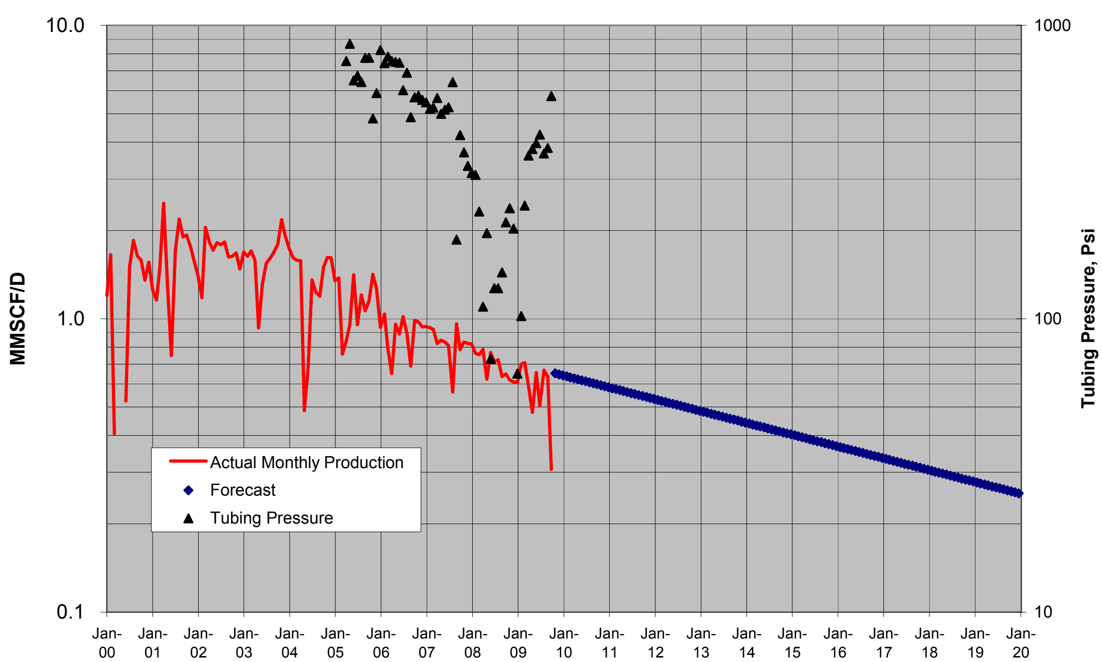
KENAI BELUGA UNIT 44-06



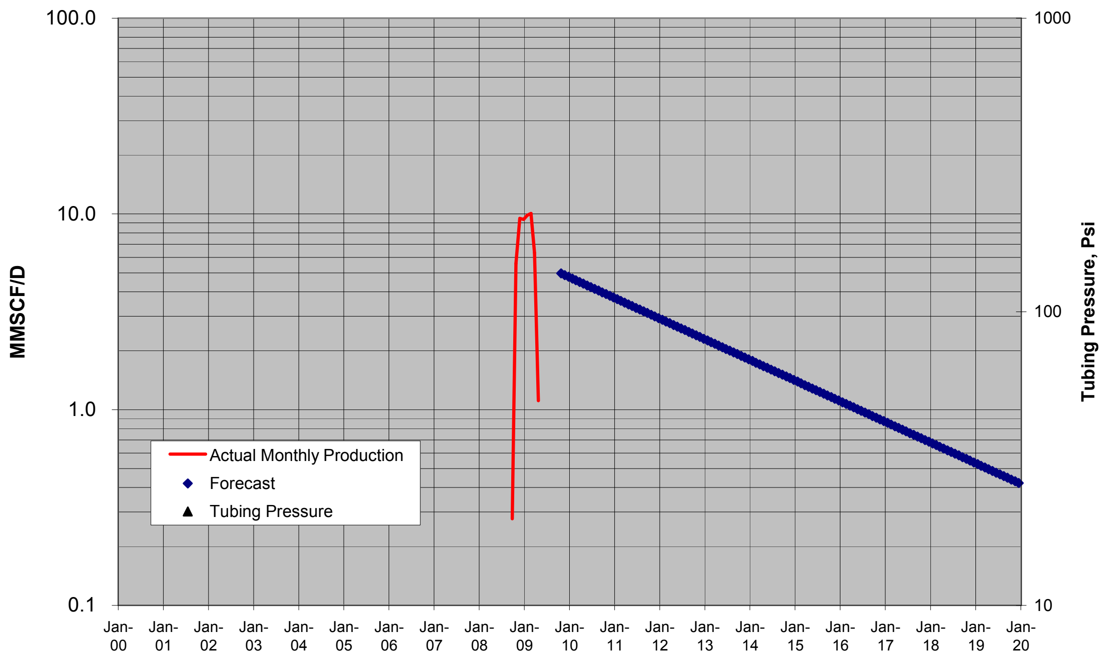
KENAI DEEP UNIT 1



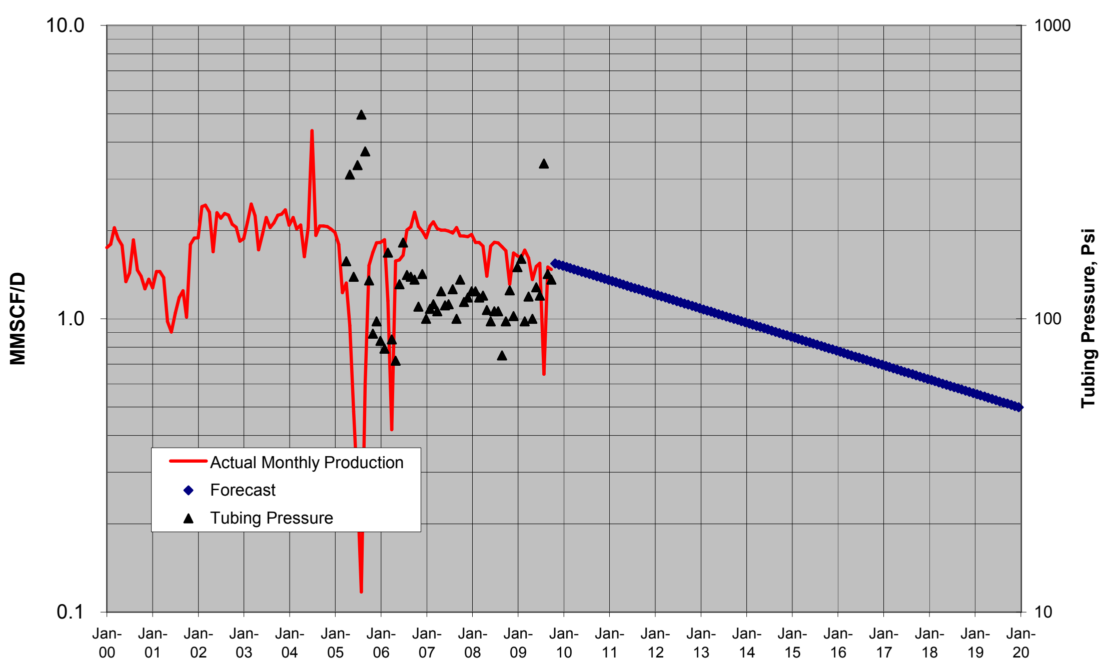
KENAI DEEP UNIT 2(21-8)



