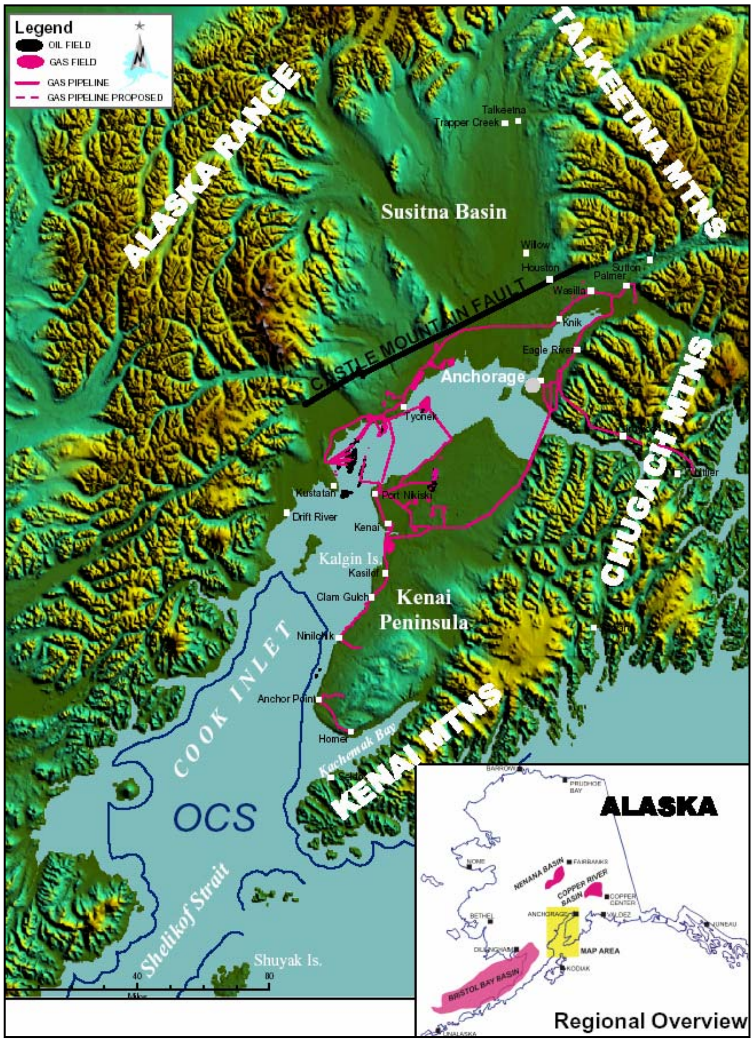
SOUTH-CENTRAL ALASKA NATURAL GAS STUDY



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SOUTH-CENTRAL ALASKA NATURAL GAS STUDY

ABSTRACT

The south-central Alaska Natural Gas Study is a geologic, engineering, and economic assessment of the options to meet the intermediate- and long-term natural gas demand for the region. An abundant supply of low-cost natural gas from the Cook Inlet Basin was discovered more than 30 years ago as a by-product of oil exploration. This low-cost gas has supplied all of south-central Alaska's residential, commercial, and industrial demand including manufacture and export of large quantities of fertilizer and liquefied natural gas (LNG) since the late 1960's. Consumers and businesses throughout the region have also benefited from low-cost gas.

The estimated ultimate recovery from existing Cook Inlet gas fields is approximately 8.5 trillion cubic feet (Tcf) and the proven reserves remaining on January 1, 2004 were 1.8 Tcf. Proven reserves in known Cook Inlet fields are forecast to meet demand until 2012, if the Agrium fertilizer plant is shut down in 2005 because of a lack of adequate affordable gas supplies and LNG export ends when the export license expires in 2009. A shortage could occur as early as 2009 unless industrial use is reduced or new gas reserves are developed.

Ninety-five percent of the Cook Inlet gas was found before 1970 during exploration for *structurally* trapped oil. A total Cook Inlet gas resource endowment of 25 to 30 Tcf original-gas-in-place (OGIP), more than two times the amount already discovered, is postulated. Land access, market price, and technology issues will determine the success of developing some portion of this gas endowment. Reserves growth in existing fields is expected to play a major role and is the lowest cost option with investment estimated to be $0.35/thousand cubic feet (Mcf) compared to a finding and development cost for exploration of approximately $0.75/Mcf, or over $5 billion to find and develop 50% of the undiscovered resources. For this to occur, prices will have to be high enough for Cook Inlet investment to complete with investment opportunities worldwide.

A spur gas pipeline from a North Slope pipeline with a takeoff point at Fairbanks to the Anchorage area is estimated to cost $500 million for 330 million cubic feet per day capacity (120 billion cubic feet/year, Bcf/yr) and may allow North Slope gas to be delivered to south-central Alaska at a price advantage of $1.00/Mcf below Lower 48 prices. Sufficient long-term demand must exist in the region to support investment in a spur pipeline. Currently, the total industrial demand is 130 Bcf/yr and commercial and residential demand is about 70 Bcf/yr.

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EXECUTIVE SUMMARY

Summary Conclusions

- The Cook Inlet Basin is the source for all of the natural gas used in south-central Alaska. This gas supplies the residential and commercial demand for utility gas and electricity generation and two industrial facilities, Agrium's fertilizer plant and the ConocoPhillips/Marathon LNG plant, in Nikiski, Alaska on the Kenai Peninsula.
    - The current remaining proven reserves represent about a 9-year supply at current demand rates.
    - The estimated ultimate recovery for existing Cook Inlet gas fields is approximately 8.5 trillion cubic feet (Tcf).
    - Ninety-five percent of the gas was found before 1970 during exploration for *structurally* trapped oil.
    - There was no gas-focused exploration until the late 1990s.
- The Cook Inlet Basin lacks numerous medium to large gas fields when viewed from the geologic expectation of a lognormal distribution of field size and reserves. The analysis suggests a total gas resource endowment of 25 to 30 Tcf OGIP best represents the expected lognormal state. This is more than two times the in-place gas volumes already discovered.
    - The potential exists for an additional 13 to 17 Tcf of conventionally recoverable gas in the Cook Inlet basin in addition to the 8.5 Tcf recoverable gas already discovered. A recovery factor of 85% is used in these estimates.
    - These resources are expected to be largely biogenic gas in *stratigraphic* or combination traps.
    - No exploration has yet occurred for *stratigraphic* accumulations.
    - Land access, market price, and technology issues will determine the degree to which these potential volumes can be achieved.
- Proven reserves in known fields are forecast to meet demand until 2012 for the base case, which assumes the Agrium fertilizer plant shuts down in 2005 as a result of lack of sufficient quantities of low-cost gas and that LNG export ends when the current contract and export license expires in the first quarter of 2009.

- A shortage will occur by 2009 unless new reserves are found and developed, or industrial use is curtailed. Large seasonal swings in demand and very limited gas storage could lead to seasonal shortages before 2009. Fortunately, new gas is being discovered and developed as a result of the stimulus being provided by higher prices and market demand; e.g., the recently discovered Ninilchik and Happy Valley fields on the Kenai Peninsula.
- A second case including reserves growth of 1.4 Tcf in existing fields, including field extensions, is sufficient to meet the projected residential and commercial consumer demand through 2025 with a limited amount of gas available for industrial use.
    - The estimated investment required for reserves growth is $0.35/Mcf, or $500 million, for the additional 1.4 Tcf. Although this magnitude of reserves growth is reasonable to expect in this basin, it will not occur without investment and thorough geologic and engineering revaluation of the larger producing fields.
    - Reserves growth is expected to occur in response to an increase in real prices. A recent contract has indexed prices to a 36-month average of Lower 48 reference prices (Henry Hub).
- The minimum economic field sizes (MEFS) at $4.50/Mcf are 108 billion cubic feet (Bcf) for offshore locations, 49 Bcf for transition zone locations, and 40 Bcf for onshore locations. Finding and development costs for onshore locations are estimated to vary from about $0.75/Mcf for small fields to $0.30/Mcf for large fields with 400 to 1,500 Bcf OGIP.
- Investment required to explore and develop 50% of the estimated 13 to 17 Tcf resources *potentially* available to be discovered could require investment of $5 to $6 billion, if the fields are predominantly onshore. If they are predominantly offshore, the investment would be higher.
- A spur pipeline from a North Slope gas pipeline (assumed to be built to move 4,500 million cubic feet per day (MMcf/day) or 1,642 Bcf/year) with a takeoff point at Fairbanks to the Anchorage area and connection to the existing distribution system is estimated to cost approximately $500 million dollars for a 330 MMcf/day (120 Bcf/year) capacity 24-in. line. This first-cut analysis suggests that North Slope gas could be delivered to south-central Alaska at a structural price advantage of about $1.00/Mcf below Lower 48 prices. The estimated timing for completion of a pipeline range from 2013 to 2015.
    - Sufficient demand must be present to support the investment required to construct a spur pipeline. Currently, total demand is 356 MMcf/day (130 Bcf/year) for industrial use and about 192 MMcf/day (70 Bcf/year) for residential and commercial use.

- For a spur line to be viable as a market-driven development, industrial activities must be profitable at prices significantly higher than historical Cook Inlet industrial gas contracts, and possibly higher than the current Cook Inlet prevailing gas price for utility use.

- Coalbed natural gas is a major *potential* resource for south-central Alaska with estimated technically recoverable resources of 7 Tcf. The economic viability and timing of any contribution from this resource is highly uncertain because of the high cost of development, the lack of sufficient data to predict gas productivity and the amount of water that must be handled, and land access issues.
- Curtailing industrial use and importing LNG from foreign sources are both options for maintaining sufficient supply to meet the critical demand for heating and electric power but are not economically appealing options for Alaska.

Purpose

The purpose of this investigation is to identify and evaluate the options available to meet future south-central Alaska natural gas demand and provide for economic growth. The south-central Alaska region is shown in Figure ES-1. The primary opportunities for ensuring adequate future supply of natural gas are development of additional gas reserves in existing Cook Inlet fields, exploration and development of new gas fields in the Cook Inlet Basin, and development of a spur pipeline to bring Alaska North Slope gas to the region.

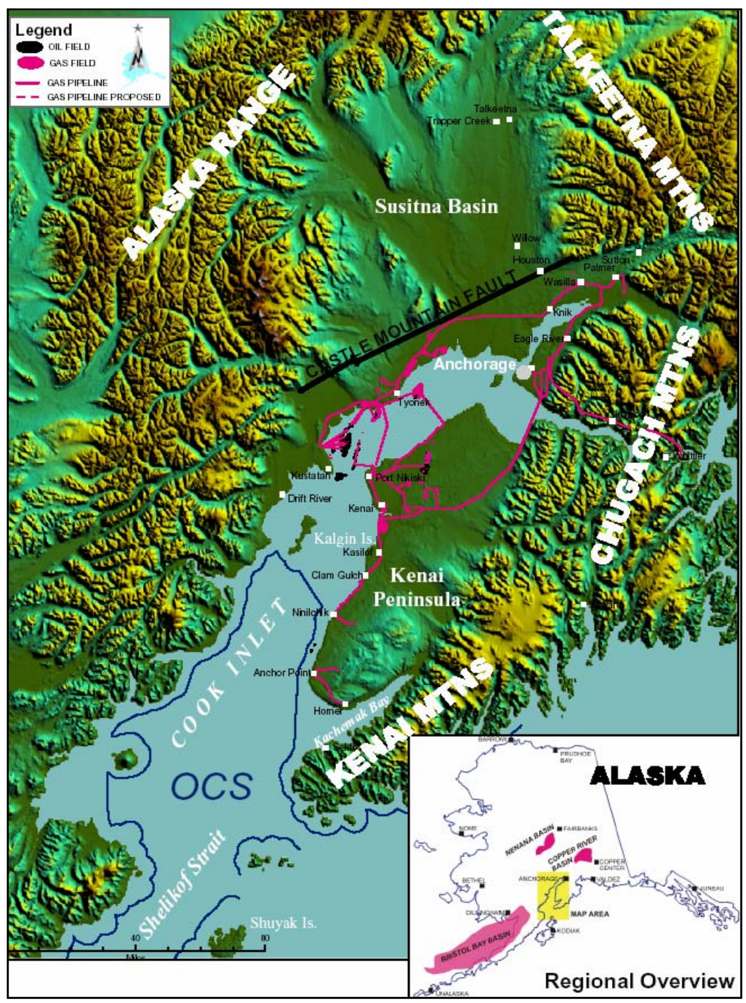

Figure ES.1. South-central Alaska region and Cook Inlet Basin location map with gas fields and gas pipelines.

Introduction

The south-central Alaska region, shown in Figure ES-1, includes the upper and lower Cook Inlet Basin including the Outer Continental Shelf (OCS) portion and the Susitna Basin. The coalbed natural gas that is being actively investigated is located north of Anchorage in the Matanuska-Susitna Valley on both sides of the Castle Mountain Fault near Houston and Wasilla. This figure includes the gas fields and the gas pipelines in the Cook Inlet region and the location of the Bristol Bay Basin, Copper River Basin, and the Nenana Basin. These basins may have long-term gas potential.

The supply of locally-produced natural gas in south-central Alaska has exceeded demand since discovery of about 8 Tcf of economically recoverable conventional gas resources by 1970. This gas was discovered as a by-product of oil exploration.

The large supply of low-cost gas spurred manufacture of fertilizer and allowed Alaska to export large quantities of LNG to Japan. Historically, industrial use has consumed over 60% of the gas produced in the Cook Inlet as shown in Figure ES.2. This low-cost gas, consistently below U.S. Lower-48 gas prices, has benefited residential gas and electric utility consumers from Homer to Fairbanks. Electricity for the south-central Alaska region is based exclusively on natural gas.

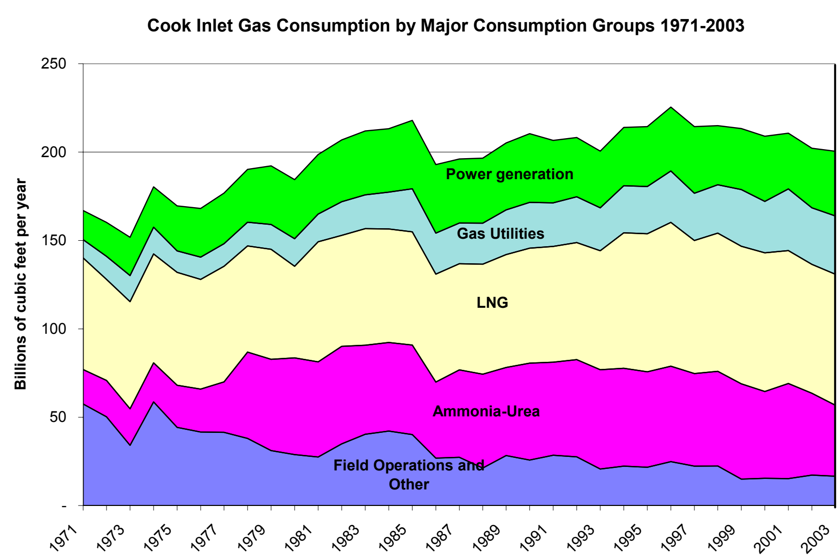

Figure ES.2. Historical gas consumption by major groups in south-central Alaska, 1971 to 2003 (Alaska Department of Natural Resources, Division of Oil and Gas, Oil and Gas Report 2003 (ADNR, 2003) & forthcoming 2004 Report).

Today the abundant supply of low-cost gas has run out. Fields and accumulations whose estimated ultimate recovery (EUR) is now known to be about 8 Tcf had been discovered by 1970. This was a reserves-to-production ratio of 50 in 1970 but by 2002 the reserves-to-production ratio has decreased to nine as a result of gas use. As a result of the decreased low-cost gas supply, unwanted changes are taking place:

- Fertilizer production at the Agrium fertilizer plant in Nikiski has been reduced due to lack of access to low-cost gas and the plant could cease production by the end of 2005 resulting in the loss of over 250 jobs. Agrium is also the second highest tax payer in the Kenai Peninsula Borough.
- The LNG export license and the existing supply contracts with Tokyo Electric and Tokyo Gas expire the first quarter of 2009. Long-term proven supplies of natural gas must be available to support continued operation of the LNG plant.
- The gas utility, ENSTAR Natural Gas Company, has recently negotiated a contract with a producer indexed to Lower 48 reference prices (36-month trailing average of Henry Hub prices) to encourage exploration for gas to ensure long-term supply and the stimulus has resulted in increased exploration and discoveries of new resources.
- If the upward trend of gas prices in the Cook Inlet continues toward parity with U.S. Lower 48 prices, prices for residential and commercial gas consumers and electric consumers will continue to increase.

The Cook Inlet Basin is lightly explored and only in the last five years has there been any effort to look specifically for new gas. The questions to be answered are:

- What is the potential for new gas resources?
- Will access to the most prospective areas be possible?
- What will new gas cost?
- What will be the investment required?

Scope and Approach

The supply options for the south-central Alaska region analyzed in detail are: (a) finding and developing additional conventional Cook Inlet Basin natural gas reserves, and (b) building a spur gas pipeline to bring North Slope gas to the south-central Alaska region. Future demand is based on assumptions about future industrial use, a recent Railbelt Power Study published by the electric utilities, and projection from historical utility gas use. Reserves and production forecasts published by the Alaska Department of Natural Resources (ADNR, 2003) and prepared by the authors of this report are used as the basis for the analysis. The results produced by the economic models are dependent on many factors including the structure and architecture of the models; the level of detail in the models; the mathematical algorithms used; and the input assumptions, which rely on publicly available data. The results produced by the models should not be viewed as precise forecasts of any future level of supply, demand, or price. Instead, they should be viewed as estimates of trends and ranges of possible outcomes from the specific assumptions made. The model results provide guidance regarding the likely impacts of pursuing particular choices relative to the south-central Alaska natural gas market.

Part of the solution to the supply-demand problem would be to curtail demand by stopping or reducing industrial use but this only delays the problem and will have negative economic impact on Alaska and especially on the Kenai Peninsula Borough. Future demand can also be reduced by: (a) conservation by consumers; (b) more efficient electric generation through investment in more efficient equipment by the utilities (Anchorage Municipal Light and Power (ML&P) and Chugach Electric Association); (c) power generation from alternative sources such as coal, wind, or hydropower, which would also require major investments; and (d) gas storage in depleted or near-depleted oil or gas fields for short-term and peaking needs. The impact and cost of these options are not analyzed in this study. More efficient electricity generating equipment and alternatives such as wind, coal, and additional hydropower are being studied by the utilities. Gas storage has occurred in the past in the Swanson River field and is expected to continue; however, storage capacity and deliverability are likely to be more critical in the future to meet peaking demands, if the supply-demand margin continues to decrease.

A final option would be to import LNG from foreign sources through existing LNG export facilities at Nikiski, Alaska. This would require facilities to re-gasify the LNG and increase the pressure to levels necessary to input gas to the ENSTAR gas pipeline system. Importing natural gas into Alaska would have negative impact on the region and state through lost revenue from royalty gas and taxes and the economic drain of capital from the region to pay for imports. It would also make Alaska part of the worldwide LNG market and subject to worldwide LNG prices for gas to serve local markets. These prices could turn out to be higher or lower than gas can be found and developed in the Cook Inlet basin or delivered from the North Slope.

The interaction of supply from new gas reserves in the region and a spur pipeline to bring North Slope gas to the region will impact gas prices in the region and will be an iterative process. Successful exploration and addition of a large quantity of new reserves will tend to moderate prices and possibly slow investment in exploration and production (E&P) activity.

Geological Assessment

Exploration in the Cook Inlet Basin has historically been focused on *structural* plays in the search for oil with no attempt to evaluate *stratigraphic* potential or to look primarily for gas. Only 240 exploration wells have been drilled in the basin and only in the last five years has gas come into its own as a primary exploration and evaluation objective. There is still no effort to explore for the *stratigraphic* plays that typically account for 50% or more of the ultimate production in basins elsewhere. The exploration well locations and the limits of the Tertiary sediments are shown in Figure ES.3. Modern 3-D seismic technology is also just starting to be used in the basin to locate additional gas resources. The lower Cook Inlet subbasin, basically the OCS area south of Kalgin Island, and the Susitna Basin have only been lightly explored with little effort directed toward conventional gas exploration.

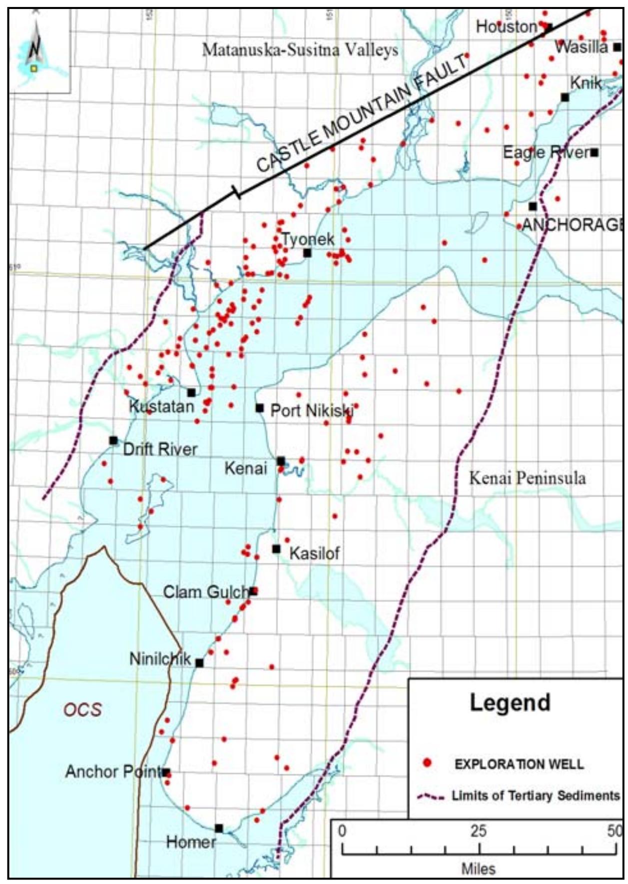

Figure ES.3. Cook Inlet exploration wells, 1955 to 2003, and limits of Tertiary sediments.

The Cook Inlet oil and associated gas were derived thermogenically from Middle Jurassic and possibly Late Triassic marine source rocks and subsequently reservoired in the lower Tertiary West Foreland, Hemlock and lower Tyonek formations. The non-associated biogenically derived dry gas is sourced from coals and carbonaceous fine-grained sediments in the Tertiary sediments, upper Tyonek, Beluga, and Sterling formations, and is found in reservoirs intimately associated with the source lithologies in these younger sediments.

The vast majority of the proven gas reserves (94%) are non-associated biogenic gas that has no genetic relationship to the origin and distribution of oil, which has historically been the primary exploration objective. Therefore, it is not realistic to conclude that exploration based on oil prospects will necessarily lead to a true evaluation of the basin's gas potential.

Ninety-five percent of the estimated ultimately recoverable gas, 8.5 Tcf, was found by 1970. Production to date has been approximately 6.7 Tcf, with proven remaining reserves of about 1.8 Tcf. The 8.5 Tcf of recoverable gas is equivalent to about 10 Tcf OGIP.

According to accepted geologic theory and evidence, the number of fields and the size of those fields should be log-normally distributed. This analysis leads to the conclusion that the total conventionally recoverable gas resource endowment in the Cook Inlet Basin is much larger than suggested by the 10 Tcf OGIP in the known fields. There are undiscovered fields with 200 to 1,500 Bcf OGIP missing from the expected field-size distribution. The estimated total gas resource endowment for upper Cook Inlet suggested by the analysis is 25 to 30 Tcf OGIP. The missing fields needed to fill in the log-normal distribution for a 25 Tcf total gas-in-place endowment are shown in Figure ES.4.

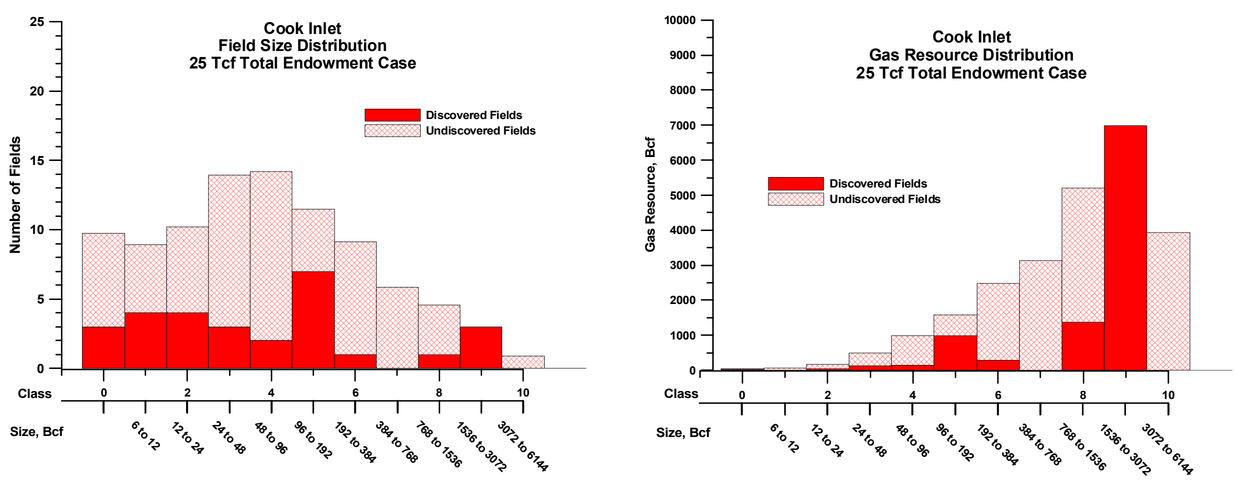

Figure ES.4. Cook Inlet Basin 25 Tcf gas endowment case: Inferred field size distribution and inferred gas resource distribution by class size.

The estimated total conventionally recoverable gas resource is about 13 to 17 Tcf more than the 8.5 Tcf that is expected to be recovered from the existing fields based on current proven reserves estimates and an average 85% recovery factor. These conventionally recoverable gas resources may be accounted for by reserves growth in existing fields and by discovery of new fields. U.S. Geological Survey (USGS) analysis provides an estimate of reserves growth of 2.5 to 3.0 Tcf in existing fields in the upper Cook Inlet Basin. Lower Cook Inlet and the Susitna Basin may have the potential to add another 2 to 3 Tcf of undiscovered conventionally recoverable resources.

The bulk of the undiscovered conventional gas resources are believed to be *stratigraphic* with virtually the entire upper Cook Inlet subbasin having some level of exploration potential. The greatest likelihood for success is along the flanks of the large structures that have had an intermittent structural growth history accompanied by repeated cycles of uplift, erosional truncation, and deposition. The eastern and western margins had similar histories associated with movement along the basin-bounding faults. In these areas and elsewhere in the basin, the interleaved nature of stream channel systems and alluvial fans with finer-grained flood plain, lacustrine, and paludal deposits creates pure *stratigraphic* traps.

The USGS estimated volume of coalbed natural gas is approximately 140 Tcf, of which only 10% is assumed to be accessible, and of that 50% recoverable. This yields a potential resource of 7 Tcf of coalbed natural gas. The economic potential of this resource is currently unknown and the timing for any commercial development is so uncertain that its role in the future gas supply for south-central Alaska cannot be predicted.

The geological assessment of the Cook Inlet Basin strongly suggests that there are large remaining natural gas resources to be found. However, exploration cannot proceed if access to prospective lands is hindered or denied by constraints on exploration and development. Constraints may be imposed by the regulations and stipulations associated with many of the various land withdrawals in the Cook Inlet Basin area. These areas could potentially make 30 to 50% of the most prospective areas off limits. Technologies to reduce environmental impact from 3D seismic acquisition and extended reach horizontal drilling may serve to mitigate these impacts on resource evaluation and development.

Reserves and Production Rate Forecasts

The total remaining proven gas reserves for the Cook Inlet Basin non-associated dry gas fields as of January 1, 2004 are estimated to be 1,785 billion cubic feet (Bcf). The estimate of ultimately recoverable reserves for these dry gas fields is 7,927 Bcf. This compares favorably with the estimates prepared by the ADNR Division of Oil and Gas (ADNR, 2003), which lists proven remaining reserves at 1,714 Bcf and estimated ultimate recovery for the same dry gas fields of 7,857 Bcf. Production forecasts are determined for eight fields: Beaver Creek, Belgua River, McArthur River, North Cook Inlet, Swanson River and Ninilchik and Happy Valley, two recent discoveries. These eight fields contain over 90% of the remaining reserves in the Cook Inlet dry gas fields. The aggregated production forecast for all the other non-associated gas fields published by the ADNR Division of Oil and Gas in the December 2003, Oil and Gas Report (ADNR, 2003) is used for the economic evaluations for those fields.

Economic Analysis

The Cook Inlet gas market is clearly in transition as a result of the utilization and monetization of stranded gas found in the 1960's. Cook Inlet gas has been used to meet the needs of two large industrial facilities, and a growing commercial and residential market. The reserves-to-production (R/P) ratio is now at about nine years, which is approaching the R/P ratio in the Lower 48. The Lower 48 gas supply has repeatedly responded to increasing real price signals with the transfer of probable and possible reserves to proven reserves in existing fields (reserves growth) through development, and through active frontier exploration; e.g., exploration in deep water in the Gulf of Mexico, and the continuing development and application of new technology such as ultra-deep water drilling, horizontal wells, and 3-D seismic. The Cook Inlet region is at a turning point in its history, with the exploration focus turning to natural gas rather than exclusively on oil and the recent success in adding new gas reserves. In response to increased real prices being seen in the latest contracts, Cook Inlet projects appear to be able to compete for capital with other investment opportunities worldwide.

Reserves growth in the Cook Inlet is expected to be a major component of new proven reserves with recent operator activity and increased spending to increase proven and probable reserves through workovers, opening previously undeveloped zones, new wells, and redrills into existing and new reservoirs identified by modern 3-D seismic. Significant reserves additions that occurred in the mid-1980's and again in the mid-1990's were primarily the result of detailed geologic and reservoir engineering analysis of existing data. Future reserves growth will occur as the operators continue to reevaluate existing fields with new technology and make the investments needed to increase reserves based on increasing prices. The recent increase in 3-D seismic activity is further evidence that the operators are responding to the increased value of their proven reserves. Delineation drilling using extended reach and horizontal wells will be used to expand the search for satellite accumulations, similar to what has occurred on the North Slope. The continued high prospectivity of the Cook Inlet bodes well for increased industry interest to add reserves to meet the demand for natural gas provided the opportunities and essential fiscal stability remain in place.

The economic analysis conducted is a deterministic evaluation of the south-central Alaska supply of conventional gas from four sources: (1) proven reserves, (2) reserves growth, (3) exploration in the Cook Inlet basin, and (4) a spur gas pipeline to bring North Slope gas from Fairbanks to the south-central Alaska region. The analysis does not examine the impact of public funding or other non-market-based price incentives. Other options such as coalbed natural gas, electricity from coal plants and alternatives such as wind power and hydropower, and conservation are not analyzed but could play a role in the meeting energy needs in the future.

Gas storage in some form to meet seasonal demand variations and sustained peak demand is likely to become more and more important in the next five to ten years. Gas storage in oil and gas reservoirs, salt domes, and as LNG is used in the Lower 48 to meet seasonal and daily demand swings. The gas storage option will need to be analyzed in detail to assess its viability and cost. Such an analysis is not included in this report.

The gas prices used for the existing fields are based on the best available data for the existing contracts for the various fields. The transition to a Lower 48 Henry Hub price basis (based on a recent Unocal and ENSTAR Natural Gas Company contract that indexed prices to a 36-month trailing average of Henry Hub prices) is used for reserves growth, new exploration, and as the comparison basis for the spur gas pipeline analysis. Cook Inlet gas prices have historically been significantly lower than average Lower 48 gas prices, which is a major factor in the historical lack of interest by operators to explore for natural gas.

Base Case:

The base case demand assumes: (1) Agrium's fertilizer plant stops operations at the end of 2005 as a result of limited low-cost gas supply, (2) the LNG plant stops operations in the first quarter of 2009 at the end of the current export license, and (3) gas demand for utility use and for electric power generation continues to increase. Demand projections are based on historic growth trends for utility gas use and the power generation projection is from a recent study of power generation needs by the electric utilities. The analysis shows:

- For this scenario, the proven reserves are forecast to meet the commercial and residential needs until 2012. Yearly average demand volumes are shown in Figure ES.5 by the bar graphs and the forecast production for all fields by the top curve.
- Demand could exceed supply by 2009, if non-industrial demand continues to increase as forecast and all the gas from the fields whose production is dedicated to industrial customers (Kenai River, McArthur River, and North Cook Inlet fields) is used for that purpose. The production forecast for all fields except Kenai, McArthur River, and North Cook Inlet is shown by the lower curve in Figure ES.5.

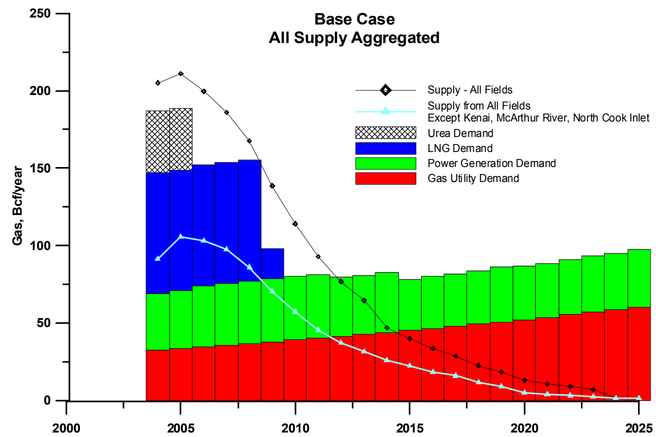

Figure ES.5. Base case for total aggregated supply and demand (top curve), and All Supply less fields dedicated to industrial demand (bottom curve).

- If all unused gas from industrial consumers (fertilizer and LNG plants), becomes available for utility and power generation use, supply could meet demand for three to five years beyond 2012 based on the yearly average volumes. However, the yearly average volumes mask large seasonal swings in demand (e.g., the ENSTAR demand swing is 2.7:1) and the spare, on-call production capacity could be less than required to meet peak demand without gas storage or additional production capacity. Such shortfalls could possibly occur before 2009 but a more detailed study of short-term peak demand and field-by-field deliverability would need to be conducted to provide a more precise estimate.

Reserves Growth Case:

A scenario with potential reserves growth of 1.4 Tcf in the existing fields, including field extensions, was examined using an increase in real prices indexed to Henry Hub prices. Reserves growth of this magnitude is not an unreasonable assumption in and around the existing fields but will require significant new investment to support aggressive development programs through workovers, redrills, and new wells drilled to targets identified by 3-D seismic programs.

The addition of 1.4 Tcf through reserves growth is sufficient to supply the projected basic commercial and residential consumer's gas demand through 2025. A limited amount of gas remaining after supplying commercial and residential demand would be available to continue industrial activity at reduced levels. Reserves growth of this magnitude will require an estimated investment of up to $500 million.

Minimum Economic Field Size:

The minimum economic field size (MEFS) for offshore, transition zone, and onshore locations, each having different exploration, development and operating cost structures are examined for a range of prices from $1.00/Mcf to $6.00/Mcf. For a $4.50/Mcf price the offshore field MEFS was 108 Bcf OGIP, 49 Bcf OGIP for the transition zone, and 40 Bcf OGIP for the onshore fields. Finding and development costs are estimated to vary from about $0.75/Mcf for the smaller fields, Class 3 to 4 (24 to 96 Bcf), to about $0.30/Mcf for Class 7 and 8 (384 to 1,526 Bcf) sized fields.

Exploration Case:

Potential new fields in the Class sizes 6 (192 to 384 Bcf), 7 (384 to 768 Bcf), and 8 (768 to 1,536 Bcf) were analyzed as unrisked, grass-roots exploration projects using the Henry Hub pricing basis and onshore location costs. The finding and development cost varied by the amount of gas discovered and developed. New capital investments are about $152 million for a Class 6 field, $250 million for a Class 7, and $385 for a Class 8.

The total unrisked capital required to explore for and develop 50% of the estimated remaining potential undiscovered reserves in the Cook Inlet (out of the total 13 to 17 Tcf) would require investment of $5 to $6 billion at a $0.75/Mcf finding and development cost for onshore fields. If the new discoveries are offshore, the investment will likely be higher. Additionally, regulatory and permitting challenges to exploration and development offshore and offshore continue to increase and add significant risks and costs to future investments.

