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STATE OF ALASKA

BEFORE THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Stephen A. McAlpine, Chairman Paul F. Lisankie Rebecca L. Pauli Robert M. Pickett Janis W. Wilson

In the Matter of the Petition filed by COOK INLET NATURAL GAS STORAGE ALASKA, LLC for Advance Determination of Decisional Prudence and Assurance of Cost Recovery for Redundancy Project	)))))	Docket No. U-18-024

AFFIDAVIT OF JOHN J. LAU

STATE OF ALASKA)
) ss.
THIRD JUDICIAL DISTRICT)

John J. Lau, being first duly sworn, deposes and says:

Introduction

1. My name is John J. Lau. My business address is 401 East International Airport Road, Anchorage, Alaska 99518. I am the Vice President of Operations for ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc. ("ENSTAR"), and for Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"). ENSTAR provides operational services under contract to CINGSA.

2. I have been employed by ENSTAR since May 5, 1989, and have held various supervisory and managerial positions with responsibility for ENSTAR operations since then. Previous to ENSTAR, I was employed by Conoco North American Production holding various positions in both engineering and field operations. Since 2001, I have been a member of ENSTAR's senior leadership team. I received a Bachelor of Science

degree with a major in Electrical Engineering from the University of Wyoming in 1978 and a Master of Business Administration from the University of Washington in 2001. My resume is attached hereto as <u>Exhibit JJL-1</u>.

3. I am responsible for all of ENSTAR's engineering, operations, and construction, as well as those of CINGSA, pursuant to an Operation and Maintenance Agreement ("OMA") between ENSTAR and CINGSA.

4. I have previously provided written and oral testimony before the Commission in Docket No. P-02-006.

Background

5. CINGSA operations are driven by uniqueness of customer needs. In order to address seasonal heating loads, CINGSA injects gas during off-peak demand periods such as summer and withdraws gas to cover winter requirements. Though less seasonal swing demands are experienced with the electric generation customers, CINGSA does provide interday and intraday gas to meet market needs.

6. Certainty of peak natural gas delivery is paramount to both CINGSA and ENSTAR, CINGSA's largest customer. Observation of CINGSA's storage well and surface facility performance over the initial five years of operations has triggered scrutiny as to risks affecting deliverability. It is important for a utility (both CINGSA and ENSTAR) to understand the implications of asset failure, along with the reliance on the service one provides, when calculating potential risks and future liabilities.

7. As Mr. John D. Sims describes in his affidavit, CINGSA has recently studied the gas supply and demand issues in Cook Inlet and the risks associated with continuing to provide reliable storage and withdrawal service to its customers who depend on it. I

oversaw the commissioning, coordination, and completion of these studies on behalf of CINGSA.

2017 Gas Study

8. CINGSA commissioned an update of prior studies concerning the gas supply situation in the Cook Inlet. This study, entitled "Cook Inlet Gas Study – 2017 Update", was conducted by Petrotechnical Resources of Alaska ("PRA") and completed in November 2017 ("2017 Gas Study"). A true and correct copy of the 2017 Gas Study is attached to this affidavit as Exhibit JJL-2 and incorporated herein for all purposes. The data it relied upon, methodologies it used, and conclusions it reached are all set forth therein. While I will not attempt to summarize or restate each aspect of the study, I will highlight certain findings for the Commission's attention.

9. Generally, the 2017 Gas Study forecasted current and near-term future demand and supply for natural gas in the Cook Inlet area. This analysis included evaluation of individual wells and their production decline curves. By comparing forecasted gas supply and demand, the study then projected the approximate timing of supply shortfalls under various scenarios and assumptions. These projections were based in part on whether new production occurs. The 2017 Gas Study concluded that if there is no drilling activity to add new production in the Cook Inlet, a shortfall could occur as early as 2019. If there are equivalent levels of drilling of gas wells as occurred in recent experience, a shortfall is not expected until 2021.

Risk Report

10. CINGSA also commissioned a second study to evaluate scenarios under which gas consumers in the Cook Inlet region might experience a shortfall during a cold day (peak

day) in 2017 and 2020. This second study, entitled "Cook Inlet Gas Deliverability Risk Analysis," was conducted by RPS Group, a multinational energy resource group, in collaboration with Evoleap, LLC, and it was completed in April 2018 ("Risk Report"). RPS Group was selected to conduct the Risk Report in part because it had the experience and resources available to analyze all three areas needed for the study: wells, fields, and pipeline capacity/throughput. A true and correct copy of the Risk Report is attached to this affidavit as Exhibit JJL-3 (CONFIDENTIAL) and incorporated herein for all purposes. The data it relied upon, methodologies it used, and conclusions it reached are all set forth therein. While I will not attempt to summarize or restate each aspect of the study, I will highlight certain findings in the Risk Report for the Commission's attention.

11. In the Risk Report, assets in the Cook Inlet region were broken into three major areas: (1) wells, which included production and storage wells; (2) fields, which included field and production equipment; and (3) the pipeline system, which included the transmission pipeline network and available compression. The Risk Report analyzed the capability or capacity of Cook Inlet to overcome a given failure scenario and relatively ranked consequences. Relative likelihood of failure estimates were established by using industry resources. The result of the analysis was a risk matrix that highlighted the most significant facilities having a critical impact on gas deliverability.

12. The Risk Report recommended that a spare dehydration unit be considered at CINGSA and that additional storage wells be considered either at CINGSA or at another location to increase the overall storage capacity in the Cook Inlet area. The Risk Report did not

include evaluation of CINGSA's compressors within its scope because they are often offline during peak withdrawal days unless the storage wells fall below a certain pressure. This component of the Redundancy Project will enhance efficiency and reliability as explained below.

CINGSA's Redundancy Project Whitepaper

13. As further support for the Redundancy Project proposed in this proceeding, CINGSA prepared the CINGSA Storage Facility Redundancy Project Whitepaper, dated April 2018 ("Redundancy Project Whitepaper"). The Redundancy Project Whitepaper summarizes and synthesizes the findings in the 2017 Gas Study and the Risk Report and sets forth the components of, justifications for, and estimated costs for the Redundancy Project. A true and correct copy of this document, which was prepared by me or under my direct supervision, is included as Exhibit JJL-4 (CONFIDENTIAL) and incorporated herein for all purposes. While I will not attempt to summarize or restate each aspect of the study, I will highlight certain aspects of the Redundancy Project Whitepaper for the Commission's attention.

14. The behavior of CINGSA's customers differs from normal storage customers in the Lower 48. The Lower 48 has a substantial natural gas transportation system consisting of multitudes of production fields, interconnected pipelines, and robust gas storage facilities. If a particular storage facility has a problem, it is common to call upon a different storage facility to provide the needed deliverability. As the deliverability of Cook Inlet producing wells has declined, reliance upon CINGSA as a peak day provider has increased. CINGSA, at its current rated capacity of 150,000 thousand cubic feet

("Mcf/day"), is capable of providing one-third of the Cook Inlet's peak day deliverability needs.

15. As Mr. Sims' affidavit discusses, another difference is that in the Lower 48, storage customers primarily inject gas in the summer, when availability is high and costs are generally lower, and withdraw gas in the winter. CINGSA customers, on the other hand, use the facility for many purposes to fit their business needs. It is not unusual for CINGSA customers to switch from injection to withdrawal and back again on a daily basis, or even during the course of a day.

16. The Redundancy Project consists of the following components: (1) drilling two additional storage wells and installing velocity string in one of its existing storage wells; (2) installing an additional dehydration process train; and (3) installing a new turbine compressor unit.

17. The Risk Report recommended, and the Redundancy Project Whitepaper provides additional detail supporting, the addition of two new storage wells and installation of an additional dehydration process train.

18. Drilling two new storage wells would, among other things, significantly reduce the risk of deliverability problems that may result from loss of one or more of CINGSA's five existing wells—in particular, the loss of one specific CINGSA storage well, which provides more than double the deliverability of the next highest producing gas well in the entire Cook Inlet. CINGSA anticipates that drilling new storage wells would add 30,000 Mcf/day of deliverability for each new well. The proposed velocity stringing work at one storage well is intended to reduce well bore water accumulations and thereby improve performance of that well.

19. Installing an additional dehydration process train would also greatly reduce deliverability risk. The dehydration train is composed of a number of operational processes such as pumps, reboilers, control systems, environmental control systems, etc., that must be on line to dry up the withdrawal gas. If the dehydration train is down due to a process upset or mechanical failure, gas from CINGSA will become wet and not be within pipeline/commercial specifications. Wet gas in a pipeline can cause a number of operational and safety issues. Ice may form within pressure control valves, measurement can be affected, filters can become clogged, and it can potentially cause pipe wall corrosion. During cold weather and peak flows it is of particular importance to ensure gas meets specifications as increases in the water content of the gas can cause problems with downstream customer equipment, including frozen regulators and meters. With the current equipment and configuration, a loss of the dehydration system on a peak winter day would likely result in a total loss of gas flow to customers.

20. CINGSA currently has two reciprocating engines (2,500 horsepower each) driving reciprocating compressors. As the Redundancy Project Whitepaper explains, due to the numerous operational and reliability benefits it would provide, CINGSA proposes to install a turbine drive compressor rated at 1,600 horsepower as the third component of the Redundancy Project.

21. CINGSA's maintenance program utilizes several methodologies to maintain the availability of the engines and compressors at 100%. Condition-based monitoring, manufacturer-recommended hour-based requirements, and calendar-based preventative maintenance tasks are utilized to meet this goal. To manage maintenance costs, a comprehensive annual work plan has been implemented to accomplish all of

CINGSA's maintenance tasks. Engine and compressor maintenance is scheduled for the months of November and December. This time of year should allow uninterrupted engine and compressor maintenance since the station operating mode at the beginning of the heating season is typically designed for free-flow withdrawal.

22. However, over the last four winters, CINGSA's customers have requested injection service on 61% of the days in November and December. Initial design for CINGSA was based on traditional gas storage operations as practiced in the Lower 48. Significant compression can be required to inject gas into the formations during the summer season when surplus gas is available and then withdraw in the winter to meet peak delivery needs. Although CINGSA does follow the seasonal load requirements for heating needs, the electrical utility customers have interday or even intraday demands placed on CINGSA. Injection gas may vary from 5,000 to 50,000 Mcf/day. Full loading for each of the two reciprocating compressors could vary between 50,000 and 75,000 Mcf/day depending upon pressure.

23. If customers nominate injections primarily in the summer, the compressors can be expected to operate close to capacity during this time, which increases their efficiency. Because the level of customer injections varies throughout the year, however, the compressors are used less efficiently. The injection and withdrawal activity that CINGSA experiences means that: (1) the compressors often have to run at a much lower capacity than is optimal; and (2) there is more wear and tear on the compressors. At the same time, CINGSA must nonetheless stand ready to meet its customers' firm injection and withdrawal nominations every day of the year.

24. There are a number of operational advantages to adding a smaller horsepower, turbine-driven compressor to CINGSA operations:

a. The smaller compressor will more efficiently handle gas on days when the injection rate is low. Historical records show such a compressor would be able to meet CINGSA's operational requirements on 80% of the total annual injection days. Using the smaller, more efficient, compressor would result in less fuel gas use.

b. Turbines significantly reduce mechanical vibration on facilities compared to reciprocating compressors. Since beginning operation, CINGSA has repaired or replaced a number of components on the system. Design considerations were made to reduce mechanical vibrations due to reciprocating compression but vibration cannot be eliminated.

c. General wear and tear on reciprocating compressors, and therefore downtime, is significantly greater compared to turbine-driven compressors.

d. The electric power consumption for a turbine-driven compressor is significantly less than for the current reciprocating compressors. The savings are realized in accessory equipment such as cooling pumps and fans, which have electric drives.

e. Annual carbon dioxide emissions will also be reduced with operation of a smaller compressor.

f. Most importantly, a third compressor would ensure a backup unit is always available for either injection or withdrawal. Currently, if one of the two compressors is down for annual maintenance or repairs, there is no backup for the remaining on-line compressor.

25. In addition to the operational benefits, installing the turbine compressor is estimated to save approximately $92,000 per year in operations and maintenance ("O&M") expenses, based on 1,200 hours per year of projected runtime. These savings are largely attributable to reduced compressor maintenance cost, electrical usage, and less vented natural gas. CINGSA's customers also provide natural gas in-kind for use in CINGSA's compressors via a fuel use charge, which is currently 1.1% of injections. Separate and apart from CINGSA's expected O&M cost savings, CINGSA also expects the proposed turbine compressor would provide its customers annual fuel cost savings.

26. The Redundancy Project Whitepaper estimates total project costs of approximately $41.0 million as follows:

CINGSA Redundancy Project Cost Estimates	
Surface Facilities	
Materials: Withdrawal Train/Dehydration	$3,080,000
Materials: Piping, Valves, Fittings, Electric, etc.	$1,100,000
Labor: Internal & Contractor	$1,705,000
Turbine Compressor: Materials, Contractors	$4,400,000
Permitting, Engineering, Inspection, Compliance, etc.	$715,000
Surface Facility Sub-Total	$11,000,000
Sub-Surface Facilities	
Drill Two Additional Storage Wells: Materials, Rig, Labor, etc.	$25,850,000
Water Remediation at One Well: Materials, Labor	$1,650,000
Sub-Surface Facility Sub-Total	$27,500,000
Total Project Direct Cost	**$38,500,000**
Estimated Project Overheads	$990,000
Estimated AFUDC	$1,540,000
Total Estimated Project Cost	**$41,030,000**

27. CINGSA estimates an annual increase to O&M expenses of approximately $412,000 relating to all components of the Redundancy Project. As mentioned above, however, installing the new proposed turbine compressor would contribute estimated annual O&M savings of $92,000, resulting in an estimated net increase of $320,000 to CINGSA's annual O&M expenses. These O&M savings do not include customers' fuel cost savings mentioned above.

28. Assuming Commission pre-approval of the Redundancy Project within 180 days of filing, CINGSA currently intends to begin construction in January 2019, with a projected in-service date by December 31, 2019 (or earlier if feasible).

Business Records

29. The 2017 Gas Study, Risk Report, and Redundancy Project Whitepaper are each a business record of CINGSA under Alaska Rule of Evidence 803(6). Each document is a memorandum, report, record and/or data compilation made by or near the time indicated therein at the direction of CINGSA, by persons with knowledge of CINGSA's regularly conducted business activities. In addition, the making and keeping of such memoranda, reports, records and/or data compilations are within CINGSA's regular business practices. I have personally overseen their making and keeping in the normal course of CINGSA's business operations and in the normal course of my job duties.

FURTHER AFFIANT SAYETH NOT.

SUBSCRIBED AND SWORN TO before me, the undersigned notary, this 27th day of April, 2018, to which witness my hand and seal.

DANIEL REEVES
NOTARY PUBLIC
STATE OF ALASKA

John J. Lau

Notary Public, State of Alaska

My Commission Expires:
June 27, 2021

John J. Lau

EMPLOYMENT

ENSTAR Natural Gas Company/Alaska Pipeline Company: 1989 – Present

- Vice President, Operations: 2015 – Present
- Director, Transmission Operations: 2001 – 2015
- Manager, Transmission Operation: 1990 – 2001
- Measurement Supervisor: 1989 – 1990

Conoco, Inc.: 1981 – 1989

- Production Supervisor: 1986 – 1988
- Supervising Engineer: 1984 – 1986
- Engineer: 1981 – 1983

Pacific Corp., Engineer: 1978 – 1980

EDUCATION

University of Wyoming: Bachelor of Science – Electrical Engineering: 1978

University of Washington: Master of Business Administration: 2001

OTHER

Professional Licenses

- Professional Engineer, Alaska
- Professional Engineer, Wyoming

Professional Engineer Society

Project Management Institute

Instrument Society

The Alaska Support Industry Alliance

Resource Development Council

Advisory Board Member for University of Alaska – Anchorage School of Engineering

Cook Inlet Gas Study - 2017 Update

prepared for

ENSTAR

Natural Gas Company

November 2017

Peter J. Stokes, PE

Petrotechnical Resources of Alaska
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Petrotechnical Resources Alaska

Due to the uncertainties of drilling and producing activities of operating and exploration companies and Alaska state agencies in influencing drilling activities, this study should be considered a best estimate at present with the current data available. It was prepared using generally accepted engineering predictive methods.
As such, Petrotechnical Resources of Alaska can make no warranty as to the actual future performance of the Cook Inlet gas production.

Executive Summary

Petrotechnical Resources of Alaska (PRA) was asked to update gas supply and demand forecasts of the October 2012 report entitled "Cook Inlet Gas Study – 2012 Update".

The Cook Inlet Gas Study - 2012 Update indicated that there would be a Cook Inlet supply shortfall as early as 2014 with production from current fields only. A shortfall, where demand exceeds supply, has been consistently projected in prior studies.

The following table summarizes the CI gas well drilling activity since 2010:

Year	# New Gas Wells	Total Rate Added, MMSCF/D	Average Rate/Well, MMSCF/D
2010	5	18.5	3.7
2011	7	12.3	1.8
2012	4	23.4	5.9
2013	0	0	0.0
2014	14	65	4.6
2015	8	20.3	2.5
2016	4	23.5	5.9
2017 5 Months	4	12.3	3.1

Table 1: Gas Well Drilling Activity 2010 to 2017

PRA 2017 Update Report Findings

This Cook Inlet Gas Study - 2017 Update indicates that if activity continues at the average pace experienced in 2015-2016, adding 21.9 MMSCF/D of new production per year, there will not be a Cook Inlet supply shortfall until 2021.

Figure 1 shows a comparison of projected demand compared to supply forecast from the wells of existing fields with the assumed Cook Inlet gas well development of adding 21.9 MMSCF/D for years 2018-2030.

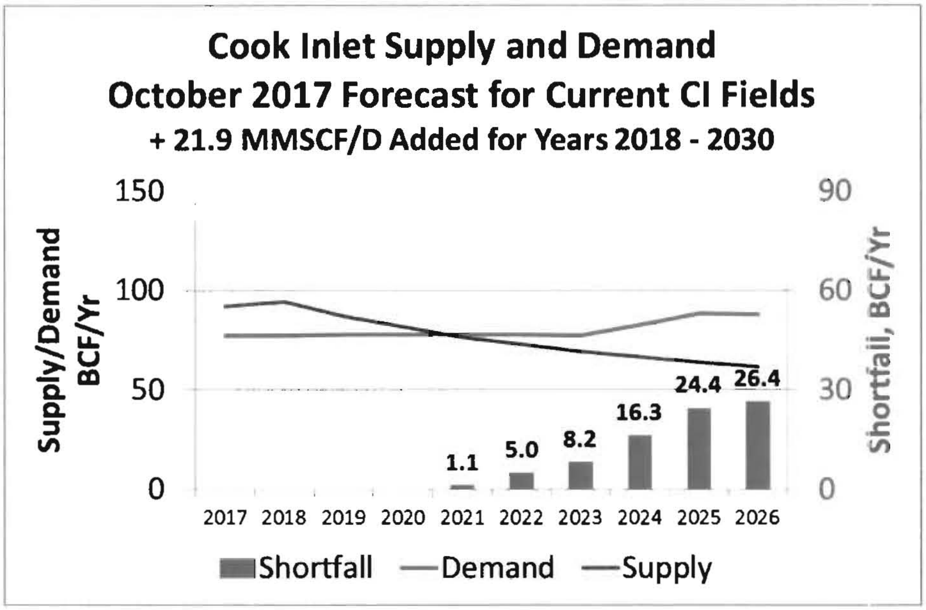

Figure 1: 2017 Cook Inlet Supply/Demand & Shortfall from current drilling activity level

Table 1 shows a summary of the scenarios investigated in the 2017 Update. If there is no drilling activity to add new production in Cook Inlet, a shortfall occurs as early as 2019. If there are equivalent levels of drilling of gas wells as occurred in the 2015-16 period, adding 21.9 MMSCF/D annually, a shortfall is not predicted until 2021.

Scenario	Initial Year of Shortfall	Initial Year Shortfall Amount, BCF
Existing Cook Inlet Fields	2019	4.0
Existing Fields + Annual Addition of 21.9 MMSCF/D Production from New Wells 2018-2030	2021	1.1
Existing Fields + Annual Addition of 36.3 MMSCF/D Production from New Wells 2018-2030	2025	0.7

Table 2: 2017 Cook Inlet Gas Supply Scenarios

The scenario of adding 36.3 MMSCF/year is based on the average development pace for 2014-16; this includes the large number of gas wells added in 2014.

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Introduction

In March 2010, PRA completed the "Cook Inlet Gas Study – An Analysis for Meeting the Natural Gas Needs of Cook Inlet Utility Customers" that was commissioned in 2009 for ENSTAR Natural Gas Company, Chugach Electric Association and Municipal Light & Power.

The March 2010 report was based on AOGCC production data available for Cook Inlet wells through October 2009.

The 2010 Study concluded that:

- With existing producing fields in Cook Inlet and the current forecasted demand, there would be a critical shortage of natural gas supply starting in 2013.
- If drilling activity remained at the 13.6 wells completed per year level that occurred during 2007-mid 2009, the shortage of gas would 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 contemporaneous Cook Inlet oil and gas industry forums indicated that this level of activity was not likely to continue.
- To meet demand through 2020, a total of 185 wells would 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 was deemed likely that a source of gas outside of the Cook Inlet, such as LNG importation or other in-state reserves, would 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 would be required to meet the winter deliverability swings.

There have been 2 reviews of gas well drilling activity in Cook Inlet that showed Cook Inlet development pace was much lower than experienced in 2007-2009.

- In the November, 2010 Cook Inlet Gas Drilling Update, it was found that:
  - The twelve month drilling and permitting activity showed eight net wells (ten wells permitted and two previously permitted wells cancelled) over the twelve month period from Nov-2009 through Oct-2010.
  - Over this twelve month period there were five wells completed that averaged 3.7 MMSCF/D per well for their first six months of production.
- In November, 2011 Cook Inlet Gas Drilling Update, it was found that:
  - The twelve month drilling and permitting activity showed eight new wells over the twelve month period from Nov-2010 through Oct-2011.
  - There had been 3 apparent exploration discoveries in the last year; the Kenai Loop Unit, the Shadura No. 1 and the offshore Kitchen Lights Unit.
  - The Kenai Loop had a certified proven reserve announced, the gas was contracted, and development facilities were being constructed for gas sales in 2012.
  - While the Shadura prospect was being permitted for development, there had been no announced estimates of reserves and additional testing was planned prior to sizing production equipment. The earliest testing and delineation would be permitted was the winter of 2012-13.

- There was some question about the veracity of the announced Kitchen Lights discovery and as it is an offshore development, it would likely take several years to delineate and develop.
- The recently completed six wells that had reported production averaged 1.65 MMSCF/D per well for their first six months of production.

An update study of the Cook Inlet Supply and Demand was completed in 2012. The 2012 Cook Inlet Gas Study Update concluded that:

- With the pace of current development, absent a major gas discovery that could be available to utilities in less than two (2) years, a shortage of Cook Inlet natural gas supply would occur by 2015.
- If 31 MMSCF/D of new production was added each year from new completions in 2013-2019, a shortfall would be avoided.
- It was estimated that 157 new gas completions were required to meet demand through 2020.
- The most likely sources of new production in Cook Inlet would be from existing fields such as Beluga River Unit and Trading Bay Unit or development of recent discoveries such as Kenai Loop and Shadura or possible successes at Otter, Tiger Eye or the Apache Tyonek well.
- Any major new gas discoveries from offshore exploration were not likely to be brought on production within 3-5 years due to permitting, planning and construction of offshore facilities and pipelines.

The 2017 Update of Cook Inlet Supply and Demand was undertaken as follows:

I. 2017 Cook Inlet Demand Forecast
II. 2017 Cook Inlet Supply Forecast
III. Timing of Supply Shortfall with Current Wells in Cook Inlet Fields
IV. Potential New Developments
V. Future Production Scenarios
VI. Ranking of Cook Inlet Gas Wells
VII. Conclusion

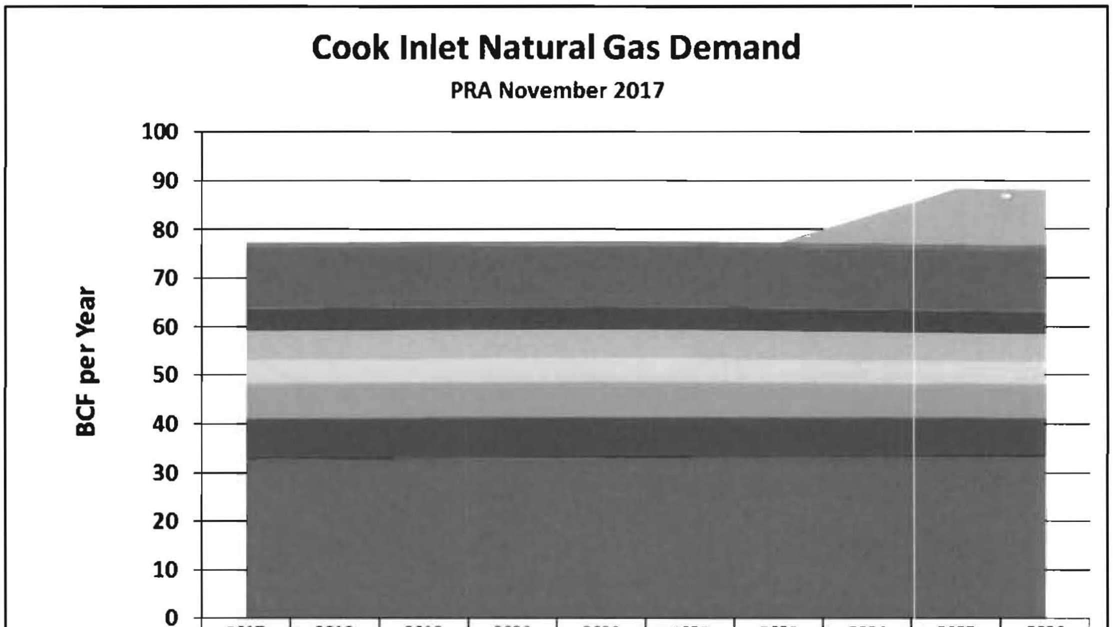
Production and Forecast of Field and Well Decline Curves are presented in the Appendix.

I. 2017 Cook Inlet Demand Forecast

The demand forecast for the Cook Inlet Basin is shown in Figure 2. It is based on data provided by ENSTAR, RCA gas contracts for Cook Inlet electrical utilities, and Donlin Creek Mine.

Cook Inlet demand has changed slightly over the last few years with a reduction in utility gas demand from more efficient electric generation. The current demand forecast for the Cook Inlet Basin is shown below in Figure 2.

Cook Inlet Field usage is based on the average 2011-2016 AOGCC record of fuel, flare and shrinkage for Cook Inlet fields.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Donlin Gold							-	5.7	11.5	11.5
FNG	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Field Fuel Gas	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
Tesoro	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
MEA	6.0	6.0	6.0	6.0	6.0	6.0	5.9	5.8	5.8	5.7
HEA	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.6	4.6	4.5
ML&P Native Load	7.3	7.3	7.3	7.3	7.3	7.2	7.2	7.1	7.0	6.9
CEA	8.4	8.4	8.4	8.4	8.4	8.3	8.2	8.1	8.1	8.0
ENSTAR	32.8	32.9	33.0	33.0	33.1	33.1	33.2	33.2	33.3	33.3
Total Cook Inlet	77.4	77.5	77.6	77.6	77.7	77.6	77.4	82.9	88.4	88.2

Figure 2: Forecasted Annual Demand for Cook Inlet Gas

Figure 3 shows the Cook Inlet demand forecasted in the 2010 Study and the 2012 Update in comparison to this 2017 Update. In general, the 2017 forecast is lower, although Donlin Creek Mine is now projected to start up in mid-2024.

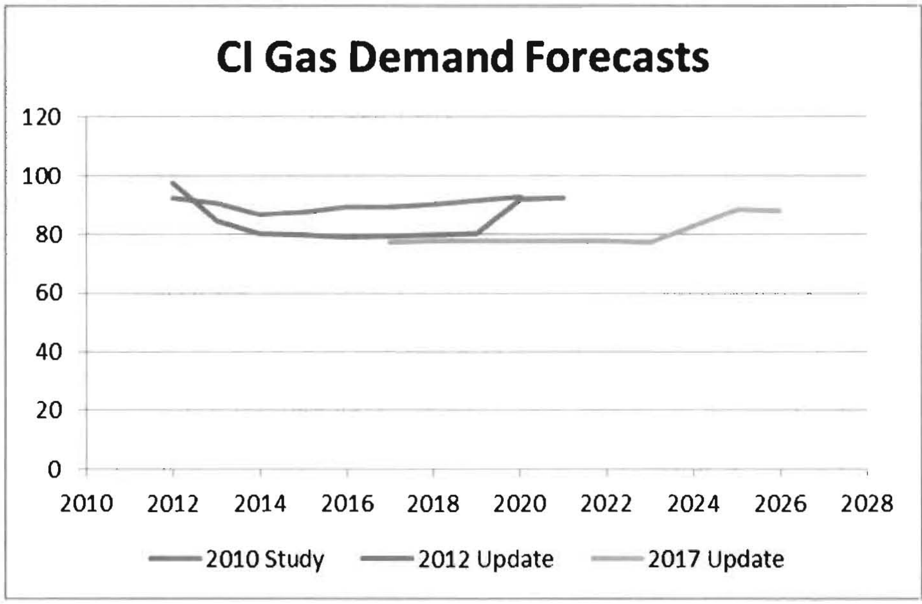


Figure 3: Comparison of Cook Inlet Demand 2010 Study and 2012 Update vs. 2017 Update

II. 2017 Cook Inlet Supply Forecast

PRA evaluated existing production declines and made a future production forecast for the major units in the Cook Inlet Basin.

Larger producing units, and those that had recent development activity, were analyzed on a well-by-well basis and the unit total was the sum of the individual wells. The following units were analyzed by individual wells and those cumulative results are shown below:

	2017 Predicted Average Rate, MMSCF/D	Predicted Annual Decline	Remaining BCF as of 1/1/17
Beluga River Unit	41.5	19%	88.6
Kenai Unit	49.0	18%	103.9
Kenai Loop	8.0	15%	17.5
Ninilchik Unit	36.0	15%	82.1
Kitchen Lights Unit	17.7	10%	56.3
North Cook Inlet Unit	18.6	11.3%	60.9
North Fork Unit	6.3	20%	9.3
Trading Bay Unit	18.8	20%	28.4

Note: Ninilchik Unit excludes production and reserves from the Kalotsa #'s 2, 3 & 4, and Blossom #1 wells, which are not currently completed.

Units with future production are predicted on a unit total basis and results are as follows:

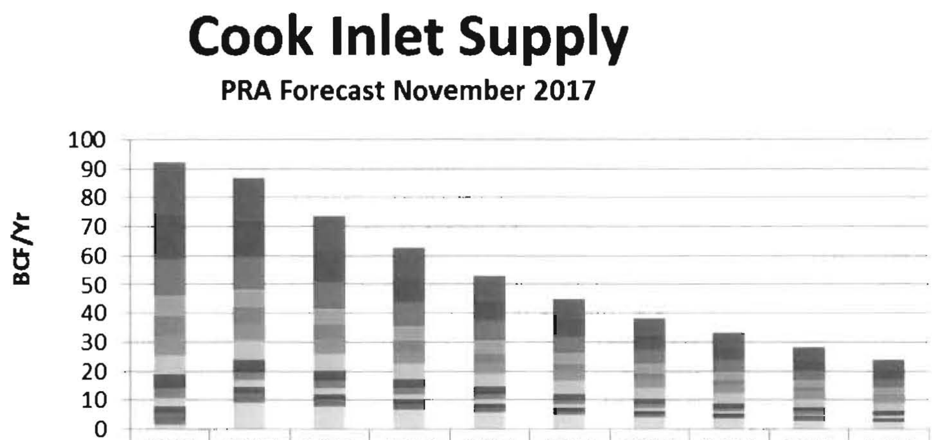
	2017 Predicted Average Rate, MMSCF/D	Predicted Annual Decline	Remaining BCF as of 1/1/17
Beaver Creek Unit	13.0	15%	28.4
Cannery Loop Unit	9.0	15%	19.7
Deep Creek Unit	6.5	15%	14.1
Swanson River Unit	5.5	15%	12.0
Other Cook Inlet Fields	20.0	12%	50.7
Cook Inlet Total	**249.9**		**571.9**

Production curves and forecasts for each of the units above are shown in Appendix A.

The individual well decline curves for Beluga River, Kenai, Ninilchik, North Cook Inlet, North Fork and Trading Bay units are shown in Appendix B.

For the predictions in this study, an individual well was deemed to have reached an economic limit at 250 MSCF/D.

Figure 4 shows the estimate of annual supply from the existing wells in the current units. It is an estimate of the decline curve analysis for wells completed up to May 2017 and includes an estimate of 2017 wells not yet completed.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kenai Unit	18.2	14.8	12.2	10.3	8.7	7.3	6.1	5.2	4.4	3.7
Beluga River Unit	15.2	12.5	10.3	8.5	7.0	5.8	4.8	4.1	3.4	2.9
Ninilchik Unit	12.4	11.1	9.4	8.0	6.7	5.7	4.8	4.2	3.6	3.0
Other CI	7.3	6.4	5.7	5.0	4.4	3.9	3.4	3.0	2.6	2.3
TBU	6.8	5.5	4.4	3.4	2.5	2.0	1.5	1.1	0.8	0.4
North CI Unit	6.8	6.1	5.4	4.8	4.3	3.9	3.5	3.2	2.8	2.4
Kitchen Lights Unit	6.5	6.7	6.0	5.4	4.9	4.4	3.9	3.6	3.2	2.9
Beaver Creek Unit	4.7	4.0	3.4	2.9	2.5	2.1	1.8	1.5	1.3	1.1
Cannery Loop	3.3	2.8	2.4	2.0	1.7	1.5	1.2	1.1	0.9	0.8
Kenai Loop Unit	2.9	2.5	2.1	1.8	1.5	1.3	1.1	0.9	0.8	0.7
Deep Creek	2.4	2.0	1.7	1.5	1.2	1.0	0.9	0.8	0.6	0.5
North Fork Unit	2.2	1.7	1.4	1.1	0.9	0.7	0.5	0.4	0.2	0.1
Swanson River	2.0	1.7	1.5	1.2	1.0	0.9	0.8	0.6	0.5	0.5
2017 New Wells	1.4	8.9	7.6	6.5	5.5	4.7	4.0	3.4	2.9	2.4
Total Cook Inlet	92.1	86.8	73.5	62.5	52.9	45.1	38.3	33.0	28.0	23.8

Figure 4: 2017 Cook Inlet Gas Forecasts 2017-2026

Figure 5 shows the differences in Cook Inlet production forecasts between the 2010 Study, the 2012 Update and the 2017 Update for the existing Cook Inlet Fields.

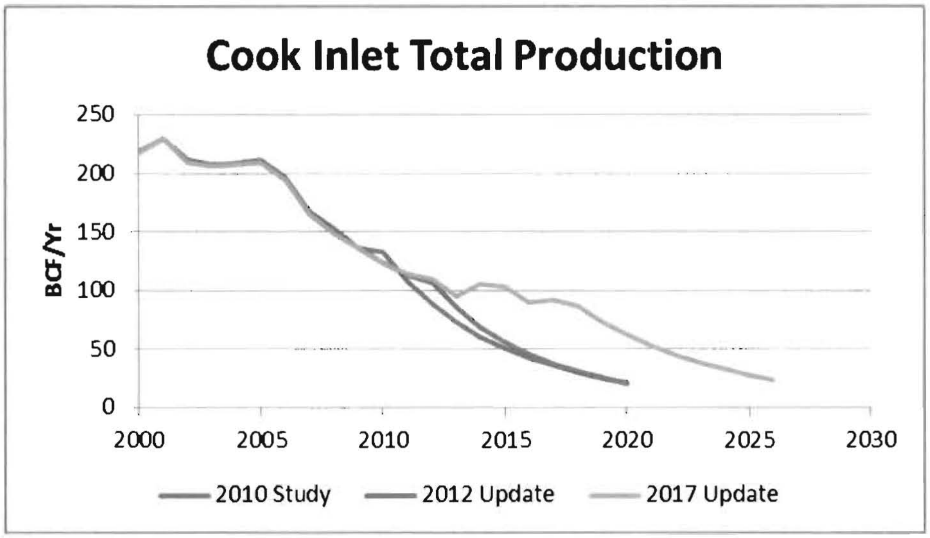


Figure 5: Cook Inlet Production & Forecast: 2010 Study v. 2012 Update & 2017 Update

2013-2017 Drilling Activity

Table 3 shows the drilling activity since the 2012 Update.

Year Completed	Number of Wells	Average 6 Mo Rate, MMSCF/D	Total Rate Developed, MMSCF/D
2013	0	0	0
2014	14	4.6	65.0
2015	8	2.5	20.3
2016	4	5.9	23.5
2017 – 5 Mo.	4	4.1	12.3

Table 3: Cook Inlet new gas wells completed and total production added during 2013 through May 2017.

Figures 6, 7 and 8 show the differences in forecasts from the 2010 Study and the 2012 Update and the 2017 Update for Beluga River, Ninilchik and TBU Units, respectively. As can be seen, there has been significant new development in Ninilchik Unit and this does not include 4 wells not yet producing.

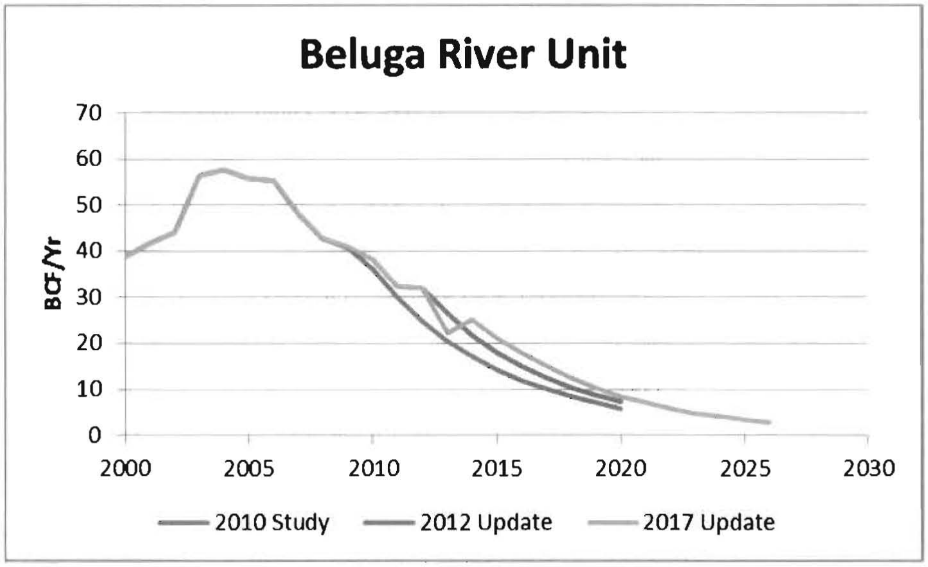


Figure 6: Beluga River Unit Production & Forecast: 2010 Study v. 2012 Update & 2017 Update

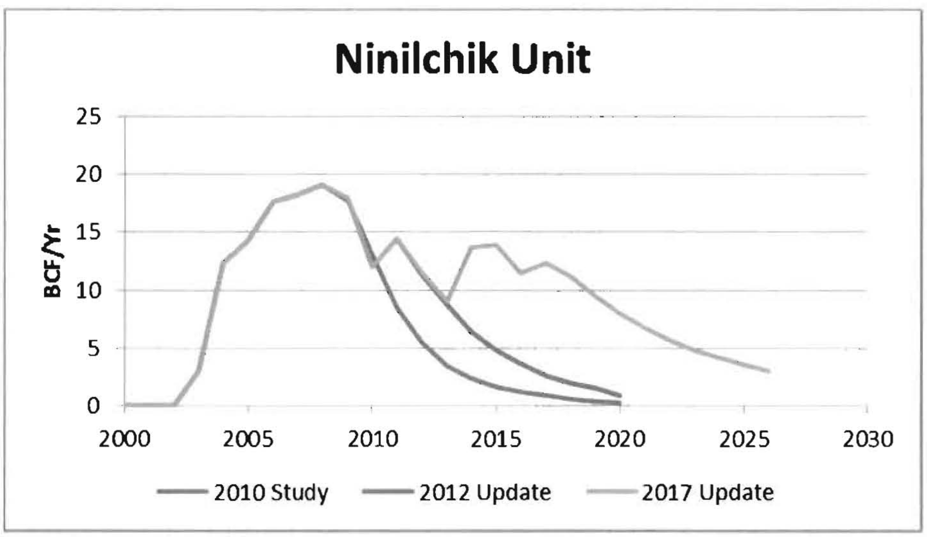


Figure 7: Ninilchik Unit Production & Forecast: 2010 Study v. 2012 Update & 2017 Update

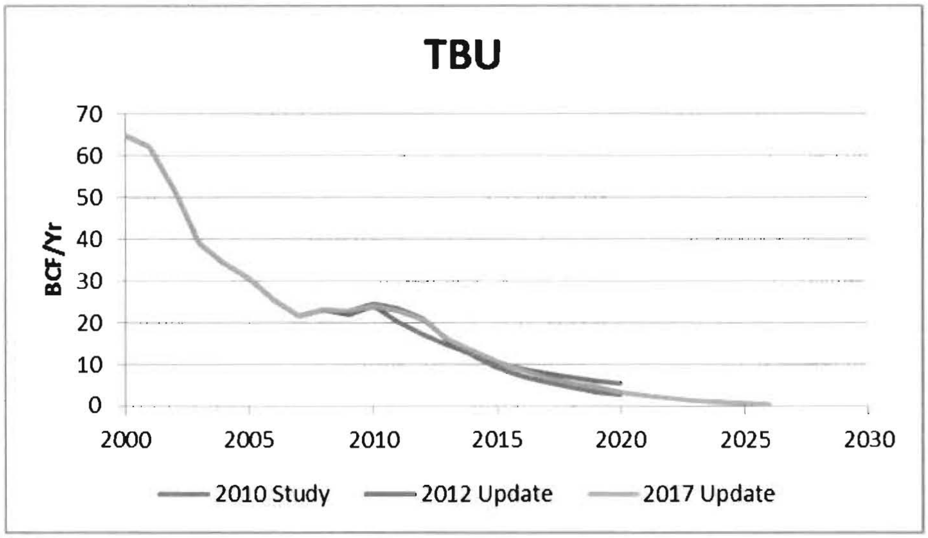


Figure 8: Trading Bay Unit Production & Forecast: 2010 Study v. 2012 Update & 2017 Update

III. Timing of Supply Shortfall with Current Cook Inlet Fields

Figure 9 shows a comparison of projected demand and supply forecast from the wells in existing fields with no further development.

A shortfall develops in 2019 under this scenario.

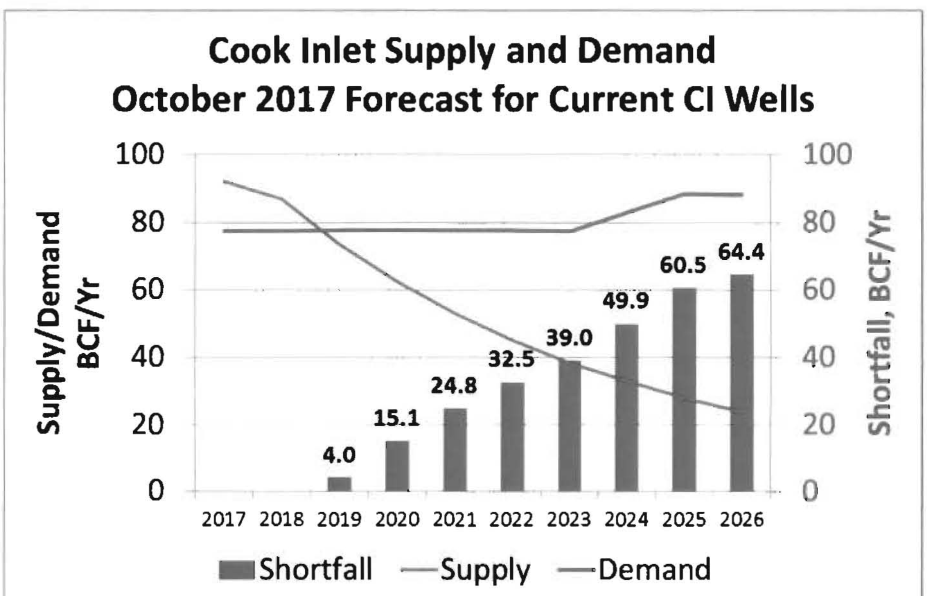


Figure 9: 2017 CI Supply/Demand and Shortfall from Current CI Wells.

IV. Potential New Developments

From review of recent Plans of Developments submitted to the AK DNR Division of Oil and Gas, there are no major new gas developments planned in Cook Inlet.

Hilcorp plans to continue delineation and development of the Ninilchik Unit with drilling at the Pearl Pad, in the southern end of the unit. As can be seen from their recent drilling performance, Hilcorp will continue to develop infill potential identified in other fields such as the Kenai Units.

Furie plans to complete a third and potentially drill a fourth gas production well in the Kitchen Lights Unit.

V. Future Production Scenarios

To understand how future development of gas wells will affect timing of potential shortfalls, sensitivities were made assuming the annual production added in the 2015-16 time period (21.9 MMSCF/D) and the 2014-16 time period (36.3 MMSCF/D).

Figures 10 and 11 show existing production and future scenarios of 21.9 MMSCF/D, and 36.3 MMSCF/D of production added annually. The decline for new production is assumed to be 15% per year.

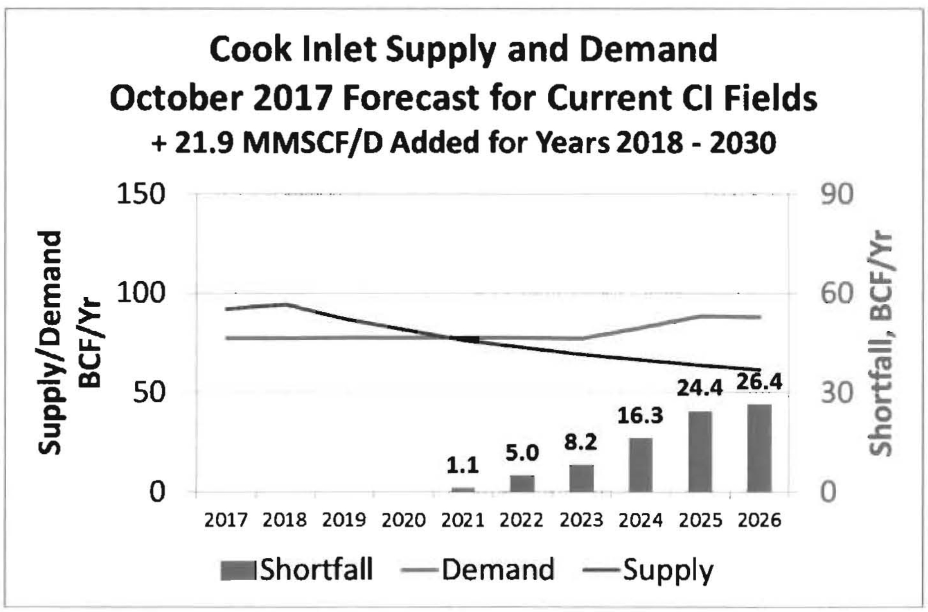


Figure 10: Supply/Demand & Shortfall with 21.9 MMSCF/D of New Production Added Annually.