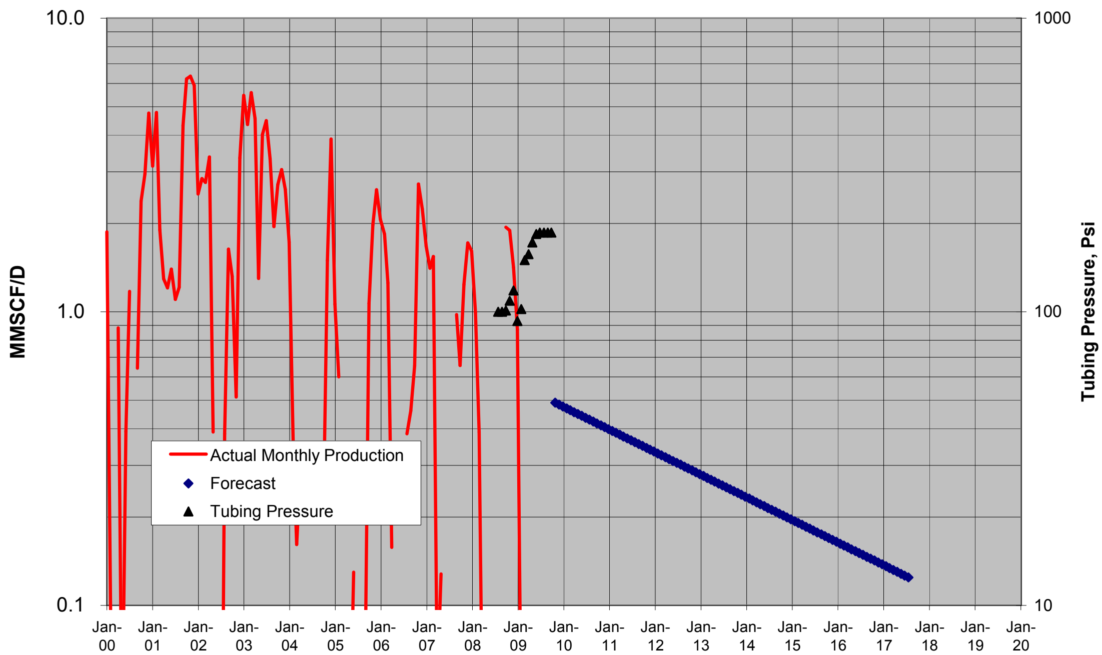
KENAI DEEP UNIT 9



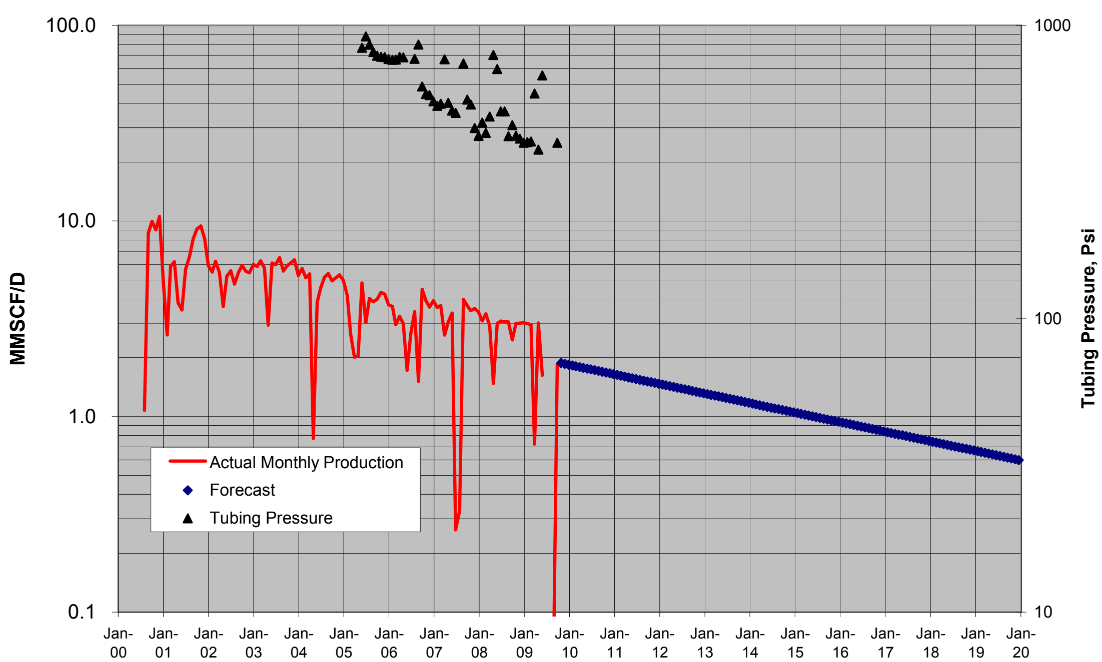
KENAI TYONEK UNIT 13-05



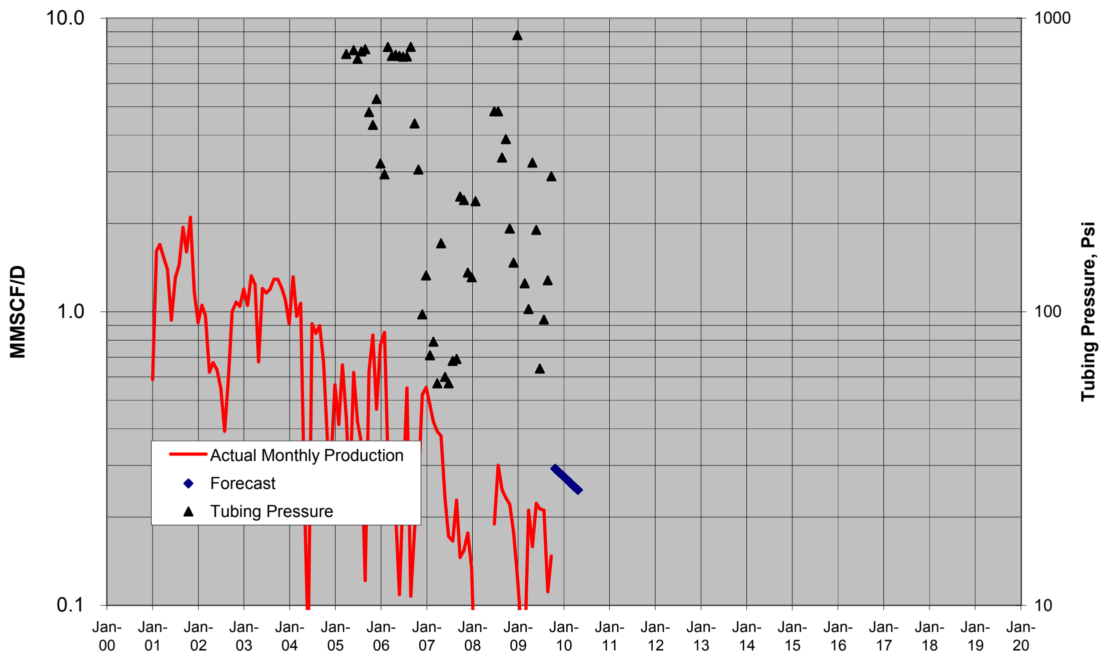
KENAI TYONEK UNIT 13-06



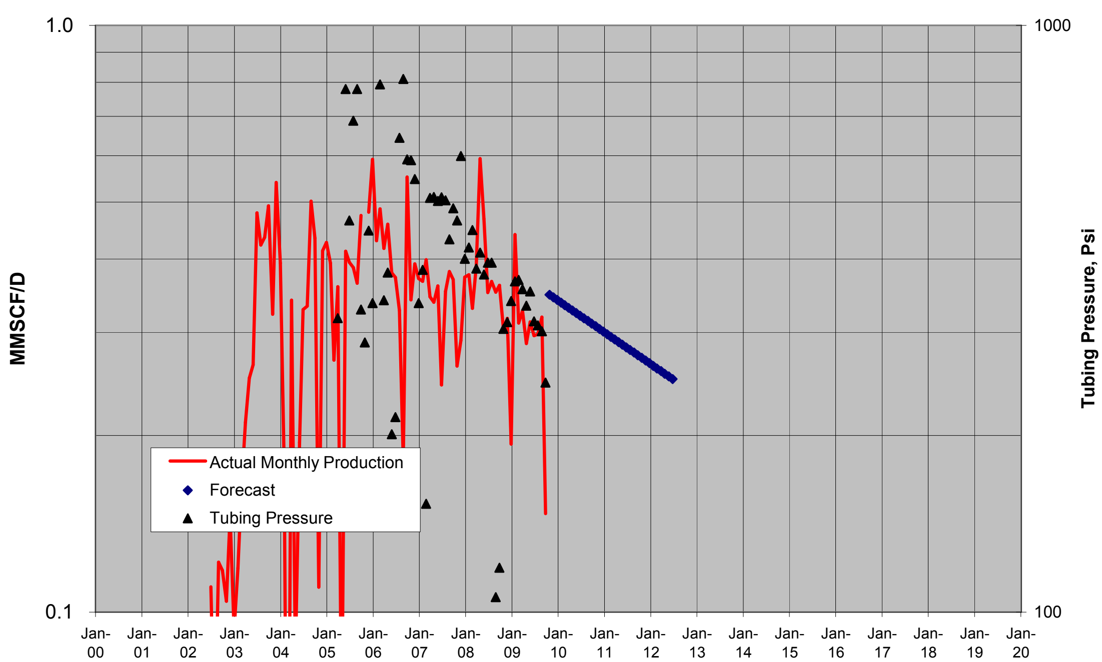
KENAI TYONEK UNIT 24-06H



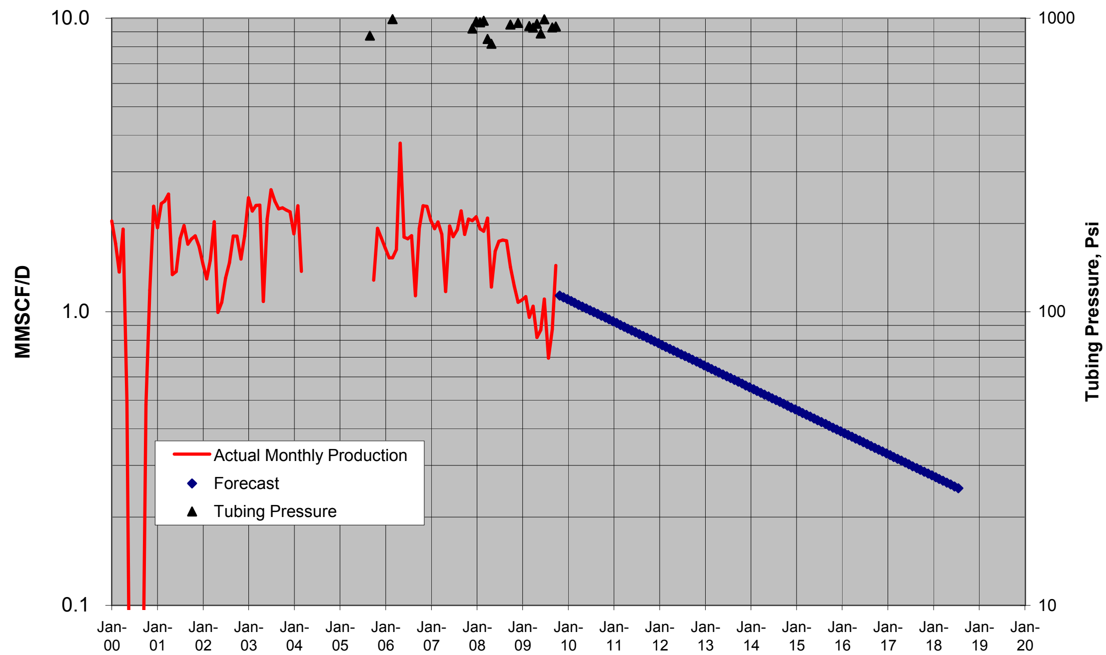
KENAI TYONEK UNIT 32-07



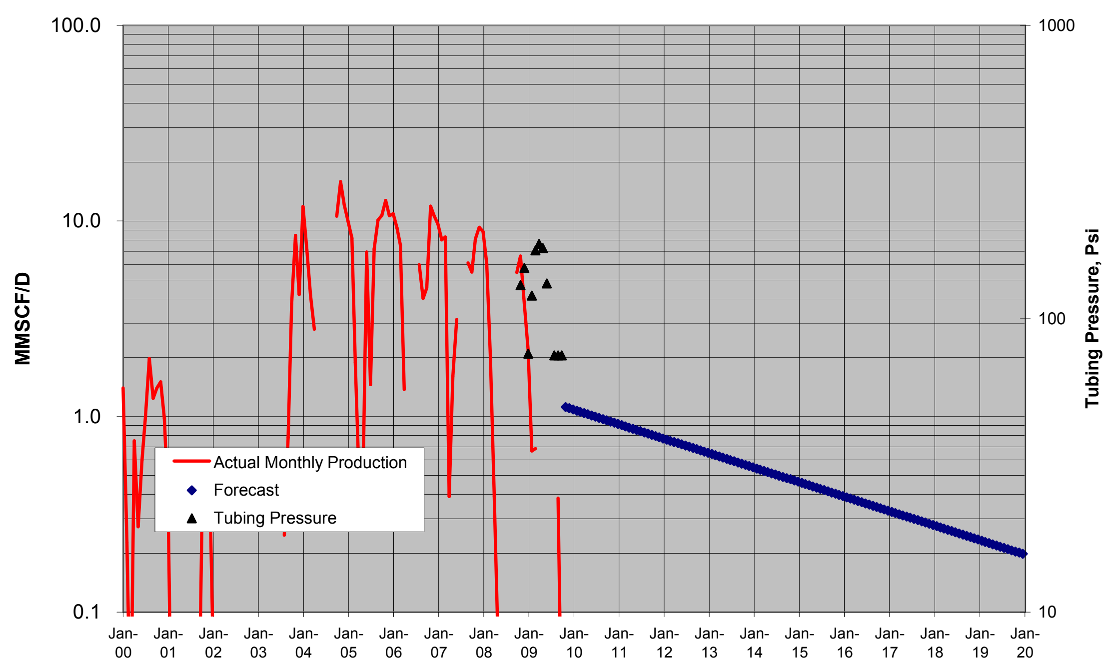
KENAI TYONEK UNIT 32-07H



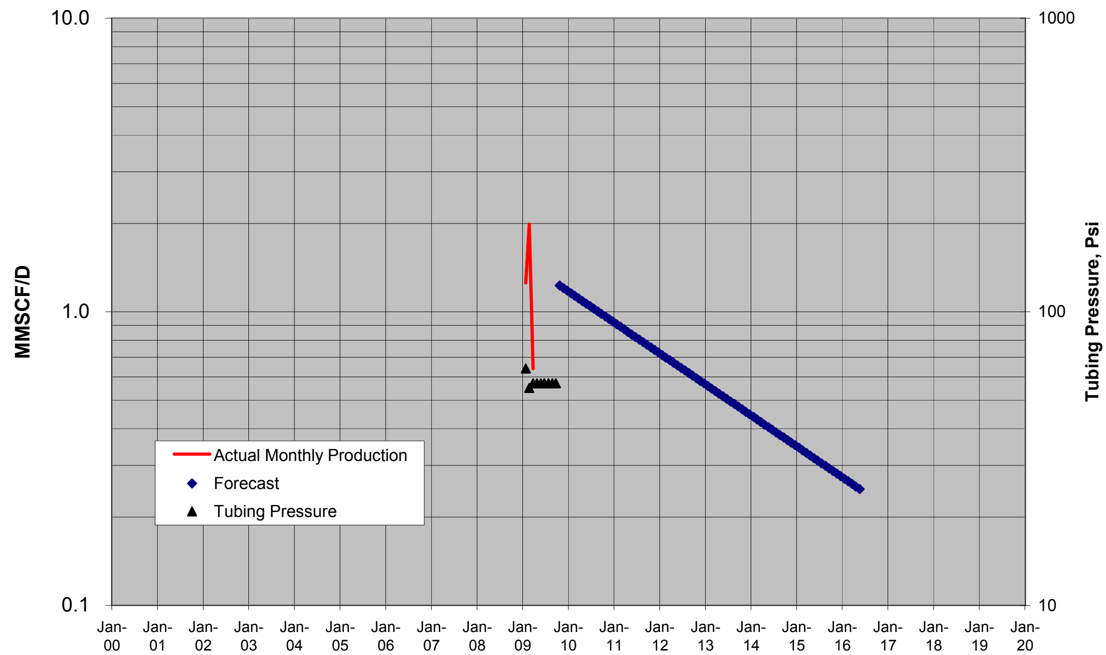
KENAI TYONEK UNIT 43-6XRD2



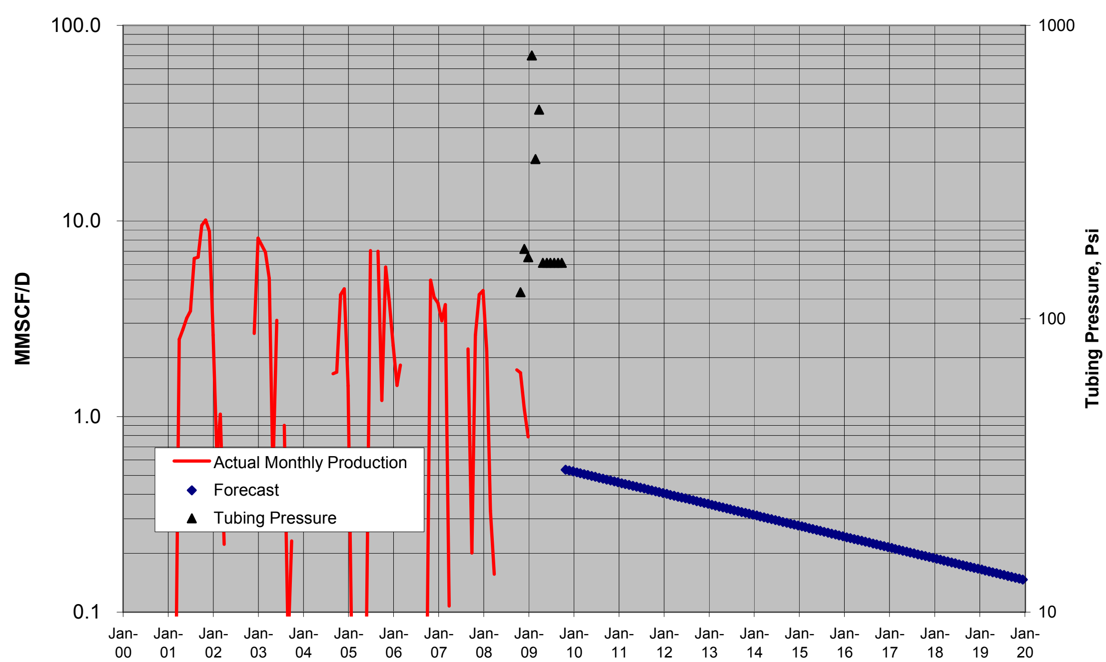
KENAI UNIT 14X-06



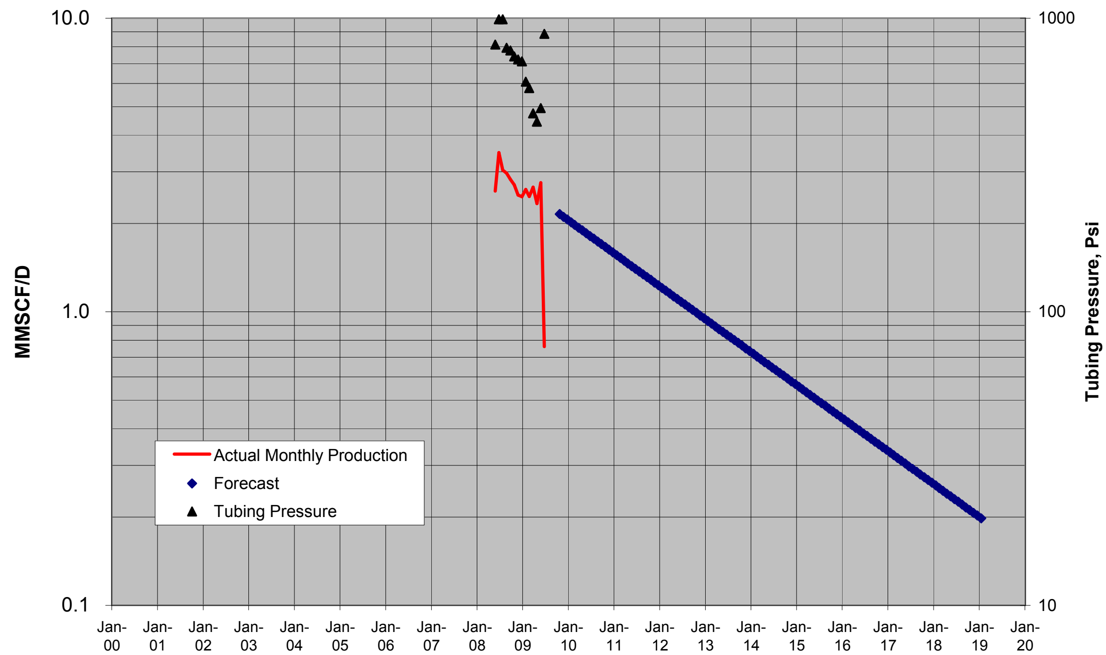
KENAI UNIT 22-6X



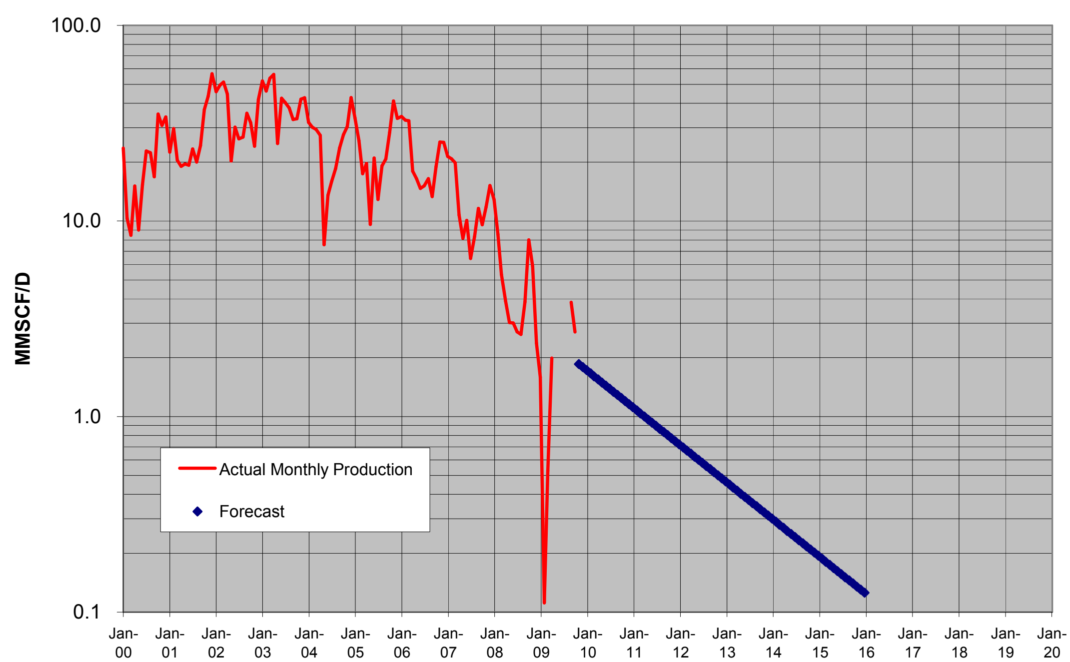