Spur Pipeline Case:

A spur pipeline from a North Slope gas pipeline to the Anchorage area and connection to the existing gas distribution system was examined to determine its potential as a cost effective gas supply option. While a number of issues need to be resolved, the estimated tariffs are $1.46/Mcf to $1.12/Mcf, with the higher tariff for a lower pipeline capacity of 330 MMcf/day (120 Bcf/year) throughput rate and the lower tariff for a higher rate of 670 MMcf/day (245 Bcf/year). This is a first-cut analysis and is based on preliminary design estimates made by ENSTAR from their experience in building pipelines in south-central Alaska. The tariff calculation for the North Slope gas pipeline is based on the Mid-American pipeline proposal to the state of Alaska for a North Slope pipeline to the Canadian border. The actual delivered price for gas to South-central Alaska would include the wellhead price for gas on the North Slope. The wellhead price would likely be set by prices in the Lower 48 less the tariff to Chicago city gate or a negotiated price contract with the owners of the gas, which includes the state of Alaska and its royalty gas.

The spur pipeline tariff analysis indicates North Slope gas may be delivered to south-central Alaska at a structural price advantage of approximately $1.00/Mcf below Lower 48 prices. However, there must be sufficient long-term demand to support the investment in a spur gas pipeline. The current industrial users have a capacity of 130 Bcf/year and the residential and commercial consumers demand is about 70 Bcf/year. Benefits of a spur pipeline include opportunities to continue and possibly expand operations at the existing LNG and fertilizer plants, or add new energy-intensive value-added industrial activities such as petrochemicals, ore processing, and other industries seeking lower cost energy than can be obtained in the Lower 48.

A more detailed conceptual study of a spur pipeline options, economics, and North American gas markets is required to confirm and refine the estimates made in this analysis.

The industrial operations must be able to be profitable at prices higher than the historically low Cook Inlet prices. The prices will be at North Slope wellhead price plus transportation costs. Agrium's operations are very price sensitive and they have indicated that they need gas at around $2.00/Mcf or less to be competitive in the Asia fertilizer markets. This price threshold seems unlikely unless large gas discoveries are made in the very near future, creating stranded gas pricing again for Cook Inlet gas, and driving the prices below the prevailing prices being paid by non-industrial users; i.e., the Cook Inlet Prevailing Value published by the Alaska Department of Revenue for first quarter 2004 is $2.49/Mcf.

A potential downside to a spur pipeline, from an exploration and production company point-of-view, is that a large supply of gas from the North Slope at a structural price below the Lower 48 prices may establish a price cap for new Cook Inlet reserves in the 10- to 15-year time frame. This could have a dampening effect on exploration and development for new gas reserves in the Cook Inlet. Hence, it is urgent that decisions such as the date and timing for a North Slope pipeline be made soon so that all options for south-central Alaska region can be determined in a timely manner so that high-cost reactive solutions are not required to meet critical needs.

Income and Tax Revenue from Cook Inlet Production

The income to the industry through profits and the state and the federal government from taxes and royalties are estimated to be: 53% to industry, 27% to the federal government, and 20% to the state of Alaska.

Coalbed Natural Gas

The potential coalbed natural gas resource in south-central Alaska is estimated to be about 7 Tcf of technically recoverable resources. However, the economic viability of those resources is highly uncertain because sufficient data on gas and water productivity does not exist and the political concerns are very high. Economic projections can not be made until additional information is available.

Recommendations

- The spur pipeline analysis is a first-cut analysis and a detailed conceptual study to better define the cost and other factors should be performed.
- The possible need in the near-term for gas storage to meet seasonal demand swings should be studied and the cost, benefits, and problems with gas storage and deliverability assessed.

- The economics of the existing and potential new industrial activities should be analyzed to determine the impact of global and Lower 48 gas markets on the optimum mix of supply options to continue economic growth in Alaska to provide state of Alaska decision-makers with essential information on cost and benefits for all Alaskans.
- All the analyses performed in this work are deterministic and unrisked. A probabilistic analysis that accounts for above-ground and below-ground risks may provide useful additional insight into the complex interactions of the options and economic benefits. The deterministic analysis provides the essential basic understanding of the market forces, gas flow, and the unrisked potential for additional gas resource. A more detailed and complex analysis is required to fully delineate the optimum mix of supply and demand options.

ACRONYMS AND ABREVIATIONS

ADN	Anchorage Daily News
ADNR	Alaska Department of Natural Resources
ADOR	Alaska Department of Revenue
AOGCC	Alaska Oil and Gas Conservation Commission
Bcf	Billions of cubic feet
BLM	Bureau of Land Management
CBM	coalbed methane
CIRI	Cook Inlet Region Incorporated
DOE	U.S. Department of Energy
DOG	Division of Oil and Gas, Alaska Department of Natural Resources
EIA	Energy Information Administration, U.S. Department of Energy
E&P	exploration and production
LNG	Liquefied natural gas
Ma	Million years age
MEFS	Minimum economic field size
Mcf	Thousands of cubic feet
ML&P	City of Anchorage Municipal Light and Power
MMcf	Million of cubic feet
MMS	Mineral Management Service
OCS	Outer Continental Shelf
OGJ	Oil and Gas Journal
RCS	Regulatory Commission of Alaska
R/P	Reserves to production ratio
SAIC	Science Application International Corporation
SEC	U.S. Securities and Exchange Commission
Tcf	Trillion cubic feet
USGS	United States Geological Survey

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SOUTH-CENTRAL ALASKA NATURAL GAS SUPPLY STUDY

1. INTRODUCTION

The south-central Alaska region, shown on Figure 1.1, depends exclusively on natural gas from the Cook Inlet basin for utilities and electric power generation. The region includes the major population centers of Anchorage, the Matanuska-Susitna Valley, and the Kenai Peninsula.

Natural gas demand in the south-central Alaska will exceed the remaining proven natural gas reserves[1] in Cook Inlet basin in less than 10 years according to recent Alaska Department of Natural Resources remaining reserves forecasts (ADNR, 2003, Dismukes et al., 2002) unless additional supplies of natural gas are developed within the region or become available from other regions of the state or outside sources. The purpose of this investigation is to evaluate the options for adding to the supply of natural gas to meet short, intermediate- and long-term demands of the

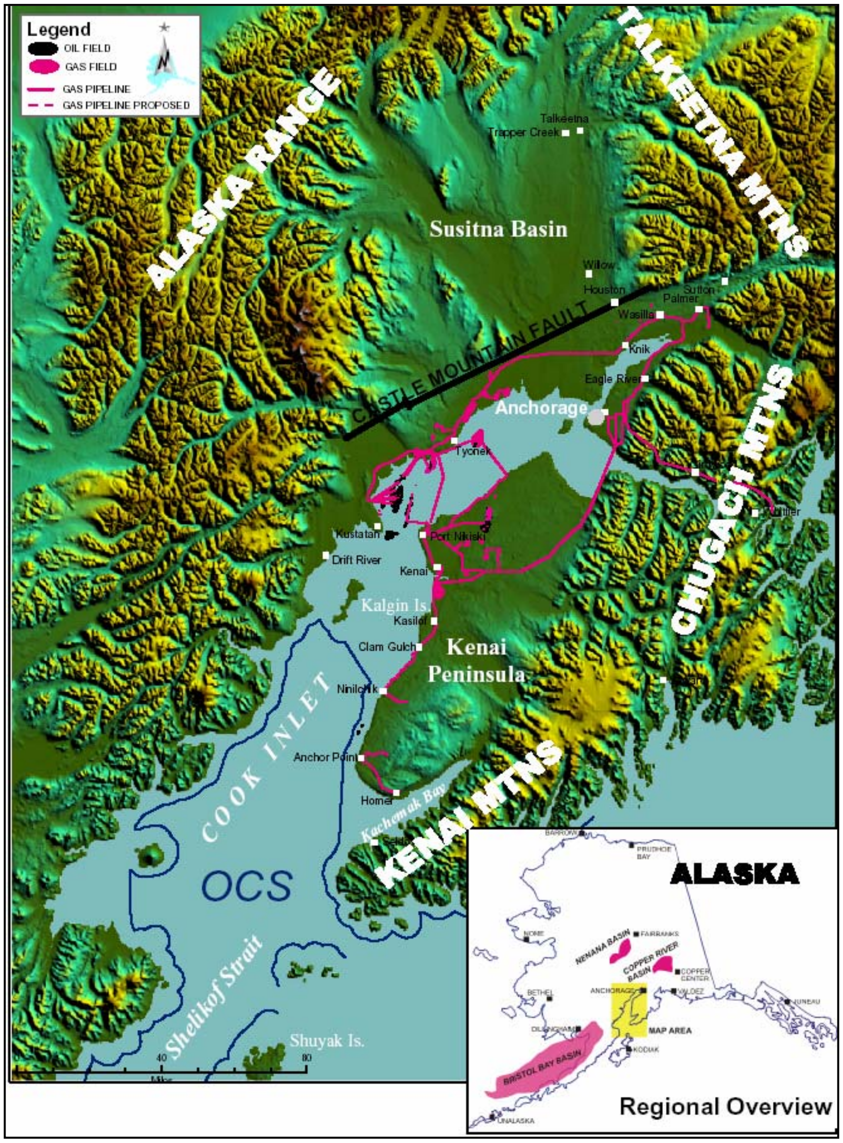

Figure 1.1. South-central Alaska region and Cook Inlet Basin location map with gas fields and gas pipelines.

[1] Reserves are those quantities of oil or gas that are anticipated to be commercially recovered from discovered (known) accumulations.

south-central region and support continued economic development. The primary options include:

- Development of additional Cook Inlet natural gas resources[2]
- Gas from the North Slope via a spur pipeline to the region or from other basins in the state.

The results of the investigation will provide policymakers and stakeholders with information and data to make difficult and timely decisions on priorities that could have huge economic impacts on residential and commercial consumers and industrial users. The analysis is expected to provide state and local governments, citizens, power generation utilities, gas distribution companies, and current and new operators with a overall picture of the current and future natural gas supply and demand for the region and assist government agencies and industry to begin the detailed analysis necessary to meet specific objectives for economic stability and growth in the state.

1.1 Cook Inlet Basin - History

The Cook Inlet basin was explored for oil beginning in the 1950s and 1960s and the Alaska Department of Natural Resources (ADNR), Division of Oil and Gas (DOG) reports a total of about 1.5 billion barrels of oil (BBO) reserves were discovered (ADNR, 2003). Oil production peaked in 1970 at 227,000 barrels per day (B/D). The production rate in 2002 was 30,915 B/D and a total of 1,293 BBO had been produced by the end of 2002 with about 0.167 BBO of remaining oil reserves (ADNR, 2003). About 8.0 trillion cubic feet (Tcf) of natural gas reserves were also discovered by 1970 during the exploration for oil. This gas resource was stranded because there was no pipeline to take it to large markets in the Lower 48. The abundance of low-cost gas led to the development of industrial plants to produce liquefied natural gas (LNG) and fertilizer (ammonia and urea) to monetize the large gas resource. The LNG and fertilizer have been exported, mostly to East Asia, and all the LNG has gone to Japan under long-term contracts. The two industrial facilities, located on the Kenai Peninsula at Nikiski, have provided good jobs and economic benefit to Alaska for over three decades.

[2] Resources are undiscovered oil and gas accumulations believed to exist outside known fields or accumulations based on geologic knowledge and theory. Undiscovered *conventionally recoverable* resources are resources that could be recoverable using current conventional technology (resources reduced by a percent recovery factor). Undiscovered *conventional economically recoverable* resources are those resources that could be economically viable at specified price levels, if discovered.

In 1971, the gas consumed was about 167 billion cubic feet (Bcf), which was made up of 26.8 Bcf for power generation and utility use, 83 Bcf by the LNG and fertilizer facilities, and 57 Bcf used in field operations or other field-related uses. That use rate was a reserve-to-production (R/P) ratio of 50, or a 50-year supply at a static use rate. By the early 1980's the annual use rate had increased to over 200 Bcf/yr and by the end of 2002 the reserves had decreased to 2.032 Tcf for an R/P ratio of 10. The use in 2001 was made up of 67 Bcf for power generation and utilities, 129 Bcf for industrial use for LNG and fertilizer, and 15 Bcf for field operations and other. The gas consumption by user from 1971 through 2001 is shown in Figure 1.2 (ADNR, 2003).[3] The average consumption by user for 1996 through 2001 was 14.4% for gas utilities, 16.4% for power generation, 36.3% for LNG, 24.7% for ammonia-urea, and 8.5% for field operations and other uses.

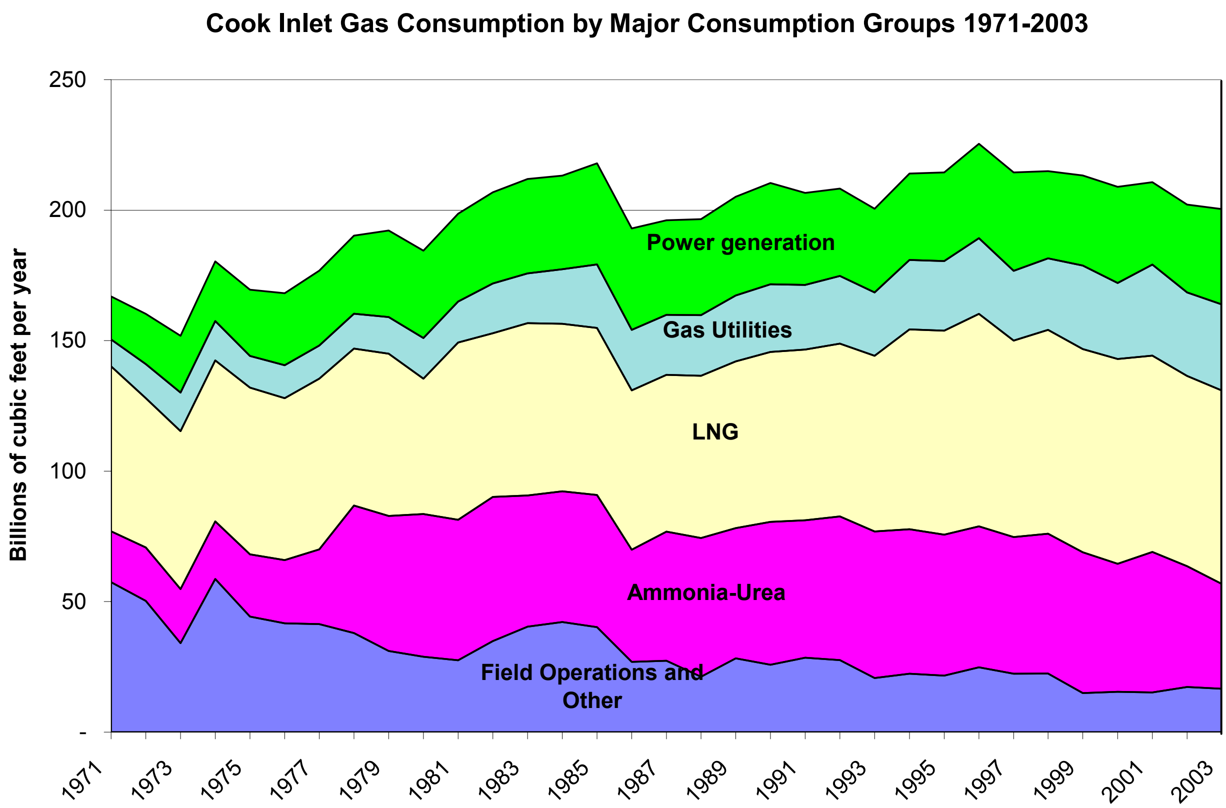

Figure 1.2. Historical gas consumption by major groups in south-central Alaska, 1971 to 2003 (Alaska Department of Natural Resources, 2003).[3]

[3] Data for 2002 and 2003 are not ADNR, 2003. Personal communication - Will Nebesky, ADNR Division of Oil and Gas; forthcoming in 2004 Oil and Gas Report.

The most recent production forecast prepared by the ADNR Division of Oil and Gas for the Cook Inlet basin is shown in Figure 1.3.[4] This production forecast and the current demand indicates a shortfall in the near future unless there are additional supplies or a reduction in demand. The demand from the power and utility consumers is expected to increase over time as the population and commercial sectors grow. Hence, the supply of natural gas for the region needs to be increased or the industrial usage will need to be reduced. The current LNG export license expires at the end of the first quarter of 2009 and viability of continued operation is uncertain. The fertilizer plant, owned by Agrium, has already reduced its usage from a capacity of 52 Bcf/yr to about 40 Bcf/yr in 2003 and has indicated that the plant may have to be shut down by the end of 2005 (Anchorage Daily News (ADN) 2004a) unless there is a continued supply of gas at prices low enough to allow it to continue to operate profitably.

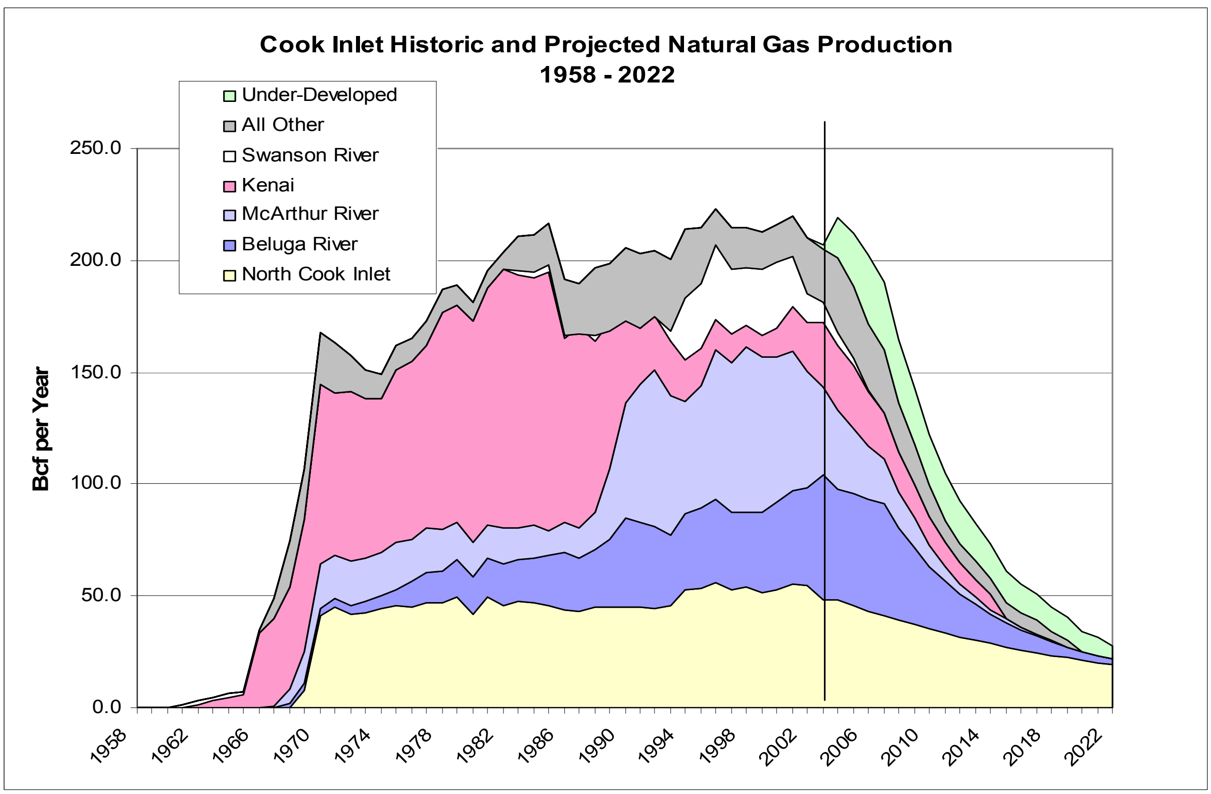

Figure 1.3. Cook Inlet historic and projected gas production from 1958 to 2022.[4]

Curtailing industrial use would have a negative impact on Alaska and especially on the Kenai Borough as a result of the loss of jobs and the related negative economic impact on the

[4] ADNR Division of Oil and Gas, Alaska Oil & Gas Report, December 2003 has been updated and the new forecast in included in Figure 1.3. Personal communication - Will Nebesky, ADNR Division of Oil and Gas; forthcoming in 2004 Oil and Gas Report.

region. The alternative of increasing natural gas supplies at prices that allow continued industrial use and growth in high value-added industrial activity is the most desirable solution. Hence, a technical and economic evaluation of the alternatives to meet future natural gas demand for south-central Alaska is the primary objective of this study.

1.2 Supply Options

The basic alternatives analyzed for increasing natural gas supply for the south-central Alaska region include:

- Finding and development of additional Cook Inlet natural gas resources, and
- Construction of a spur gas pipeline to connect the south-central region with a gas pipeline from the North Slope through Alaska and Canada to the Lower 48, or both.

In addition to increasing natural gas supply or curtailing industrial use, there are other options that may be an important part of the overall solution that are not analyzed in this study. They include:

- Conservation by residential and commercial consumers
- More efficient electric power generation
- Power generation using coal, wind, or hydropower
- Gas-storage in existing depleted or near-depleted oil or gas fields
- Importing LNG from foreign sources through existing LNG export facilities at Nikiski.

Gas storage can contribute to management of short-term shortfalls during high-demand periods but cannot provide a long-term solution to the declining reserves. It is expected to become a critical part of the solution because the spare production capacity may no longer be adequate to meet the high peak demand that frequently occurs in winter in Alaska. Importing LNG into Alaska would provide an unlimited source of gas from foreign sources. Imported LNG price would be determined by world LNG trade and investment would be required to convert facilities from export to import. This is not a solution that will be viewed favorably in Alaska.

1.3 Scope and Approach

Section 2 contains a geological assessment of the Cook Inlet basin. It includes a description of the geological framework of the basin, discusses the aspects of the petroleum geology of the area, and examines the magnitude of the present and potential new gas reserves. The discussion of potential new reserves includes:

- Increasing reserves through additional development in and around the known conventional non-associated gas fields
- The potential for discovery of new conventional gas fields in the Cook Inlet basin
- An overview of coalbed natural gas or coalbed methane (CBM) potential
- An overview of adjacent regions in southern Alaska; i.e., the Copper River basin to the east of the Cook Inlet Basin and the Bristol Bay basin to the west (see insert in Figure 1.1)
- Constraints on reserves additions and new discoveries such as:
  - Land areas off limits to exploration
  - Inadequate use and cost of 3-D seismic acquisition
  - Cost-effective 3-D seismic interpretation technology to locate stratigraphic traps
  - No Alaska-based drill ships for offshore exploration
  - Expense of long-reach directional drilling.

The emphasis throughout the report is on conventional non-associated gas fields.

Section 3 contains a review of remaining reserves and estimated ultimate recovery for the Beaver Creek Unit, Beluga River Unit, Kenai River Unit, McArthur River Unit, North Cook Inlet Unit, Swanson River Undefined Gas Zone, and the two new discoveries at Ninilchik and Happy Valley on the Kenai Peninsula. The ADNR (2003) forecast for the small fields, labeled "All Others," is used in the analysis. The review relies on publicly available production and pressure survey data from the Alaska Oil and Gas Conservation Commission (AOGCC), the ADNR Division of Oil and Gas, and published information from news announcements by operators. The status of coalbed natural gas development is described and the high level of uncertainty surrounding this potential resource is discussed.

Section 4 describes economic analyses that include:

- Production of current reserves from existing producing fields in the Cook Inlet basin
- Development of additional reserves in known fields in the Cook Inlet basin

- Successful exploration for new fields in the Cook Inlet basin
- Minimum economic field size estimates for offshore, tidal zone, and onshore locations, all of which have different cost structure
- Comparison of Cook Inlet supply, demand, and market dynamics
- Analysis of the economics of a spur pipeline to bring North Slope gas to the south-central Alaska region
- The investment required to develop additional reserves in known fields and finding and developing new reserves
- Gas cost versus supply curves for current and future time periods
- Estimates of income to the state of Alaska, the federal government, and industry for the various cases.

The potential impacts and interactions the various scenarios will have on future supply and economics are discussed. The economic models, costs estimates, sensitivities to the economic variables, and state of Alaska and federal benefits from the Cook Inlet gas production are described.

Limitations

An investigation of this type has several constraints placed on it by time, resources, and availability of data. Limitations specific to this project include:

- The geological and engineering assessment is limited to an evaluation of the publicly available data primarily from ADNR, AOGCC, and from industry public announcements and interviews with industry representatives.
- A detailed and exacting well-by-well analysis that an operator would perform to justify the funding necessary to drill wells, perform workovers, and explore for new reserves is beyond the scope of this study.
- The economic evaluations are deterministic and do not include an evaluation of risk. A Monte Carlo analysis for variations in reservoir parameters, production rates, costs, and prices on the economics would be required to evaluate risk – above-ground as well as below-ground risks. Detailed data needed for such an analysis are not readily available in the public domain and would require significant additional work to collect.

- The economics of the existing or potential new industrial facilities and their sensitivity to gas feed stock prices are not analyzed.
- An economic analysis of the coalbed natural gas potential for the Cook Inlet region was determined to be impractical at this time beyond a general estimate of the resource size and potential technically recoverable resources.

1.4 Acknowledgements

The analytical portion of this study was conducted over a seven-month period beginning in August 2003. Funding was provided by the U.S. Department of Energy's Arctic Energy Office. Assistance and support was received from many agencies and industry. Specifically, the authors thank members of the Steering Committee (see Section 1.5) for input and guidance; and the staff of the AOGCC, the ADNR Division of Oil and Gas, and the Alaska Department of Revenue who provided assistance in obtaining the publicly available data in a timely and efficient manner. The authors profited by discussions with the U.S. Department of Interior's Minerals Management Service (MMS) and by assistance on understanding markets, demand issues, and the distribution system from management and staff at ENSTAR, ML&P and Chugach Electric. The Cook Inlet producers and Agrium provided public data and information relative to their operations and plans for the future.

1.5 Steering Committee

A Steering Committee was formed to review the plans and progress as the study was being performed. The primary function of the committee was to make sure the most critical issues were addressed by the study and to assist in obtaining critical data. The Steering Committee met on September 22, 2003, November 13, 2003, January 22, 2004, March 3, 2004, and March 22, 2004. The committee members are listed below.

Joe Griffith/Lee Thibert:	Chugach Electric
Harold Heinze:	Alaska Natural Gas Development Authority
Tony Izzo:	ENSTAR Natural Gas
Tom Irwin/William Nebesky:	Department of Natural Resources, Division of Oil and Gas
James Posey:	Anchorage ML&P
Brent Sheets:	U.S. Department of Energy
Cam Toohey:	U.S. Department of Interior

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2. GEOLOGICAL ASPECTS OF COOK INLET HYDROCARBON PROVINCE

This chapter addresses the geological framework of the Cook Inlet Basin, discusses the aspects of the petroleum geology of the area, and examines the magnitude of the present reserves and potential resources in the area.

2.1 Introduction

Production from the Cook Inlet Basin is the sole source of natural gas used for commercial and residential purposes in south-central Alaska. The Cook Inlet Basin is part of a larger forearc basin that lies between the Aleutian Trench and the active volcanic arc on the Alaska Peninsula. The aspects of the basin's geology and hydrocarbon system are essential to the understanding of the current and future resource.

The Cook Inlet Basin is a northeast-trending topographic depression approximately 250 miles (400 km) long and 60 miles (97 km) wide. The basin covers some 15,000 square miles (38,850 sq. km), with almost half lying offshore under the waters of Cook Inlet (Hite and Nakayama, 1980). The basin is largely bounded by the Bruin Bay Fault on the west and the Border Ranges Fault Zone on the east (Figure 2.1).

Many of the critical data regarding reserves and field characteristics are available only from state agencies such as the AOGCC and ADNR Division of Oil and Gas. To a lesser extent the Division of Geological and Geophysical Surveys (DGGS) and industry have provided data in the public domain that are important to a successful evaluation and understanding of the basin.

While the current production and exploration efforts are largely confined to the upper Cook Inlet subbasin with minor emphasis on the lower inlet and the Susitna Basin (Figure 1.1), areas such as the Copper River Basin, Bristol Bay, and even the Nenana Basin, may have some potential for providing gas to the area in the future (Figure 1.1). The timing for development of these potential resources is probably too far into the future to significantly influence the findings of this study.

Coalbed natural gas may have future potential, due to the vast quantities of coal in the basin. Exploration drilling and testing has occurred in the Houston area with leasing in the Matanuska and Susitna valleys. The Beluga coalfield, on the west side of the upper inlet also has potential for coalbed natural gas, but there is no activity in that area at present.

2.2 Geological Framework

The Cook Inlet Basin lies between the Alaska Range on the west and the Kenai Range (Figure 1.1) on the east. The Cook Inlet Basin is an elongate northeast-southwest trending forearc basin with its margins largely defined by major faults. On the west, the Bruin Bay Fault separates the volcanic arc from the basin and, on the east, the Border Ranges Fault Zone juxtaposes the accretionary prism of the Chugiak Terrane and the forearc basin (Figure 2.1) (Swenson, 1997). The Castle Mountain Fault provides the northern limit to the basin and forms the boundary between the Cook Inlet Basin and the Susitna Basin and Talkeetna Mountains (Figure 1.1). The Augustine-Seldovia Arch separates the basin into two depocenters: a northern depocenter in upper Cook Inlet with as much as 25,000 feet of Tertiary section and a southern depocenter in lower Cook Inlet and Shelikof Strait (Figure 1.1) that contains a

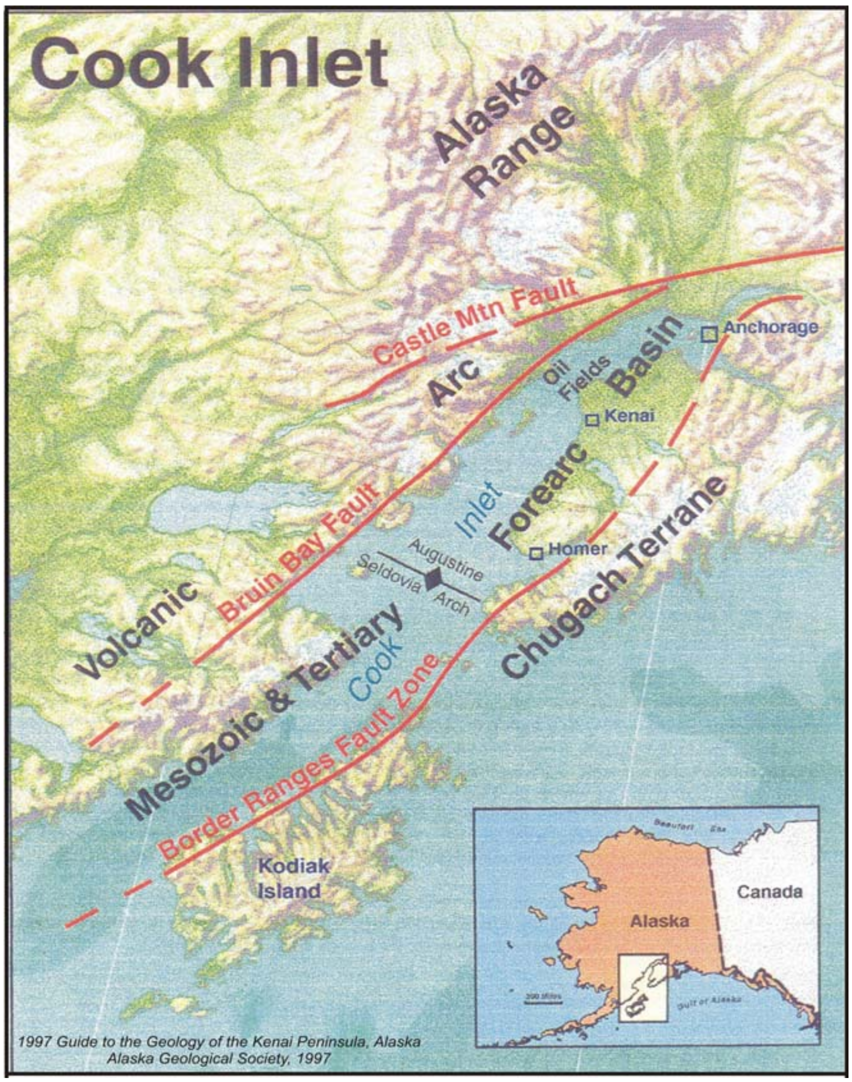

Figure 2.1. Present day Cook Inlet Basin morphology and regional tectonic boundaries.

thin Tertiary section that unconformably overlies up to 36,000 feet of Mesozoic strata (MMS, 2003a).

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The principal focus of this study is the upper Cook Inlet subbasin, from the Augustine-Seldovia Arch in the south to the Castle Mountain Fault in the north. Figure 2.1 is the location map for the Cook Inlet area. One hundred percent of the current conventional gas exploration and production is focused in this area of approximately 9,000 square miles (23,300 sq. km). Additional areas of note are the Susitna Basin, located north of the Castle Mountain Fault, and the lower Cook Inlet subbasin lying south of the Augustine-Seldovia Arch (Figure 2.1).

2.2.1 Tectonics and Structure

In the Cook Inlet region, the onset of active tectonism began in the Late Triassic and is recorded by the shift from the tectonically quiescent regime responsible for the shelf carbonates of the Kamishak Formation to the volcaniclastic Talkeetna Formation (Figure 2.2). Subsequent Mesozoic and Cenozoic sediments reflect the tectonically active character of the basin and indicate repeated episodes of uplift, deformation, and erosion. Figure 2.2 (Curry, et. al., 1993 and Figure 2 of Swenson, 1997) briefly summarizes the most significant of these events. Sedimentation throughout the remainder of the Mesozoic and the Cenozoic took place in a foreland/forearc basin setting (Swenson, 1997).

The dominantly marine stratigraphy of the Mesozoic was deformed and eroded at the close of the Cretaceous and forms the present-day “economic basement” for Cook Inlet oil and gas exploration. Throughout the Tertiary, the Cook Inlet area was the site of non-marine deposition. Sediment was shed from the tectonically active eastern and western margins of the basin (Hite, 1976).

The repeated uplift and erosion, related to movements along the basin-margin faults and driven by subduction of the Kula Plate, resulted in minor structural growth throughout the Tertiary. This tectonic and depositional regime persisted until the end of the Pliocene when the latest phase of deformation resulted in north-northeast trending, generally tight asymmetric anticlines which are the traps for most of the currently developed oil and gas accumulations in the Cook Inlet Basin.

2.2.2 Stratigraphy

The basin is comprised of an older deep marine to non-marine Mesozoic section, which is largely sourced from the volcanic/plutonic complex along the west/northwest side of the modern-day basin, and a younger marine to marginal marine Late Cretaceous and non-marine Tertiary section with dual sources. The Tertiary rocks were derived from both the volcanic arc to the west/northwest and the accretionary terrane to the east/southeast. Figure 2.2 provides a generalized stratigraphic column and correlation chart for Cook Inlet.

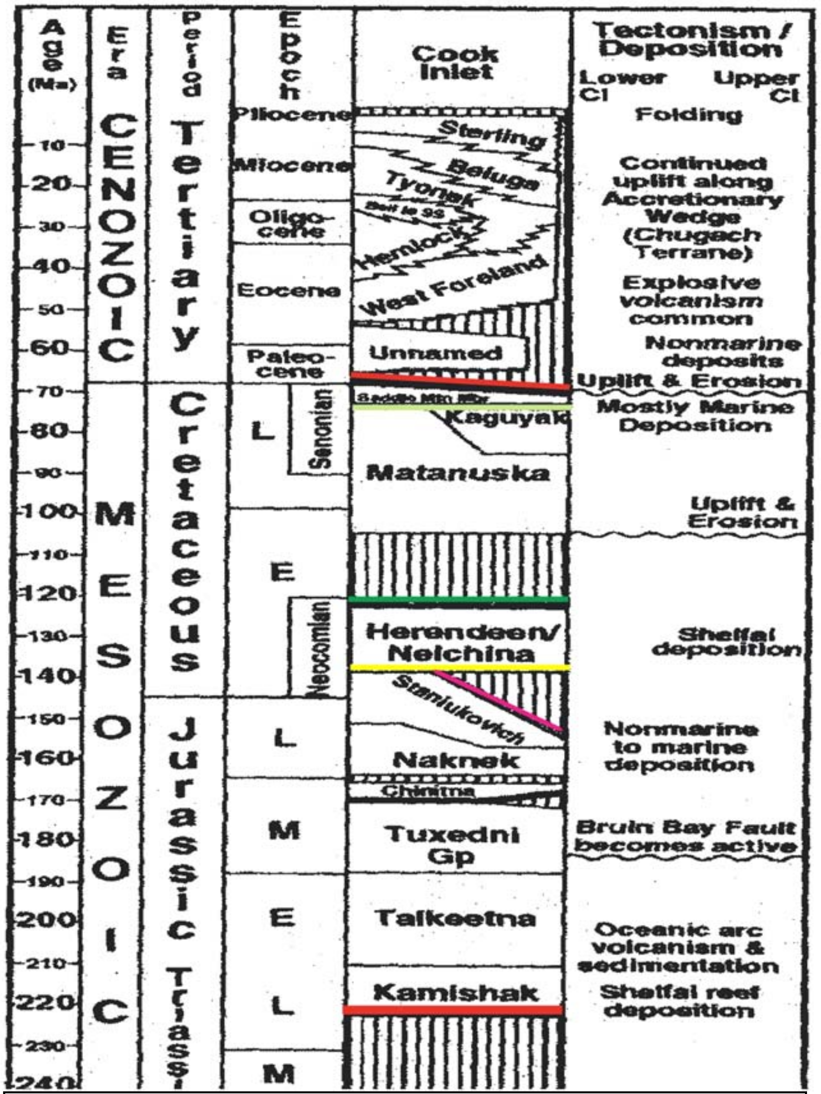


Figure 2.2. Cook Inlet Basin, Alaska. Tectonostratigraphic Correlation Chart, From Curry, et al. 1993, "1997 Guide to the Geology of the Kenai Peninsula Alaska," Alaska Geological Society, 1997.)