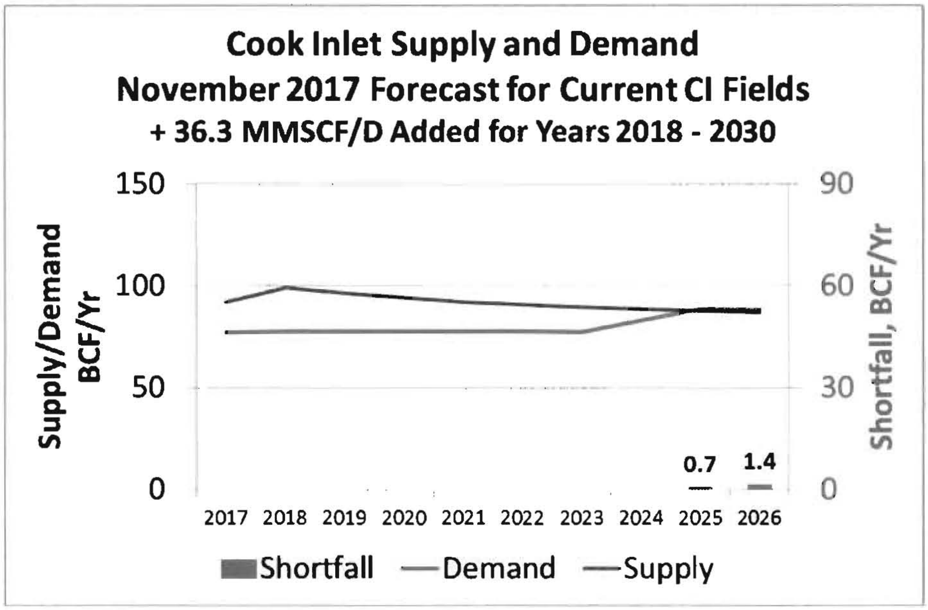


Figure 11: Supply/Demand & Shortfall with 36.3 MMSCF/D of New Production Added Annually.

Sensitivities were made to show the additional amount of new gas additions required under each of the two scenarios to allow meeting projected shortfalls through 2030. Table 4 shows the additional gas required by year in each scenario.

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
21.9 MMSCF/D Added 2018-2030	3.2	11.0	10.8	25.5	29.1	15.4	15.4	15.1	15.7	15.2
36.3 MMSCF/D Added 2018-2030					2.0	2.0	2.0	1.7	2.4	1.8

Table 4: Additional annual additions of gas production to meet demand through 2030.

VI. Ranking of Individual Cook Inlet Gas Wells

Individual Cook Inlet gas wells, including storage wells, were ranked for peak delivery over the 12 month period of June 2016 through May 2017. This peak delivery was based on the monthly production divided by the days produced.

The top 10 wells are shown in Table 5. Appendix D shows a complete listing of all Cook Inlet wells.

Well	Max Rate Jun 16-May-17 (Mo. Prod./Days Prod) MMSCF/D	Month of First Production
CANNERY LOOP UNIT S-1	22.882	Nov-2012
KLU A-2A	20.195	Sep-2016
CANNERY LOOP UNIT S-3	13.145	Nov-2012
KLU 3	11.862	Nov-2015
KALOTSA #1	11.761	Mar-2017
CANNERY LOOP UNIT S-2	10.113	Nov-2012
SOLDOTNA CK UNIT 22B-04	9.971	Apr-2014
CANNERY LOOP UNIT 05RD	9.511	Dec-2015
Beluga River Unit #224-34	9.254	Dec-1986
KENAI LOOP 1	8.328	Jan-2012

Table 5: Top 10 Cook Inlet Producing Wells

VII. Conclusion

Table 5 shows a summary of the scenarios investigated in the 2017 Update. If there is no drilling activity to add new production in Cook Inlet, a shortfall occurs as early as 2019.

Scenario	Initial Year of Shortfall	Initial Year Shortfall Amount, BCF
Existing Cook Inlet Fields	2019	4.0
Existing Fields + Annual Addition of 21.9 MMSCF/D Production from New Wells 2018-2025	2021	1.1
Existing Fields + Annual Addition of 36.3 MMSCF/D Production from New Wells 2018-2025	2025	0.7

Table 6: 2017 Cook Inlet Gas Supply Scenarios

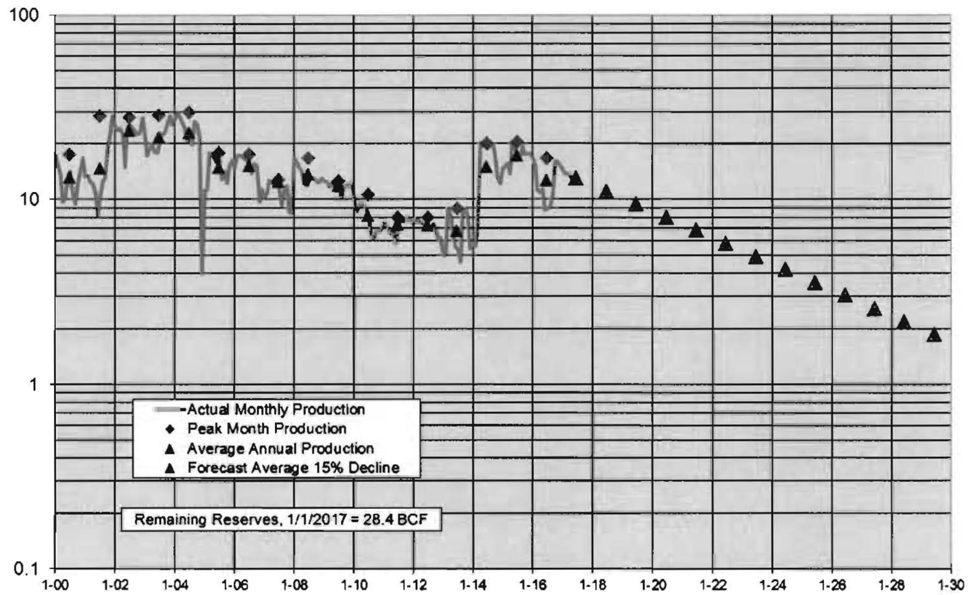
The recent activity has demonstrated that wells are being developed in as necessary to meet contracts. Average activity level from 2015 through 2016 has added 21.9 MMSCF/D of production from new gas well completions, which will delay any shortfall until 2021.

Additional production additions beyond 21.9 or 36.3 MMSCF/D is required to meet demands through 2030.

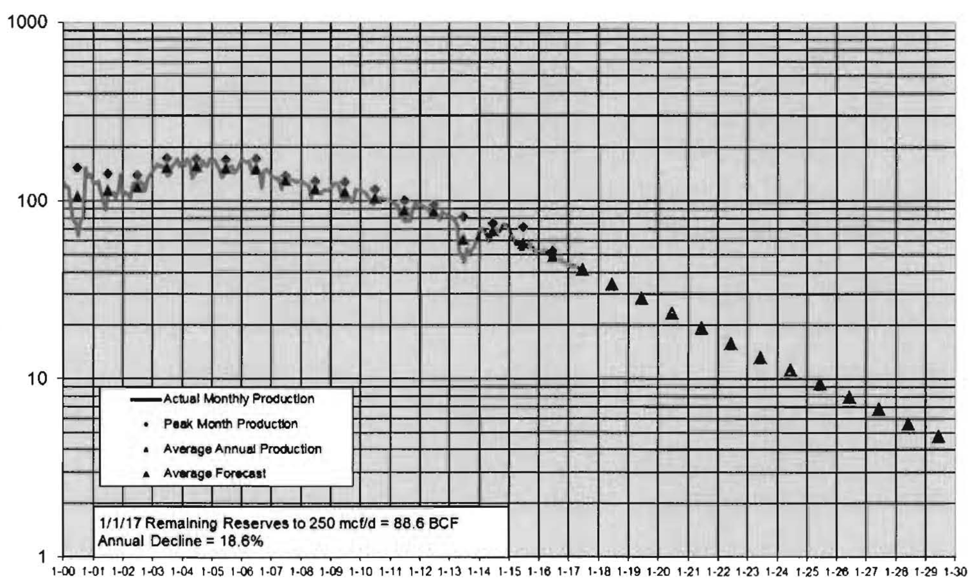
VIII. Appendices

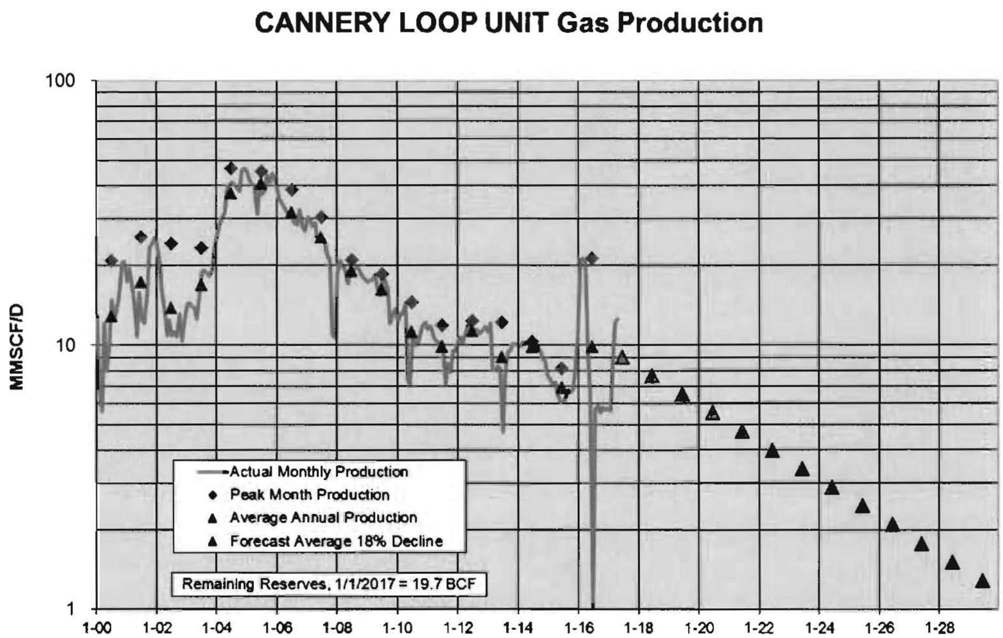
Appendix A: Cook Inlet Unit Production and Forecasts

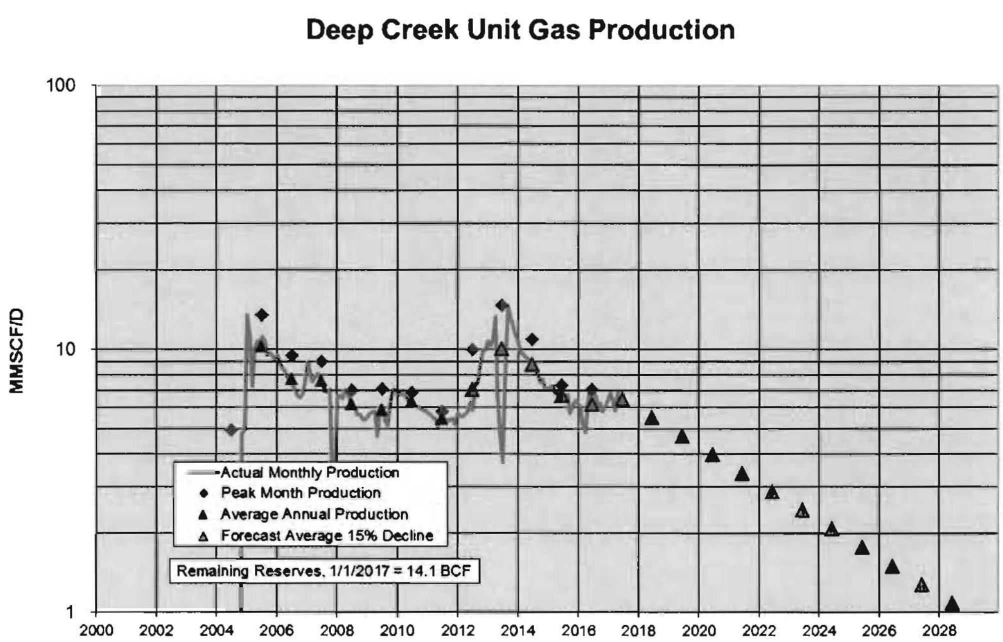
BEAVER CREEK UNIT Gas Production



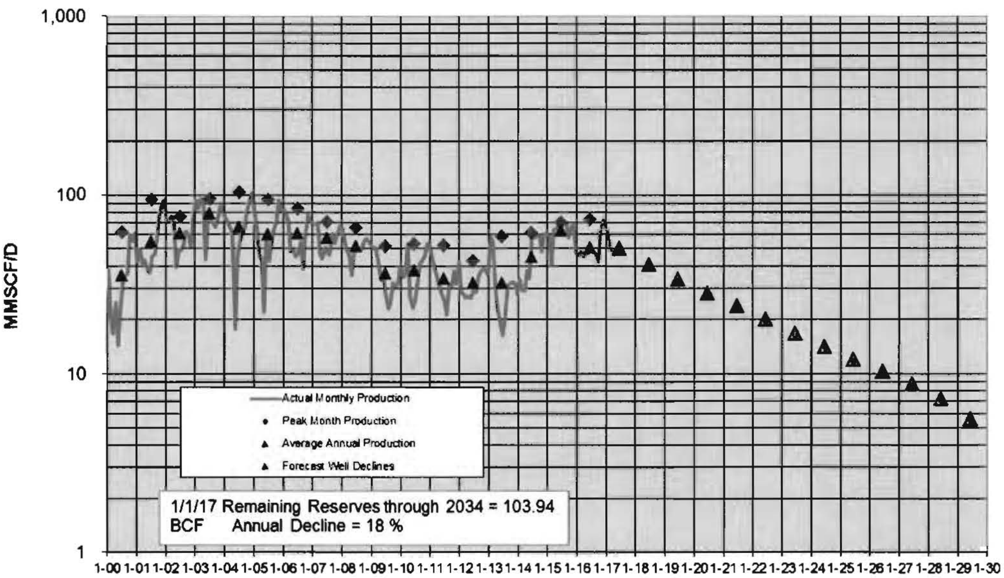
Beluga River Unit Total



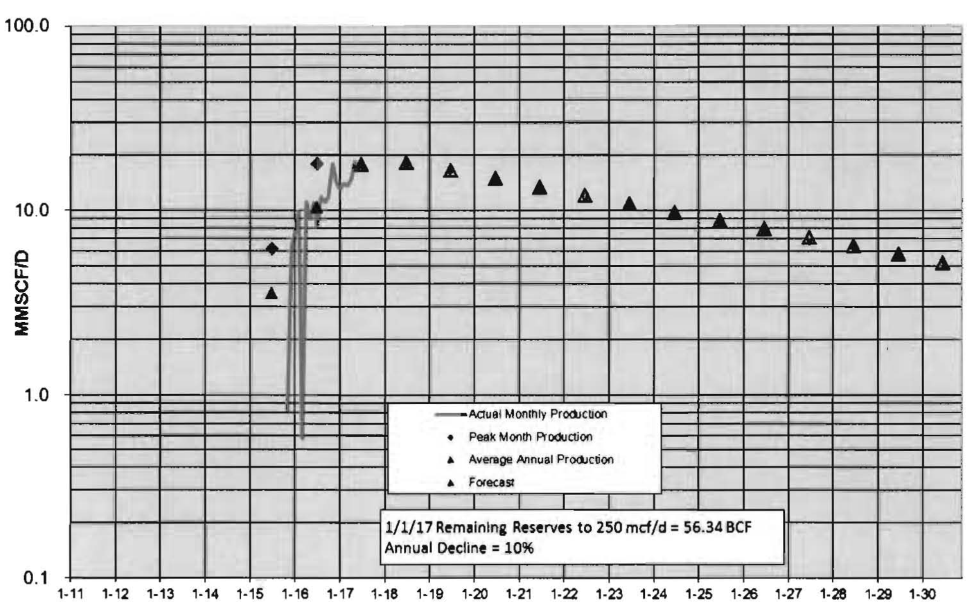

CANNERY LOOP UNIT Gas Production
MMSCF/D
100
10
1
1-00
1-02
1-04
1-06
1-08
1-10
1-12
1-14
1-16
1-18
1-20
1-22
1-24
1-26
1-28
Actual Monthly Production
Peak Month Production
Average Annual Production
Forecast Average 18% Decline
Remaining Reserves, 1/1/2017 = 19.7 BCF


Deep Creek Unit Gas Production
MMSCF/D
100
10
1
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
Actual Monthly Production
Peak Month Production
Average Annual Production
Forecast Average 15% Decline
Remaining Reserves, 1/1/2017 = 14.1 BCF

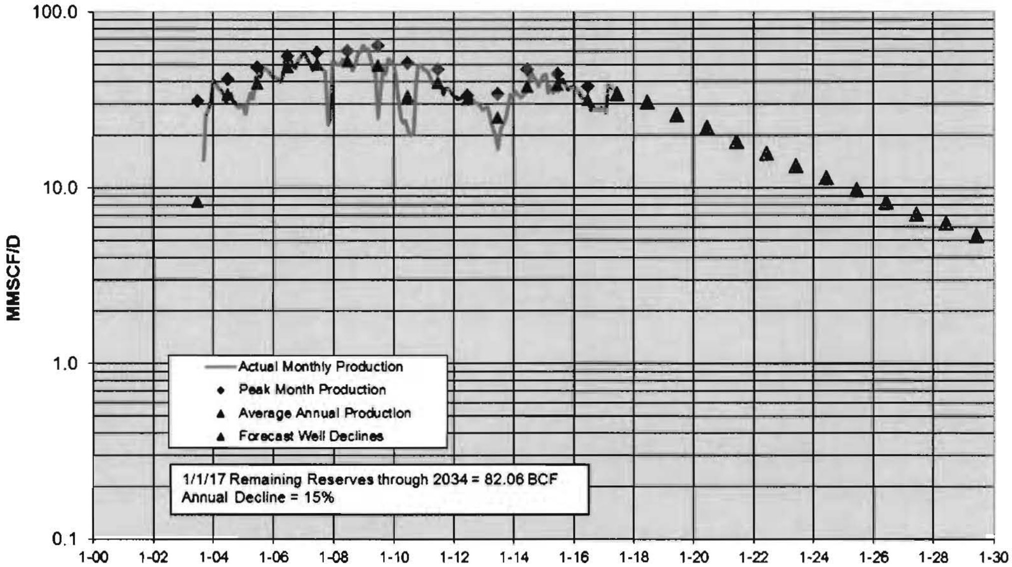
KENAI UNIT TOTAL



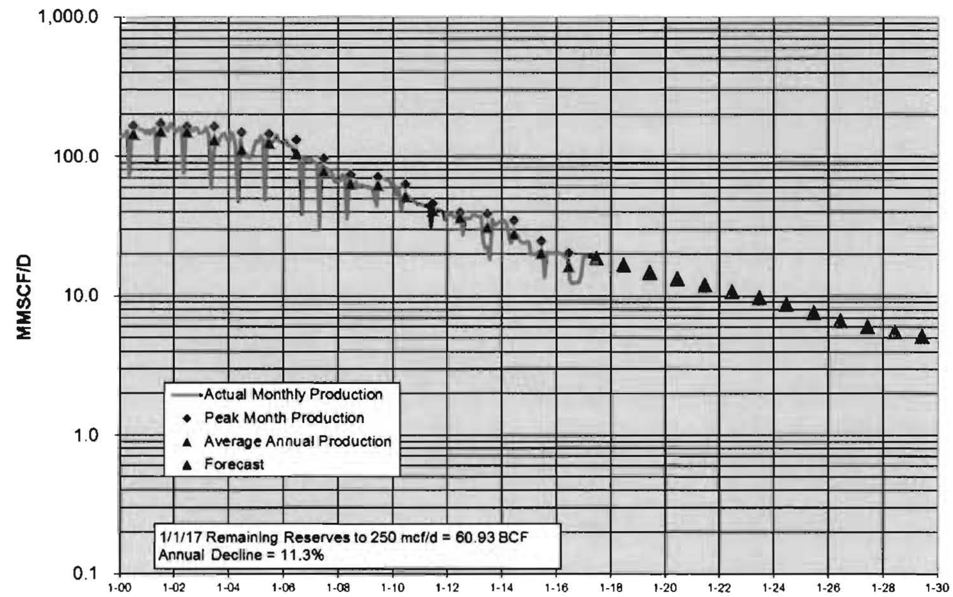
Kitchen Lights Unit Gas Production



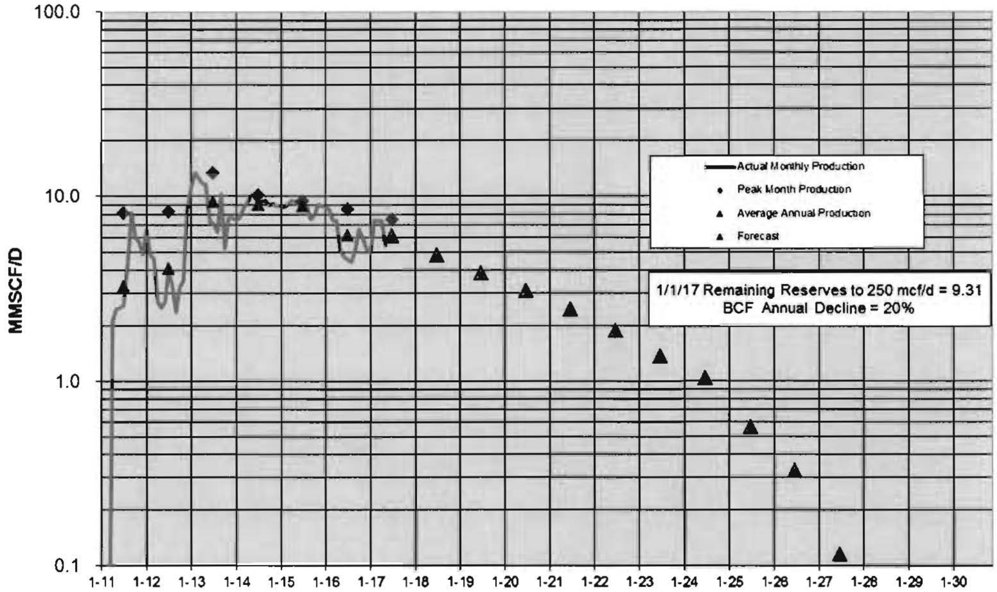
Ninilchik Unit Gas Production



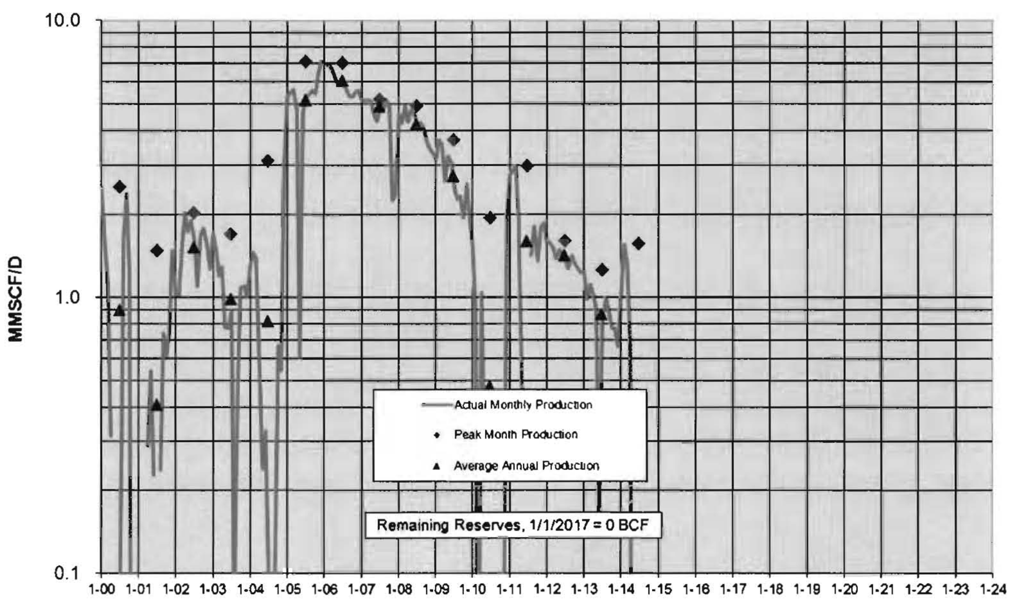
North Cook Inlet Total

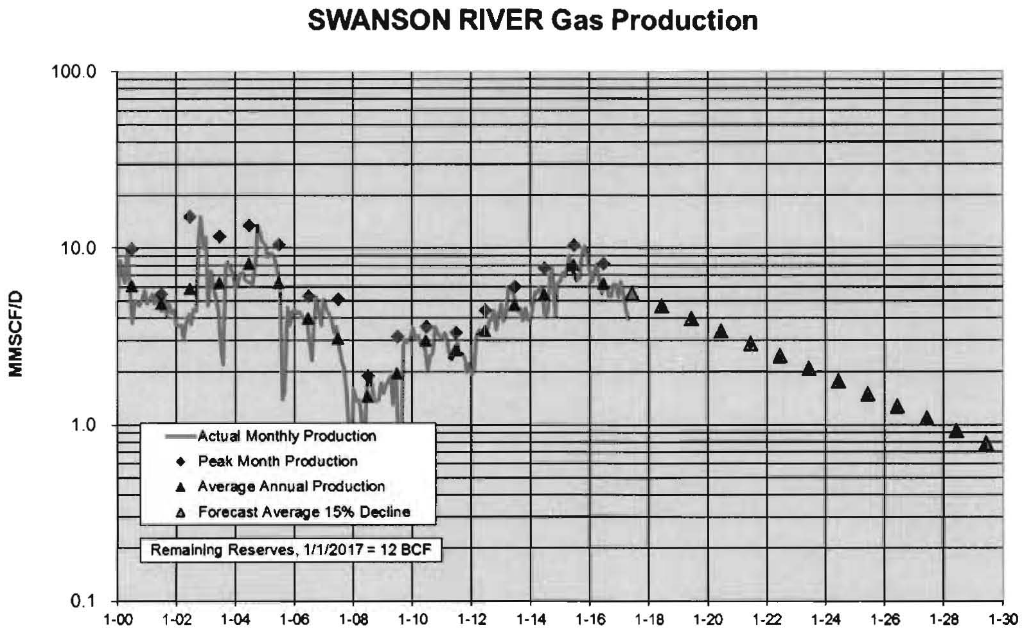


NORTH FORK UNIT Gas Production

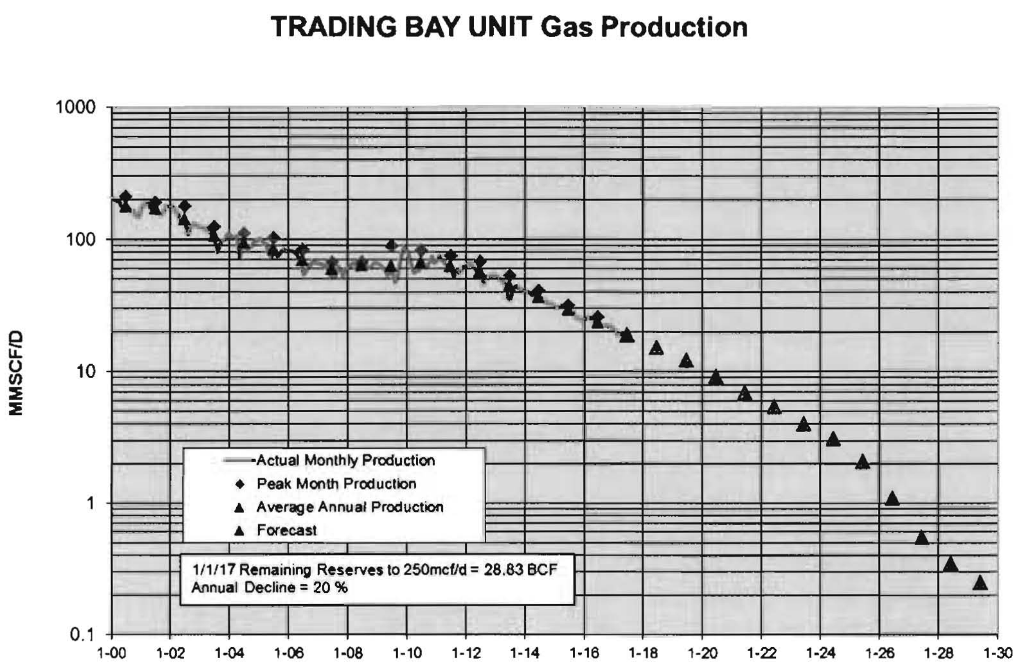


STERLING UNIT Gas Production



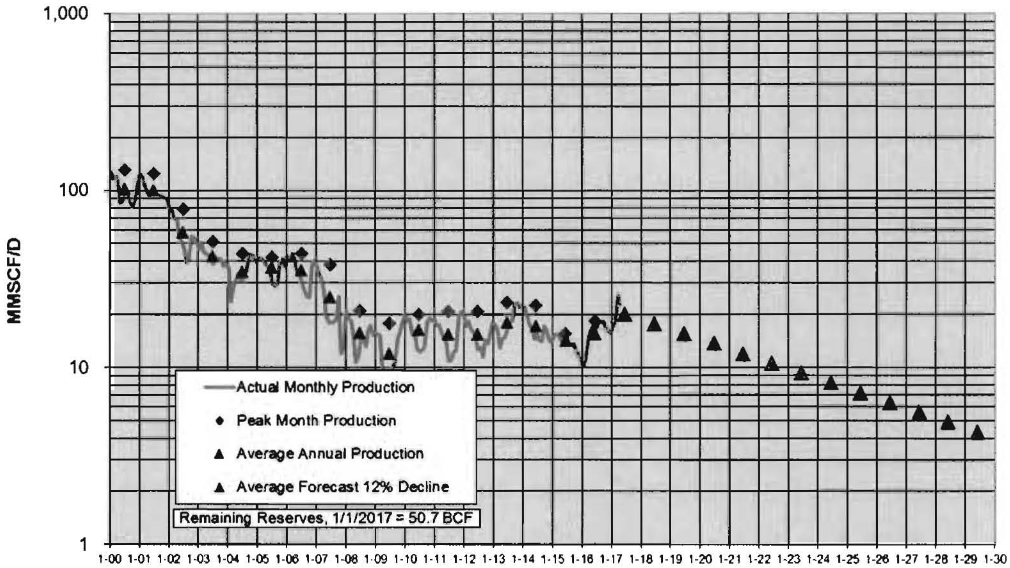


SWANSON RIVER Gas Production
100.0
10.0
1.0
0.1
MMSCF/D
1-00
1-02
1-04
1-06
1-08
1-10
1-12
1-14
1-16
1-18
1-20
1-22
1-24
1-26
1-28
1-30
Actual Monthly Production
Peak Month Production
Average Annual Production
Forecast Average 15% Decline
Remaining Reserves, 1/1/2017 = 12 BCF



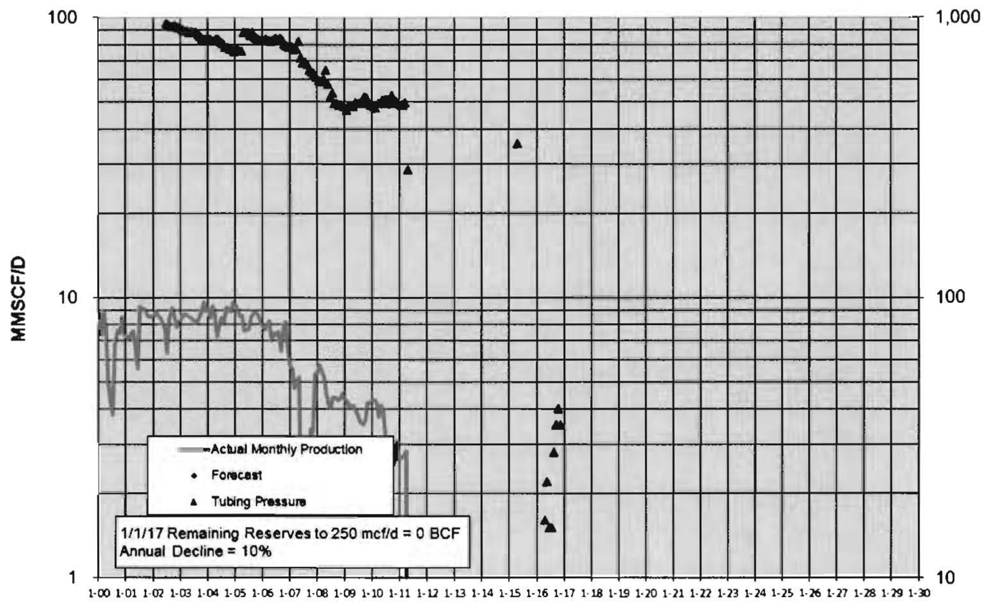
TRADING BAY UNIT Gas Production
1000
100
10
1
0.1
MMSCF/D
1-00
1-02
1-04
1-06
1-08
1-10
1-12
1-14
1-16
1-18
1-20
1-22
1-24
1-26
1-28
1-30
Actual Monthly Production
Peak Month Production
Average Annual Production
Forecast
1/1/17 Remaining Reserves to 250mcf/d = 28.83 BCF
Annual Decline = 20 %

Cook Inlet Other Field Production w/o Storage

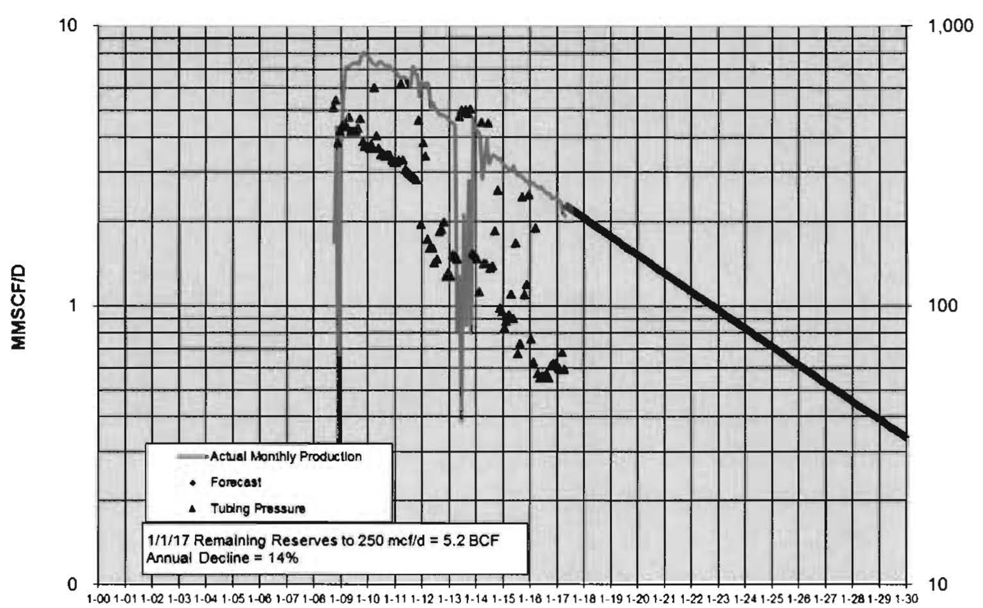


Appendix B-1: Beluga River Unit Well Decline Curves

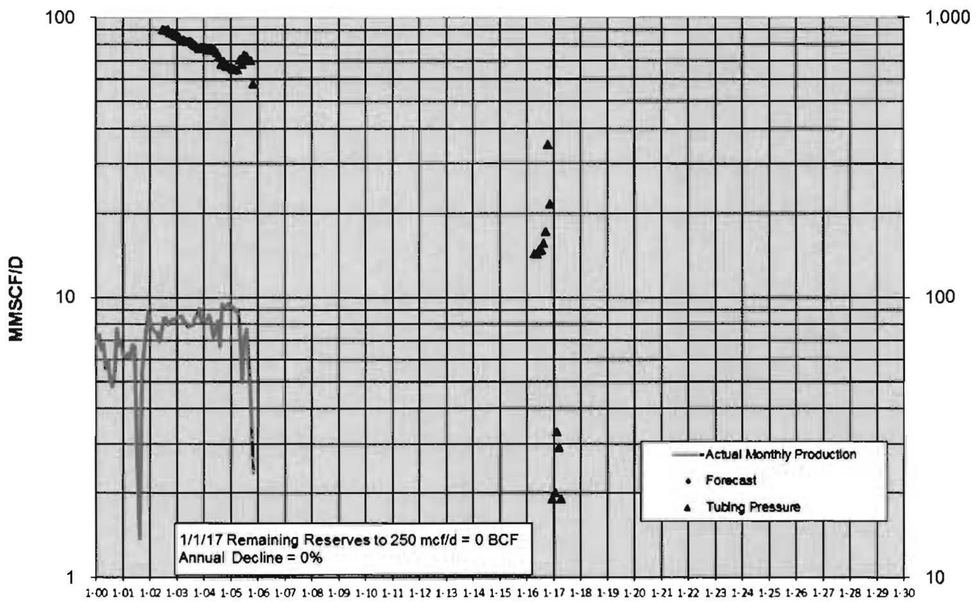
Beluga River Unit #211-03



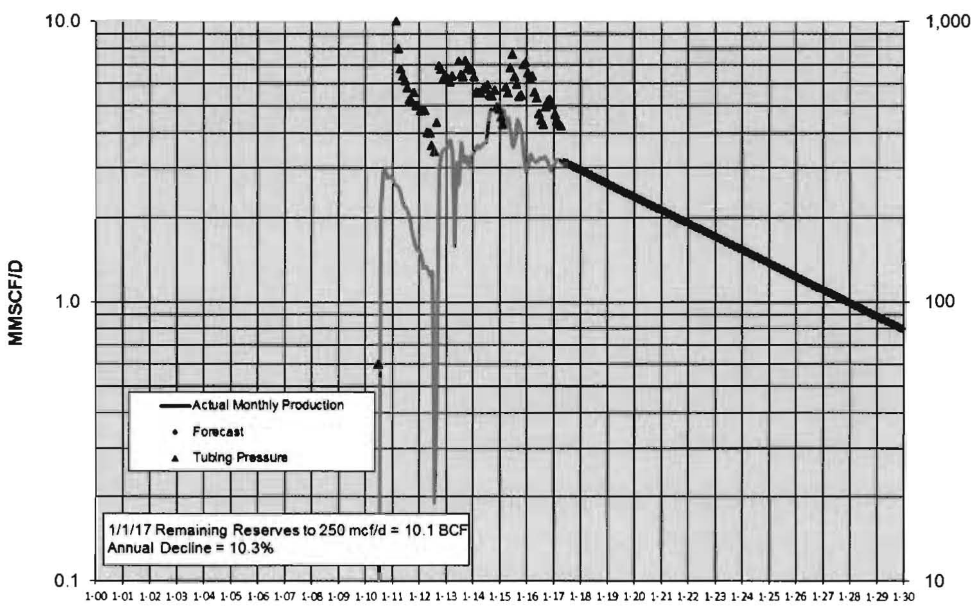
Beluga River Unit #211-26



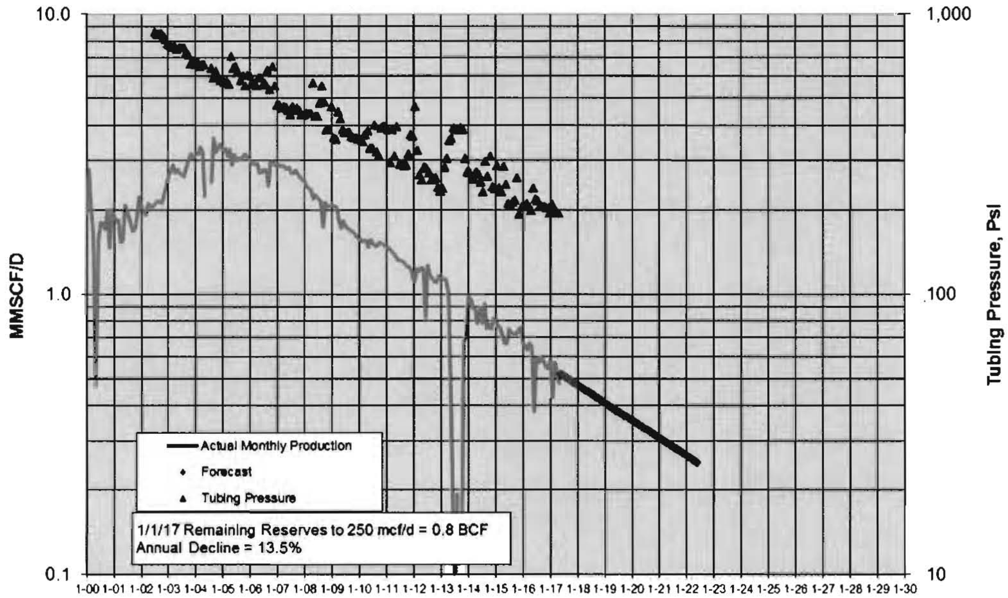
Beluga River Unit #212-24



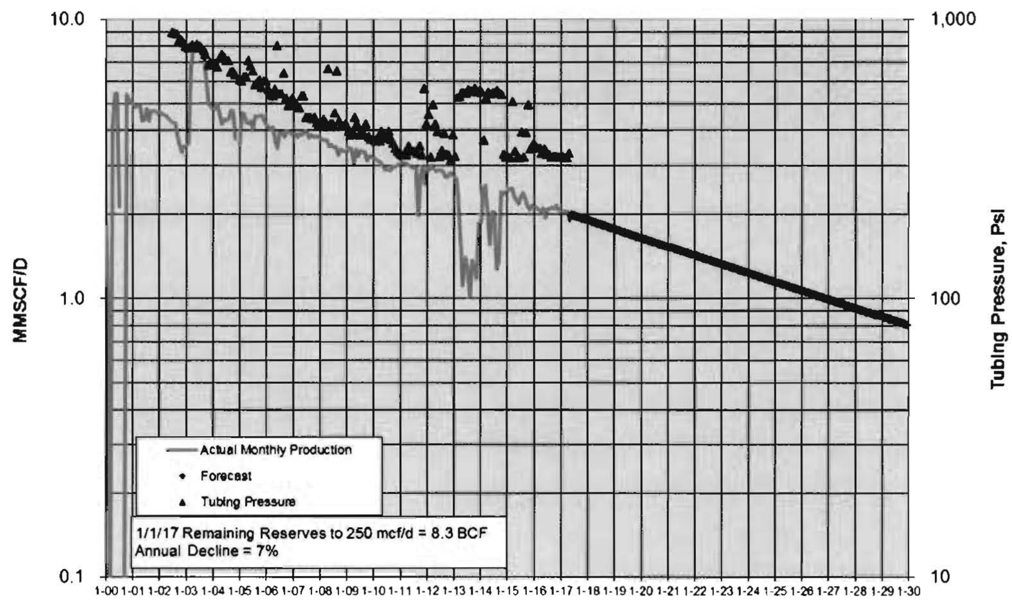
Beluga River Unit #212-24T

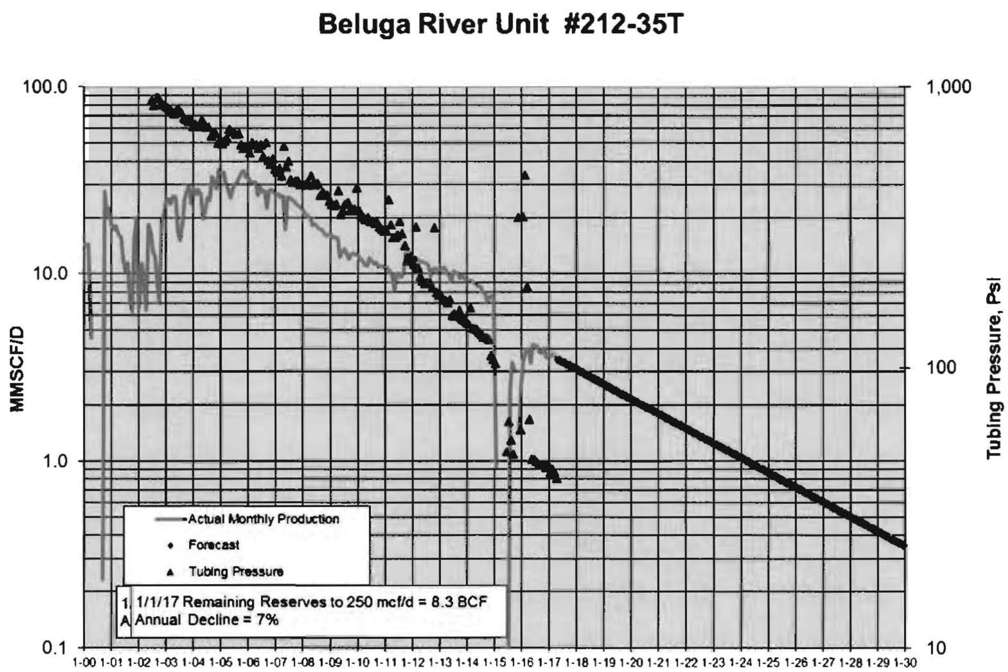


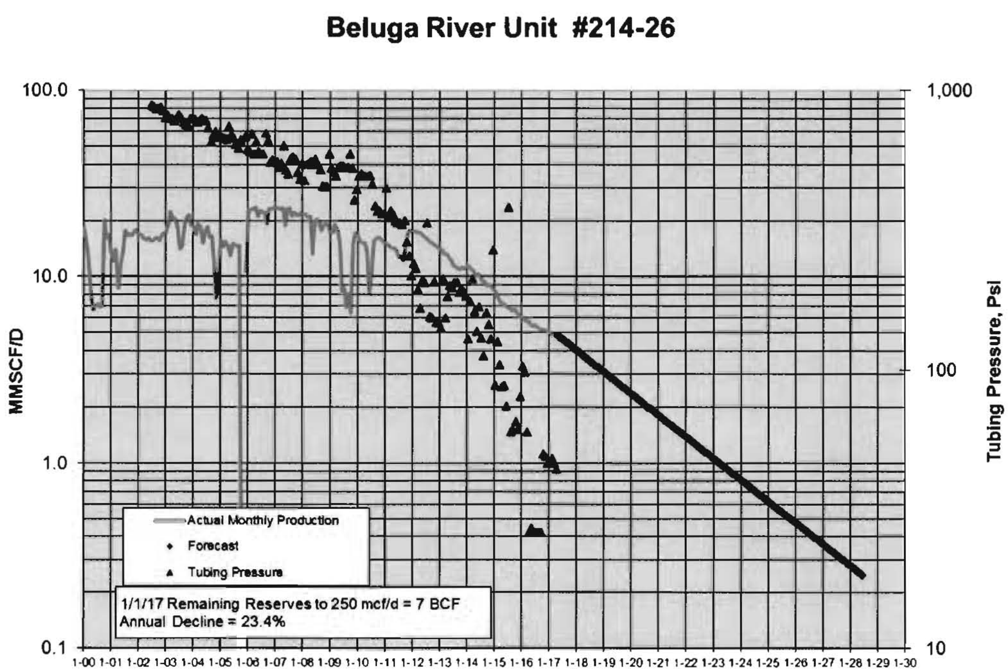
Beluga River Unit #212-25



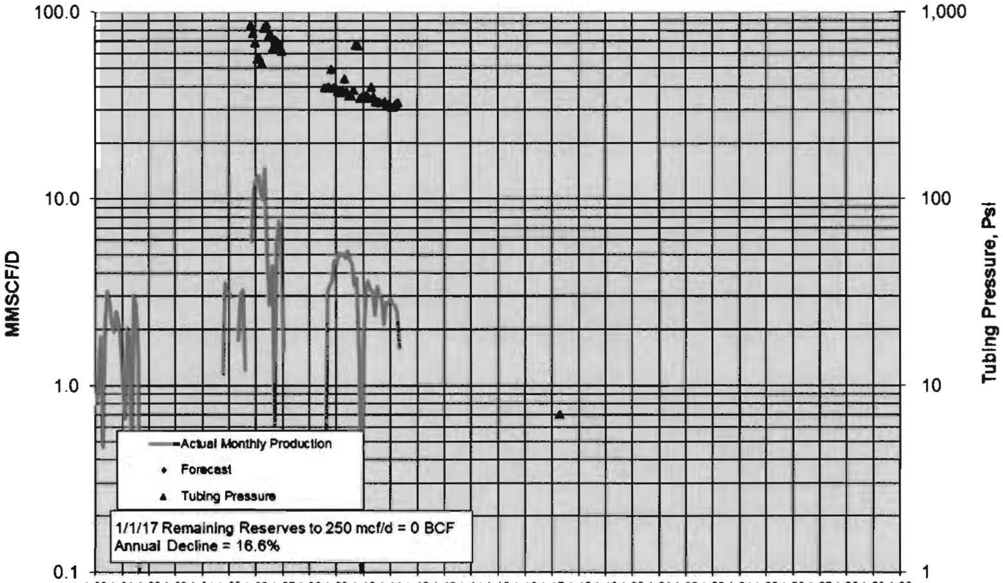
Beluga River Unit #212-35



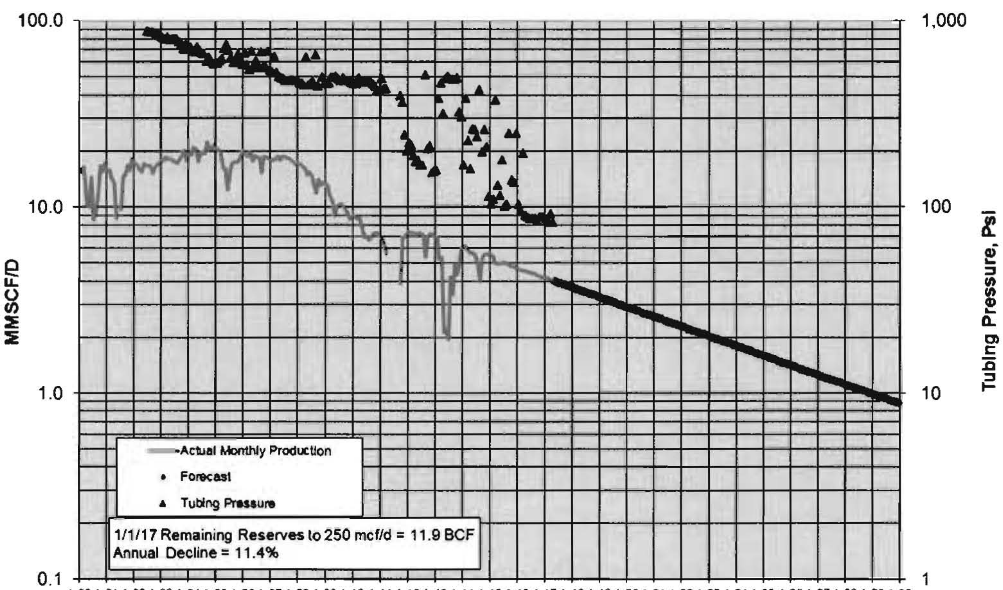

Beluga River Unit #212-35T
100.0
10.0
1.0
0.1
MMSCF/D
1,000
100
10
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
1/1/17 Remaining Reserves to 250 mcf/d = 8.3 BCF
Annual Decline = 7%
1-00 1-01 1-02 1-03 1-04 1-05 1-06 1-07 1-08 1-09 1-10 1-11 1-12 1-13 1-14 1-15 1-16 1-17 1-18 1-19 1-20 1-21 1-22 1-23 1-24 1-25 1-26 1-27 1-28 1-29 1-30