KENAI UNIT 31-07X



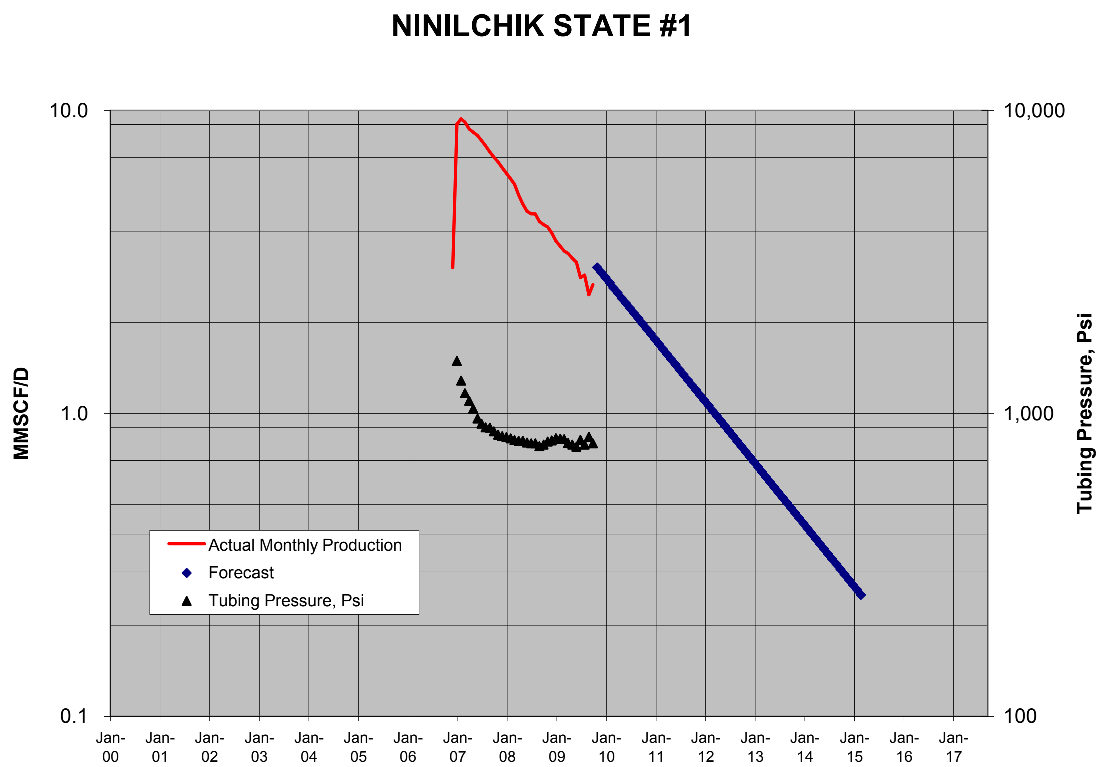
KENAI UNIT 41-18X

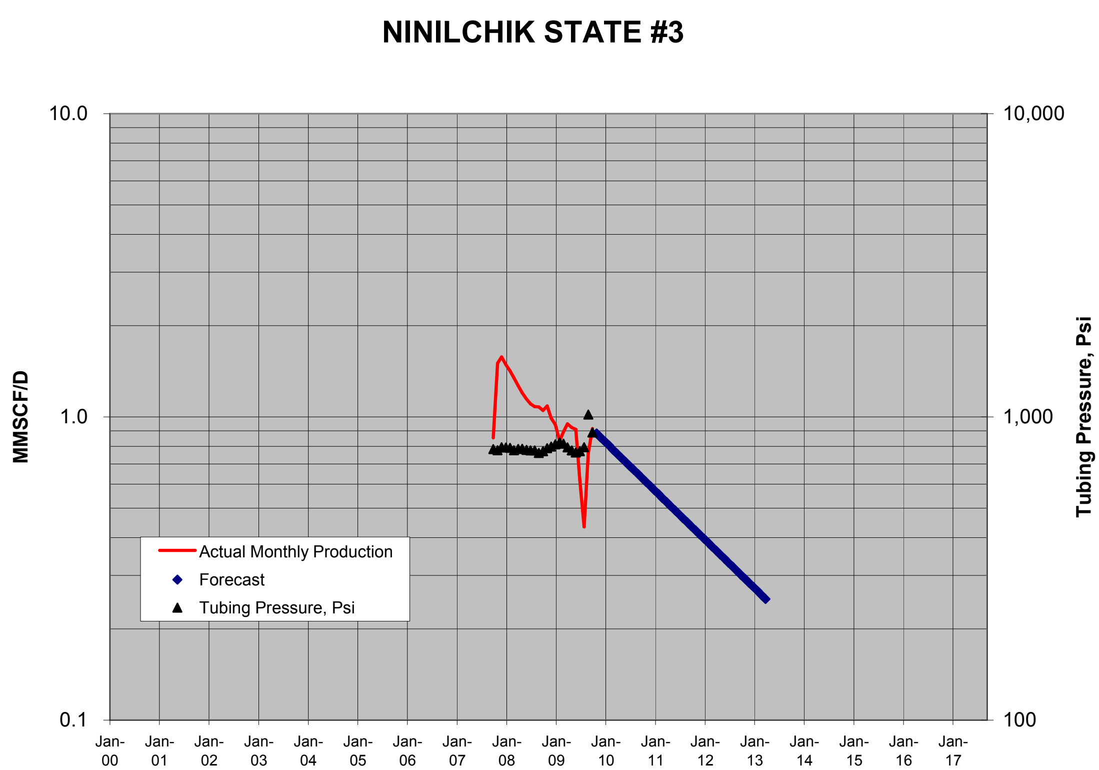


Other KU Wells

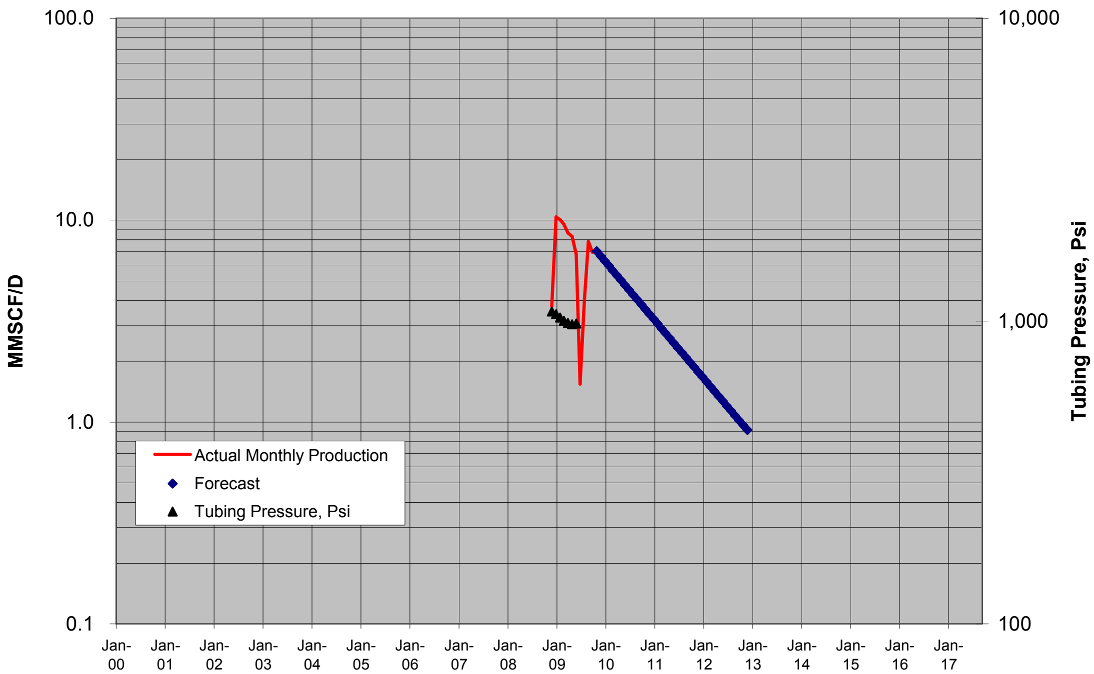


Appendix D-3: Ninilchik Unit Well Decline Curves

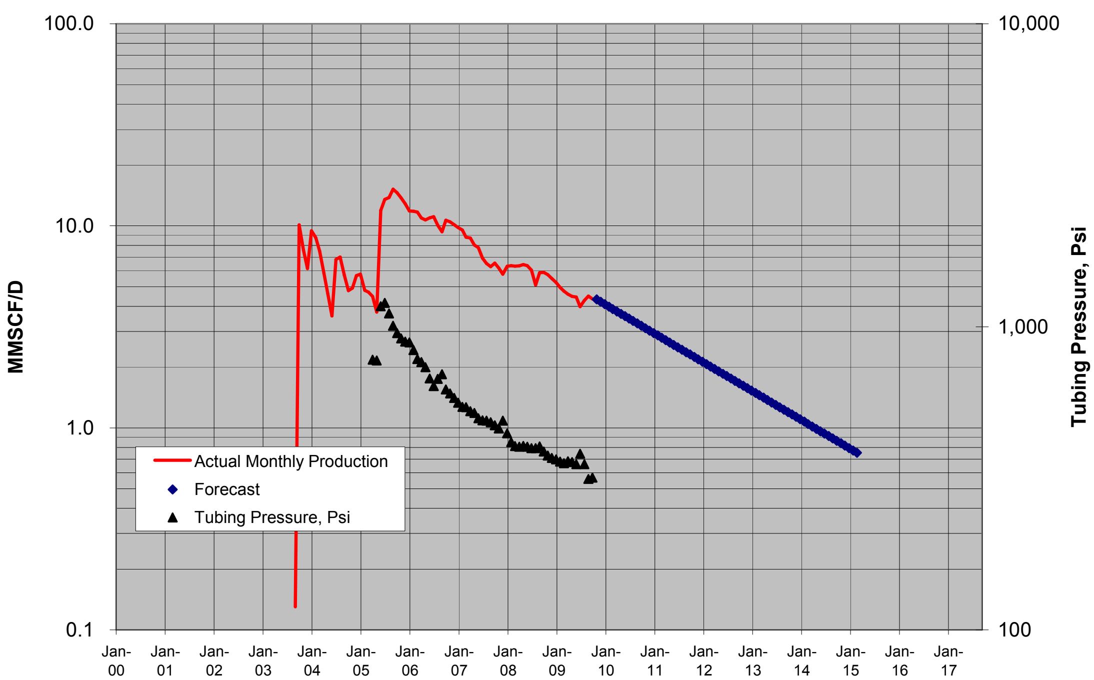




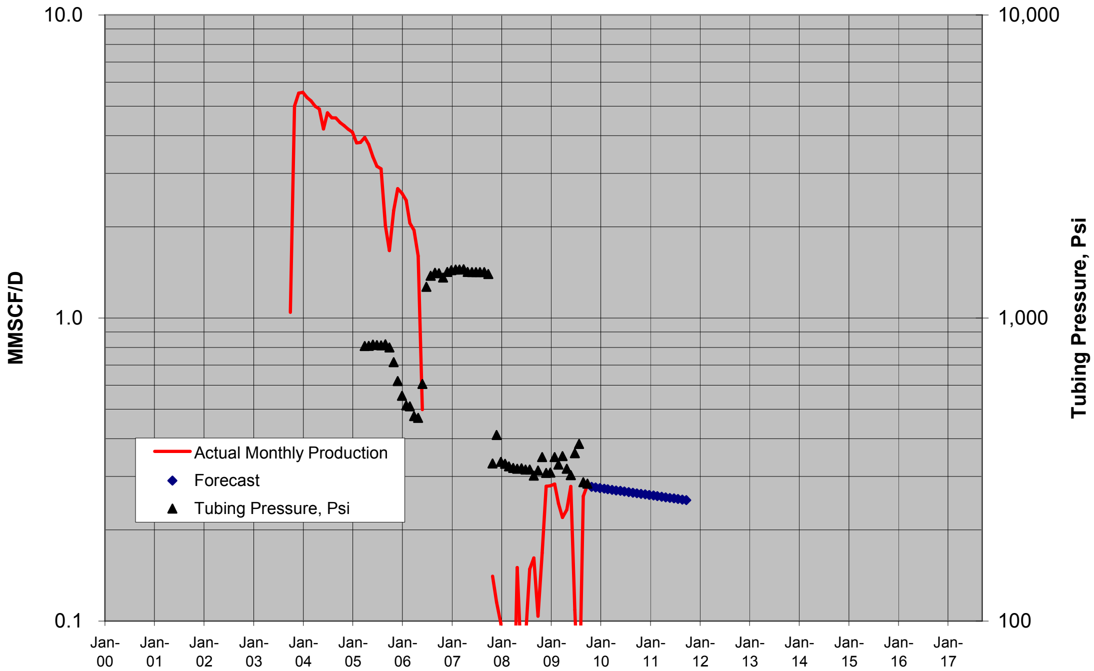
NINILCHIK UNIT #SD-6



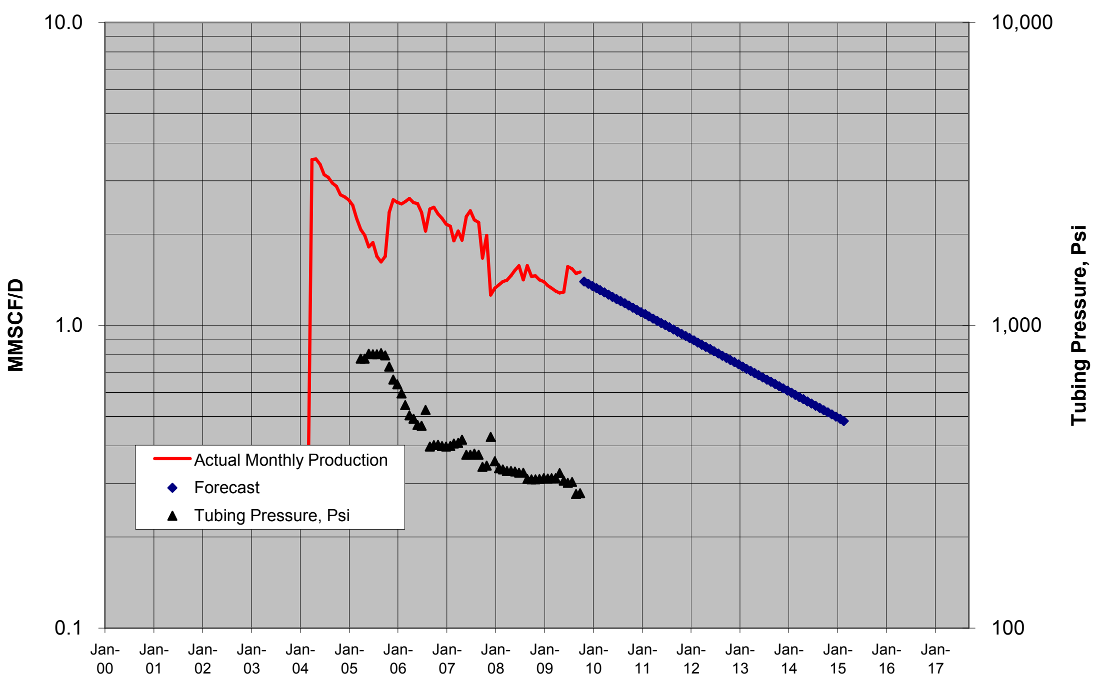
NINILCHIK UNIT FALLS CK #1RD



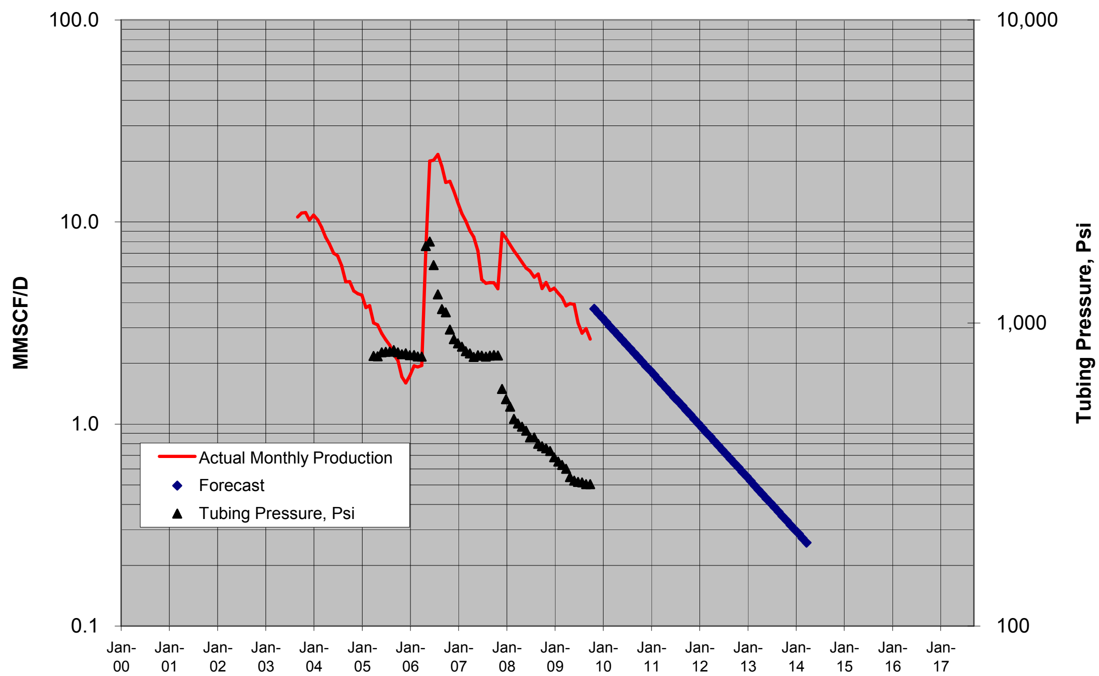
NINILCHIK UNIT FALLS CK #3



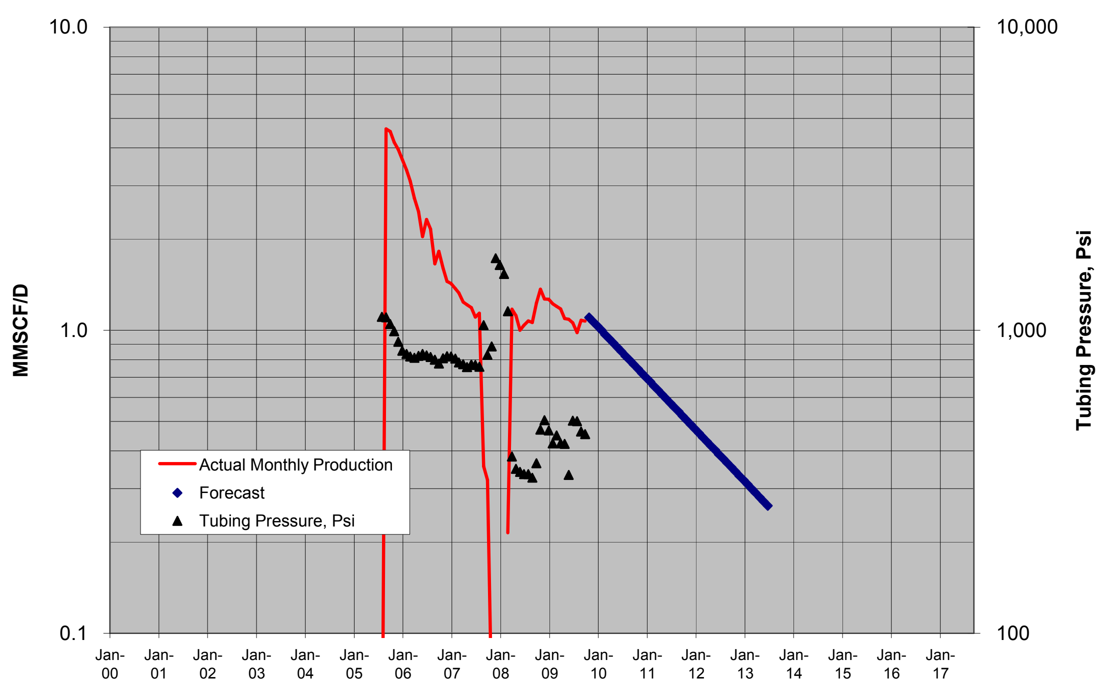
NINILCHIK UNIT FALLS CK #4



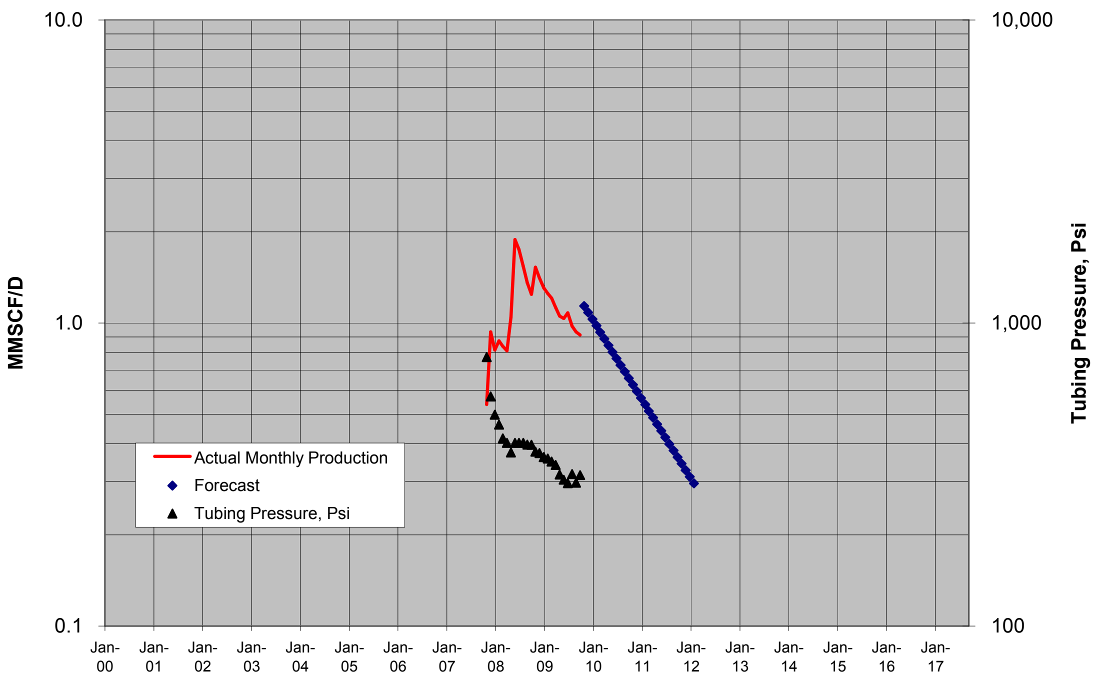
NINILCHIK UNIT G OSKOLKOFF #1