2.2.2.1 Mesozoic Stratigraphy

The Mesozoic succession has been penetrated by the OCS wells in lower Cook Inlet and the deeper wells in upper Cook Inlet. It was one of the primary objectives during the initial exploration efforts in the 1950s and early 1960s and the target of the OCS exploration programs in the 1980s. The Mesozoic section ranges from Late Triassic shelfal reef carbonates of the Kamishak Formation and equivalent rocks at Puale Bay to the deep water facies of the Late Cretaceous Kaguyak and Matanuska formations (Figure 2.2). This succession contains important oil-prone source rocks and poor-quality reservoirs. The Mesozoic section predominates in the lower

Cook Inlet subbasin where there is only a thin early (?) Paleogene section. In upper Cook Inlet, the Tertiary section locally exceeds 25,000 feet in thickness.

2.2.2.2 Tertiary Stratigraphy

The Tertiary section is thickest in the north-central portion of the basin and thins rapidly toward the fault-bounded margins in the east and west as well as toward the Augustine-Seldovia Arch in the south. The nomenclature and stratigraphy of the Tertiary section are depicted in Figure 2.3 (Swenson, 1997, Figure 5).

In 1892, Dall and Harris identified the Tertiary section in upper Cook Inlet and applied the term "Kenai Group" to this thick assemblage of non-marine strata. The Kenai Group was subsequently subdivided into five formations (Parkinson, 1962 and Calderwood, and Fackler, 1972), all of non-marine origin. Figure 2.3 shows these units, which in ascending order are the West Foreland, Hemlock Conglomerate, Tyonek, Beluga, and Sterling Formations. These formations do not have a simple layer-cake stratigraphy, rather many of the units are time transgressive, laterally

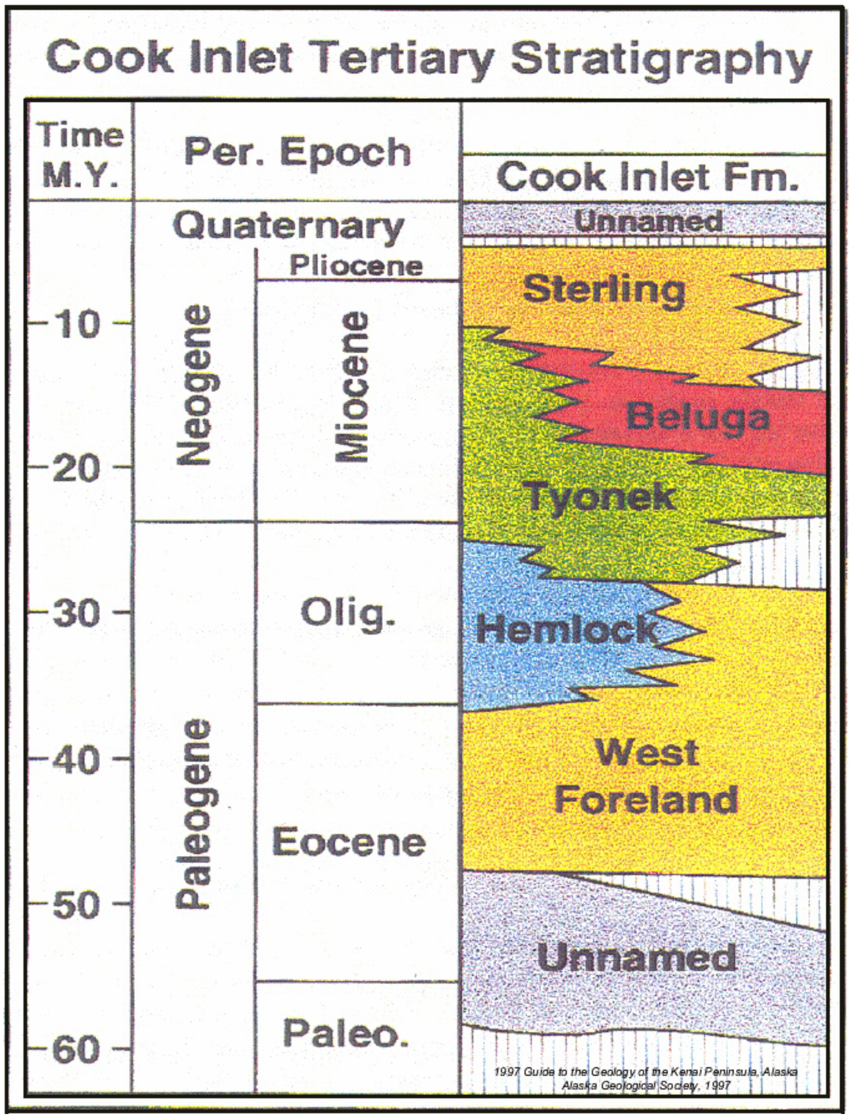


Figure 2.3. Generalized Cook Inlet Tertiary Stratigraphy.

correlative facies, representing a variety of non-marine, tectonically influenced fluvial, alluvial fan, lacustrine, and paludal environments.

Unnamed unit--The unnamed unit of Figure 2.3 is basically a space-holder intended to represent the oldest Tertiary sediments, largely pre-West Foreland Formation, found within the basin. Four formations of Paleocene/Eocene age outcrop in the Matanuska Valley. These rocks are also non-marine facies and have been assigned to the Tsdaka, Wishbone, Chickaloon, and Arkose Ridge Formations. The lateral extent of these units is areally restricted and the distribution of Paleocene strata in the subsurface is limited (Magoon, and Claypool, 1979).

West Foreland Formation--The Eocene/Oligocene West Foreland Formation is a tuffaceous, siltstone-claystone containing minor conglomeratic sandstones and conglomerates. It is the basal Tertiary unit throughout most of the basin. The formation has a maximum known thickness of 890 feet on the west side of the basin but is believed to range from 0 to 1,600 feet (Hite, 1976). The West Foreland Formation and the Hemlock Conglomerate are difficult to distinguish on logs. The volcanic-lithic and heavy mineral content are the primary distinguishing characteristics. The unit has generally poor reservoir quality but locally is an oil reservoir.

Hemlock Conglomerate--The Oligocene Hemlock Conglomerate overlies the West Foreland formation and is in part laterally equivalent to the West Foreland and Tyonek formations. The formation is 570 feet thick in the Richfield Oil Corporation Swanson River Unit No. 1 (34-10) and thickens to approximately 750 feet in the Middle Ground Shoal area (Hite, 1976). The total thickness range is of the order of 0 to 900 feet. The dominant lithologies are fine- to coarse-grained sandstones, conglomeratic sandstones, and conglomerates. The finer facies consist of siltstones with local coalbeds. Because of the more compositionally mature nature of the sandstones and conglomerates the Hemlock has good reservoir quality and is the most important oil reservoir in the basin.

Tyonek Formation--The Oligocene and Miocene Tyonek Formation is locally unconformable on older units, but throughout most of the basin the contact with the underlying Hemlock is gradational or intertonguing. The thickness at the type section is 7,650 feet and ranges from 0 to 9,000 feet. Stratigraphically the base of the Tyonek (top of the Hemlock) is placed at the top of the last occurrence of thick coarse sandstone and conglomerate with a general lack of coal. Lithologically the Tyonek is similar to the overlying Beluga Formation and consists of massively bedded sandstones and thick coal beds with siltstone and mudstone interbeds. The Tyonek coals are higher quality than those in the Beluga (sub-bituminous to bituminous) and more regionally continuous. The Tyonek sandstones are reservoirs for both oil and gas.

Beluga Formation--The Miocene Beluga Formation is gradational upon and locally equivalent with the Tyonek Formation. At the type locality, it is 4,150 feet thick and ranges from 0 to 6,000 feet, being thickest in the vicinity of the Beluga River and East Forelands, with zero-edges along the east and west margins of the basin resulting from pre-Sterling uplift and erosion (Hartman, Pessel, and McGee, 1972). The Beluga Formation is composed predominantly of siltstone with common channelized sandstones, thin coals and tuffs. In contrast to the Tyonek, the Beluga coals are generally thin (< 5'), lignitic to sub-lignitic, and regionally discontinuous (Swenson, 1997). The base of the Beluga is difficult to identify on logs and is generally placed at the top of the last thick coal (> 10') in the Tyonek. The channel sands of the upper Beluga are significant gas reservoirs in the basin.

Sterling Formation--The Miocene/Pliocene Sterling Formation is at least locally unconformable upon the Beluga and older formations. In the central portions of the basin, it may be conformable and gradational with the Beluga. The type section is 4,490 feet thick and basinwide the thickness ranges from zero along the basin margins to nearly 11,000 feet in the vicinity of East Forelands. The formation consists of a thick sequence of massive sandstones and conglomeratic sandstones with interbedded mudstones/siltstones and thin coals. The Beluga-Sterling contact is picked at the stratigraphically last occurrence of abundant coals and the first development of thick sandstones. The sandstones are commonly stacked fluvial channels and where adequate seals are developed to provide excellent gas reservoirs.

2.3 Petroleum Geology

The Cook Inlet Basin and adjacent areas have been considered prospective for oil and gas since the early part of the 20th century. Oil seeps along the Cook Inlet side of the Alaska Peninsula have been known since the arrival of the earliest explorers and settlers. Exploration started on the Iniskin Peninsula in 1902, where seven wells were drilled (Magoon, 1994). The earliest exploration targets were Mesozoic reservoirs, because the oil seeps are commonly from

Mesozoic rocks. An additional nine exploratory wells were drilled between 1921 and 1957 prior to the discovery of the Swanson River oil field.

The first active exploration programs in upper Cook Inlet commenced in 1955 and led to the 1957 discovery of the Swanson River oil field by Richfield Oil Corporation. The Swanson River discovery well was drilled as a Mesozoic play and the lower Tertiary oil-bearing reservoirs were encountered while drilling to that deeper objective. The first major gas field, the Kenai gas field, was discovered by Union Oil Co. in 1959 and was originally drilled as an oil prospect. This has been the case for virtually all gas discoveries in the basin. The exploration objective was oil not gas. Only in the last few years has there been a concerted effort to explore for gas on its own merit. Since the beginnings of serious exploration, in 1955, there have been 11 oil discoveries and 28 gas discoveries of note.

Table 2.1 indicates the intensity of exploration activity and the relative success of the exploration program in Cook Inlet area over the 48 years from 1955 to 2003. Wells drilled prior to 1955 on the Alaska Peninsula are included with the 1955 to 1960 interval. Commonwealth North (2001) constructed a similar table with somewhat different numbers of wells and success rates per 5-year interval, but approximately the same number of wells and fields through the year 2000. The AOGCC reports a number of CBM wells that are also excluded from these figures. Care must be taken when referencing specific values for the total volume of gas found (Table 2.1). These volumes tend to vary from source to source but are relatively consistent and range from about 8,150 to 8,700 Bcf for the estimated ultimately recoverable gas. These numbers will be addressed in more detail later.

Table 2.1. Oil and gas exploration wells and gas field discoveries in Cook Inlet, 1955 to 2003.

Time period	Number of exploratory wells drilled	Number of gas fields discovered	Success ratio (%)	Estimated ultimate recovery (Bcf)
1955-60	17	5	29.4	2,603.50
1961-65	42	9	21.4	3,575.23
1966-70	85	6	7.1	1,814.86
1971-75	29	1	3.4	10.86
1976-80	14	1	7.1	8.19
1981-85	13	0	0.0	0.00
1986-90	5	0	0.0	0.00
1991-95	11	2	18.2	139.78
1996-00	10	3	30.0	151.72
2001-03	14	1	7.1	100.00(?)
TOTAL	**240**	**28**	**11.7**	**8,404.14**

The 240 wells reported to date include wells drilled west of the basin on the Alaska Peninsula and in the southern portion of the Susitna Basin. Only 220 of the reported exploration wells are from the upper Cook Inlet subbasin as defined above. Figure 2.4 is a map depicting the locations of the exploration wells drilled to the present time and the approximate limit of Tertiary strata in the upper Cook Inlet Basin (these limits are also shown on Figures 2.6, 2.7 and 2.9). Neither Table 2.1 nor Figure 2.4 includes the wells drilled on federal OCS lands in the lower Cook Inlet subbasin. A total of 13 exploration wells were drilled there between 1978 and 1984 with no economic discoveries (MMS, 2001).

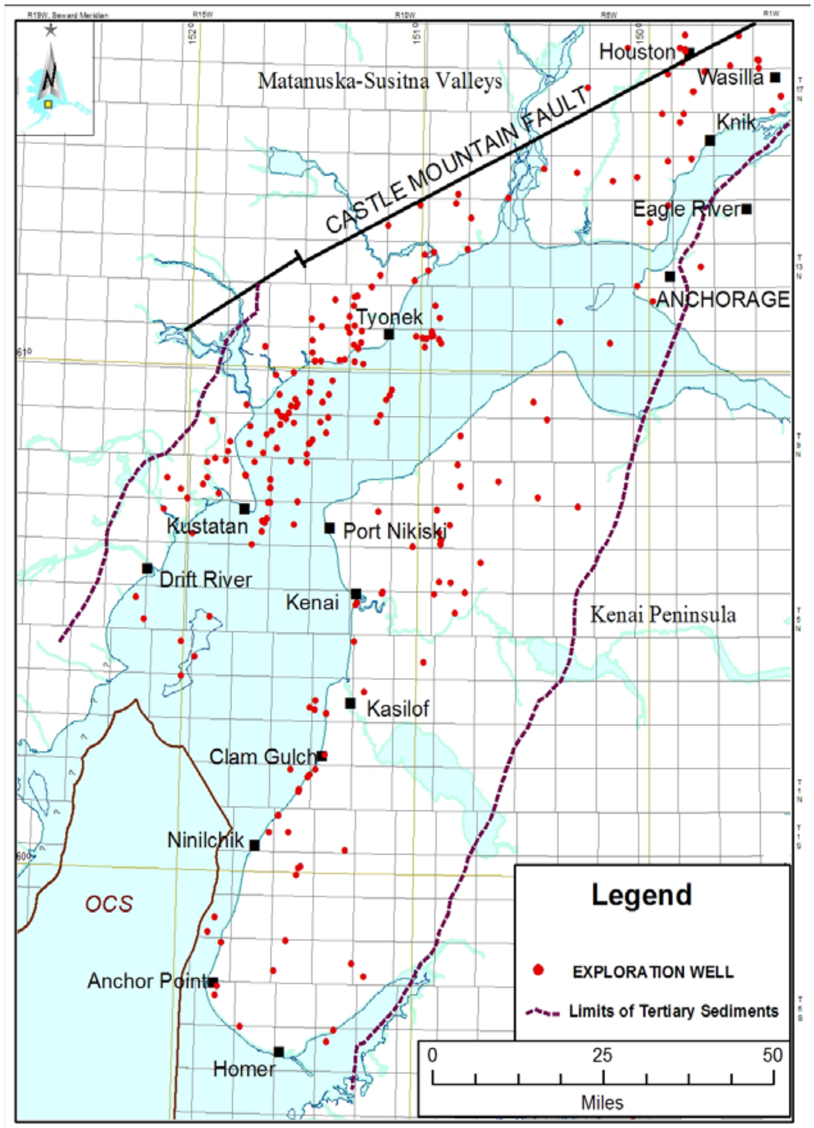


Figure 2.4. Cook Inlet exploration wells, 1955 to 2003.

In terms of gas exploration, the significance of Table 2.1 lies in the fact that 72.1% of the exploration wells were drilled and more than 95% of the gas was "found" in the first 20 years of exploration in the basin and was a by-product of oil exploration. The aggressive exploration phase ended in the late 1960s, coincident with the discovery of Prudhoe Bay on the North Slope. Since then, only a modest exploration effort has been put forth by the industry and most of this was directed to the quest for oil. The gas-first exploration began in the late 1990s. At least two discoveries have been made since 2000, and they reflect the new focus on gas. Of the 10 largest Cook Inlet gas fields, only the Cannery Loop field (smallest of the 10) was found while specifically exploring for gas (Irwin, 2003).

Although the fields were discovered in the timeframe indicated by Table 2.1 and Table 2.2, the magnitude of the reserves associated with the fields was not recognized at the time of discovery. There has been significant increase in the recognized volume of gas reserves (reserve growth) through more complete evaluation and development of the existing fields. As stated in U.S Department of Energy (DOE)/FE Opinion and Order No. 1473 (DOE, 1999), “Without any significant exploration activities in Cook Inlet since 1980, reserves have nonetheless continued to increase through reserve growth in existing fields.” This is demonstrated by comparing the proved reserves of 3,544 Bcf at the beginning of 1980 with 6,730 Bcf, which is the total proved reserves (3,066 Bcf) on January 1, 1998, plus cumulative production through 1997 (3,664 Bcf). This comparison shows an increase of over 3 Tcf of proved reserves through reserve growth in 17 years and confirms that reserve growth in Cook Inlet mirrors the historical trend in reserve growth seen in other basins” (DOE, 1999). Quite possibly, additional reserve growth will be recognized in the existing and newly discovered accumulations. Past and future reserve growth has been and will be accomplished by the use of secondary and tertiary recovery techniques, seismic acquisition and reprocessing, and drilling infill and extension wells.

The objectives of this study are to evaluate the supply/demand relationships of natural gas in south-central Alaska and any additional discussion of oil fields, production, and reserves will be the minimum necessary to provide the proper perspective of basin’s hydrocarbon potential and distribution. The bulk of this portion of the section is intended as an overview of the hydrocarbon systems operating in Cook Inlet and adjacent areas. The focus is on source, reservoir, and trap. Timing issues are beyond the scope of this treatment and not as critical when considering biogenic gas as they are when dealing with thermogenic hydrocarbons.

2.3.1 Hydrocarbon Sources

Hydrocarbons in the Cook Inlet Basin have been derived from two distinct and mutually exclusive sources. Figure 2.5 (MMS, 2003a) shows the oil and gas reservoir and source rock intervals in Cook Inlet. Oil production is from the West Foreland through the Middle Ground Shoal Member of the Tyonek Formation and gas is produced from the Tyonek through lower Sterling formations. The oil and associated gas in the lower portions of the Kenai Group are of thermogenic origin and the non-associated gas of the upper parts of the Kenai Group is of biogenic origin. Non-associated biogenic gas is by far the most important component of the natural gas reserve base in Cook Inlet. The biogenic non-associated gas accounts for 94% of the gas reserves in Cook Inlet (Claypool, Threlkeld, and Magoon, 1980) and approximately 92% of the production to date.

2.3.1.1 Oil and Associated Gas

The oil and associated gas in the early Tertiary sandstones and conglomerates are of thermogenic origin and constitute the Tuxedni-Hemlock petroleum system (Magoon, 1994). The source for the upper Cook Inlet oil and associated gas is the Chuitna Formation of the Middle Jurassic Tuxedni Group (Figure 2.5). In the lower Cook Inlet the oil has been thermogenically derived from the Middle Jurassic Tuxedni Group and the Upper Triassic "shales of Puale Bay" (Magoon, Molenaar, Bruns, Fisher, and Valin, 1996 and Minerals Management Service, 2003a). The timing of the initiation of oil generation is questionable and has been variously stated as commencing as early as the Eocene and continuing into the Pliocene (Magoon, Molenaar, Bruns, Fisher, and Valin, 1996) or within the last five million years and continuing to the present (Magoon, 1994).

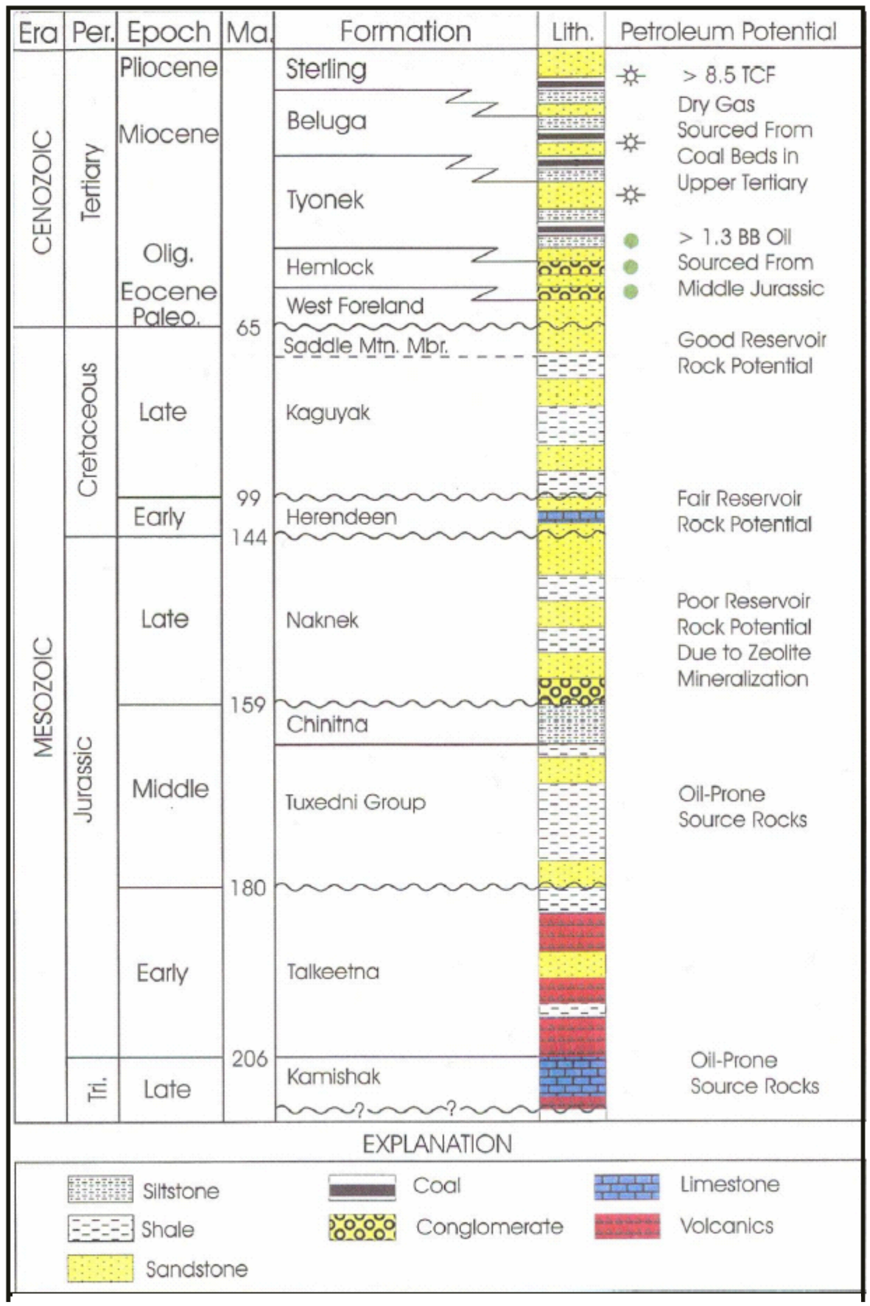


Figure 2.5. Cook Inlet Basin, Alaska - Stratigraphic column – oil and gas reservoir intervals.

2.3.1.2 Non-Associated Gas

The shallow, non-associated gas reservoired in the Sterling, Beluga, and upper Tyonek formations is of biogenic origin and is attributed to the existence of the Beluga-Sterling petroleum system (Magoon, 1994). The shallow portion of the stratigraphic section is thermally immature. The source for this gas appears to be the non-marine organic-rich facies of the Beluga Formation and to a lesser extent the Sterling and Tyonek formations (Figure 2.5). These units have considerable coal and type-III kerogen. Most of the coal and type-III kerogen are below the primary gas-producing interval of the lower Sterling and thus in good position to charge the Sterling and Beluga reservoirs. Because this system requires no overburden to mature the source rocks, the duration time is short – from late Miocene to Holocene, or about 12 million years (Magoon and Egbert, 1986).

2.3.2 Reservoirs

Producing reservoirs in the Cook Inlet Basin are non-marine sandstones and conglomerates of the Tertiary Kenai Group. While the Mesozoic section supplies large volumes of source rock and has generated significant quantities of oil and associated gas, the associated Jurassic reservoirs are of poor quality, largely due to pervasive zeolite cementation (Franks, and Hite, 1980). Limited intervals of good porosity and permeability have been noted in Cretaceous clastic intervals but no hydrocarbons have been commercially produced from these zones. Lower Cook Inlet wells, drilled in federal waters during the early 1980s, did encounter small quantities of oil in Upper Cretaceous sandstones but not in economic volumes (MMS, 2003a).

The lower Tertiary sandstones and conglomerates of the West Foreland, Hemlock, and Tyonek are the reservoirs of the upper Cook Inlet oil fields (Figure 2.5). They also are the reservoirs for the majority of the thermogenic gas. Some percentage of the thermogenic gas has migrated into shallower, upper Tertiary reservoirs where it is produced with the biogenic gas of the Tyonek, Beluga, and Sterling gas fields. These lower Tertiary reservoirs are fluvial, alluvial fan, and related non-marine deposits. Most of the individual depositional packages have relatively limited lateral extent, but are frequently stacked or overlap to the extent that these reservoirs have semi-regional to regional distribution. The stacking is especially effective along the basin margins where repeated movement along the basin-margin faults provided long-term supply of coarse clastic detritus to the basin.

By far the greatest volumes of natural gas are found in reservoirs of the Sterling, Beluga, and upper Tyonek formations (Figure 2.5). This is biogenic gas, generated essentially insitu, and some amount of migrated thermogenic gas. The reservoir facies of these formations are much the same as those in the lower Kenai oil-producing section, but the proportions are different with the axial fluvial facies being the predominate reservoir. There is a general tendency throughout the Kenai Group for the ratio of alluvial fan/fluvial channel to decrease through time. Thus, the reservoirs tend to become more restricted areally over time and stratigraphic plays/traps become potentially more significant. Stratigraphic traps may present an important upside potential for gas in the Cook Inlet. In order of decreasing importance, the gas-bearing units are the Sterling, Beluga, and Tyonek.

Reservoir characteristics/parameters are generally good to excellent but vary over considerable ranges. Data from the AOGCC 2002 Annual Report provide some indication of the magnitude of this variability (AOGCC, 2003b). Net pay, porosity, permeability and water saturation values are presented in that report for a number of the Cook Inlet gas fields.

Based on data from 22 fields, net pay, presented by formation, ranges from 15 to 461 feet and on a field basis from 15 to 764 feet (Table 2.2). Porosity data from 18 fields ranges from 10 to 33% and averages 23% (Alaska Oil and Gas Conservation Commission, 2003b). Permeability is available for 15 fields and ranges from 0.1 to 2000 md and averages 333 md (AOGCC, 2003b). Water saturation data are available from 19 gas fields (AOGCC, 2003b). The water saturation levels range from a low of 25 to a high of 57% and average 42%.

Fragmentary information regarding gas recovery factors is available from a number of sources. The Sproule report (1998) provides estimated and calculated recovery factors for 18 fields. The range is from a low of 85% for the McArthur River field to a high of 95% for the Cannery Loop, Beluga River, and Ivan River fields. The other 14 are given 90% recovery factors. There are calculated factors for only the McArthur River, Kenai, and North Cook Inlet fields. The other 15 recovery factors are estimates, and their reliability is unknown. Representatives of the DOG suggested that an average recovery factor of 85% would be representative. Thus, a value of the reciprocal of 0.85 (1.176) was used to calculate OGIP throughout this report.

Table 2.2. Compilation of data for Cook Inlet gas fields – plus general reservoir information.

Gas field	Discovery Date	Production	Producing Intervals	Effective Depth (ss)	Net pay	Area (acres)
Albert Kaloa	Jan., 1968	1970-971	Tyonek	??	??	??
Beaver Creek	Feb., 1967	1972-Present	Sterling Beluga Tyonek	-5,000' -8,100' -9,874'	110' 50' 45'	≈1,300
Beluga River	Dec., 1962	1963-Present	Sterling Beluga	-3,300' -4,000'	107' 106'	≈4,500
Birch Hill	June, 1965	1965-1965	Tyonek	-7,960'	31'	≈ 500
Cannery Loop	Oct., 1959	1988-Present	Sterling Beluga U. Tyonek L. Tyonek	-4,965' -5,175' -8,700' -10,000'	76' 33' 17' 35'	??
Falls Creek/ Ninilchik	June, 1961	1966-1966/2003	Tyonek	-7,045'	??	≈ 900+
Granite Point	June, 1993	1967-Present	Tyonek	-4,088'	135'	??
Happy Valley	April, 2003	2004 (?)	Tyonek	-6,000' (Or deeper)	110'	??
Ivan River	Oct., 1966	1990-Present	Tyonek	-4,088'	37'	≈1,000
Kenai	Oct., 1959	1961-Present	Sterling Beluga Tyonek	-3,700' -4,900' -9,000'	461' 213' 100'	≈14,000
Lewis River	Sep., 1975	1984-Present	Buluga	-4,700'	85'	≈ 400
Lone Creek	Oct., 1998	2003	??	??	??	??
McArthur River	Dec., 1968	1967-Present	Tyonek	-4,500'	375'	≈2,500
Middle Ground Shoal	Feb., 1962	1966-Present	Tyonek	-3,550'	31'	??
Moquawkie	Nov., 1965	1967-1970 & 2003	Tyonek	??	45-108'	??
Nicolai Creek	May, 1966	1968-1977 & 2001-Present	Tyonek	-1,924'	284'	≈7,000?
North Cook Inlet	Aug., 1962	1969-Present	Sterling Beluga	-4,200' -5,100'	350' 160'	≈8,000
North Fork	Dec., 1965	1966-1966 & 2003 (?)	Tyonek	-7,200'	40'	??
North Trading Bay	Nov.,1964	1968-2000	Sterling/ Beluga	??	24'	??
Pretty Creek	Feb., 1979	1986-Present	Beluga	-3,864'	60'	≈ 300+
Sterling	Aug., 1961	1962-Present	Sterling Beluga Tyonek	-5,030' -8,104' -9,449'	25' 100' 55'	≈2,000
Stump Lake	May, 1960	1990-Present	Beluga	-6,740'	91'	≈1,000
Swanson River	May, 1960	1958-Present	Sterling	-2,870'	??	??
Trading Bay	Oct., 1968	1967-Present	Tyonek	-9,000'	250'	??
West Foreland	Mar., 1962	----	Tyonek	-4,250'	15'	??
West Fork	Sept., 1960	1978-1985 & 1991-1995	Sterling	-4,700'	22'	??
West Mcarthur River	Dec., 1991	1993-Present	Tyonek	??	??	??
Wolf Lake	Oct., 1998	2001-Present	Tyonek	-6,749'	28'	??

Table 2.3 shows the range in reservoir parameters (porosity, permeability, and water saturation) by formation. The data are not complete and the Sterling is underrepresented by the sample data; however, the data tend to demonstrate the superior reservoir characteristics of the Sterling Formation. It has higher average porosities and permeabilities and lower water saturations. A more comprehensive sampling of the three reservoir intervals would be necessary to fully characterize the units. The data are sufficient to provide a workable range of anticipated values that may be useful to model potential new fields.

Table 2.3. Reservoir parameters by productive horizon. (AOGCC, 2003a)

Productive Horizon	Porosity (%) Range ------ avg.	Perm. (md) Range ------- avg.	Water Sat. (%) Range ------avg.
Sterling Formation	10 to 33 -------28 (n=8)	125 to 2000---579 (n=6)	35 to 50 -- 39.5 (n=13)
Beluga Formation	10 to 28 -------21.7 (n=6)	0.1 to 300 ------75 (n=5)	40-45 ----- 43.7 (n=6)
Tyonek Formation	12 to 29 -----20.7 (n=12)	0.25 to 1600—-312 (n=9)	25 to 57 ---- 43.2 (n=14)

2.3.3 Traps

Only one trap type has been tested by exploration drilling in the Cook Inlet – the structural trap. The large, often highly faulted, asymmetrical anticlines have been the primary exploration targets since the onset of exploration. The first generation of exploration evaluated the largest and seismically most obvious structures. Exploration drilling and better seismic data quality reveal that faulting has created multiple possible traps on a single structure, not all of which are found to have trapped oil or gas.

To be effective traps, adequate seals must exist and in the case of oil and associated gas a conduit to the oil-generation kitchen must exist. This has been assumed to require either direct migration across the pre-Cenozoic unconformity or migration of oil and associated gas along open faults from the Mesozoic source rocks into the traps. This relationship is not required to charge traps with the Tertiary biogenic gas. Faulting of the large structures may have isolated fault blocks from these conduits and prevented charging. Alternatively, there may be a large component of stratigraphic trapping even on the most well-developed structures. At this point in the exploration of the basin, most if not all known accumulations have been attributed to structural trapping.

Because of the nature and distribution of the reservoirs in the basin, there must be a large number of stratigraphic trapping opportunities. No concerted effort has been made to pursue stratigraphic traps as exploration targets. Fluvial channels and to a lesser extent other non-marine facies should provide good-to-excellent stratigraphic traps, especially in the younger, biogenic gas-prone portions of the section where these facies are interbedded with the coals and type-III kerogen bearing mudstones. Additional stratigraphic traps may be associated with many of the internal unconformities resulting from repeated uplift and erosion of the basin margins due to faulting. These features may provide the basis for significant future reserve additions providing significant economic incentive exists to explore for and develop these accumulations.

The presence of the large anticlinal and fault structures and the stratigraphic trapping potential yield favorable conditions for combination traps. There has been little recognition of the role these traps may have in known and undiscovered gas accumulations. Careful mapping of individual pays, in several of the large fields, reveals that the stratigraphic trapping component is critical to the existence or at least the size of some accumulations. Individual gas/water or oil/water contacts plus the geometry and distribution of the pay demonstrate the stratigraphic nature of these traps.

The questions of seal and seal integrity are of little consequence in the older more deeply buried portion of the section, but may be important considerations in the development and preservation of traps in the shallow reservoirs of the uppermost Beluga and the Sterling. Due to insufficient compaction, seals may not be effective at burial depths of less than 3,000 feet. At depths of 3,000 feet and perhaps slightly deeper, there is a good chance that the seals are leaky. Few of the shallow gas reservoirs are filled to the spill point and this may be a result of poor seal integrity or weakness rather than insufficient volumes of gas to fill the trap to the spill point.

2.3.4 Cook Inlet Basin Field Example

Few studies have been published on the Cook Inlet Basin oil and gas fields (Figure 2.6). The only readily available data known to this author are from the Kenai gas field (Brimberry, Gardner, McCullough, and Trudell, 1997). To provide a realistic perspective, a brief summary of this field, the largest gas field in Cook Inlet, will set the stage for following discussions.

This field produces from virtually all the important gas-bearing units in the basin – the Sterling, the Beluga, and both the upper and deep Tyonek (Table 2.2). It is a large anticlinal feature, and the gas is 99% methane, 0.5% nitrogen, and 0.2% carbon dioxide. The remaining 0.3% of the gas is not specified. The high methane content and isotope markers indicate that the gas is of biogenic origin. The trap is a large simple anticline, which extends more than 10 miles north-south and four miles east-west. The only significant fault is a normal fault that separates the Kenai field from the Cannery Loop field to the north (Brimberry, Gardner, McCullough, and Trudell, 1997).