Beluga River Unit #214-26
100.0
10.0
1.0
0.1
MMSCF/D
1,000
100
10
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
1/1/17 Remaining Reserves to 250 mcf/d = 7 BCF
Annual Decline = 23.4%
1-00 1-01 1-02 1-03 1-04 1-05 1-06 1-07 1-08 1-09 1-10 1-11 1-12 1-13 1-14 1-15 1-16 1-17 1-18 1-19 1-20 1-21 1-22 1-23 1-24 1-25 1-26 1-27 1-28 1-29 1-30

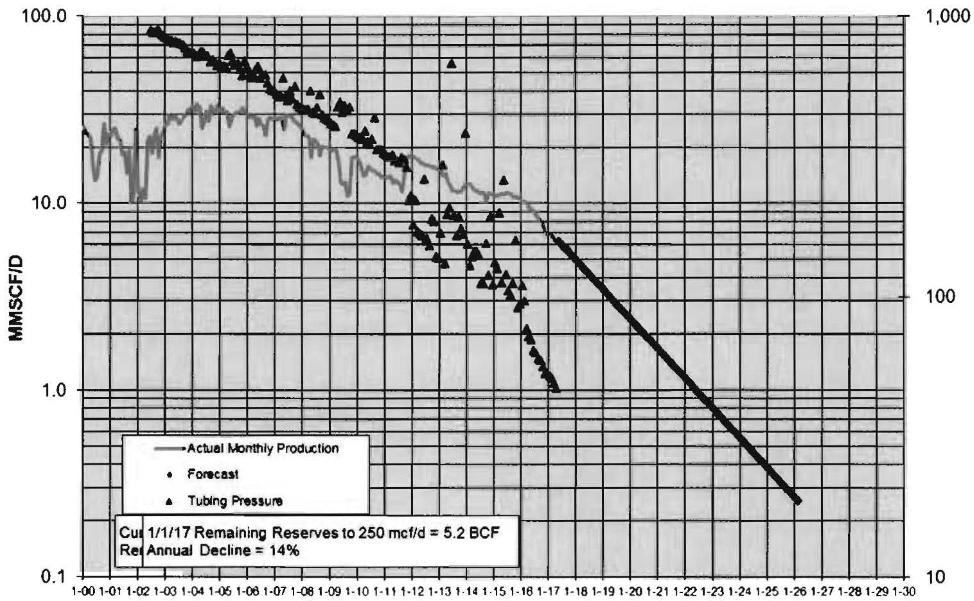
Beluga River Unit #224-13



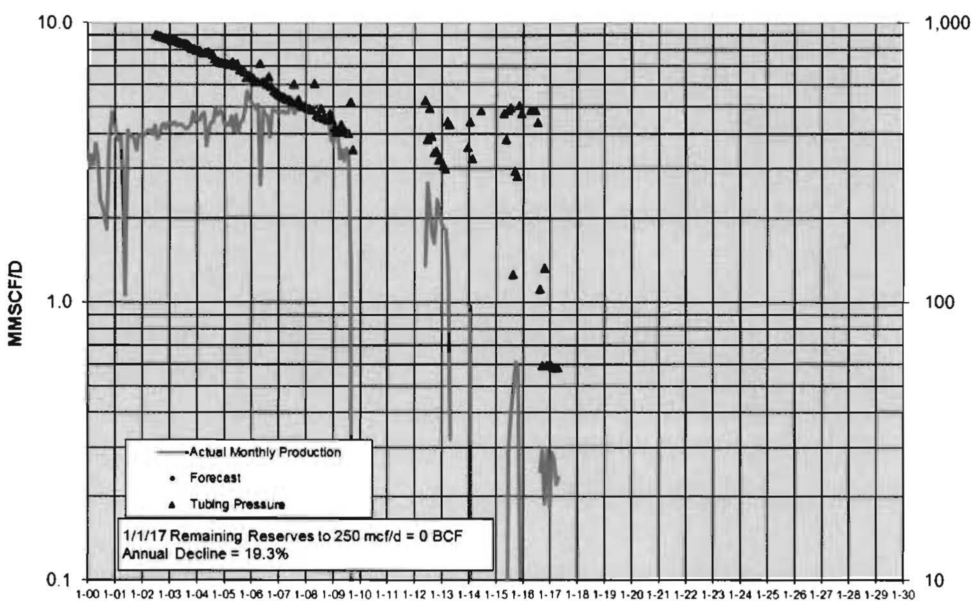
Beluga River Unit #224-23 & 224-23T



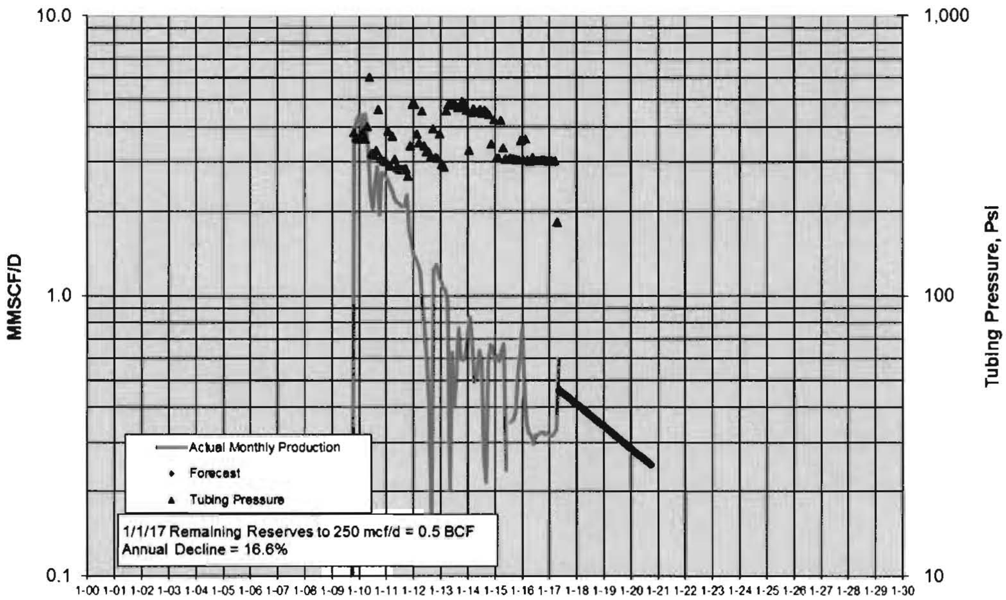
Beluga River Unit #224-34



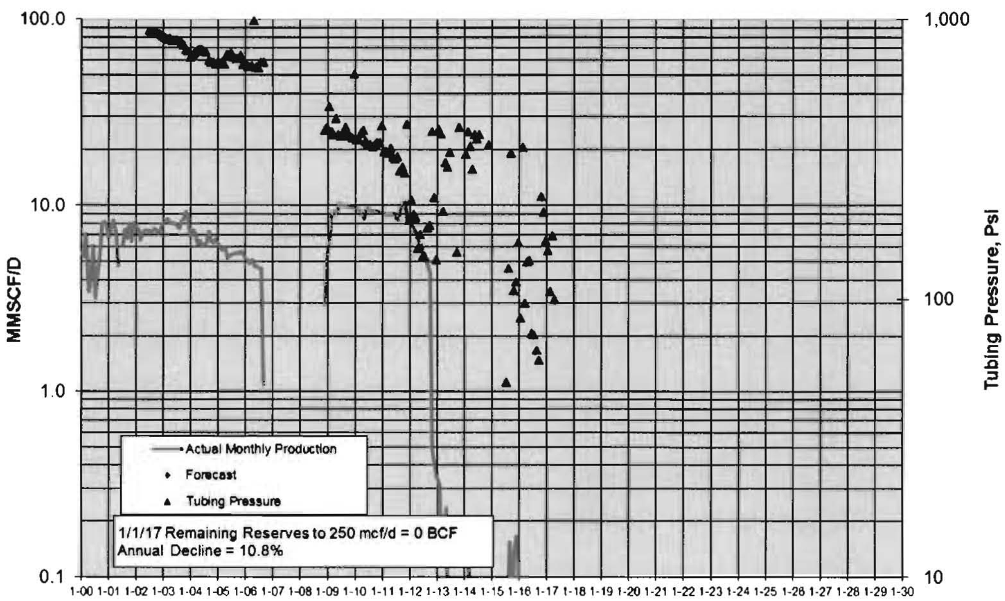
Beluga River Unit #232-04



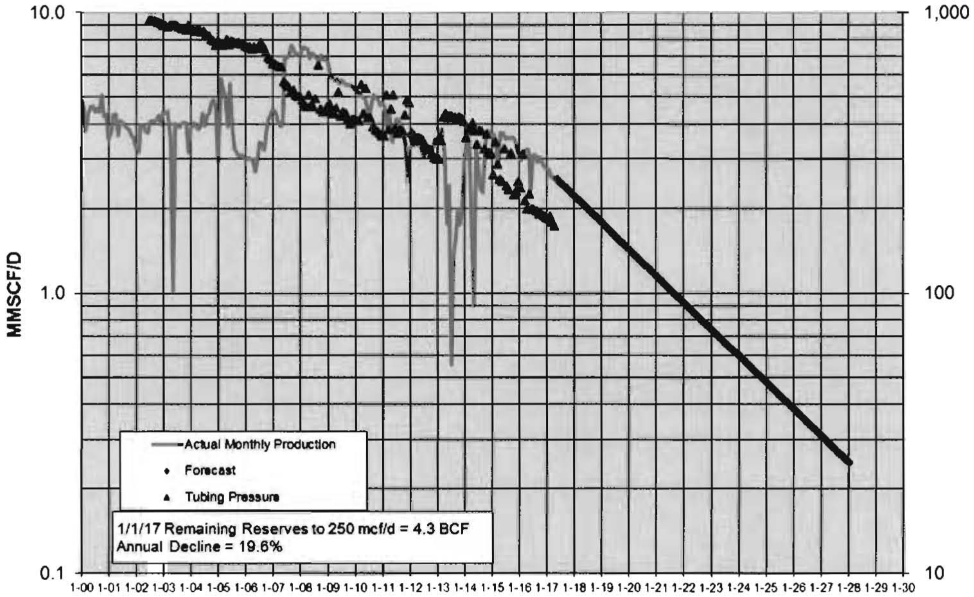
Beluga River Unit #232-23



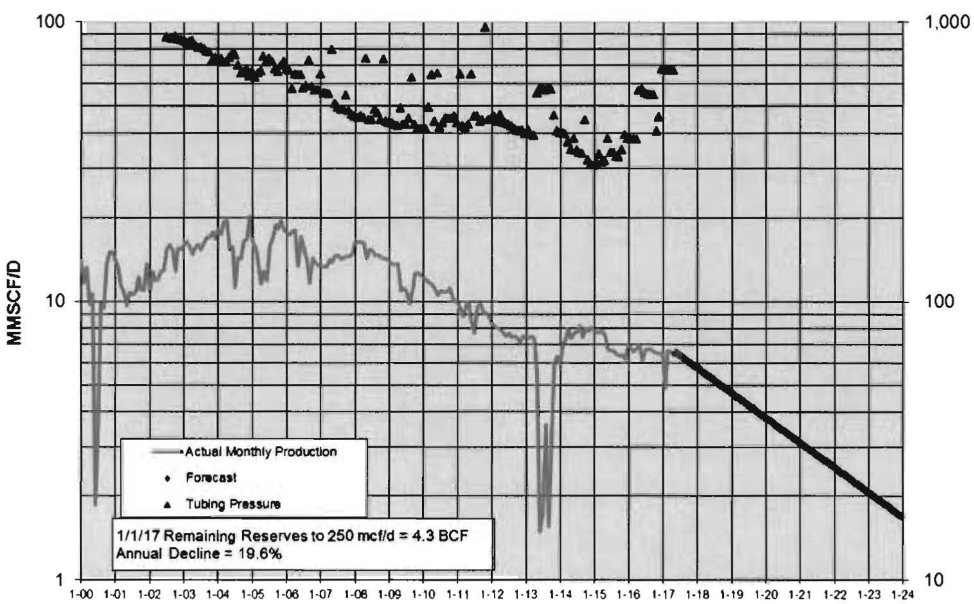
Beluga River Unit #232-26

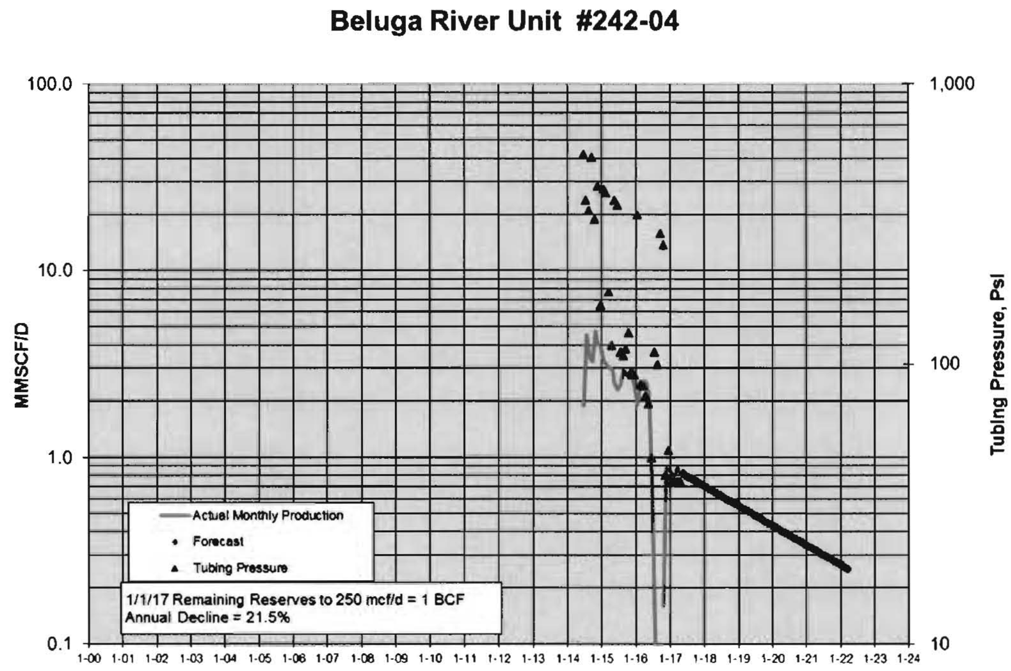


Beluga River Unit #233-27

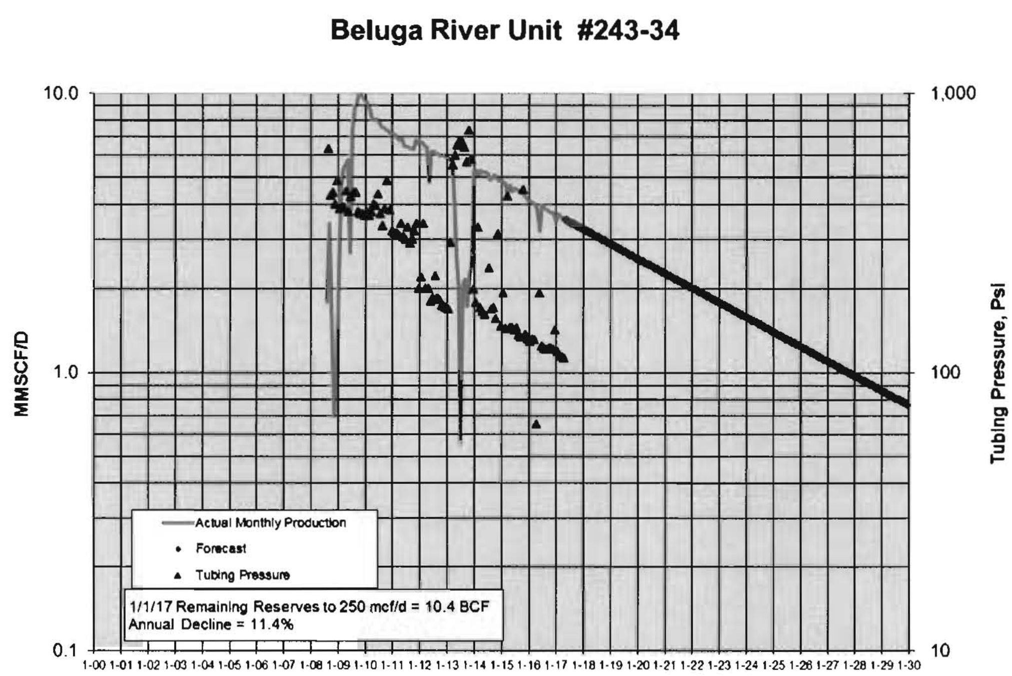


Beluga River Unit #241-34



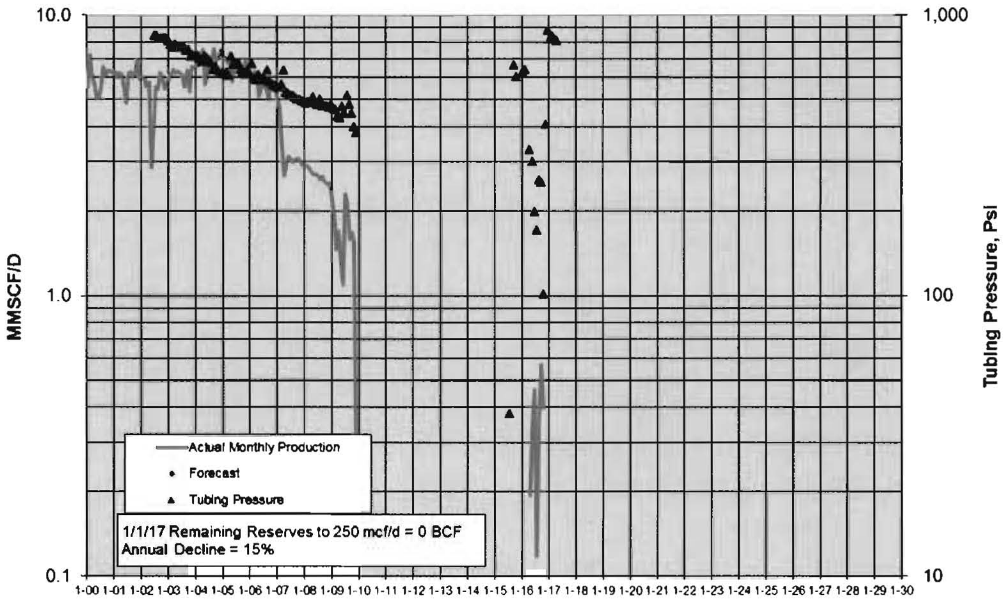


Beluga River Unit #242-04
100.0
10.0
1.0
0.1
MMSCF/D
1,000
100
10
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
1/1/17 Remaining Reserves to 250 mcf/d = 1 BCF
Annual Decline = 21.5%
1-00 1-01 1-02 1-03 1-04 1-05 1-06 1-07 1-08 1-09 1-10 1-11 1-12 1-13 1-14 1-15 1-16 1-17 1-18 1-19 1-20 1-21 1-22 1-23 1-24

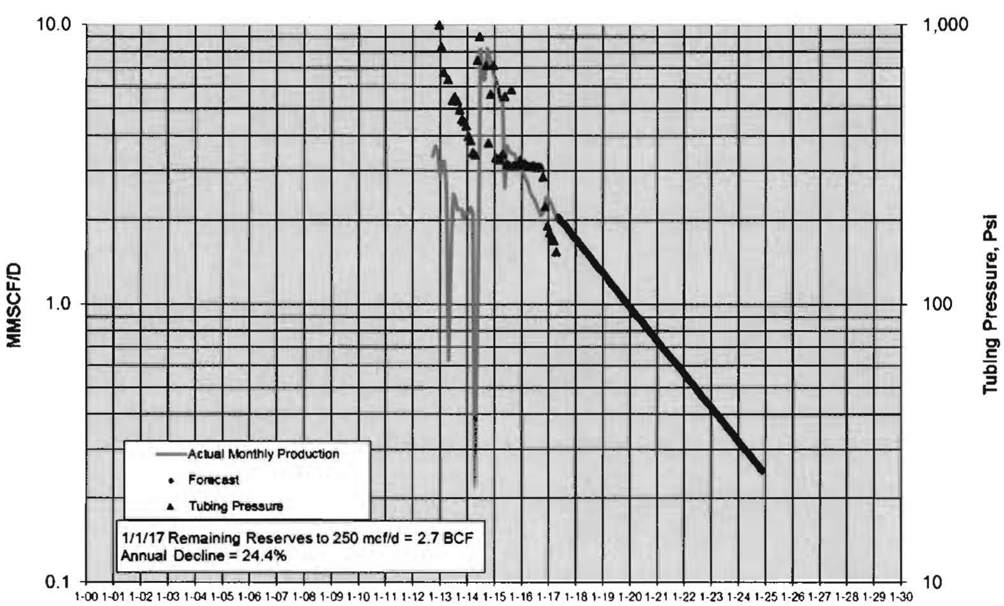


Beluga River Unit #243-34
10.0
1.0
0.1
MMSCF/D
1,000
100
10
Tubing Pressure, Psi
Actual Monthly Production
Forecast
Tubing Pressure
1/1/17 Remaining Reserves to 250 mcf/d = 10.4 BCF
Annual Decline = 11.4%
1-00 1-01 1-02 1-03 1-04 1-05 1-06 1-07 1-08 1-09 1-10 1-11 1-12 1-13 1-14 1-15 1-16 1-17 1-18 1-19 1-20 1-21 1-22 1-23 1-24 1-25 1-26 1-27 1-28 1-29 1-30

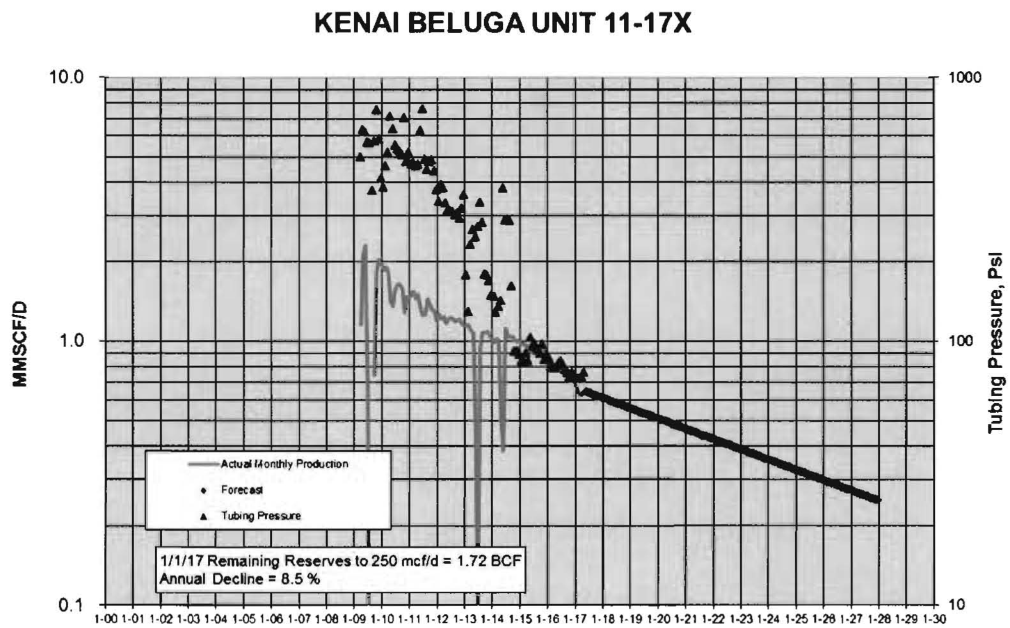
Beluga River Unit #244-04

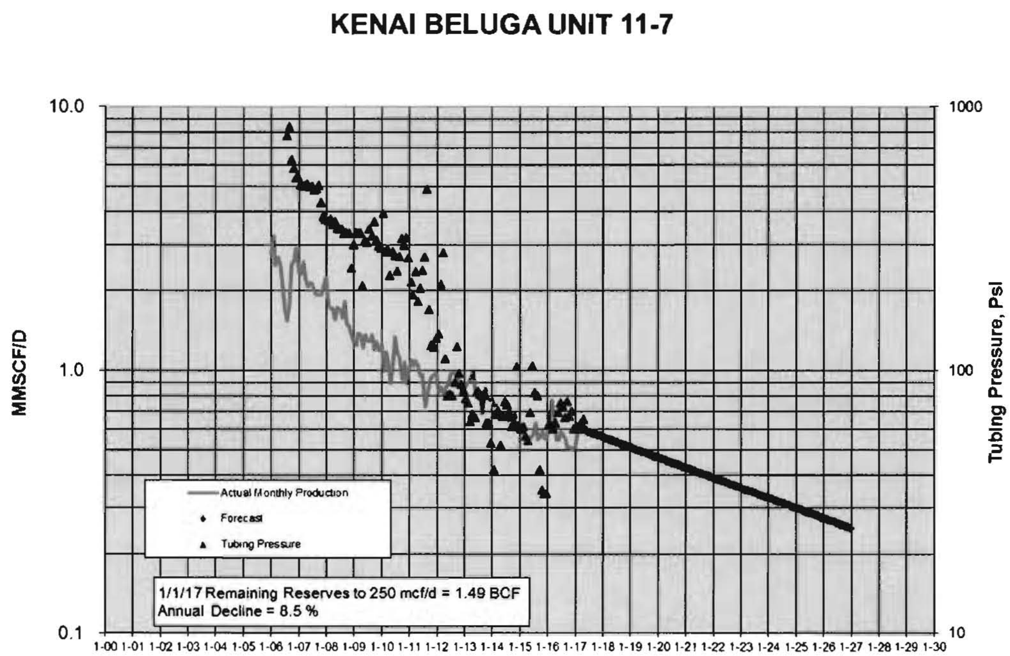


Beluga River Unit #244-23

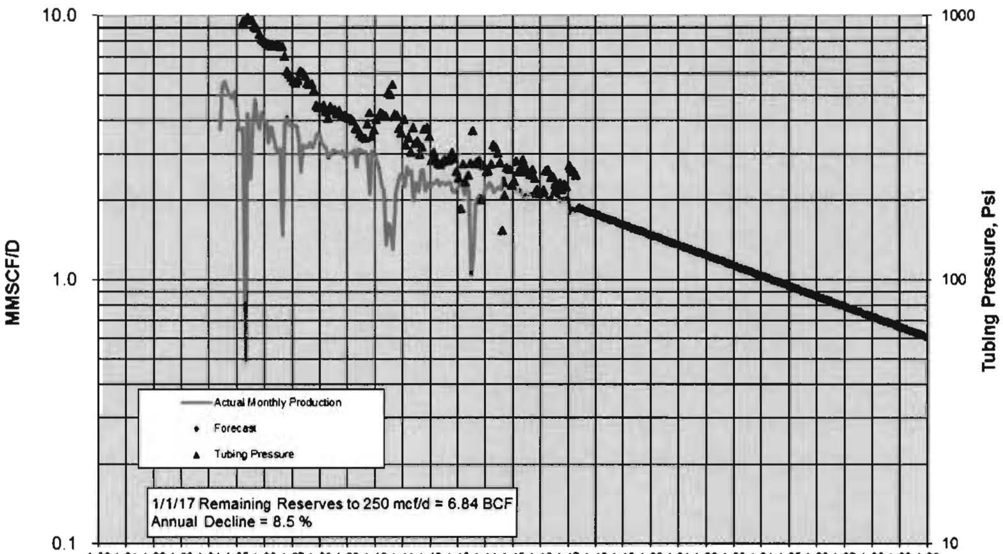


Appendix B-2: Kenai Field Units Well Decline Curves

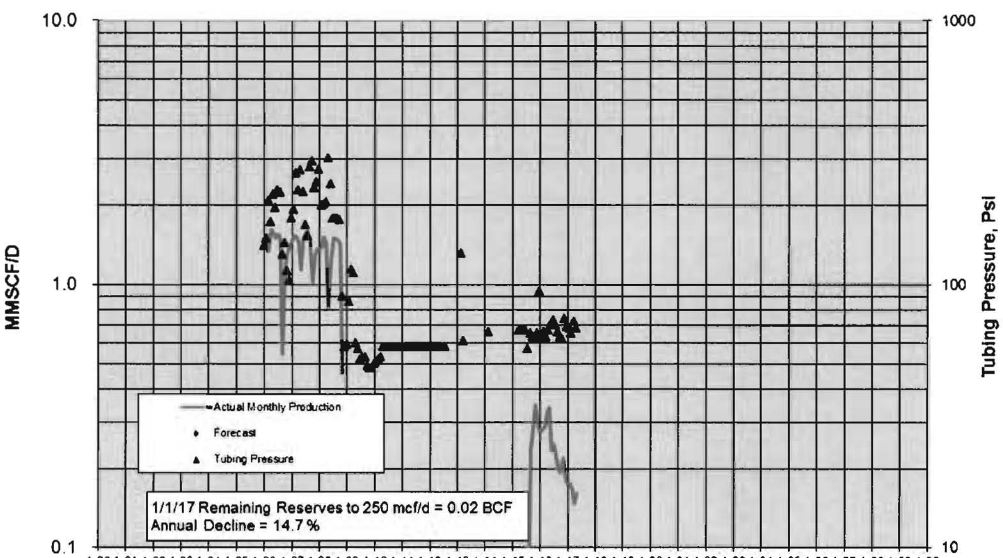




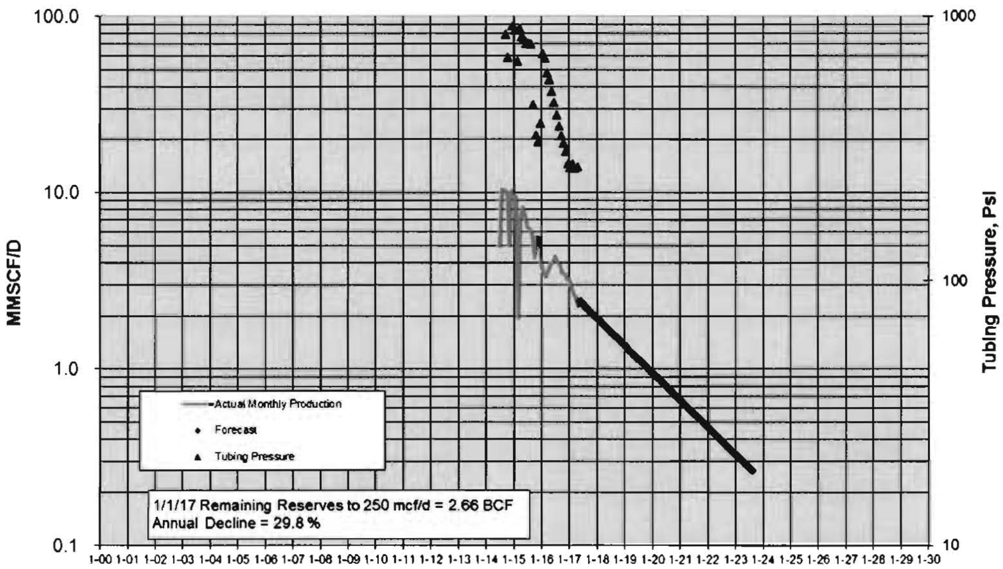
KENAI BELUGA UNIT 11-8X



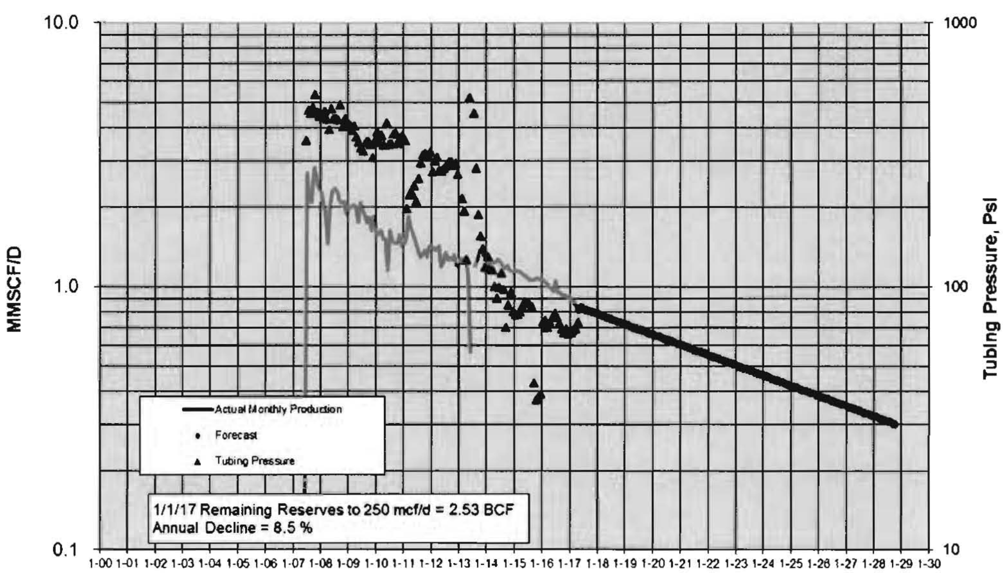
KENAI BELUGA UNIT 11-8Y



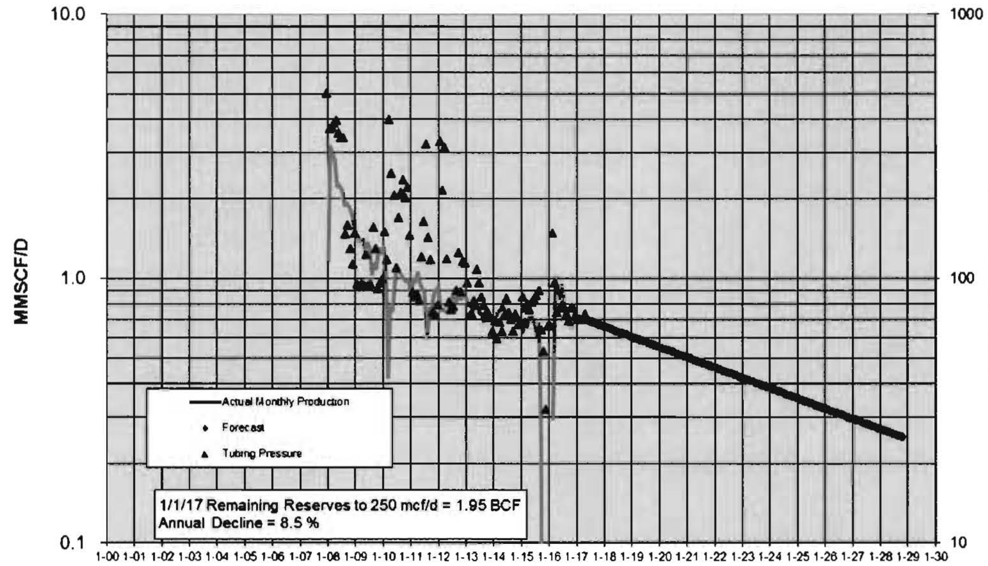
KENAI BELUGA UNIT 11-08Z



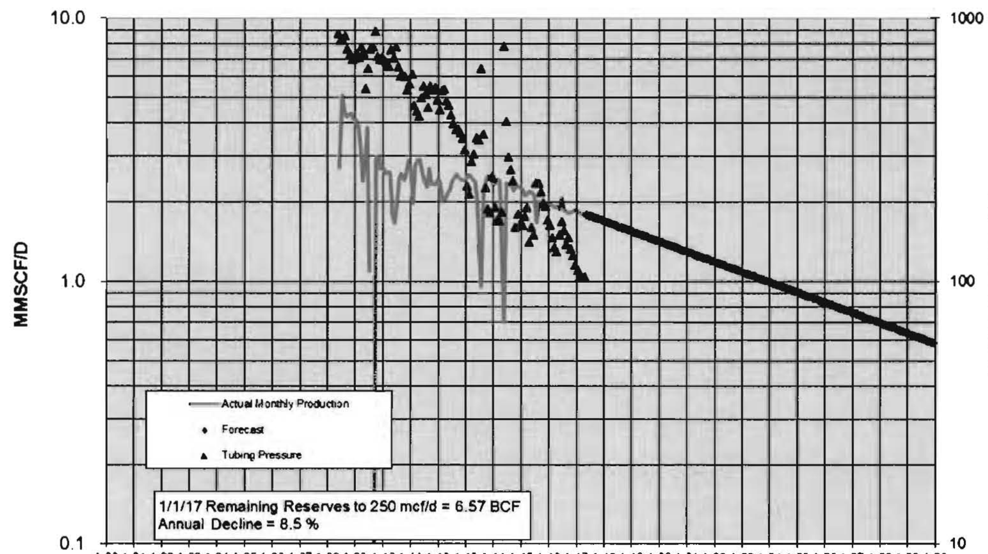
KENAI BELUGA UNIT 12-5



KENAI BELUGA UNIT 14-6Y



KENAI BELUGA UNIT 14-8



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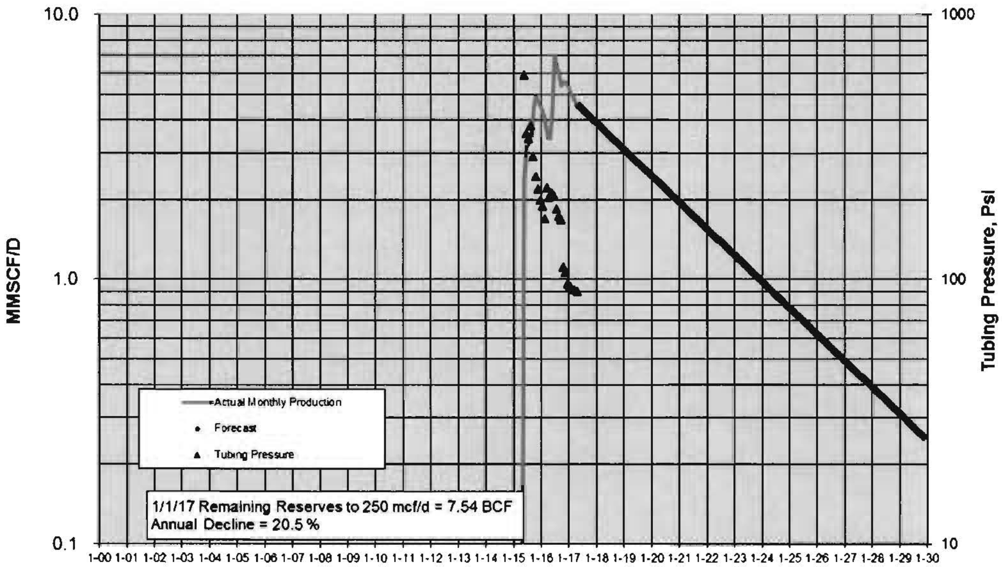
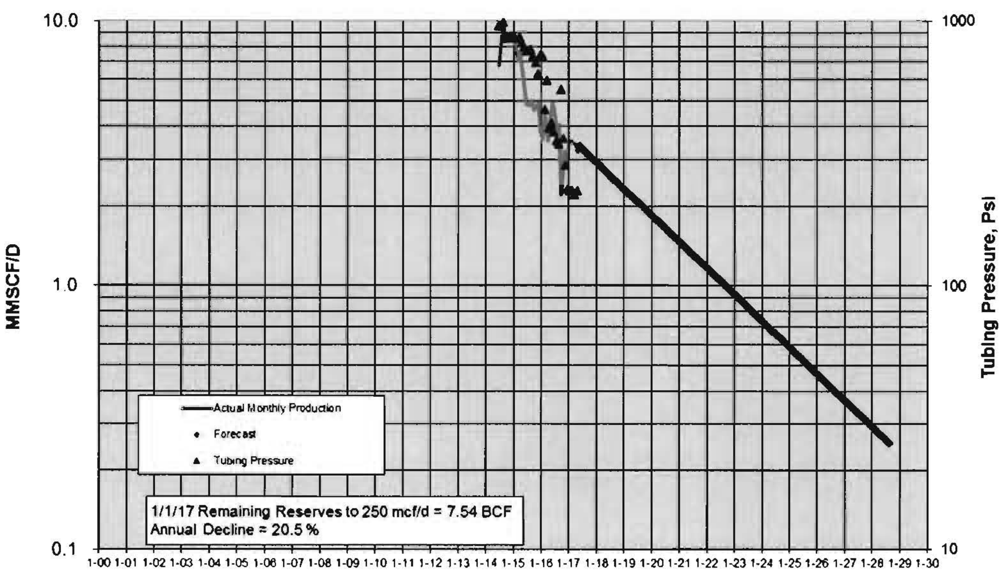
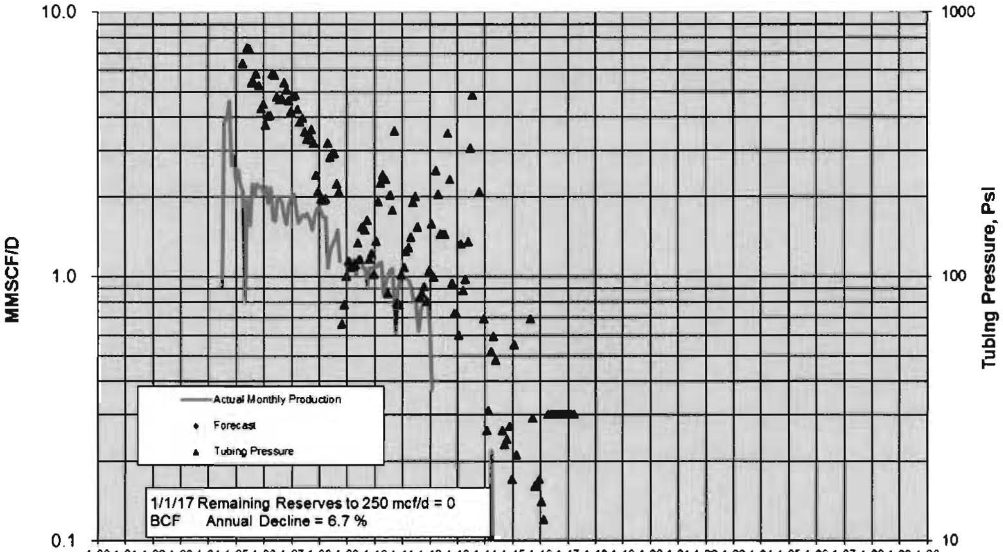


KENAI BELUGA UNIT 23-05



KENAI BELUGA UNIT 23-7



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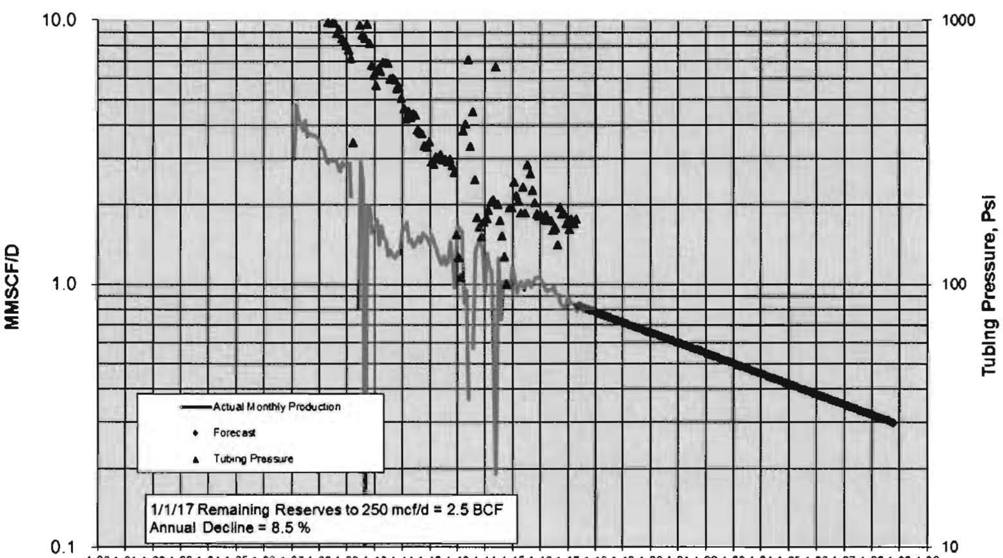

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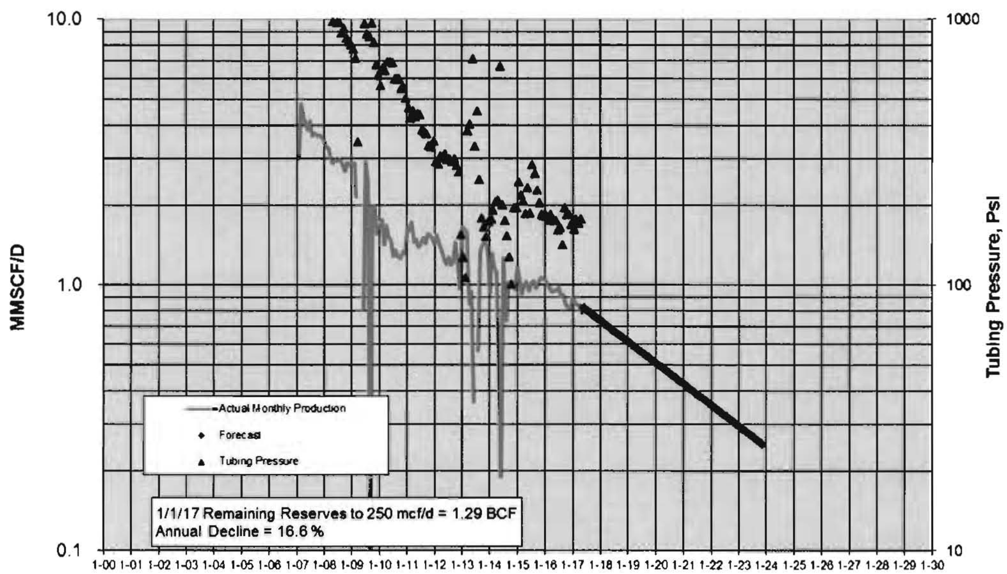