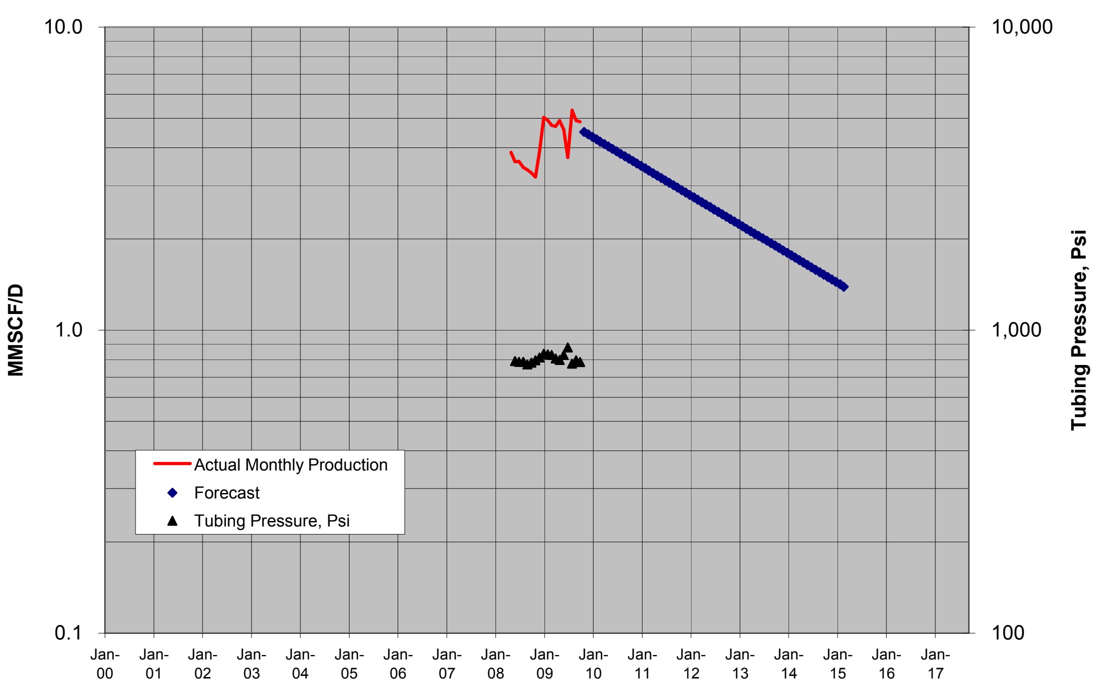
NINILCHIK UNIT G OSKOLKOFF #3



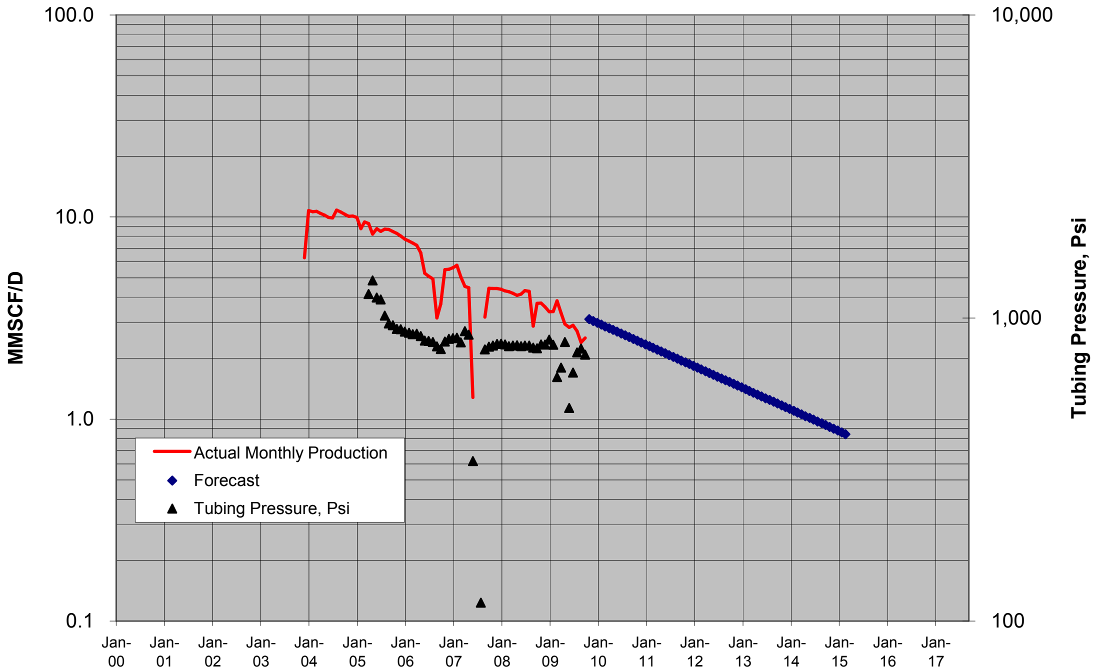
NINILCHIK UNIT G OSKOLKOFF #6



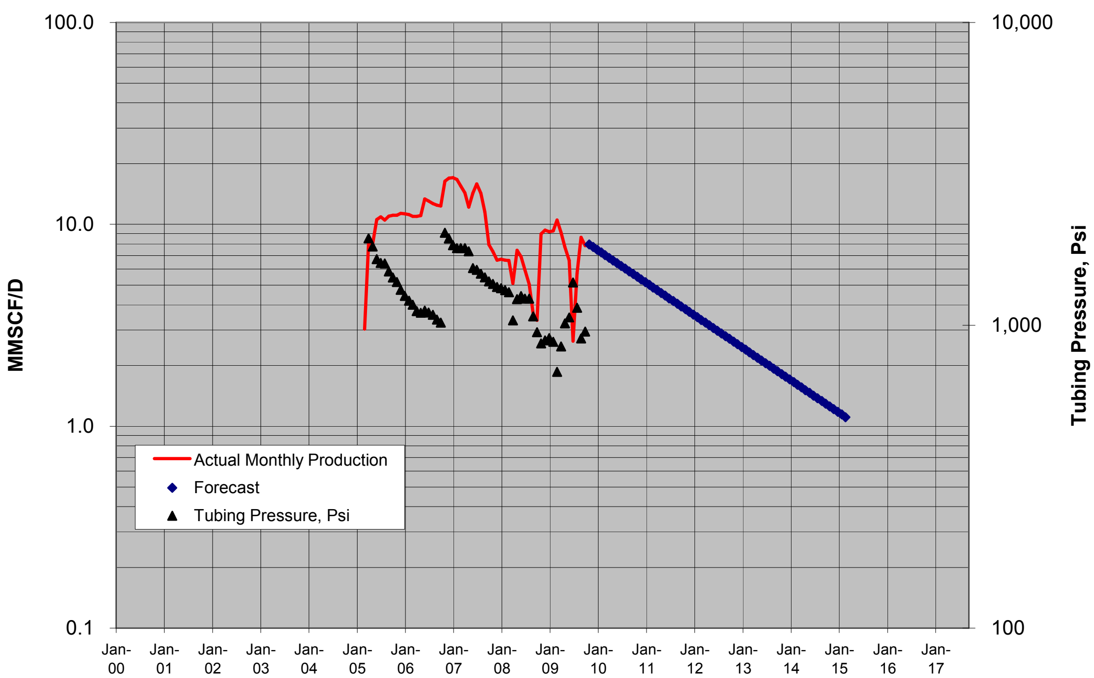
NINILCHIK UNIT PAXTON #2

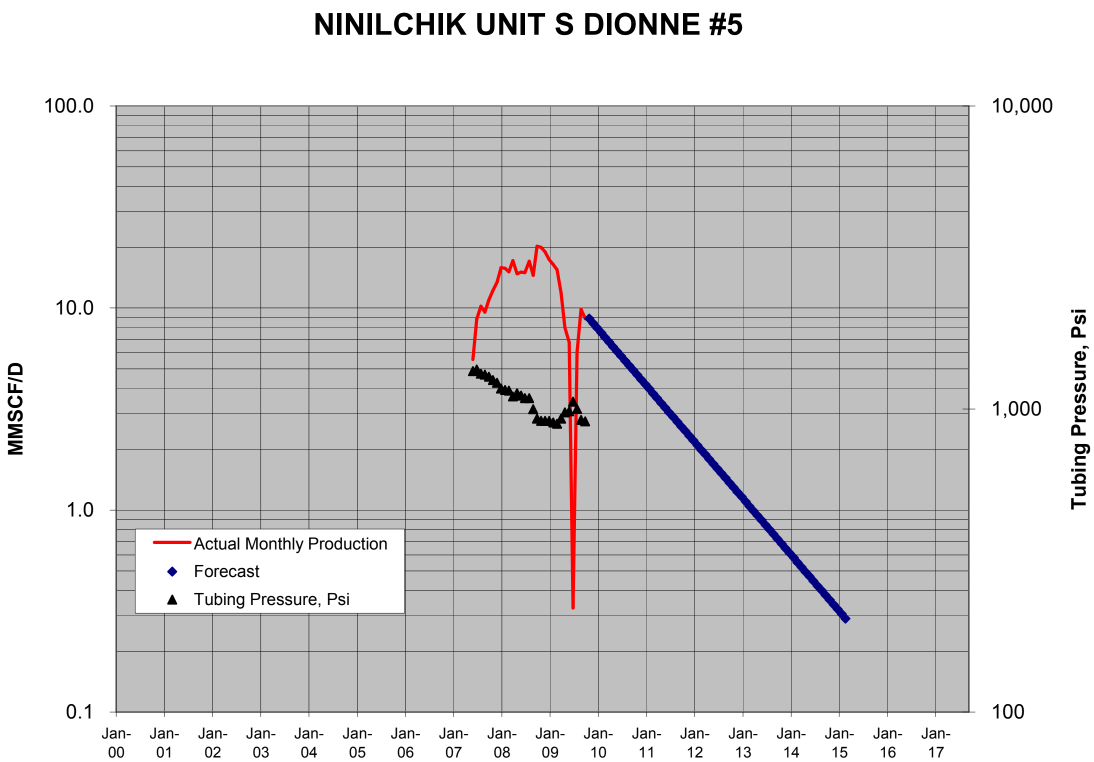


NINILCHIK UNIT S DIONNE #3

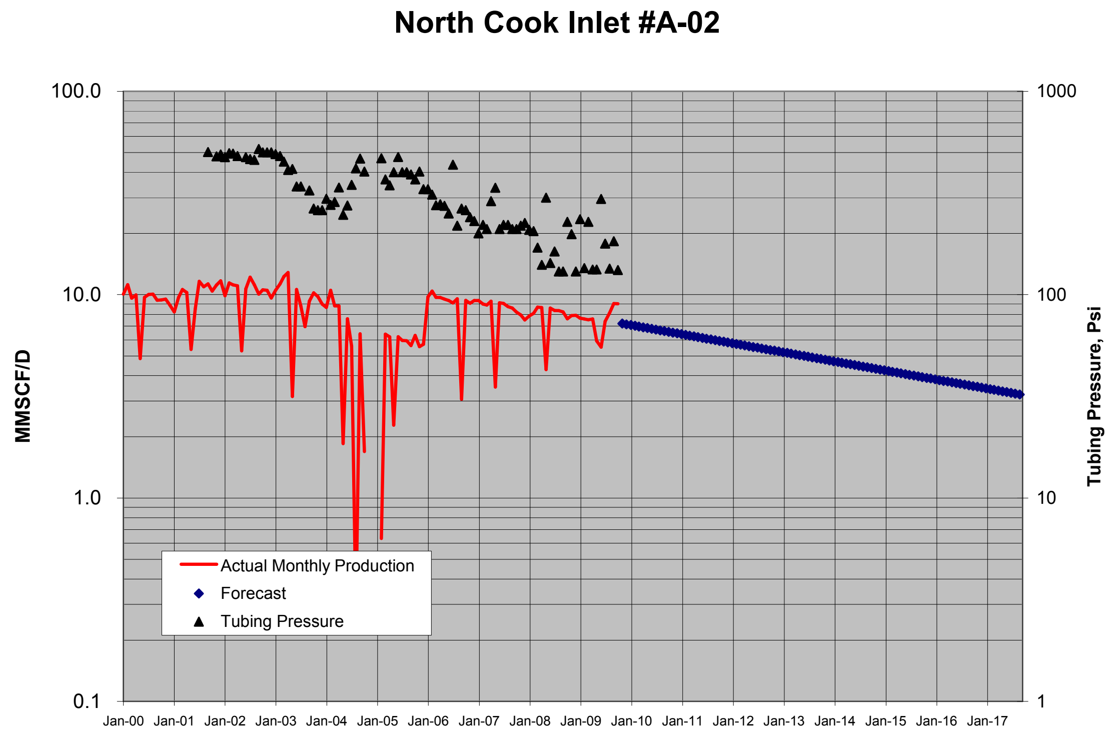


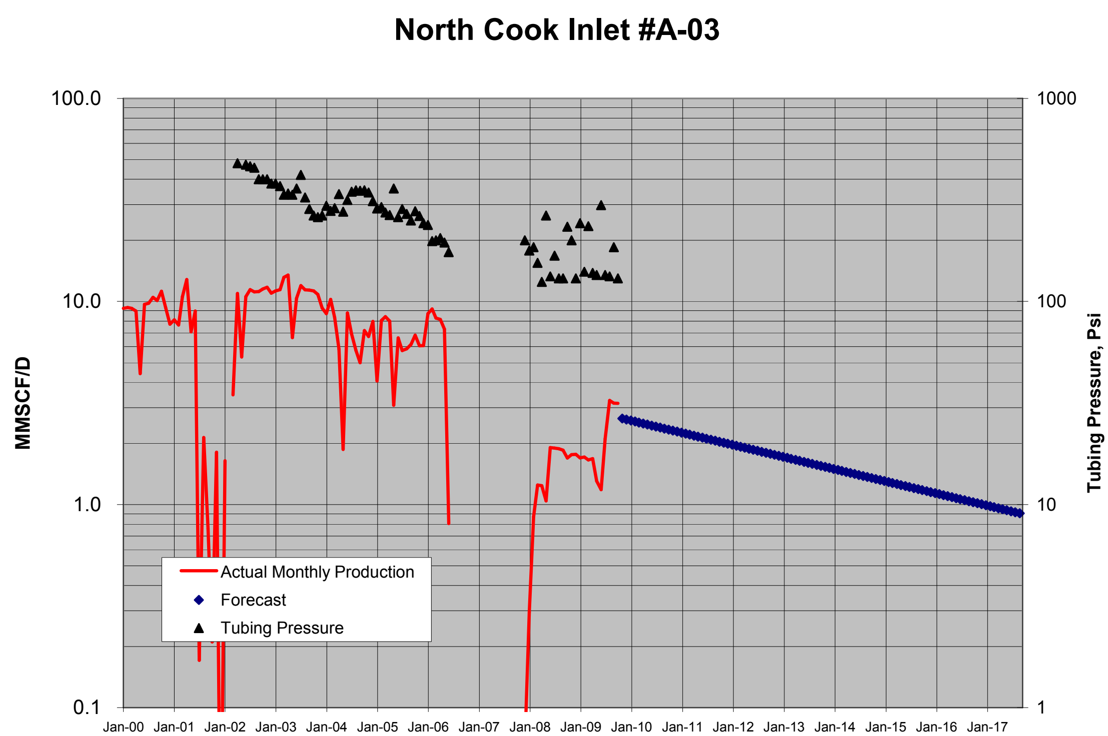
NINILCHIK UNIT S DIONNE #4



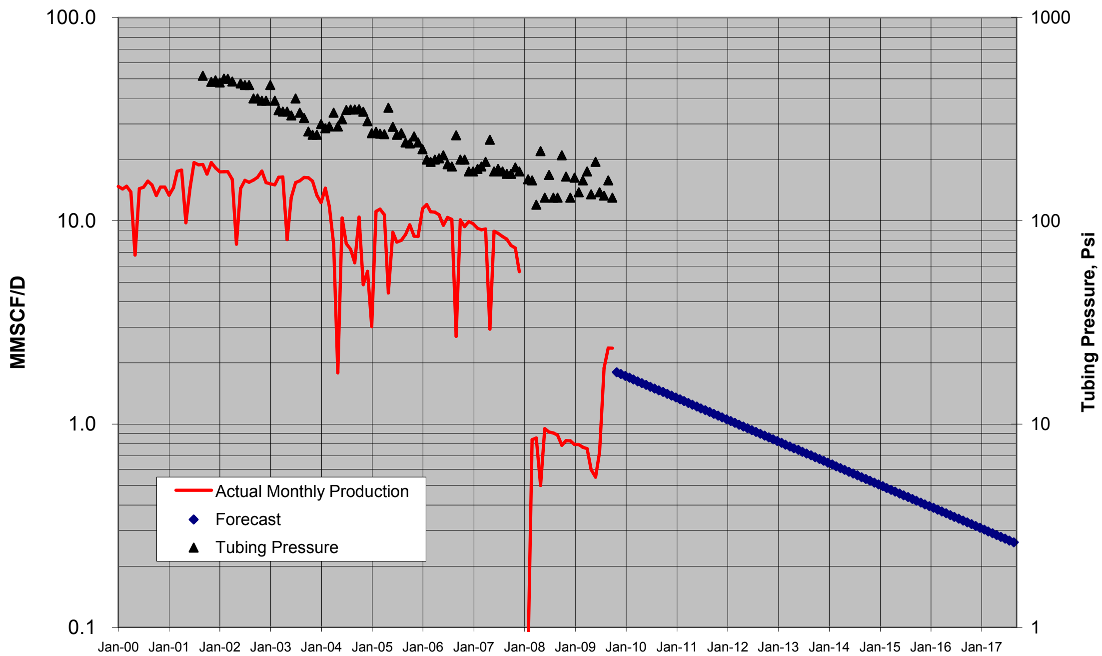

NINILCHIK UNIT S DIONNE #5
100.0
10.0
1.0
0.1
MMSCF/D
10,000
1,000
100
Tubing Pressure, Psi
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Actual Monthly Production
Forecast
Tubing Pressure, Psi