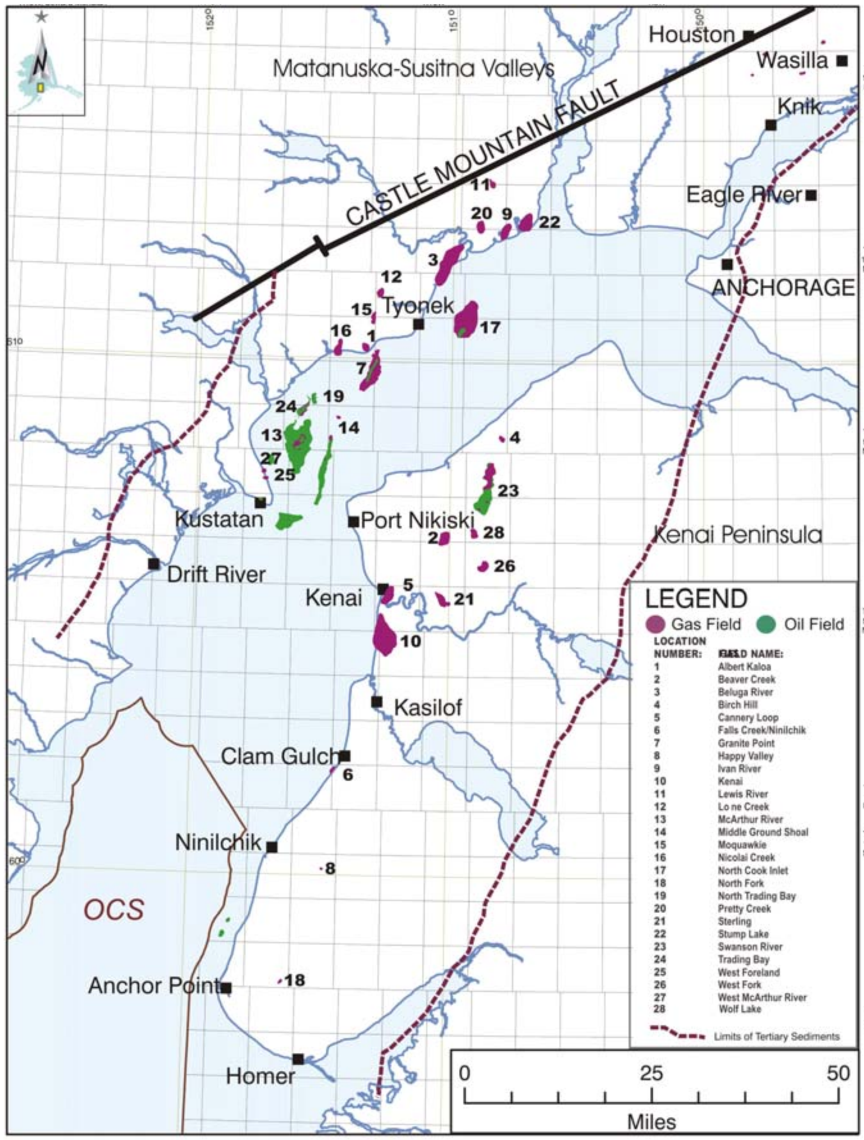


Figure 2.6. Cook Inlet Basin, Alaska, Oil and Gas Fields.

At the time of publication of the Brimberry et al. (1997) paper, the total field production was 2,080 Bcf. The principle reservoirs are in the Sterling Formation, which had produced 1,700 Bcf (81.7 %). The Sterling reservoirs are typically 30 to 60 feet thick with some being more than 100 feet thick. Effective porosity ranges from 25 to 31% and permeability of more than one Darcy (1000 md) is common.

The Beluga reservoirs are of somewhat lesser quality. The Beluga had produced 147 Bcf (7.1 %) at the time of the report, most from sandstones in the upper part of the formation. Lower and middle Beluga sandstones are typically 10 to 20 feet thick and the upper Beluga reservoirs are approximately 20 feet thick. The upper sandstones generally have effective porosities of more than 15% and permeabilities in the 5 to 50+ md range. The lower and middle Beluga sandstones are of somewhat poorer quality.

The total Tyonek production was 233 Bcf (11.2 %), with 6 Bcf from the upper Tyonek and 227 Bcf from the deep Tyonek. The upper Tyonek reservoirs range 20 to 40 feet thick, have porosities of 12 to 15%, and permeabilities in the 1 to10 md range. The reservoirs of the deep Tyonek interval are superior to those in the upper part of the Tyonek. The deep Tyonek sandstones are generally more than 40 feet thick, have effective porosities of about 12%, and possess permeabilities of more than 50 md.

The available data from individual fields are very limited; thus, the Kenai field information, as sparse as it may be, constitutes the best available model or guide for the basin and for the evaluation of potential additional discoveries. The Kenai field is somewhat atypical in that the Tyonek provides a better reservoir than the Beluga. Basinwide, the Beluga tends to be a better reservoir than the Tyonek.

2.4 Reserve Base

Exploration in the upper Cook Inlet area has resulted in the discovery of 11 oil accumulations and 28 gas accumulations (ADNR, 2002). Two of the gas discoveries postdate the ADNR 2002 annual report cited above. The distribution of the Cook Inlet oil and gas fields is shown in Figure 2.6. Not all of these fields have been developed and several are currently shut in.

Since the initial production in 1958 through the end of 2003, Cook Inlet oil fields have produced 1,293.049 MMbo (ADNR, 2003, Table IV.4). The largest field is the McArthur River field with approximately 620 million barrels of recoverable oil. The Division of Oil and Gas 2003 Annual Report (Table IV.2) places the known recoverable reserves in Cook Inlet at 166.7 milion barrels of oil. Discoveries such as Cosmopolitan (Petroleum News, 2003) may offset this decline, if proven economic.

Oil has been discussed in this chapter to provide an overview of the hydrocarbon resources and potential of the Cook Inlet Basin. Since the focus of this study is on natural gas, no additional discussion of oil resources in the Cook Inlet Basin will be provided.

2.4.2 Gas

Gas production and commercialization commenced in 1961 with the development of the Kenai gas field (Brimberry, Gardner, McCullough, and Trudell, 1997). The Kenai gas field is the largest in Cook Inlet with estimated ultimate recovery of nearly 2,350 Bcf. Based on data from the AOGCC from 1961 through 2003, Cook Inlet gas fields have a net production of 6,689.896 Bcf (AOGCC, 2004). Associated gas production was 546.315 Bcf and non-associated gas was 6,143.581 Bcf. Among the numbers presented in the AOGCC summary are volumes associated with gas injection, principally in the Beaver Creek and Swanson River fields. These numbers have been backed out of the totals. The most recent DOG production figures are through the end of 2002 (ADNR, 2003) and calculate to be 6,421.066 Bcf.

The Swanson River gas production is an enigma. AOGCC (2004) lists production of 42.313 Bcf and the DOG (ADNR, 2003) has a net production of 241.020 Bcf through December, 2002, but does not appear to include that value in the cumulative total of 6,421.066 Bcf. Since the primary sources of information are the AOGCC reports of monthly production, the total cumulative production will be assumed to be 6,689.896 Bcf as of January 1, 2004.

The ADNR Division of Oil and Gas (2003) production projections through 2022 indicate that as of January 2004 there are approximately 1,800 Bcf of additional proven unproduced reserves remaining. Other studies and findings have quantified the size of “proven unproduced” reserves. Chief among these are the Geoquest study prepared for Marathon and Phillips in 1996 and the Malkewicz-Hueni Associates study for ENSTAR in 1997. Table 2.4 summarizes and compares the findings of the Geoquest and Malkewicz-Hueni studies with the projections of the ADNR (2003, Table IV.10). The conclusion of the Geoquest study was that as of January 1, 1996, the total proven gas reserves in the Cook Inlet area were 3,787.1 Bcf. Using production volumes for 1996 through 2003, the proven unproduced reserves indicated by the Geoquest study are 2,020.9 Bcf, as of January 2004. The Malkewicz-Hueni study, treated in a similar fashion, suggests that January 2004 proven unproduced reserves are 1,459.5 Bcf.

Table 2.4. Comparison of magnitude of unproduced proven reserves as of January 1, 2004. (Reserves associated with the recently discovered Ninilchik and Happy Valley fields are included).

Data Source	Vol. at time of Report (Bcf)	Vol. Prod. Report to Janaury 1, 2004 (Bcf)	Unproduced proven reserves (Bcf)
Alaska Oil and Gas Conservation Commission (2004)	6,689.90 (1-1-2004)	0.00	1,790.3
Geoquest Report (1996)	4,923.77 (1-1-1996)	1,766.13	2,020.86
Malkewicz-Hueni Report (1997)	5,361.50 (1-1-1998)	1,328.40	1,459.46

The variation and uncertainty among these three sets of reserves numbers are of prime concern to users of the resource and one of the driving factors for this study. In this study probable and possible reserve additions as well as the proven reserve estimates are evaluated. The volumes presented above represent only conventional gas and do not include any production or potential from coalbed natural gas, which is in the early stages of economic evaluation. Coalbed natural gas will be addressed later in the text when future reserve additions are considered.

2.5 Distribution of Natural Gas

The foregoing discussion was restricted to the upper Cook Inlet (Figure 2.1) -- the portion of the basin bounded by the Augustine-Seldovia Arch, the Castle Mountain Fault, the Border Ranges Fault Zone, and the Bruin Bay Fault. Additionally, coalbed natural gas was not included. The stratigraphic distribution of gas reserves within the Kenai Group was mentioned and included a reference to the presence of associated gas in the lower portions of the Kenai Group and non-associated gas being confined to the upper portions. The associated gas is solution gas in undersaturated oil reservoirs. The oil fields have no gas caps and typically have gas-oil ratios (GOR) ranging from 250 to 400 cfg/bbl.

Non-associated biogenic gas is by far the most important component of the natural gas reserve base in Cook Inlet. The biogenic non-associated gas accounts for 94% of the gas reserves in Cook Inlet (Claypool, Threlkeld, and Magoon, 1980) and approximately 92% of the production to date. This section is intended to provide information regarding these aspects of

Cook Inlet gas and to suggest where additional undiscovered reserves will most probably be found through future exploration efforts

2.5.1 Conventional Gas

Data for the known gas accumulations are not consistently available. The variety and quality of the data vary from field to field. The older, larger fields tend to have the most complete data sets, while the smaller fields and most recent discoveries may have little basic information. Much of the reservoir and production/reserve data from recent discoveries are classified confidential, and the information is not available to the public. Tables 2.1 and 2.4 were constructed to summarize the available information regarding these fields. These data were primarily derived from AOGCC (2003b and 2004) and ADNR (2003) reports. Table 2.2 lists the fields in alphabetical order and gives the discovery date, duration of production, principal reservoir horizons, depth to reservoir (sub sea), and net pay thickness.

Table 2.5 again presents the fields in alphabetical order and provides production and reserve data in billions of cubic feet (Bcf) of gas. The data are presented as follows: production from date of discovery to January, 1, 2004; additional proven unproduced reserves (post-2003); and estimated ultimate recovery for Cook Inlet natural gas (ADNR, 2002 and AOGCC, 2004). In Section 3, an independent reserves analysis is described and production forecasts developed that form the basis for the economic analysis in Section 4.

Note should be taken of the several differences in the reporting formats between the AOGCC and DOG. The DOG reports production from both a Trading Bay field and a North Trading Bay field. AOGCC reports for only a Trading Bay field. In Table 2.5 the DOG procedure is used and the production reported for the Trading Bay field by AOGCC (2004) is assigned to the two fields in the volumes used by DOG. The Kenai Gas field and Cannery Loop are reported as a single entity by the AOGCC but are considered two separate fields and reported as such by the DOG. The Swanson River field gas production given by the AOGCC is used. The volumes presented by the DOG are not used in this instance because of the uncertainty associated with their derivation.

When summed, these numbers do not precisely equal those shown in the first row of Table 2.4. This is due at least in part to the uncertainty in the magnitude of estimates of recoverable reserves from the recent discoveries at Ninilchik and Happy Valley. The four major

Table 2.5. Production data and reserve estimates by gas field in the Cook Inlet basin. (AOGCC 2002a, 2003b, 2003c, 2003d, 2004 and ADNR 2003.

Gas Field	Production, Non-Associated Gas, Discovery to January 1, 2004 (Bcf)	Production, Associated Gas Discovery to January 1, 2004 (Bcf)	Proven Unproduced Reserves as of January 1, 2004 (Bcf)[5]	Estimated Ultimate Recovery (Bcf)
Albert Kaloa	0.119	0.000	0.000	0.119
Beaver Creek	170.150	2.020	71.110	243.280
Beluga River	847.163	0.000	312.908	1,160.071
Birch Hill	0.065	0.000	11.000	11.065
Cannery Loop	110.771	0.000	8.839	119.610
Falls Creek/ Ninilchik[1]	3.064	0.000	96.936	100.000
Granite Point	0.800	125.099	11.164	137.063
Happy Valley	0.000	0.000	100.000(1)	100.000
Ivan River[2]	74.049	0.000	8.226	82.275
Kenai	2,245.566	0.000	99.599	2,345.525
Lewis River	10.882	0.000	See Ivan River	10.882+
Lone Creek	1.011	0.000	??	1.011+
McArthur River	966.750	253.938	173.353	1,395.041
Middle Ground Shoal	16.383	91.691	3.432	111.506
Moquawkie	0.988	0.000	20.000	20.988
Nicolai Creek	2.207	0.000	1.000	3.207
North Cook Inlet	1,621.587	0.000	571.971	2,193.558
North Fork	0.105	0.000	12.000	12.105
North Trading Bay	0.000	11.873	??	11.873+
Pretty Creek	8.273	0.000	See Ivan River	8.273+
Sterling	4.058	0.000	29.088	33.146
Stump Lake	5.643	0.000	See Ivan River	5.643+
Swanson River[4]	42.313	0.000	82.201	124.514
Trading Bay[3]	5.265	59.363	26.412	91.040
West Foreland	1.059	0.000	19.043	21.102
West Fork	4.212	0.000	4.000	8.212
West McArthur River	0.000	2.331	0.385	2.716
Wolf Lake	0.654	0.000	50.000	50.695
Totals	**6,143.581**	**546.315**	**1,713.583**	**8,403.479**

(1) Estimated recoverable reserves of 100 Bcf were assigned to the Ninilchik and Happy Valley discoveries [Marathon initially estimated recoverable reserves of 60 Bcf at Ninilchik and Unocal has placed initial estimates for Happy Valley at 75 to 100 Bcf (Petroleum News, 2003b), but Unocal puts the potential of the area from Ninilchik south to Anchor Point at 100 to 600 Bcf (Petroleum News, 2002)];
(2) DOG combined several smaller fields together when assigning future production; the unproduced reserves have been placed with the Ivan River field in this table;
(3) DOG reserve values have been used with the Trading Bay fields and future reserves put with the Trading Bay field;
(4) The to-date production figure represents the AOGCC value; the data presented by DOG shows much larger reserves (241 Bcf) but is difficult to rationalize.
(5) These values are derived from the DOG 2003 Annual Report for the major fields and the 1999 DOG Historical and Projected Oil and Gas Consumption Report for the smaller fields.

fields, Kenai, North Cook Inlet, McArthur River, and Beluga River, have estimated ultimate recovery totaling 7,094.6 Bcf or 84.4% of the known recoverable volume of gas as calculated in Table 2.5. ConocoPhillips attributes 85% of the gas discovered in Cook Inlet to these four fields (Jepsen, 2002). The agreement among the reserve estimates presented by a variety of sources is quite good for the four large, well-documented fields. The greatest variation in reserve estimates is in the smaller fields and in the undiscovered reserve estimates for the basin.

This is shown, in part, by the range in estimates of total proven reserves for the Cook Inlet Basin from the sources indicated in Table 2.4 and the summation of Table 2.5. These values are presented for comparison in Table 2.6.

Table 2.6. Comparison of ultimate recovery estimates.

Source of Data	Estimated Ultimate Recovery (Bcf)
Alaska DNR	8,480.2
Geoquest	8,710.8
Malkewicz-Hueni	8,149.6
Table 2.5	8,403.4

Based on the figures of Table 2.6, the estimates of ultimate recoverable gas for the known accumulations range from 8,149.6 to 8,710.8 Bcf. This is a difference of more than 560 Bcf. This level of uncertainty has potential impact on the timing of supply versus demand deficits and the economic life of several fields. This uncertainty is addressed in Sections 3 and 4 and the potential for additional future economic reserve additions in the Cook Inlet basin and elsewhere in south-central Alaska.

2.5.1.1 Areal Distribution of Existing Fields and Reserves

Figure 2.7 shows the location of the known gas accumulations and gas pipelines in Cook Inlet. Numerically speaking, the 28 known accumulations (Tables 2.1 and 2.4) are primarily concentrated on the western portion of the Kenai Peninsula and on the northwest side of the inlet, with the notable exceptions of the Granite Point, North Cook Inlet, McArthur River, and Middle Ground Shoal fields. These four fields and smaller offshore accumulations are estimated to have total production of 3,925 Bcf. The west Cook Inlet fields, Beluga River, the Lewis River/Stump Lake/Pretty Creek/Ivan River cluster, and Nicolai Creek will ultimately produce approximately 1,340 Bcf. The western Kenai Peninsula string of fields, from Birch Hill in the north to North Fork/Happy Valley in the south and including the Kenai field, have total recoverable gas in the range of 3,290 Bcf.

The offshore fields and those on the west side of Cook Inlet are situated along a series of north-northeast trending asymmetrical anticlinal structures. The Kenai field and the smaller fields on the Kenai Peninsula are situated on a parallel series of anticlinal structures (Magoon, Adkinson, and Egbert, 1976). The deep axial portion of the basin serves to separate the two known producing trends.

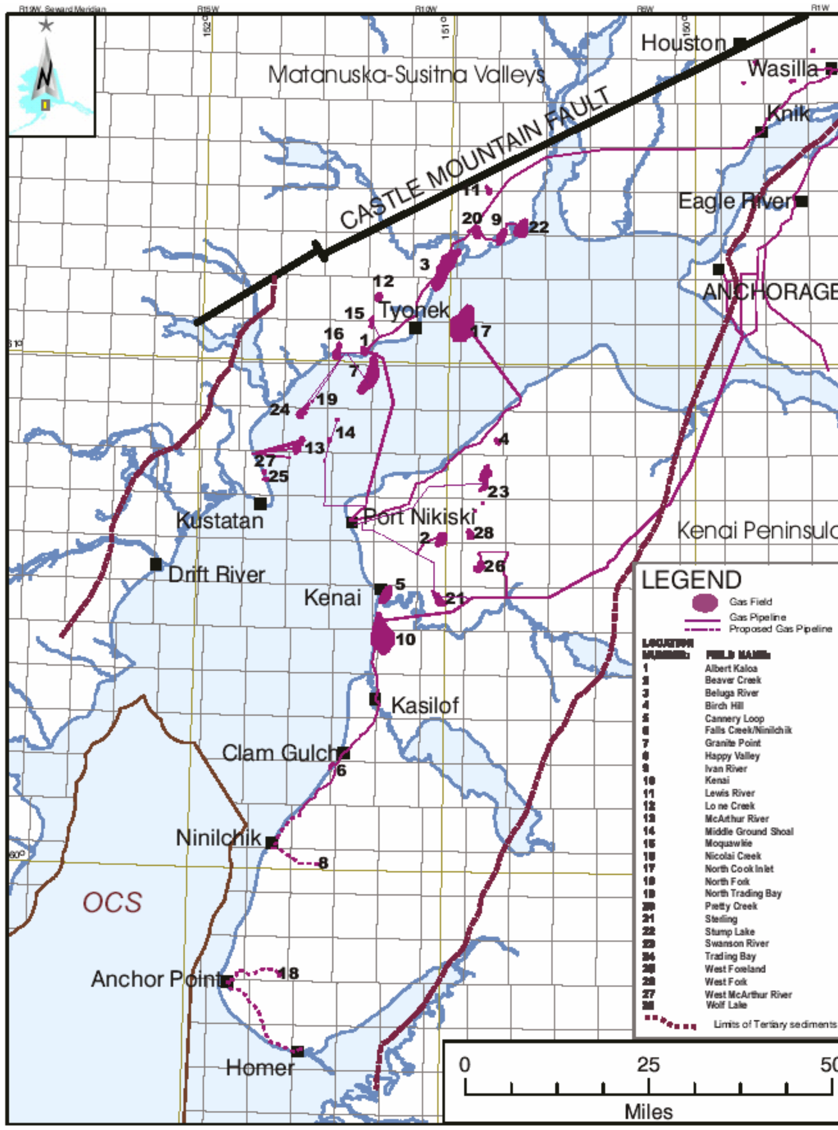


Figure 2.7. Cook Inlet Basin, Alaska. Gas fields and accumulations and gas pipelines.

Geological mapping on the Kenai Peninsula (Magoon, Adkinson, and Egbert, 1976) shows another more easterly set of anticlines with the same trend as those hosting the producing fields. There is sparse well and seismic control over much of the eastern portion of the Kenai Peninsula. The magnitude and character of these structures is yet to be fully appreciated. They are mapped with a high degree of certainty in the Kachemak Bay (Figure 1.1) area and in the vicinity of Chickaloon Bay, but the area between is poorly understood. A third gas-bearing anticlinal trend may exist beneath the Kenai National Wildlife Refuge (see Figure 2.17).

While the obvious structural trends cited earlier have served to focus the past exploration efforts in the basin and generally do so today, the exploration of the future will be more varied in play type. More subtle structural plays, combination structural-stratigraphic plays, and pure stratigraphic plays will assume the dominant roles in the discovery of additional reserves. This will expand the scope of the area of interest and require more sophisticated exploration technologies to find and develop these resources.

2.5.1.2 Stratigraphic Distribution of Reserves

Gas reserves are generally restricted to the upper portion of the Tertiary section (Figure 2.5) where the biogenic gas is both sourced and reservoired. Based on production data available from the AOGCC (2003d), the total produced gas can be partitioned among the major gas-producing formations in the following proportions: 57% from the Sterling, 14% from the Beluga, and 25% from the Tyonek. The remaining 4% is attributable to associated gas from the Hemlock and West Foreland formations. A large percentage of the gas is produced from the younger Tertiary section, latest Oligocene through Pliocene (24 to 2 Ma) and is the result of the bulk of the gas being biogenic and associated with the shallow coal-bearing section. It was earlier noted that 94% of the gas is of biogenic origin, and the Tyonek through Sterling portion of the Kenai Group has produced 96% of the gas; i.e., essentially all the biogenic gas plus some “leaked” thermogenic gas. Recent isotopic analyses of gases in several of the Cook Inlet gas fields have revealed that ethane and propane have been detected in small quantities in some of the deeper Beluga reservoirs and that the amount of these heavier gases tends to increase with depth. This appears to be more characteristic of gas fields overlying oil accumulations, such as the North Cook Inlet gas field.

The Sterling and upper Beluga reservoirs tend to be the thickest, most prone to having sandstone-on-sandstone contacts (more continuity of reservoir or accumulation), and the best porosity and permeability, thus making this interval of Sterling and upper Beluga the most attractive gas exploration targets in the basin.

2.5.1.3 Depth of Gas Fields

Depth appears to be an additional controlling factor associated with the occurrence of gas accumulations. The great bulk of the gas in the basin has been found in reservoirs at depths of approximately 3,000 to 5,000 feet subsea. This may be due to latest Pliocene(?)/

Pleistocene compaction of the shallow section associated with glacial loading. More than 4,000 feet of ice filled Cook Inlet during the Pleistocene glacial epochs and was theoretically capable of sufficiently compacting the sedimentary section to create somewhat leaky seals (Van Kooten, 2003). Today, the upper limit of such seals is at about 3,000 feet subsea. Figure 2.8 shows the zero-edge and the 1000-, 2000-, and 3000-foot contours for the Tyonek, Beluga, and Sterling Formations in upper Cook Inlet. This figure serves to combine the stratigraphic interval with depth. Figure 2.8 can be used to predict which of the three important gas-bearing formations may be at the most productive depths (-3,000 to -5,000 feet) at a proposed location in the basin.

Regardless of formation (Sterling, Beluga, or Tyonek) 90% of the gas produced in Cook Inlet has come from reservoirs in the general depth range of 3,000 to 5,000 feet subsea. This value was derived from reservoir data and production volumes in reports of the AOGCC (2003b and 2003d). Given the theory that the minimum effective depth of gas accumulation is controlled by the development of seals resulting from overburden loading, any gas generated at shallower depths would have quickly escaped to the surface. This concept may provide a means of efficiently evaluating the unexplored and poorly

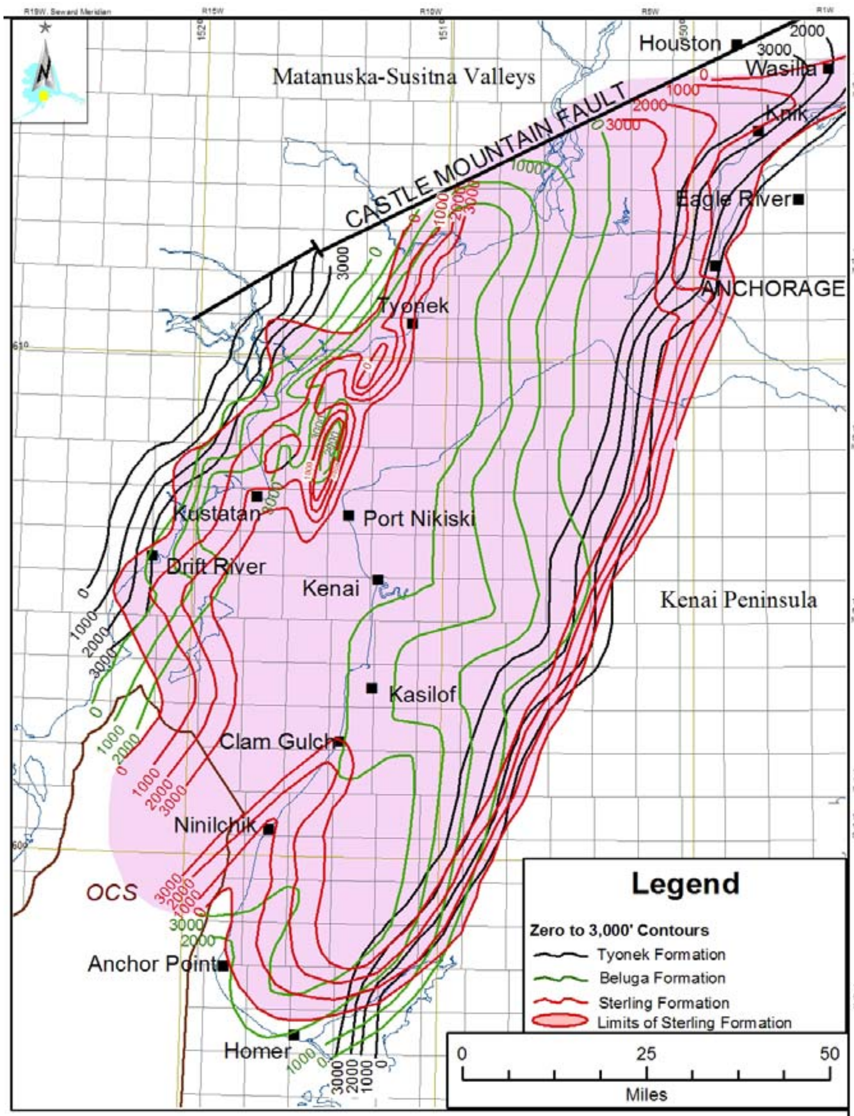


Figure 2.8. Cook Inlet Basin, Alaska. Limits of distribution for Tyonek, Beluga, and Sterling formations with 0-, 1,000-, 2000-, and 3000-foot isopachs of formation thickness.

explored portions of the basin relative to their gas potential. This approach will be examined in some detail in the section titled "Opportunities for Future Reserve Additions." There may be local exceptions to this generalization in instances where gas has accumulated in older, originally more deeply buried formations that have been brought to shallow depths by uplift and erosion of the overlying strata.

2.5.2 Unconventional Gas

Unconventional (non-conventional or less conventional) gas resources are "gas present in low-permeability (tight) reservoirs with matrix permeabilities generally less then 0.1 md." "The gas may be present in sandstones, siltstones, coalbed, or shales. This category is essentially equivalent to the United States Geological Survey's (USGS) continuous-type deposits except that no permeability limitation is specified by the USGS" (DOE, 1999).

In the south-central Alaska area, future opportunities may exist for several of these potential sources but only coal-related natural gas is actively being pursued at this time. Evergreen Resources and predecessor companies have drilled a number of exploration wells in the Pioneer Unit (Figure 2.9) of the Houston area. They recently discontinued a pilot project intended to dewater the coals prior to flowing gas for production and rate tests.

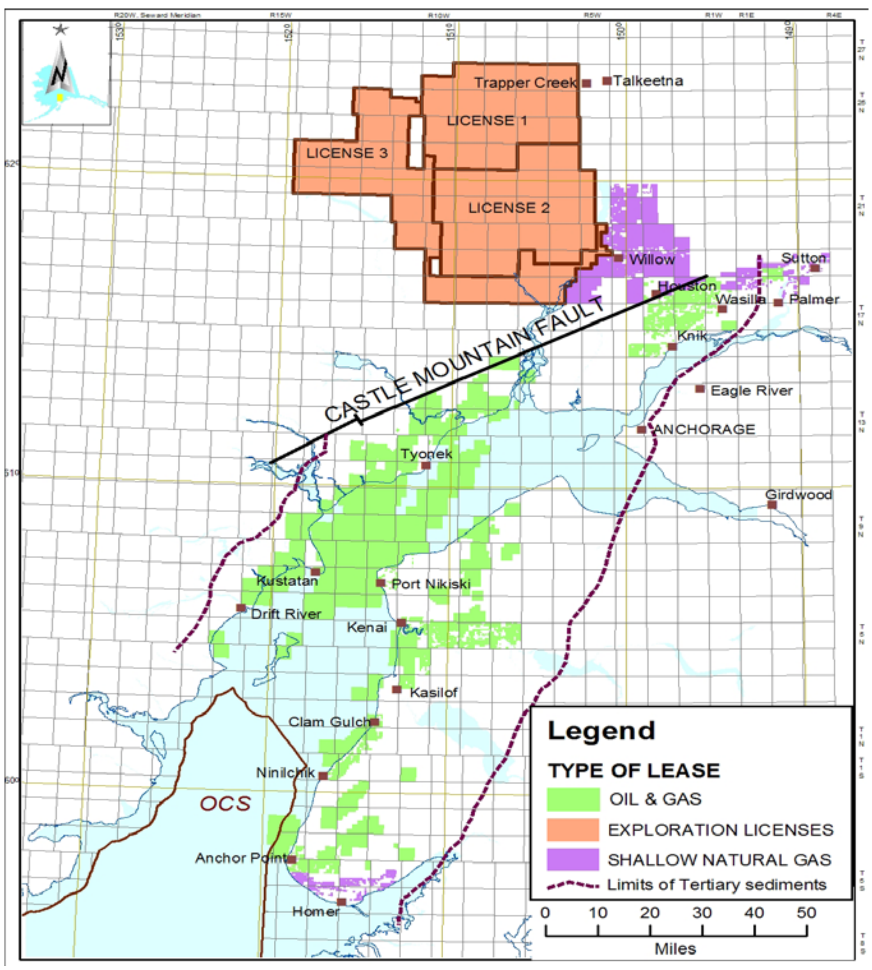


Figure 2.9. Cook Inlet/Susitna Valley, Alaska. Area of current leases and exploration licenses.

There appears to be considerable potential for coalbed natural gas in the south-central Alaska area; however, well costs, subsurface versus surface ownership issues, production rates, and water disposal are all problems that need to be resolved or mitigated. In late October 2003, Evergreen announced that it was abandoning the Pioneer unit wells until either the economics or technology was more favorable (ADN, 2003). The company is shifting its efforts to areas north of the Castle Mountain fault and is pursuing a multi-corehole program to more effectively evaluate the coals (Petroleum News, 2003c). The potential for coalbed natural gas to contribute to the future gas supply of the area is discussed further in Section 2.6.3 and in Section 3.5.

2.6 Opportunities for Future Reserve Additions – Cook Inlet

The magnitude of potential undiscovered gas reserves is poorly understood and constrained. One example of the variability is evident in DOE/FE Opinion and Order No. 1473 (DOE, 1999; Table 1). DOE's Table 1 presents a series of estimates of proved, unproved, undiscovered unproved, and speculative reserves or reserve additions as of January 1998. The variability in that table reflects the uncertainty or disagreement in the volume of both probable unproved reserves (600 to 1,050 Bcf) and estimated undiscovered unproved economically recoverable reserves (0 to 441 Bcf at $2.00/Mcf or 779 Bcf at $3.34/Mcf). Summing these projections provides an estimate of potential reserve additions that ranges from 600 to more than 1,800 Bcf, and ultimately results in estimates of total remaining gas supply for the Cook Inlet area (as of January 1, 1998) that range from a low of 3,003.9 Bcf to a high of 4,545.0 Bcf (DOE, 1999, Table 1). These numbers reflect the situation as perceived in early 1998 and are presented here for comparison purposes only and do not reflect the current assessment.

Three possible sources must be considered when evaluating future additions to the gas reserve base of the Cook Inlet area: 1) additional growth of reserves in existing fields, 2) undiscovered resources of conventional natural gas, and 3) unconventional sources such as coalbed natural gas. Appendix C of the DOE/FE Opinion and Order No. 1473 (DOE, 1999) presents an evaluation by the USGS of the magnitude of the possible contribution from these sources. The conclusions reached at that time were that 1) reserves growth was the most certain of these additions to reserves and that growth would add more than 1,000 Bcf prior to 2015 and perhaps ultimately as much as 3,000 to 4,000 Bcf; 2) the discovery of additional conventional natural gas resources is less certain and economically dependent, but the USGS estimated that between 400 and 800 Bcf could be added through the discovery of new fields; and 3) the presence of coalbed natural gas resources is confirmed, but insufficient evidence is available to make reasonable estimates of recoverable volumes.

Each of these three categories is reevaluated from the perspective and advantage of six additional years of production, a modest increase in exploration drilling, a better understanding of the coalbed natural gas potential of the basin, and a greater demand and higher price for gas. In this section, the potential for reserve additions within the area of currently active and proposed exploration and leasing within the Greater Cook Inlet area is evaluated. In Section 2.8 the areas of south-central Alaska external to the Cook Inlet Basis are examined.

As used here, the Greater Cook Inlet Basin encompasses the upper and lower Cook Inlet subbasins and the Susitna Basin to the north of the Castle Mountain fault, where active exploration licensing and coalbed natural gas exploration is underway. Figure 2.9 shows the area under consideration. Current production of conventional gas is solely restricted to the upper Cook Inlet subbasin, where the vast majority of exploration has occurred (more than 90% of the exploration wells). The federal waters of lower Cook Inlet were the loci of a minor Outer Continental Shelf (OCS) exploration effort in the late 1970s and early 1980s. The southern portions of the Susitna Basin have historically been exposed to a very low level of oil and gas exploration and are currently the focus of coalbed natural gas exploration and land acquisition through exploration licenses.

2.6.1 Reserves Growth

The Cook Inlet Basin has experienced large increases in reserves and ultimately production through the incremental development of originally unrecognized reserves in the established producing fields (DOE, 1999). This experience reflects the historically well-established growth in reserves observed in producing basins elsewhere.

The USGS performs periodic assessments of the oil and gas resources of the United States and included in these assessments are estimates of the amount of anticipated reserve growth in existing fields. The USGS's 1995 National Assessment of Oil and Gas Resources of the United States (USGS National Resource Assessment Team, 1995) included estimates of reserve growth in existing Cook Inlet gas fields. These estimates are based on statistical projections of a series of data in the proprietary EIA Oil and Gas Integrated Field File (OGIFF).

A growth trend is present in most petroleum provinces in the United States (DOE, 1999). The 1995 statistical projection of reserve growth was based on OGIFF data through 1992 and resulted in the estimated reserve growth for Cook Inlet shown in Table 2.7. The report (DOE, 1999) goes on to state that, “Based on this analysis and considering that part of the 1994-2015 reserve growth estimate has already taken place, it is reasonable to assume that more than 1,000 billion cubic feet (Bcf) of gas will be added to existing fields in the Cook Inlet before 2015.” An additional 2,000 to 3,000 Bcf may be added before the fields are abandoned (DOE, 1999).

Table 2.7. Estimated Reserve Growth In Cook Inlet Gas Fields –Based On OGIFF Data through 1992 (Source; Department of Energy, Appendix C, 1999)

Reserve Growth During The Time Interval	1994-2015	1994-2080
Associated Gas (Bcf)	468	1,135
Non-Associated Gas (Bcf)	1,390	3,207
Total Natural Gas (Bcf)	1,858	4,342

To determine the applicability of the concept of reserves growth as applied to Cook Inlet, production and reserve estimates for Cook Inlet fields were examined. The reserve estimates for the time period of 1982 to 2004 are presented in Table 2.8 (ADNR, 1982, 1983, 1984, 1985, 1986, 1987, 1988, 1989, 1990, 1991, 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, 2000, and 2002). These reserve values indicate several abrupt increases in proven but unproduced reserves, most notably between 1984 and 1985 and again between 1994 and 1996. When compared with Table 2.1, these increases are either only fractionally or not at all associated with the discovery of new gas fields. As can be seen from Table 2.1, the 1981 to 1990 time interval was totally devoid of exploration success and only about 20% of the increase seen in the 1995 to 1997 interval can be attributed to newly discovered gas fields. These data are shown graphically in Figure 2.10.