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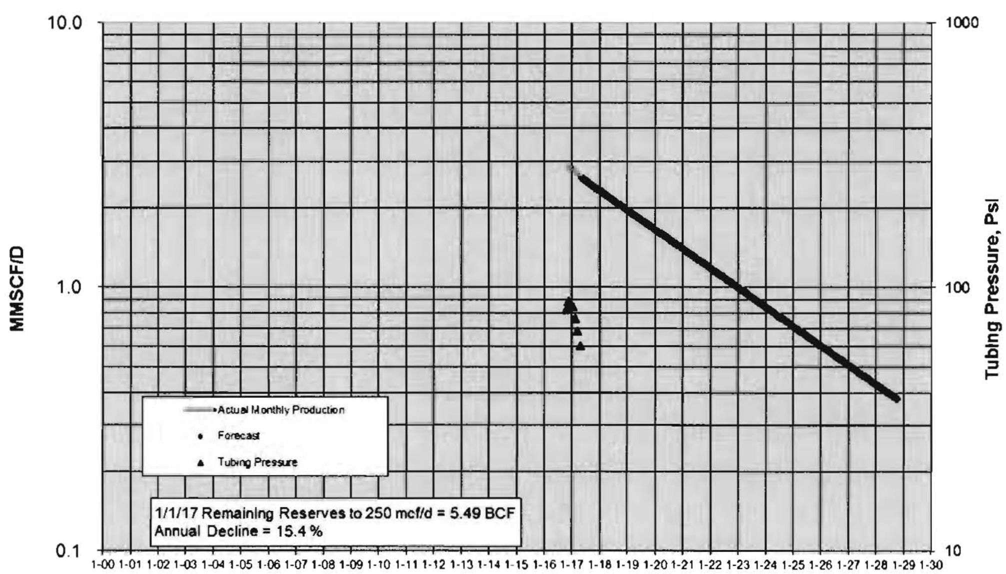

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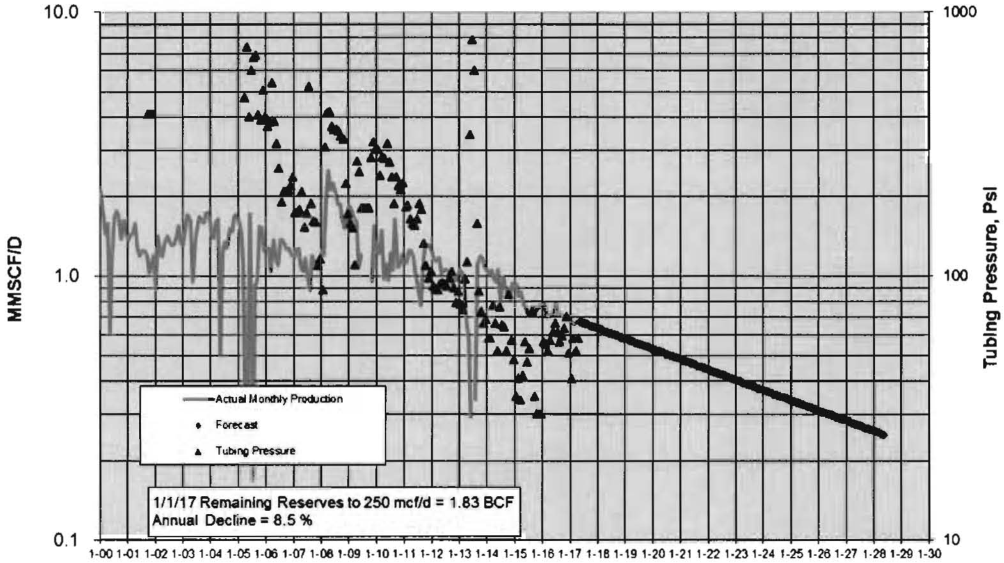

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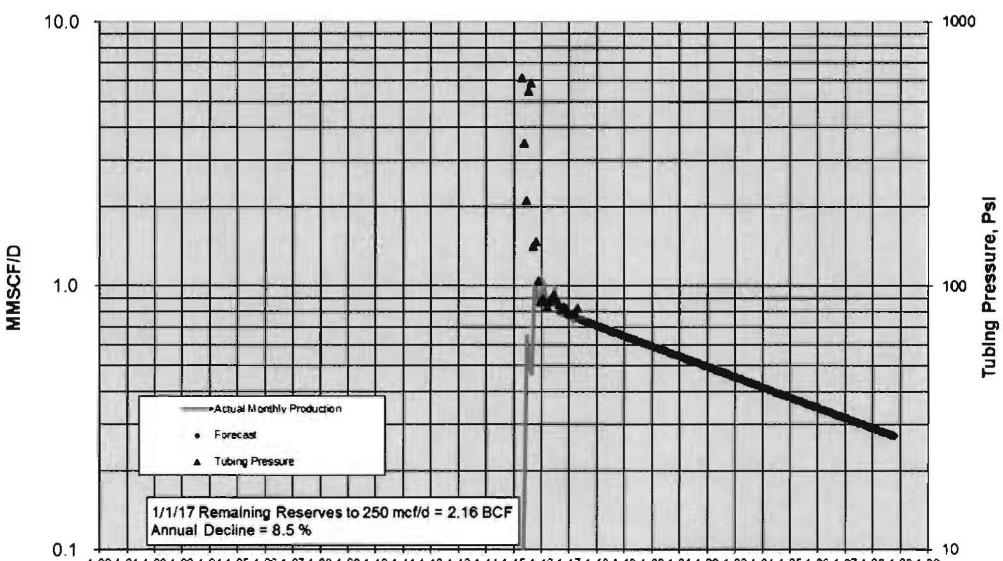

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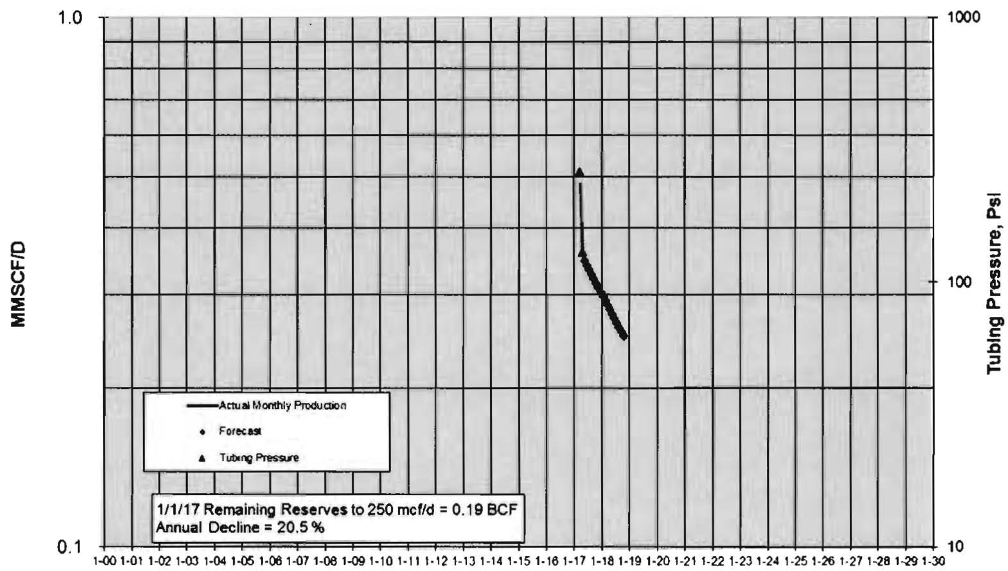

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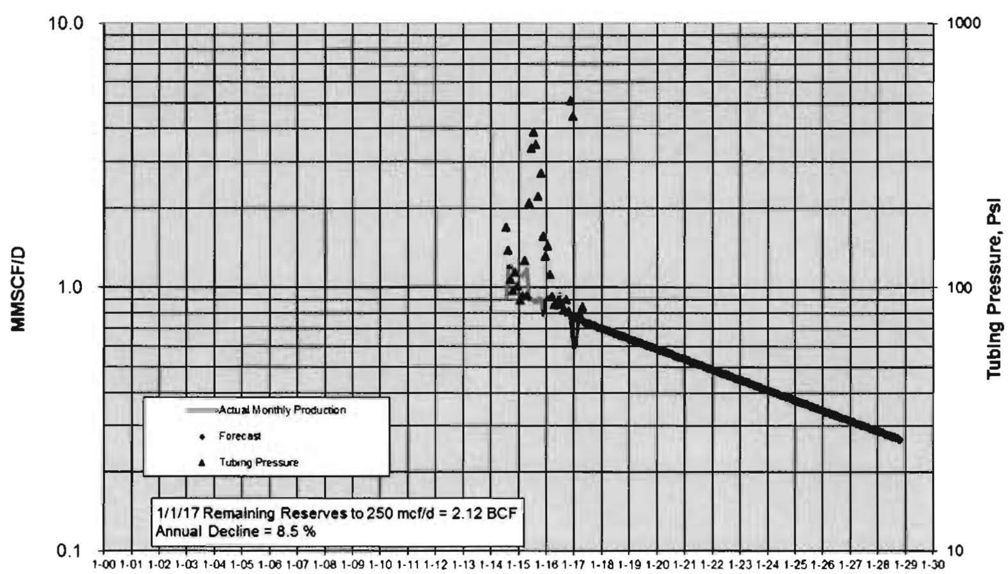

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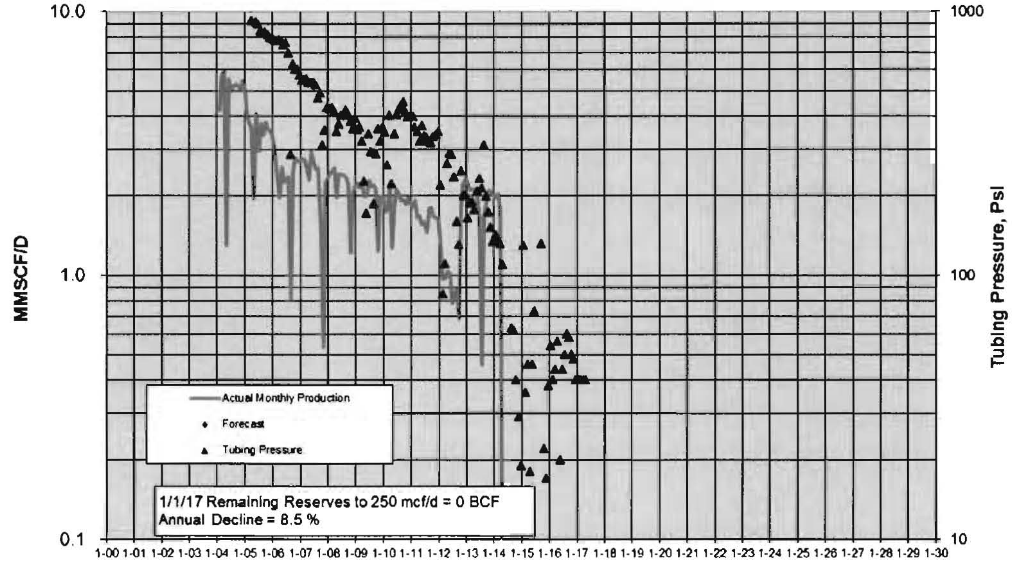

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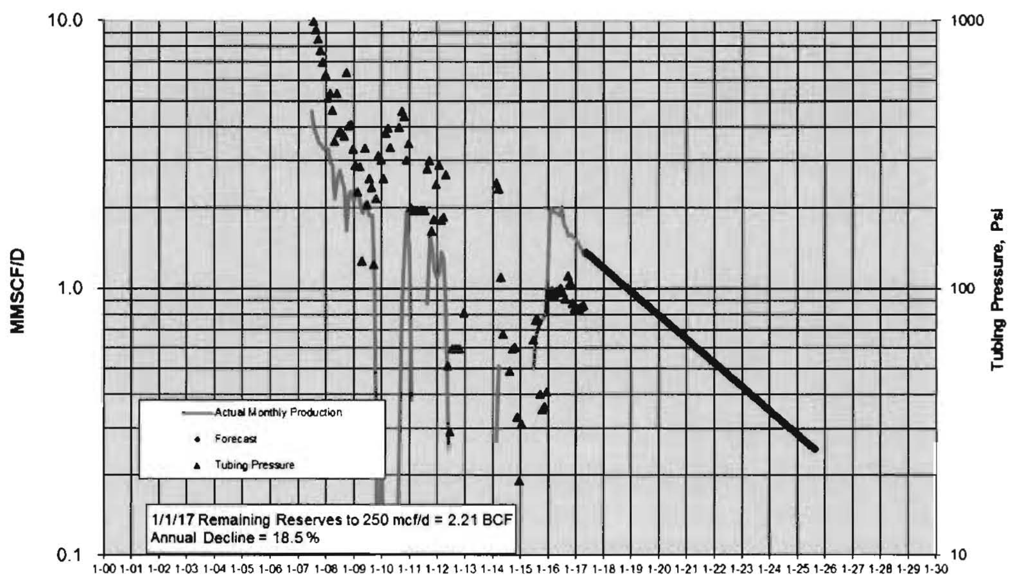

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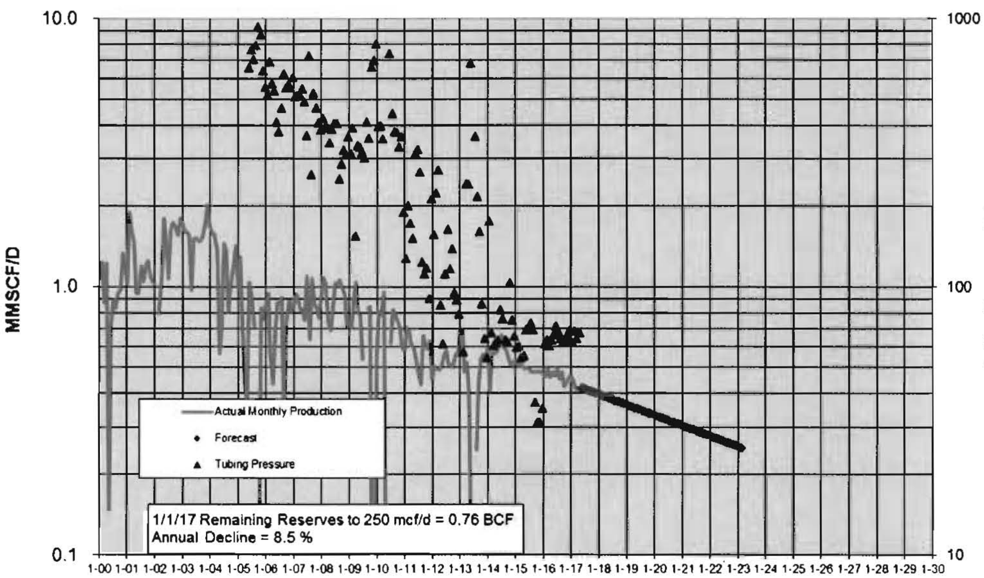

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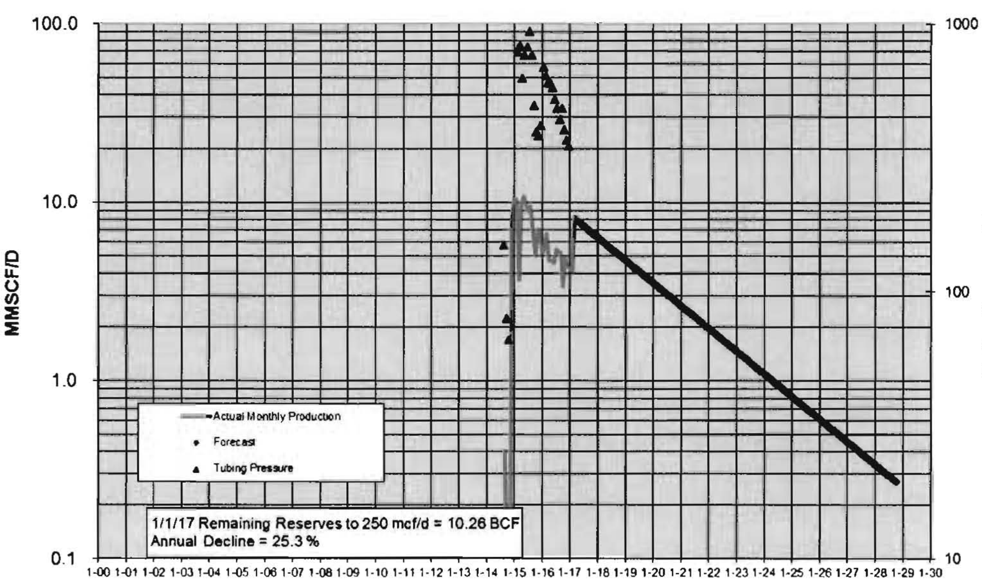

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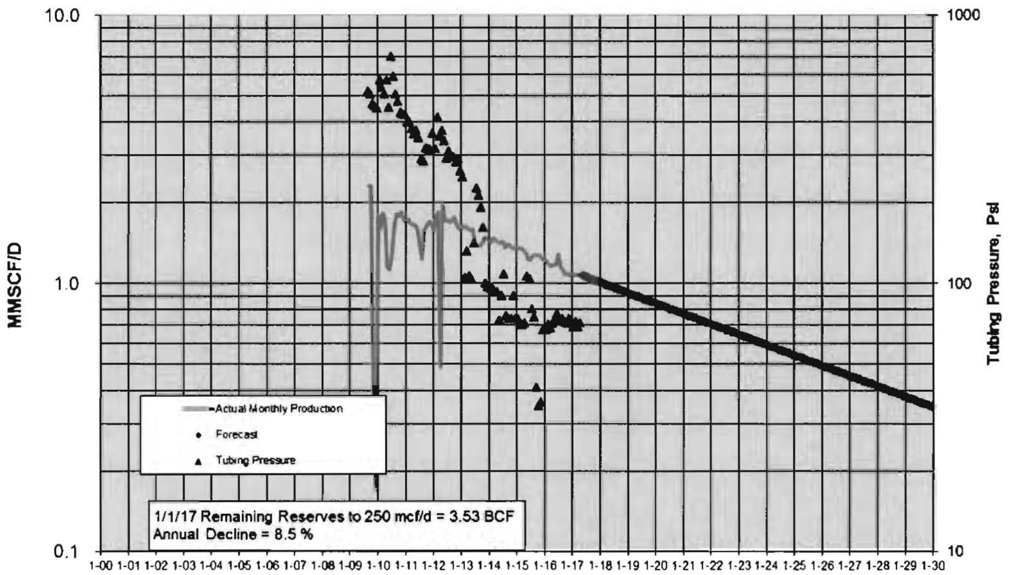

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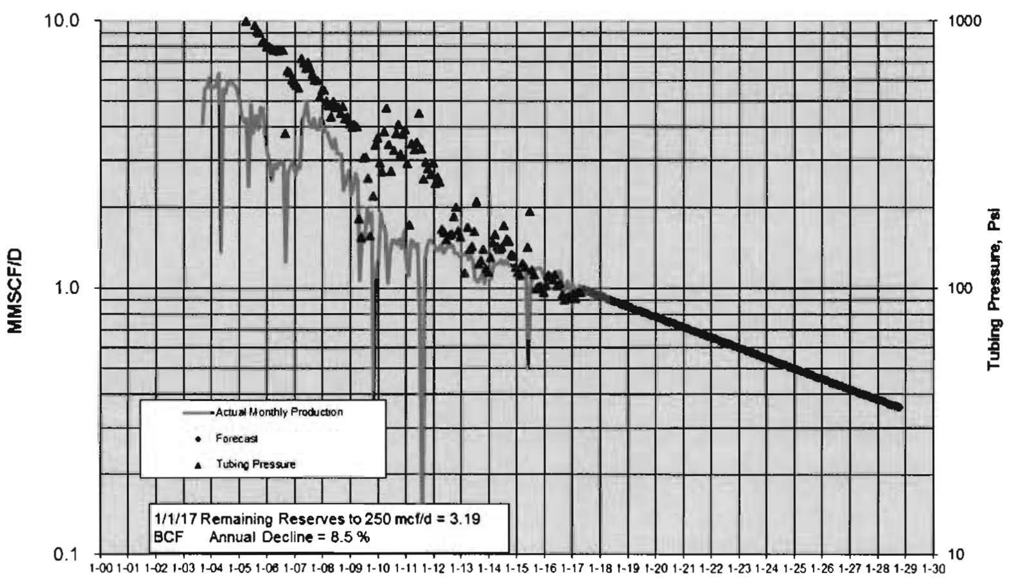

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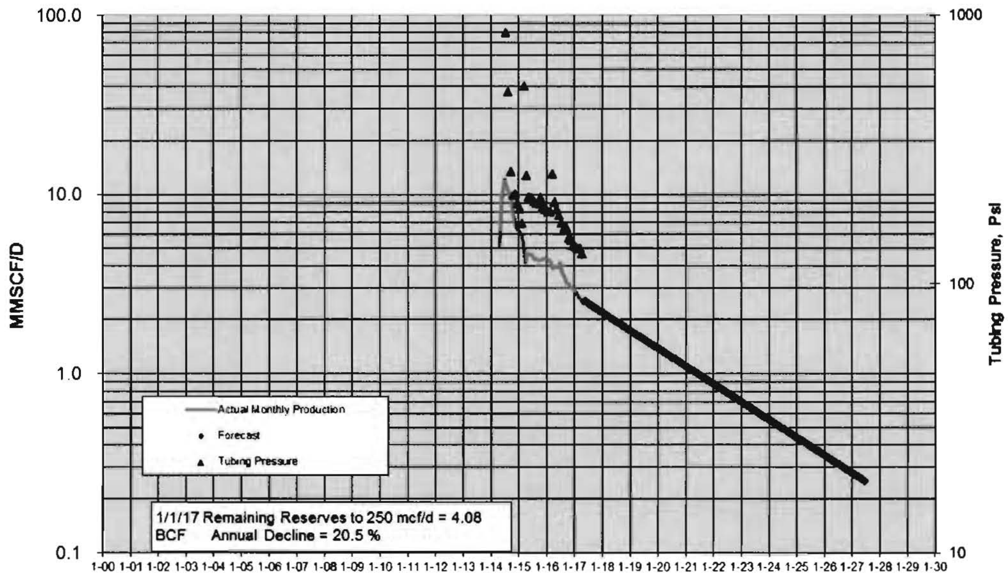

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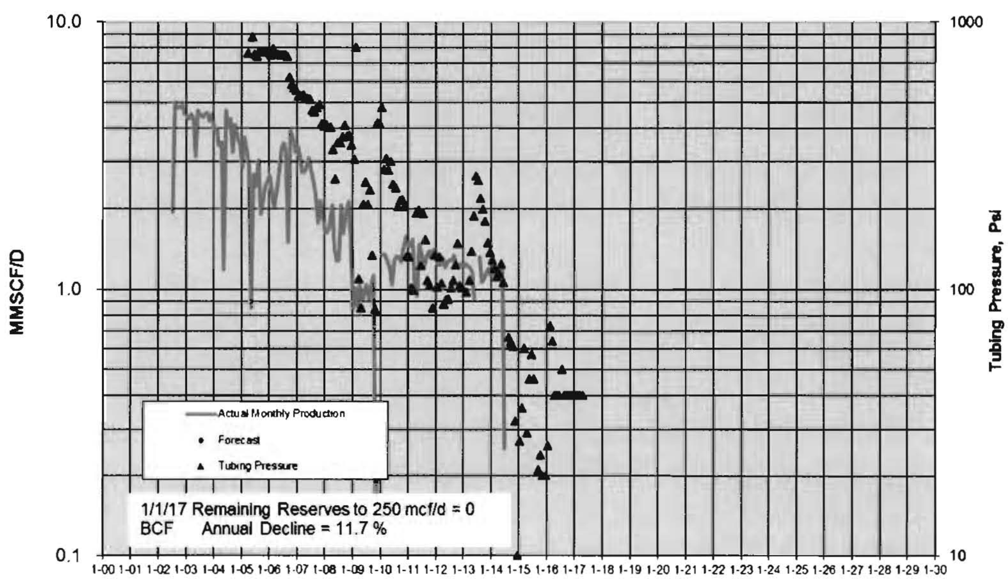
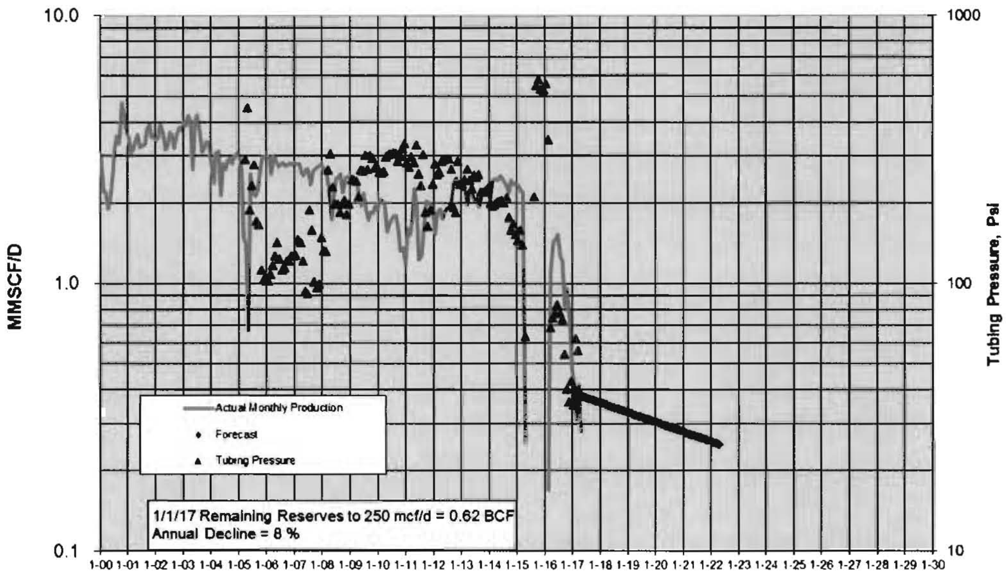


KENAI DEEP UNIT 1



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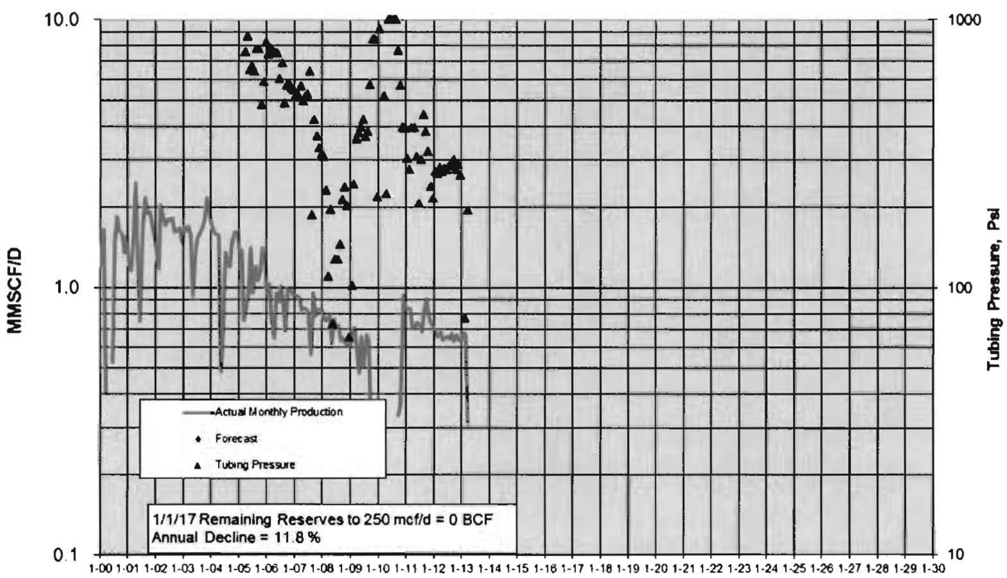
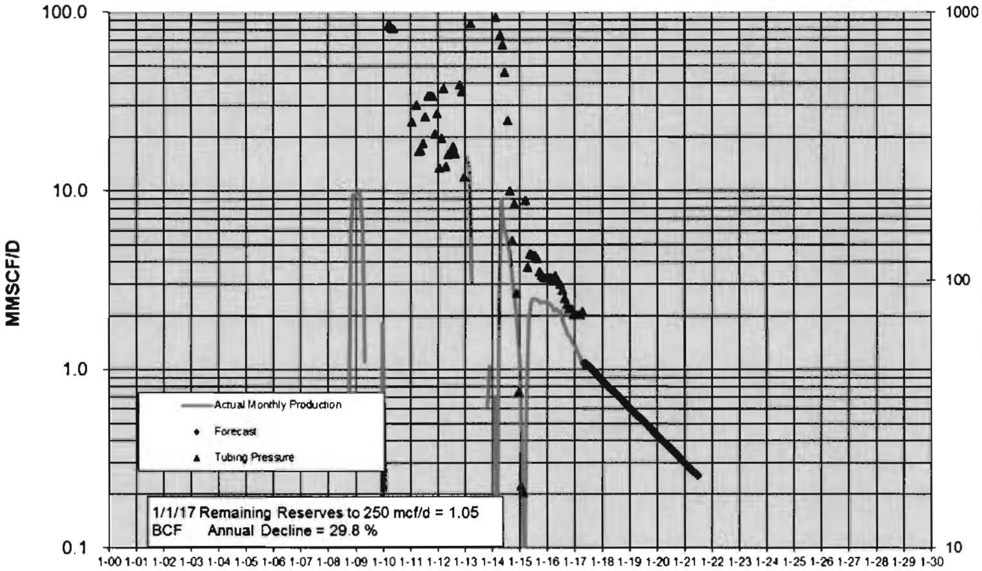
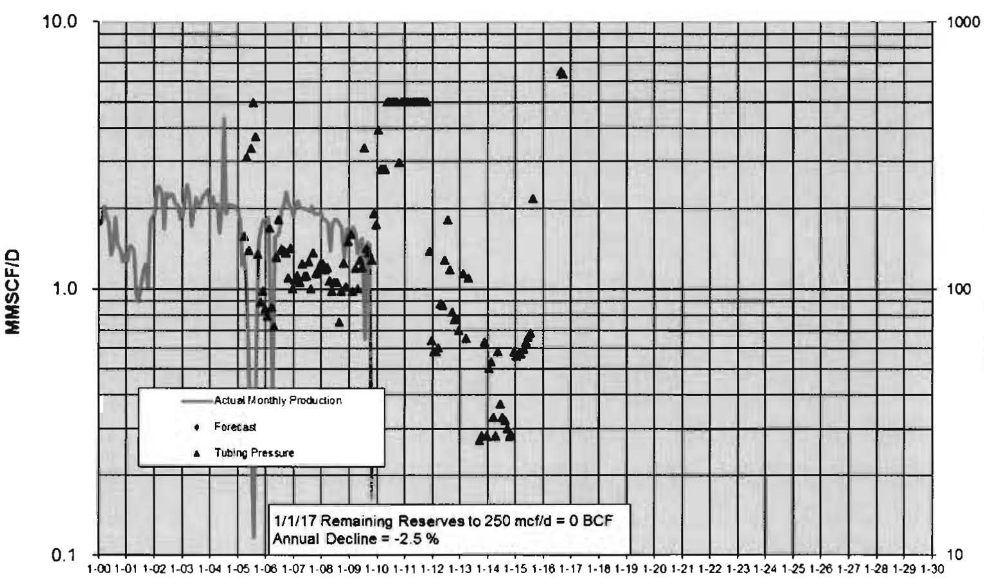


KENAI DEEP UNIT 9



KENAI TYONEK UNIT 13-05



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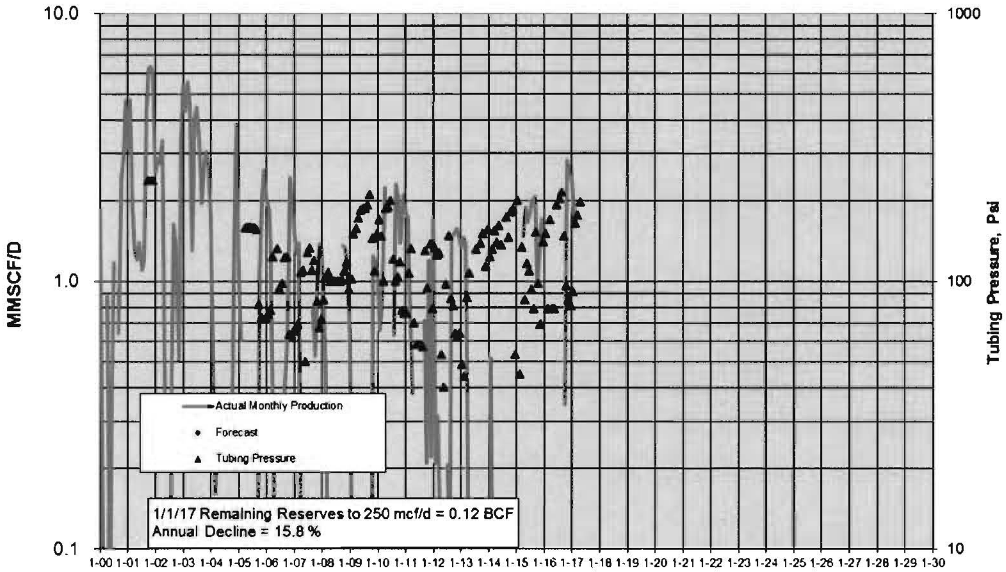

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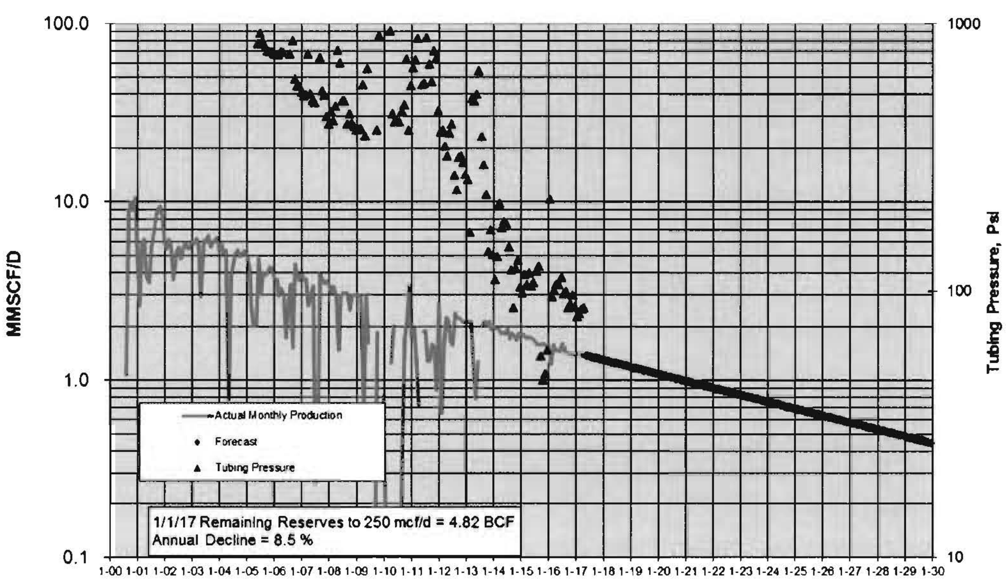

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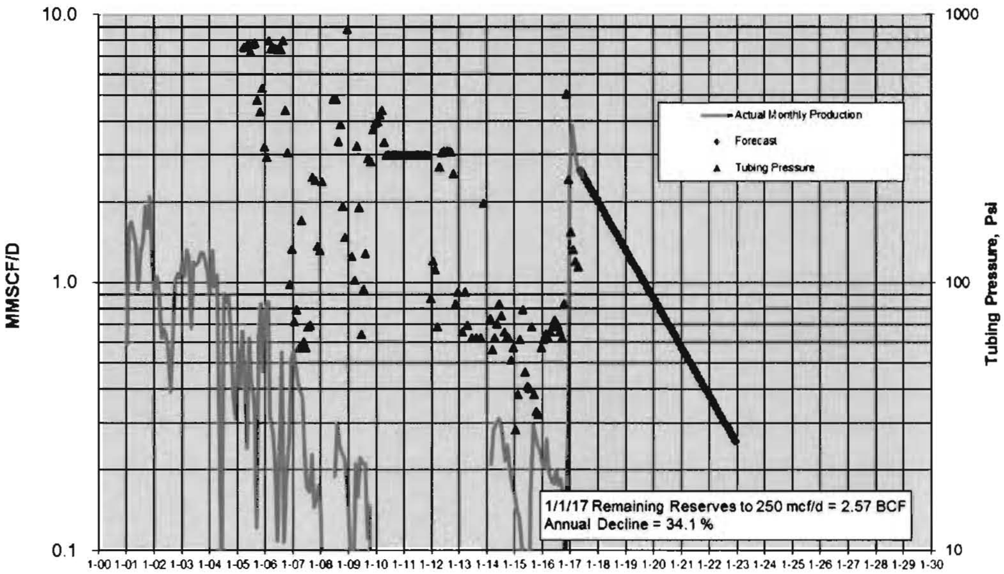

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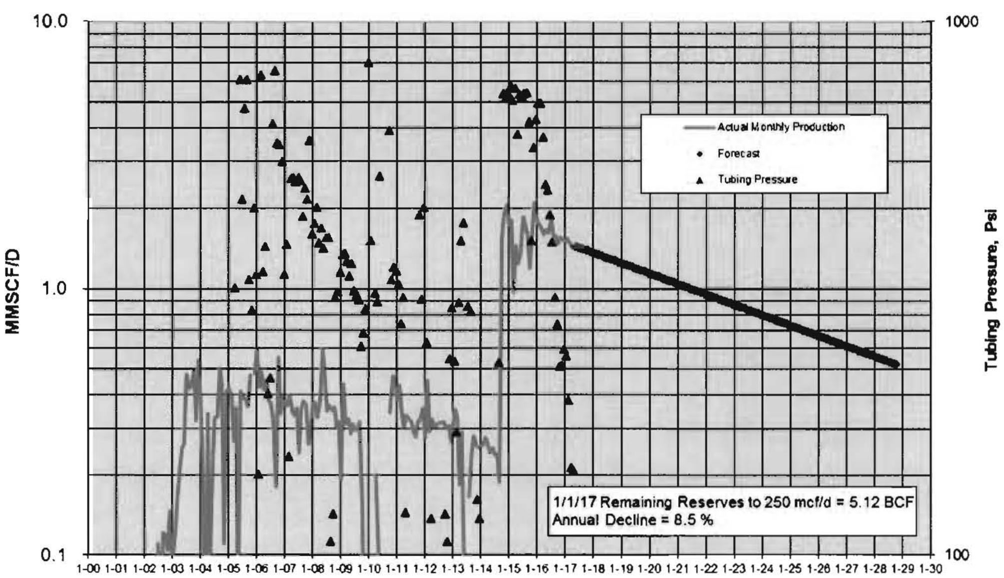
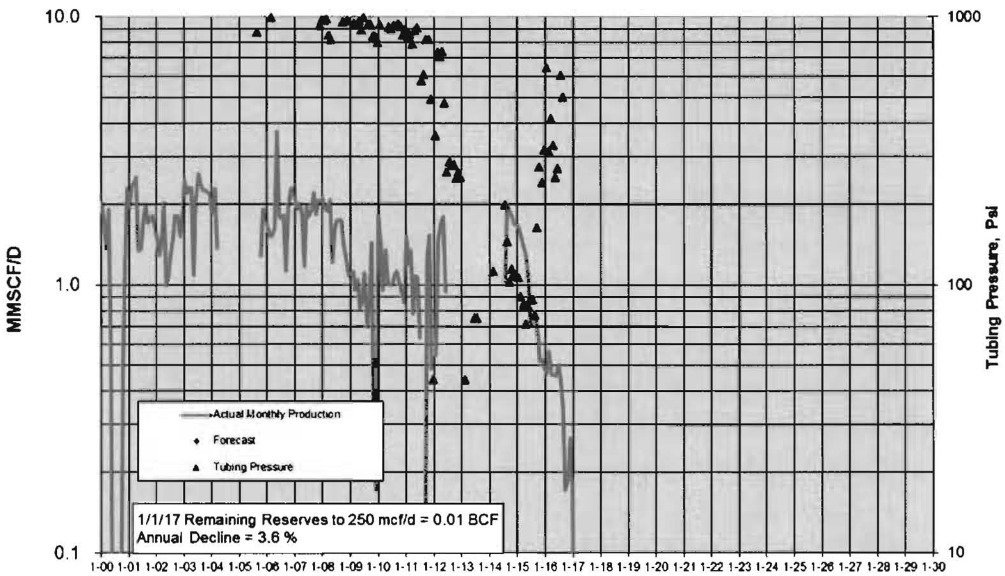
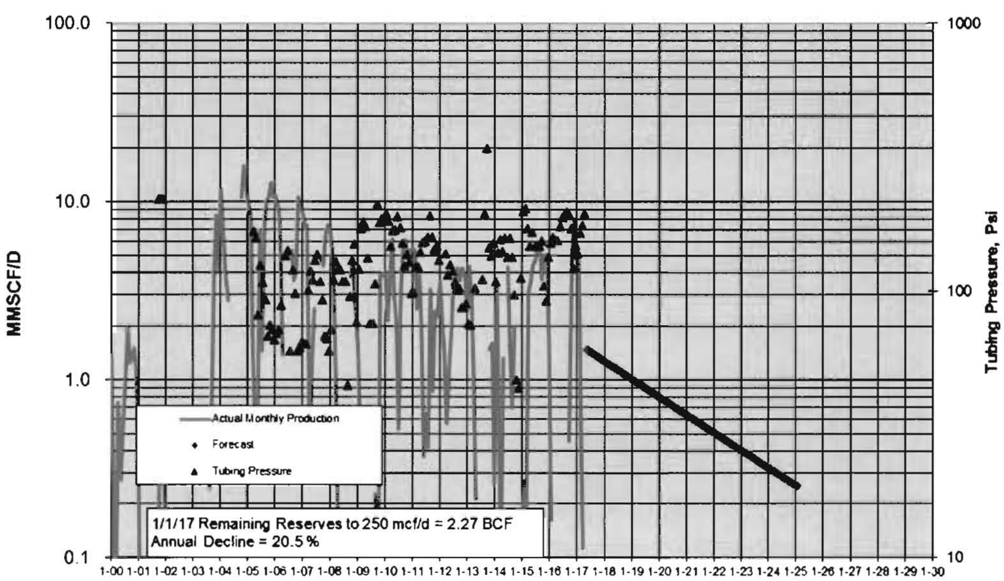


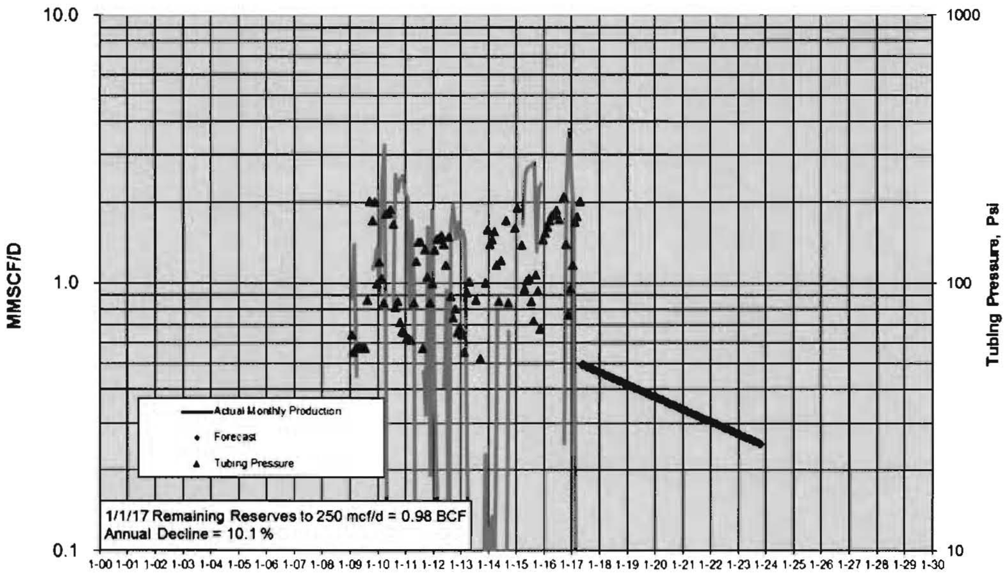
KENAI TYONEK UNIT 43-6XRD2



KENAI UNIT 14X-06



KENAI UNIT 22-6X



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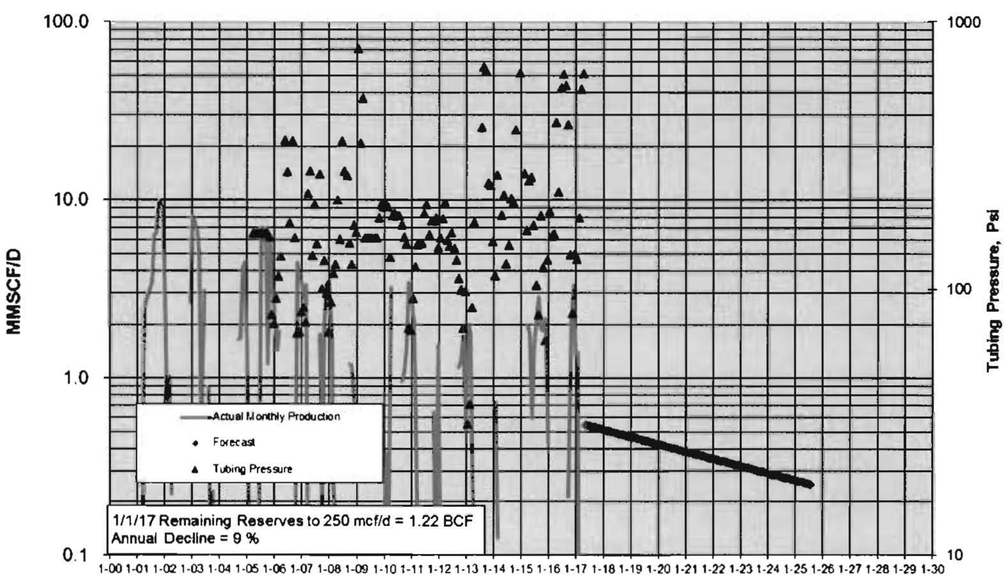
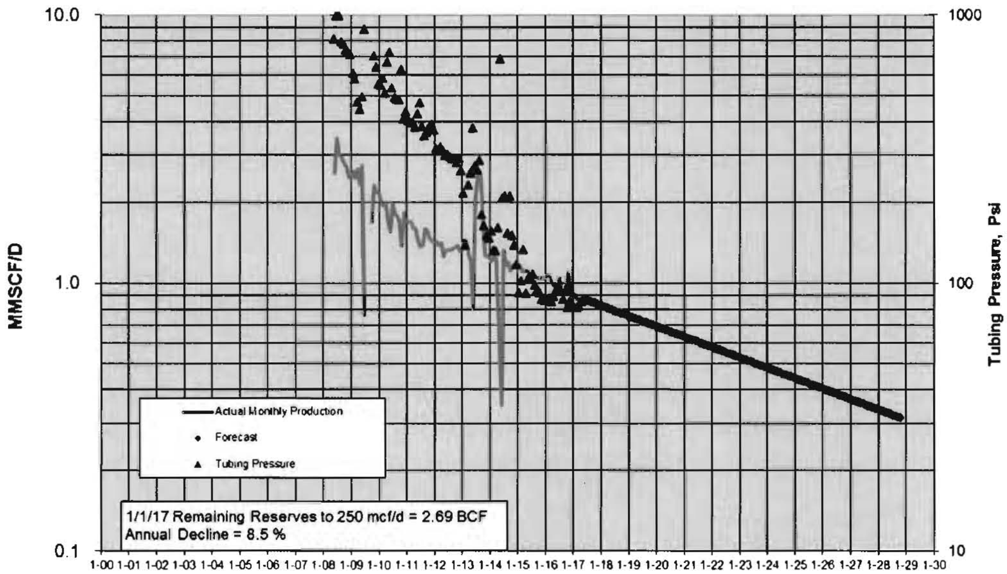
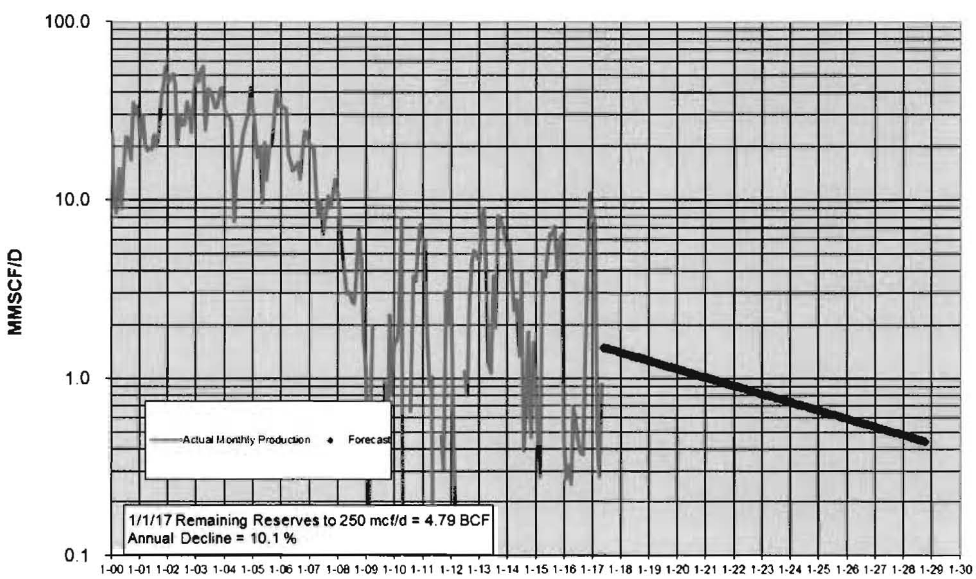