Appendix D-4: North Cook Inlet Well Decline Curves

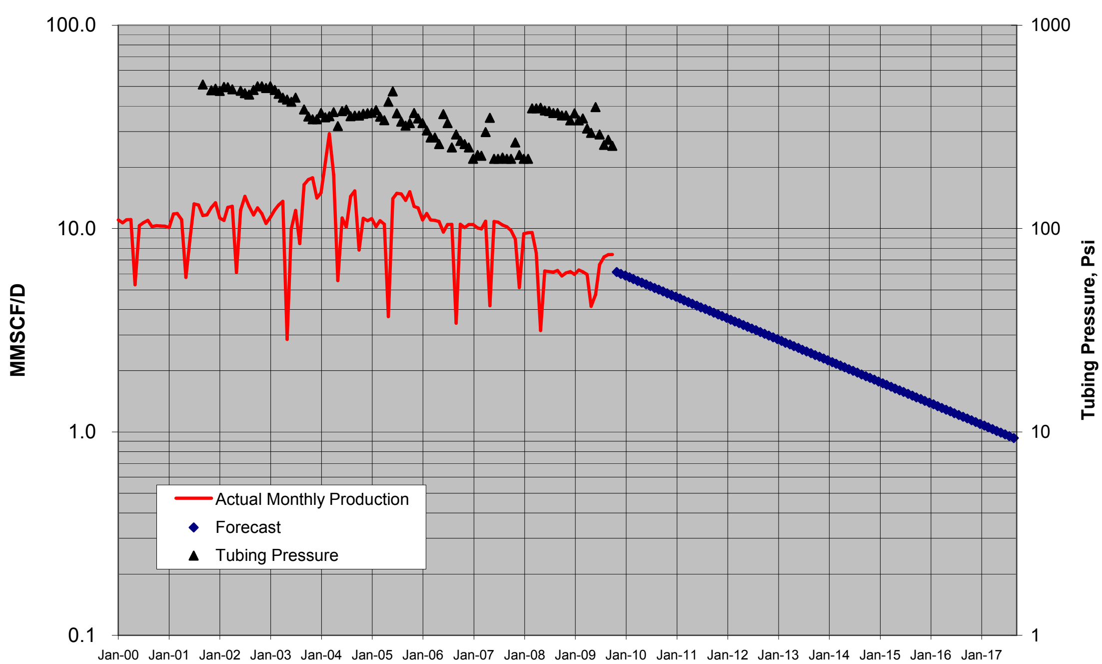




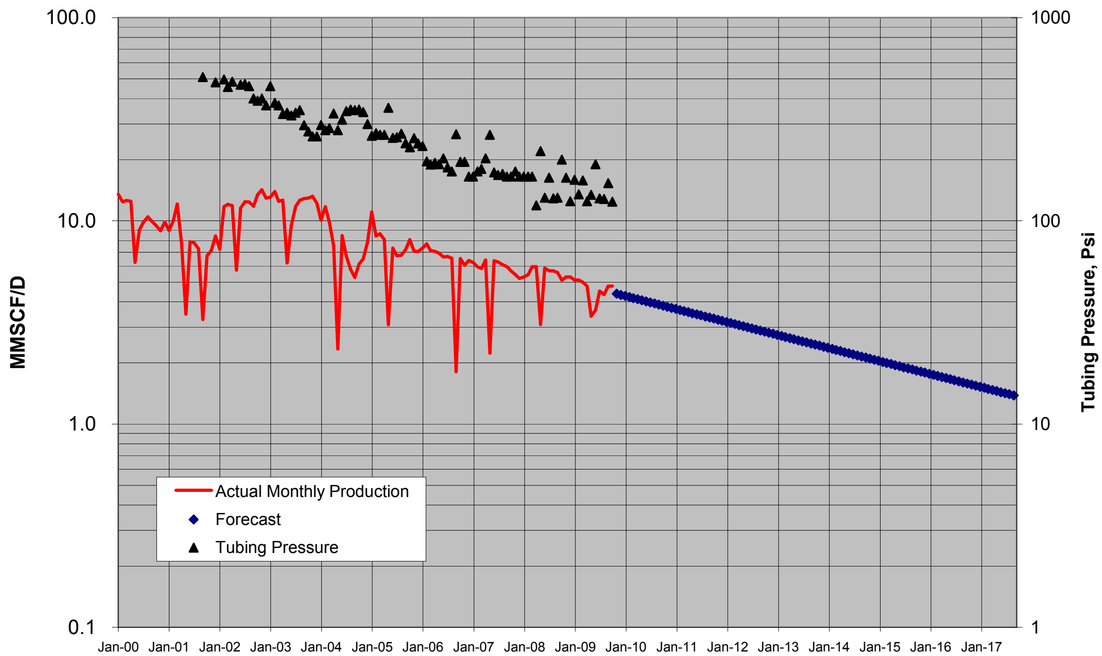
North Cook Inlet #A-04



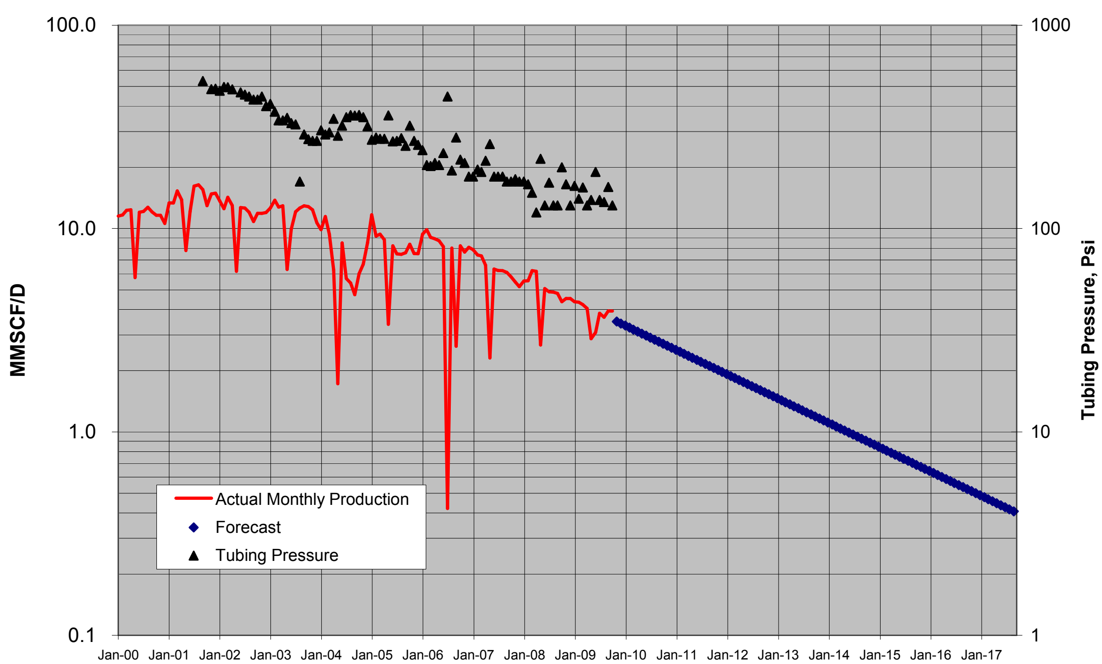
North Cook Inlet #A-05



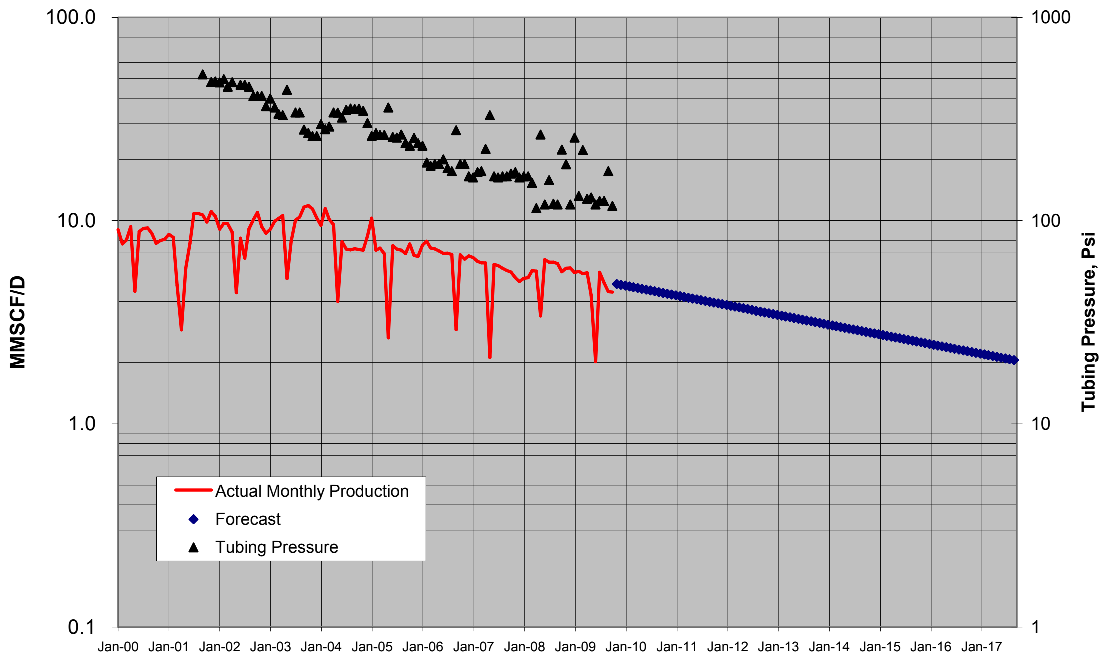
North Cook Inlet #A-06



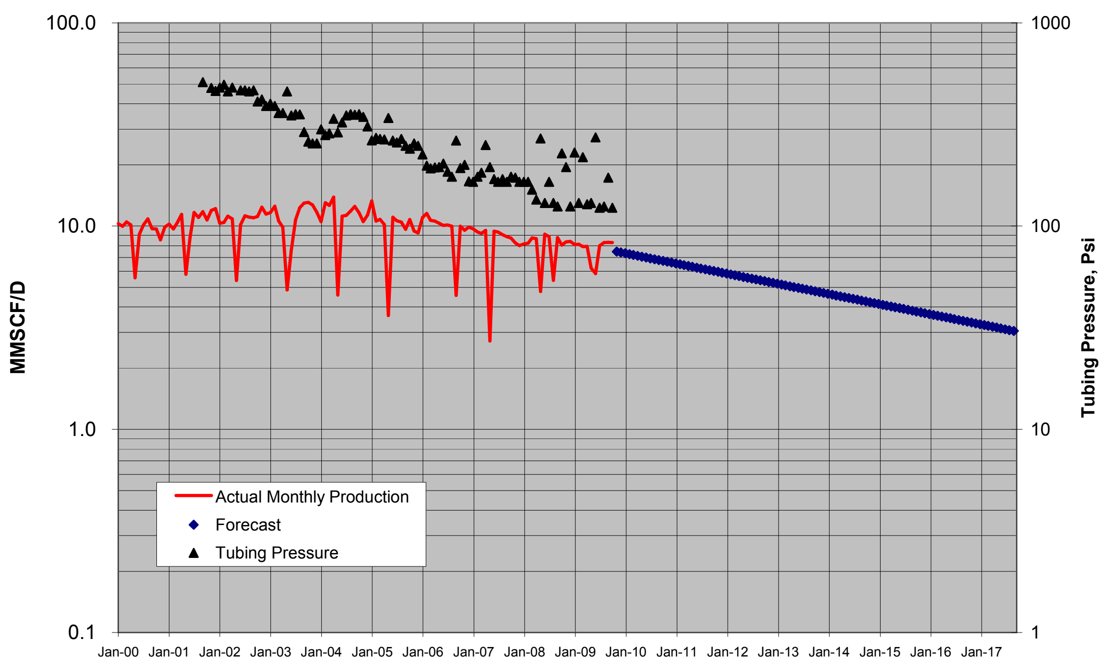
North Cook Inlet #A-07



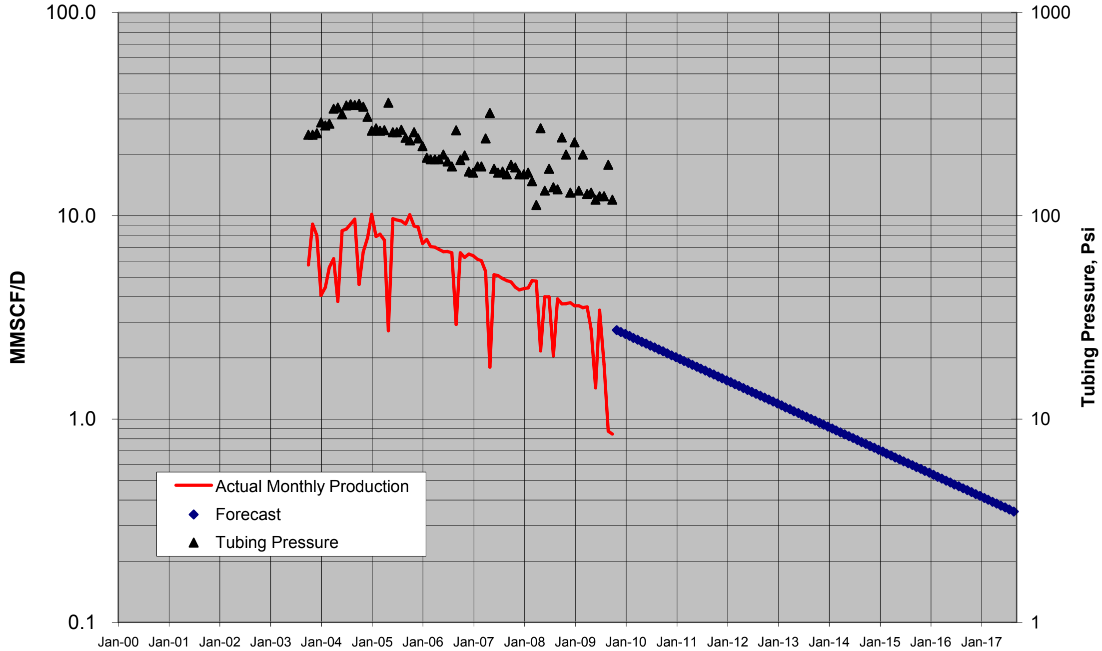
North Cook Inlet #A-08



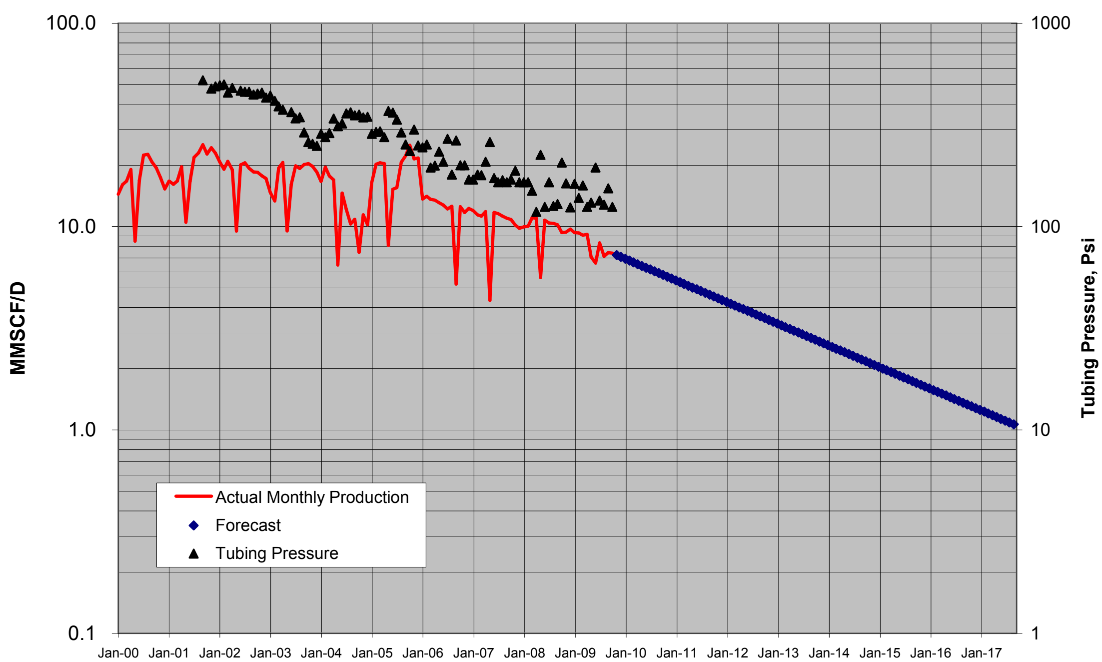
North Cook Inlet #A-09



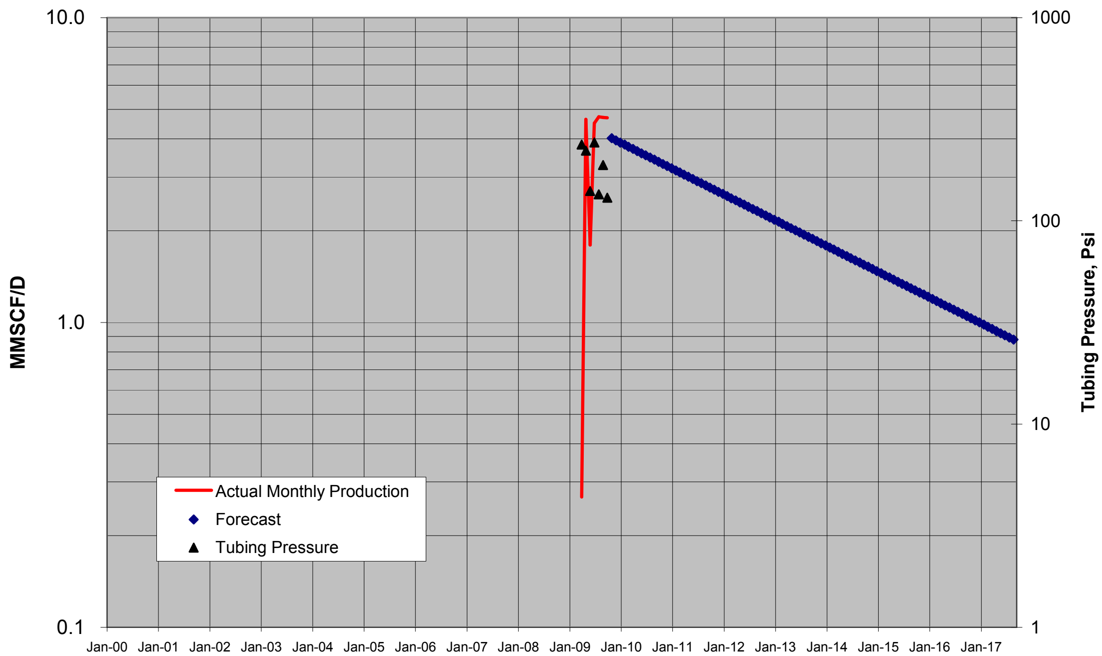
North Cook Inlet #A-10



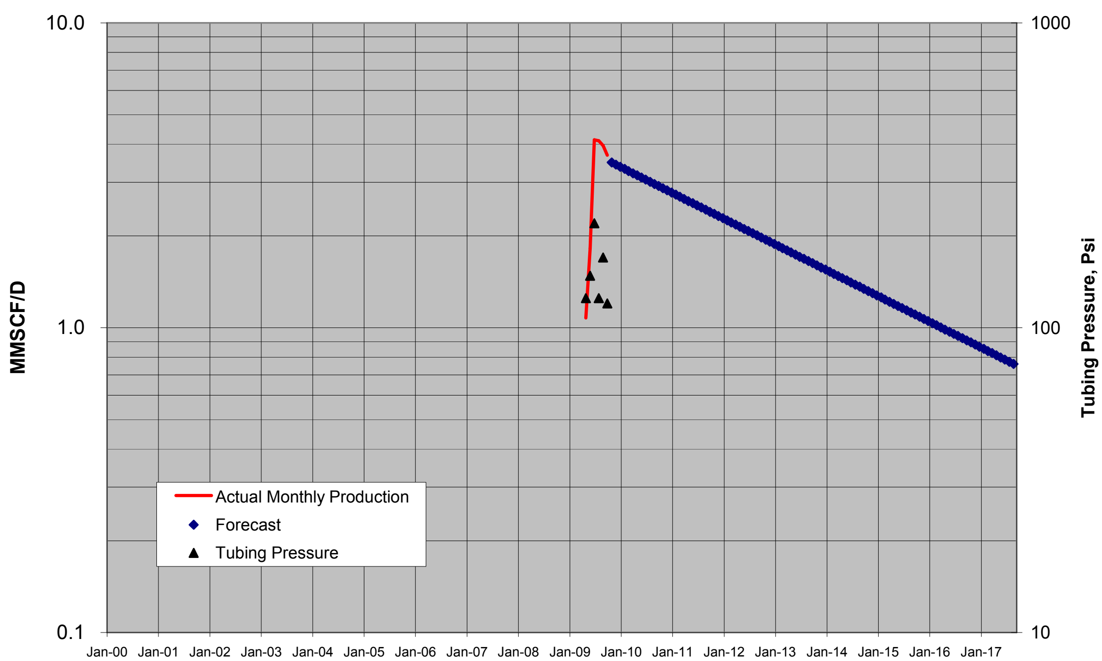
North Cook Inlet #A-12



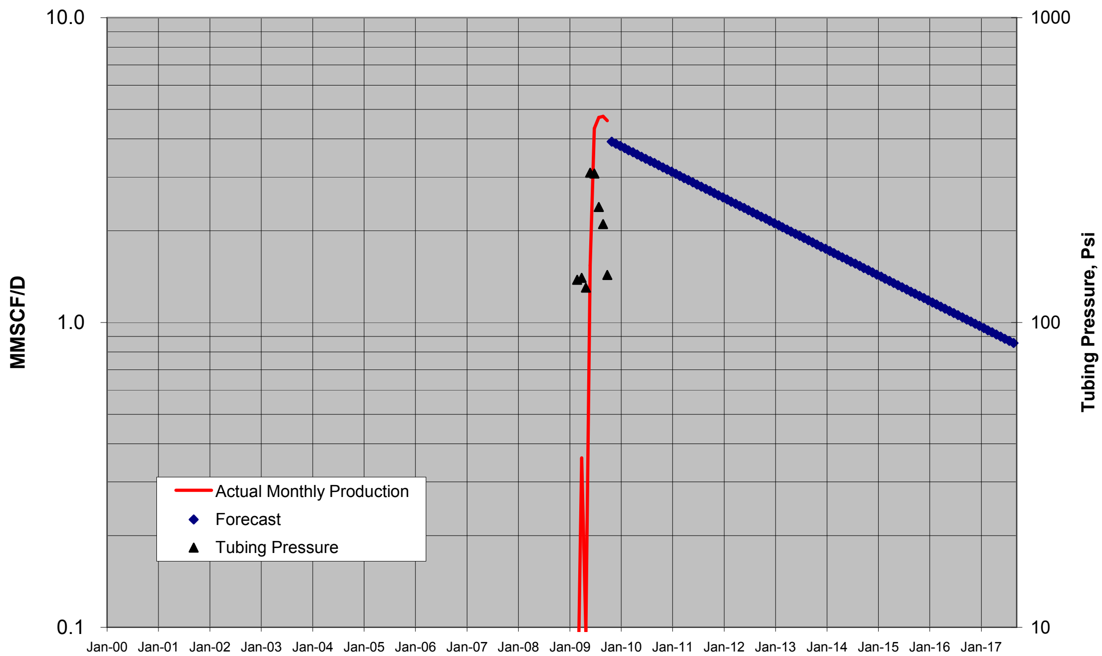
North Cook Inlet #A-14



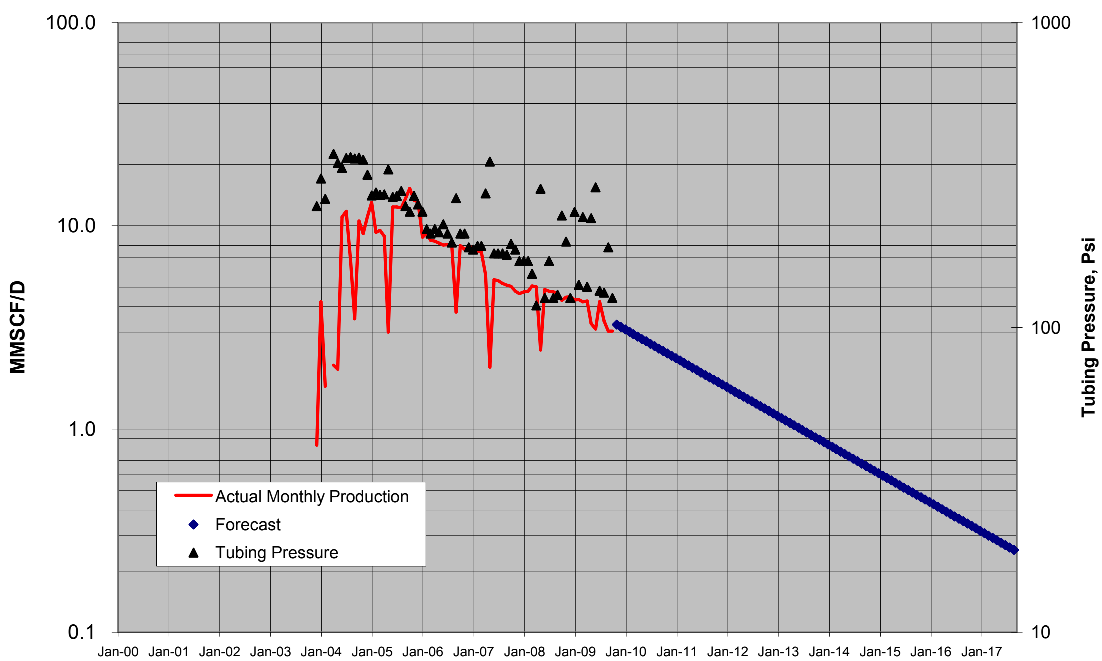
North Cook Inlet #A-15



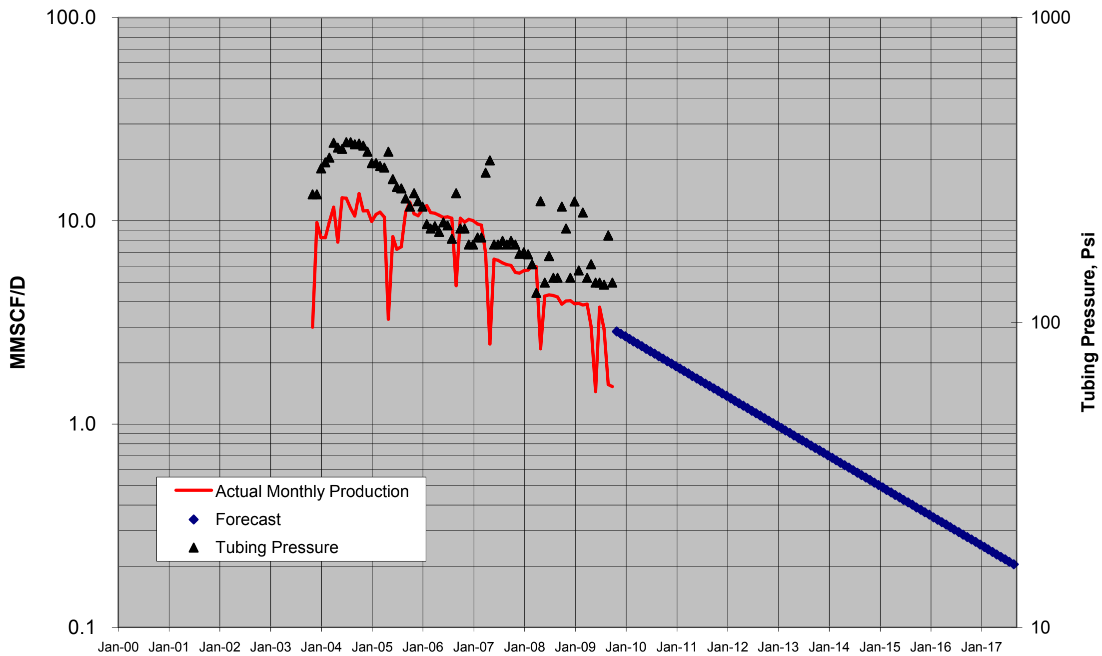
North Cook Inlet #A-16



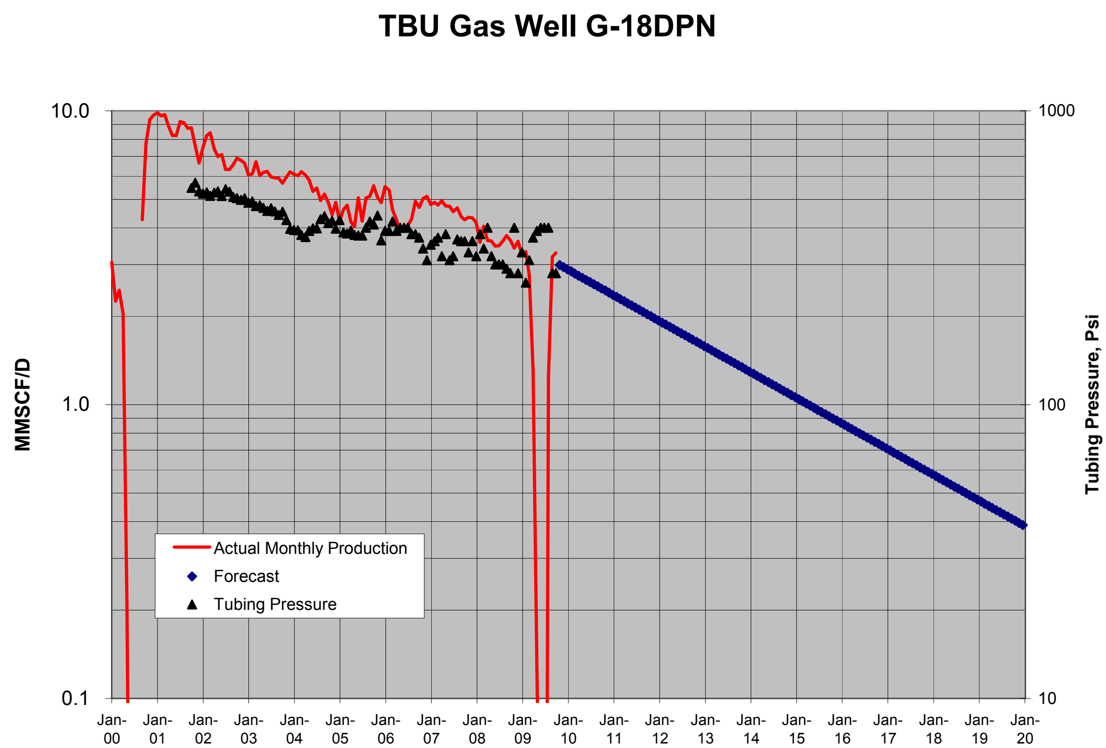
North Cook Inlet #B-01A

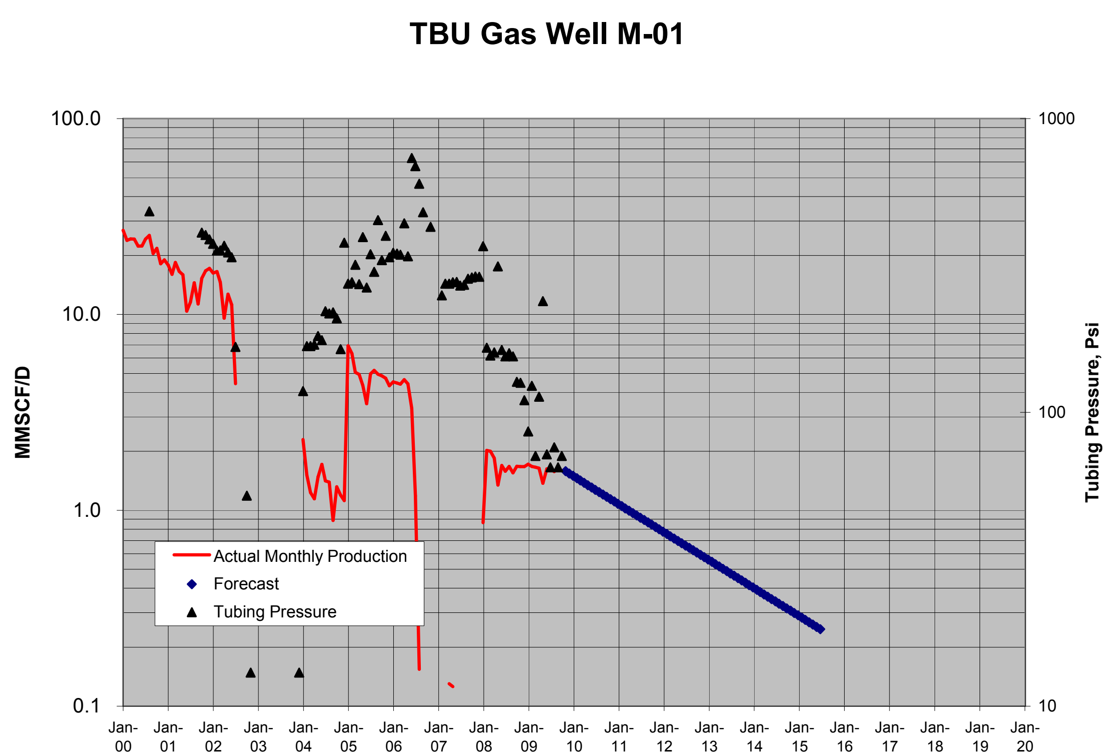


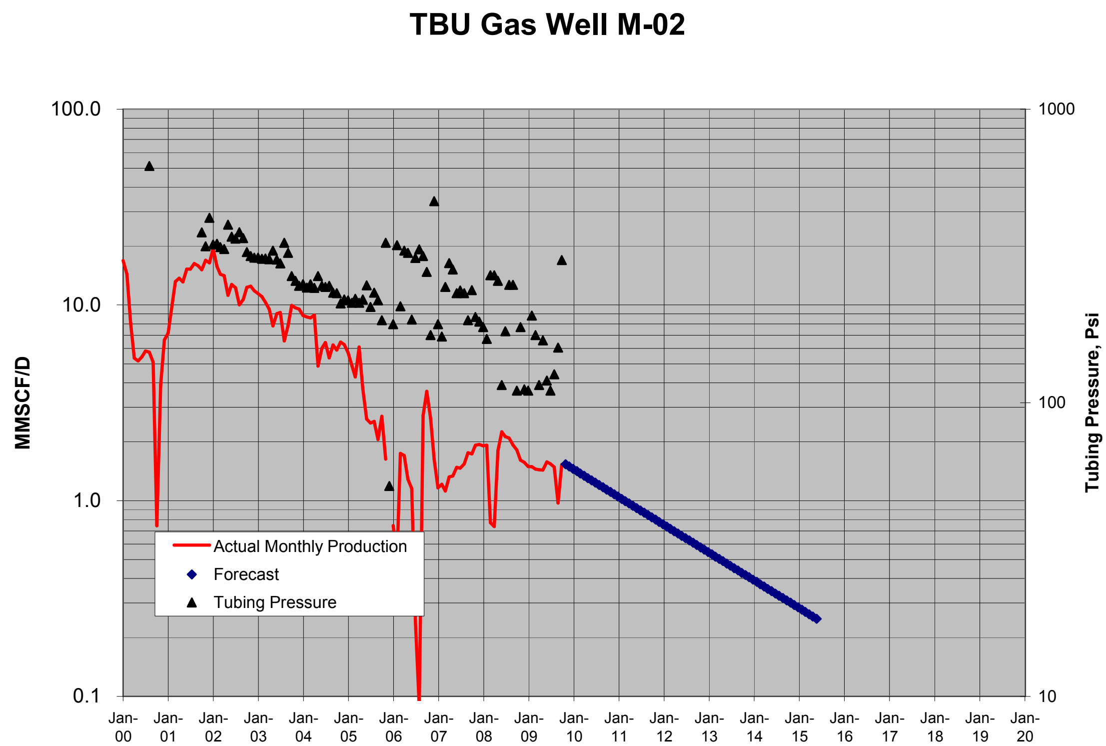
North Cook Inlet #B-03



Appendix D-5: Trading Bay Unit Gas Well Decline Curves






TBU Gas Well M-02
100.0
10.0
1.0
0.1
MMSCF/D
1000
100
10
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
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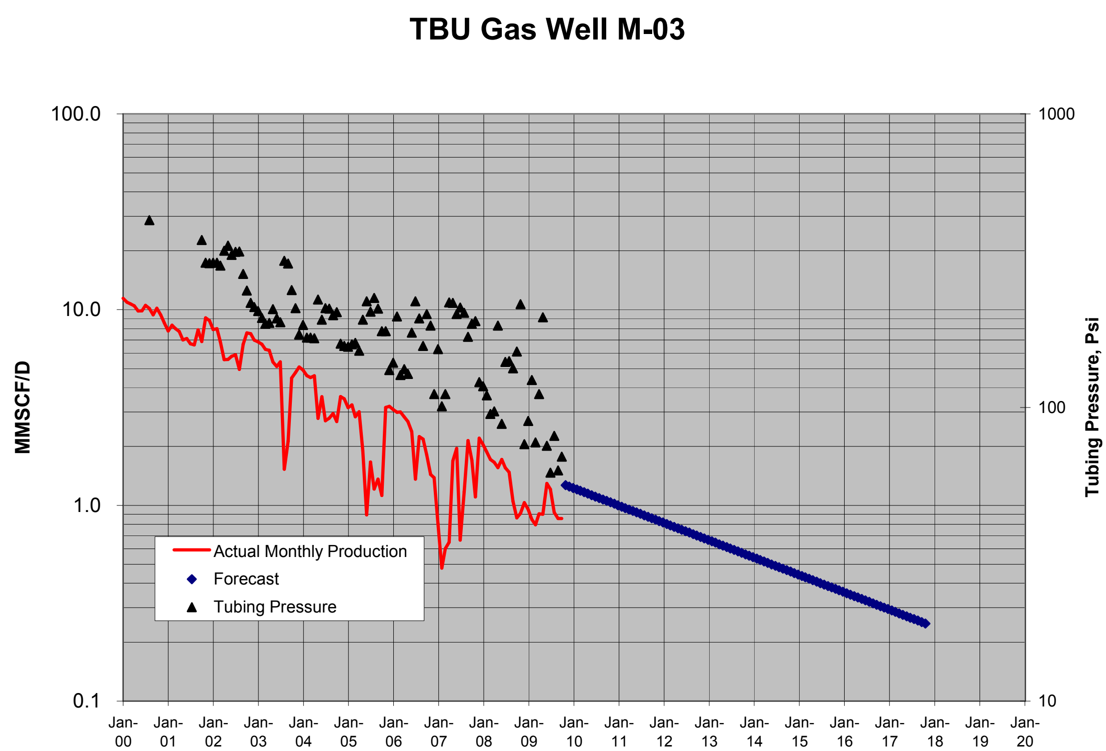
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20


TBU Gas Well M-03
100.0
10.0
1.0
0.1
MMSCF/D