Also, the increases evident in the data in Table 2.8 are larger than they appear at first inspection. The true magnitude of the reserve increase is partially offset by annual production rates of 200 to 220 Bcf. Thus, there is an increase in total gas reserves of 1,600 Bcf in the 1986 data, 1,400 Bcf jump in remaining reserves plus the 200+ Bcf produced in 1985. Similarly between 1995 and 1997 the data show an increase in proven unproduced reserves of 1,394 Bcf and, according to discoveries recorded in that time interval (Table 2.1), a maximum of 290 Bcf of that increase appears to be associated with new field discoveries. Additionally, more than

Table 2.8. Estimates of economically recoverable gas reserves (Bcf) – January 1982 to January 2004.

Date of reserve estimate	Recoverable reserves (Bcf)	Net change from prior year (Bcf)	Date of reserve estimate	Recoverable reserves (Bcf)	Net change from prior year (Bcf)
January 1, 1982	3,785	n. A.	January 1, 1994	2,187	-640
January 1, 1983	3,594	-191	January 1, 1995	1,887	-300
January 1, 1984	3,426	-168	January 1, 1996	2,842	+955
January 1, 1985	3,246	-162	January 1, 1997	3,281	+439
January 1, 1986	4,664	+1,400	January 1, 1998	3,066	-215
January 1, 1987	4,377	-287	January 1, 1999	2,843	-223
January 1, 1988	4,158	-219	January 1, 2000	2,564	-279
January 1, 1989	3,906	-252	January 1, 2001	2,348	-216
January 1, 1990	3,619	-287	January 1, 2002	2,241	-107
January 1, 1991	3,417	-202	January 1, 2003	2,020	-221
January 1, 1992	3,215	-202	January 1, 2004	1,905	-115
January 1, 1993	2,827	-388			

400 Bcf were produced in 1995 to 1996. The net result was an increase in total reserves of more than 1,500 Bcf. Some of this increase in the 1995 to 1997 interval may be a readjustment to account for apparent discounting, in the 1992 to 1994 time span, of 650 to 700 Bcf of previously recognized reserves. The large increase in reserves in the mid-1990s may be in part attributable to a restoration of those discounted reserves.

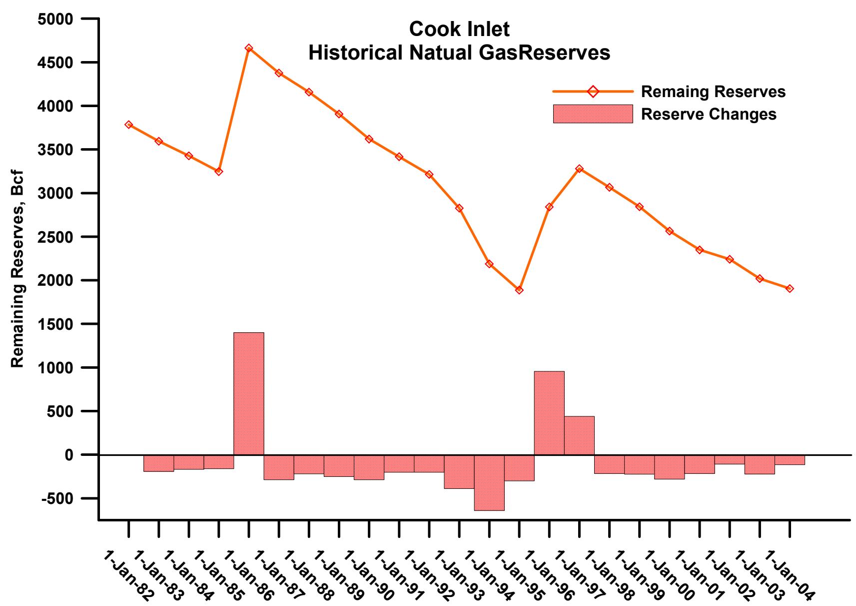


Figure 2.10. Estimates of economically recoverable gas reserves (Bcf) – January 1982 to January 2004.

Re-evaluations of Cook Inlet's major fields have repeatedly resulted in the recognition of additional undeveloped or bypassed reserves. The North Cook Inlet Field provides an example of such "growth." The ADNR had attributed reserves of 468 Bcf to the field in 1993, 410 Bcf in 1994, 358 Bcf in 1995, 1,000 Bcf in 1996, and 1,075 Bcf in 1997 (Petroleum News, 2001a). The reserves were then decreased through continued production to 917 Bcf in ADNR's 2000 Annual Report. A total of 208 Bcf were produced from the field during the four years (1993 to 1996). Without the reserve growth, there would have been only 260 Bcf at the start of 1997; thus, reserve additions of more than 800 Bcf are attributed to the North Cook Inlet field in that timeframe (1,075 Bcf – 260 Bcf = 815 Bcf). At the current demand level that is approximately a four-year supply of gas.

As evidence that reserve growth is an ongoing phenomenon, current remapping/re-evaluation of the North Cook Inlet gas field is targeting untapped channel belts, with virgin pressures, and adding reserves to the field. Also, Marathon has recently applied to the AOGCC (2004) to define a new gas pool in the Kenai Gas Field, the Beluga/Upper Tyonek Gas Pool.

While reserve growth has been realized in the major fields, there is still additional potential, and the newer fields will probably experience similar relative growth in reserves throughout their production history provided there is sufficient economic incentive to encourage the investment that will be required to continue the development needed to increase the reserves. (The required investment is discussed in Section 4.5.1.2.) These data provide strong support for the observation that full development of discoveries in Cook Inlet results in continued growth in reserves throughout the life of the field. Little additional information is available that can be utilized to project the magnitude and timing of future reserve growth in the Cook Inlet gas fields. The reserve growth of 1,000 Bcf or more over the next 10 to 12 years projected by the USGS (USGS, 1995; DOE, 1999) may provide a realistic estimate of recoverable reserves for the known fields. This projection of growth in gas reserves appears to be a reasonable expectation. An additional 2,500 to 3,000 Bcf may eventually be added through reserves growth in the existing fields and possibly more in recently discovered accumulations before the fields are abandoned.

2.6.2 Exploration for Conventional Gas

As recently as 2000, 98% of the gas production was from fields that were discovered more than 30 years ago (Petroleum News, 2000a). This is a reflection of the lack of active gas exploration in Cook Inlet. Despite the low levels of exploration drilling over the last 20 to 25 years (Table 2.1), there is a high potential for additional gas discoveries in the Cook Inlet Basin. The recent modest increases in exploration drilling and the new emphasis on gas exploration have yielded encouraging results (350 to 400 Bcf discovered) and indicate that an intensive gas-focused exploration effort will lead to additional discoveries in the near future.

The *Petroleum News* (2004) cites a ConocoPhillips manager as stating “ConocoPhillips believes that the Cook Inlet is entering a period of new exploration and discovery.” He went on to say that Cook Inlet is just beginning to come out of its first stage of discoveries when “easily accessible” reserves are developed and now higher prices for gas have “led to an increase in drilling, followed by new discoveries.” He concluded by saying that in the next five to 10 years, exploration “will tell us a lot about the potential of the basin.”

The future exploration prospectivity of the Greater Inlet Basin is discussed within the context of three geographic subbasins or areas of federal and state administration of land and resources. For these purposes, the three sections are upper Cook Inlet subbasin (Section 2.6.2.1), lower Cook Inlet subbasin (Section 2.6.2.2), and Susitna Basin (Section 2.6.2.3). The focus of the effort to add new reserves will be on the non-associated gas.

To satisfy resource assessment responsibilities or in preparation for leasing, federal (Attanasi, 1998, USGS, 1995, and MMS, 2000) and state (ADNR, 2002) agencies have addressed the oil and gas potential of the Greater Cook Inlet area, or portions of it. Private organizations (Potential Gas Committee, 2003) have made similar assessments. The undiscovered resource estimates were presented by these assessors in a variety of formats and one-to-one comparisons are difficult to make. Nonetheless, the magnitude of these numbers is of interest and provides some measure of the remaining potential as seen by the various organizations using the data available at the time those assessments were performed.

The Potential Gas Committee (2002) and J. B. Curtis (2003) estimated probable gas reserves for the Greater Cook Inlet Basin and subdivided the area into two parts, the onshore Cook Inlet-Susitna Basin and offshore Cook Inlet Basin (including both state and federal areas). The onshore portions were estimated to have probable potential reserves of 0.65 Tcf, possible potential reserves of 1.4 Tcf and speculative potential reserves of 2.4 Tcf, or a total of 4.45 Tcf with various levels of confidence. The offshore areas were estimated to have 0.4 Tcf probable potential reserves, 0.7 Tcf possible potential reserves, and 1.0 Tcf speculative reserves, or a total of 2.1 Tcf. Based on the Potential Gas Committee estimates, the basin’s undiscovered reserves may range up to 6.55 Tcf.

Federal evaluations (Attanasi, 1998 and MMS, 2000) have estimatee that undiscovered conventionally recoverable gas have an estimated range of 0.67 Tcf (95% probability) to 2.46 Tcf (5% probability). The undiscovered potential for upper Cook Inlet (Attansai, 1998) has an estimated range of 1.03 Tcf to 3.56 Tcf and a mean of 2.16 Tcf. Assuming these figures are compatible, the federal estimates for the Cook Inlet Basin yield a mean of 3.54 Tcf and a range of 1.70 Tcf to 6.02 Tcf. An additional published estimate by the USGS (Masters, Root, and Turner, 1998) puts the range for conventional undiscovered natural gas in Cook Inlet at 1.50 Tcf to 6.74 Tcf.

The ADNR has not prepared independent estimates of potential undiscovered reserves for Cook Inlet. The state has relied on estimates by federal agencies and/or the companies and their hired consultants. For the purpose of comparison, all the foregoing estimates must be adjusted to a common time reference – the present. This may be accomplished by subtracting the reserves added through exploration successes (Table 2.1) since the date of the individual estimate, indicated by the reference citation. The reserve additions are approximately 200 Bcf since the federal estimates and 100 Bcf since the latest Potential Gas Committee evaluations. Thus, when adjusted to the date of this report, these sources suggest that the upper end of the range for undiscovered conventional gas is about 6.0 to 6.5 Tcf.

Due to the limited amount of exploration drilling, the level of uncertainty regarding undiscovered recoverable reserves is high as indicated by the above estimates. The current known produced and unproduced reserves (Tables 2.4 and 2.6) do not represent the true potential of the basin, and, based on the estimates presented above, the ultimate reserves may be two to three times the total proven unproduced reserves (Table 2.4). If this hypothesis is true, where are the remaining reserves and what is the magnitude of the remaining conventional gas resources in the basin?

To address these questions and provide reasonable estimates of the resource potential, each of the three basin subdivisions and a number of play types are examined, and the possible magnitude of the total gas endowment is investigated.[5] In the latter instance, five gas resource endowment cases were constructed and evaluated. These cases will be discussed in Section 2.7. The case for the gas endowment scenarios is established by an examination of the three basin subdivisions and the following play types: 1) Tertiary structural plays – the only play type

[5] Total gas endowment means the total volume of gas in place in the basin.

pursued to date, 2) Tertiary stratigraphic plays in the shallow, biogenic-gas dominated part of the section -- a concept being used to increase reserves in existing fields, and 3) deeper basin plays in the style of the Kitchen prospects of Demarchos et al. (2002) and Mesozoic plays – high risk and high potential.

- ***Tertiary Structural Plays --*** All the current and developing production is from structurally driven exploration plays. In the upper Cook Inlet the great majority of the accessible, large seismically-expressed structures have been drilled. Most of these large structures have proven to be productive of oil and/or gas and account for all of the oil and gas discoveries to date. In the lower Cook Inlet subbasin all exploration wells have been drilled on large structures involving Mesozoic rocks and the thin Tertiary cover. The Susitna Basin conventional gas or oil exploration has also been structurally driven.

- ***Tertiary Stratigraphic Plays --*** Mature hydrocarbon basins generally exhibit a two-phase exploration history. The first phase consists of exploration for structural traps and then a second phase focuses on stratigraphic plays. At this point in time, Cook Inlet exploration is still in the structural-prospect phase. Few if any exploration plays have been pursued and drilled solely on stratigraphic trapping concepts. Based on exploration results in basins elsewhere, this implies that as much as 50% or more of the basin's reserve potential has not been investigated.

  In the Cook Inlet Tertiary section, stratigraphic traps are present as fluvial channel facies and the cleaner portions of alluvial fans. The fluvial channels tend to be concentrated in the axial portions of the northeast-southwest trending basin and migrate laterally across the basin in response to activity on the basin-bounding faults.

  During intervals of active faulting, on one of the fault systems, the axial channel system tends to migrate laterally toward the opposite side on the basin. This is in response to uplift in the vicinity of the fault and increased deposition and growth of alluvial fans along the active fault margins. Thus, the two predominant non-marine facies sets tend to stratigraphically interleave and produce reservoirs of differing geometries and reservoir quality.

Additional stratigraphic traps are developed along the basin margins in response to the uplift, erosion, and renewed deposition associated with active faulting. A series of unconformity traps may be expected between and within the principal reservoir horizons. Similar unconformity-related traps may exist along the flanks of growing structures. Because of the youthfulness of many of the structures, this pattern should be especially pronounced in the uppermost Beluga and Sterling Formations.

- ***Deep Basin Plays*** – These plays include the deep Tertiary plays proposed by Demarchos et al. (2002), evidenced by proprietary processing of seismic data, and targets in the Mesozoic portion of the section. While these plays may be either structural or stratigraphic in nature they target either Mesozoic horizons or deeper Tertiary plays, made attractive via enhancement of the seismic data.

These plays and their importance will be examined in the context of the role they are anticipated to play in future exploration efforts in the Greater Cook Inlet Basin, on a subbasin by subbasin basis.

2.6.2.1 Upper Cook Inlet Subbasin

In the past, oil-driven exploration has taken place throughout the Greater Cook Inlet Basin, but drilling density is very light outside the major producing fairways of the upper Cook Inlet (Figures 2.4 and 2.6). The upper Cook Inlet subbasin has had 220 exploration wells drilled in an area of approximately 9,000 square miles (23,330 sq. km) or a density of one well per 41 square miles (106 sq. km). Outside the upper Cook Inlet subbasin, the drilling density is an order of magnitude lighter.

For the immediate future, the area of most intensive gas exploration will continue to be the upper Cook Inlet subbasin where virtually all the active oil and gas leases exist (Figure 2.10). For that reason, the bulk of the following discussion will focus on this portion of the Greater Cook Inlet Basin. Figure 2.11 depicts the probable limits of possible gas accumulations in the upper Cook Inlet Basin. The “limit of accumulations,” shown on Figure 2.11, is the approximate 3,000 foot contour for the Kenai Group, and the principal area of interest is enclosed by this contour. These limits are used later on Figures 2.17 and 2.18.

Based on current understanding, the estimated ultimate recovery from the gas fields of the upper Cook Inlet is approximately 8.5 Tcf (Table 2.6). With an 85 % recovery factor this represents an OGIP value of 10.0 Tcf. The key factor for future exploration success in this subbasin lies in the magnitude of the total conventional gas endowment and the number and size of remaining undiscovered gas accumulations.

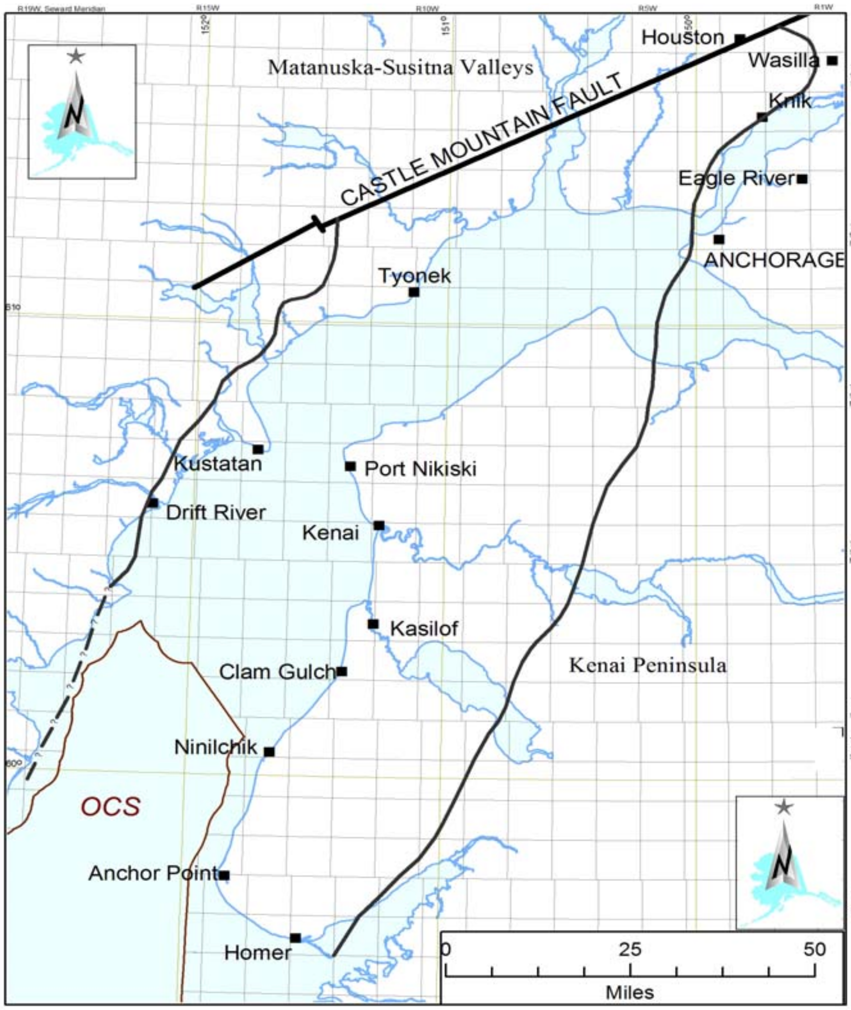


Figure 2.11. Cook Inlet Basin, Alaska -- probable limits of potential gas accumulations based on Kenai Group thickness (3000 foot isopach).

Structural Plays: Much of the current exploration is focused on smaller, less pronounced structures and under- or unexplored fault blocks on productive features. The Cannery Loop field was discovered on such a fault block at the north end of the structure responsible for the Kenai field. Recent exploration drilling and retesting on smaller structures has led to the gas discovery at Happy Valley and the confirmation of an oil accumulation at Cosmopolitan (Starichkof). It is anticipated that most of the near-term exploration will continue to be directed toward these play types. The recent discoveries have been in the range of several score to a hundred, or more, Bcf of gas

The eastern portion of the Kenai Peninsula is largely unexplored due to land access issues regarding the wildlife refuge (Figure 2.4). Maps of this area (Magoon, Adkinson, and Egbert, 1976) show anticlinal structures in both the Kachemak Bay area in the south and the

Chickaloon Bay area to the north but a lack of mapped structures in a large area between these extremes. This is probably a result of the lack of seismic control and rock exposures that would provide a basis for structural mapping. The mapped structures trend directly into the area and there is every reason to expect that anticlinal features are present and should represent attractive exploration targets. Small en-echelon (?) structures on the west side of the inlet, in the Moquawkie to West Forelands area, continue to provide exploration targets like those at Nicolai Creek and Lone Creek (Figure 2.7) and can be expected to yield fields with reserves in the several tens of Bcf or greater.

The number and location of such fields are impossible to predict, but conventional seismic methods should provide the needed data to find, evaluate, and ultimately drill those features deemed to have sufficient potential.

Stratigraphic Plays: Much of the current and past production has been from fields that possess a stratigraphic component. Since the fundamental Cook Inlet reservoir is either an alluvial fan or fluvial channel facies, few if any reservoirs will have a sheet-like geometry and the concurrence of structure and reservoir is largely a product of chance. Gas-bearing reservoirs are just as likely to occur on the flanks of structure and off-structure as on-structure.

The non-associated biogenic gas constitutes the vast majority of the gas endowment of the subbasin. Because of its mode of generation and the proximity of source and reservoir, non-associated gas may be found in traps throughout the basin. The presence and quality of seals are theoretically the primary controls on the accumulation of economic quantities of gas. If the Cook Inlet Basin replicates the exploration and production history of many basins worldwide, it may have yielded only a fraction of its natural gas endowment. Historically, stratigraphic plays have out-produced structural plays in areas like the Powder River Basin. The most promising areas for stratigraphic plays are the eastern and western margins of the basin and the flanks of the major structures. These areas are the easiest to identify and require less sophisticated seismic data to delineate prospective targets. Elsewhere in the northern Cook Inlet area 3-D seismic will be required to localize and prioritize purely stratigraphic opportunities.

The associated gas is less likely to have accumulated in purely stratigraphic traps. Since the associated gas was sourced from the Jurassic and migrated up-section into the lower Kenai reservoirs (Figure 2.5), its distribution is largely dependent on the existence of communication pathways from the source rocks to the reservoirs. This migration is believed to be facilitated by deeply penetrative faults or the presence of unconformities that superpose the Kenai section on the Mesozoic source intervals. These relationships are most commonly or even exclusively associated with the large anticlines exhibiting early growth.

The bulk of the estimated undiscovered unproven gas reserves are expected to be found in this portion of the greater Cook Inlet Basin and in stratigraphic plays.

Deep Basin Plays: This category includes two different sets of plays in the upper Cook Inlet subbasin. These are Mesozoic objectives of both a structural and stratigraphic nature and the deeper Tertiary features suggested by the technique of energy absorption analysis seismic processing (Demarchos, et al., 2002). The authenticity of both plays is questionable and they carry a high level of risk.

The Mesozoic plays were the primary objectives in the early phase of exploration in Cook Inlet. This emphasis was the direct result of numerous oil seeps from Jurassic and Cretaceous exposures on the Alaska Peninsula. In fact, the Swanson River Field was discovered as the result of drilling an exploration well to evaluate a Cretaceous objective. The potential Mesozoic plays are in the uppermost Jurassic, and the Cretaceous portions of the section. The principal reservoir objectives would be the Naknek, Staniukovich, Herendeen, Kaguyuk, and Saddle Mountain (Figure 2.5). Gas in the Mesozoic reservoirs would be associated gas derived thermogenically from Jurassic sources. The probability that these potential resources would be the objective of an intensive exploration effort is low. The costs and risks associated with this play would be difficult to overcome.

The second category of play considered under this classification is a deep Tertiary play with the primary zone of interest being the “Tertiary and pre-Tertiary Formation” (Demarchos, et al., 2002). The appellation “Tertiary and pre-Tertiary Formation” is applied to rocks that could be Hemlock, West Foreland, or Upper Jurassic/Cretaceous sediments. The prospective features are large fault-bounded structures with both stratigraphic and structural traps and in addition to the “Tertiary and pre-Tertiary Formation” have shallower opportunities in the Tyonek through Sterling formations. These shallower objectives are included in the normal structural and stratigraphic plays discussed earlier. Two major features are present, the Kitchen and East Kitchen prospects with 9,000 feet and 4,000 feet of structural closure, respectively. The Kitchen prospect and the East Kitchen prospect are gauged to have 39,000 and 18,000 acres of closure. The main target is the "Tertiary and pre-Tertiary Formation," estimated to have 12.3 Tcf of potentially recoverable reserves at depths of 12,000 to 20,000 feet, and the shallower horizons are estimated to contain an additional 11.9 Tcf (Demarchos et al., 2002).

The validity of the Kitchen prospects is an unknown. No wells have been drilled to test the hypothesis. The volumes tentatively attributed to these prospects seem at first examination to be unrealistically large; however, there are gas endowment scenarios where fields approaching this size are possible. These scenarios will be examined later.

2.6.2.2 Lower Cook Inlet Subbasin

In this discussion, the term lower Cook Inlet subbasin is used to include the subbasin south of the Augustine-Seldovia Arch (Figure 2.1) plus the OCS area south of Kalgin Island to the arch. The OCS area from south of Kalgin Island to the Shelikof Straits (Figure 1.1) has been very lightly explored, and only 13 wells have been drilled in the 1978 to1985 timeframe (MMS, 2001). The area that has been offered for leasing in the past and is currently being evaluated in preparation for two planned lease sales consists of approximately 2,500,000 acres or 4000 square miles (10,400 sq. km). The exploration well density is approximately one well per 300 square miles (800 sq. km). The wells were drilled on oil prospects. There are currently only a few active leases in the OCS, near Anchor Point (Figure 2.9).

The undiscovered conventionally recoverable gas resources of the Cook Inlet Planning area, the site of proposed lease sales 191 and 199, are estimated to range from 660 Bcf (F95) to 2,490 Bcf (F05) with a mean of 1,389 Bcf (MMS, 2003b).

Structural Plays: The lower Cook Inlet subbasin and the OCS portions of upper Cook Inlet have abundant untested structures, but a generally thin Kenai Group section. The more prolific reservoirs of the upper Kenai Group are absent and the gas is more likely to be of thermogenic origin and derived from the oil-prone Mesozoic source rocks. The 13 wells in this area are all on-structure and three had oil shows. The MMS considers this area to have only modest potential for structurally trapped gas. Approximately 550 to 600 Bcf of the mean estimated resources are expected to be reservoired in structural traps (MMS, 2003b). The MMS (1998, Figure 23-6 and 2003b, Figures B-6) considers the bulk of the OCS from Kalgin Island to the southern end of Shelikof Straits to have potential for Mesozoic structural plays. Potential structural plays in the Tertiary section (MMS, 2003b, Figure B-5) are limited to the OCS area north of the Augustine-Seldovia Arch and south of Kalgin Island (Figure 2.1).

Stratigraphic Plays: Only the portion of the OCS north of the Augustine-Seldovia Arch and south of Kalgin Island should have reasonable potential for non-associated biogenic gas. It is an extension of the geologic province in state waters and lands to the north. The Tertiary section thins significantly to the south, onto the Augustine-Seldovia Arch, but sufficient section remains to provide for Tertiary stratigraphic play opportunities (MMS, 1998, Figure 23-5 and 2003b, Figure B-5). Of the mean expected reserves, nearly 60% or over 800 Bcf is estimated to be in stratigraphic traps. The bulk of the reserves are in Tertiary reservoirs.

The area south of the Augustine-Seldovia Arch may have modest Mesozoic stratigraphic potential for thermogenic gas. The MMS (1998, Figure 23-5 and 2003b, Figure B-7) considers the western portion of the OCS from Kalgin Island to the southern end of the Shelikof Straits to have potential for Mesozoic stratigraphic plays. The Tertiary section is thin and the conditions necessary for generation and accumulation of biogenic gas do not exist; hence, any potential Tertiary stratigraphic traps are unlikely to be charged. Most gas potential in this area is associated with the Mesozoic-sourced oil and would probably be found in Mesozoic structural and stratigraphic traps with oil.

Deep Basin Plays: The aforementioned Mesozoic targets constitute the deeper plays in this subbasin. There is no equivalent to the “Kitchen” prospects of the upper Cook Inlet.

2.6.2.3 Susitna Basin

A total of nine wells (ADNR, 2003a) have been drilled in the Susitna Basin, an area of approximately 3,000 square miles (7,775 sq. km), for a density of one well per 330 square miles (855 sq. km). Even this density is deceptive since most of these wells have been drilled in a small area just north of the Castle Mountain Fault (Figure 2.4). No basin-specific estimates of gas reserves have been published for the Susitna Basin.

The basin contains the younger portions of the Kenai Group, but it lacks the West Foreland and Hemlock equivalents (ADNR, 2003a). The prospective Tertiary interval is at least 13,000 feet thick (Merritt, 1986, Figure 3). In contrast to the Cook Inlet Basin, the Jurassic oil-prone source rocks have not been found in the subsurface or in outcrop. The presence of dry-gas source rocks in the Susitna Basin, similar to those found in the Cook Inlet Basin, and the apparent absence of oil-prone source rocks indicate that the potential for finding gas in the Susitna Basin is much greater than for oil (Ryherd, 1997).

Structural Plays: The Susitna Basin has few rock exposures suitable for mapping purposes and limited seismic control, but some broad low amplitude structures are known to exist. Faulting associated with the Castle Mountain and other faults has developed additional structural features that may act as traps (Merritt, 1986 Figure 3). The dominant structural style of the Susitna Basin is a combination of graben and half-graben basement faulting (ADNR, 2003a). Most if not all the exploration wells have been drilled on seismically recognized structures. With the apparent lack of a Mesozoic oil-prone source-rock, the gas is probably biogenic and thus only casually associated with structure. The structures are the obvious plays of first choice, simply because they are easy to identify. The magnitude of potential volumes of gas is unknown, but individual accumulations should be equivalent to the intermediate size fields in the upper Cook Inlet (50 to 200 Bcf).

Stratigraphic Plays: The Susitna Basin is expected to have the same relationship among source, reservoir, and trap type as seen in the upper Cook Inlet subbasin. The area has abundant coals and coaly mudstones in the Tyonek, and potential fluvial and alluvial fan reservoirs abound in the stratigraphic section. The potential for biogenic gas is excellent and the quality of seals at relatively shallow depths is expected to be better than it is in the upper Cook Inlet area. Accumulations may be expected to be in the tens to a few hundred Bcf.

Deep Basin Plays: The Susitna Basin appears to lack plays of this type. The pre-Tertiary source rocks have not been recognized and the Mesozoic basement is non-prospective.

2.6.3 Coalbed Natural Gas

Coalbed natural gas recently has been the focus of much attention in south-central Alaska. Leasing and exploration in the Matanuska-Susitna area, specifically near Houston and Sutton, has dominated the local press and politics. As a result, the state is taking a fresh look at leasing policies and the regulatory structure for shallow gas or coalbed natural gas leasing and exploration. Those issues aside, the Cook Inlet Basin and the Susitna Basin continue to be the areas of primary interest for coalbed natural gas exploration.

2.6.3.1 Coal Quality and Quantity

Coal is abundant in portions of the Tertiary section of both the Cook Inlet and Susitna basins and provides a potential source for large quantities of dry gas. The coal quality and rank ranges from lignite or subbituminous to anthracite. Montgomery, et al. (2003, Figure 1) present a figure that shows the geographic distribution of coal by grade in the Greater Cook Inlet Basin area. Semianthracite and anthracite are restricted to the Matanuska Valley coal field. Bituminous coals are limited to the Wasilla-Houston area of the Susitna Basin along the Castle Mountain Fault and to the western margin of the Susitna Basin, in the Beluga and Yenona coal fields. By far the greatest portion of the basin is characterized by subbituminous coals or even lignites.

These coals form a large resource totaling 0.5 trillion tons of bituminous and 1.0 trillion tons of subbituminous rank (Merritt, and Belowich, 1984 and Merritt, and Hawley, 1986). Most of the coal occurs in the Tyonek and Beluga formations, with locally significant volumes in the Chickaloon Formation of the Matanuska Valley. Coals of bituminous and higher rank are present at relatively shallow depths (<5,000 feet) only in the northeastern part of the basin. The character of the basin's coals are presented by Montgomery et al. (2003, Table 1). The greatest volume of coal is found in the Tyonek where there are 30 or more seams ranging from 5 to 50 feet thick, totaling 300 feet of subbituminous C to bituminous coal. The Beluga coals are subbituminous C in rank and range from 2 to 30 feet thick with a total of 125 feet. The Sterling coals are lignites and generally less than 5 feet thick and total about 150 feet.

2.6.3.2 Exploration and Leasing

The potential for coalbed natural gas in the Cook Inlet Basin has been recognized for more than a decade and there are nearly 1,000,000 acres, with coalbed natural gas potential, either leased or licensed in the uppermost regions or Cook Inlet and the Susitna basin. The ADNR provided the first test of this potential when they drilled the AKDNR AK-94 CBM-1 well in 1994. This well was drilled near Wasilla and reached a total depth of 1,245 feet in the Tyonek Formation. The first Cook Inlet exploration program targeting coalbed natural gas was initiated in 1998 by Unocal and Ocean Energy (Dallegge, and Barker, 2002 and Montgomery, et al., 2003). This program continued until late 2003 under the management of Evergreen Resources, which discontinued the pilot program for the near term and embarked on a core test program. The Alaska DOG and AOGCC have approved drilling plans and permits for a total of five core holes in the area between Palmer and Willow (Petroleum News, 2003c).

Two separate programs are available for land acquisition, shallow gas leasing, and exploration licensing. Shallow gas leasing has been utilized extensively in the Sutton area, the Willow area, and in scattered parcels near Homer (Figure 2.9). The leasing program in the more developed areas of the Matanuska-Susitna Borough has come under heavy criticism from the local residents, many of whom do not own the subsurface mineral rights beneath their property. The shallow gas leasing program is on hold at the time of this report while the state establishes a revised regulatory framework for leasing and development of shallow gas resources.

Before the recent stop in the shallow gas leasing program, the state received application and work commitments for three licenses in the Susitna Basin (Figure 2.9 and ADNR 2003a, Figure 2.2). These licenses were issued in late 2003. Terms for these licenses are published by the ADNR (2003b). Two of the licenses (License no. 1 and no. 2) were granted to Forest Oil (Petroleum News, 2003d). These leases have a total of 857,680.86 acres (ADNR, 2003b). Forest Oil is evaluating their options for exploring these licenses. Exploration License no. 3 was issued to Clearflame Resources LLC. The license was for 478,584.35 acres. Clearflame subsequently declined to take the license (Petroleum News, 2003d).

Nearly 1,000,000 acres with coalbed natural gas potential are either leased or licensed in the uppermost regions or Cook Inlet and the Susitna basin. Based on Evergreen's efforts and the negative reaction of local land owners, exploration will probably move slowly for the next few years until the state develops and puts in place a revised regulatory framework for shallow gas exploration and development.

2.6.3.3 Potential Reserves

The evaluation of coalbed natural gas potential for a specific basin involves analysis of coal samples to measure the gas content and adsorption capacity. The adsorption capacity is the maximum volume of gas that a coal can contain under different pressures and temperatures. In the Cook Inlet area, the average methane content for subbituminous coals is approximately 80 scf/ton and for bituminous coals 230 scf/ton (Montgomery, et al. 2003). Montgomery et al. (2003) present a total gas in place (GIP) estimate of 245 Tcf. The basis for this estimate is presented in the 2003 paper (page 12). If 10% of this resource is accessible to production at 50% recovery, potential reserves are on the order of 12 Tcf.

However, subsequent investigations by Dallege, and Barker, (2002) suggest that the original estimates of GIP are high, due to inadvertently including repeated section in the volumetric calculations published in Montgomery, et al. (2003). The reevaluation of the coal volume resulted in a GIP resource estimate of 140 Tcf. Again, utilizing the assumption that 10% is accessible for production and a 50% recovery rate the potential undiscovered producible reserves are reduced to 7 Tcf. This is still a significant resource and is equivalent to more than 30 years of supply for south-central Alaska at the current demand level of approximately 200 to 220 Bcf/year.

Considerable uncertainty remains about the economic viability and environmental consequences of coalbed natural gas production in south-central Alaska. See Section 3.5 for additional discussion.

2.7 Magnitude of Gas Endowment in Cook Inlet Basin

Estimating the natural gas resource that may represent the ultimate potential for conventional gas in Cook Inlet Basin is difficult. Historically, Cook Inlet's natural gas has been underexplored and there has not been an intensive effort to explore for and evaluate the resource. However, the proven natural gas reserves in south-central Alaska have been depleted to the level that the capability to meet future demand is in question, which mandates an understanding of the remaining undiscovered natural gas resource. To do so, a mechanism must be provided to characterize the distribution and approximate the magnitude of the total amount of conventional gas, or gas endowment, in the basin.