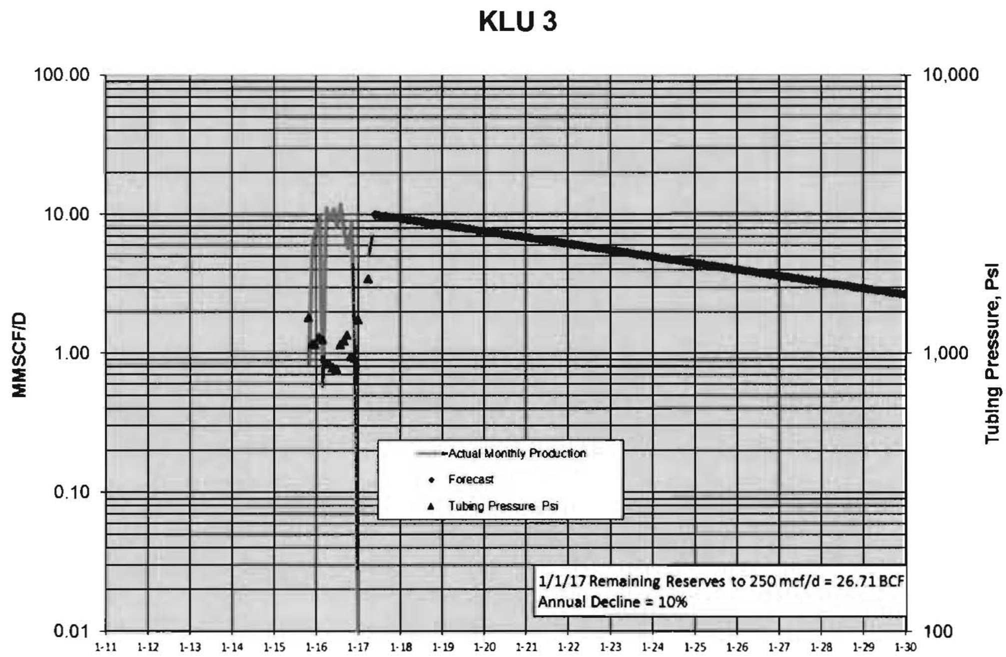
KENAI UNIT 41-18X

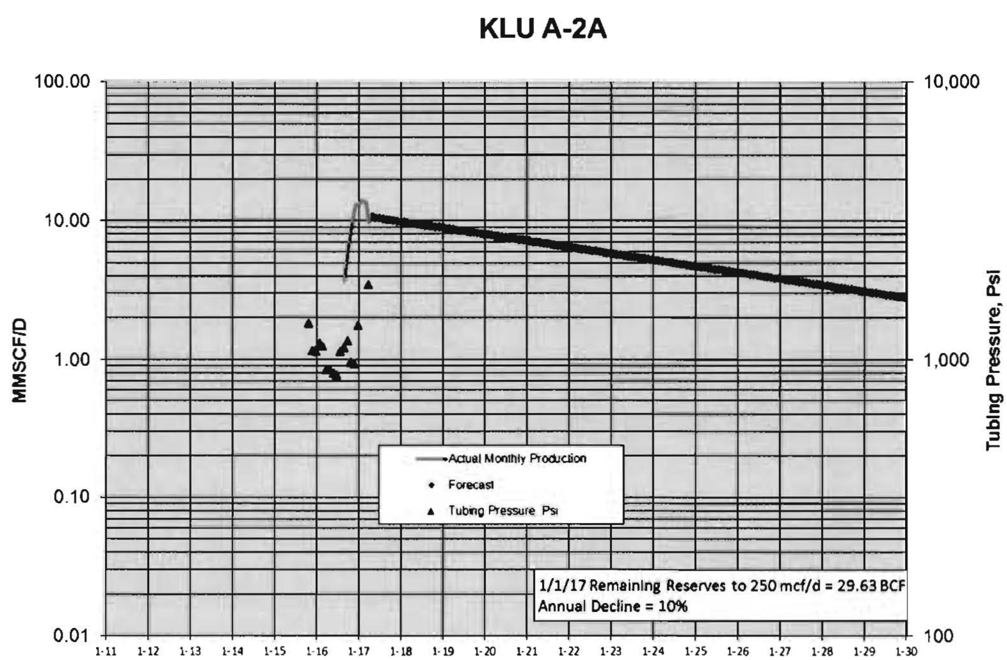


Other KU Wells



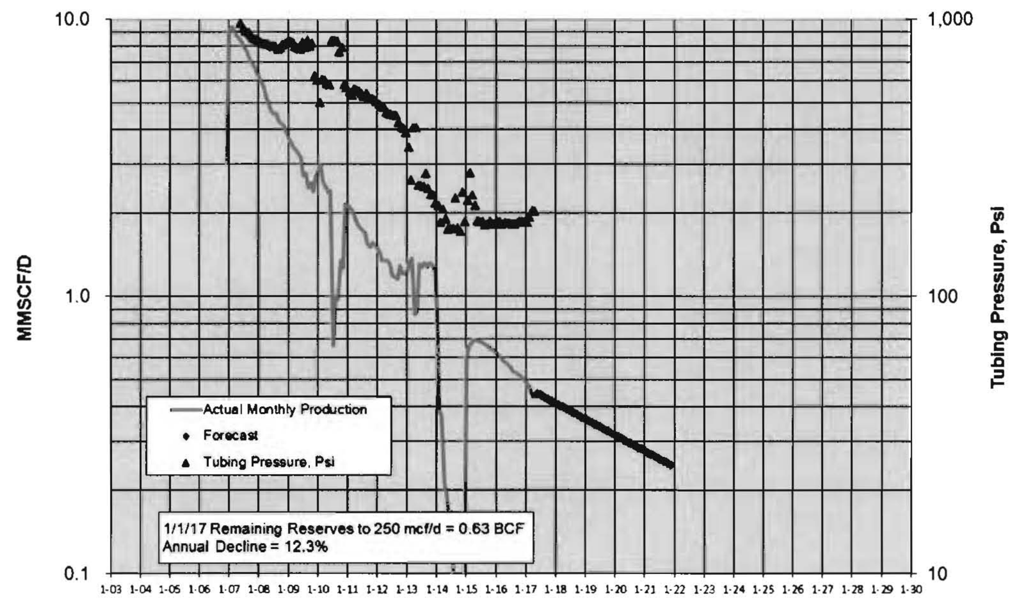
Appendix B-3: Kitchen Lights Unit Well Decline Curves