1000
100
10
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
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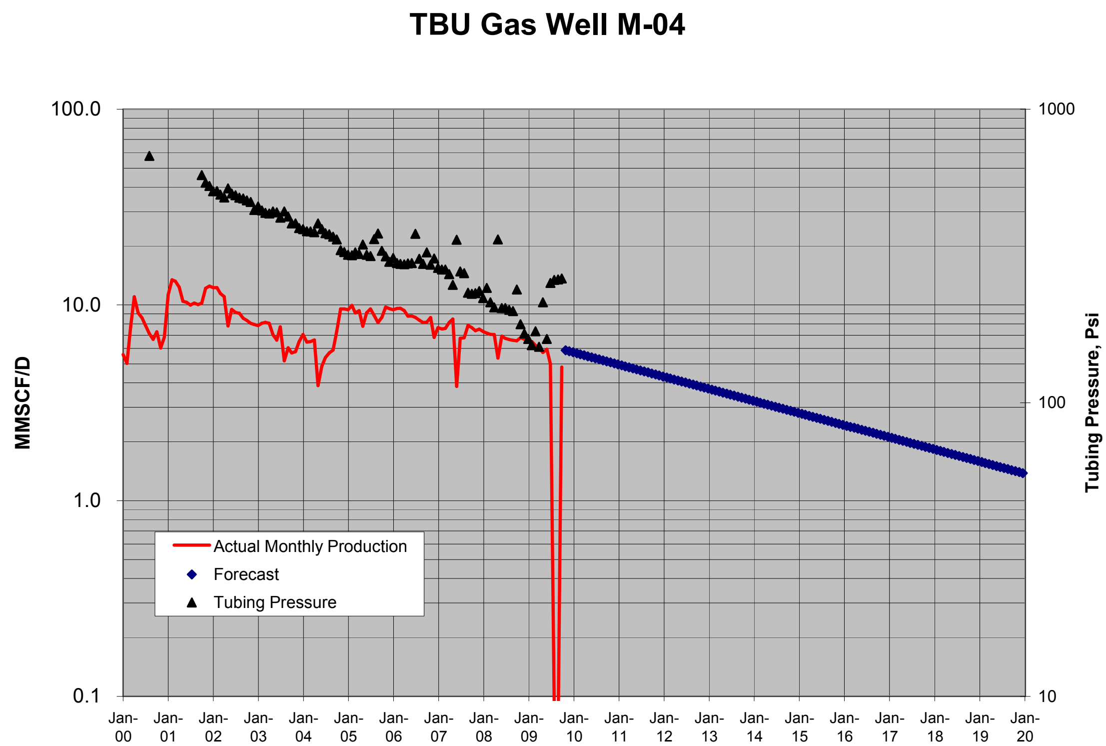
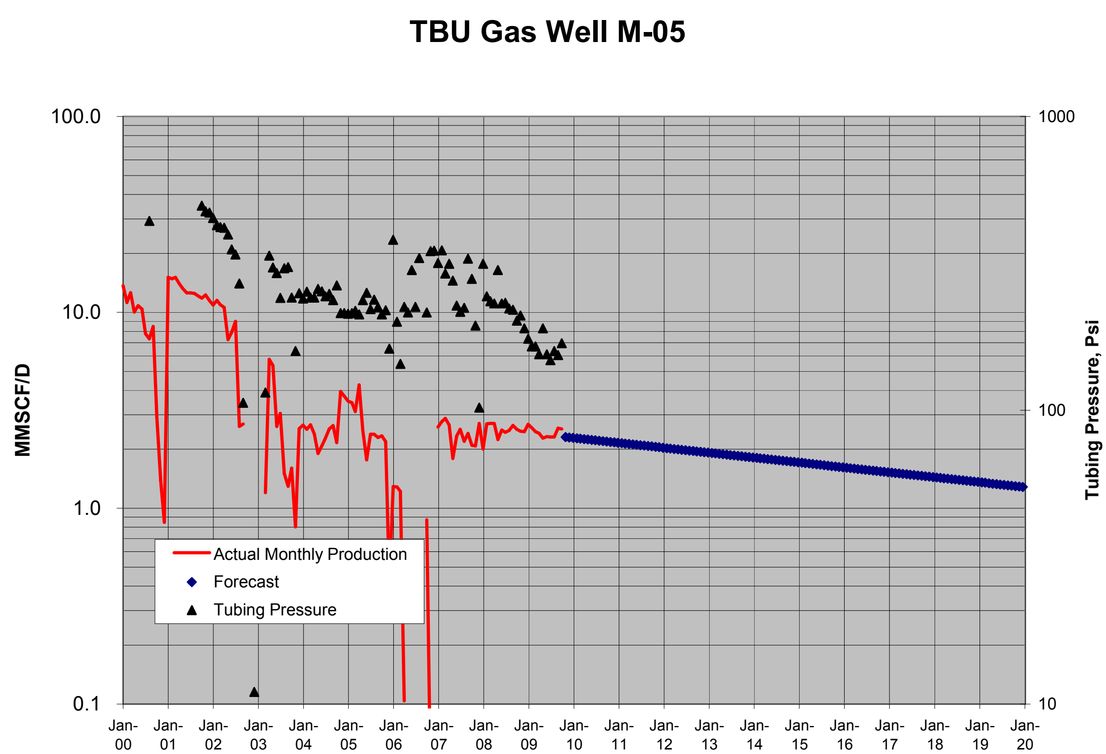
Jan-18
Jan-19
Jan-20


TBU Gas Well M-04
100.0
10.0
1.0
0.1
MMSCF/D
1000
100
10
Tubing Pressure, Psi
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20
Actual Monthly Production
Forecast
Tubing Pressure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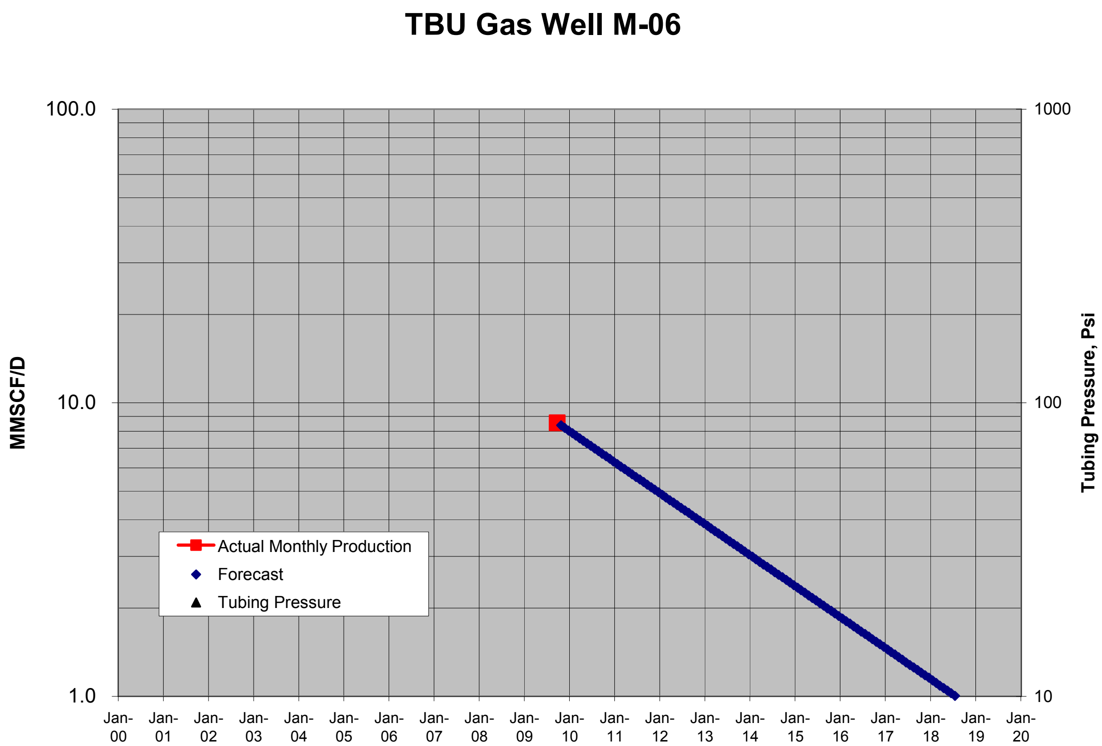
100.0
10.0
1.0
0.1
MMSCF/D
1000
100
10
Tubing Pressure, Psi
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20
Actual Monthly Production
Forecast
Tubing Pressure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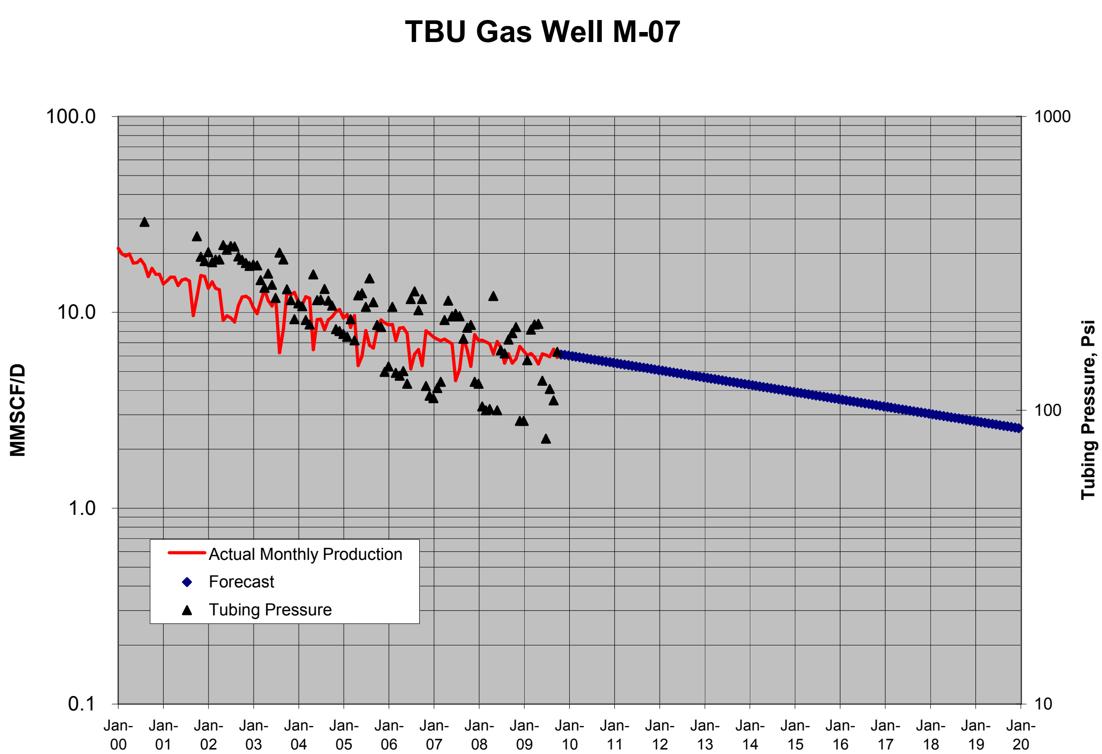
10.0
1.0
1000
100
10
MMSCF/D
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20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100.0
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1.0
0.1
1000
100
10
MMSCF/D
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
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Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
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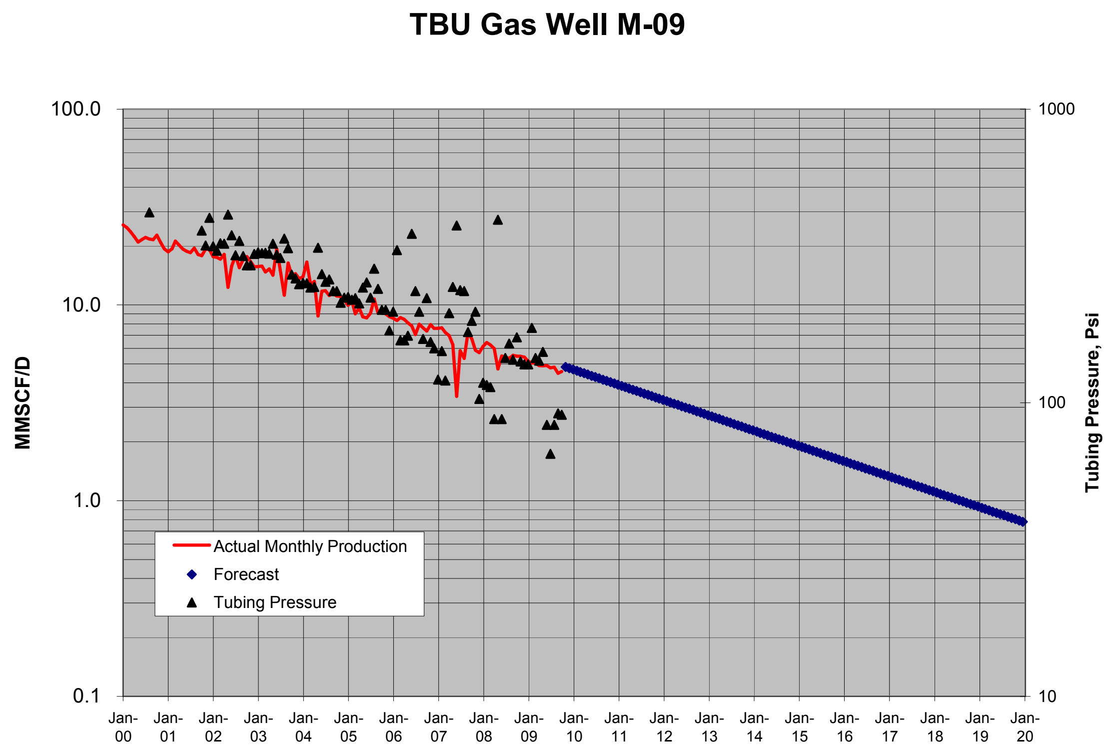
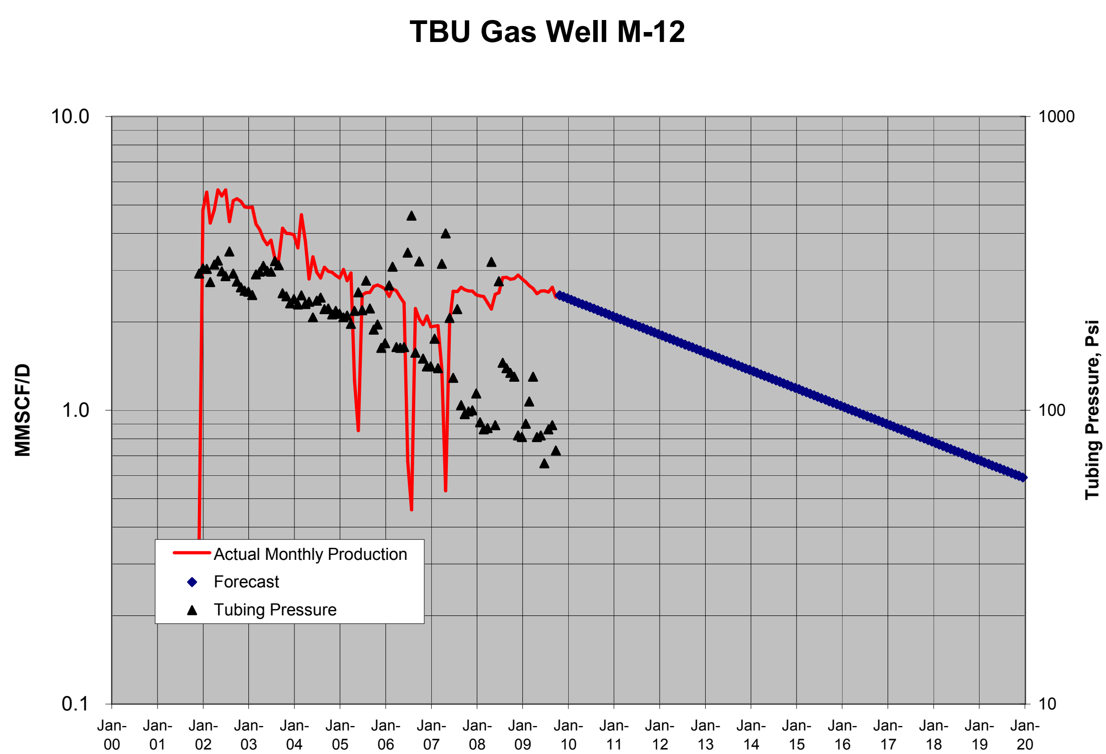
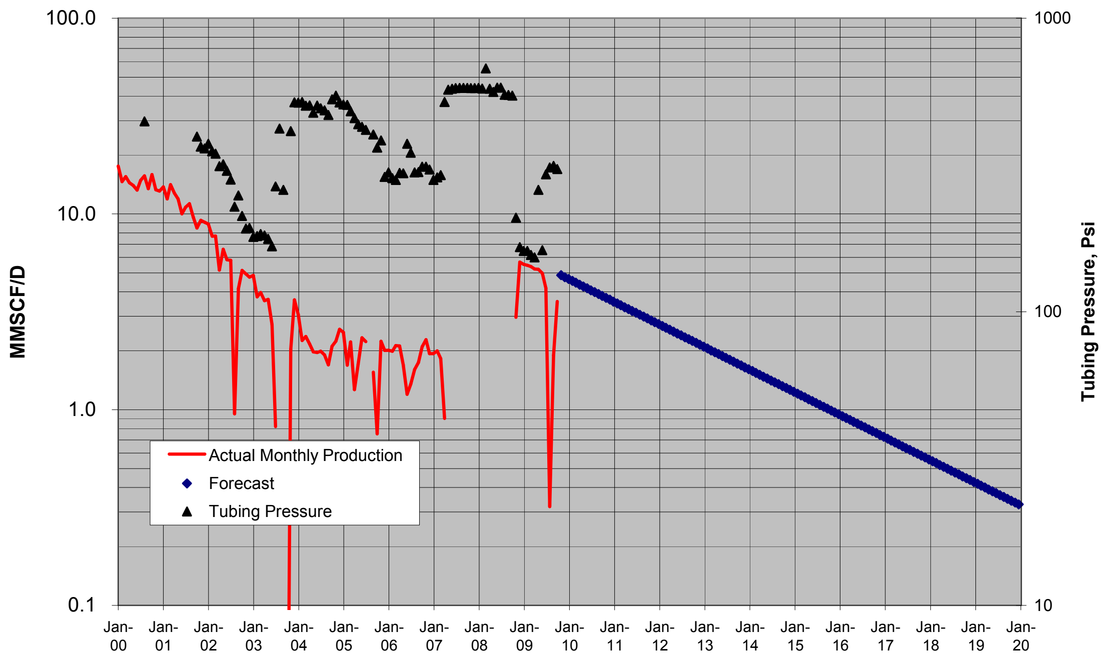
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20