Recent concerns regarding the adequacy of future gas supply have led some to compare the statistical distribution of field sizes in upper Cook Inlet with those of other large hydrocarbon basins (Jepsen, 2002). The significance of this type of comparison is that hydrocarbon basins have been shown to contain fields of different sizes and that the field size distribution is log-normal (Rose, 1996 and Potential Gas Committee, 2002). Simply put, this means that there will be a few large fields (giants) with an increasing number of smaller fields (Jepsen, 2002). Application of the USGS field class size descriptions to the gas fields of Cook Inlet leads to the conclusion that a large gap exists in the distribution of gas fields in the basin: Class 9 (1,536 to 3,072 Bcf) has three fields; Class 8 (768 to1,536 Bcf) has one field; Class 7 (384 to 768 Bcf) has zero fields; Class 6 (192 to 384 Bcf) has one field; and Class 5 (96 to 192 Bcf) has seven fields (Figures 2.11 to 2.15). In a log-normal distribution, Class 8 would have more fields than Class 9, Class 7 more than Class 8, and so on.[6]

To examine a range of possible conventional gas endowments and log-normal distributions of field sizes in the Cook Inlet basin, five cases were constructed to represent original gas in place (OGIP) volumes ranging from 15 to 35 Tcf. Four steps were followed to evaluate these cases and develop an estimation of the resource base. The steps are as follows:

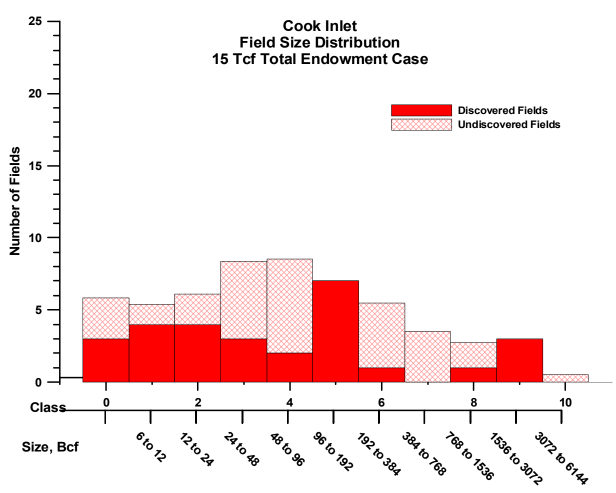
- Utilization of USGS field class size description to sort field sizes:
  - Class 1: 6 to 12 Bcf
  - Class 2: 12 to 24 Bcf
  - Class 3: 24 to 48 Bcf
  - Class 4: 48 to 96 Bcf
  - Class 5: 96 to 192 Bcf
  - Class 6: 192 to 384 Bcf
  - Class 7: 384 to 768 Bcf
  - Class 8: 768 to 1536 Bcf
  - Class 9: 1536 to 3072 Bcf
  - Class 10: 3072 to 6144 Bcf

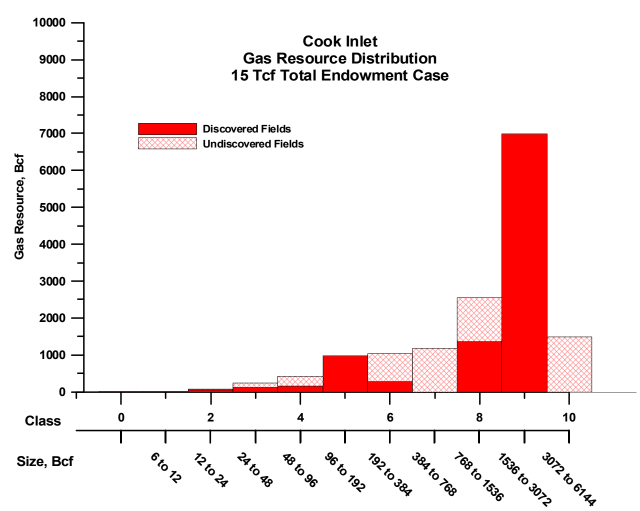
[6] Detailed discussions and scientific background for estimating the volume of undiscovered oil and gas resources can be found in *Studies in Geology No. 1*, *Methods of Estimating the Volume of Undiscovered Oil and gas Resources,* edited by John D. Haun, American Association of Petroleum Geologists, 1975 and in *Documentation of Oil and Gas Supply Module (OGSM)*, Energy Information Administration, DOE/EIA-M063(2001), January 2001.

- Identification of known accumulations and OGIP volumes
- Estimation of total conventional gas resource endowment in Cook Inlet for five cases: 15, 20, 25, 30, and 35 Tcf
- Utilization of log-normal field size distribution to estimate undiscovered gas resources (number of fields and resources per class).

The approach used here differs from that used by the USGS in its reserve assessments, but the results are similar and the conclusions comparable.

Five cases were selected to provide a representative scope of possible conventional gas endowments for upper Cook Inlet, including the federal OCS area north of the Augustine-Seldovia arch. They range from a minimum resource (15 Tcf) to a robust basin case (35 Tcf). Each case was constructed with an average field size of 330 Bcf and a standard deviation of 2,000 Bcf. The products of these evaluations are represented by a series of two-component figures (Figures 2.12a and b through 2.16a and b) that show the field size and gas resource distributions by class. For Figures 2.12 through 2.16, the discovered fields and resources are plotted in a solid pattern and the undiscovered fields and resources are plotted in a cross-hatched pattern. In this report, only classes 3 through 10 appear to have impact on the resource scenarios. The results of Figures 2.12 through 2.16 are summarized in Table 2.9.





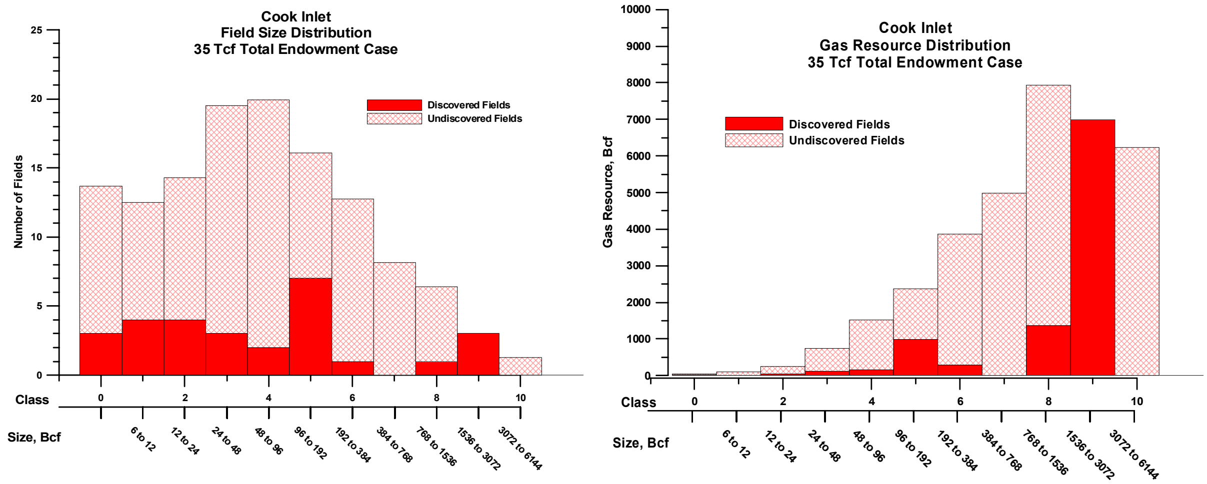
a. ***b.***

Figure 2.12. 15 Tcf Total gas endowment case: (a.) Inferred field size distribution; (b) inferred gas resource distribution by class size.

Ideally, in a mature basin where the bulk of the resource has been discovered through an extensive exploration program, the field size distribution should approximate a smooth curve with an increasing number of fields when progressing from the large to small classes until the modal class is reached. The converse would be true with the gas resource distribution. The greatest resources would be found in the large-size classes with a continuous decrease in resources per class as the classes became smaller. Gaps, in either or both of these distributions imply that there are missing resources or fields corresponding to specific class sizes. A pronounced skewness or bimodality in the distribution of discovered resources indicates portions of the distribution are not accounted for and are undiscovered or potential gas resources. In its 2002 report, the Potential Gas Committee noted, "Four fields each have estimated ultimate recoveries (EUR's) in excess of 1.0 Tcf, four range from 100 to 250 Bcf, and a handful of fields range from 50 to 100 Bcf. From this distribution one would expect that more mid-size fields remain to be discovered in the province."

The smallest endowment scenario is shown in Figure 2.12 and represents 15 Tcf OGIP or about 50% more gas than accounted for by the sum of production and proven unproduced reserves. In this conservative case, there are nine "undiscovered" fields in classes 6 through 8 with approximately 3,200 Bcf of OGIP (Table 2.9). At a recovery factor of 0.85, this translates to undiscovered conventionally recoverable resources of 2,700 Bcf. The 11 smaller fields, in classes 1 to 5 would provide 450 Bcf OGIP (Table 2.9) or about 380 Bcf of additional undiscovered conventionally recoverable resources. The total for additional undiscovered recoverable resources is approximately 3,100 Bcf in this scenario. Future reserves growth in the order of 2,500 to 3,000 Bcf, as discussed in Section 2.6.1 and the 1,000 Bcf of undiscovered reserves postulated by some evaluators would easily account for this quantity.

At the other extreme is a hypothetical endowment of 35 Tcf OGIP (Figure 2.13). This endowment provides for a class 10 field (Figure 2.13a) with a possibility of more the 6,000 Bcf OGIP and 24 class 6 through 8 fields totaling more than 14,000 Bcf OGIP (Figure 2.13b). The sum of potential undiscovered conventionally recoverable resources in classes 6 through 10 is 17,300 Bcf (Table 2.9). The 43 smaller fields in classes 3 through 5 could provide an additional 3,300 Bcf of OGIP or 2,800 Bcf potential undiscovered conventionally recoverable resources (Table 2.9). The 35 Tcf endowment case suggests additional undiscovered conventionally recoverable resources totaling approximately 19,800 Bcf. Reserve growth in existing fields may constitute 15 to 20% of this total.



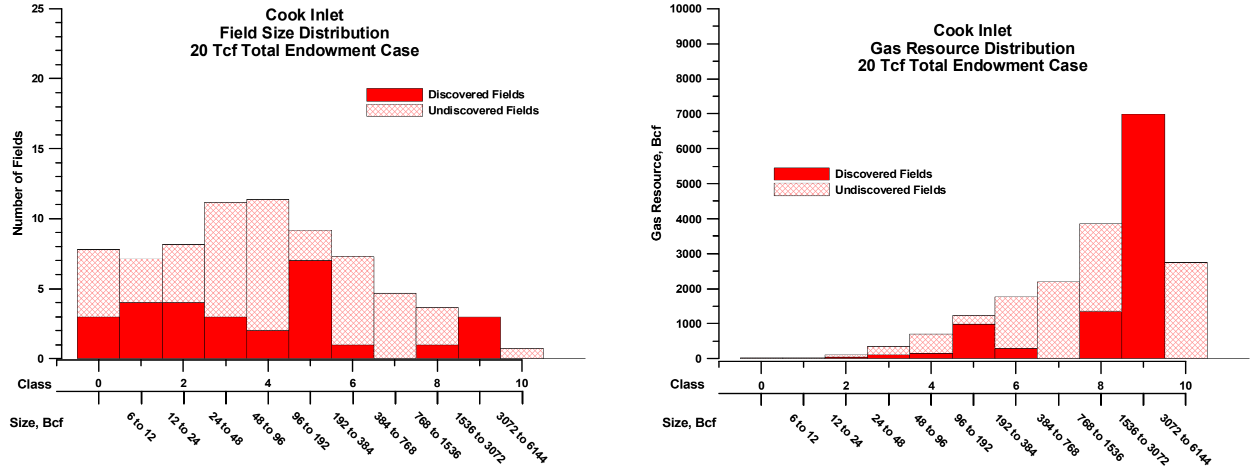
a. **b.**

Figure 2.13. 35 Tcf total gas endowment case: a.) Inferred field size distribution; b.) Inferred gas resource distribution by class size.

These two end-members of the possible distributions appear to bracket the most realistic endowment case. The distribution of both known field sizes and undiscovered field sizes in the 15 Tcf case do not provide a good fit to a log-normal distribution. The distribution is "pinned" by the three fields of class 9 (Figure 2.12) and to a lesser extent by seven fields of class 5. The shape of the curve controlled by the known field distribution indicates that the endowment of 15 Tcf is too small. In the 35 Tcf case, the field size and resource distributions (Figure 2.13) appear to be approaching a maximum probable case for gas endowment in the basin. The number of 400 to 1,500 Bcf fields (13) remaining to be discovered in this case far exceed those discovered to date (1) and would suggest little exploration of the basin's gas potential. This may be true, at least with respect to the potential for stratigraphic accumulations.

Acknowledging the historical lack of stratigraphic exploration, it appears plausible that at least half of the basins potential gas resources have not been found or even been the targets of exploration drilling. In this vein, the 20 Tcf endowment (Figure 2.14) also appears to be insufficient to account for the basin's potential and the 25 or 30 Tcf endowment cases appear to be the most realistic scenarios.

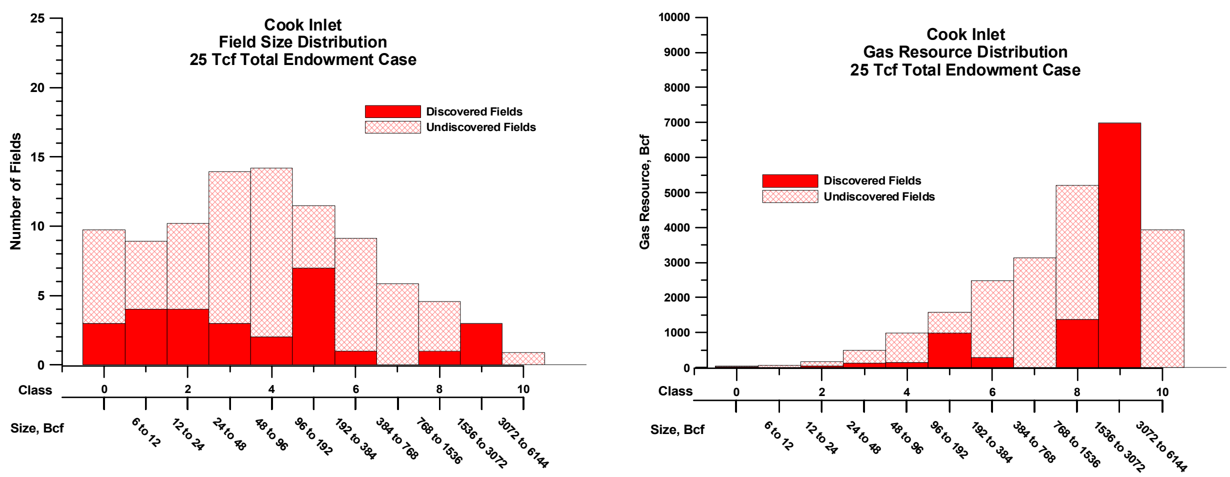
Figure 2.14a and Table 2.9 indicate that in the 20 Tcf endowment scenario 14 fields are possible in classes 6 through 8 with a total of 6,100 Bcf OGIP; a possible class 10 field with 2,800 Bcf OGIP (Figure 2.14b); and 19 fields in classes 3 through 5 with 1,000 Bcf OGIP. This is a total of 9,900 Tcf OGIP or 8,400 Bcf of undiscovered conventionally recoverable resources.



a. **b.**

Figure 2.14. 20 Tcf gas endowment case: a.) inferred field size distribution; b.) inferred gas resource distribution by class size.

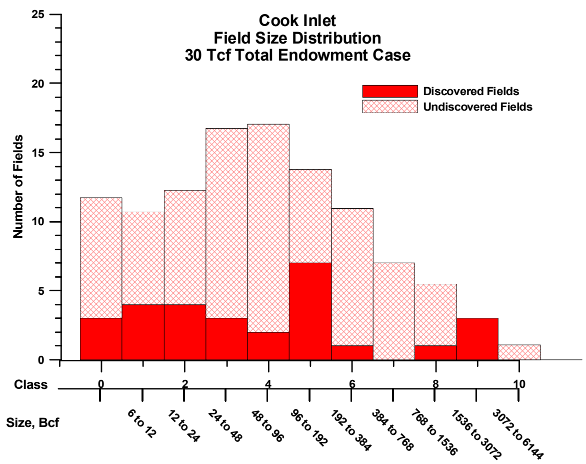
Figures 2.15a and 2.15b and Table 2.9 show the number of fields and resource distributions for the 25 Tcf endowment case. Similarly Figures 2.16a and 2.16b represent the distribution of field sizes and resources for the 30 Tcf case. In the 25 Tcf endowment (Table 2.9), there are 17 class 6 through 8 fields with 9,200 Bcf OGIP and a possible class 10 with about 4,000 Bcf. There are 28 class 3 through 5 fields with an estimated 1,700 Bcf OGIP. This yields a total of approximately 15,000 Bcf OGIP and 12,700 Bcf undiscovered conventionally recoverable resources.



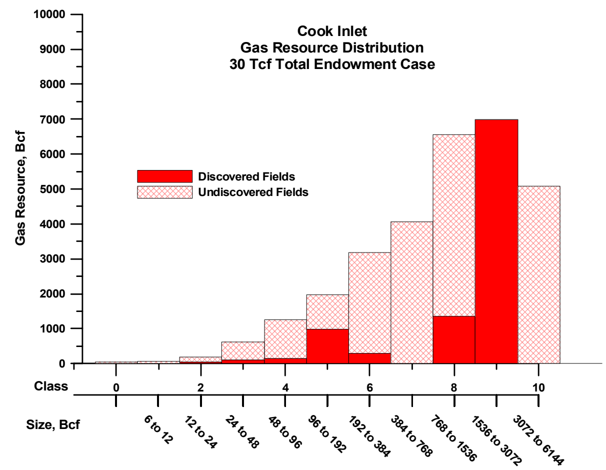
a. **b.**

Figure 2.15. 25 Tcf gas endowment case: a.) inferred field size distribution; b.) inferred gas resource distribution by class size.

In the 30 Tcf endowment (Figures 2.16a and 2.16b and Table 2.9), the undiscovered fields and associated resources are estimated to be found in 21 class 6 through 8 fields with 12,000 Bcf OGIP, one class 10 field with 5,000 Bcf OGIP, and 34 smaller class 3 through 5 fields with 2,700 Bcf OGIP. These undiscovered fields have the potential for 19,700 Bcf of OGIP or more than 16,700 Bcf of undiscovered conventionally recoverable resources.



a.



b.

Figure 2.16. 30 Tcf total gas endowment case: a.) Inferred field size distribution; b.) Inferred gas resource distribution by class size.

Table 2.9. Distribution of undiscovered gas resources by USGS class size in five possible gas endowment scenarios – Cook Inlet Alaska.

Gas Endow-ment OGIP (Tcf)	**Undiscovered Fields by Class Size**				**Undiscovered OGIP by Class Size (Bcf)[1]**				**Undiscovered Conventionally Recoverable Resources by Class Size (Bcf)[2]**			
Class Size range	3-5	6-8	10	Total	3-5	6-8	10	Total	3-5	6-8	10	Total
15.0	11	9	0	20	450	3,200	NA	5,000	380	2,700	NA	3,100
20.0	19	14	1	34	1,000	6,100	2,800	10,000	850	5,180	2,380	8,400
25.0	28	17	1	46	1,700	9,200	4,000	15,000	1,450	7,820	3,400	12,700
30.0	34	21	1	56	2,700	12,000	5,000	20,000	2,300	10,200	4,250	16,750
35.0	43	24	1	68	3,300	14,000	6,000	25,000	2,800	11,900	5,100	19,800

1. Total represents the volume of the gas endowment minus the OGIP in the known fields.
2. Total represents the sum of the undiscovered conventionally recoverable resources distributed among classes 3 to 10.

The most important portion of the log-normal distribution, in terms of impact on future reserve additions, is the distribution of reserves associated with field classes 6 through 8, which represent fields of 200 to 1,500 Bcf OGIP (170 to 1,275 Bcf recoverable). The two most probable endowment cases have between 16 and 21 fields in these size ranges (Figures 2.15a and 2.16a) with the potential for 7,800 to 10,200 Bcf of additional undiscovered conventionally recoverable resources (Figures 2.15b and 2.16b). Given that these fields exist, they should be the easiest to discover and develop because of their size. Most of these fields may be stratigraphic and require a more sophisticated exploration approach than has been used in the basin to date.

While the MMS assumes log-normality in its assessments, the USGS has utilized a different technique, a truncated shifted pareto (TSP) distribution to characterize the distribution of field sizes and resources. If the TSP approach is utilized for the 25 Tcf endowment case, the resulting undiscovered recoverable reserves attributed to field size classes 6 through 8 (14 fields) are somewhat less than those seen in the log-normal case. Undiscovered conventionally recoverable resources in these key field sizes are approximately 6,600 Bcf compared to 7,800 Bcf in the log-normal case.

These estimates of undiscovered recoverable resources are unrisked and the accessibility or economic aspects of accumulations corresponding to these potential undiscovered resources are largely unknown or highly variable factors. Published estimates of undiscovered resources are generally much more conservative than the estimates presented here, with the sole exception of the estimate of approximately 24.0 Tcf attributed to the Kitchen prospects (Demarchos, Warthen, Davis, and Economides, 2002). Most estimates are in the range of 3,550 Bcf (MMS, 2000 and USGS, 1995) to 6,550 Bcf (Potential Gas Committee, 2002). The Federal estimate cited is the sum of the MMS and USGS basinwide mean values for undiscovered conventionally recoverable resources and by contrast the Potential Gas Committee estimate includes probable, possible, and speculative reserves. These estimates may be somewhat dated, since they were made over a period of time from 1995 to 2002.

Based on the log-normal approach to the distribution of undiscovered fields, it is estimated that the upper end of the range of undiscovered conventionally recoverable resources lies between 12.7 and 16.7 Tcf of gas as shown in Table 2.9. While this quantity may appear to be quite large, several key factors tend to make volumes of this magnitude appear within reason: (1) only a recent and very modest effort to explore specifically for gas, (2) no exploration for stratigraphically trapped gas, and (3) large areas of the basin are under- or unexplored. These numbers include the expected reserve growth volumes associated with the known accumulations and thus may be reduced by 2.5 to 3.0 Tcf. The upside for undiscovered conventionally recoverable resources, in the strictest sense, may be adjusted to approximately 10 to 14 Tcf.

A more conservative estimate would be one based on the reserves expected to be associated with the as-yet undiscovered class 6, 7, and 8 gas fields with undiscovered conventionally recoverable resources estimated to range from about 7.8 to 10.2 Tcf.

These foregoing totals have not included fields of class size 1 and 2 as they tend to contribute little to the overall resource picture when compared with the class 6 through 8 fields. This treatment does include class 3 and larger fields. In Section 4.5, the minimum economic field size for onshore locations near infrastructure includes class 3 fields.

As the previous sections indicate, a large volume of untapped gas remains within the greater Cook Inlet Basin. Any estimate that seeks to combine reserves growth within existing fields, the magnitude of undiscovered conventional gas resources, and the potential contribution of coalbed natural gas, is certain to lack precision. While precision may be lacking, there is evidence that the undiscovered resource may be in excess of 10 Tcf OGIP and may be as much as 20 Tcf OGIP. A resource potential of this magnitude may be parsed out among reserve growth (2.5 to 3.0 Tcf), undiscovered conventionally recoverable gas (10 to 14 Tcf), and coalbed natural gas ($\approx$7 Tcf).

It is worth repeating that these resource volumes are not all equal in terms of risk, economic viability, and accessibility. The intent is to provide a magnitude of potential resource for the purpose of considering the need for, timing of, and economics of alternative sources of natural gas for south-central Alaska into the second decade of the 21st Century and beyond.

2.8 Potential of Adjacent Regions in Southern Alaska

Two other areas in southern Alaska may have potential for natural gas. These are the Copper River Basin, east of Cook Inlet, and the Bristol Bay Basin (Figure 1.1), situated on the west side of the Alaska Peninsula and under the adjacent waters of Bristol Bay. Both of these areas have undergone one or more episodes of oil-oriented exploration. There has been no exploration for gas, but good gas shows have been reported during these earlier exploration programs.

Exploration licenses either have been issued, as in the case of the Copper River Basin, or are pending, as in the Bristol Basin. Some level of exploration activity can be expected in both basins within the next two to three years.

2.8.1 Copper River Basin

The Copper River Basin (Figure 1.1) is centered approximately 150 miles east-northeast of Anchorage and, as a topographic feature, occupies an area of approximately 6,500 square miles. The basin has a maximum length of 120 miles and width of 75 miles (Hite, 1993). There is no exploration, production, or transportation infrastructure in the basin and the last exploration well was drilled in 1980. Nonetheless there has been recent interest in the area and several companies have invested in field programs, seismic reevaluation, and assessments for licensing purposes.

2.8.1.1 Exploration History

Geological field work commenced in the late 19th Century and has continued to the present. Field work over the last half century has confirmed that the Mesozoic and Tertiary strata of the adjacent Chugach and Talkeetna Mountains correlate with the highly productive stratigraphy of the Cook Inlet oil and gas province (Hite, 1993). These correlations strongly suggest that hydrocarbon reservoirs and source rocks should exist in the subsurface of the Copper River Basin, and limited exploration drilling has confirmed that equivalent units are present.

Oil stain and petroliferous odor are found in the Nelchina Limestone and associated sandstones of Early Cretaceous age (Figure 2.2), and there are unconfirmed reports of live oil seeps. A reliable source has confirmed that Mobil Oil has extracted an unknown volume of 30º API oil from the Nelchina Limestone.

Mud volcanoes in the Tolsona area have a high percentage of methane in the emitted gasses. The three small mud volcanoes in this group average 57.4% methane with up to 0.2% ethane and traces of propane and butane+ (Nichols, and Yehle, 1961). Nitrogen is the second most abundant component of the gas, averaging 41.8%. The recognition of the gas composition of these mud volcanoes further fueled interest in the basin.

2.8.1.2 Geophysical Investigation

Geophysical work in the Copper River Basin and the surrounding area has been largely conducted in a reconnaissance format. Aeromagnetic and/or gravity surveys were conducted by various companies/agencies and over different portions of the basin, starting in the mid- to late-1950s through the mid-1980s (Hite, 1993). Interpretation of an aeromagnetic survey acquired in 1985 resulted in the placement of the basement in the southern portion of the basin below 16,500 feet (Case et al., 1985). Based on magnetic susceptibility, the basement is probably the Triassic-Jurassic Talkeetna Formation (Figure 2.2), which implies the probable existence of a thicker, potentially prospective Mesozoic section than was previously thought.

Exploration driven seismic data were acquired in the late 1950s and early 1960s. Unocal's Vince Lemieu (1993) stated that "Unocal did conventional seismic acquisition in the basin and acquired at least 100 miles of data." There is good reason to believe that Amoco may have acquired seismic data prior to drilling the two Ahtna wells in the eastern portion of the basin in 1980. Under the exploration license acquired by Anschutz (Petroleum News, 2000b), Forest Oil Corporation is obligated to acquire new seismic data in 2004 (Petroleum News, 2000b and 2001b) to further evaluate the exploration license it holds in the basin. Forest Oil will acquire a small 2D program in the license area during the 2004 seismic season.

2.8.1.3 Exploration Drilling

Exploration drilling commenced in 1953 and continued sporadically until 1980. During this interval, 11 wells were drilled within the basin. The section penetrated ranged in age from Miocene clastics to the Late Triassic-Early Jurassic Talkeetna Formation. Several of the wells had oil shows and/or overpressured zones, frequently with associated methane gas flows. The overpressured zones were principally found in the Nelchina Limestone.

The drilling activity revealed that reservoir quality is highly variable, but possible reservoirs are present in the lower part of the Matanuska Formation, the Nelchina Limestone and associated Lower Cretaceous sandstones, and locally in the Jurassic Naknek Formation and Tuxedni Group (Figure 2.2). Only the Matanuska Formation and possibly portions of the Nelchina and Tuxedni appear to possess lithologies that could serve as source rocks. The basal Tertiary and non-marine portions of the Matanuska Formation contain coals that may be sources for dry gas. Source rock quality is largely unknown. Oil-staining and petroliferous odor are found in local exposures of the Nelchina Limestone and the associated Lower Cretaceous sandstones, and gas has been encountered in modest quantities (up to 500 Mcf/day) in at least one water well. Thus it is possible that both a thermogenically mature source for oil and associated gas and a coal-derived biogenic source may exist.

Well density is low, approximating one well per 600 square miles. The lack of good quality seismic data hinder the verification of the adequate structural positioning of the wells, and the data are not of sufficient quality to provide a meaningful evaluation of the basin.

2.8.1.4 Leasing and Land Ownership

The land ownership is a mixture of federal, state, and Native Corporation (Ahtna) holdings. The federal agencies have shown no recent interest in leasing lands in the basin for oil and gas exploration. The state has held lease sales in 1979 (34,678 acres leased) and 1982 (168,849 acres leased). The state of Alaska had scheduled a sale of approximately 500,000 acres (Sale No. 84) for April 1996, but it was cancelled due to lack of industry support. Ahtna Native Corporation has a large land holding and is interested in leasing to prospective exploration companies.

On August 25, 2000, the state announced it was granting an exploration license, covering 398,445 acres, to Anschutz Exploration Corporation. The effective date of the license was October 1, 2000, and it was issued for a term of five years (ADNR, 2003c). The Anschutz proposal included geologic field work, acquisition and reprocessing existing seismic data, collection and interpretation of gravity data, and acquisition and evaluation of new seismic data (Petroleum News, 2000b). The exploration license is now held by Forest Oil Corporation. No other leases are active at this time.

2.8.1.5 Gas Potential

As part of the USGS's appraisal of southern Alaska's hydrocarbon, Magoon et al. (1996) recognized an Upper Cretaceous-Tertiary biogenic gas play. They call upon coal and associated organic-rich shales within the Matanuska Formation and Tertiary for source and the interbedded sandstones for reservoirs. The USGS gives the biogenic gas play a low probability because it believes evidence is lacking for traps or sufficient gas to fill the traps.

It appears that not all parties consider the prospects for economic hydrocarbons to be low. Anschutz, and now Forest Oil, is proceeding to evaluate the basin. Despite their commitment, any contribution to south-central Alaska's gas supply is doubtful in the next five to 10 years, unless a moderately large field was found and a spur line was built from a North Slope gas pipeline that a Copper River Basin producer could utilize. This scenario appears unlikely for the near future.

2.8.2 Bristol Bay Basin

The Bristol Bay Basin (Figure 1.1) is situated between 300 and 500 miles southwest of Anchorage and underlies the west side of the Alaska Peninsula and adjacent waters of Bristol Bay. The area of interest includes the Tertiary basin and adjacent/subjacent Mesozoic objectives. The basin is a structural depression that underlies much of the northern side of the Alaska Peninsula and extends offshore in a southwestward direction. The total area of the basin is approximately 10,400 square miles (27,200 square kilometers) with 80% being offshore (MMS, 1985). The state's area of interest also includes onshore areas that lie well to the north of the basin as described above. The basin's sedimentary section is composed mostly of Cenozoic sediments that are more than 20,000 feet (6,000 meters) thick. A thick Mesozoic section (25,000 to 30,000 feet) is beneath the Cenozoic basin and beyond the limits of the basin itself.

The Bristol Bay Basin is far removed from the core area of interest, but it is being included for completeness. Native groups, the federal government, and the state of Alaska have recently expressed renewed interest in exploration and development of the area's hydrocarbon potential.

2.8.2.1 Exploration History

The area has held the attention of the industry for many years due to the presence of numerous oil seeps along the southern half of the Alaska Peninsula. A total of 26 wells have been drilled on shore since 1903 (Brizzolara, 2004). The most recent well is the Amoco Becherof No. 1, drilled in 1985. There is one offshore well in Bristol Bay, the ARCO North Aleutian COST well No. 1.

The stratigraphic section is composed of a lower Mesozoic section that is virtually identical to that of the Cook Inlet (Figure 2.2) and a younger Cenozoic section described in Magoon et al. (1996, Figure 2). The composite Mesozoic section is at least 12,600 feet thick and perhaps as much as 40,000 feet thick. The Cenozoic thickness is between 6,500 feet and 23,000 feet. The Mesozoic rocks are largely marine and the Cenozoic largely non-marine.

Oil and gas shows are evident in many of the wells, but no commercial flow of oil or gas has been demonstrated to date. Hydrocarbon source rocks of Tertiary age appear to be largely gas prone but deeper Mesozoic strata may possess both oil and gas generation potential (Magoon, Molenaar, Bruns, Fisher, and Valin, 1996, and Brizzolara, 2004).

Seismic control onshore is somewhat limited and of old vintage; thus, it is of very little use to those reentering this area. The offshore portion of the basin has an extensive grid of 2D seismic that was collected in the early 1980s. These data are of good quality and provide an excellent starting point for future evaluations.

2.8.2.2 Leasing and Land Ownership

As in the Copper River Basin, the land ownership in the Bristol Bay Basin area is a mix of Native Corporation, federal, and state holdings. All landowners have held lease sales at some time in the last 45 to 50 years. In 1968, the state of Alaska held a lease sale in state waters of the Port Moller/Port Heiden area. A total of 164,961 acres was leased and one well was drilled as a result. After numerous postponements, the federal government leased 121,757 acres in Sale 92, (North Aleutian Basin) held in October 1988 (MMS, 2003c). The sale was subsequently voided and the money refunded to the apparent winning bidders.

Onshore, the federal and state governments and the Bristol Bay Native Corporation have all held lease sales. During the late 1950s and early 1960s, federal noncompetitive leases and federal development contracts were issued. Consequently, nine exploratory wells were drilled along the northern coastal lowland area of the Alaska Peninsula. The state of Alaska held a sale in the Bristol Bay Uplands in 1984 during which 278, 939 acres were leased. An additional sale was scheduled for 1988 in the area between Liesko Cape and Port Heiden but was cancelled.

Because of renewed interest in the area and an increase in the level of regional support, both federal and state agencies are reevaluating the region and considering the possibility of lease sales in the next few years. The state of Alaska has also instituted exploration licensing in the Bristol Bay area. A 3,000,000 acre area was designated for licensing with a maximum of 500,000 acres per license (Petroleum News, 2003e). As of December 28, 2003, one proposal had been submitted by Bristol Shores, LLC (Petroleum News, 2003f, and ADNR, 2003d). The proposal includes 829,440 gross acres and includes significant non-state acreage, but the state is limited to 500,000 acres when it awards an exploration license.

These actions and possible state and federal sales herald a new era in exploration in the Bristol Bay area. This would be especially significant if the federal moratorium was lifted in the OCS and the MMS renewed planning for a sale in the old North Aleutian sale area. Even if the moratorium was lifted, the MMS could not schedule a sale prior to 2008. The level of industry interest has not yet been determined and low interest levels could deter any leasing plans.

2.8.2.3 Gas Potential

There is much uncertainty regarding resource estimates for the Bristol Bay Basin area. The MMS 2000 estimate is 6,790 Bcf for the mean case and a range of 0.00 (95% probability) to 17,350 Bcf for the maximum case (Sherwood and Craig, 2001). The MMS is currently reassessing the old North Aleutian Shelf area. The 2000 estimates are for the old lease sale area only and are not indicative of the entire Bristol Bay area or even of the basin itself, which extends beyond the original sale limits and onshore. Including the onshore portion of the basin and the other lands both on- and offshore these numbers may be expected to be significantly larger. The magnitude of gas resources, including both conventional and unconventional (coalbed natural gas) sources, could be in the vicinity of 20,000 Bcf. The feasibility of economically producing all or a fraction of that volume is unknown.

The state of Alaska has not released any estimates of resources for the Bristol Bay area and is not expected to do so soon. Their only public statements are that resources could be in the trillions of cubic feet (Brizzolara, 2004)

2.8.3 Summation

The magnitude of possible gas resource in the Copper River and Bristol Bay basins of southern Alaska are speculative and not confirmed by hard data. The potential contribution to the users in south-central Alaska is likely far into the future, if at all. Factors such as cost, technology, accessibility, and competing sources are nearly impossible to evaluate in terms of timing and magnitude of impact on local resource development. The estimates of "trillions of cubic feet" provide little in the way of comfort and will probably not have significant impact on the exploration plans and expenditures of most companies.

If exploration and development does take place in these and other basins, the probability that such activity will impact south-central Alaska's supply-demand picture is remote. The alternative sources would most probably have a distinct economic advantage unless the volumes were sufficient to support some other economic undertaking in addition to the industrial and residential needs of the greater Anchorage area and adjacent portions of south-central Alaska.

2.9 Constraints on Reserve Additions

The possible magnitude of potentially recoverable undiscovered conventional and unconventional natural gas is impressive, but it is encumbered with constraints and limits on industry's ability or willingness to explore and develop its fullest potential. Factors that may serve to preclude development of all or a significant portion of this potential resource include: (a) the cost of exploration and development activities in Cook Inlet and surrounding areas; (b) development and utilization of technology that will facilitate exploration for stratigraphic accumulations and reduce drilling problems; (c) accessibility of lands (waters) that may hold a major portion of these undiscovered reserves; and (d) development of alternative energy sources or supplies such as wind, hydropower, and coal.

The shift to alternate energy sources or supplies may be treated as a special case of the cost or "price-of-doing-business" factor. These options are being evaluated by the local power producers, Chugach Electric and Anchorage ML&P, and are not analyzed in this study. The constraints or issues of most concern in the current context are access to land for exploration activities, drilling and development operations, transportation corridors, leasing, and the application or development of technology that will maximize the ability to find and develop the resource.

2.9.1 Technology

At present, two key technologies are just beginning to come into full and routine application in the basin, 3D seismic acquisition and extended-reach horizontal drilling. The routine use of these methods will be essential to achieve anything approaching the full realization of the basin's potential. These tools permit the recognition of more subtle stratigraphic traps and access via the drill to environmentally sensitive areas in the near-shore zone or beneath critical habitat.