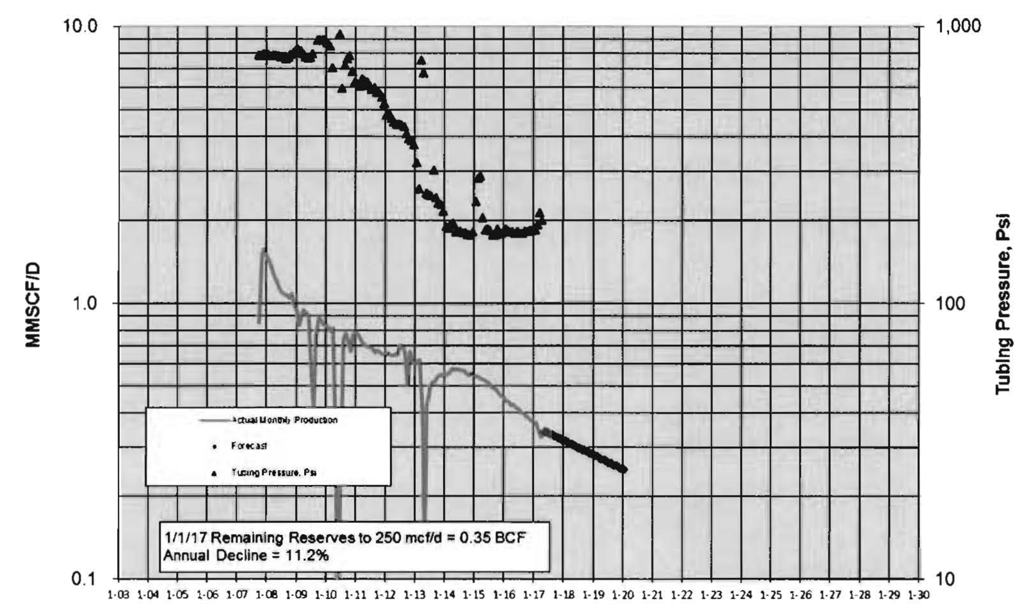


Appendix B-4: Ninilchik Unit Well Decline Curves

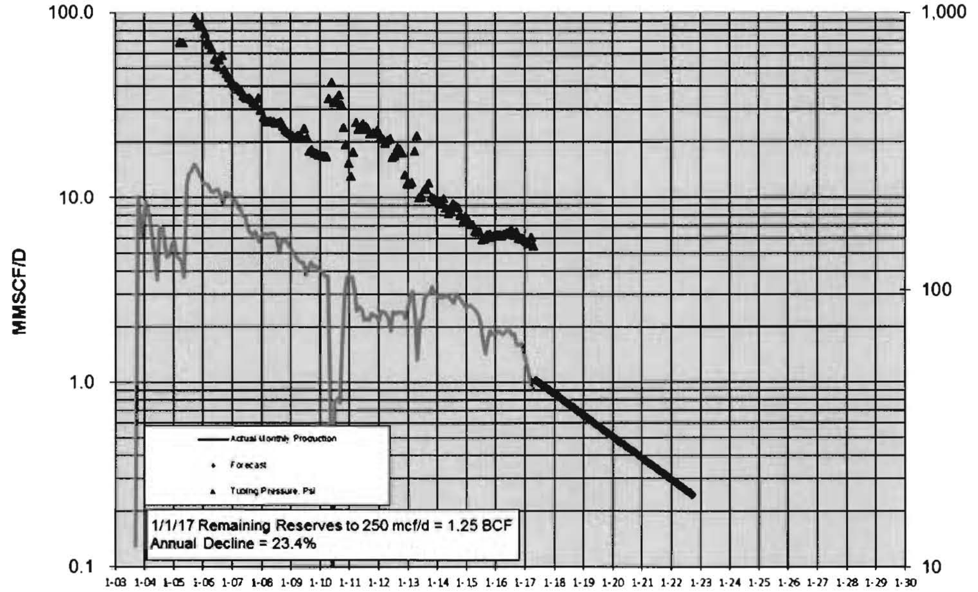
NINILCHIK STATE #1



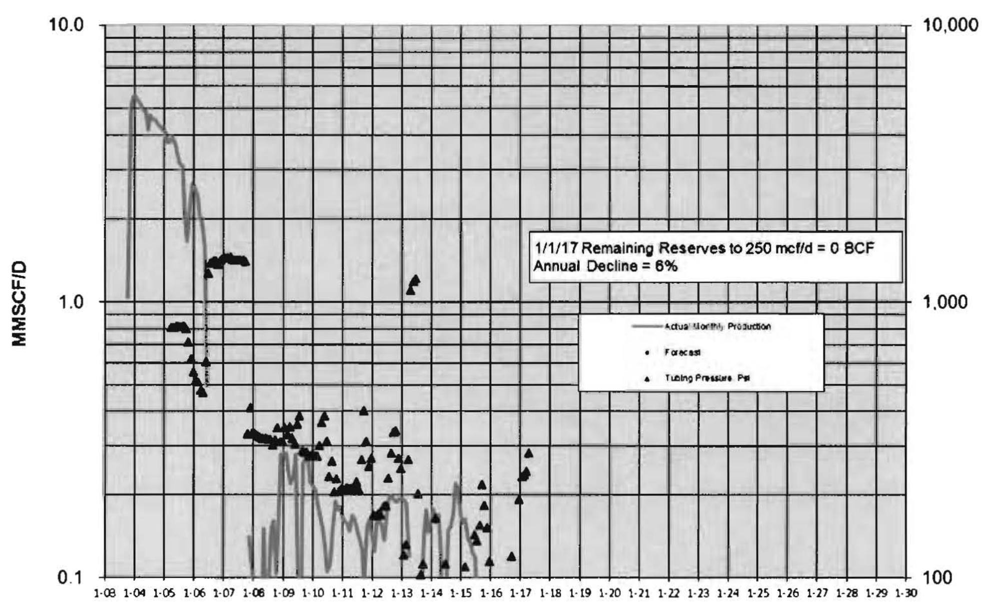
NINILCHIK STATE #3



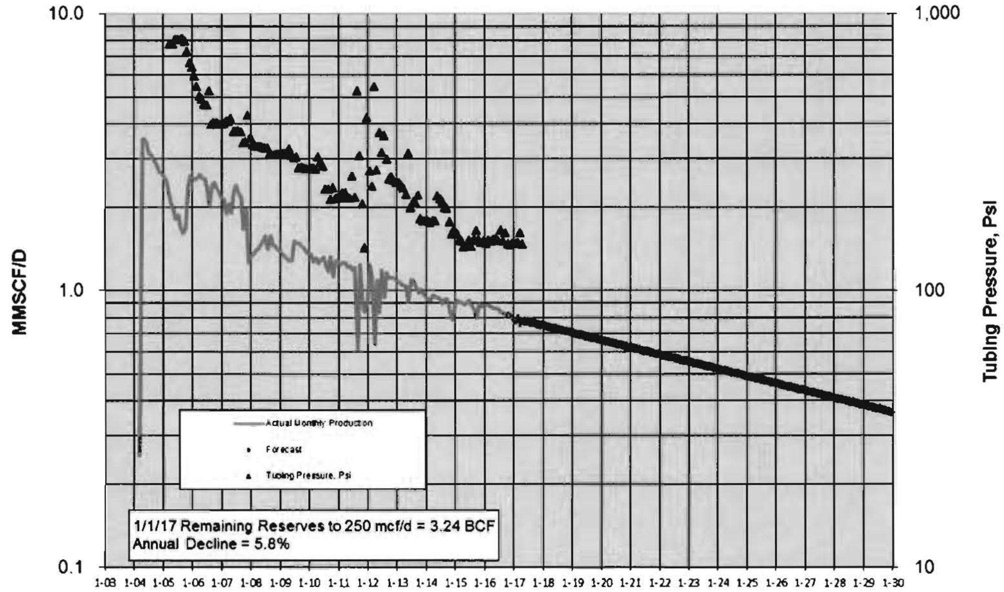
NINILCHIK UNIT FALLS CK #1RD



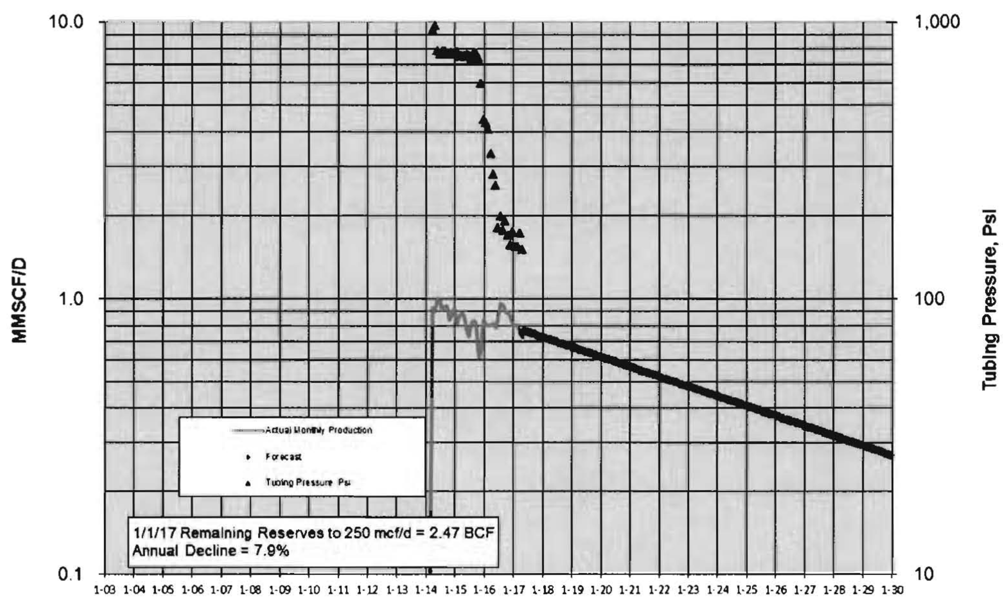
NINILCHIK UNIT FALLS CK #3



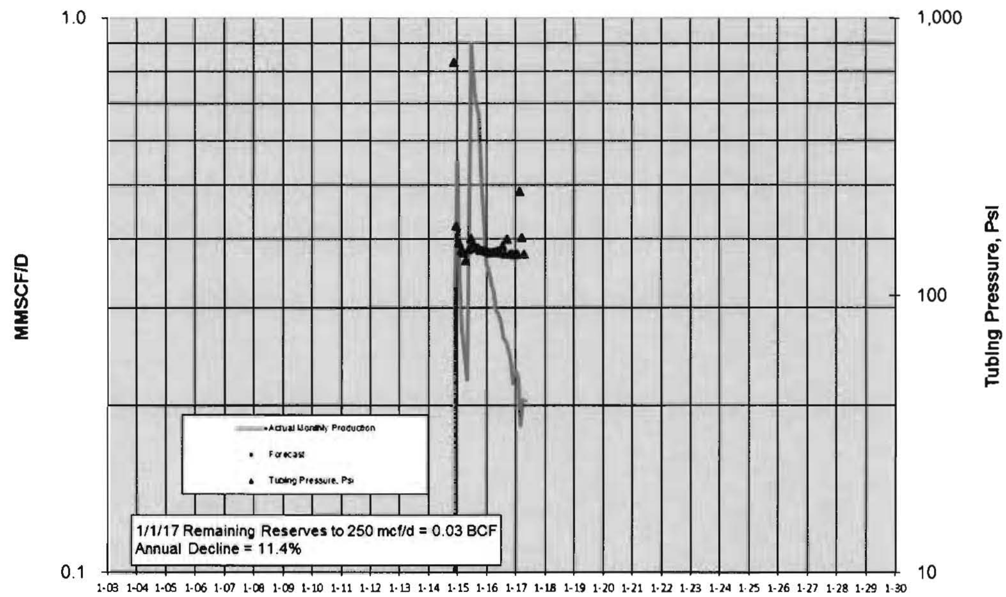
NINILCHIK UNIT FALLS CK #4



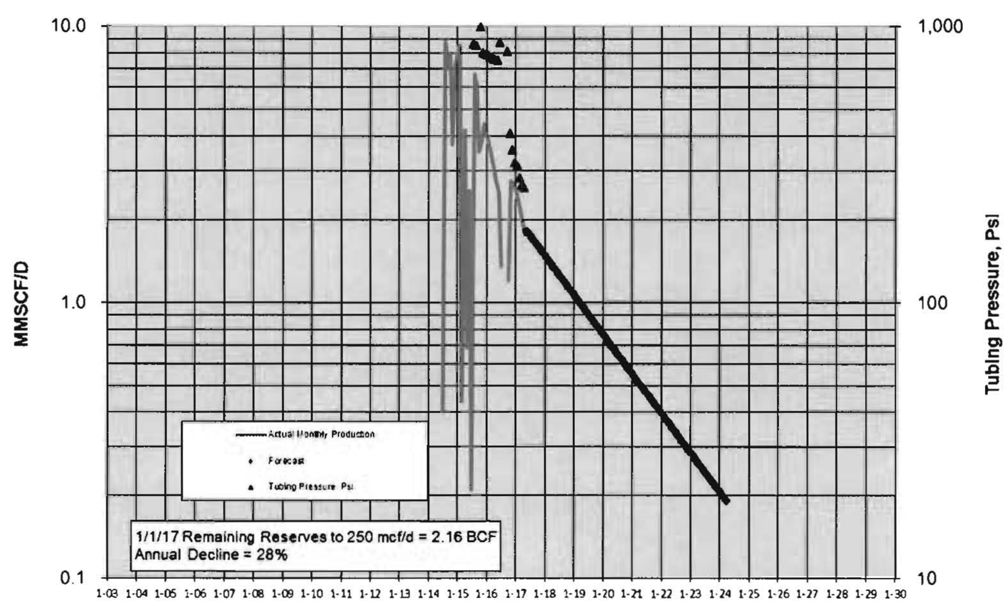
NINILCHIK UNIT FALLS CK #5



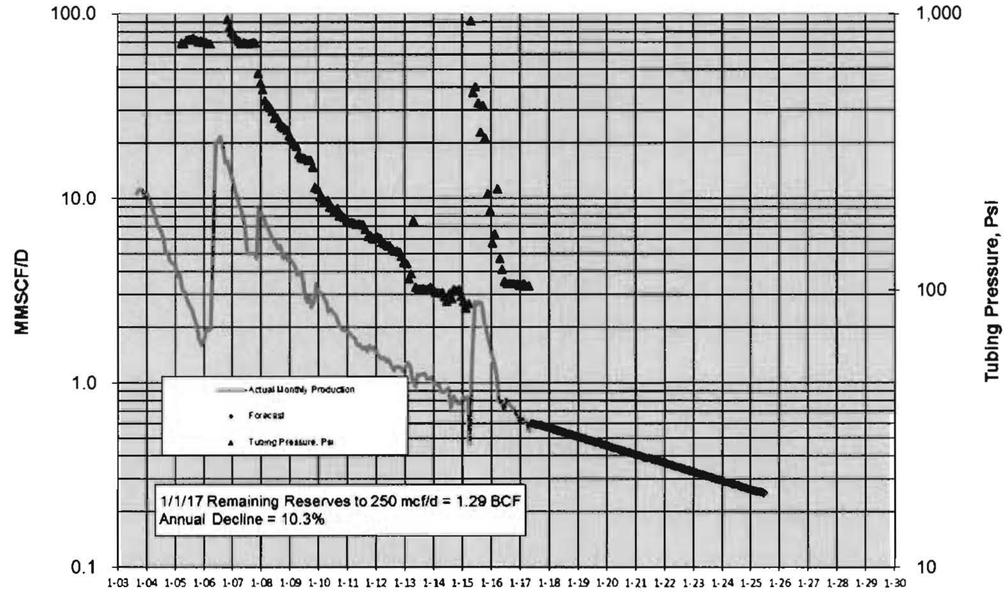
NINILCHIK UNIT FALLS CK #6



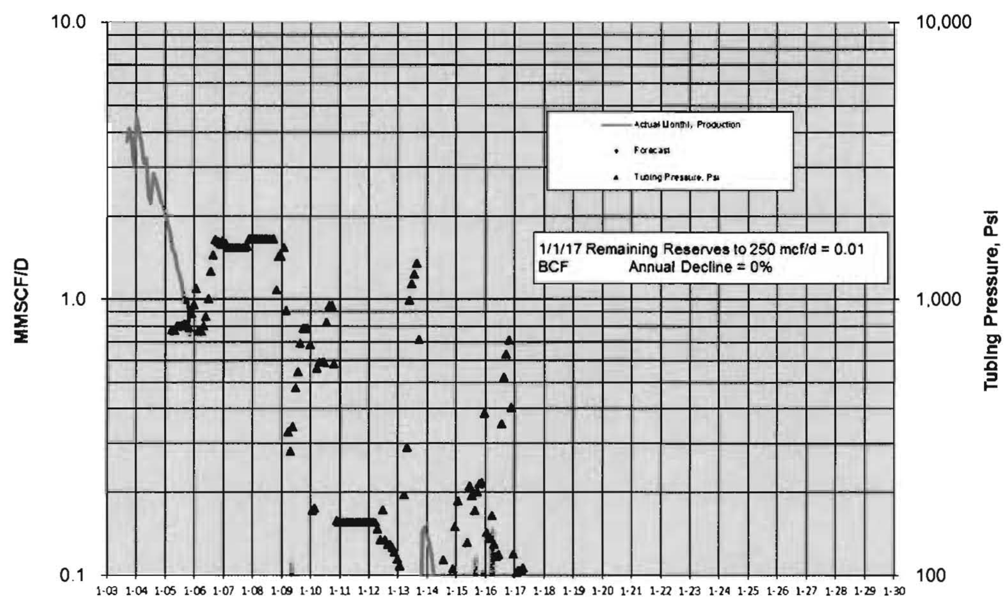
FRANCES #1



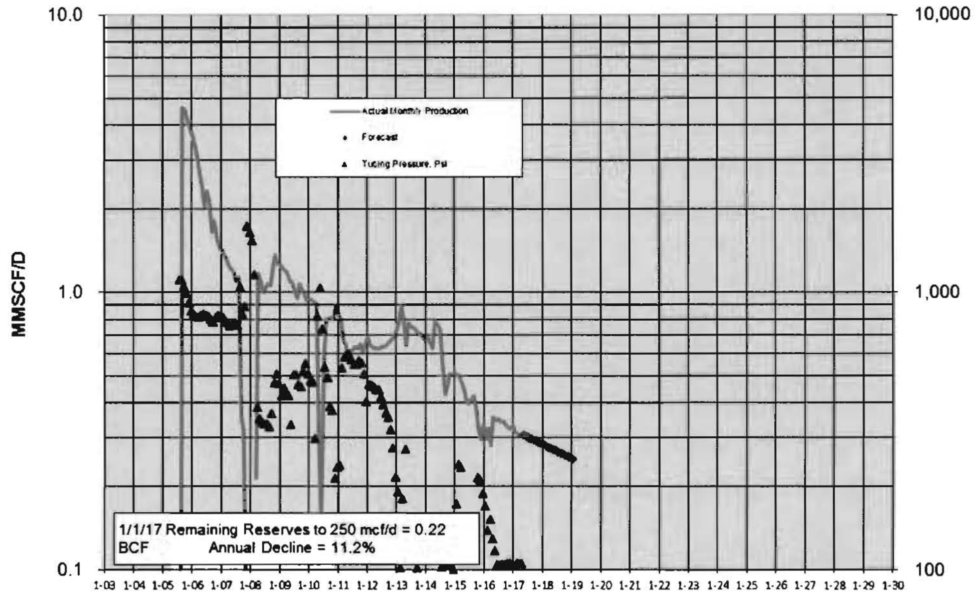
NINILCHIK UNIT G OSKOLKOFF #1



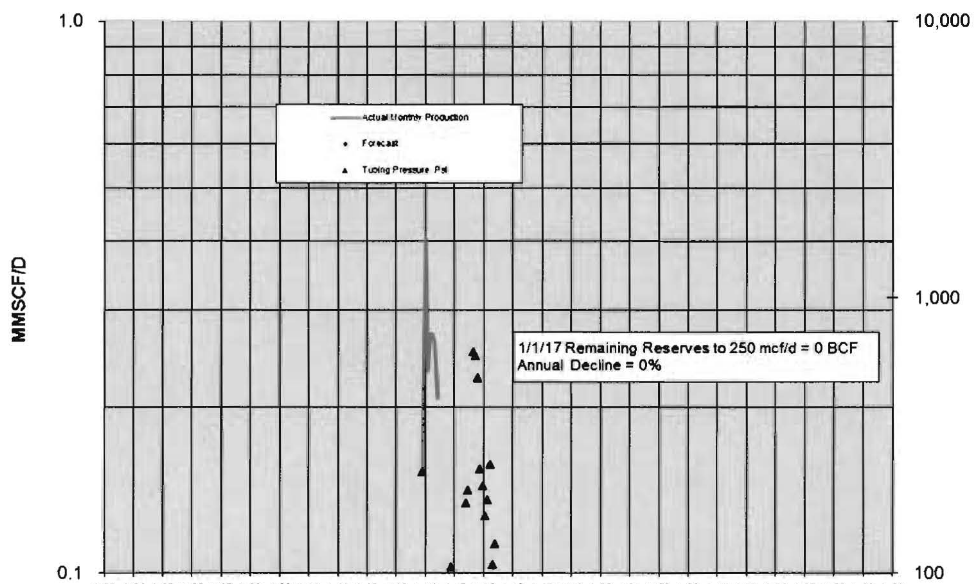
NINILCHIK UNIT G OSKOLKOFF #2



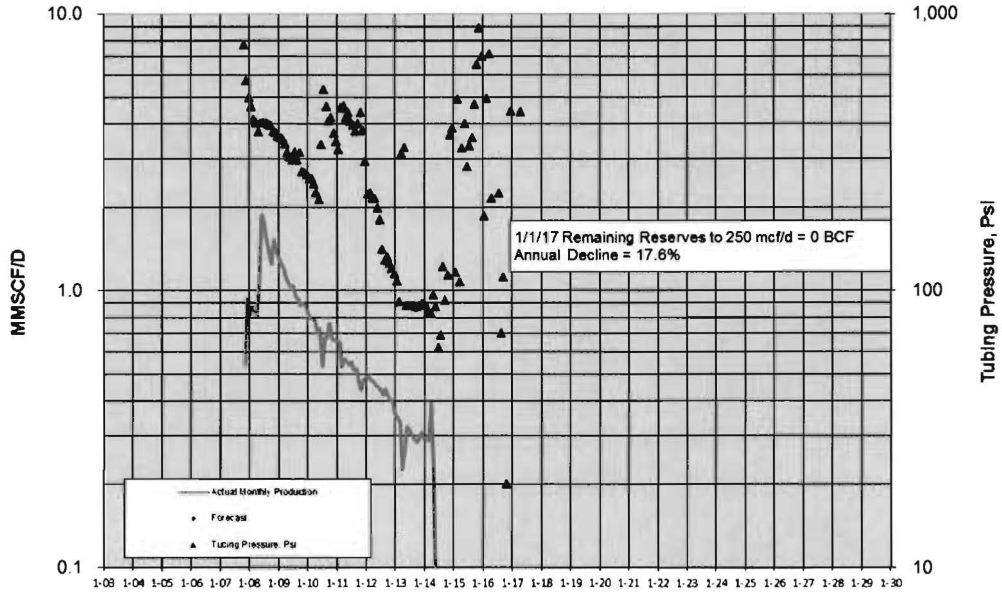
NINILCHIK UNIT G OSKOLKOFF #3



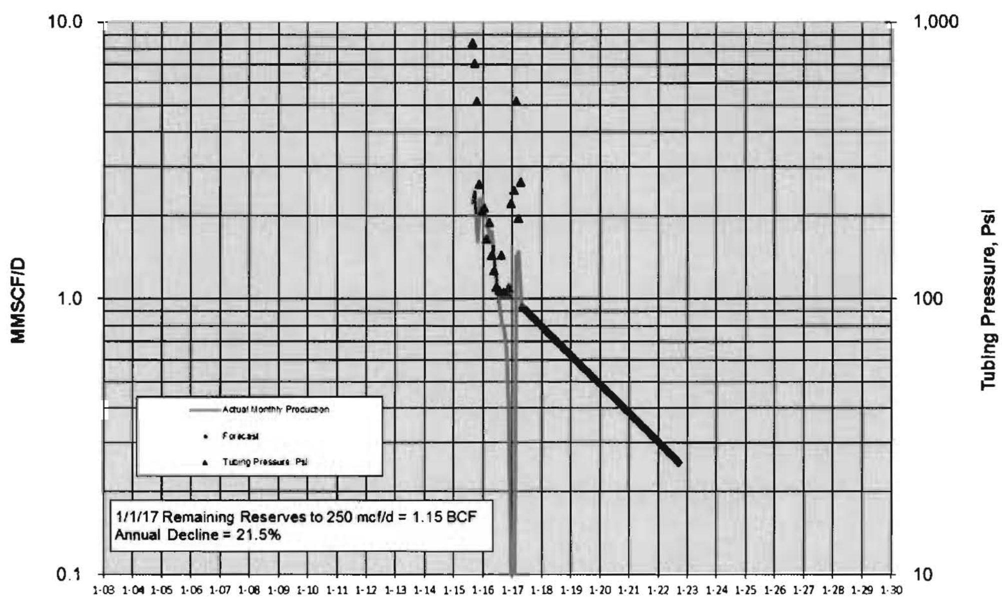
NINILCHIK UNIT G OSKOLKOFF #4



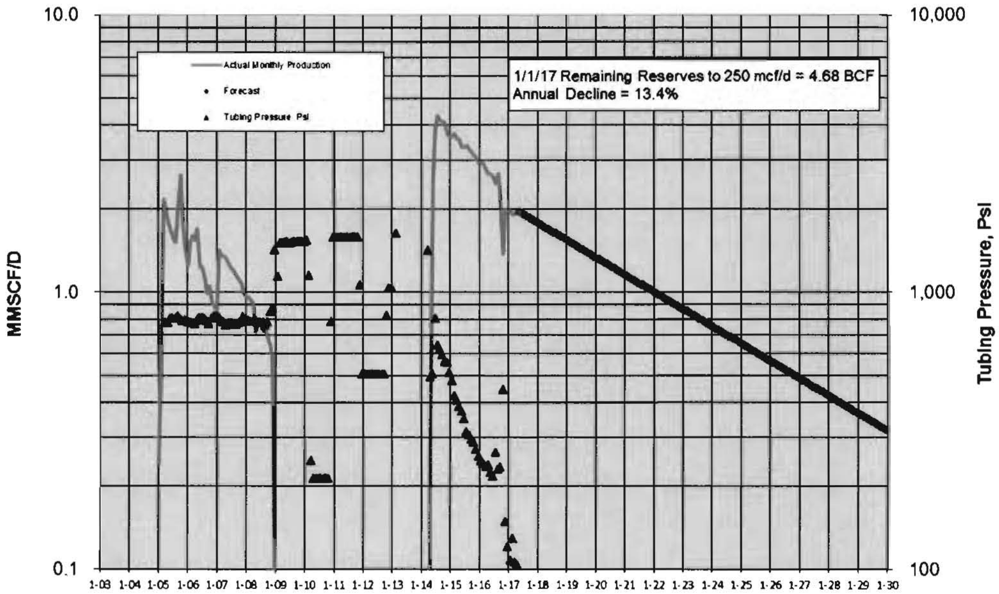
NINILCHIK UNIT G OSKOLKOFF #6



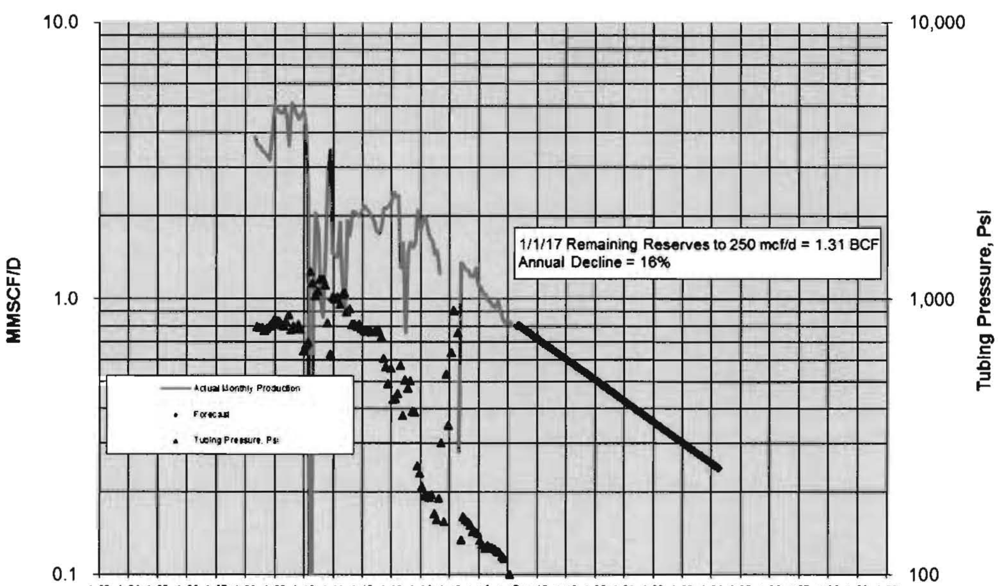
NINILCHIK UNIT G OSKOLKOFF #8



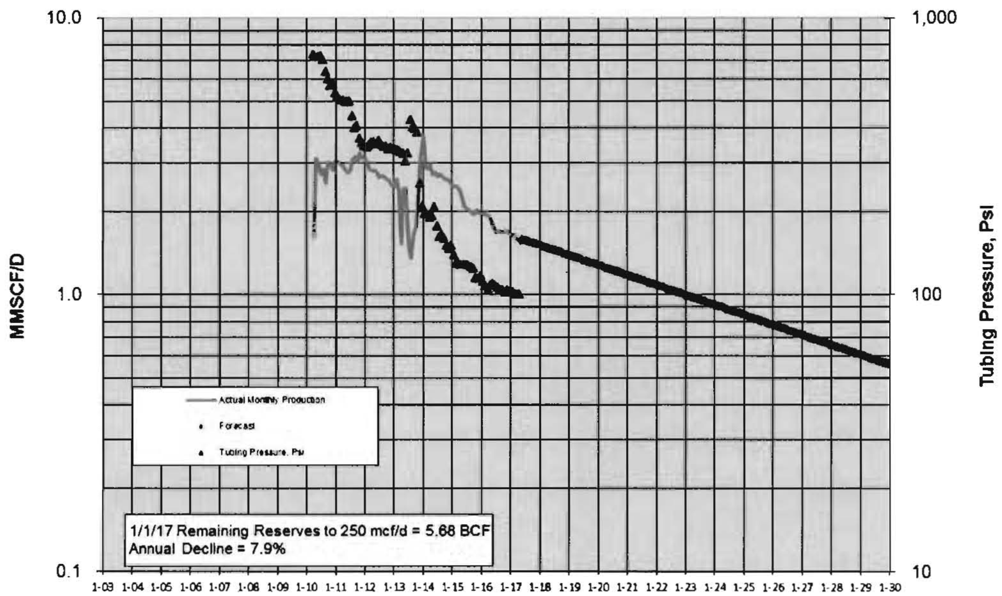
NINILCHIK UNIT PAXTON #1



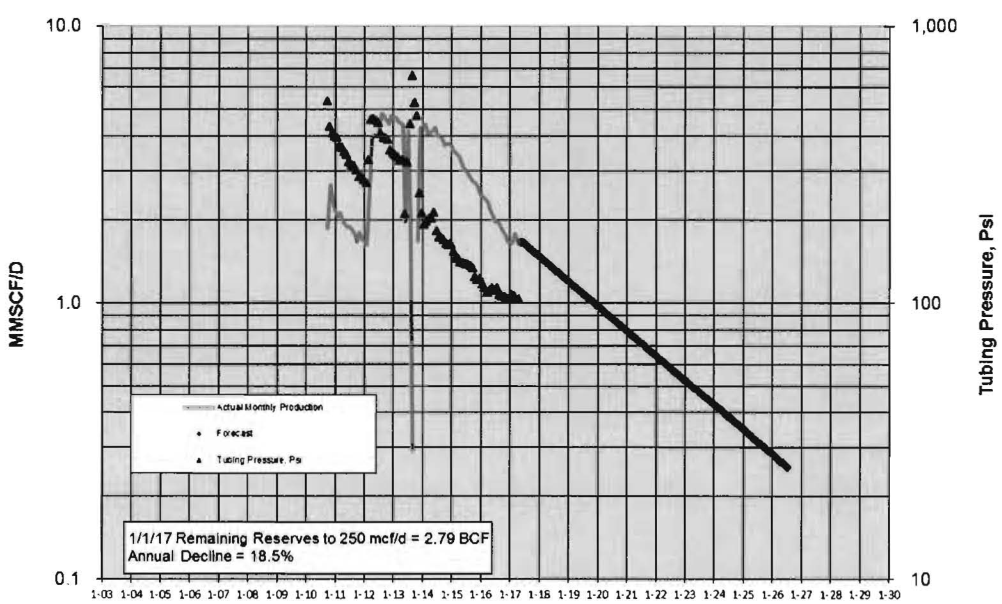
NINILCHIK UNIT PAXTON #2



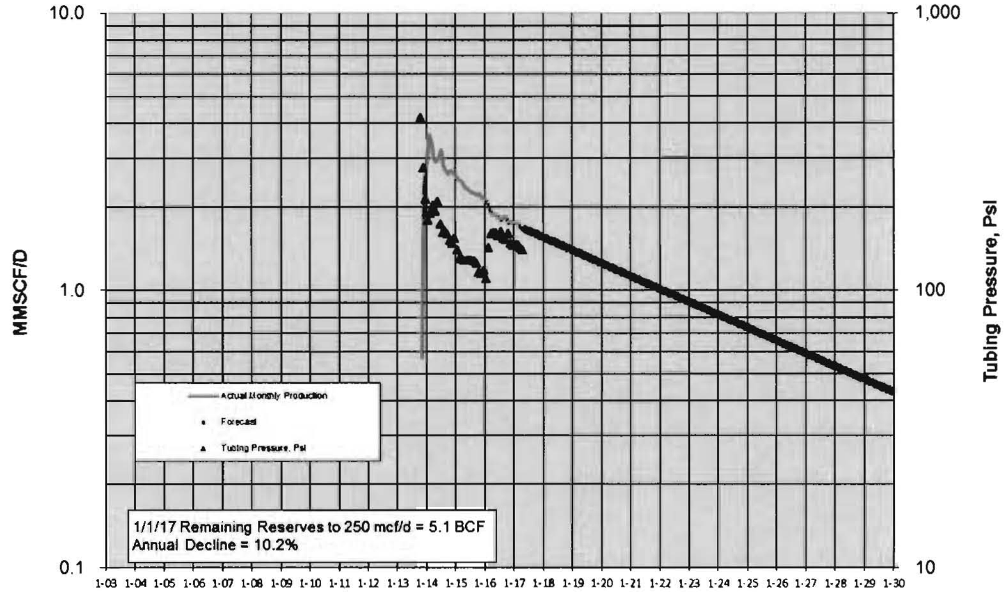
NINILCHIK UNIT PAXTON #3



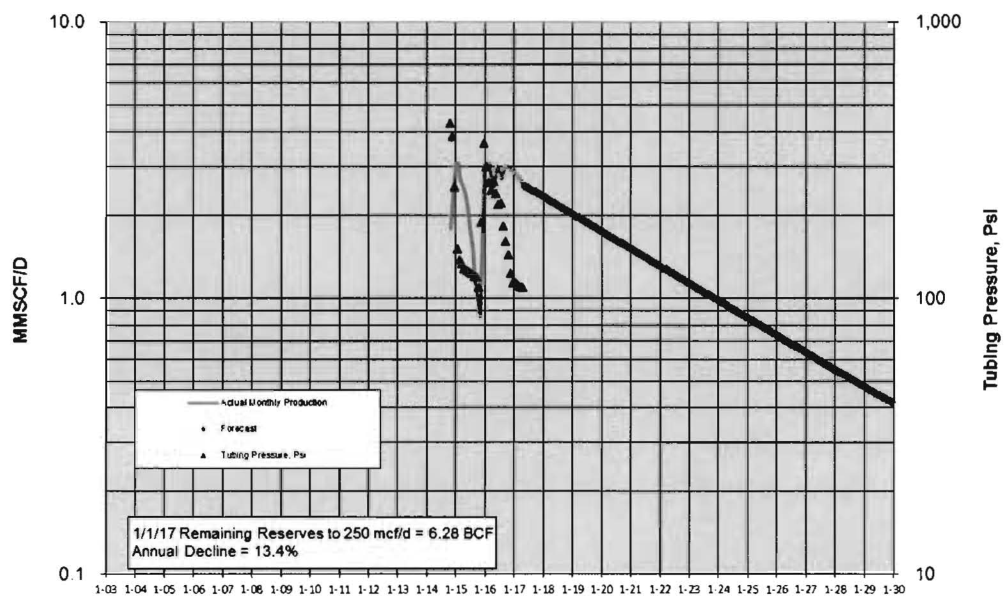
NINILCHIK UNIT PAXTON #4



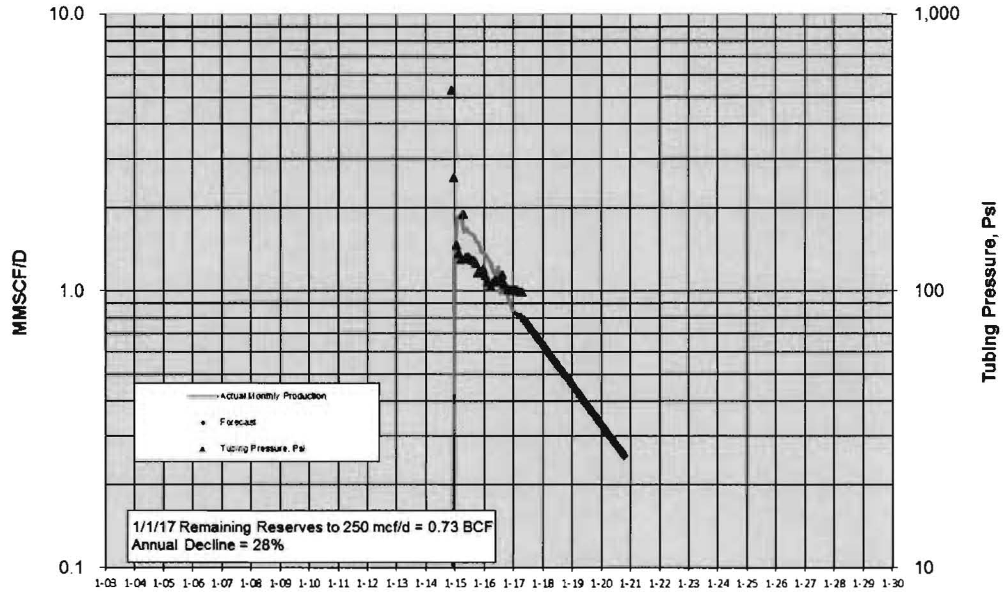
NINILCHIK UNIT PAXTON #5



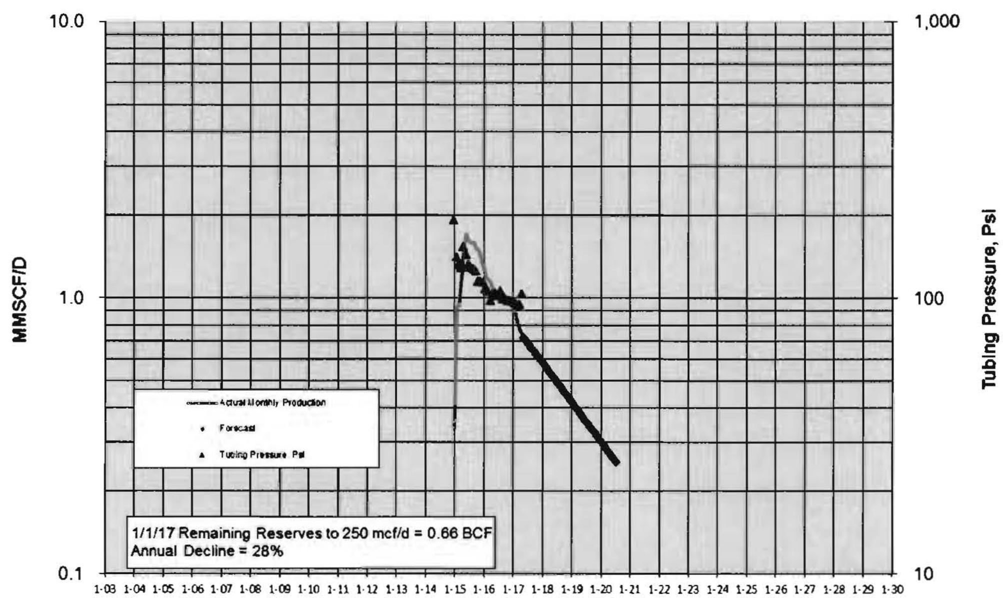
NINILCHIK UNIT PAXTON #7



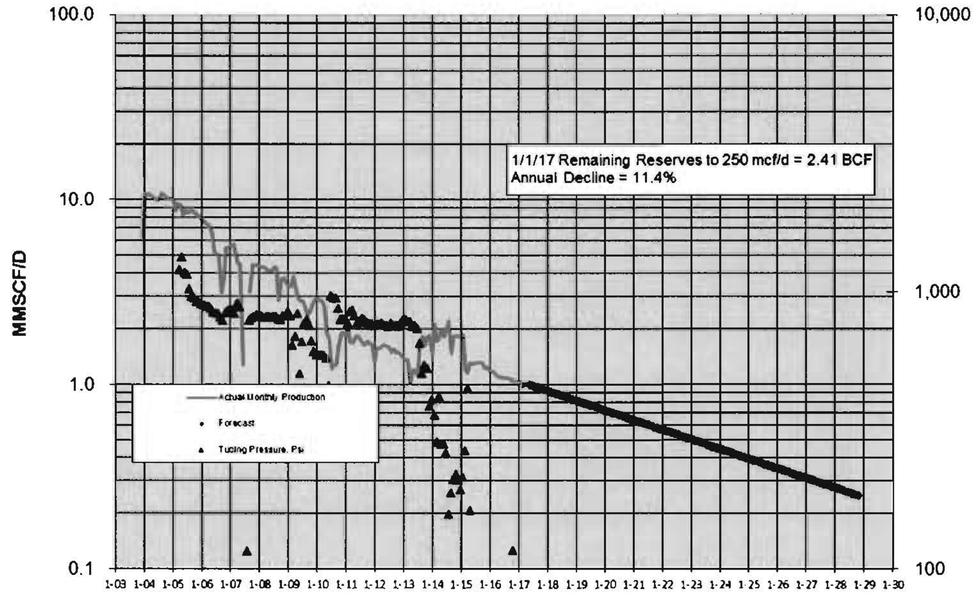
NINILCHIK UNIT PAXTON #8



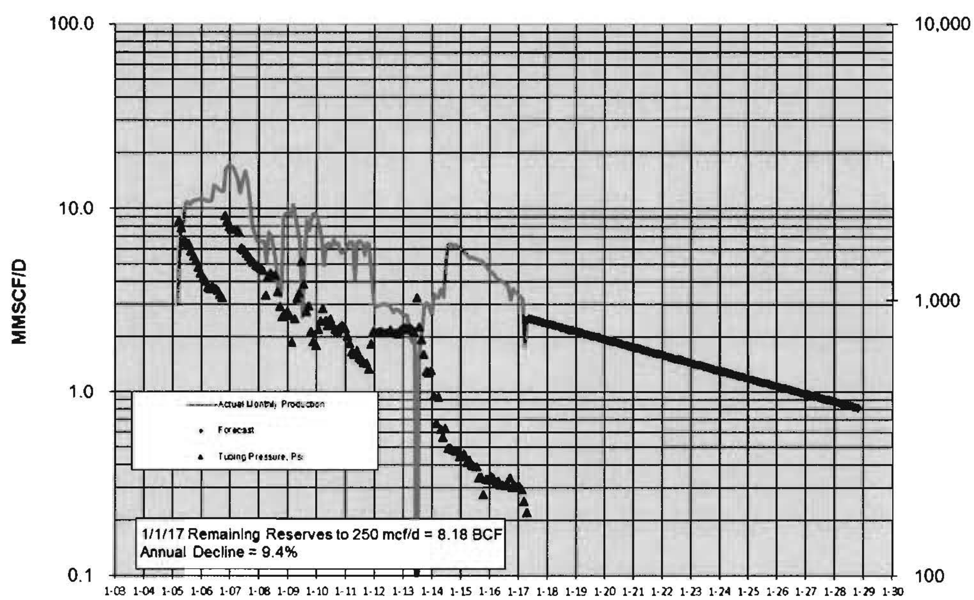
NINILCHIK UNIT PAXTON #9



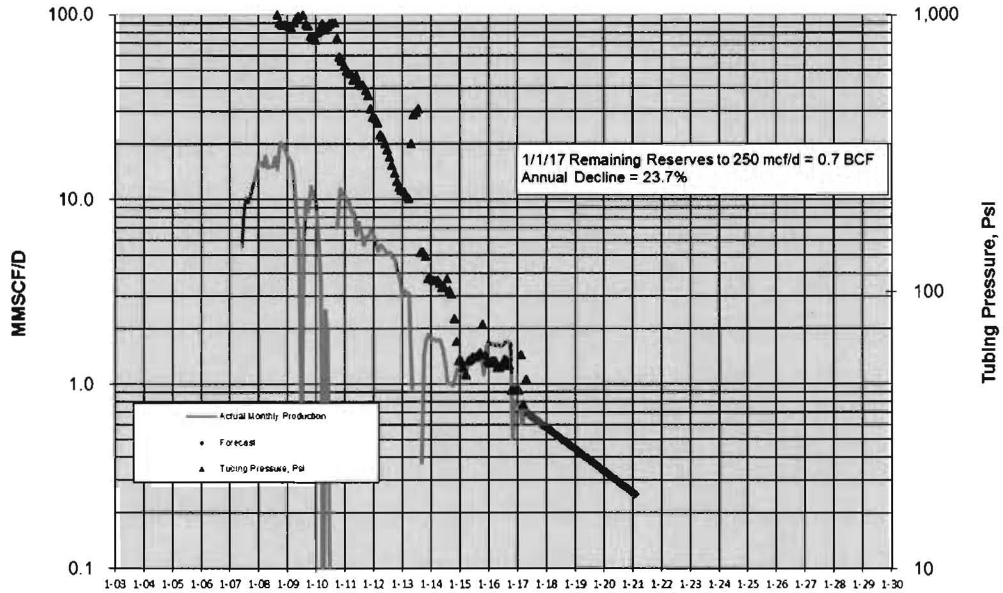
NINILCHIK UNIT S DIONNE #3



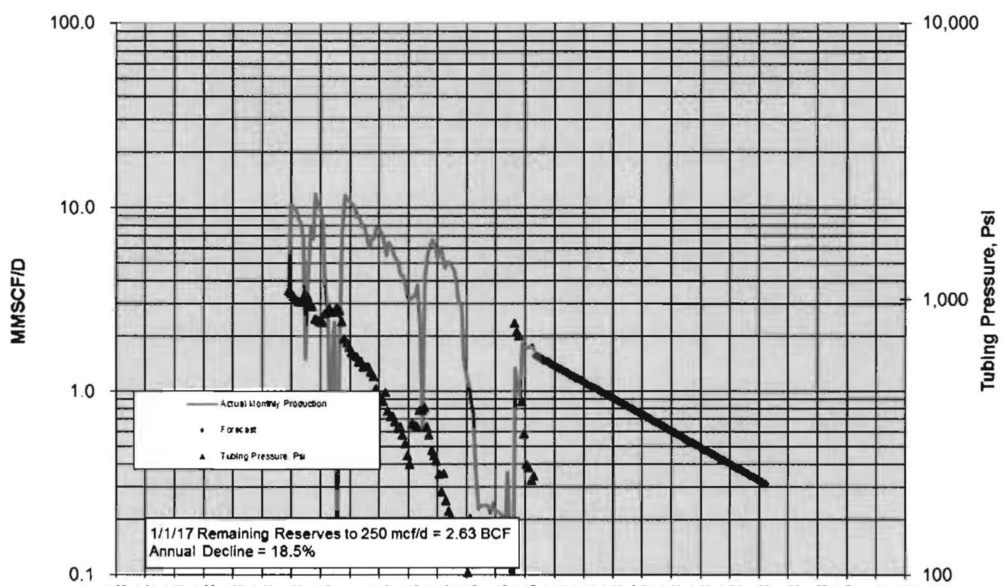
NINILCHIK UNIT S DIONNE #4



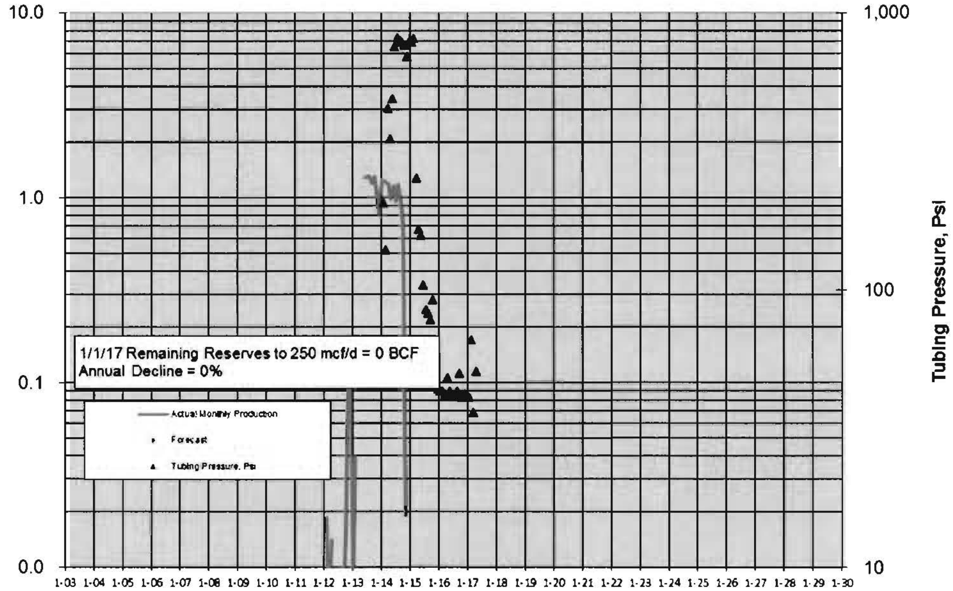
NINILCHIK UNIT S DIONNE #5



NINILCHIK UNIT S DIONNE #6



NINILCHIK UNIT S DIONNE #7



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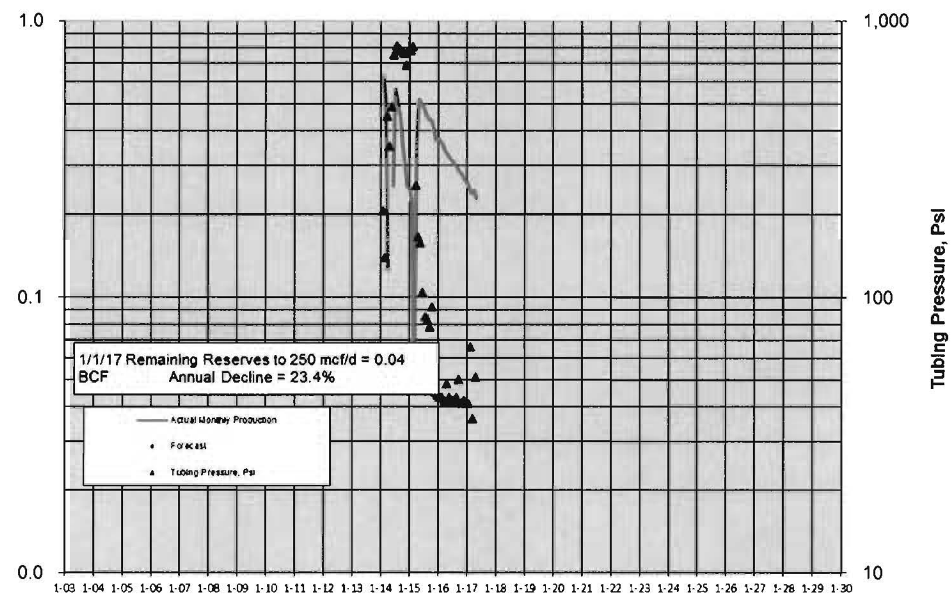
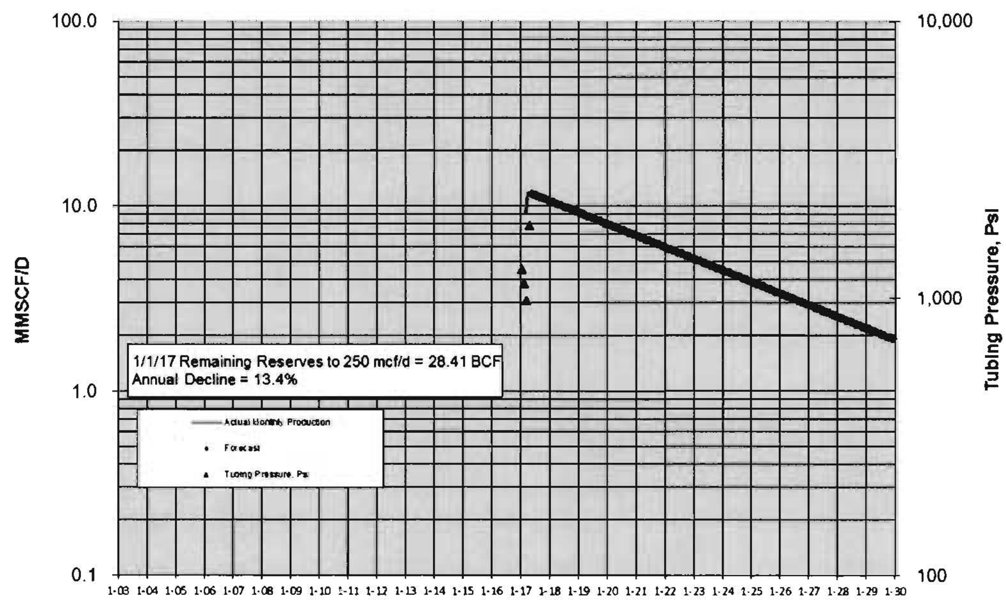
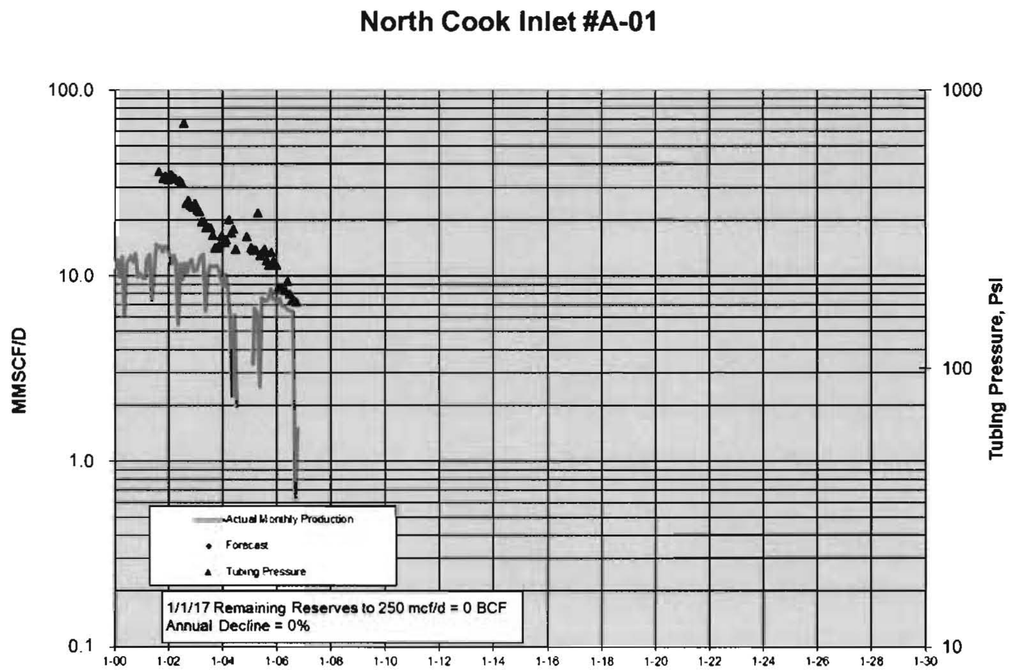
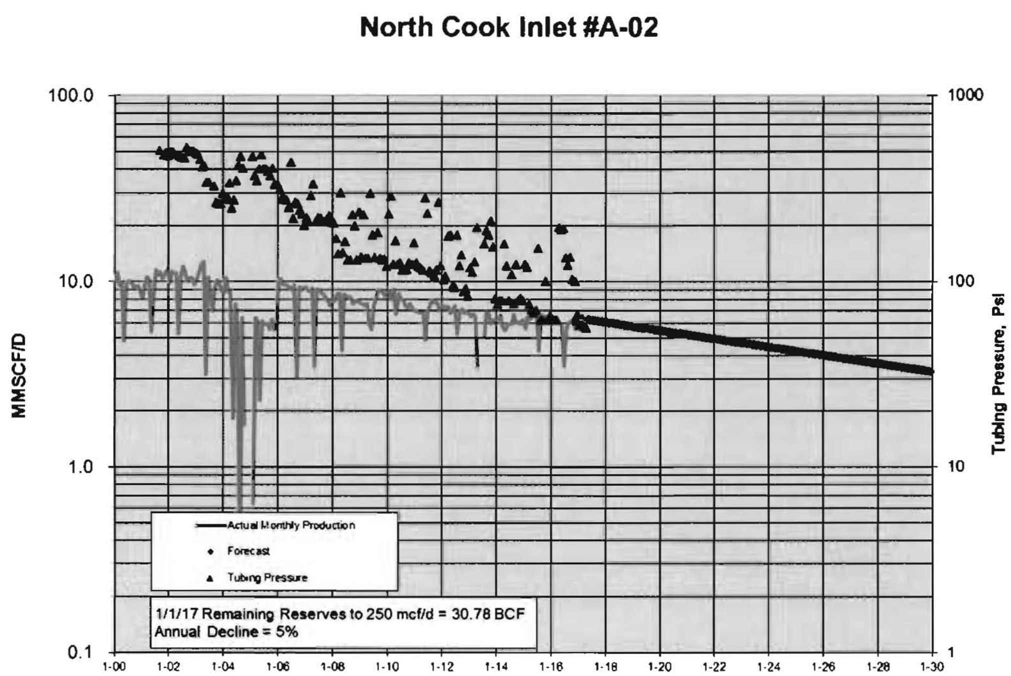


KALOTSA #1

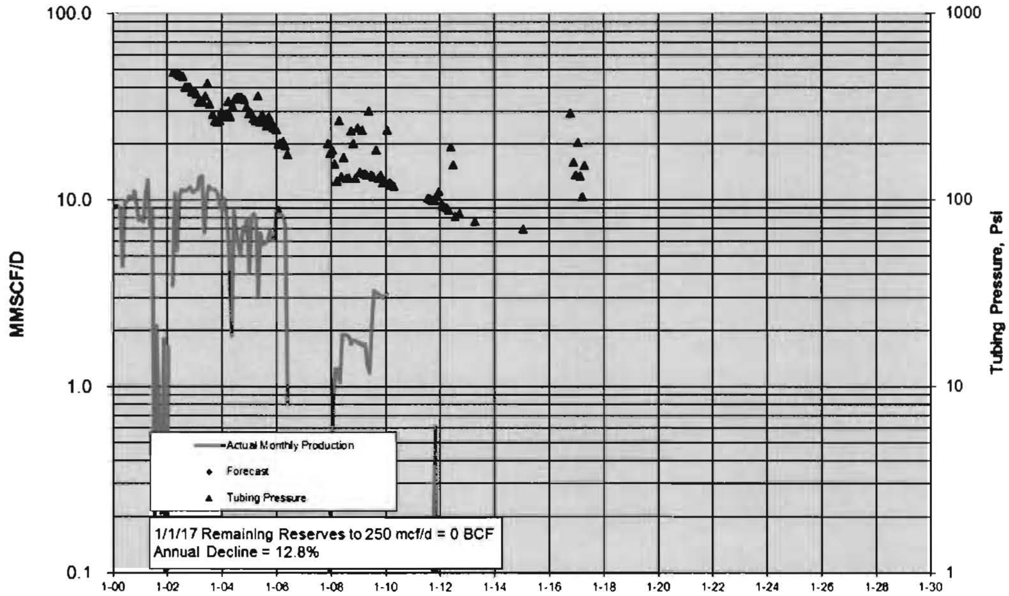

100.0
10.0
1.0
0.1
MMSCF/D
10,000
1,000
100
Tubing Pressure, Psi
1/1/17 Remaining Reserves to 250 mcf/d = 28.41 BCF
Annual Decline = 13.4%
Actual Monthly Production
Forecast
Tubing Pressure, Psi
1-03 1-04 1-05 1-06 1-07 1-08 1-09 1-10 1-11 1-12 1-13 1-14 1-15 1-16 1-17 1-18 1-19 1-20 1-21 1-22 1-23 1-24 1-25 1-26 1-27 1-28 1-29 1-30