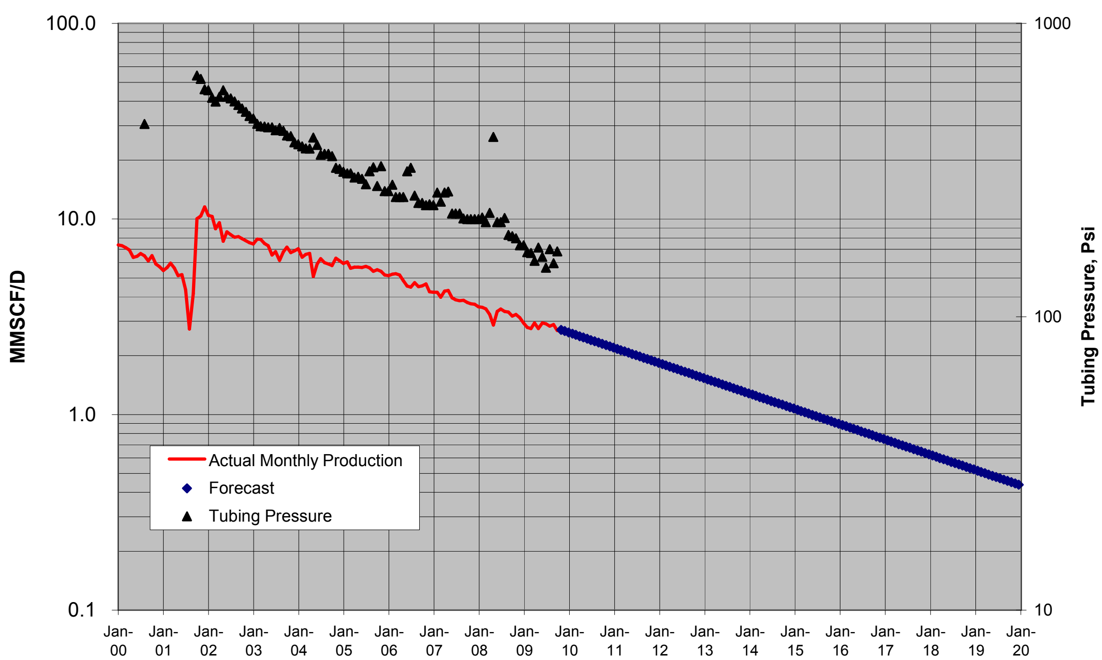

TBU Gas Well M-09
MMSCF/D
Tubing Pressure, Psi
100.0
10.0
1.0
0.1
1000
100
10
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20


TBU Gas Well M-12
MMSCF/D
Tubing Pressure, Psi
10.0
1.0
0.1
1000
100
10
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Jan-18
Jan-19
Jan-20

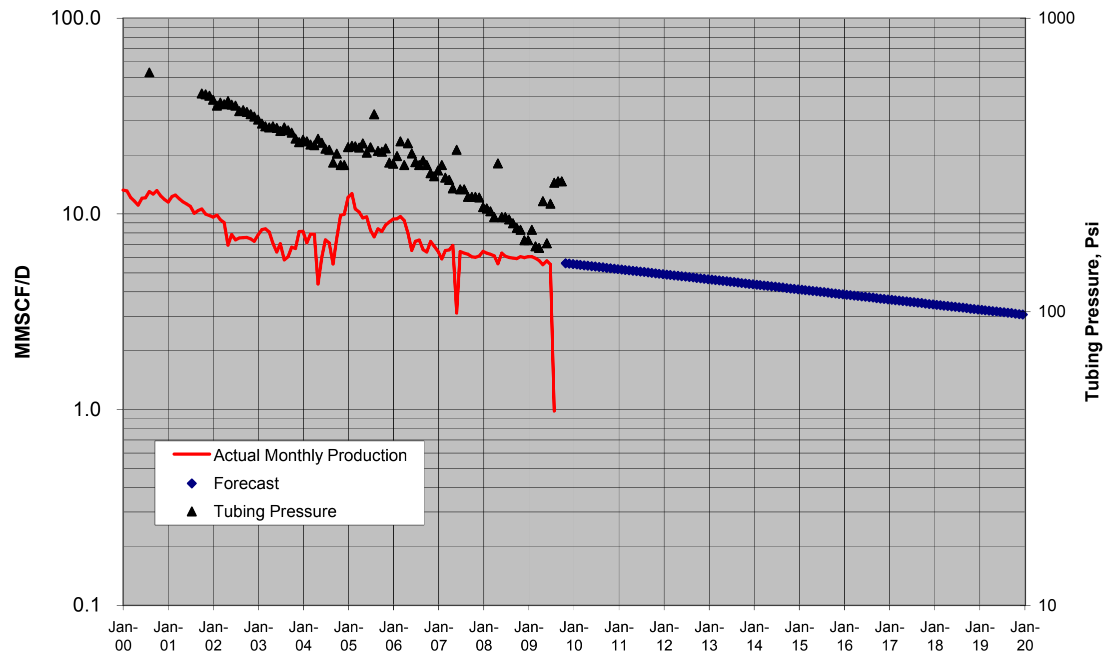
TBU Gas Well M-13



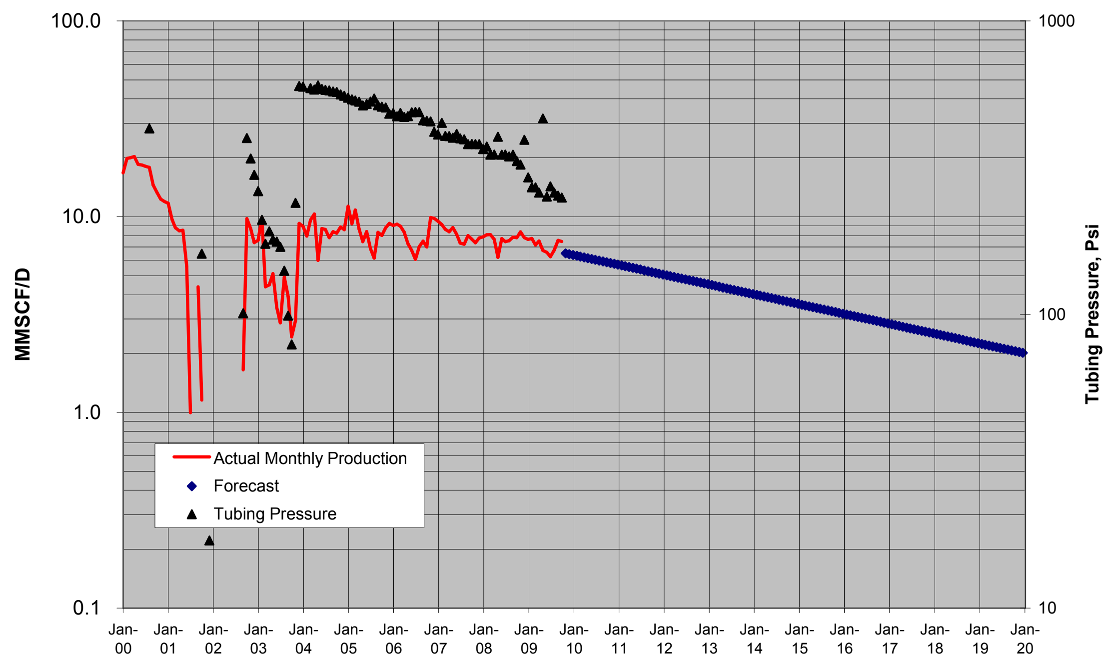
TBU Gas Well M-14RD

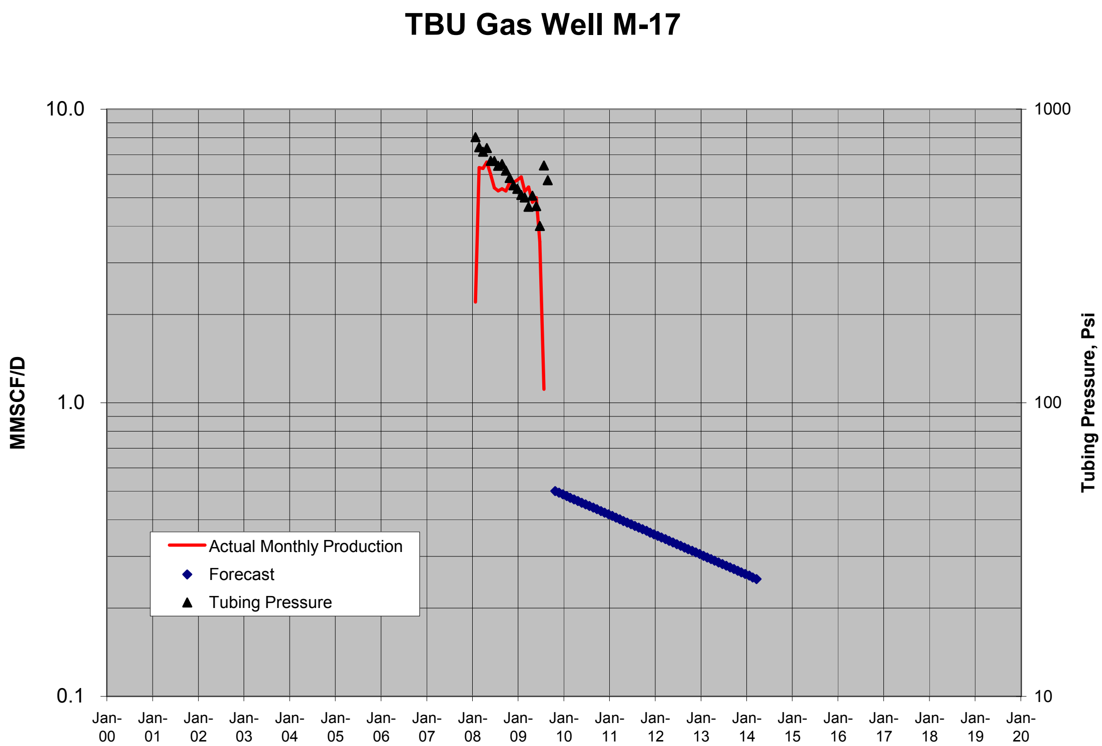


TBU Gas Well M-15



TBU Gas Well M-16RD




TBU Gas Well M-17
MMSCF/D
Tubing Pressure, Psi
10.0
1.0
0.1
1000
100
10
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
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Jan-12
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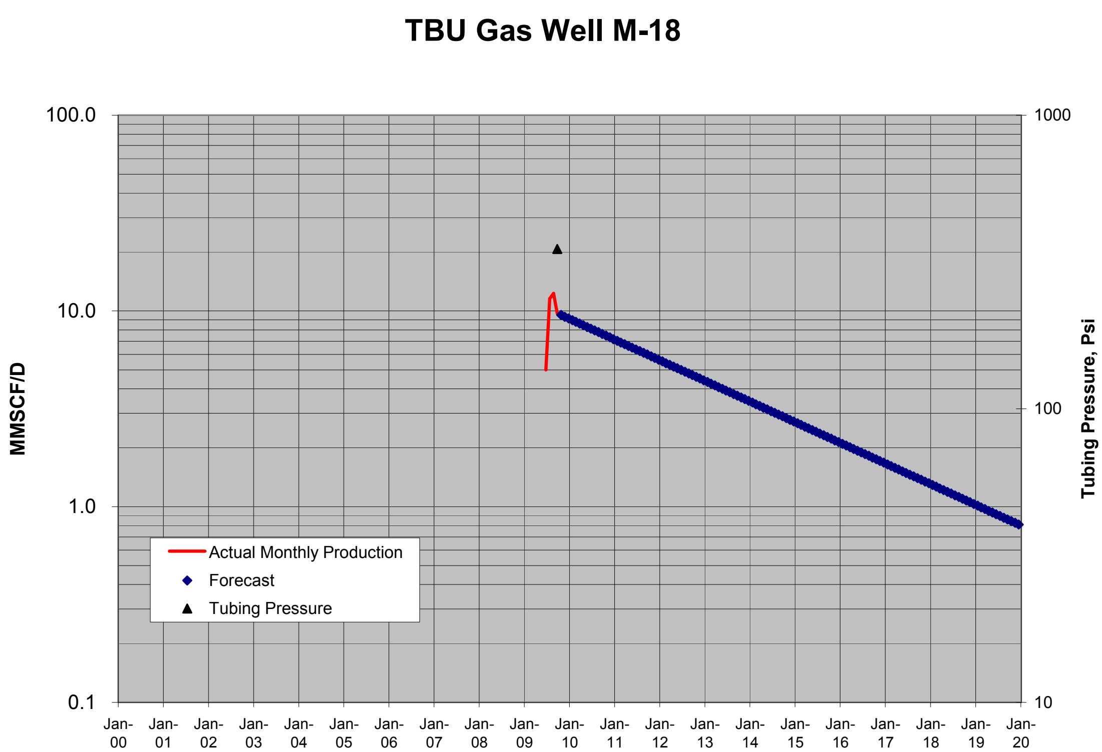
Jan-17
Jan-18
Jan-19
Jan-20


TBU Gas Well M-18
MMSCF/D
Tubing Pressure, Psi
100.0
10.0
1.0
0.1
1000
100
10
Actual Monthly Production
Forecast
Tubing Pressure
Jan-00
Jan-01
Jan-02
Jan-03
Jan-04
Jan-05
Jan-06
Jan-07
Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
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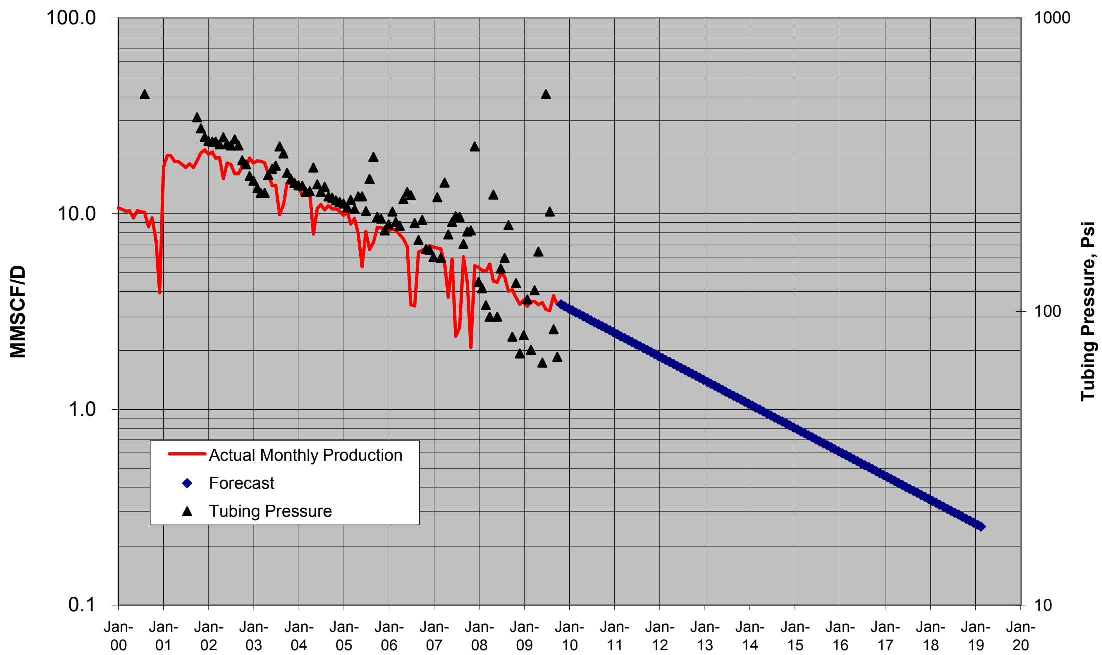
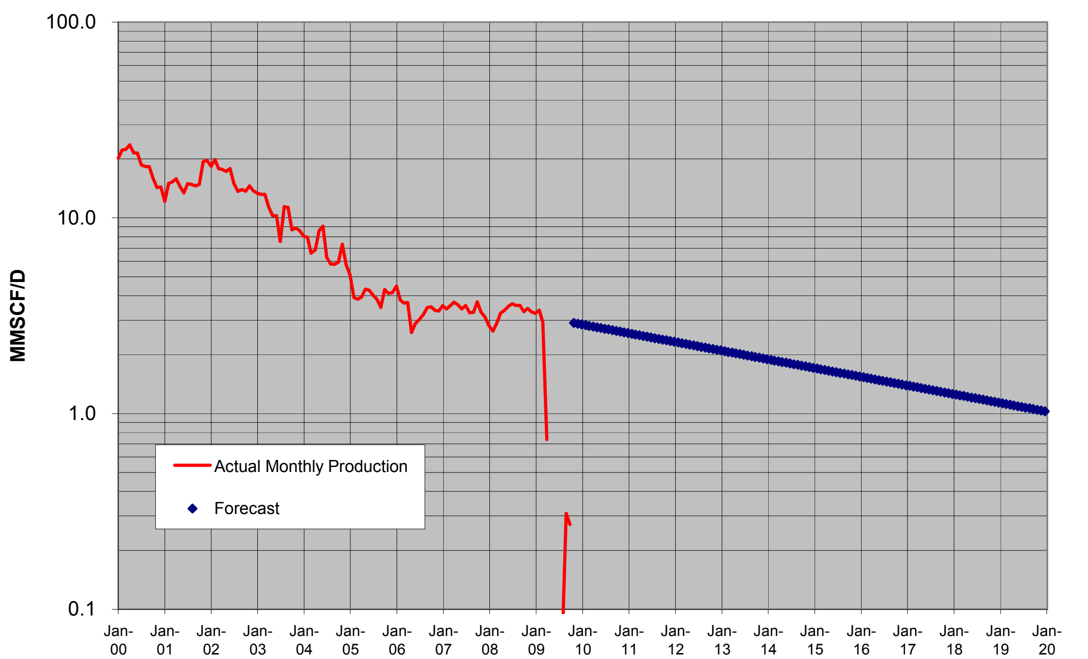
Jan-17
Jan-18
Jan-19
Jan-20