2.9.1.1 3D Seismic Acquisition

The shift from 2D to 3D seismic acquisition along with the focus on the shallow portion of the section, will greatly facilitate the exploration for stratigraphic traps. The lion's share of seismic data in the Cook Inlet Basin is 2D and has been acquired with parameters that focus on the deeper oil-prone reservoirs of the Hemlock and lower Tyonek. This approach, while working well in the quest for structures that may have trapped hydrocarbons, has served to minimize the utility of the data for shallow stratigraphic gas. Acquisition of onshore 3D seismic data began in 1996 with a program in the Kenai gas field. During the 1996 to 2003 interval, eight 3D seismic programs were acquired onshore in Cook Inlet and seven of those programs were acquired over existing fields. The total area covered by these surveys is approximately 200 square miles (Hastings, 2004). Offshore, four 3D streamer surveys were acquired between 1993 and 1998. These surveys are all over existing fields.

Currently, 3D seismic acquisition and processing costs vary considerably throughout upper Cook Inlet and are dependent where the data are acquired (Hastings, 2004). Onshore, the costs range from $85,000 to $90,000/square mile with the higher costs for west side programs. Offshore acquisition and processing costs, at $45,000/square mile, are about half of onshore expenditures. In the troublesome transition zone, costs range from $110,000 to $115,000/square mile with the higher costs once again being on the west side of the inlet.

The fact that 3D programs are being acquired with parameters designed to emphasize the shallow section is an indication of the shift in emphasis to gas exploration and sets the stage basinwide for 3D seismic exploration for gas. Techniques are being developed and utilized that minimize the environmental impacts of seismic acquisition and hold promise for exploration in some of the more sensitive areas. The use of 3D seismic methods holds great promise for the future of gas exploration in the Cook Inlet area. Improved and lower-cost acquisition technology and interpretation techniques to locate stratigraphically trapped gas is an area where collaborative industry, federal, and state R&D programs can contribute to improved prospects for finding the gas resources in the Cook Inlet basin and throughout Alaska.

2.9.1.2. Horizontal Drilling

The use of extended-reach horizontal drilling could greatly enhance the ability to explore for and develop natural gas fields in the basin. As an example, horizontal drilling was used in the Cosmopolitan Unit to reach offshore objectives from a land-based drill site (Petroleum News, 2003a). The Hansen well was drilled to a target nearly four miles from its surface location. In addition to providing access to areas with surface occupation problems, this technology allows for the development of large, shallow fields from a small number of surface sites. This tends to reduce both development costs and environmental impacts. The technology would be ideal for exploration of the transitional zone (tidal flat regime) and beneath developed or restricted access areas onshore. Thus, horizontal drilling has the potential to open up large areas onshore and near shore to exploration and development. The same logic regarding development of large areas of shallow reserves applies to the offshore environment.

Some of the problems that must be overcome to realize full benefit from extended-reach horizontal drilling are availability of appropriate drilling rigs and sufficient opportunities to justify the long-term utilization of these rigs. If extended-reach horizontal drilling is required to develop or even explore in Cook Inlet, large rigs capable of drilling wells that may have a measured depth of 15,000 to 20,000 feet must be available in the basin. These are expensive rigs, and a single-well program may not be sufficient to justify the costs of mobilizing a rig to the Cook Inlet, drilling the well, and then demobilizing it after the well has been drilled. A program involving multiple wells would probably be required to make such an undertaking economically viable.

2.9.2 Land Access

The issues of access to land and the proper and timely exploration of that acreage are key elements in developing the full gas potential of the basin. Large tracts of acreage have been under- or unexplored because of a bias toward structural plays and against stratigraphic plays, land classification, and/or perceived risk of environmental degradation. Figure 2.17

depicts the distribution of currently leased lands/exploration licenses and the ownership of lands available for leasing. The lands currently being offered for leasing are owned by Cook Inlet Region Incorporated (CIRI), an Alaska Native Corporation; the state of Alaska through three administrative units; and the Federal Government.

The state of Alaska has the largest ownership position regarding currently leasable acreage. The state's primary lands are administered by ADNR and these holdings are shown on Figure 2.17 as the state of Alaska's Cook Inlet Areawide Sale Area. Two other state-related land owners have holdings in the basin, the University of Alaska and the Alaska Mental Health Trust. The state controlled acreage comprises about 75% of the available acreage in upper Cook Inlet. The federal government, through the MMS, administers the OCS acreage north of the Augustine-Seldovia Arch. The OCS lands in upper Cook Inlet constitute about 20% of the acreage available for leasing. The remaining acreage is controlled by CIRI.

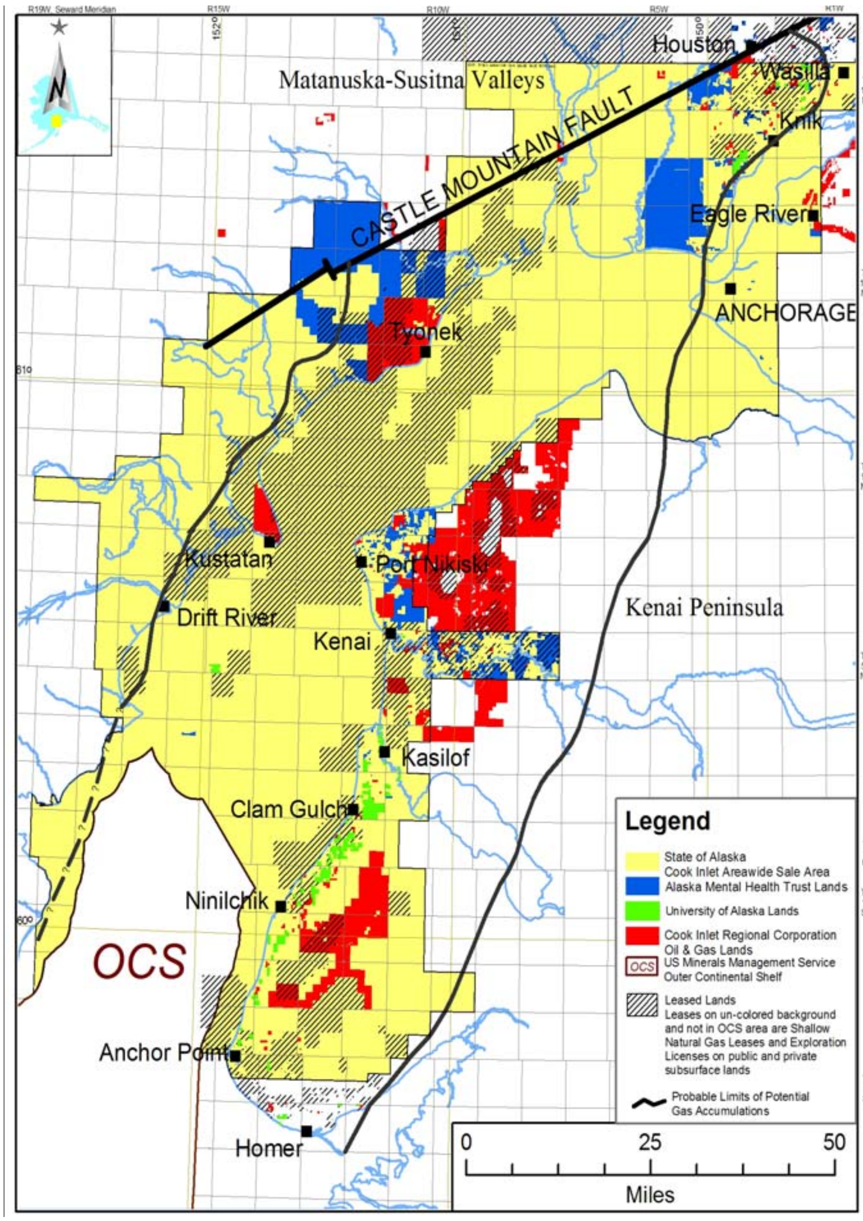


Figure 2.17. Cook Inlet Basin, Alaska: Categories of land ownership and leased acreage.

The hachured pattern of Figure 2.17 represents three types of leases: 1) standard oil and gas leases, seen from Anchor Point to the Castle Mountain Fault; 2) shallow gas leases in the Homer and Wasilla areas; and 3) exploration licenses, west and north of Houston. The pattern of conventional oil and gas leasing reflects the trends seen in Figures 2.4, 2.6, and 2.7 and is generally confined to the major anticlinal trends in the basin. The state of Alaska, through ADNR, conducts areawide lease sales on an annual basis. The areawide sales are designed to offer for leasing virtually all of ADNR's unleased acreage in the upper portion of the basin. Certain areas are withheld or deferred primarily because of environmental concerns. The University and Mental Health lands have occasionally been offered for lease at the time of the state's areawide sales but more commonly are leased independently of the ADNR sales.

Exploration rights to CIRI lands are acquired by negotiating exploration contracts between exploration companies and CIRI. There are no open competitive lease sales. Notable blocks of CIRI acreage are under lease in the Swanson River, Happy Valley, and Tyonek areas. In the area depicted in Figure 2.17, virtually all the leased acreage is either state or CIRI land. The only federal OCS acreage under lease consists of two leases northwest of Anchor Point and just outside the state of Alaska's three-mile limit. Unlike the state of Alaska, the MMS has not regularly scheduled sales. The last MMS sale was in 1997 and only four sales have been held since the early 1970s. The two active leases in the OCS were acquired in the 1997 sale. The MMS current Alaska Region five-year lease plan includes two Cook Inlet lease sales in May 2004 and May 2006. The area to be offered in these sales includes all or parts of 517 lease blocks encompassing approximately 2.5 million acres. The proposed sale area is seaward of the state of Alaska submerged lands boundary in Cook Inlet and extends from 3 to 30 miles offshore from Kalgin Island south to near Shuyak Island (Figure 1.1), 60 to 70 miles south of the limits of Figure 2.17.

The probable limits of significant gas accumulations in the upper Cook Inlet are shown relative to the currently leased acreage and lands open to leasing. Significant portions of the state-owned acreage fall outside of these limits. While it is possible that small accumulations in the Tyonek Formation may be found in these areas, larger fields in the several hundred Bcf range probably do not exist outside these limits. A small number of leases on the west side of the basin extend beyond the postulated limit of significant gas accumulations.

A comparison of Figures 2.4 and 2.17 reveals that large portions of the area open to exploration and development have never been adequately evaluated, especially relative to gas and stratigraphic-style trapping mechanisms. These areas with no active leases and few if any exploration wells should be prime exploration territory when stratigraphic gas plays become the focus of exploration and development in upper Cook Inlet. There is little reason to believe that the non-associated biogenic gas should not be found in stratigraphic traps throughout the basin in off-structure positions. Additionally, 3D seismic acquisition and extended reach horizontal drilling provide the methods and opportunities to find and develop these reservoirs much more efficiently.

Figure 2.18 presents the Administrative Land Withdrawals in the upper Cook Inlet subbasin and adjacent areas. The lease holdings of Figure 2.17 are duplicated in Figure 2.18, which highlights the areas (largely unleased) that have limited or no access for oil and gas exploration and development activities. The existing gas pipelines are also shown on Figure 2.18. Here as in Figure 2.17, the probable limits of potential significant gas accumulations are displayed against the background of administrative land withdrawals and active leases. Three classifications of land withdrawals have the potential to profoundly impact exploration and development in the upper Cook Inlet Basin: 1) national wildlife refuge lands, 2) state refuge lands, and 3) state-restricted areas. Each of these three withdrawals currently has active leases within its boundary. This can be observed on state refuge lands both north and south of Tyonek, state and national refuge lands on the Kenai Peninsula, and state-restricted lands between Drift River and Tyonek (Figure 2.18). Comparing Figures 2.17 and 2.18 reveals not only active leases within portions of the withdrawals but also ongoing leasing and oil and gas production. The ADNR, Alaska Mental Health Trust, and CIRI have active leasing programs that include acreage within the boundaries of the withdrawals. As an example, the Swanson River oil and gas field has been producing from within the refuge since the late 1950s. Even so, more than 500,000 acres in the eastern portion of the Kenai lowlands have not been explored by the drill, and only eight wells have been drilled within an area of more than 1,000,000 acres on the southern and eastern portions of the Kenai lowlands. This represents an exploration well density of less than one well per 200 square miles (520 sq. km).

The ability to acquire seismic data, lease acreage, and drill exploration wells may be severely hindered, if not banned, by the various administrative agencies. Access to lands controlled by each of the major land owners/managers is regulated, restricted, or prohibited by different criteria and philosophies. Within a single large entity, such as the federal government, individual agencies (BLM, MMS, etc.) have differing sets of regulations and policies that may further limit resource evaluation and extraction programs. Thus, it tends to be an expensive and time-consuming effort to explore and develop even those areas that are open to some level of exploration and development activity. In a world market of vigorous competition for a company's capital, costly and time-consuming hurdles to exploration and development may preclude such activity.

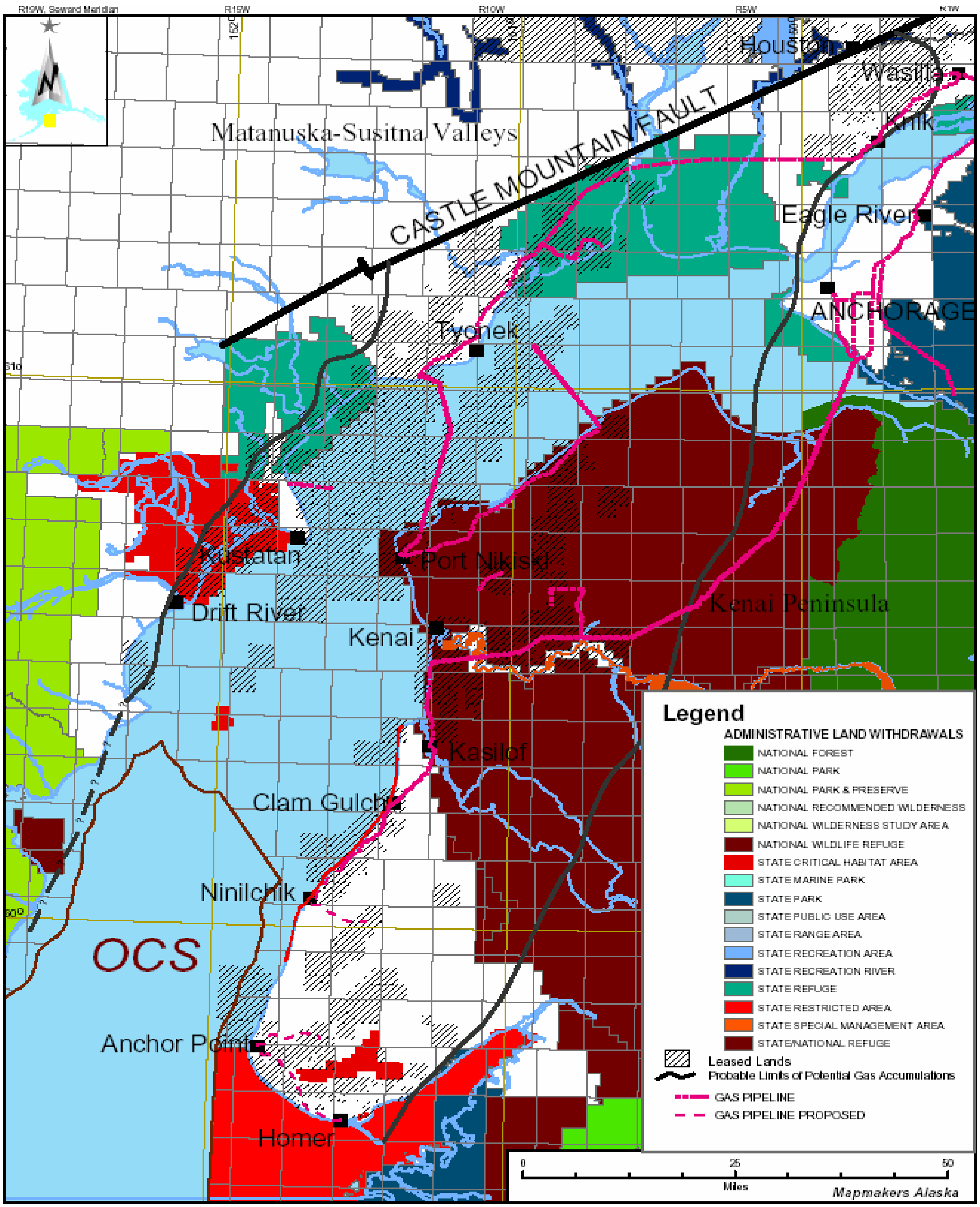


Figure 2.18. Cook Inlet Basin, Alaska. Areas of Administrative Land.

The eastern portion of the Kenai lowlands is sparsely explored but may provide some of the best remaining structural opportunities and has excellent stratigraphic potential. The anticlinal features seen in the Kachemak Bay and Chickaloon Bay areas trend into the eastern portion of the lowlands (Magoon, Adkinson, and Egbert, 1976) and could be a third productive structural trend, paralleling those currently developed on the western Kenai Peninsula and in the inlet and along the west side of the inlet (Figure 2.6). The stratigraphic potential includes both fluvial channel and alluvial fan facies enclosed in the finer lithologies of the alluvial plain and associated environments and combination stratigraphic and unconformity traps associated with repeated uplift and erosion along the active faults of the eastern basin margin. The Sterling, Beluga, and Tyonek formations all have depositional or erosional zero-edges in this area and each could provide attractive stratigraphic trapping opportunities.

The prospective portion of the Kenai Peninsula comprises about a third of the prospective area of the upper Cook Inlet subbasin and half of that is virtually unexplored, principally due to access problems and restrictions. If the upper Cook Inlet subbasin has a OGIP endowment of approximately 30 Tcf , assuming a relatively uniform distribution of biogenic gas, the Kenai Peninsula should have about 10 Tcf with half of it in the unexplored eastern portion, or about 5 Tcf OGIP. Approximately 3.7 Tcf OGIP is associated with the 10 fields on the Kenai Peninsula, theoretically leaving 1.3 Tcf to be found in the more heavily explored portion of the peninsula. Under this scenario, there is three to four times as much undiscovered gas to be found in the restricted, poorly explored eastern portion of the Kenai as there is along the peninsula’s current exploration/production trend. Whether the magnitude or relative distributions suggested are valid is debatable, but the concept is not. Potentially large volumes of gas may be awaiting the drill bit in these restricted areas of the basin. The scale of the withdrawals is such that they could represent 50% or more of the remaining recoverable resources in the upper Cook Inlet subbasin.

Recent advances in drilling technology and seismic acquisition methodology have significantly reduced the real and perceived impact on the land and its biota. The extensive or exclusive use of extended-reach horizontal drilling facilitates the development of large areas from a single drillsite, even if the objectives are at shallow depths. Currently, in the Cook Inlet, care is taken to create narrow (1 to 2 meter-wide) low-sinuosity trails for seismic acquisition. This is in stark contrast to the prevailing, if somewhat dated, view of wide, straight trails that cut across the landscape for miles and ruin the viewscape for many people.

With these technologies in place, an appropriate balance of regulations and restrictions, and a regular leasing schedule, careful and timely exploration and development could result in an evaluation of the resource and reserves for the future. This approach would provide a way to more fully realize the conventional gas potential of the basin and allow for continued export of LNG and a long-term gas supply for the local consumers at a fair market price.

2.10 Summary and Conclusions

South-central Alaska is dependent upon locally produced natural gas for much of its energy supply, and as an important component of the industrial base in the Kenai area. The concerns regarding the future supply and demands for natural gas in the Cook Inlet area have led to this evaluation and subsequent conclusions. From geological and exploration perspectives, a number of observations and conclusions can be made regarding the ability of the producing fields in Cook Inlet and the future gas resource potential of the Greater Cook Inlet Basin to continue to meet these needs.

- Exploration in Cook Inlet has historically been focused on structural plays in the search for oil with no attempt to evaluate stratigraphic potential or to look primarily for gas. Only in the last five or six years has gas come into its own as a primary exploration and evaluation objective. There is still no effort to explore for the stratigraphic plays that typically account for 50% or more of the ultimate production in basins elsewhere. The lower Cook Inlet subbasin and the Susitna Basin have not been explored for conventional gas.
- The oil and associated gas are derived thermogenically from Middle Jurassic and possibly Late Triassic marine source rocks and subsequently reservoired in the lower Tertiary West Foreland, Hemlock, and lower Tyonek formations. The non-associated biogenically derived dry gas is sourced from coals and carbonaceous fine-grained sediments in the upper Tyonek, Beluga, and Sterling formations and is found in reservoirs intimately associated with the source lithologies in these younger sediments.
- The vast majority of the proven gas reserves (94%) are non-associated biogenic gas and this non-associated gas has no genetic relationship to the origin and distribution of oil, which has been the primary exploration objective. Therefore, it is unrealistic to conclude that exploration based on oil prospects will necessarily lead to a true evaluation of the basin’s gas potential.

- Ninety-five percent of the estimated ultimately recoverable gas, or approximately 8.0 Tcf, was found by 1970. Production to date has been approximately 6.7 Tcf, with proven unproduced reserves of 1.8 Tcf. The total estimated ultimately recoverable reserves 8.5 Tcf, or approximately 10 Tcf OGIP, appears to be only a fraction of the true potential of the basin.
- Assuming that the number of fields and the size of those fields are log-normally distributed leads to the conclusion that the total conventionally recoverable gas resource endowment is much larger than suggested by the 8.5 Tcf expected to be produced from the known fields. Undiscovered fields with 200 to 1,500 Bcf OGIP should be present in the distribution of field sizes according to accepted geologic theory and evidence. The estimated total gas resource endowment for upper Cook Inlet is 25 to 30 Tcf OGIP, or about 21 to 26 Tcf of conventionally recoverable resources at a recovery rate of 85%. This is approximately 13 to 17 Tcf more than is expected to be recovered from the existing fields based on proven reserves estimates.
- The estimated upper Cook Inlet conventionally recoverable gas resources of 13 to 17 Tcf may be accounted for by reserves growth in existing fields and new discoveries. USGS analysis provides an estimate of reserves growth of 2.5 to 3.0 Tcf in existing fields. This leaves 10 to 14 Tcf in new discoveries to reach the estimated total upper Cook Inlet gas resource endowment of 25 to 30 Tcf OGIP. Lower Cook Inlet and the Susitna may have the potential to add another 2 to 3 Tcf recoverable resources.
- Additional fields can be expected to be discovered along the currently producing structural trends such as Happy Valley and Ninilchik fields on the western portion of the Kenai Peninsula and the Moquawkie – Nicolai Creek area on the west side of the inlet. A third structural trend may exist in the eastern portion of the Kenai lowlands.
- The bulk of the undiscovered conventional gas resources are believed to be stratigraphic with virtually the entire upper Cook Inlet subbasin having some level of exploration potential. The greatest likelihood for success is along the flanks of the large structures that have had an intermittent growth history accompanied by repeated cycles of uplift, erosional truncation, and deposition. The eastern and western margins had similar histories associated with movement along the basin-bounding faults. In these areas and elsewhere in the basin, the interleaved nature of stream channel systems and alluvial fans with finer-grained flood plain, lacustrine, and paludal deposits creates pure stratigraphic traps.

- Based on revised calculations of coal volumes, the estimated volume of coalbed natural gas is approximately 140 Tcf, of which only 10% is assumed to be accessible, and of that 50% recoverable. This yields a potential resource of 7 Tcf of coalbed natural gas. The economic potential of this resource is currently unknown and the timing for any commercial development is so uncertain that its role in the future gas supply for south-central Alaska cannot be predicted.
- Access to prospective lands may be hindered or denied by the constraints on exploration and development activity imposed by the regulations and stipulations associated with many of the various land withdrawals in the Cook Inlet Basin area. Technologies such as 3D seismic acquisition and extended reach horizontal drilling may serve to mitigate these impacts on resource evaluation and development.
- The ability to realize a significant portion of the basin's natural gas producing potential is largely dependent on cost of doing business, a viable market, access to the resource, and competing sources of supply.

Cook Inlet exploration and production has provided an inexpensive, reliable source of natural gas for Anchorage and surrounding areas for nearly forty years. Given a favorable operating environment, the basin appears to have the potential to continue providing the energy for residential and commercial users for decades to come. The volumes that may be produced will most probably not be equal to those estimated in this evaluation. The factors controlling the economics of gas exploration and production and the ability to access these undiscovered and undeveloped resources will most certainly prevent full realization of the basin's resources. However, the order of magnitude indicated by these conclusions should prove to be appropriate.

3. RESERVES AND RATE FORECASTS – KNOWN FIELDS

Estimated future gas reserves and recovery rates for the non-associated dry gas fields currently producing in the Cook Inlet area are discussed in this section. The reserves estimates and production forecasts are used Section 4 as the base case for the economic evaluations.

3.1 Introduction

Estimates of remaining reserves[7] and production forecasts will be described for eight fields, Beaver Creek, Belgua River, McArthur River, North Cook Inlet, Swanson River and the two recent discoveries Ninilchik and Happy Valley. These eight fields contain over 90% of the remaining reserves in the Cook Inlet dry gas fields. The ADNR Division of Oil and Gas forecasts of reserves and production rates for the other remaining fields presented in its 2003 Report were reviewed and are used for this study (ADNR 2003).

The term "proved reserves" has a specific meaning for the purposes of U.S. Security and Exchange Commission (SEC) reporting and is based on a formal methodology described by the Society of Petroleum Engineers (SPE, 1998). The detailed and exacting process that would be required for SEC reporting by an operator is not within the scope of this study.

3.1.1 Previous Reserves and Rate Forecasts

Recent Cook Inlet natural gas reserves forecasts include the ADNR forecast published in December 2003 (ADNR, 2003) and two other studies conducted in the late 1990s related to the 1996 application to extend the authorization to export LNG from Alaska to Japan. These two studies are the following:

1. GeoQuest Reservoir Technologies (GeoQuest) – "Proven Reserve Assessment, Cook Inlet, Alaska," March 1996.

[7] Reserves are defined in Society of Petroleum Engineers, Monograph 1, Second Edition, "Guidelines for Application of Petroleum Reserves Definitions" (SPE 1998, p. 5). "Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward." "Proved reserves are those quantities of petroleum, which by analysis of geological and engineering data can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped." (SPE, 1998, p. 5.)

2. Malkewicz-Hueni Associates (MHA) – "Analysis of Cook Inlet Alaska Gas Reserves and Deliverability," December 1997.

These reports used detailed reservoir studies to estimate volumes of original-gas-in-place (OGIP) in some gas fields. No attempt is made to duplicate their work in detail. They were reviewed and used to compare results in six large fields.

3.1.2 Forecasting Methods

All available performance data are used in forecasting rates and reserves. When reservoir pressure data are available, material balance estimates are updated. Combined production and pressure data are used in fields where producing zones are commingled in the well bore. Where there was insufficient or no reservoir pressure data available, production performance of the particular reservoir and other similar reservoirs is used for forecasting. Production performance of similar reservoirs is used as a basis to estimate the rates for two newly discovered gas accumulations, Ninilchik and Happy Valley.

The Cook Inlet dry gas fields and their respective Unit names, participating areas, working interest ownership, and producing formation are shown in Table 3.1. Table 3.1 contains the information for the eight fields discussed in detail in Section 3.2 first followed by the smaller fields that make up the All Others group of fields. This information is extracted from ADNR (2003, Section 3).

3.2 Large Fields

Individual reserves and rate forecast estimates are developed for six large fields and two recent discoveries. The large fields are Beaver Creek Unit, Beluga River Unit, Kenai Unit, McArthur River (part of the Trading Bay Unit), North Cook Inlet Unit, and the Swanson River Unit. All the other smaller fields are discussed in Section 3.3 and the new discoveries, Deep Creek Unit (Happy Valley field) and the Ninilchik Unit, are discussed in Section 3.4.

Reservoir performance and production rate forecasts are described in the following sections.

Table 3.1. Cook Inlet Units working interest fractions; major dry gas fields (ADNR, 2003).

Unit/Field (Participating Areas)	**Ownership**	**Working Interest**	**Reservoir/**
Beaver Creek Unit Sterling Gas, Beluga Gas, and Tyonek Gas Pools	**Marathon**	100%	Beluga, Sterling, Lower Tyonek formations
Beluga River Unit	**Chevron USA**	33.3%	Tertiary Sterling Formation
	ML&P	33.3%	
	ConocoPhillips	33.3%	
Kenai River Unit Sterling Formation Gas Zone PA (A Zone PA), Beluga PA (Beluga Formation Gas Zones PA)	**Marathon**	100%	Tertiary Sterling Formations (Sterling 3, Sterling 4, Sterling 5.1, Sterling 6) Tertiary Beluga Formation Tertiary Tyonek
McArthur River Field Trading Bay Unit Grayling Gas Sands PA	**Unocal**	51.2%	Tertiary Tyonek
	Marathon	48.8%	
North Cook Inlet Unit North Cook Inlet Initial PA	**ConocoPhillips**	100%	Tertiary Tyonek, Beluga and Sterling formations
Swanson River Unit ""B, C, D & E" Zone Gas Pools 1 and #2 "	**Unocal**	100%	Tertiary Hemlock, Lower Tyonek and Beluga formations
Ninilchik Unit Falls Creek PA, Grassim Oskolkoff PA, Susan Dionne PA	**Marathon**	60%	Tertiary Tyonek Formation
	Unocal	40%	
Deep Creek Unit Happy Valley Field	**Unocal**	100%	Tertiary Beluga
All Others – Small Fields			
Birch Hill Unit	**Unocal**	79%	Tertiary Tyonek
	CIRI Prod. Co.	20%	
	Marathon	1%	
Cannery Loop Unit	**Marathon**	100%	Tertiary Sterling, Beluga,Tyonek Formations
Ivan River Unit	**Unocal**	100%	Tertiary Tyonek Formation
Lewis River Unit	**Unocal**	100%	Tertiary Tyonek and Beluga formations
Nicolai Creek Unit	**Aurora Gas, LLC**	100%	Tertiary Tyonek and Beluga
Middle Ground Shoal	**Unocal**	100%	Tyonek Undefined
Moquawkie Unit Lone Creek PA	**Aurora Gas, LLC**	100%	Tertiary Tyonek
Moquawkie Unit	**Aurora Gas, LLC**	100%	Tertiary Tyonek
North Fork Unit	**Alliance/Gas Pro Alaska**	73%	Tertiary Tyonek
	ConocoPhillips	27%	

Table 3.1 Continued			
Pretty Creek Unit	**Unocal**	100%	Tertiary Beluga
South Granite Point Unit Granite Point Sand PA	**ExxonMobil**	75%	Tertiary Tyonek
	Unocal	25%	
Sterling Unit	**Marathon**	100%	Tertiary Sterling Formation, Tertiary Beluga Formation
Stump Lake Unit Stump Lake #1 PA	**Unocal**	100%	Tertiary Beluga
West Fork Field	**Marathon**	100%	Tyonek
West McArthur River Unit (West Foreland Field)	**Forest Oil**	100%	Tertiary Tyonek
Wolf Lake Field	**Marathon**	100%	Sterling

3.2.1 Beaver Creek Unit

The Beaver Creek field, located on the eastern side of Cook Inlet, was discovered in 1972. Formations shown to be productive were the Hemlock (oil) and the Beluga, Sterling, and Tyonek for gas. Initial production occurred in 1972 from the Beaver Creek Oil Pool. Gas reserves and future production rates for the three gas formations are discussed in the following sections.

3.2.1.1. Beluga Formation

Cumulative recovery through December 31, 2003, is 39,857,950 Mcf gas and 186,202 bbls of water. Production during December 2003 was 762,942 Mcf and 5,938 bbls of water from five wells. Production performance, shown in Figure 3.1, is used to estimate recoverable reserves and future production rates.

Figure 3.2 is a plot of bottomhole pressure divided by compressibility factor (P/Z) versus cumulative production on the same date (P/Z plot). There are insufficient bottomhole pressure data to give reliable material balance results; however, using the two data points available, an OGIP of 72.5 Bcf is indicated. This estimate is too low when production performance is considered. Volumetric calculations by Geoquest and MHA were reviewed and used only for comparison of results.

It is assumed the production performance of the three new wells drilled in the last three years will be similar to the two initial wells with an adjustment for partial depletion. The production rate from the new wells indicates some depletion of their drainage area. An

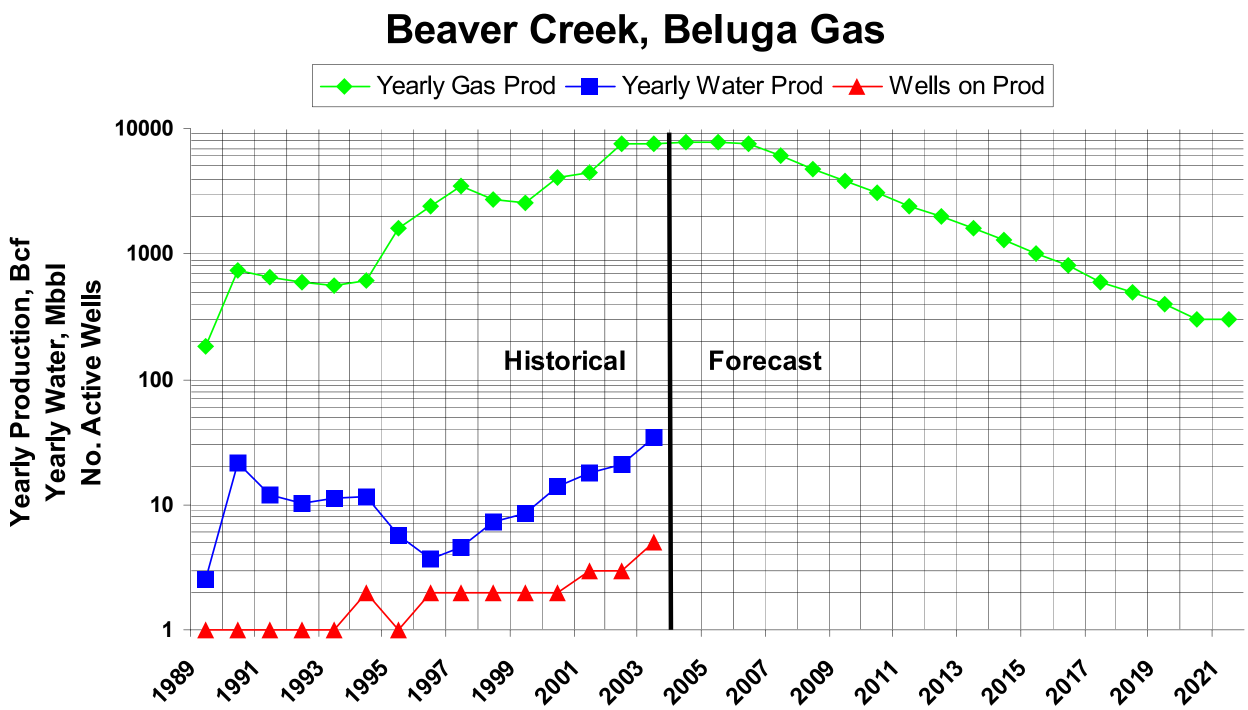


Figure 3.1 Beaver Creek field, Beluga formation, production history and forecast.

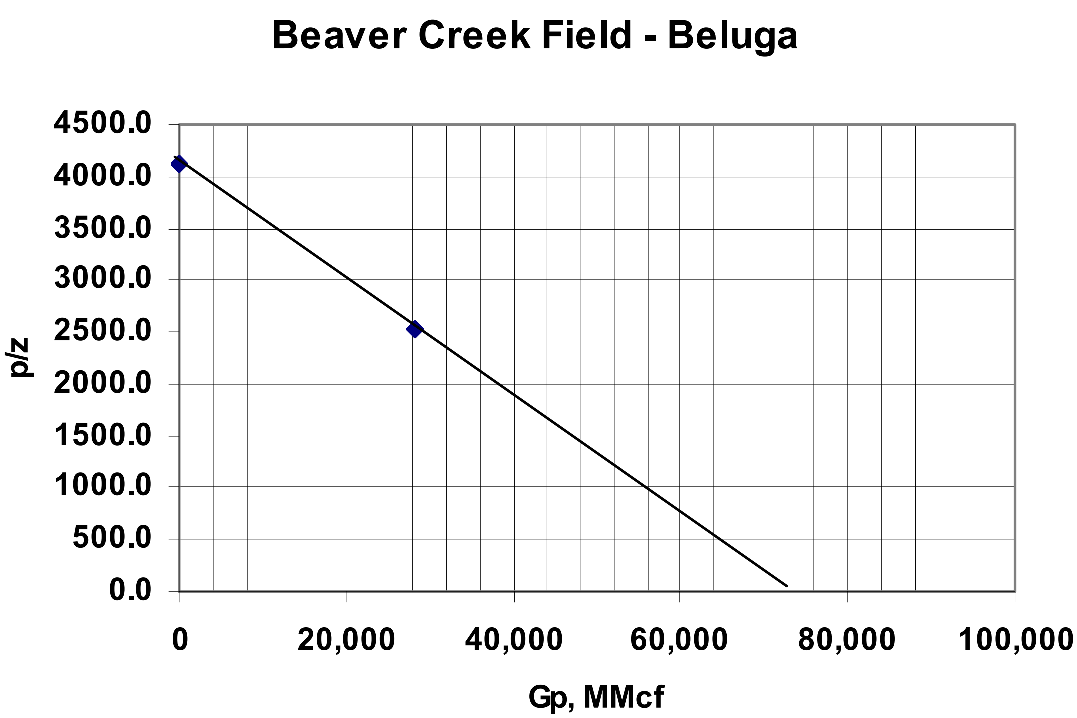


Figure 3.2. Beaver Creek field, Beluga formation P/Z versus cumulative production.

estimated ultimate recovery of 41.7 Bcf was determined for the initial two wells. This recovery volume and a 20% depletion factor are used to estimate the recovery from the three recent wells. The recovery for the new wells by this method is 50.0 Bcf giving an ultimate Beluga recovery of 91.7 Bcf. Using the cumulative production of 39.9 Bcf at January 1, 2004, the estimated future recovery is 51.8 Bcf.