Appendix B-5: North Cook Inlet Unit Well Decline Curves

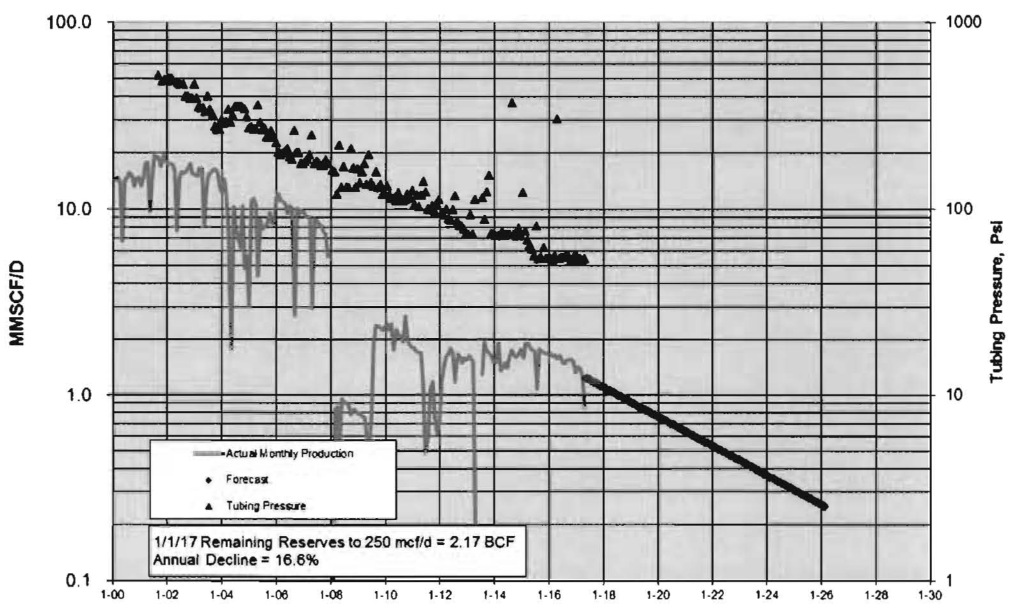




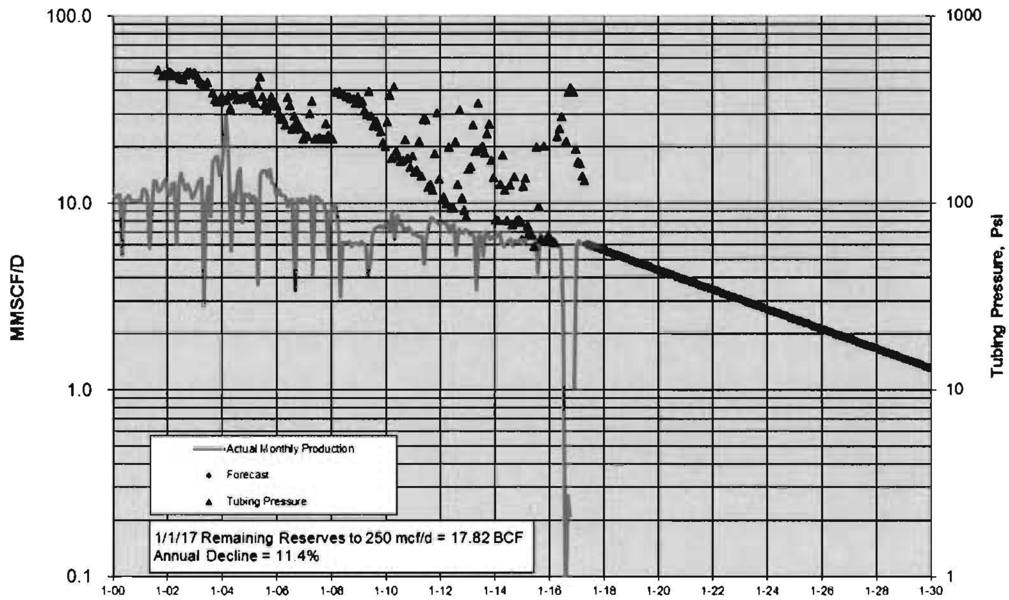
North Cook Inlet #A-03



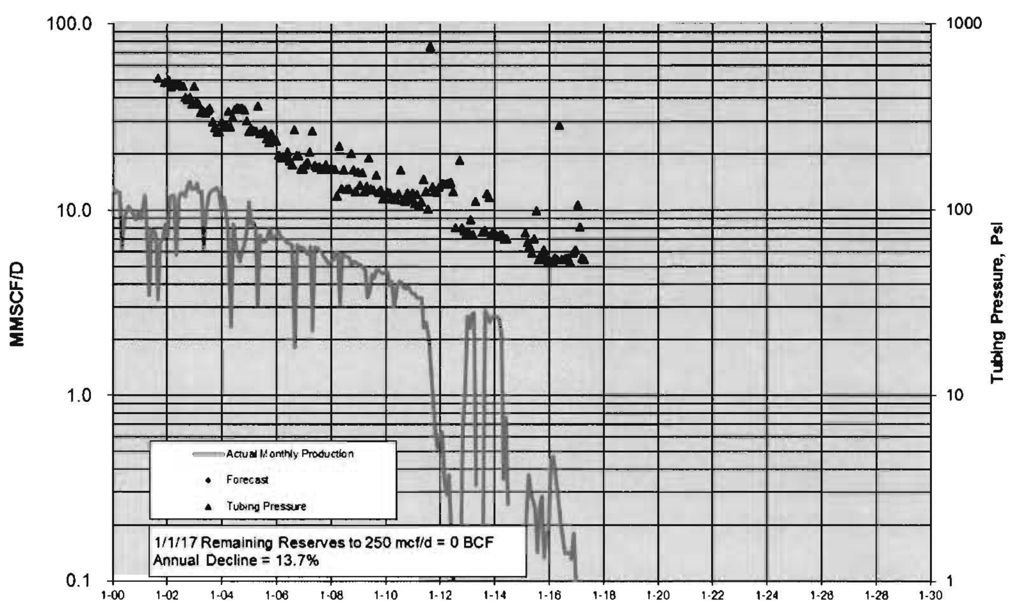
North Cook Inlet #A-04



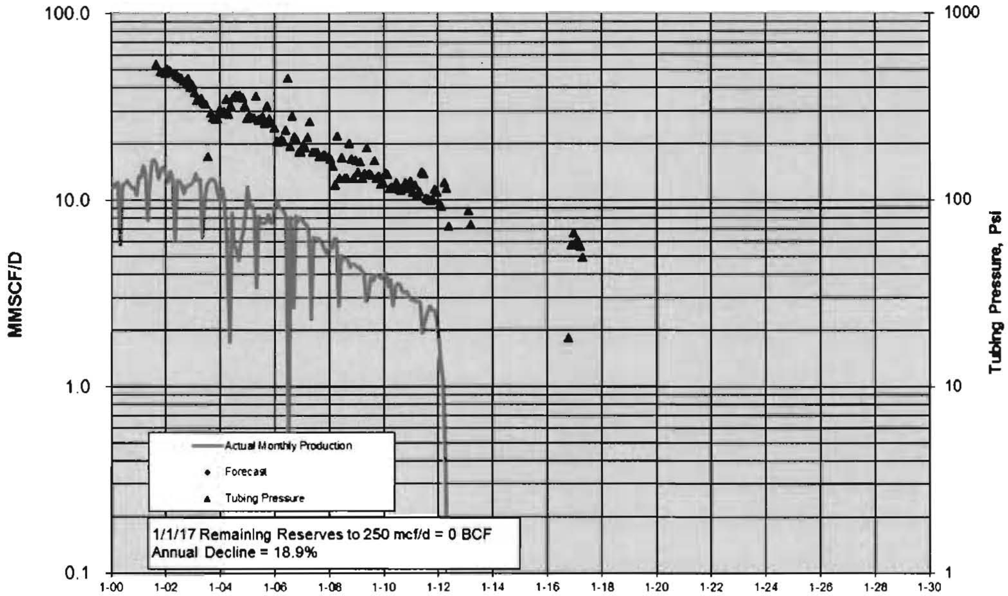
North Cook Inlet #A-05



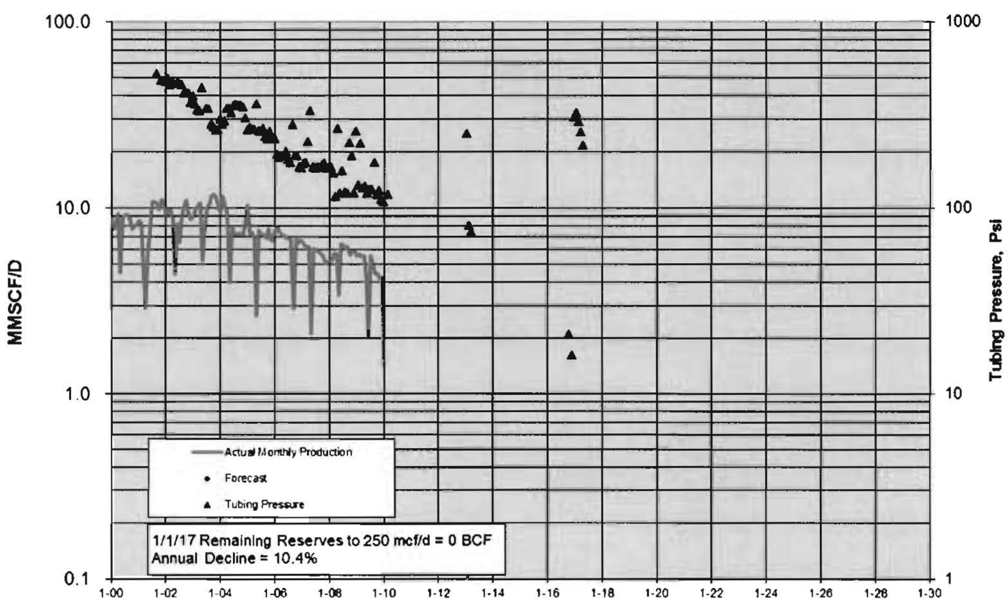
North Cook Inlet #A-06



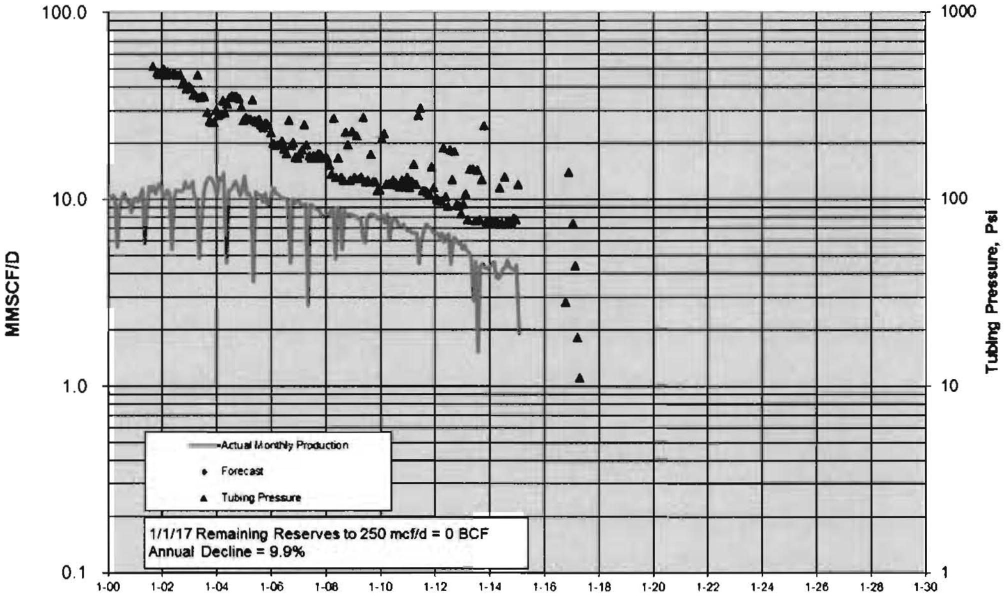
North Cook Inlet #A-07



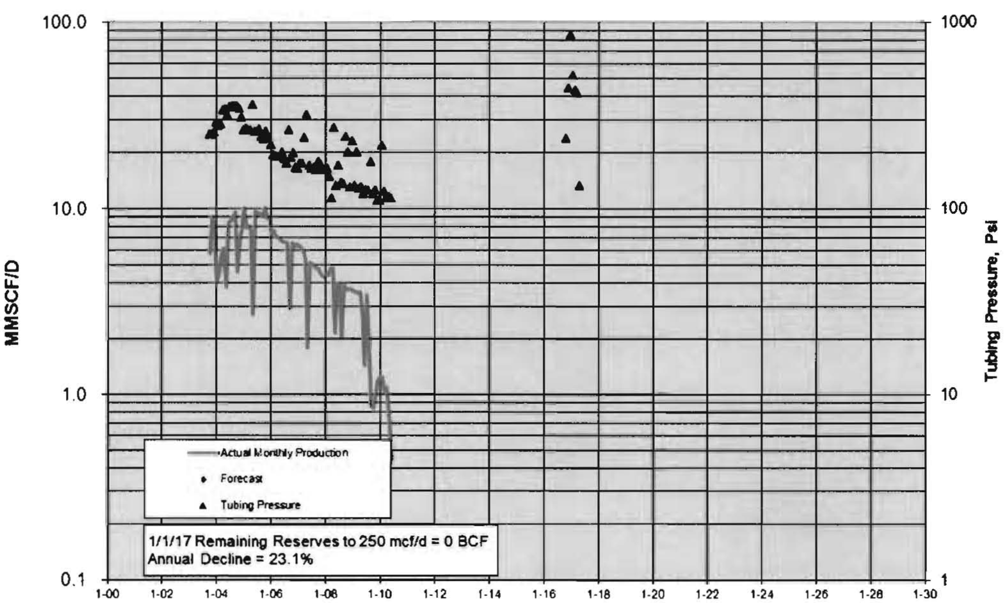
North Cook Inlet #A-08



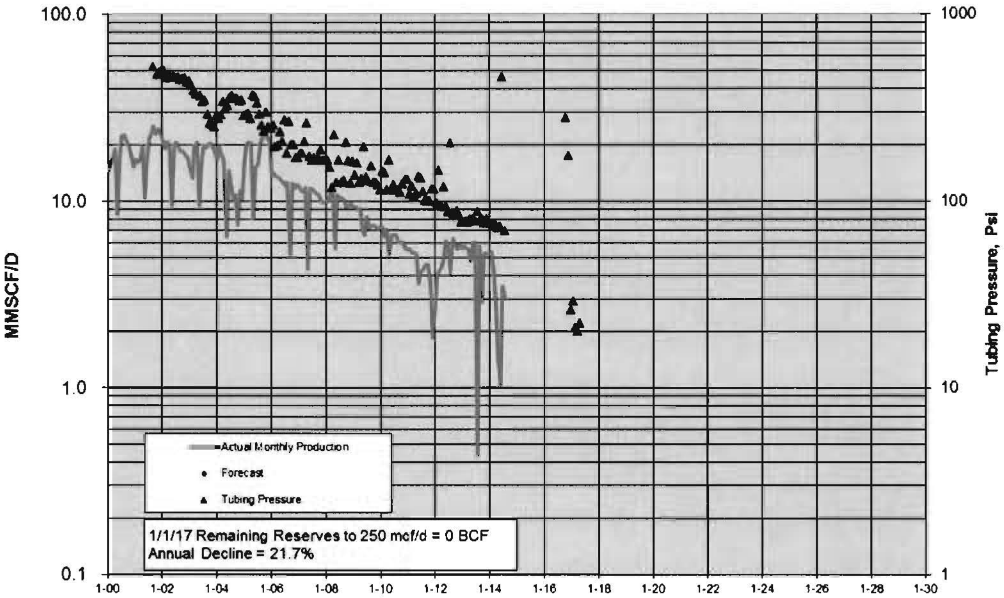
North Cook Inlet #A-09



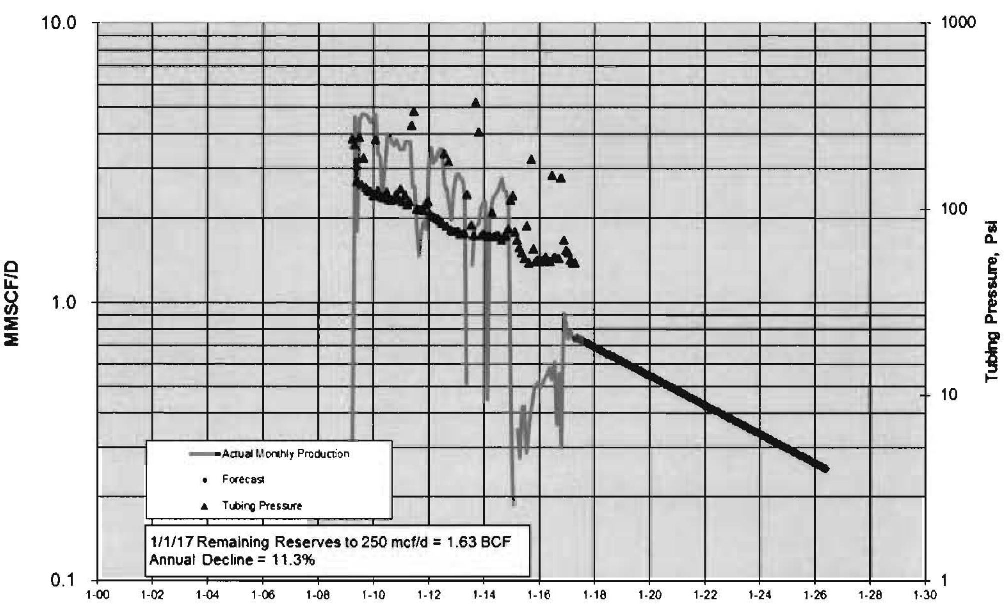
North Cook Inlet #A-10



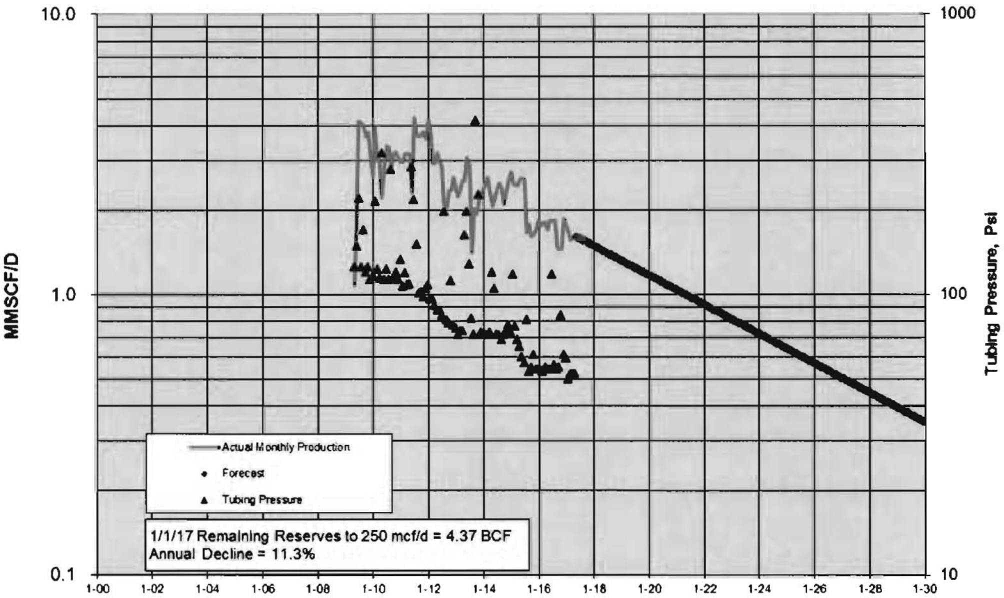
North Cook Inlet #A-12



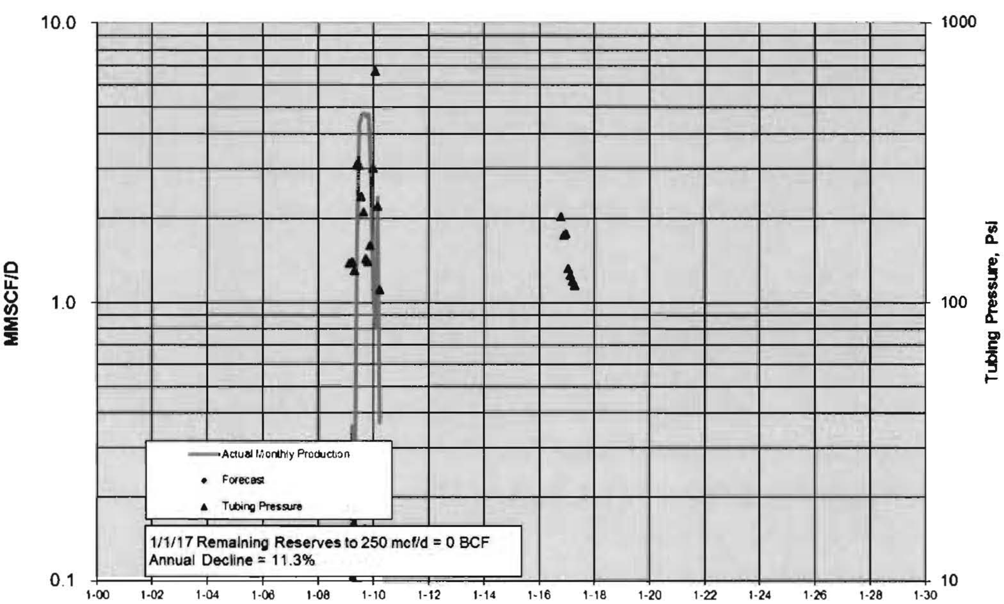
North Cook Inlet #A-14



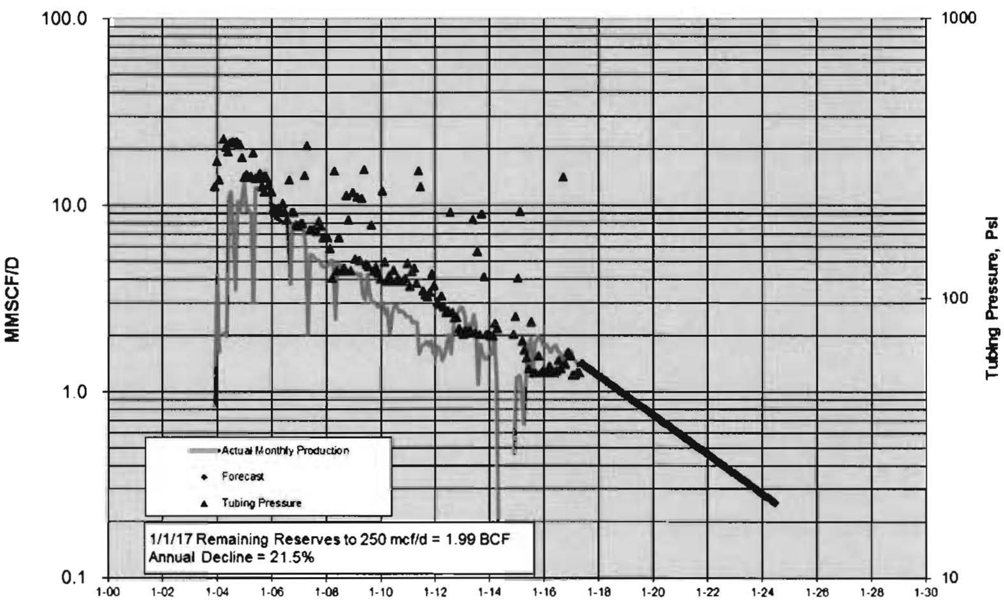
North Cook Inlet #A-15



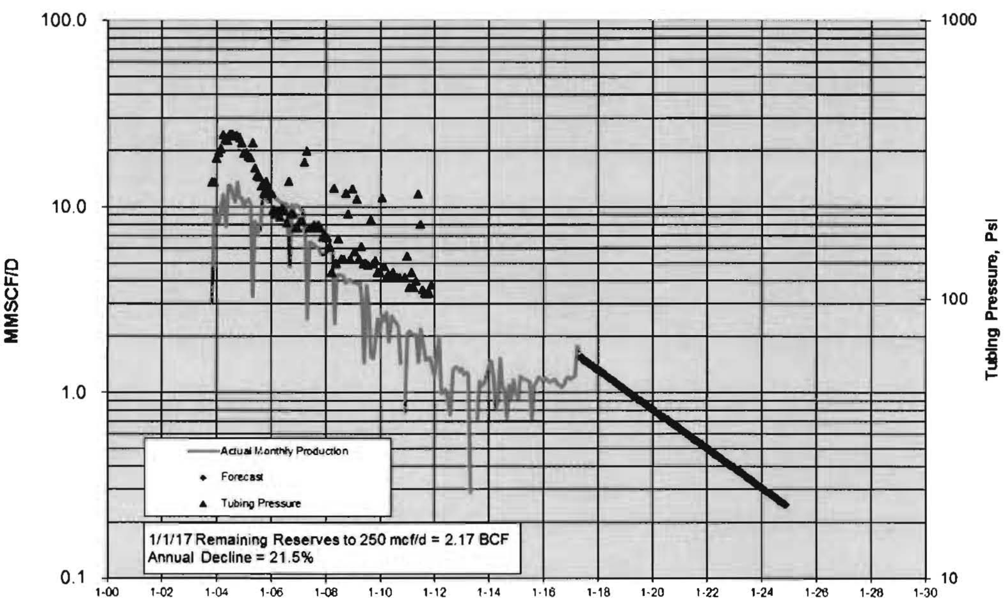
North Cook Inlet #A-16



North Cook Inlet #B-01A

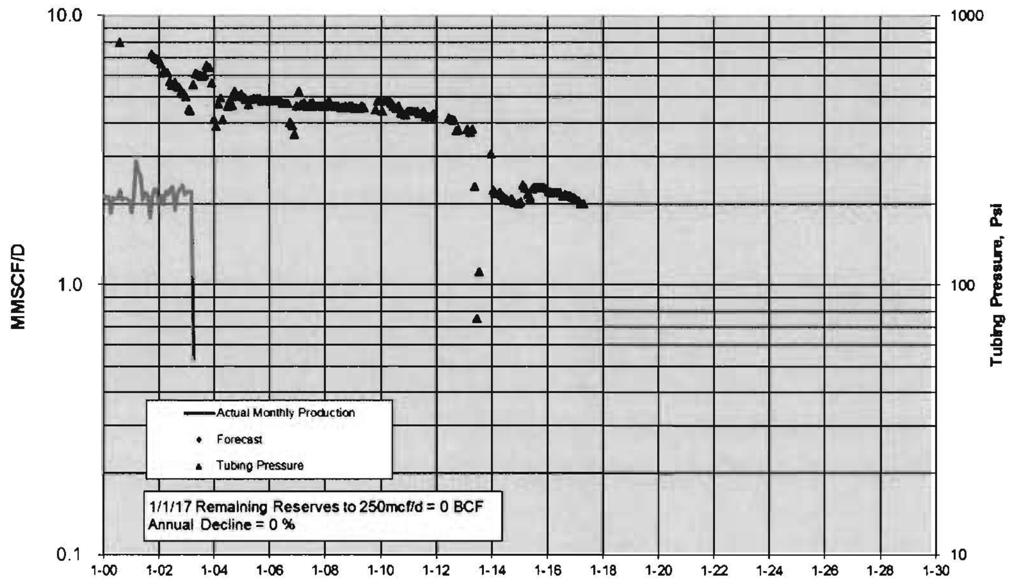


North Cook Inlet #B-03

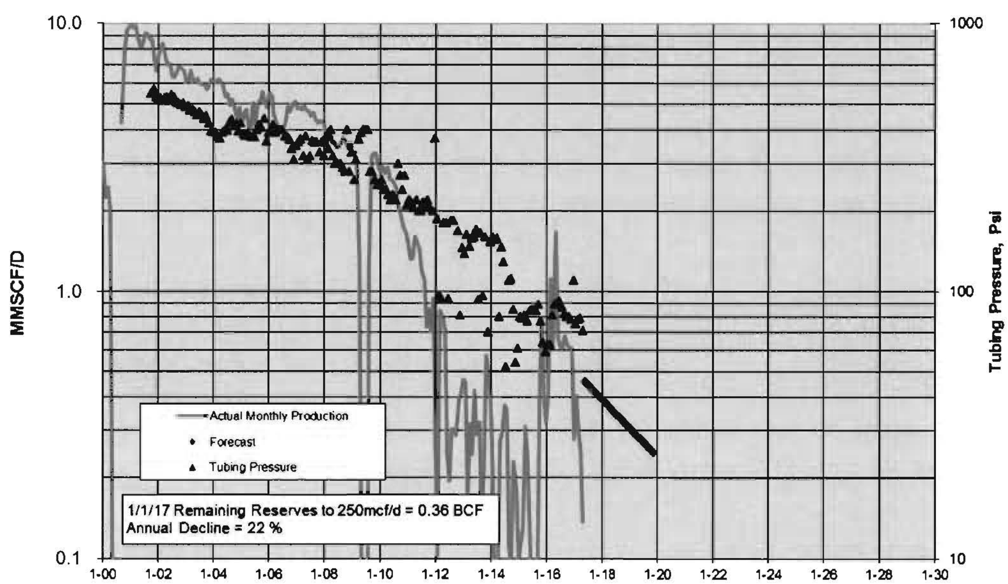


Appendix B-6: Trading Bay Unit Well Decline Curves

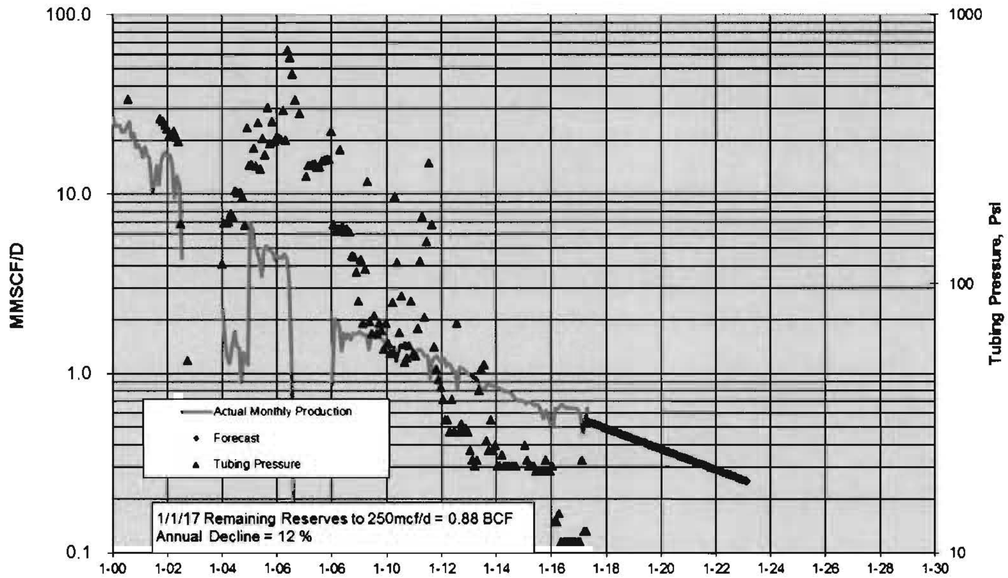
TBU Gas Well D-18



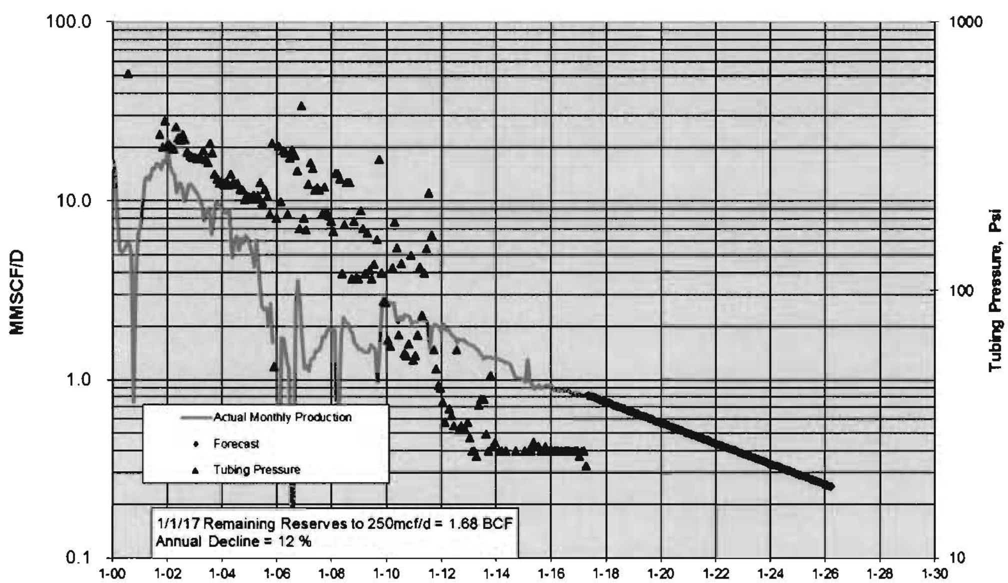
TBU Gas Well G-18DPN



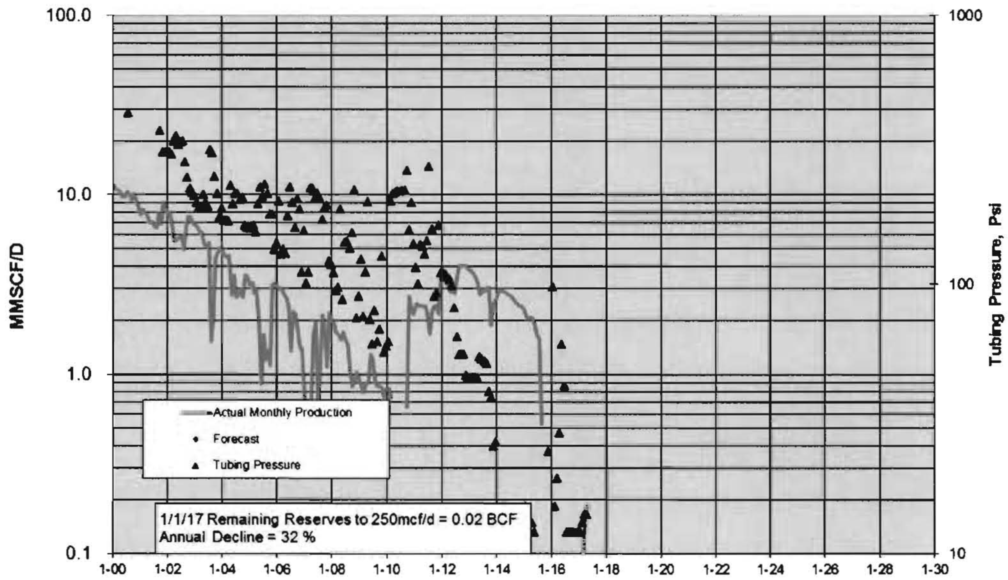
TBU Gas Well M-01



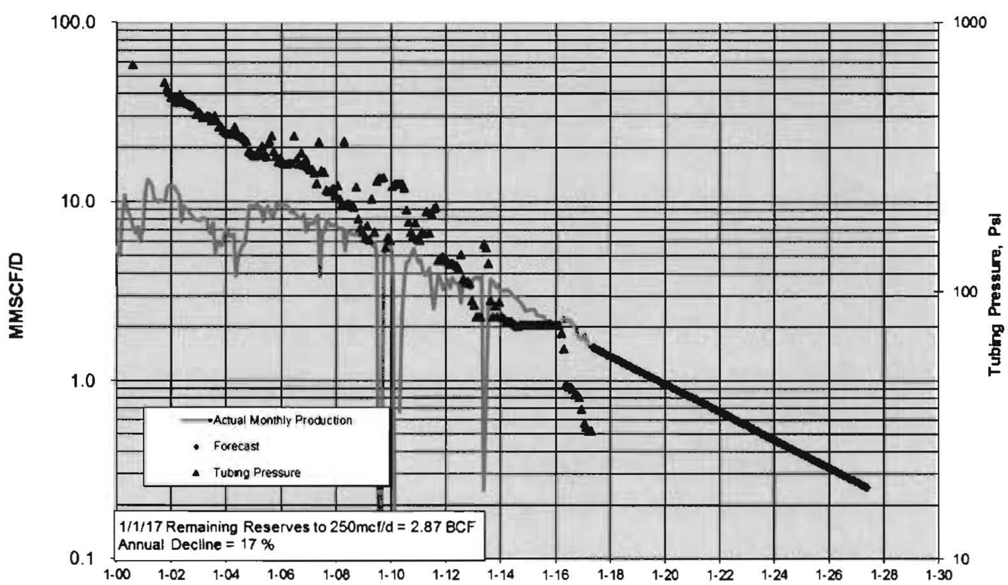
TBU Gas Well M-02



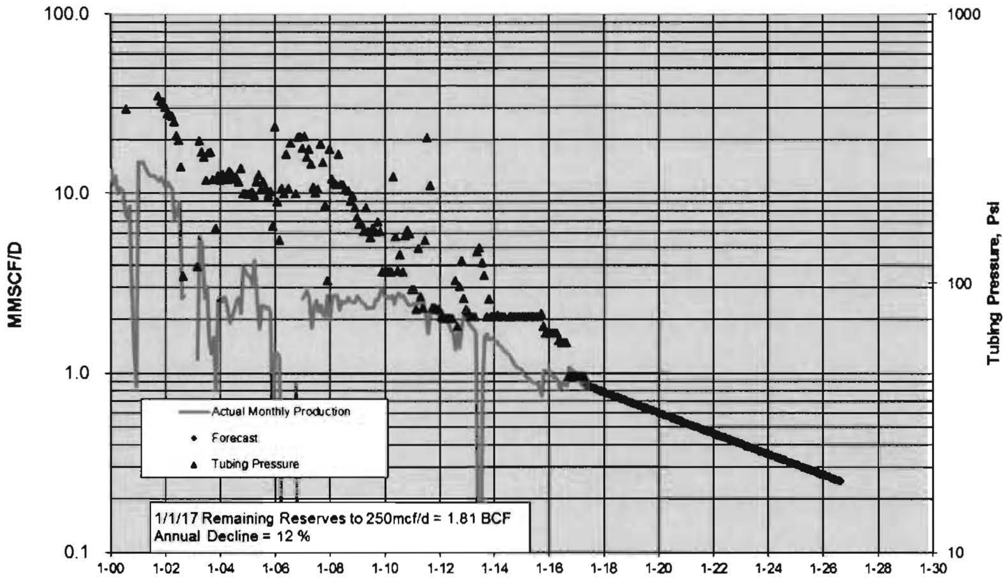
TBU Gas Well M-03



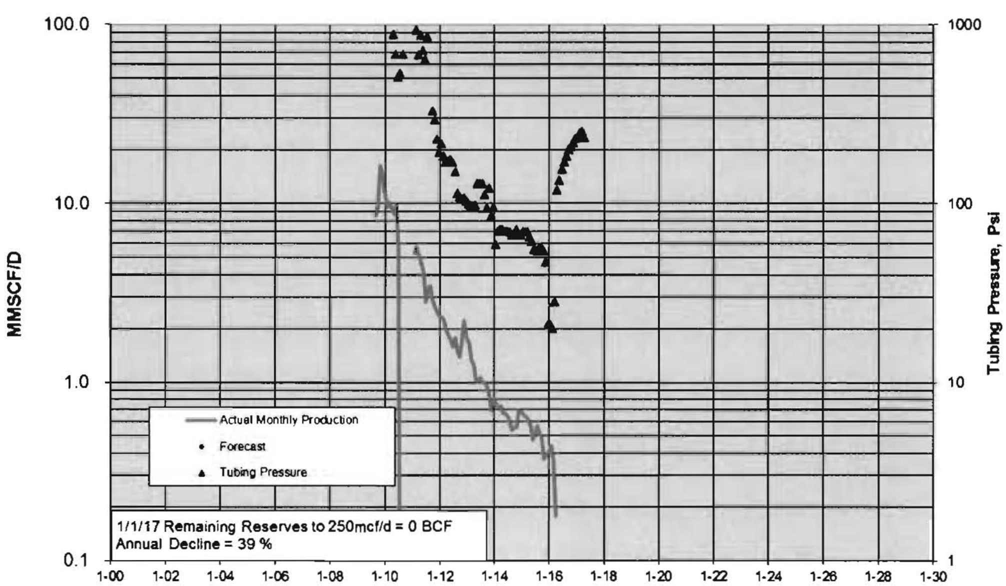
TBU Gas Well M-04



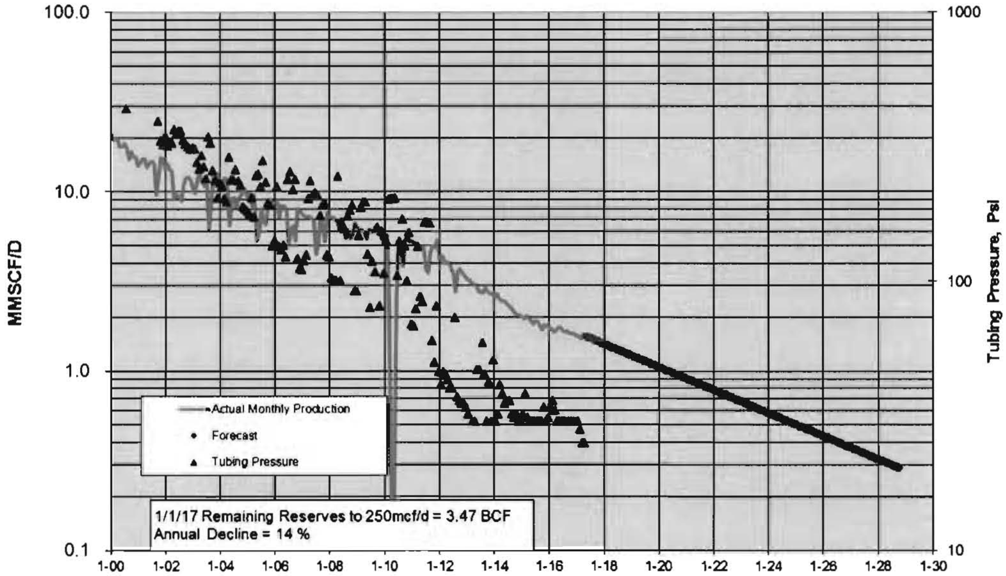
TBU Gas Well M-05



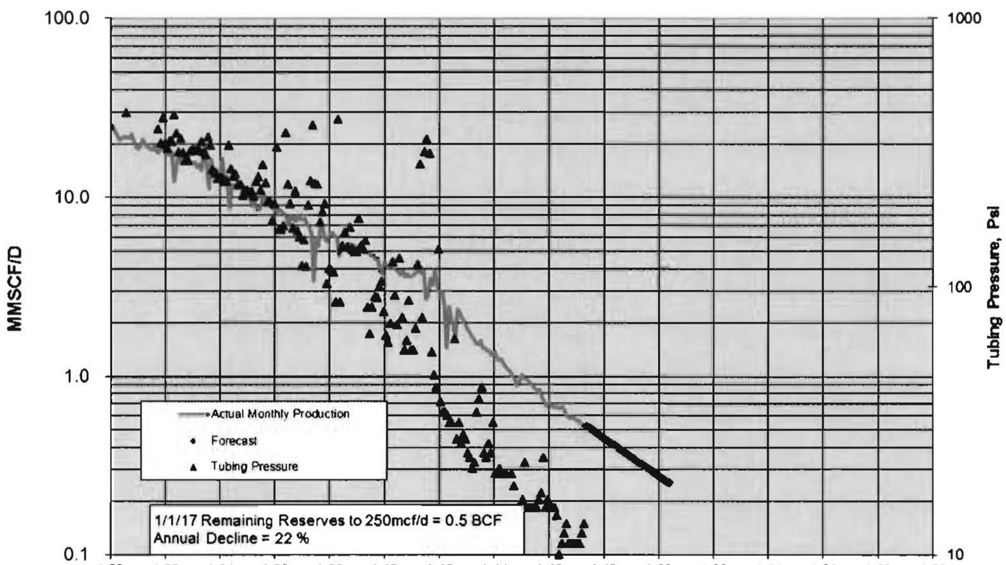
TBU Gas Well M-06



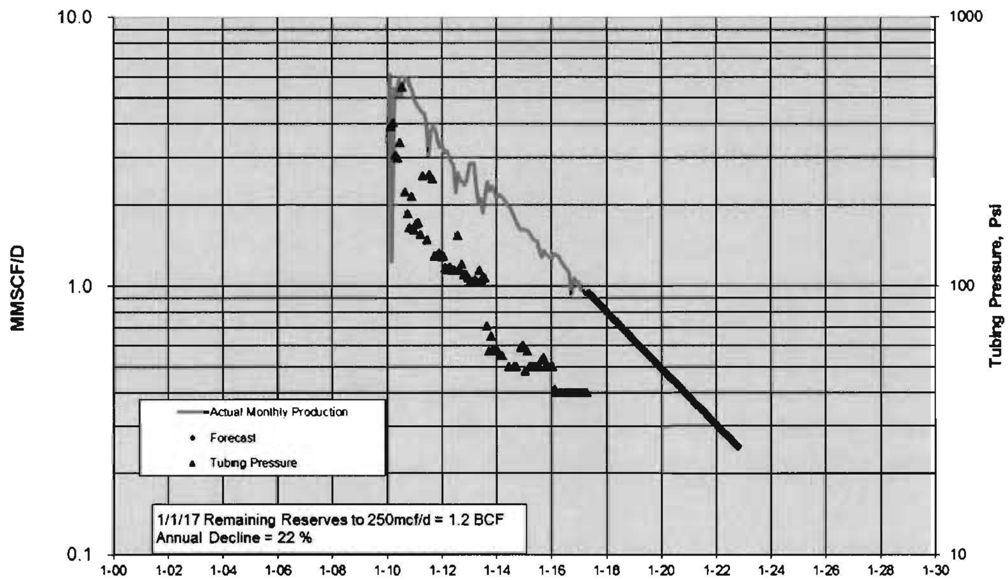
TBU Gas Well M-07



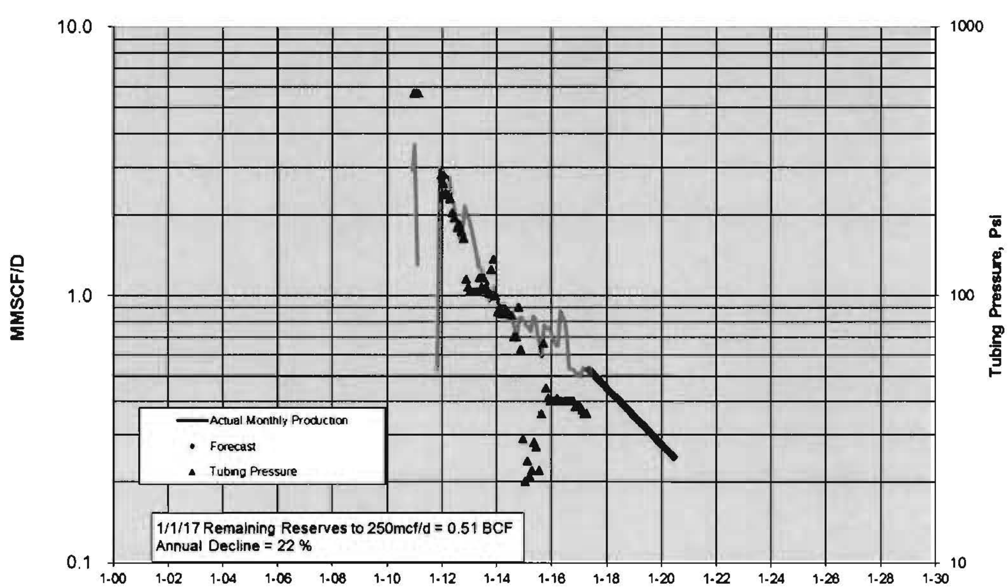
TBU Gas Well M-09



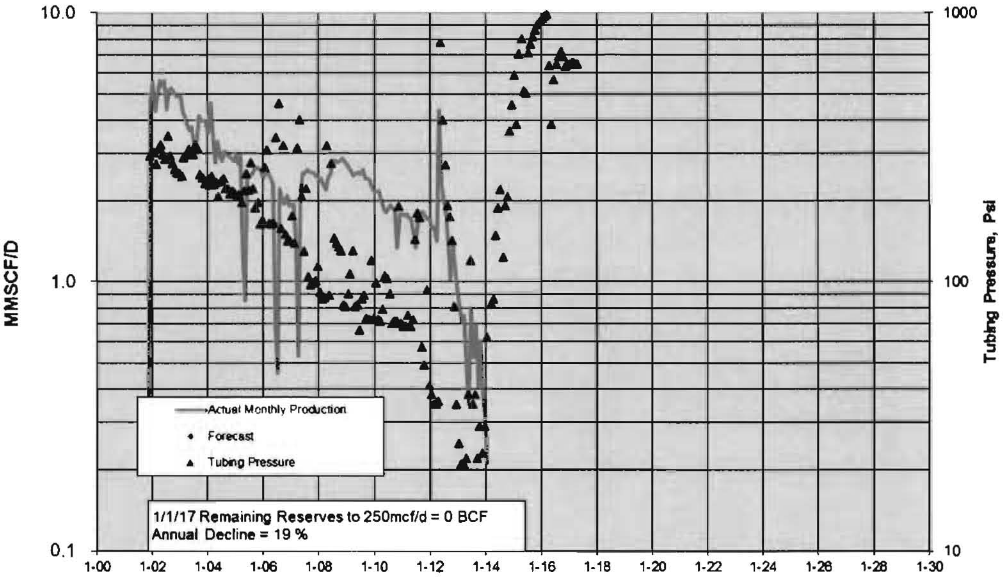
TBU Gas Well M-10



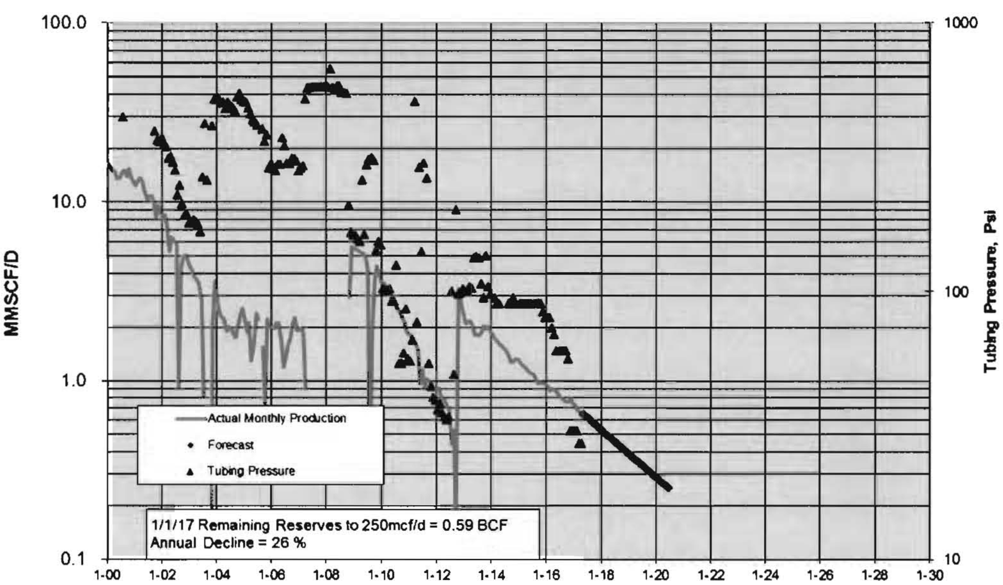
TBU Gas Well M-11



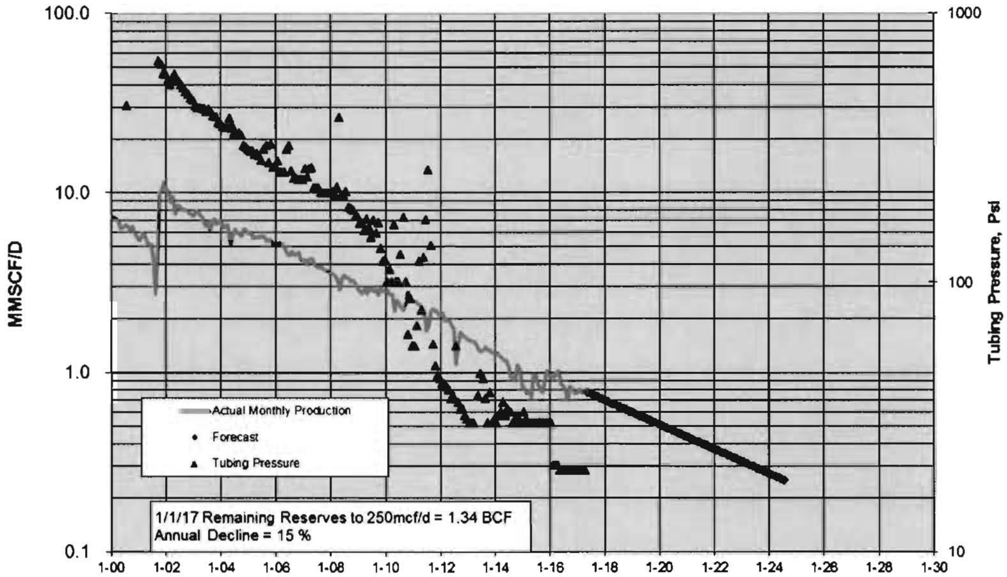
TBU Gas Well M-12



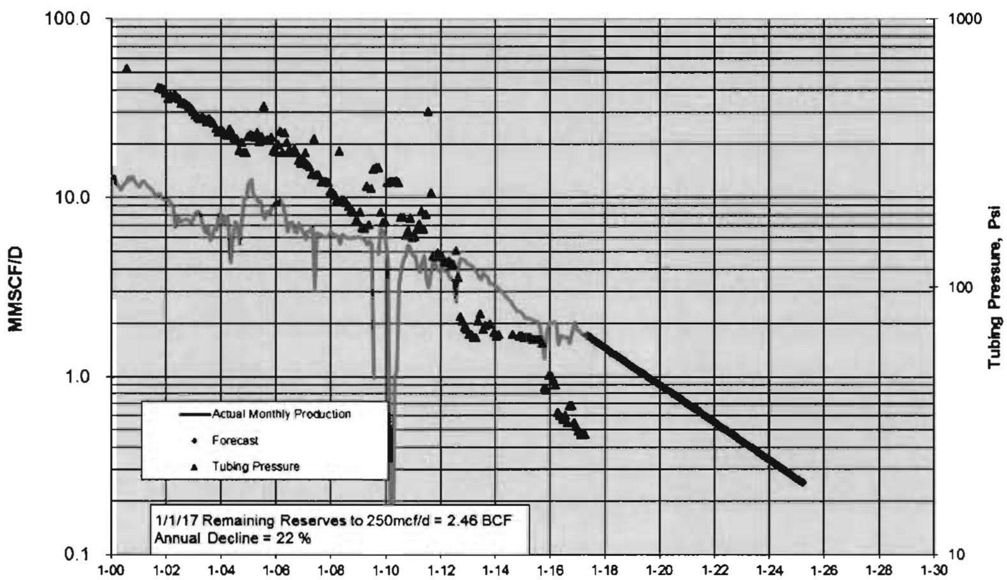
TBU Gas Well M-13



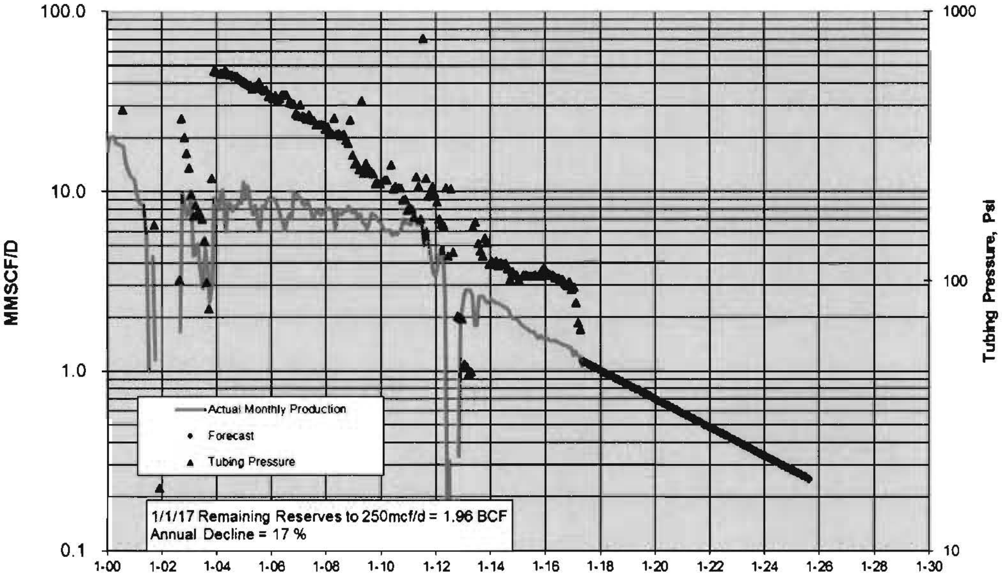
TBU Gas Well M-14



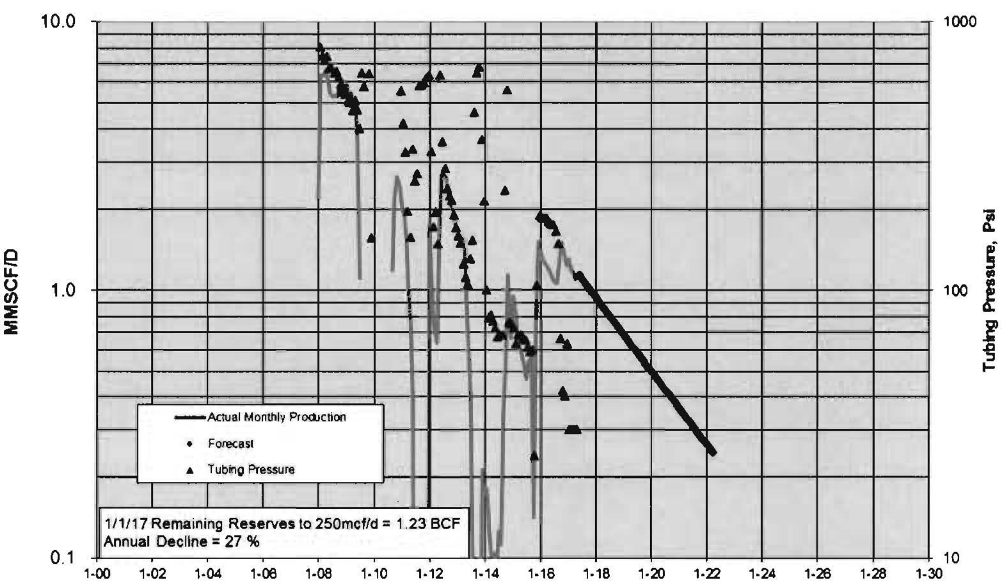
TBU Gas Well M-15



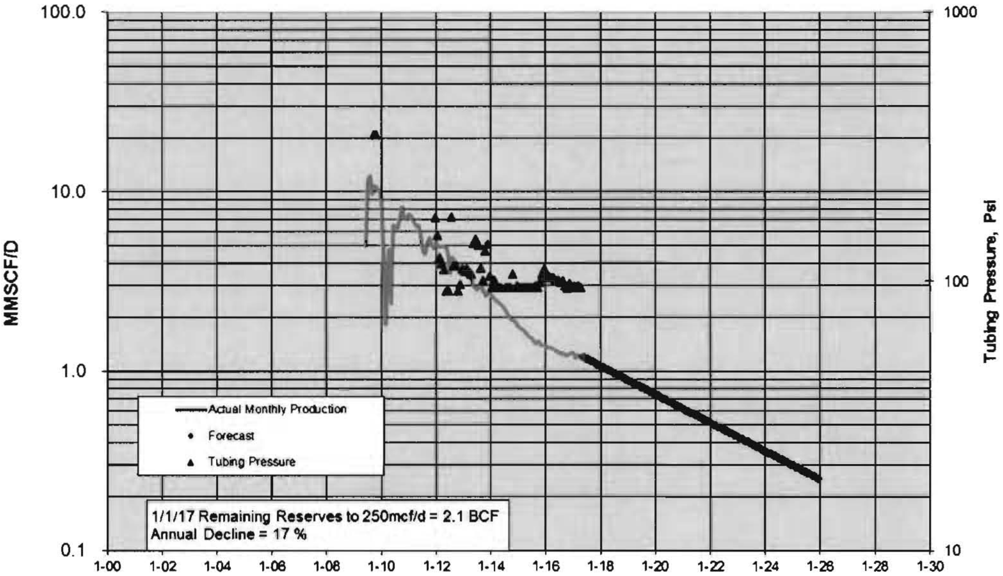
TBU Gas Well M-16



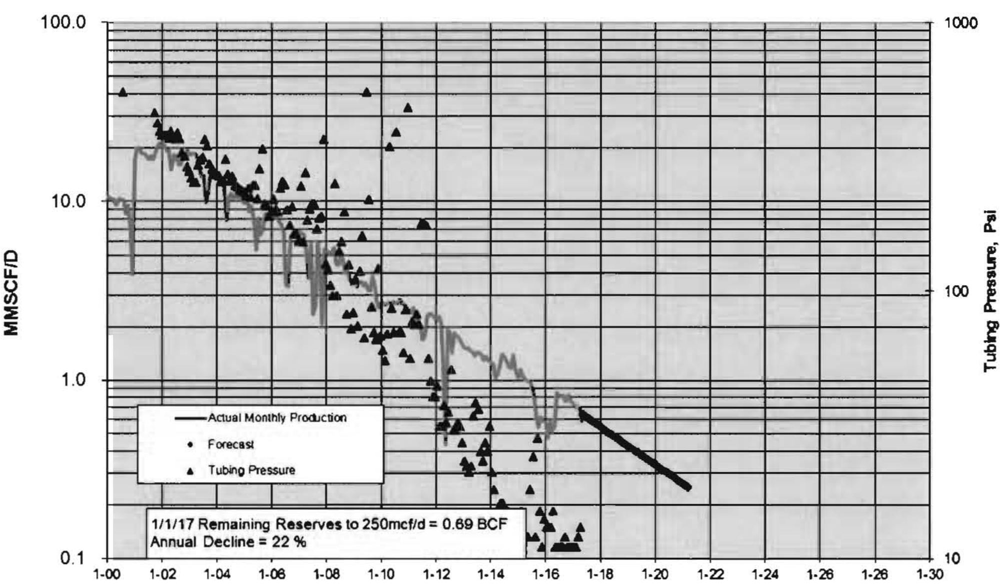
TBU Gas Well M-17



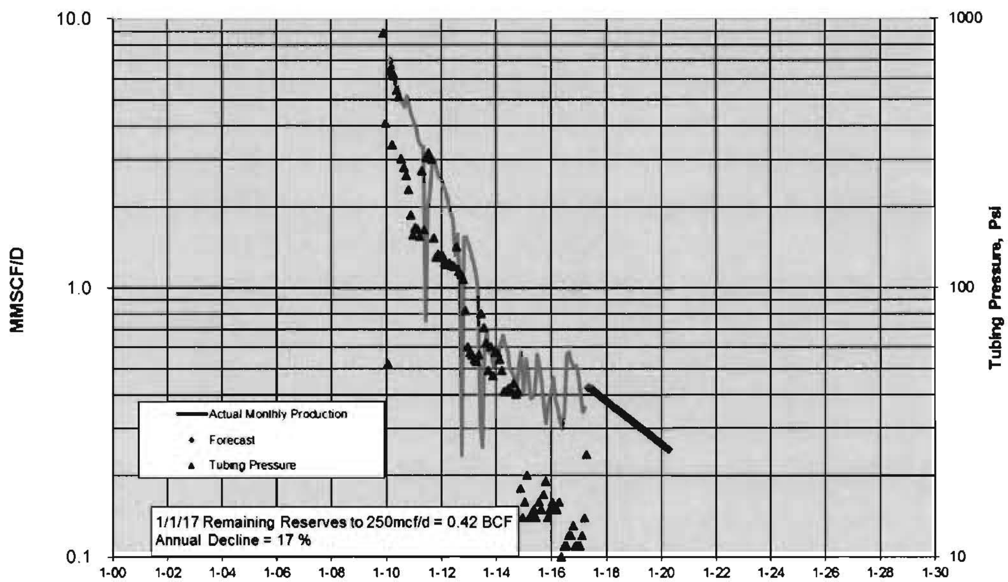
TBU Gas Well M-18



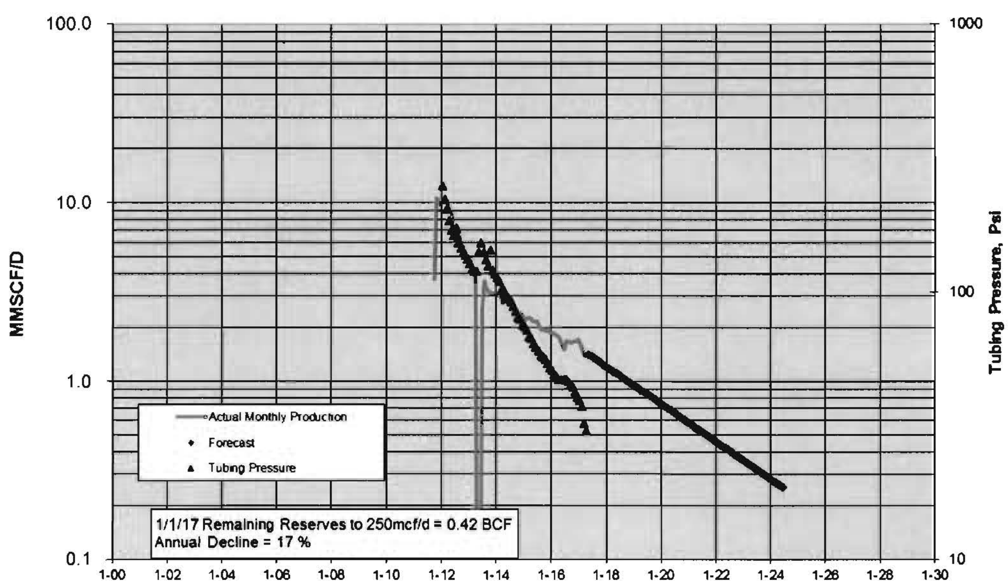
TBU Gas Well M-19RD



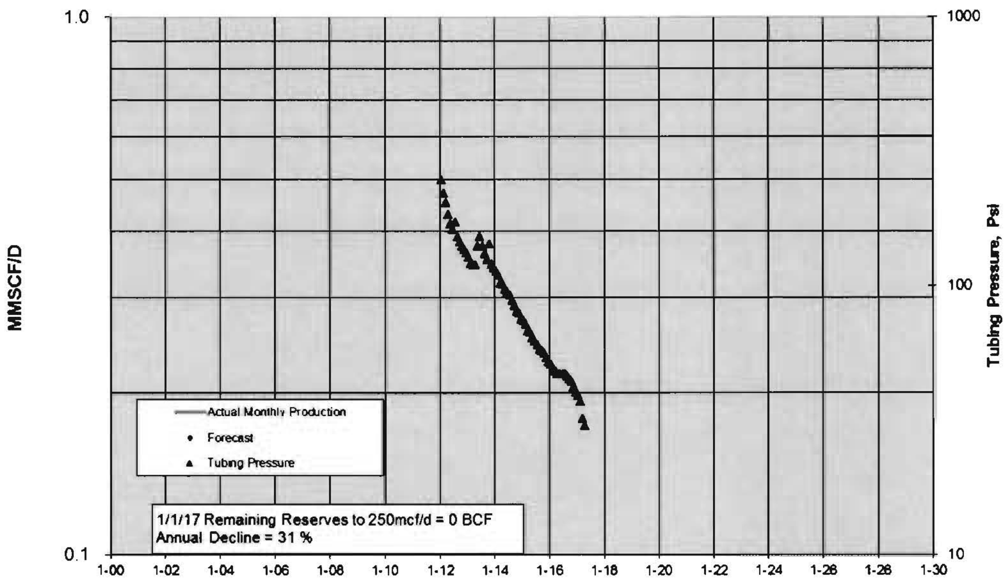
TBU Gas Well M-20



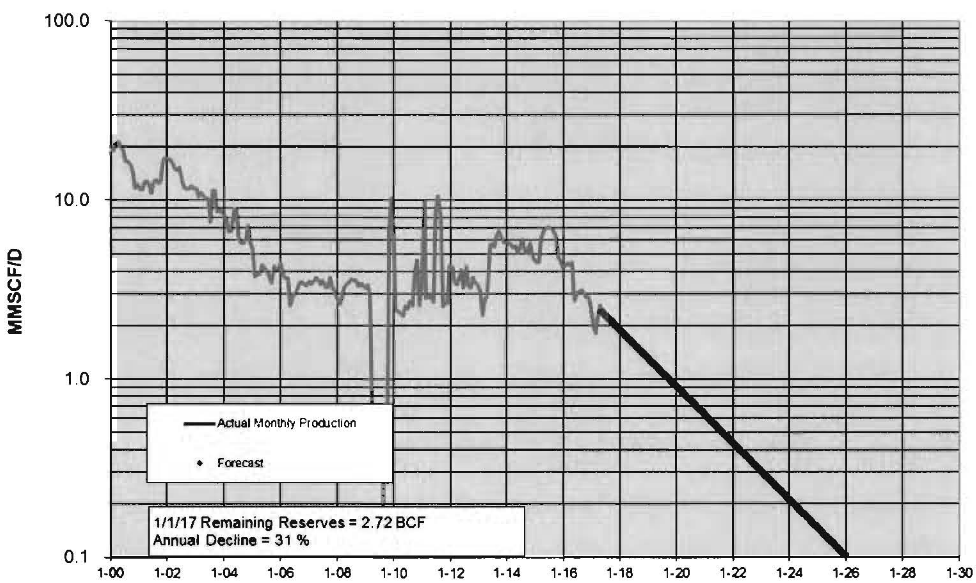
TBU Gas Well M-21



TBU Gas Well M-32RD



TBU Oil Wells



Appendix C: CI Gas Wells Completed in November 2009 to May 2017

November 2009 through October 2010

Well Name	Operator	Well Class	Month of First Production	Initial Rate, 6 Month Avg. MMSCF	Status
Nicolai Creek 11	Aurora	Expl – Gas	Nov-09	1.3	Producing
TBU M-20	Chevron	Dev – Gas	Mar-10	6.1	Producing
TBU M-10	Chevron	Dev – Gas	Feb-10	5.3	Producing
NU Paxton 3	Marathon	Dev – Gas	Apr-10	3.1	Producing
BRU 212-24T	ConocoPhillips	Dev – Gas	Aug-10	2.7	Producing

There were five wells completed as Cook Inlet gas wells between November 2009 and October 2010 that averaged 3.7 MMSCF/D for their first six months of production. This is in line or slightly higher than the 3.1 MMSCF/D twelve month average for wells completed in the 2007-2009 period.

November 2010 through October 2011

Well Name	**Operator**	**Well Class**	**Month of First Production**	**Initial Rate, 6 Month Avg. MMSCF**	**Status**
NU Paxton 4	Marathon	Dev – Gas	Oct-10	2.4	Producing
No. Fork 32-35	Armstrong	Expl – Gas	Apr-11	2.0	Producing
No. Fork 14-25	Armstrong	Expl – Gas	Apr-11	0.2	Producing
No. Fork 34-26	Armstrong	Expl – Gas	Apr-11	1.3	Producing
No. Fork 41-35	Armstrong	Expl – Gas	Apr-11	2.1	Producing
Nicolai Creek 10	Aurora	Dev – Gas	Oct-11	2.4	Producing
TBU M-11	Chevron	Dev – Gas	Jan-11	1.8	Producing

There were seven wells completed as Cook Inlet gas wells between November 2010 and October 2011 that averaged 1.75 MMSCF/D for their first six months of production. This is about 57% of the 3.1 MMSCF/D twelve month average for wells completed in the 2007-2009 period.

November 2011 through June 2012

Well Name	Operator	Well Class	Month of First Production	Initial Rate, 6 Month Avg. MMSCF	Status
Kenai Loop 1	Buccaneer	Exp - Gas	Jan-12	4.2	Producing
TBU M-21	Hilcorp	Dev - Gas	Nov-11	10.0	Producing
NU S Dionne 7	Marathon	Dev - Gas	Feb-12	0	Shut In
BRU 224-23T	ConocoPhillips	Dev - Gas	Oct-11	7.2	Producing

There were four wells completed as Cook Inlet gas wells between November 2011 and June 2012 that averaged 5.4 MMSCF/D for their first six months of production. This is about 173% of the 3.1 MMSCF/D twelve month average for wells completed in the 2007-2009 period.

July 2012 through May 2017

Well Name	Operator	Well Class	Month of First Production	Initial Rate, 6 Month Avg. MMSCF	Status
Beaver Cr. Unit 14A	Hilcorp	Dev - Gas	May-14	0.8	Idle
Beaver Cr. Unit 1B	Hilcorp	Dev - Gas	Apr-14	0.9	Producing
Kenai Bel. Unit 32-08	Hilcorp	Dev - Gas	Aug-14	1.2	Producing
Kenai Bel. Unit 43-07Y	Hilcorp	Dev - Gas	May-14	10.7	Producing
Kenai Bel. Unit 11-08Z	Hilcorp	Dev - Gas	Jul-14	10.2	Producing
Kenai Bel. Unit 23-05	Hilcorp	Dev - Gas	Jul-14	8.52	Producing
Kenai Deep Unit 1	Hilcorp	Dev - Gas	Aug-14	0.8	Producing
Beaver Cr. Unit 12A	Hilcorp	Dev - Gas	Sep-14	6.4	Idle
Kenai Bel. Unit 42-06Y	Hilcorp	Dev - Gas	Sep-14	9.9	Producing
NU Paxton #8	Hilcorp	Dev - Gas	Dec-14	1.7	Producing
Beaver Creek 24	Hilcorp	Dev - Gas	Dec-14	9.9	Producing
NU Paxton #7	Hilcorp	Dev - Gas	Nov-14	2.7	Idle
Beaver Creek 25	Hilcorp	Dev - Gas	Dec-14	1.1	Idle
NU FC 6	Hilcorp	Dev - Gas	Dec-14	0.3	Producing
North Fork 42-35	Glacier Energy	Dev - Gas	Mar-15	0.3	Producing
NU Paxton #9	Hilcorp	Dev - Gas	Feb-15	1.3	Producing
Kenai Bel. Unit 31-18	Hilcorp	Dev - Gas	May-15	0.8	Producing
Kenai Bel. Unit 22-06Y	Hilcorp	Dev - Gas	May-15	3.6	Producing

NU GO #8	Hilcorp	Dev - Gas	Sep-15	2.1	Producing
Swanson RU. 213-15	Hilcorp	Dev - Gas	Oct-15	1.7	Producing
Kenai Bel. Unit 31-06X	Hilcorp	Dev - Gas	Nov-16	2.7	Producing
Swanson RU 213B-15	Hilcorp	Dev - Gas	Oct-15	2.2	Producing
CLU 5RD	Hilcorp	Dev - Gas	Dec-15	8.3	Intermittent
Happy Valley B-17	Hilcorp	Dev - Gas	May-16	1.2	Producing
KLU 3	Furie Op.	Dev - Gas	Jun-15	8.8	Producing
KLU A-2A	Furie Op.	Dev - Gas	Sep-16	10.7	Producing
NU Kalotsa 1	Hilcorp	Dev - Gas	Mar-17	11.1	Producing
Kenai Bel. Unit 32-06	Hilcorp	Dev - Gas	Apr-17	0.4	Producing
Kenai Unit 14-05	Hilcorp	Dev - Gas	May-17	0.8	Producing

A summary of wells completed by year for 2014-2017 is shown below

Year Completed	Number of Wells	Average 6 Mo Rate, MMSCF/D	Total Rate Developed, MMSCF/D
2014	14	4.6	65.0
2015	8	2.5	20.3
2016	4	5.9	23.5
2017 – 5 Mo.	4	4.1	12.3

As observed, there was no development in 2013, followed by a large activity level in 2014 and 2015. This timing corresponds to the Cook Inlet tax relief provisions enacted by the State as well as the period following the Hilcorp acquisition of Chevron and Marathon's Cook Inlet assets.