TBU Gas Well M-19RD



TBU Oil Wells



Appendix E: Listing of Gas Wells Drilled 2001-09

Well List by Name	Permit to Drill Number	Current Well Status	Current Status Date	Total Depth	Permit Class	Permit Status	Operator Name
TRADING BAY UNIT M-14RD	201-171-0	1-GAS	9/10/2001	6690	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI UNIT 21-06RD	201-097-0	1G-GS	5/8/2006	5650	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 2	201-096-0	1-GAS	7/3/2003	12026	EXP	1-GAS	MARATHON OIL CO
PRETTY CK UNIT 4	201-193-0	2G-GS	11/15/2005	9580	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
LEWIS RIVER UNIT C-01RD	201-168-0	1-GAS	12/9/2001	6469	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
TRADING BAY UNIT M-12	201-176-0	1-GAS	12/20/2001	10732	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI UNIT 24-05RD	201-144-0	1-GAS	12/22/2001	4816	DEV	1-GAS	MARATHON OIL CO
DEEP CREEK NNA 1	201-215-0	WDSP2	12/13/2004	10590	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI UNIT 43-06RD	201-231-0	1G-GS	5/8/2006	5740	DEV	1-GAS	MARATHON OIL CO
PEARL 1	202-011-0	P&A	4/11/2003	8000	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT FALLS CK 1RD	201-155-0	1-GAS	7/3/2003	8900	DEV	1-GAS	MARATHON OIL CO
GRINER 1	202-041-0	P&A	4/21/2003	6880	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI TYONEK UNIT 32-07H	202-043-0	1-GAS	5/20/2002	11857	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 41-07X	202-025-0	1-GAS	6/4/2002	5300	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT S DIONNE 3	202-070-0	1-GAS	7/3/2002	10255	EXP	1-GAS	MARATHON OIL CO
SWANSON RIV UNIT 213-10	202-118-0	1-GAS	8/4/2002	4105	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
NICOLAI CK UNIT 1B	202-162-0	1-GAS	9/22/2002	3672	DEV	1-GAS	AURORA GAS LLC
WOLF LAKE 1RD	202-088-0	1-GAS	10/8/2002	8770	DEV	1-GAS	MARATHON OIL CO
ABALONE 1	202-129-0	SUSP	3/9/2003	10356	EXP	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 11	203-025-0	1-GAS	6/30/2003	8931	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-1	203-072-0	1-GAS	7/9/2003	10872	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
BEAVER CK UNIT 3RD	203-044-0	1-GAS	7/16/2003	10005	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-2	203-113-0	1-GAS	8/4/2003	10225	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT FALLS CK 3	203-102-0	1-GAS	8/11/2003	10668	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 43-07X	203-066-0	1-GAS	9/5/2003	8610	DEV	1-GAS	MARATHON OIL CO
N COOK INLET UNIT A-10A	203-075-0	1-GAS	9/28/2003	8840	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
NICOLAI CREEK 9	202-208-0	1-GAS	10/3/2003	2102	DEV	1-GAS	AURORA GAS LLC
MOQUAWKIE 1	203-069-0	1-GAS	10/17/2003	3000	DEV	1-GAS	AURORA GAS LLC
TRADING BAY UNIT M-16RD	203-182-0	1-GAS	11/19/2003	3958	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
CANNERY LOOP UNIT 1RD	203-129-0	1-GAS	11/27/2003	10835	DEV	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 13	203-138-0	1-GAS	1/26/2004	10500	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 33-06X	203-183-0	1-GAS	2/5/2004	8405	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 7	203-191-0	1-GAS	2/21/2004	10864	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-3	203-222-0	1-GAS	3/12/2004	11345	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY A-4	203-223-0	1-GAS	3/23/2004	10620	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KASILOF SOUTH 1	202-256-0	1-GAS	3/25/2004	17545	EXP	2-GAS	MARATHON OIL CO
NINILCHIK UNIT FALLS CK 4	203-221-0	1-GAS	3/26/2004	7910	EXP	1-GAS	MARATHON OIL CO
KASILOF SOUTH 1L1	202-257-0	SUSP	4/15/2004	17665	EXP	2-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 8	204-005-0	1-GAS	4/28/2004	9777	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT PAXTON 1	204-010-0	1-GAS	5/29/2004	10115	EXP	1-GAS	MARATHON OIL CO
SWANSON RIV UNIT 241-16	204-088-0	1-GAS	6/10/2004	4264	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 11-8X	204-035-0	1-GAS	6/11/2004	7659	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-6	204-044-0	1-GAS	6/15/2004	11798	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KALOA 2	204-096-0	1-GAS	7/16/2004	3720	EXP	1-GAS	AURORA GAS LLC
RED 1	204-084-0	1-GAS	7/17/2004	12458	EXP	2O-2G	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 23-7	203-217-0	1-GAS	7/23/2004	9320	DEV	1-GAS	MARATHON OIL CO
STAR 1	204-117-0	P&A	6/10/2005	9130	EXP	2-GAS	UNION OIL CO OF CALIFORNIA
BEAVER CK UNIT BC-12	203-188-0	1-GAS	8/12/2004	8839	DEV	1-GAS	PELICAN HILL OIL AND GAS INC.
HAPPY VALLEY A-7	204-106-0	1-GAS	8/25/2004	10274	DEV	2-GAS	UNION OIL CO OF CALIFORNIA
LONG LK 1	203-068-0	SUSP	8/25/2004	3550	EXP	1-GAS	AURORA GAS LLC
HAPPY VALLEY A-8	204-114-0	1-GAS	8/27/2004	8900	DEV	2-GAS	UNION OIL CO OF CALIFORNIA
RED 2	204-148-0	1-GAS	9/5/2004	10100	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
ILIAMNA 1	203-172-0	P&A	9/5/2004	3530	EXP	1-GAS	PELICAN HILL OIL AND GAS INC.
BEAVER CK UNIT 14	204-086-0	1-GAS	9/22/2004	9361	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 9	204-161-0	1-GAS	11/3/2004	9100	DEV	1-GAS	MARATHON OIL CO
HAPPY VALLEY A-9	204-170-0	1-GAS	11/5/2004	8478	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY A-10	204-186-0	1-GAS	11/19/2004	8420	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY A-11	204-207-0	1-GAS	11/30/2004	10082	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT S DIONNE 2	204-107-0	1-GAS	12/6/2004	11094	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 42-6	204-209-0	1-GAS	12/9/2004	8624	DEV	1-GAS	MARATHON OIL CO
W FORELAND 2	204-143-0	2-GAS	12/11/2004	11387	DEV	1-GAS	FOREST OIL CORP
W FORK 03	204-156-0	1-GAS	1/11/2005	10620	DEV	1-GAS	MARATHON OIL CO
THREE MILE CK UNIT 1	204-183-0	1-GAS	1/23/2005	8180	EXP	1-GAS	AURORA GAS LLC
N BELUGA 1	204-226-0	P&A	1/28/2005	5122	EXP	1-GAS	PELICAN HILL OIL AND GAS INC.

Well List by Name	Permit to Drill Number	Current Well Status	Current Status Date	Total Depth	Permit Class	Permit Status	Operator Name
NINILCHIK UNIT S DIONNE 4	204-233-0	1-GAS	3/18/2005	11953	DEV	1-GAS	MARATHON OIL CO
MOQUAWKIE 3	205-080-0	1-GAS	6/26/2005	2560	EXP	1-GAS	AURORA GAS LLC
KENAI BELUGA UNIT 11-8Y	205-091-0	1-GAS	7/20/2005	8220	DEV	1-GAS	MARATHON OIL CO
LONE CREEK 3	205-097-0	1-GAS	7/25/2005	3025	EXP	1-GAS	AURORA GAS LLC
KENAI BELUGA UNIT 22-06	205-054-0	1-GAS	8/3/2005	8855	DEV	1-GAS	MARATHON OIL CO
NINILCHIK STATE 1	205-023-0	1-GAS	8/25/2005	10221	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 3	204-255-0	1-GAS	9/1/2005	13771	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 10	205-106-0	1-GAS	9/1/2005	8450	DEV	1-GAS	MARATHON OIL CO
KENAI TYONEK UNIT 43-6XRD2	205-117-0	1-GAS	10/1/2005	9470	DEV	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 16	205-116-0	P&A	9/26/2007	6422	DEV	1-GAS	MARATHON OIL CO
KALOA 4	205-131-0	P&A	10/6/2005	4431	EXP	1-GAS	AURORA GAS LLC
THREE MILE CK UNIT 2	205-143-0	1-GAS	11/25/2005	5307	DEV	1-GAS	AURORA GAS LLC
KENAI BELUGA UNIT 41-6	205-141-0	1-GAS	12/8/2005	9733	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 11-7	205-165-0	1-GAS	1/6/2006	7900	DEV	1-GAS	MARATHON OIL CO
MIDDLE LK UNIT 1A	205-149-0	SUSP	1/16/2006	9350	EXP	1-GAS	PACIFIC ENERGY RESOURCES LTD
NINILCHIK UNIT G OSKOLKOFF 4	205-190-0	1-GAS	2/3/2006	8175	EXP	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 24-06RD	206-013-0	1-GAS	4/27/2006	7830	DEV	1-GAS	MARATHON OIL CO
ENDEAVOUR 1	205-213-0	P&A	5/13/2006	9225	EXP	2O-1G	AURORA GAS LLC
LONG LAKE 2	206-061-0	P&A	7/27/2006	3843	EXP	1-GAS	AURORA GAS LLC
KENAI UNIT 21-7X	206-029-0	1-GAS	9/1/2006	5032	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 12	206-121-0	SUSP	9/8/2006	10415	DEV	1-GAS	MARATHON OIL CO
CANNERY LOOP UNIT 11	206-058-0	1-GAS	9/28/2006	9305	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT S DIONNE 5	206-088-0	1-GAS	10/3/2006	9600	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 24-7X	206-127-0	1-GAS	2/11/2007	8303	DEV	1-GAS	MARATHON OIL CO
NINILCHIK STATE 2	206-066-0	1-GAS	2/13/2007	11500	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 5	207-001-0	1-GAS	5/31/2007	10384	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 12-5	207-042-0	1-GAS	6/27/2007	8920	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 34-6	207-064-0	1-GAS	6/30/2007	7739	DEV	1-GAS	MARATHON OIL CO
STERLING UNIT 43-09X	207-073-0	1-GAS	8/8/2007	6185	DEV	1-GAS	MARATHON OIL CO
STERLING UNIT 41-15RD	207-088-0	1-GAS	9/12/2007	11655	DEV	1-GAS	MARATHON OIL CO
NINILCHIK STATE 3	207-018-0	1-GAS	10/5/2007	11962	DEV	1-GAS	MARATHON OIL CO
BEAVER CK UNIT 16RD	207-125-0	1-GAS	10/31/2007	9421	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 6	207-096-0	1-GAS	11/22/2007	12069	DEV	1-GAS	MARATHON OIL CO
TRADING BAY UNIT M-17	207-120-0	1-GAS	12/29/2007	7670	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 14-6Y	207-149-0	1-GAS	1/18/2008	7600	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT PAXTON 2	207-164-0	1-GAS	3/8/2008	8436	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 42-07RD	208-052-0	1-GAS	5/27/2008	7926	DEV	1-GAS	MARATHON OIL CO
KENAI UNIT 41-18X	208-026-0	1-GAS	6/5/2008	8737	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 14-8	208-048-0	1-GAS	6/6/2008	8072	DEV	1-GAS	MARATHON OIL CO
NINILCHIK UNIT G OSKOLKOFF 7	208-023-0	SUSP	6/12/2008	13500	DEV	1-GAS	MARATHON OIL CO
BELUGA RIV UNIT 243-34	208-079-0	1-GAS	7/28/2008	7005	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
NORTH FORK 34-26	208-063-0	1-GAS	9/23/2008	9021	EXP	1-GAS	ARMSTRONG RESOURCES LLC
BELUGA RIV UNIT 211-26	208-112-0	1-GAS	7/27/2008	7786	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
KENAI DEEP UNIT 9	208-106-0	1-GAS	10/23/2008	9850	DEV	1-GAS	MARATHON OIL CO
MOQUAWKIE 4	207-084-0	1-GAS	11/9/2008	3450	DEV	1-GAS	AURORA GAS LLC
SWANSON RIV UNIT 211-33	208-152-0	P&A	6/3/2009	4760	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
NINILCHIK UNIT SD-6	208-160-0	1-GAS	12/21/2008	6737	DEV	1-GAS	MARATHON OIL CO
KENAI UNIT 22-6X	208-135-0	1G-GS	2/7/2009	5989	DEV	1-GAS	MARATHON OIL CO
N COOK INLET UNIT A-16	208-098-0	1-GAS	2/24/2009	9314	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
BEAVER CK UNIT 19	208-123-0	1-GAS	4/2/2009	9068	DEV	1-GAS	MARATHON OIL CO
IVAN RIVER UNIT 11-06	208-184-0	1-GAS	4/4/2009	10060	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
BEAVER CK UNIT 18	208-185-0	1-GAS	4/7/2009	9244	DEV	1-GAS	MARATHON OIL CO
KENAI BELUGA UNIT 11-17X	209-016-0	1-GAS	4/15/2009	8055	DEV	1-GAS	MARATHON OIL CO
N COOK INLET UNIT A-14	208-096-0	1-GAS	4/23/2009	11501	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
N COOK INLET UNIT A-15	208-097-0	1-GAS	5/7/2009	8867	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
KALOA 3	209-047-0	P&A	6/20/2009	4709	DEV	1-GAS	AURORA GAS LLC
TRADING BAY UNIT M-18	208-162-0	1-GAS	7/16/2009	9930	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
STUMP LK UNIT 41-33RD	209-010-0	1-GAS	7/23/2009	10160	DEV	1G-GS	UNION OIL CO OF CALIFORNIA
KENAI BELUGA UNIT 42-6X	209-040-0	1-GAS	7/29/2009	10278	DEV	1-GAS	MARATHON OIL CO
TRADING BAY UNIT M-06	209-004-0	1-GAS	9/17/2009	12502	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
BELUGA RIV UNIT 232-23	209-057-0	1-GAS	10/7/2009	7587	DEV	1-GAS	CONOCOPHILLIPS ALASKA INC
HAPPY VALLEY B-13	207-151-0	1-GAS	4/3/2008	7747	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
HAPPY VALLEY B-12	207-123-0	1-GAS	6/1/2009	10400	DEV	1-GAS	UNION OIL CO OF CALIFORNIA
LONE CREEK 4	207-091-0	UN			DEV	1-GAS	AURORA GAS LLC

Appendix F. Cook Inlet Unit POD's 2006-2009

Unit	**Beluga River**	
Operator	**ConcoPhillips**	

2009-10 Period

POD #	**47th**	
Term	6/18/09 to 6/17/10	
Approved	5/29/2009	
Agency	BLM	
Wells	211-26	
	243-34	

Other

2008-09 Period

POD #	**46th**	**Review of projects**
Term	6/18/08 to 6/17/09	**at 47th POD appl.**
Approved	5/8/2008	
Agency	BLM	
Wells	232-26 WO	Recompl: Ster/Bel
	211-26 Drl & Cmpl	D&C: Ster/Bel
	243-34 Drl & Cmpl	D&C: Ster/Bel

2007-08 Period

POD #	**45th**	**Review of projects**
Term	6/18/07 to 6/17/08	**at 46th POD appl.**
Approved	5/15/2007	
Agency	DNR/DOG	
Wells	No drilling	
	Planned 3D seismic acquisition	3D Seismic aquired

Unit	**Kenai**	
Operator	**Marathon**	

2009-10 Period

POD #	**51st**	
Term	2/8/09-2/7/10	
Approved	1/27/2009	
Agency	BLM	
Wells	KBU 11-17X	
	KBU 23-08	
	KBU 42-06X	
	KU 31-06 Gas Stor	

Other

2008-09 Period

POD #	**50th**	**Review of projects**
Term	2/8/08-2/7/09	**at 51st POD appl.**
Approved	??	
Agency		
Wells	KBU 14-8	Drl & Cmpl: Bel/Tyon
	KBU 41-18X	Drl & Cmpl: Bel/Tyon
	KBU 42-7RD	Drl & Cmpl: Bel/Tyon
	KBU 41-6X EXCAPE	
	KU 31-7Y	
	KGF WDW2	KU 12-17 Drd & Cmpl as Cl II inj
		KDU-09 Drl & Cmpl: Tyonek
		KU 22-06X: D&C: Strlng P-6 Storage
		Rig WO KBU 42-07 RD

2007-08 Period

POD #	**49th**	**Review of projects**
Term	2/8/08-2/7/09	**at 50th POD appl.**
Approved		
Agency		
Wells		KBU 12-5 D&C: Bel/Tyon
		KBU 34-6 D&C: Bel/Tyon
		KBU 24-7X comp 2/07: Bel/Tyon
		KU 23-6 recompl P-6 Storage
		KBU 41-7X recomp Sterling

Unit	**Ninilchik**	
Operator	**Marathon**	
2009-10 Period		
POD #	**6th**	**Dec 09 Status of Projects**
Term	1/1/10 to 12/31/10	
Approved	Pending	
Agency	DNR/DOG	
Wells	Paxson #3 Paxson #4	
Other		
2008-09 Period		
POD #	**5th**	**Review of projects at 6th POD appl.**
Term	1/1/09 to 12/31/09	
Approved		
Agency		
Wells	New wells planned on Corea Creek pad and Abalone pad; locations dependent on new seismic.	No wells drilled. Compression installed Susan Dionne pad. Compression will be installed on Paxson and Ninilchik State pads by late Q4-09
2007-08 Period		
POD #	**4th**	**Review of projects at 5th POD appl.**
Term	1/1/08 to 12/31/08	
Approved		
Agency		
Wells	Additional wells at Paxson S. Dionne G. Oskolkoff New Comp at S. Dionne pad	 Paxson #2 cmpl Tyon GO #7 Drld, P&A Const in progress

Unit	**North Cook Inlet**	
Operator	**ConcoPhillips**	
2009-10 Period		
POD #	**2010**	
Term	1/1/10 to 12/31/10	
Approved	Pending	
Agency	DNR/DOG	
Wells		
Other	Will evaluate feasibility of lowering wellhead pressures.	
2008-09 Period		
POD #	**2009**	**Review of projects**
Term	1/1/09 to 12/31/09	**at 2010 POD appl.**
Approved	?	
Agency		
Wells	Drill 2 wells if previous wells are successful	Three new wells A-14, A-15, A-16 were completed. No additional drlg potential
2007-08 Period		
POD #	2008	**Review of projects**
Term	1/1/09 to 12/31/09	**at 2009 POD appl.**
Approved	12/28/2007	
Agency	DNR/DOG	
Wells	Drilling only if needed for delivery	A-14 Drilled A-15 Drilled A-16 Drilled

Unit	**TBU Grayling Gas**	
Operator	**Chevron**	

2009-10 Period

POD #	44th	
Term	8/27/09 to 8/26/10	
Approved	7/17/2009	
Agency	DNR/DOG	
Wells	M-20 Cmpl 10/09 M-10 Drl & Cmpl 1/10 M-1 WO 11/09 M-5 WO 12/09 2 other wells being evaluated for drilling & 2 others for WO.	
Other		

2008-09 Period

POD #	**43rd**	**Review of projects at 44th POD appl.**
Term	8/27/07 to 8/25/09	
Approved	7/17/2007	
Agency	DNR/DOG	
Wells	Drill M-17 Evaluated other drilling potential.	M-18 drilled M-13 WO M-2 WO M-18 Compl 5/09 M-6 Drill & Compl 6/09 M-8 Drill & Compl 8/09

2007-08 Period

POD #	**42nd**	**Review of projects at 43rd POD appl.**
Term	8/26/06 to 8/25/07	
Approved	6/29/2006	
Agency	DNR/DOG	
Wells	No drilling planned.	M-5 Gravel packed and B-5 & B-6 sands were perf'd. WO M-32RD to replace failed ESP.