Appendix D: Individual Cook Inlet Wells Ranked by Peak Production

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
CANNERY LOOP UNIT S-1	22.882	10.954	11.928	60.54471	-151.2117	Cannery Loop Unit Storage
KLU A-2A	20.195	8.948	11.246	60.9367	-151.1564	Kitchen Lights Unit
CANNERY LOOP UNIT S-3	13.145	5.429	7.717	60.54444	-151.2117	Cannery Loop Unit Storage
KLU 3	11.862	6.127	5.735	60.93672	-151.1563	Kitchen Lights Unit
KALOTSA #1	11.761	2.804	8.957	60.10389	-151.5901	Ninilchik Unit
CANNERY LOOP UNIT S-2	10.113	5.297	4.817	60.54457	-151.2117	Cannery Loop Unit Storage
SOLDOTNA CK UNIT 22B-04	9.971	1.689	8.282	60.73136	-150.8686	Other Cook Inlet
CANNERY LOOP UNIT 05RD	9.511	1.576	7.935	60.53218	-151.262	Cannery Loop Unit
Beluga River Unit #224-34	9.254	7.563	1.691	61.16629	-151.0455	Beluga River Unit
KENAI LOOP 1	8.328	6.073	2.255	60.56985	-151.2255	Kenai Loop Field
KENAI BELUGA UNIT 42-06Y	8.311	5.649	2.661	60.45898	-151.2468	Kenai Field Units
BEAVER CK 24	8.219	6.723	1.496	60.6586	-151.0175	Beaver Creek
SOLDOTNA CK UNIT 21C-04	8.034	7.235	0.799	60.72478	-150.8839	Other Cook Inlet
KENAI UNIT 14X-06	8.027	2.570	5.457	60.46036	-151.2623	Kenai Field Units
KENAI UNIT 14X-06	8.027	2.570	5.457	60.46036	-151.2623	Kenai Field Units Storage
KENAI BELUGA UNIT 22-06Y	6.990	5.382	1.608	60.46036	-151.262	Kenai Field Units
Beluga River Unit #241-34	6.775	6.446	0.330	61.17883	-151.0395	Beluga River Unit
NCOOK INLET UNIT A-02	6.615	5.906	0.709	61.07676	-150.9481	North Cook Inlet Unit
SOLDOTNA CK UNIT 42-05Y	6.385	2.450	3.934	60.72492	-150.8832	Soldotna Creek Unit Storage
SOLDOTNA CK UNIT 42-05X	6.317	2.375	3.942	60.72468	-150.8836	Soldotna Creek Unit Storage
CANNERY LOOP UNIT S-4	6.313	3.192	3.121	60.5443	-151.2117	Cannery Loop Unit Storage
PRETTY CK UNIT 4	6.297	2.165	4.132	61.26356	-150.8944	Pretty Creek Unit Storage
NCOOK INLET UNIT A-05	6.270	4.358	1.912	61.07676	-150.9481	North Cook Inlet Unit
NICOLAI CK UNIT 10	6.179	0.734	5.445	61.03194	-151.4496	Other Cook Inlet
SWANSON RIVER KGSF 7A	5.635	1.809	3.825	60.75381	-150.8537	Swanson River Unit Storage
Beluga River Unit #214-26	5.517	5.151	0.366	61.18383	-151.0299	Beluga River Unit
KENAI BELUGA UNIT 23-05	4.908	3.637	1.271	60.45948	-151.2457	Kenai Field Units
CANNERY LOOP UNIT S-5	4.802	1.136	3.666	60.54416	-151.2117	Cannery Loop Unit Storage
SWANSON RIVER KGSF 1	4.545	1.902	2.642	60.75416	-150.8544	Swanson River Unit Storage
Beluga River Unit #224-23 & 224-23T	4.499	4.262	0.237	61.19767	-151.0176	Beluga River Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
KENAI BELUGA UNIT 11-08Z	4.364	3.338	1.025	60.45765	-151.2457	Kenai Field Units
Beluga River Unit #212-35T	4.186	3.814	0.371	61.17723	-151.0277	Beluga River Unit
KENAI BELUGA UNIT 43-07Y	4.179	3.174	1.005	60.44326	-151.2435	Kenai Field Units
NINILCHIK UNIT S DIONNE #3	4.033	3.361	0.672	60.11285	-151.5734	Ninilchik Unit
Beluga River Unit #243-34	3.992	3.742	0.250	61.16998	-151.037	Beluga River Unit
KENAI TYONEK UNIT 32-07	3.872	1.424	2.448	60.45911	-151.245	Kenai Field Units
KENAI BELUGA UNIT 23X-06	3.805	1.268	2.537	60.46001	-151.262	Kenai Field Units
KENAI BELUGA UNIT 23X-06	3.805	1.268	2.537	60.46001	-151.262	Kenai Field Units Storage
KENAI UNIT 22-6X	3.729	1.356	2.373	60.47617	-151.2704	Kenai Field Units
KENAI UNIT 22-6X	3.729	1.356	2.373	60.47617	-151.2704	Kenai Field Units Storage
NORTH FORK 34-26	3.497	2.209	1.288	59.79631	-151.6306	North Fork Unit
BEAVER CK 23	3.428	2.244	1.184	60.6586	-151.0171	Beaver Creek
KENAI UNIT 31-07X	3.309	1.224	2.085	60.46009	-151.2613	Kenai Field Units
KENAI UNIT 31-07X	3.309	1.224	2.085	60.46009	-151.2613	Kenai Field Units Storage
Beluga River Unit #212-24T	3.297	3.163	0.134	61.20455	-151.0009	Beluga River Unit
Beluga River Unit #233-27	3.102	2.835	0.268	61.18625	-151.0431	Beluga River Unit
KENAI UNIT 34-32	3.071	1.125	1.946	60.47931	-151.2365	Kenai Field Units
KENAI UNIT 34-32	3.071	1.125	1.946	60.47931	-151.2365	Kenai Field Units Storage
TBU Oil Wells	3.022	2.534	0.488	misc	misc	Trading Bay Unit
NINILCHIK UNIT PAXTON #5	3.009	2.865	0.144	60.09569	-151.609	Ninilchik Unit
BEAVER CK UNIT 16RD	2.913	1.831	1.082	60.65821	-151.0178	Beaver Creek
KENAI BELUGA UNIT 31-06X	2.884	1.601	1.282	60.45765	-151.2454	Kenai Field Units
KENAI UNIT 13-06	2.836	1.079	1.757	60.46038	-151.2615	Kenai Field Units
KENAI UNIT 13-06	2.836	1.079	1.757	60.46038	-151.2615	Kenai Field Units Storage
NINILCHIK UNIT FALLS CK #6	2.758	1.956	0.802	60.20443	-151.4288	Ninilchik Unit
NINILCHIK UNIT G OSKOLKOFF #8	2.684	2.173	0.511	60.16512	-151.4864	Ninilchik Unit
KENAI LOOP 1-3	2.673	2.478	0.195	60.56986	-151.2243	Kenai Loop Field
Beluga River Unit #211-26	2.670	2.423	0.247	61.19744	-151.0171	Beluga River Unit
SWANSON RIV UNIT 241-16	2.555	1.419	1.136	60.7856	-150.8459	Swanson River Unit
Beluga River Unit #244-23	2.441	2.247	0.195	61.19705	-151.0168	Beluga River Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
KENAI BELUGA UNIT 11-8X	2.280	1.998	0.282	60.45933	-151.2454	Kenai Field Units
TBU Gas Well M-04	2.204	1.872	0.333	60.83184	-151.6016	Trading Bay Unit
KENAI DEEP UNIT 5	2.186	0.761	1.425	60.47581	-151.2698	Kenai Field Units
KENAI DEEP UNIT 5	2.186	0.761	1.425	60.47581	-151.2698	Kenai Field Units Storage
Beluga River Unit #242-04	2.178	0.751	1.427	61.1663	-151.0461	Beluga River Unit
Beluga River Unit #212-35	2.163	2.070	0.093	61.17704	-151.0281	Beluga River Unit
SWANSON RIV UNIT 213-15	2.124	1.351	0.773	60.78576	-150.8456	Swanson River Unit
KENAI DEEP UNIT 9	2.117	1.517	0.600	60.45878	-151.2471	Kenai Field Units
KENAI BELUGA UNIT 14-8	2.078	1.859	0.219	60.44355	-151.2438	Kenai Field Units
BEAVER CK UNIT 13	2.064	1.511	0.553	60.65812	-151.0184	Beaver Creek
NINILCHIK UNIT PAXTON #3	2.055	1.796	0.259	60.09593	-151.6086	Ninilchik Unit
CANNERY LOOP UNIT 01RD	2.033	1.247	0.787	60.5322	-151.2626	Cannery Loop Unit
TBU Gas Well M-15	2.019	1.744	0.275	60.83178	-151.6024	Trading Bay Unit
KENAI BELUGA UNIT 34-6	2.014	1.599	0.416	60.45957	-151.2466	Kenai Field Units
CANNERY LOOP UNIT 09	1.974	1.599	0.375	60.53225	-151.2635	Cannery Loop Unit
HAPPY VALLEY B-15	1.966	1.632	0.334	59.99045	-151.509	Deep Creek Unit
NORTH FORK UNIT 22-35	1.930	1.298	0.632	59.79614	-151.6298	North Fork Unit
NINILCHIK UNIT S DIONNE #6	1.910	1.486	0.424	60.11319	-151.5716	Ninilchik Unit
NCOOK INLET UNIT A-15	1.870	1.664	0.206	61.07661	-150.9485	North Cook Inlet Unit
NINILCHIK UNIT PAXTON #4	1.866	1.776	0.090	60.09602	-151.6087	Ninilchik Unit
NINILCHIK UNIT S DIONNE #5	1.836	1.234	0.601	60.11273	-151.5723	Ninilchik Unit
CANNERY LOOP UNIT 08	1.826	1.602	0.224	60.53226	-151.2632	Cannery Loop Unit
KENAI TYONEK UNIT 32-07H	1.824	1.547	0.278	60.45899	-151.2447	Kenai Field Units
NCOOK INLET UNIT B-01A	1.781	1.570	0.211	61.07678	-150.9488	North Cook Inlet Unit
NCOOK INLET UNIT B-03	1.776	1.252	0.524	61.07677	-150.9488	North Cook Inlet Unit
NINILCHIK UNIT PAXTON #2	1.749	1.660	0.089	60.09584	-151.6086	Ninilchik Unit
TBU Gas Well M-07	1.745	1.620	0.125	60.83185	-151.6016	Trading Bay Unit
TBU Gas Well M-21	1.744	1.619	0.125	60.83182	-151.6016	Trading Bay Unit
HAPPY VALLEY B-17	1.735	1.341	0.394	59.9887	-151.5094	Deep Creek Unit
SWANSON RIV UNIT 213B-15	1.704	0.745	0.960	60.78547	-150.8459	Swanson River Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
NINILCHIK UNIT S DIONNE #4	1.700	1.160	0.540	60.11261	-151.5727	Ninilchik Unit
NORTH FORK UNIT 32-35	1.691	1.408	0.283	59.79631	-151.6303	North Fork Unit
NCOOK INLET UNIT A-04	1.620	1.415	0.204	61.07675	-150.9481	North Cook Inlet Unit
KENAI TYONEK UNIT 24-06H	1.610	1.429	0.181	60.45911	-151.2456	Kenai Field Units
KENAI UNIT 21-06RD	1.563	0.601	0.962	60.47532	-151.2718	Kenai Field Units
KENAI UNIT 21-06RD	1.563	0.601	0.962	60.47532	-151.2718	Kenai Field Units Storage
KENAI BELUGA UNIT 24-06RD	1.561	1.306	0.255	60.46007	-151.2617	Kenai Field Units
HAPPY VALLEY B-12	1.554	1.431	0.124	59.98881	-151.5088	Deep Creek Unit
RED 1	1.548	0.487	1.061	59.85135	-151.5621	Other Cook Inlet
KENAI DEEP UNIT 1	1.521	0.828	0.693	60.46033	-151.2635	Kenai Field Units
TBU Gas Well M-17	1.511	1.219	0.292	60.83179	-151.6024	Trading Bay Unit
NINILCHIK UNIT G OSKOLKOFF #6	1.479	0.864	0.615	60.16402	-151.4878	Ninilchik Unit
HAPPY VALLEY A-10	1.473	1.299	0.174	59.98538	-151.4854	Deep Creek Unit
SWANSON RIV UNIT 242-16	1.464	0.976	0.488	60.78547	-150.846	Swanson River Unit
TBU Gas Well M-16	1.463	1.319	0.144	60.83182	-151.6024	Trading Bay Unit
TBU Gas Well M-18	1.319	1.253	0.066	60.83182	-151.6016	Trading Bay Unit
NORTH FORK UNIT 41-35	1.297	0.163	1.134	59.79274	-151.6248	North Fork Unit
KENAI BELUGA UNIT 42-6X	1.288	1.116	0.172	60.45774	-151.2469	Kenai Field Units
TBU Gas Well M-10	1.254	1.072	0.182	60.83179	-151.6024	Trading Bay Unit
NINILCHIK UNIT PAXTON #7	1.226	0.949	0.277	60.09554	-151.6091	Ninilchik Unit
KENAI UNIT 14-32	1.212	0.309	0.903	60.47594	-151.27	Kenai Field Units
KENAI UNIT 14-32	1.212	0.309	0.903	60.47594	-151.27	Kenai Field Units Storage
KENAI BELUGA UNIT 43-07X	1.160	1.034	0.126	60.45932	-151.246	Kenai Field Units
NORTH FORK UNIT 24-26	1.158	0.786	0.372	59.79631	-151.6296	North Fork Unit
KENAI UNIT 41-18X	1.096	0.930	0.167	60.44355	-151.2441	Kenai Field Units
NINILCHIK UNIT S DIONNE #1A	1.094	1.040	0.054	60.11272	-151.5735	Ninilchik Unit
TBU Gas Well M-05	1.082	0.926	0.156	60.83183	-151.6016	Trading Bay Unit
NINILCHIK UNIT PAXTON #8	1.061	0.938	0.123	60.09557	-151.609	Ninilchik Unit
KENAI BELUGA UNIT 12-5	1.057	0.918	0.139	60.45928	-151.2471	Kenai Field Units
KENAI BELUGA UNIT 31-18	0.989	0.803	0.186	60.44283	-151.2434	Kenai Field Units

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
NINILCHIK UNIT PAXTON #1	0.984	0.873	0.111	60.09574	-151.6085	Ninilchik Unit
KENAI BELUGA UNIT 24-7X	0.980	0.872	0.108	60.44356	-151.2445	Kenai Field Units
NINILCHIK UNIT FALLS CK #4	0.965	0.841	0.124	60.20426	-151.4294	Ninilchik Unit
SWANSON RIV UNIT 32C-15	0.951	0.146	0.805	60.79018	-150.84	Swanson River Unit
KENAI BELUGA UNIT 32-08	0.950	0.779	0.170	60.44334	-151.2435	Kenai Field Units
KENAI BELUGA UNIT 14-6Y	0.942	0.738	0.204	60.46053	-151.2625	Kenai Field Units
NCOOK INLET UNIT A-14	0.914	0.650	0.264	61.07663	-150.9485	North Cook Inlet Unit
KENAI UNIT 14-05	0.899	0.075	0.824	60.45761	-151.246	Kenai Field Units
TBU Gas Well M-02	0.885	0.844	0.042	60.83181	-151.6016	Trading Bay Unit
TBU Gas Well M-11	0.875	0.618	0.256	60.8318	-151.6024	Trading Bay Unit
TBU Gas Well M-13	0.864	0.750	0.114	60.8318	-151.6025	Trading Bay Unit
NINILCHIK UNIT FALLS CK #3	0.859	0.810	0.050	60.20431	-151.4294	Ninilchik Unit
TBU Gas Well M-14	0.857	0.793	0.064	60.8318	-151.6024	Trading Bay Unit
KENAI BELUGA UNIT 11-17X	0.855	0.714	0.142	60.44357	-151.2435	Kenai Field Units
TBU Gas Well M-19RD	0.848	0.757	0.091	60.8318	-151.6024	Trading Bay Unit
BEAVER CK UNIT 1B	0.845	0.680	0.165	60.64759	-151.034	Beaver Creek
BEAVER CK UNIT 07A	0.825	0.340	0.485	60.64236	-151.0379	Beaver Creek
FRANCES #1	0.821	0.677	0.144	60.19855	-151.4282	Ninilchik Unit
KENAI BELUGA UNIT 31-07RD	0.790	0.700	0.089	60.46032	-151.2614	Kenai Field Units
CANNERY LOOP UNIT 13	0.768	0.643	0.125	60.53241	-151.2617	Cannery Loop Unit
LONE CREEK 3	0.767	0.294	0.473	61.13364	-151.2888	Other Cook Inlet
HANSEN 1A	0.717	0.615	0.103	59.85819	-151.8015	Other Cook Inlet
Beluga River Unit #244-04	0.700	0.231	0.470	61.15719	-151.0562	Beluga River Unit
TBU Gas Well M-09	0.680	0.589	0.091	60.83184	-151.6016	Trading Bay Unit
TBU Gas Well G-18DPN	0.680	0.492	0.188	60.83982	-151.6128	Trading Bay Unit
KENAI BELUGA UNIT 33-07	0.673	0.254	0.419	60.4429	-151.2452	Kenai Field Units
KENAI BELUGA UNIT 33-07	0.673	0.254	0.419	60.4429	-151.2452	Kenai Field Units Storage
TBU Gas Well M-01	0.668	0.611	0.056	60.83185	-151.6016	Trading Bay Unit
KENAI BELUGA UNIT 11-7	0.655	0.561	0.094	60.46055	-151.2628	Kenai Field Units
LEWIS RIVER UNIT C-01RD	0.626	0.360	0.266	61.34288	-150.8525	Other Cook Inlet

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
Beluga River Unit #212-25	0.602	0.558	0.044	61.19022	-150.9983	Beluga River Unit
Beluga River Unit #232-23	0.596	0.344	0.252	61.20442	-151.0014	Beluga River Unit
IVAN RIVER UNIT 11-06	0.589	0.513	0.076	61.24065	-150.796	Other Cook Inlet
SOLDOTNA CK UNIT 33-33	0.578	0.346	0.231	60.73772	-150.8608	Other Cook Inlet
TBU Gas Well M-20	0.575	0.436	0.139	60.83181	-151.6025	Trading Bay Unit
SOLDOTNA CK UNIT 32B-09	0.566	0.168	0.398	60.71404	-150.8623	Other Cook Inlet
NINILCHIK STATE #1	0.565	0.503	0.062	60.13891	-151.5228	Ninilchik Unit
KALOA 2	0.543	0.065	0.478	61.01884	-151.3486	Other Cook Inlet
KENAI BELUGA UNIT 32-06	0.539	0.074	0.465	60.46065	-151.2617	Kenai Field Units
KENAI TYONEK UNIT 43-6XRD2	0.502	0.261	0.242	60.45863	-151.2456	Kenai Field Units
KENAI BELUGA UNIT 41-07	0.496	0.447	0.049	60.4587	-151.2448	Kenai Field Units
TRADING BAY ST A-27RD2	0.486	0.368	0.117	60.89681	-151.5787	Other Cook Inlet
HAPPY VALLEY B-14	0.476	0.074	0.402	59.98862	-151.5088	Deep Creek Unit
SOLDOTNA CK UNIT 13-34	0.465	0.322	0.143	60.73408	-150.8619	Other Cook Inlet
KENAI DEEP UNIT 10	0.449	0.347	0.102	60.45765	-151.2464	Kenai Field Units
TRADING BAY ST A-21RD	0.445	0.235	0.210	60.89681	-151.5787	Other Cook Inlet
SOLDOTNA CK UNIT 44B-33	0.435	0.243	0.191	60.7357	-150.8478	Other Cook Inlet
NICOLAI CREEK 09	0.422	0.313	0.109	61.01348	-151.4565	Other Cook Inlet
NINILCHIK STATE #3	0.420	0.379	0.041	60.13909	-151.5234	Ninilchik Unit
SWANSON RIV UNIT 14B-27	0.396	0.168	0.228	60.74626	-150.8549	Swanson River Unit
PRETTY CK UNIT 2	0.386	0.049	0.337	61.26359	-150.8945	Other Cook Inlet
SOLDOTNA CK UNIT 24A-09	0.377	0.044	0.332	60.71168	-150.8695	Other Cook Inlet
HAPPY VALLEY A-09	0.373	0.282	0.091	59.98534	-151.4854	Deep Creek Unit
HAPPY VALLEY A-08	0.353	0.314	0.038	59.98594	-151.4849	Deep Creek Unit
NINILCHIK UNIT G OSKOLKOFF #2	0.351	0.327	0.024	60.16489	-151.4869	Ninilchik Unit
BEAVER CK UNIT 04	0.328	0.070	0.259	60.65703	-151.0303	Beaver Creek
NINILCHIK UNIT S DIONNE #8	0.316	0.273	0.042	60.11339	-151.5706	Ninilchik Unit
SOLDOTNA CK UNIT 34-04	0.315	0.117	0.198	60.72109	-150.8619	Other Cook Inlet
W MCARTHUR RIV UNIT 5	0.313	0.091	0.221	60.78255	-151.7468	Other Cook Inlet
SWANSON RIV UNIT 21A-34	0.304	0.238	0.066	60.74655	-150.8403	Swanson River Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
SOLDOTNA CK UNIT 12A-04	0.297	0.106	0.191	60.72807	-150.8769	Other Cook Inlet
Beluga River Unit #232-04	0.296	0.195	0.101	61.1614	-151.0552	Beluga River Unit
SOLDOTNA CK UNIT 41B-04	0.294	0.185	0.109	60.73127	-150.8576	Other Cook Inlet
NINILCHIK UNIT FALLS CK #5	0.291	0.240	0.051	60.20451	-151.4292	Ninilchik Unit
NORTH FORK UNIT 42-35	0.284	0.235	0.049	59.79614	-151.6291	North Fork Unit
IVAN RIVER UNIT 44-01	0.283	0.248	0.036	61.24086	-150.7962	Other Cook Inlet
TRADING BAY ST A-28RD	0.279	0.210	0.069	60.89687	-151.5787	Other Cook Inlet
TRADING BAY ST A-07	0.270	0.063	0.206	60.89686	-151.5787	Other Cook Inlet
HAPPY VALLEY A-02	0.261	0.222	0.039	59.98577	-151.4852	Deep Creek Unit
THREE MILE CK UNIT 1	0.254	0.165	0.088	61.17717	-151.2102	Other Cook Inlet
SOLDOTNA CK UNIT 332-04	0.248	0.104	0.144	60.73105	-150.8576	Other Cook Inlet
KENAI BELUGA UNIT 11-8Y	0.247	0.195	0.052	60.45945	-151.2451	Kenai Field Units
SOLDOTNA CK UNIT 31B-04	0.247	0.079	0.167	60.72834	-150.8493	Other Cook Inlet
W MCARTHUR RIV UNIT 2B	0.211	0.150	0.061	60.78457	-151.7497	Other Cook Inlet
NCOOK INLET UNIT A-06	0.210	0.102	0.108	61.07675	-150.9482	North Cook Inlet Unit
SOLDOTNA CK UNIT 31-04	0.208	0.043	0.164	60.72512	-150.8689	Other Cook Inlet
TRADING BAY ST A-06	0.196	0.102	0.093	60.89681	-151.5788	Other Cook Inlet
SWANSON RIV UNIT 21-27	0.190	0.128	0.062	60.76106	-150.8391	Swanson River Unit
REDOUBT UNIT 5B	0.185	0.141	0.043	60.69546	-151.6707	Other Cook Inlet
SWANSON RIV UNIT 41A-15	0.184	0.120	0.064	60.78998	-150.8259	Swanson River Unit
TBU Gas Well M-03	0.183	0.068	0.115	60.83183	-151.6016	Trading Bay Unit
LONE CREEK 1	0.178	0.060	0.119	61.12407	-151.2912	Other Cook Inlet
SWANSON RIV UNIT 11-22	0.175	0.152	0.023	60.77955	-150.8352	Swanson River Unit
TRADING BAY ST A-18	0.170	0.064	0.106	60.89688	-151.5787	Other Cook Inlet
NICOLAI CREEK 11	0.168	0.068	0.100	61.01316	-151.4666	Other Cook Inlet
SWANSON RIV UNIT 23B-22	0.167	0.080	0.087	60.7648	-150.8478	Swanson River Unit
SOLDOTNA CK UNIT 21A-09	0.161	0.111	0.051	60.718	-150.8702	Other Cook Inlet
SOLDOTNA CK UNIT 41A-08	0.159	0.095	0.064	60.71817	-150.8834	Other Cook Inlet
SOLDOTNA CK UNIT 43B-08	0.158	0.050	0.108	60.71089	-150.8836	Other Cook Inlet
KENAI UNIT 34-31	0.157	0.013	0.144	60.47573	-151.2721	Kenai Field Units

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
KENAI UNIT 34-31	0.157	0.013	0.144	60.47573	-151.2721	Kenai Field Units Storage
TRADING BAY ST A-08RD2	0.156	0.073	0.083	60.89685	-151.5788	Other Cook Inlet
SOLDOTNA CK UNIT 43A-33	0.153	0.068	0.085	60.7373	-150.8548	Other Cook Inlet
SWANSON RIV UNIT 13-27	0.150	0.065	0.084	60.7462	-150.855	Swanson River Unit
TRADING BAY ST A-31	0.147	0.054	0.093	60.89682	-151.5787	Other Cook Inlet
SWORD SWORD 1	0.140	0.038	0.102	60.7829	-151.7472	Other Cook Inlet
TRADING BAY ST A-01RD	0.136	0.062	0.074	60.89686	-151.5788	Other Cook Inlet
TRADING BAY ST A-17RD	0.133	0.073	0.061	60.89684	-151.5788	Other Cook Inlet
TRADING BAY ST A-24RD	0.133	0.085	0.048	60.89687	-151.5788	Other Cook Inlet
TRADING BAY ST A-14	0.131	0.080	0.051	60.89682	-151.5788	Other Cook Inlet
MOQUAWKIE 4	0.128	0.068	0.059	61.07702	-151.3172	Other Cook Inlet
SWANSON RIV UNIT 14A-33	0.127	0.024	0.103	60.73811	-150.8715	Swanson River Unit
TRADING BAY ST A-13	0.125	0.043	0.082	60.89683	-151.5788	Other Cook Inlet
SOLDOTNA CK UNIT 12B-09	0.123	0.032	0.091	60.71216	-150.8693	Other Cook Inlet
SWANSON RIV UNIT 21-22	0.121	0.037	0.084	60.77523	-150.8399	Swanson River Unit
SWANSON RIV UNIT 24-15	0.117	0.020	0.097	60.77963	-150.8352	Swanson River Unit
TRADING BAY ST A-03RD3	0.110	0.054	0.056	60.89686	-151.5787	Other Cook Inlet
SWANSON RIV UNIT 23-15	0.108	0.048	0.060	60.78269	-150.8413	Swanson River Unit
BEAVER CK UNIT 09	0.101	0.017	0.084	60.65843	-151.0179	Beaver Creek
SOLDOTNA CK UNIT 32-08	0.098	0.036	0.062	60.71439	-150.8917	Other Cook Inlet
SOLDOTNA CK UNIT 31-08	0.088	0.040	0.047	60.71425	-150.8917	Other Cook Inlet
REDOUBT UNIT 4A	0.086	0.011	0.075	60.69546	-151.6707	Other Cook Inlet
Beluga River Unit #232-26	0.082	0.057	0.025	61.19743	-151.0173	Beluga River Unit
W MCARTHUR RIV UNIT 6	0.081	0.053	0.028	60.78479	-151.7501	Other Cook Inlet
TRADING BAY ST A-30	0.081	0.013	0.067	60.89685	-151.5787	Other Cook Inlet
TRADING BAY ST A-16RD	0.077	0.030	0.047	60.89684	-151.5788	Other Cook Inlet
TRADING BAY ST A-11	0.076	0.018	0.058	60.89687	-151.5787	Other Cook Inlet
TRADING BAY ST A-04	0.075	0.032	0.043	60.89684	-151.5787	Other Cook Inlet
TRADING BAY ST A-02	0.075	0.049	0.026	60.89685	-151.5788	Other Cook Inlet
MOQUAWKIE 3	0.073	0.016	0.057	61.07429	-151.319	Other Cook Inlet

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
NINILCHIK UNIT G OSKOLKOFF #1	0.064	0.025	0.039	60.16503	-151.4869	Ninilchik Unit
TRADING BAY ST A-05RD2	0.063	0.023	0.040	60.89683	-151.5788	Other Cook Inlet
IVAN RIVER UNIT 41-01	0.057	0.023	0.034	61.241	-150.7966	Other Cook Inlet
BEAVER CK UNIT 05RD	0.055	0.025	0.030	60.65821	-151.0185	Beaver Creek
CANNERY LOOP UNIT 07	0.053	0.025	0.028	60.53219	-151.2616	Cannery Loop Unit
MGS A22-14	0.052	0.034	0.019	60.79578	-151.4959	Other Cook Inlet
REDOUBT UNIT 2A	0.052	0.014	0.037	60.69548	-151.6707	Other Cook Inlet
MGS A12A-01	0.051	0.029	0.023	60.79578	-151.4959	Other Cook Inlet
NICOLAI CK UNIT 02	0.050	0.030	0.020	61.01345	-151.4568	Other Cook Inlet
MGS A23-01RD	0.046	0.021	0.025	60.79563	-151.4956	Other Cook Inlet
NINILCHIK STATE #2	0.044	0.012	0.032	60.13875	-151.523	Ninilchik Unit
MGS A34-11RD3	0.042	0.024	0.018	60.79578	-151.4959	Other Cook Inlet
MGS A41-11	0.039	0.026	0.013	60.7956	-151.4956	Other Cook Inlet
MGS A12-12RD	0.038	0.023	0.015	60.79563	-151.4956	Other Cook Inlet
MGS A34-14RD2	0.038	0.021	0.017	60.79578	-151.4959	Other Cook Inlet
HAPPY VALLEY A-01	0.036	0.004	0.032	59.98576	-151.4851	Deep Creek Unit
NICOLAI CK UNIT 01B	0.035	0.018	0.017	61.01345	-151.4569	Other Cook Inlet
MGS A43-11RD	0.035	0.021	0.014	60.79579	-151.4959	Other Cook Inlet
MGS A14-01	0.034	0.018	0.016	60.79564	-151.4956	Other Cook Inlet
REDOUBT UNIT 9	0.031	0.004	0.026	60.6956	-151.6705	Other Cook Inlet
TRADING BAY ST A-32	0.030	0.012	0.018	60.89683	-151.5787	Other Cook Inlet
MGS A11-01	0.029	0.019	0.010	60.7958	-151.4959	Other Cook Inlet
TRADING BAY ST A-23DPN	0.027	0.004	0.023	60.89682	-151.5787	Other Cook Inlet
MGS C32-23RD2	0.027	0.009	0.017	60.76395	-151.5024	Other Cook Inlet
MGS A13-12RD	0.025	0.016	0.009	60.79561	-151.4956	Other Cook Inlet
MGS A12-01	0.025	0.015	0.010	60.7958	-151.4959	Other Cook Inlet
MGS C31-26RD	0.025	0.008	0.016	60.76394	-151.5024	Other Cook Inlet
MGS A32-11RD	0.024	0.017	0.007	60.79595	-151.4956	Other Cook Inlet
MGS C43-14	0.022	0.012	0.010	60.76416	-151.5021	Other Cook Inlet
MGS C22A-26RD	0.019	0.009	0.011	60.76382	-151.502	Other Cook Inlet

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
MGS A13-01	0.018	0.013	0.005	60.79579	-151.4959	Other Cook Inlet
MGS C22-26RD	0.017	0.006	0.011	60.76394	-151.5024	Other Cook Inlet
TRADING BAY ST A-22	0.017	0.001	0.016	60.89681	-151.5788	Other Cook Inlet
MGS A24-01RD	0.016	0.011	0.005	60.79562	-151.4956	Other Cook Inlet
W FORELAND 2	0.015	0.005	0.010	60.76488	-151.7312	Other Cook Inlet
MGS A31-14	0.015	0.009	0.006	60.79593	-151.4956	Other Cook Inlet
MGS C13-23	0.014	0.004	0.010	60.76415	-151.5021	Other Cook Inlet
NINILCHIK UNIT FALLS CK #1RD	0.013	0.001	0.012	60.20441	-151.4297	Ninilchik Unit
SOLDOTNA CK UNIT 34-09	0.011	0.005	0.007	60.70721	-150.8626	Other Cook Inlet
MGS C12-23	0.009	0.004	0.006	60.76385	-151.502	Other Cook Inlet
MGS C42-23	0.009	0.003	0.006	60.76385	-151.5021	Other Cook Inlet
MGS C24-26RD	0.008	0.003	0.005	60.76393	-151.5023	Other Cook Inlet
MGS C21-23	0.007	0.003	0.004	60.76413	-151.5021	Other Cook Inlet
MGS C34-26	0.006	0.002	0.004	60.76394	-151.5023	Other Cook Inlet
MGS C13A-23	0.006	0.003	0.003	60.76382	-151.502	Other Cook Inlet
MGS C21A-23	0.006	0.002	0.003	60.76385	-151.502	Other Cook Inlet
NORTH FORK UNIT 14-25	0.005	0.003	0.002	59.79631	-151.6299	North Fork Unit
BEAVER CK UNIT 12A	0.005	0.000	0.005	60.65615	-151.0293	Beaver Creek
MGS C21-26	0.004	0.002	0.002	60.76413	-151.5021	Other Cook Inlet
MGS C13-13RD	0.001	0.000	0.000	60.76414	-151.5021	Other Cook Inlet
BEAVER CK 25	0.000	0.000	0.000	60.65827	-151.0174	Beaver Creek
BEAVER CK UNIT 10	0.000	0.000	0.000	60.65868	-151.018	Beaver Creek
BEAVER CK UNIT 11	0.000	0.000	0.000	60.65861	-151.0184	Beaver Creek
BEAVER CK UNIT 14A	0.000	0.000	0.000	60.64754	-151.0344	Beaver Creek
BEAVER CK UNIT 18	0.000	0.000	0.000	60.65879	-151.0176	Beaver Creek
BEAVER CK UNIT 19	0.000	0.000	0.000	60.65841	-151.0174	Beaver Creek
Beluga River Unit #211-03	0.000	0.000	0.000	61.16629	-151.0449	Beluga River Unit
Beluga River Unit #212-18	0.000	0.000	0.000	61.21969	-150.9712	Beluga River Unit
Beluga River Unit #212-24	0.000	0.000	0.000	61.2047	-151.0014	Beluga River Unit
Beluga River Unit #214-35	0.000	0.000	0.000	61.17006	-151.0367	Beluga River Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
Beluga River Unit #221-23	0.000	0.000	0.000	61.20948	-151.0213	Beluga River Unit
Beluga River Unit #224-13	0.000	0.000	0.000	61.21294	-150.9893	Beluga River Unit
Beluga River Unit #224-23T	0.000	0.000	0.000	61.19726	-151.0167	Beluga River Unit
Beluga River Unit #232-09	0.000	0.000	0.000	61.15158	-151.0636	Beluga River Unit
CANNERY LOOP UNIT 03	0.000	0.000	0.000	60.55292	-151.2176	Cannery Loop Unit
CANNERY LOOP UNIT 04	0.000	0.000	0.000	60.55294	-151.2179	Cannery Loop Unit
CANNERY LOOP UNIT 05	0.000	0.000	0.000	60.53218	-151.262	Cannery Loop Unit
CANNERY LOOP UNIT 06	0.000	0.000	0.000	60.532	-151.2631	Cannery Loop Unit
CANNERY LOOP UNIT 11	0.000	0.000	0.000	60.55295	-151.2185	Cannery Loop Unit
HAPPY VALLEY A-03	0.000	0.000	0.000	59.98581	-151.4854	Deep Creek Unit
HAPPY VALLEY A-04	0.000	0.000	0.000	59.98579	-151.4854	Deep Creek Unit
HAPPY VALLEY A-06	0.000	0.000	0.000	59.9853	-151.4858	Deep Creek Unit
HAPPY VALLEY A-07	0.000	0.000	0.000	59.98593	-151.4848	Deep Creek Unit
HAPPY VALLEY A-11	0.000	0.000	0.000	59.9858	-151.4852	Deep Creek Unit
HAPPY VALLEY B-13	0.000	0.000	0.000	59.98878	-151.509	Deep Creek Unit
KASILOF SOUTH 1	0.000	0.000	0.000	60.31619	-151.3777	Other Cook Inlet
KENAI BELUGA UNIT 22-06	0.000	0.000	0.000	60.46053	-151.2616	Kenai Field Units
KENAI BELUGA UNIT 23-7	0.000	0.000	0.000	60.46008	-151.2625	Kenai Field Units
KENAI BELUGA UNIT 33-06	0.000	0.000	0.000	60.45911	-151.2461	Kenai Field Units
KENAI BELUGA UNIT 33-06X	0.000	0.000	0.000	60.45932	-151.246	Kenai Field Units
KENAI BELUGA UNIT 41-07X	0.000	0.000	0.000	60.45856	-151.2446	Kenai Field Units
KENAI BELUGA UNIT 42-6	0.000	0.000	0.000	60.45933	-151.2454	Kenai Field Units
KENAI BELUGA UNIT 44-06	0.000	0.000	0.000	60.4591	-151.2449	Kenai Field Units
KENAI DEEP UNIT 4	0.000	0.000	0.000	60.45852	-151.2453	Kenai Field Units
KENAI DEEP UNIT 4	0.000	0.000	0.000	60.45852	-151.2453	Kenai Field Units Storage
KENAI DEEP UNIT 6	0.000	0.000	0.000	60.47624	-151.2699	Kenai Field Units
KENAI TYONEK UNIT 13-05	0.000	0.000	0.000	60.45882	-151.2456	Kenai Field Units
KENAI UNIT 14-06RD	0.000	0.000	0.000	60.45991	-151.2633	Kenai Field Units
KENAI UNIT 21-07	0.000	0.000	0.000	60.4602	-151.263	Kenai Field Units
KENAI UNIT 21-7X	0.000	0.000	0.000	60.46053	-151.2613	Kenai Field Units

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
KENAI UNIT 33-32	0.000	0.000	0.000	60.47925	-151.2374	Kenai Field Units
KENAI UNIT 33-32	0.000	0.000	0.000	60.47925	-151.2374	Kenai Field Units Storage
KENAI UNIT 41-18	0.000	0.000	0.000	60.44266	-151.245	Kenai Field Units
KENAI UNIT 43-06A	0.000	0.000	0.000	60.45845	-151.2449	Kenai Field Units
KENAI UNIT 43-06RD	0.000	0.000	0.000	60.45865	-151.2452	Kenai Field Units
KENAI UNIT 43-06RD	0.000	0.000	0.000	60.45865	-151.2452	Kenai Field Units Storage
KUSTATAN FIELD 1	0.000	0.000	0.000	60.72415	-151.7492	Other Cook Inlet
LEWIS RIVER 1	0.000	0.000	0.000	61.3355	-150.8434	Other Cook Inlet
LONE CREEK 4	0.000	0.000	0.000	61.14129	-151.2804	Other Cook Inlet
MGS A42-14	0.000	0.000	0.000	60.79594	-151.4955	Other Cook Inlet
MGS C22-23	0.000	0.000	0.000	60.76416	-151.5021	Other Cook Inlet
MGS ST 17595 14	0.000	0.000	0.000	60.82938	-151.4836	Other Cook Inlet
MGS ST 17595 27	0.000	0.000	0.000	60.82924	-151.4834	Other Cook Inlet
MGS ST 17595 28	0.000	0.000	0.000	60.82939	-151.4836	Other Cook Inlet
MOQUAWKIE 1	0.000	0.000	0.000	61.0738	-151.3188	Other Cook Inlet
NCOOK INLET UNIT A-01	0.000	0.000	0.000	61.07677	-150.9482	North Cook Inlet Unit
NCOOK INLET UNIT A-03	0.000	0.000	0.000	61.07677	-150.9481	North Cook Inlet Unit
NCOOK INLET UNIT A-07	0.000	0.000	0.000	61.07678	-150.9482	North Cook Inlet Unit
NCOOK INLET UNIT A-08	0.000	0.000	0.000	61.07676	-150.9482	North Cook Inlet Unit
NCOOK INLET UNIT A-09	0.000	0.000	0.000	61.07661	-150.9485	North Cook Inlet Unit
NCOOK INLET UNIT A-10	0.000	0.000	0.000	61.07662	-150.9485	North Cook Inlet Unit
NCOOK INLET UNIT A-11	0.000	0.000	0.000	61.07663	-150.9485	North Cook Inlet Unit
NCOOK INLET UNIT A-12	0.000	0.000	0.000	61.07676	-150.949	North Cook Inlet Unit
NCOOK INLET UNIT A-13	0.000	0.000	0.000	61.07679	-150.9488	North Cook Inlet Unit
NCOOK INLET UNIT A-16	0.000	0.000	0.000	61.07662	-150.9485	North Cook Inlet Unit
NICOLAI CK UNIT 03	0.000	0.000	0.000	61.03164	-151.4486	Other Cook Inlet
NINILCHIK UNIT G OSKOLKOFF #3	0.000	0.000	0.000	60.1647	-151.4874	Ninilchik Unit
NINILCHIK UNIT G OSKOLKOFF #4	0.000	0.000	0.000	60.16455	-151.4872	Ninilchik Unit
NINILCHIK UNIT G OSKOLKOFF #5	0.000	0.000	0.000	60.16432	-151.4878	Ninilchik Unit
NINILCHIK UNIT PAXTON #9	0.000	0.000	0.000	60.09535	-151.6093	Ninilchik Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
NINILCHIK UNIT S DIONNE #7	0.000	0.000	0.000	60.11333	-151.5714	Ninilchik Unit
NORTH FORK UNIT 23-25	0.000	0.000	0.000	59.79631	-151.6293	North Fork Unit
REDOUBT UNIT 1A	0.000	0.000	0.000	60.69548	-151.6707	Other Cook Inlet
REDOUBT UNIT 3	0.000	0.000	0.000	60.69546	-151.6707	Other Cook Inlet
REDOUBT UNIT 7	0.000	0.000	0.000	60.69562	-151.6702	Other Cook Inlet
S MGS UNIT 02RD	0.000	0.000	0.000	60.7356	-151.5127	Other Cook Inlet
S MGS UNIT 03	0.000	0.000	0.000	60.73542	-151.513	Other Cook Inlet
S MGS UNIT 04	0.000	0.000	0.000	60.7356	-151.5127	Other Cook Inlet
S MGS UNIT 13	0.000	0.000	0.000	60.7356	-151.5127	Other Cook Inlet
S MGS UNIT 14	0.000	0.000	0.000	60.73542	-151.513	Other Cook Inlet
S MGS UNIT 15	0.000	0.000	0.000	60.73542	-151.513	Other Cook Inlet
S MGS UNIT 16	0.000	0.000	0.000	60.73547	-151.5124	Other Cook Inlet
S MGS UNIT 18	0.000	0.000	0.000	60.73547	-151.5124	Other Cook Inlet
SIMPCO MOQUAWKIE 1	0.000	0.000	0.000	61.08135	-151.3163	Other Cook Inlet
SIMPCO MOQUAWKIE 2	0.000	0.000	0.000	61.0679	-151.3208	Other Cook Inlet
SOLDOTNA CK UNIT 44-33	0.000	0.000	0.000	60.7315	-150.8689	Other Cook Inlet
STERLING UNIT 32-09	0.000	0.000	0.000	60.53801	-151.0288	Sterling Unit
STERLING UNIT 41-15RD	0.000	0.000	0.000	60.53805	-151.0288	Sterling Unit
STERLING UNIT 43-09X	0.000	0.000	0.000	60.53828	-151.0287	Sterling Unit
STUMP LK UNIT 41-33RD	0.000	0.000	0.000	61.26583	-150.7058	Other Cook Inlet
SWANSON RIV UNIT 12-15	0.000	0.000	0.000	60.78542	-150.8455	Swanson River Unit
SWANSON RIV UNIT 212-27	0.000	0.000	0.000	60.75753	-150.844	Swanson River Unit
SWANSON RIV UNIT 23-33	0.000	0.000	0.000	60.73844	-150.8715	Swanson River Unit
SWANSON RIV UNIT 32A-15	0.000	0.000	0.000	60.78538	-150.8456	Swanson River Unit
SWANSON RIV UNIT 331-27	0.000	0.000	0.000	60.76267	-150.8315	Swanson River Unit
TBU Gas Well D-18	0.000	0.000	0.000	60.80763	-151.6327	Trading Bay Unit
TBU Gas Well K-20	0.000	0.000	0.000	60.86545	-151.6055	Trading Bay Unit
TBU Gas Well M-06	0.000	0.000	0.000	60.83184	-151.6017	Trading Bay Unit
TBU Gas Well M-12	0.000	0.000	0.000	60.83182	-151.6025	Trading Bay Unit
TBU Gas Well M-32RD	0.000	0.000	0.000	60.83202	-151.602	Trading Bay Unit

Well	Max Produced Day Rate Jun 16-May-17 MMSCF/D	Avg. Produced Day Rate Jun 16-May-18 MMSCF/D	Delta Prod Day Rate Max to Average	Wellhead Latitude	Wellhead Longitude	Unit or Field
THREE MILE CK UNIT 2	0.000	0.000	0.000	61.17943	-151.2095	Other Cook Inlet
TRADING BAY ST A-09RD	0.000	0.000	0.000	60.89688	-151.5788	Other Cook Inlet
TRADING BAY ST A-10	0.000	0.000	0.000	60.89684	-151.5788	Other Cook Inlet
W FORELAND 1	0.000	0.000	0.000	60.76485	-151.7315	Other Cook Inlet
W FORK 03	0.000	0.000	0.000	60.59849	-150.8616	Other Cook Inlet
W FORK CIRI WF1-21RD	0.000	0.000	0.000	60.59848	-150.8604	Other Cook Inlet
W FORK CIRI WF2-21	0.000	0.000	0.000	60.59843	-150.8611	Other Cook Inlet
W MCARTHUR RIV UNIT 1A	0.000	0.000	0.000	60.78475	-151.7501	Other Cook Inlet
W MCARTHUR RIV UNIT 7A	0.000	0.000	0.000	60.78479	-151.7501	Other Cook Inlet
W MCARTHUR RIV UNIT 8	0.000	0.000	0.000	60.78297	-151.7473	Other Cook Inlet
WOLF LAKE 1RD	0.000	0.000	0.000	60.6644	-150.8994	Other Cook Inlet
WOLF LAKE MARATHON 2	0.000	0.000	0.000	60.66491	-150.8973	Other Cook Inlet