It is assumed the production rate of 642 MMcf/month at year-end 2003 will be sustained until the decline begins. To estimate how long the field will produce at the current rate, the gas produced during the decline period is first estimated. That production volume is estimated using a decline rate of 20%/yr to represent the effect of wells watering out at different dates. An abandonment rate of 20 MMcf/month is used to offset the increased cost of larger produced water volumes. Reserves of 33.4 Bcf are calculated to be recovered during decline. This leaves reserves of 18.4 Bcf to be recovered at the 642 MMcf/month peak rate before decline begins in 2.4 years in 2006 for the total estimated remaining reserves of 51.8 Bcf.

Table 3.2 is the resulting production forecast after January 1, 2004. This forecast is also shown on Figure 3.1.

Table 3.2. Production forecast for Beaver Creek Beluga formation.

Year	Production (Bcf/yr)	Year	Production (Bcf/yr)	Year	Production (Bcf/yr)
2004	7.7	2010	3.1	2016	0.8
2005	7.7	2011	2.4	2017	0.6
2006	7.5	2012	2.0	2018	0.5
2007	6.0	2013	1.6	2019	0.4
2008	4.8	2014	1.3	2020	0.3
2009	3.8	2015	1.0	2021	0.3

3.2.1.2 Sterling Formation.

The four Sterling gas wells were placed on continuous production in 1983. Cumulative gas production through December 31, 2003, is 125,340,909 Mcf. Continuous production ceased in early 1994 when water production reached about 2700 BWPM. Since that time, the Sterling has been placed back on production for relatively short periods of time. The Sterling formation was produced only four months during 2003. Since March 1, 1994, production has totaled 1,507,906 Mcf. Sterling production performance is shown on Figure 3.3.

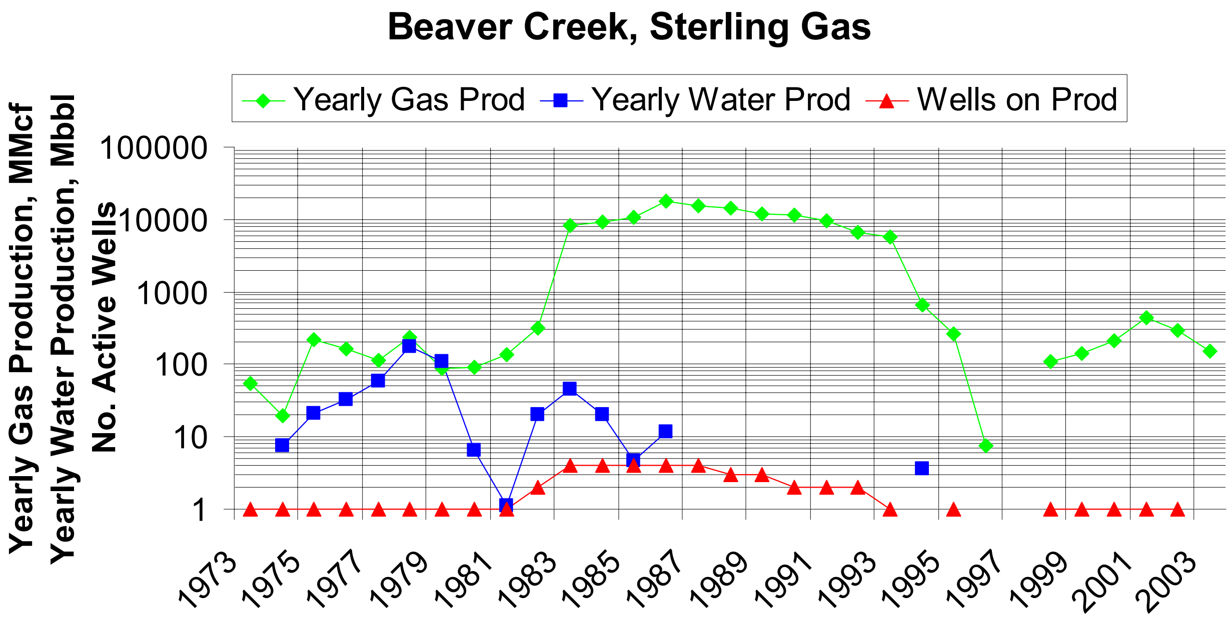


Figure 3.3. Beaver Creek, Sterling gas, production history.

There are insufficient bottom-hole pressure data available to give an accurate estimate of OGIP. The P/Z plot shown in Figure 3.4, indicates an OGIP of about 230 Bcf. Depending on the effect of water influx, this volume may or may not be accurate.

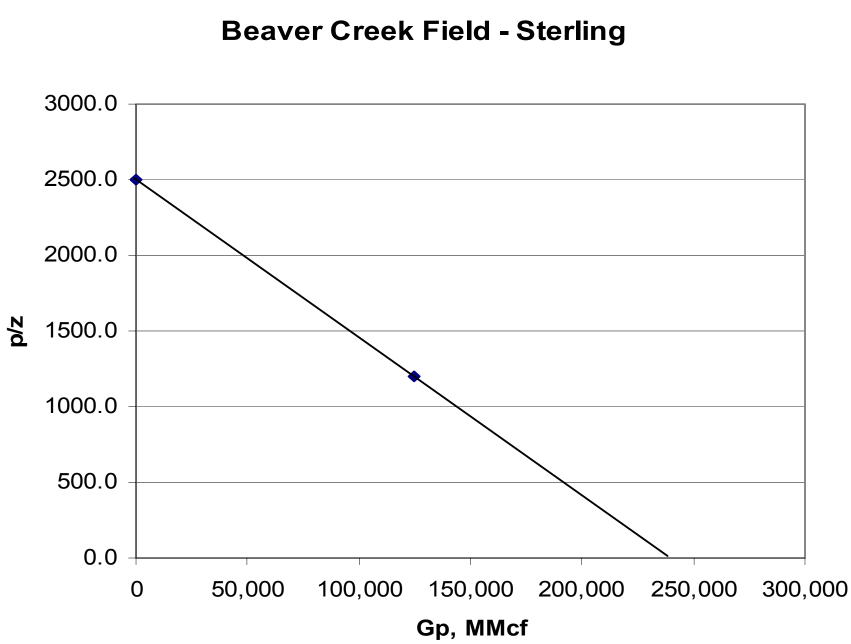


Figure 3.4. Beluga Sterling Formation P/Z versus Cumulative production (Gp).

Based on this sporadic type of operation, no estimate of proven reserves is justified. Possible reserves of 1 to 2 Bcf may be recoverable. No rate forecast is made for these reserves.

3.2.1.3 Tyonek Formation

The one Tyonek gas well was placed in production in early 1996. Cumulative gas production through December 31, 2003, is 4,950,311 Mcf of gas and 5,670 bbls of water. Production was 23,782 Mcf and 28 bbls water during December 2003 from the well. The production performance is shown on Figure 3.5.

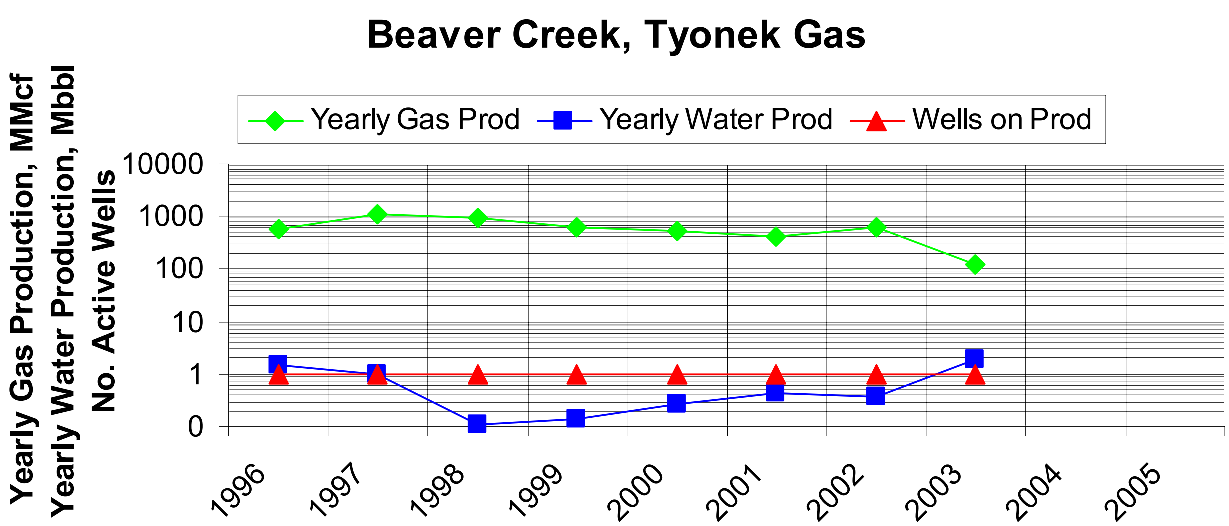


Figure 3.5. Beaver Creek Unit, Tyonek formation, production history and forecast.

Reservoir pressure data are very limited and are shown on Figure 3.6. The pressure data indicate a loss of about 50% of original pressure after six years of production and recovery of only 4.9 Bcf. The loss of reservoir pressure and the production performance indicate a limited reservoir volume being drained. An optimistic interpretation of production data indicates possible additional reserves of 2.7 Bcf. No forecast of these reserves is included in the total for the Beaver Creek Unit.

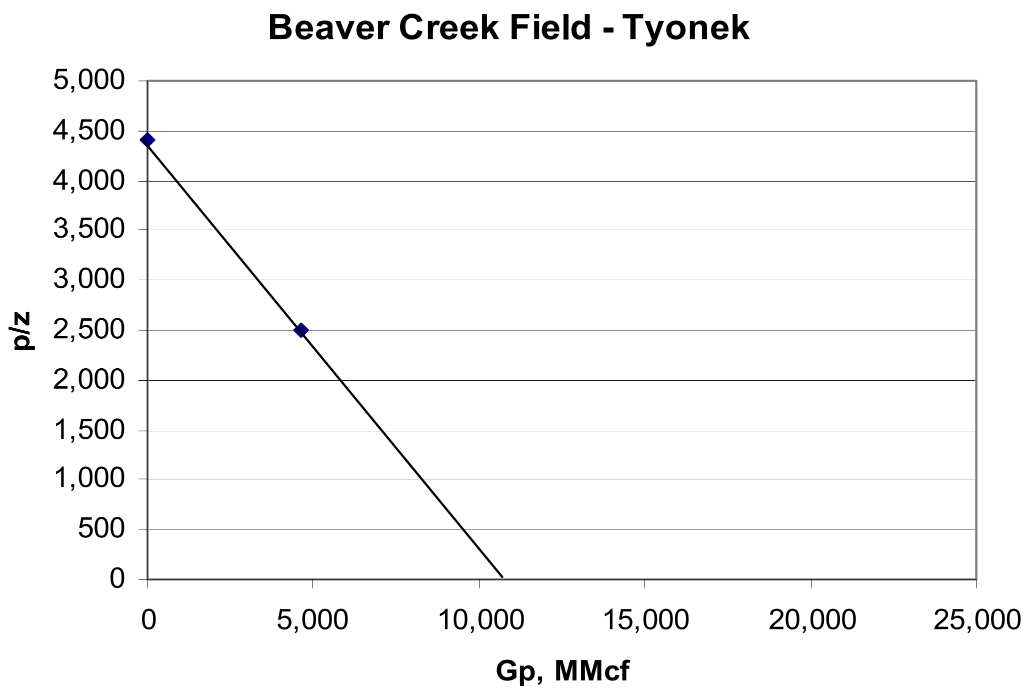


Figure 3.6. Beaver Creek Unit, Tyonek formation, P/Z versus cumulative production.

3.2.2 Beluga River Unit

The Beluga River field located on the west side of the Cook Inlet was discovered in 1962. Gas production began in 1968 from the Sterling and Beluga formations. Cumulative gas production is 847,162,575 Mcf through December 31, 2003. Cumulative water production is 20,939 bbls. Production from both zones has been commingled in the well bores. Production during December 2003 was 4,844,606 Mcf and 1,306 bbls of water from 13 wells. Production performance is shown on Figure 3.7.

3.2.2.1 Sterling and Beluga Formations

The Sterling and Beluga gas productions are commingled in the well bore in all wells. Although some wells are predominately completed in the Sterling and others predominately in the Beluga,[8] there is no method to accurately determine production and pressures by formation. Therefore, total unit production and averaged bottomhole pressure data are used.

Recent production performance shows that previous OGIP volumes of 1,290 Bcf (MHA, 1997) and 1,325 Bcf (GeoQuest, 1996) are conservative. Figure 3.8 is a P/Z plot using

[8] AOGCC Form 10-412 dated 9/5/2002 on the Beluga River Unit.

combined reservoir pressures. Use of the original P/Z points and the recent data points indicate an OGIP of about 1530 Bcf, which is used in estimating remaining reserves and a production forecast. An 85% recovery factor results in ultimate gas recovery of 1,300 Bcf. Therefore, the estimated remaining reserves after January 1, 2004 are 452.8 Bcf.

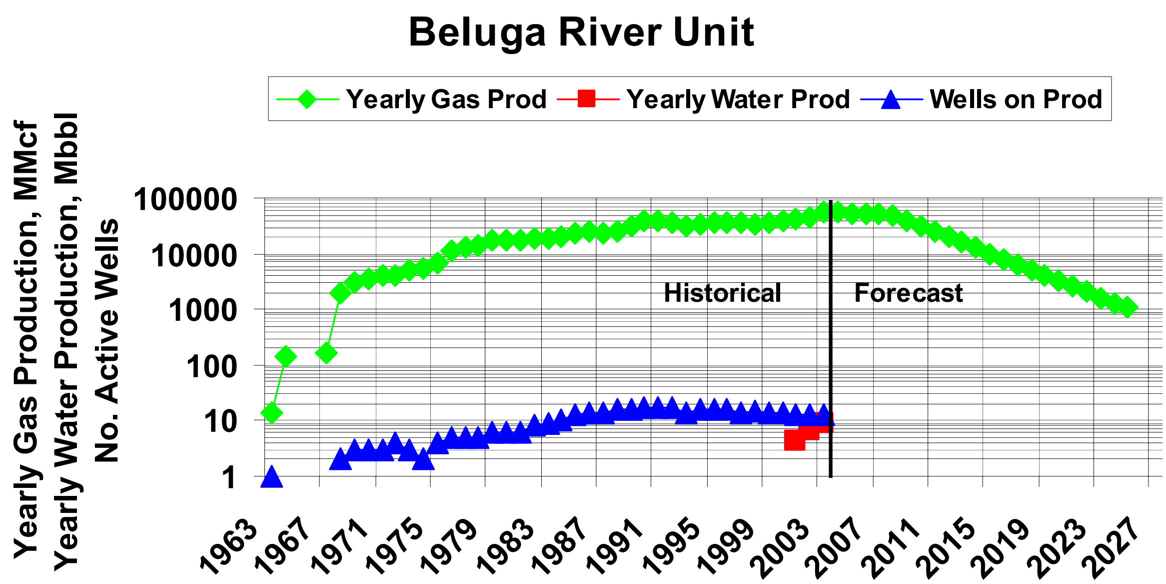


Figure 3.7. Beluga River Unit, Sterling and Beluga formations, Production History and Forecast.

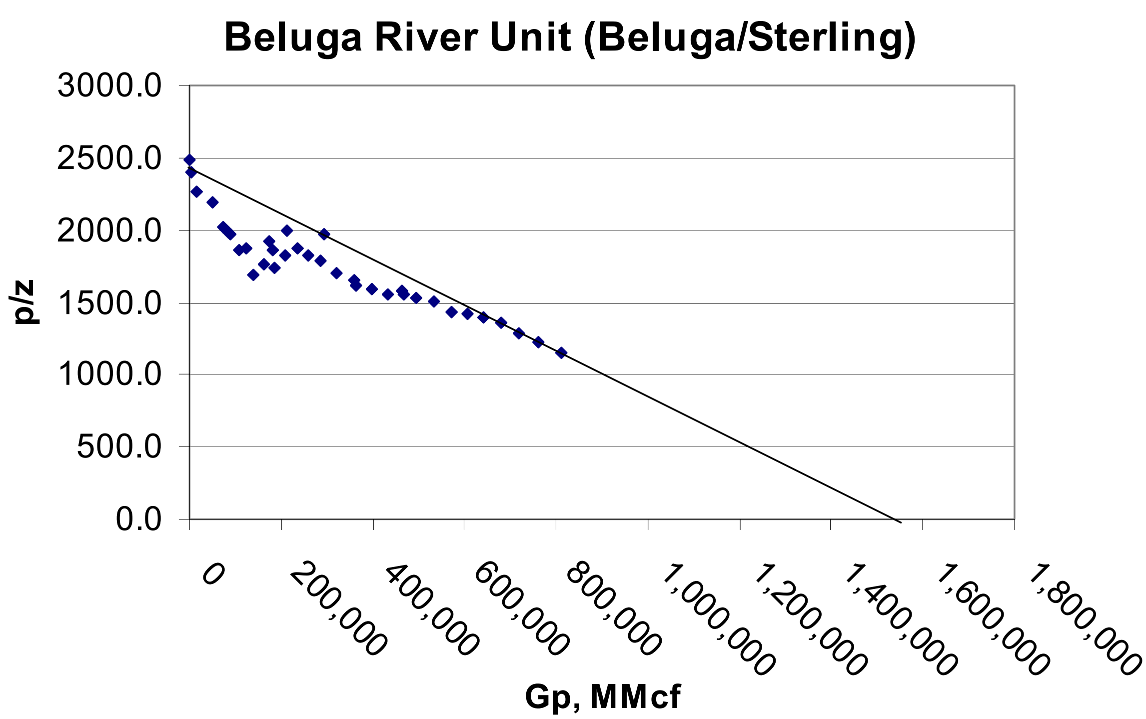


Figure 3.8. Beluga River Unit, Sterling and Beluga Formations, P/Z versus cumulative production.

Monthly production volumes and the annual volumes plotted on Figure 3.7 shows an increase in rate since mid-2001. This performance shows the Unit has spare deliverability. Production has averaged about 53.2 Bcf/yr over the last 18 months. It is assumed that production will continue at 53.2 Bcf/yr until decline begins in 2008. Gas production during the decline period is estimated using an initial rate of 4,433 MMcf/month, an abandonment rate of 20 MMcf/month, and a decline rate of 20%. The estimated recovery during the decline period is 237.3 Bcf, which leaves 215.5 Bcf to be recovered at 53.2 Bcf/yr.

Table 3.3 is the resulting production forecast after January 1, 2004. This forecast is also shown on Figure 3.7.

Table 3.3. Production forecast for Beluga River Unit.

Year	Production (Bcf/yr)	Year	Production (Bcf/yr)	Year	Production (Bcf/yr)
2004	53.2	2012	19.7	2020	3.3
2005	53.2	2013	15.8	2021	2.6
2006	53.2	2014	12.7	2022	2.1
2007	53.2	2015	10.1	2023	1.6
2008	48.3	2016	8.1	2024	1.3
2009	38.6	2017	6.5	2025	1.1
2010	30.8	2018	5.2	Remaining	3.4
2011	24.7	2019	4.1	Total	452.8

3.2.3 Kenai River Unit

The Kenai River field, located on-shore on the eastern side of Cook Inlet, was discovered in 1959. Gas has been produced from the Sterling 3, Sterling 4, Sterling 5.1, Sterling 5.2, Sterling 6, Beluga, and Tyonek formations. Cumulative recovery from all formations is 2,245,564,759 Mcf and 955,331 bbls water through December 31, 2003. Determination of individual formation gas reserves and producing rates are discussed in Sections 3.2.3.1 through 3.2.3.7.

3.2.3.1 Sterling 3 Formation

The Sterling 3 formation began producing during 1965. Continuous production commenced in 1968. Cumulative recovery to January 1, 2004, is 329,301,996 Mcf and 133,830 bbls water. Production during December 2003 was 215,775 Mcf gas and 85 bbls water from two wells. Production performance is shown on Figure 3.9.

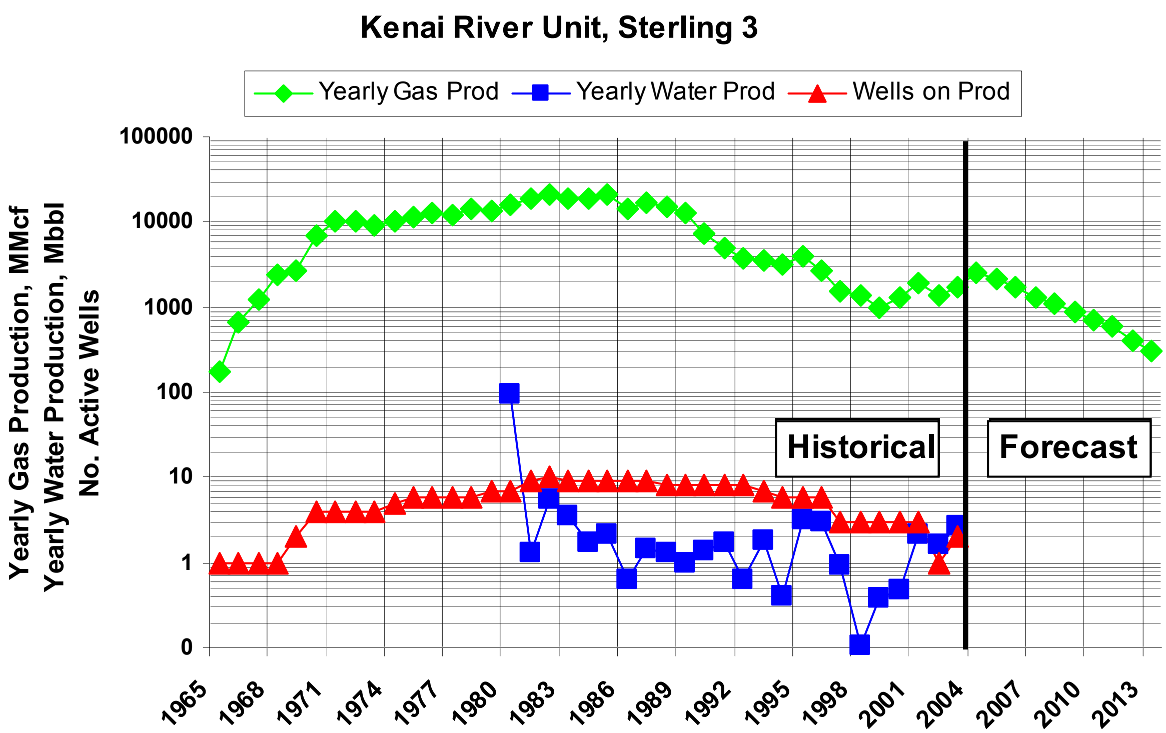


Figure 3.9. Kenai River Unit, Sterling 3, yearly production history and forecast.

Figure 3.10 is a P/Z plot for this formation. Based on different interpretations, the original gas-in-place estimates range from 375 Bcf to 420 Bcf. An estimate of OGIP of 400 Bcf is reasonable, and at an 85% recovery, ultimate recovery would be about 340 Bcf.

Production performance is used to forecast reserves and production rates. The average monthly production for the last four months of 2003 was about 245 MMcf/month. Using this volume as the initial rate, a decline factor of 20% and an abandonment rate of 20 MMcf/month, future gas reserves are estimated to be 12.1 Bcf after December 31, 2003. Ultimate developed reserves are 341.4 Bcf. This gives a recovery of about 85% of OGIP.

Table 3.4 is the resulting production forecast. This forecast is also shown on Figure 3.9.

Table 3.4. Production forecast for Kenai field, Sterling 3 formation.

Year	Production (Bcf/Year)	Year	Production (Bcf/Year)
2004	2.6	2009	0.9
2005	2.1	2010	0.7
2006	1.7	2011	0.6
2007	1.3	2013	0.4
2008	1.1	2014	0.3

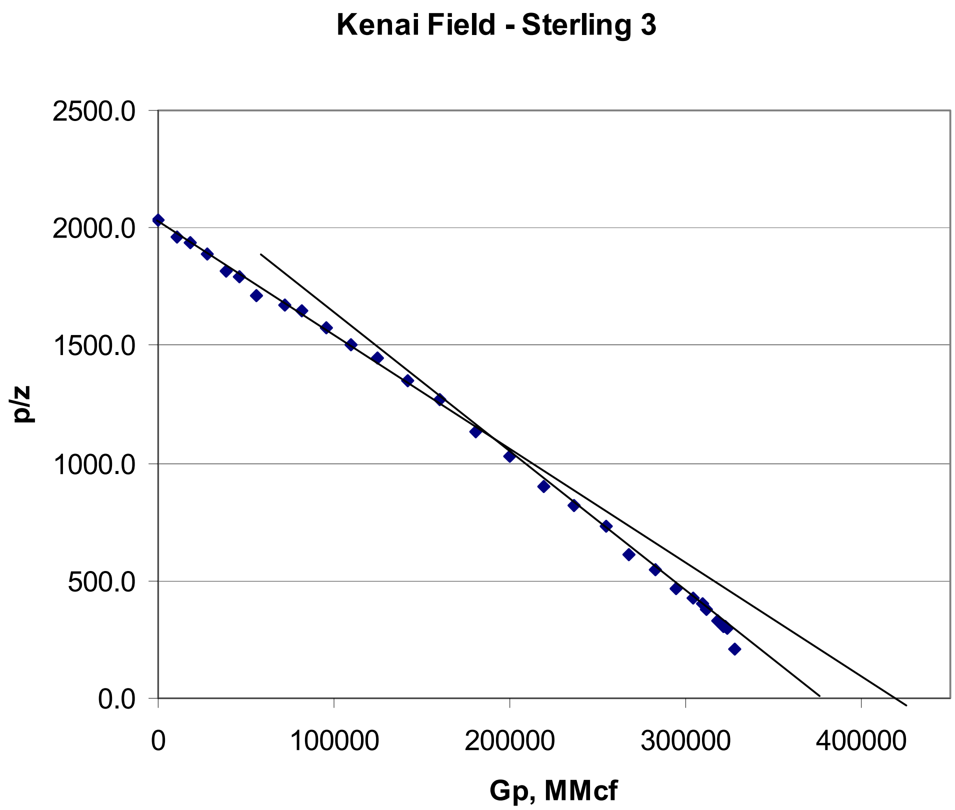


Figure 3.10. Kenai River Unit – Sterling 3 formation P/Z versus cumulative recovery.

3.2.3.2 Sterling 4 formation

The Sterling 4 formation began producing in 1965. Cumulative recovery to January 1, 2004 is 443,340,059 Mcf and 145,842 bbls water. Production during December 2003 was 439,057 Mcf and 396 bbls water from six wells. Figure 3.11 shows the production performance for this formation.

Figure 3.12 is a plot of the P/Z data versus cumulative recovery data. These data could be interpreted to show an OGIP of 455 Bcf as a minimum value to 575 Bcf as a maximum. The low volume is not justified as recovery to date would be 97%. An OGIP of 525 Bcf is a reasonable volume based on both pressure and production data.

Production performance is used to predict future reserves and recovery rates. The monthly average of 241 MMcf for the last four months of 2003 is used as the initial production rate. Using a decline rate of 20% and an abandonment rate of 20 MMcf/month, remaining reserves of 11.9 Bcf are calculated. This results in estimated ultimate recovery of 455.2 Bcf. Using an OGIP of 525 Bcf gives a recovery factor of about 87%.

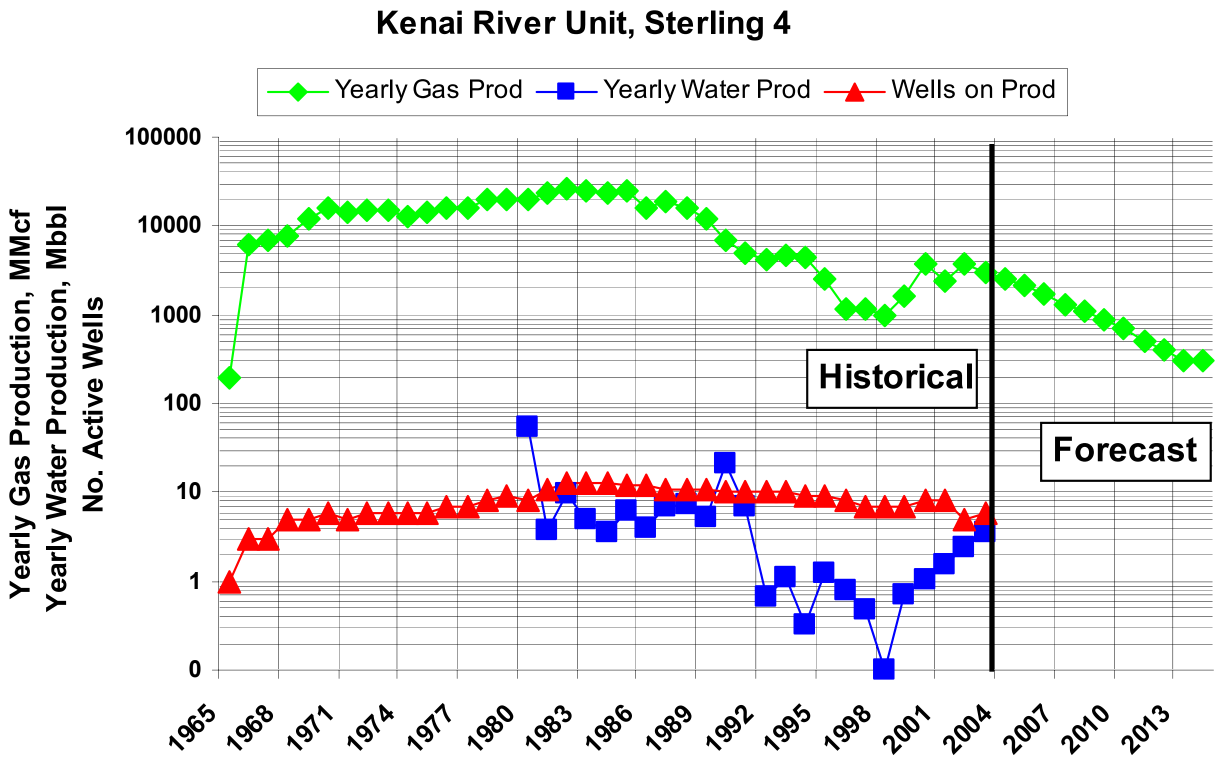


Figure 3.11. Kenai River Unit – Sterling 4, Production history and forecast.

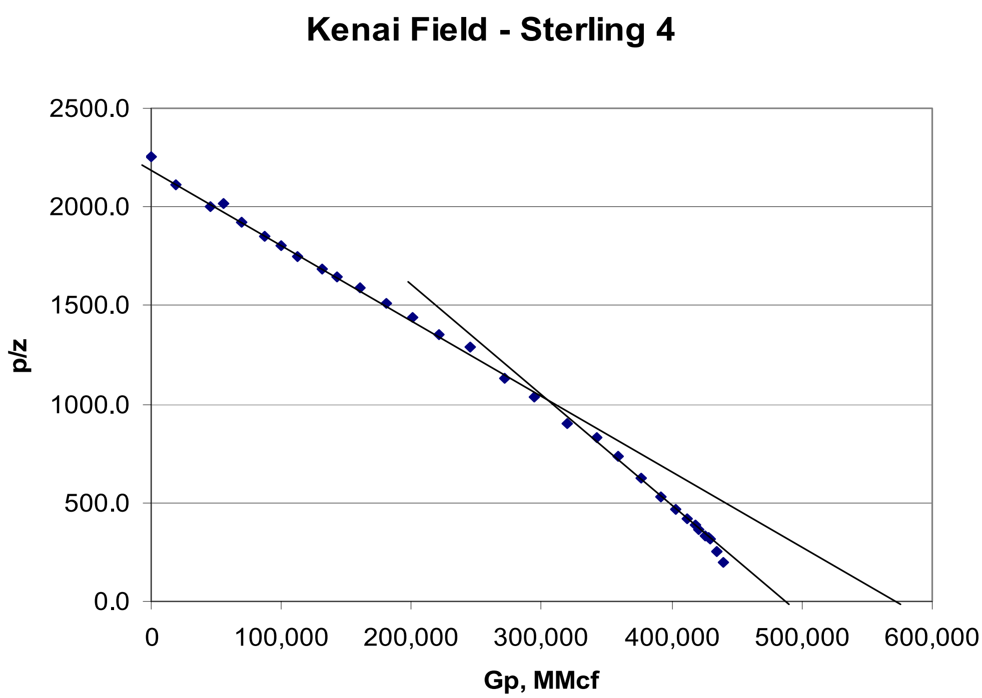


Figure 3.12. Kenai River field, Sterling 4 formation P/Z versus cumulative recovery.

This reserve estimate results in the production forecast contained in Table 3.5. This forecast is also shown on Figure 3.11.

Table 3.5. Kenai field, Sterling 4 formation production forecast.

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	2.6	2010	0.7
2005	2.1	2011	0.5
2006	1.7	2012	0.4
2007	1.3	2013	0.3
2008	1.1	2014	0.3
2009	0.9		

3.2.3.3 Sterling 5.1 formation

The Sterling 5.1 formation began producing in 1962 and continuous production was initiated in 1963. Gas production ceased in late 1999 after 484,636,177 Mcf and 154,652 bbls water had been recovered. Production history is shown on Figure 3.13.

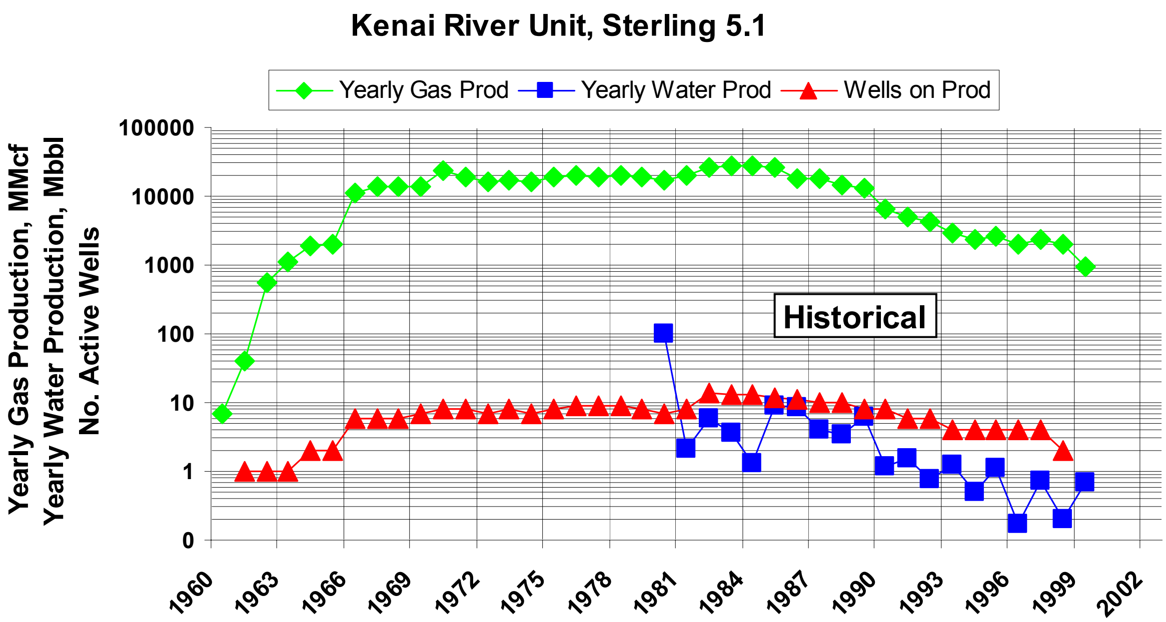


Figure 3.13. Kenai River Unit, Sterling 5.1, production history.

Figure 3.14 is a plot of P/Z versus cumulative production data. Although the operator did not report any high water volumes, the performance shown on Figure 3.14 indicates the effect of water influx as demonstrated by the concave break in the P/Z plot. No reserves are assigned to this reservoir.

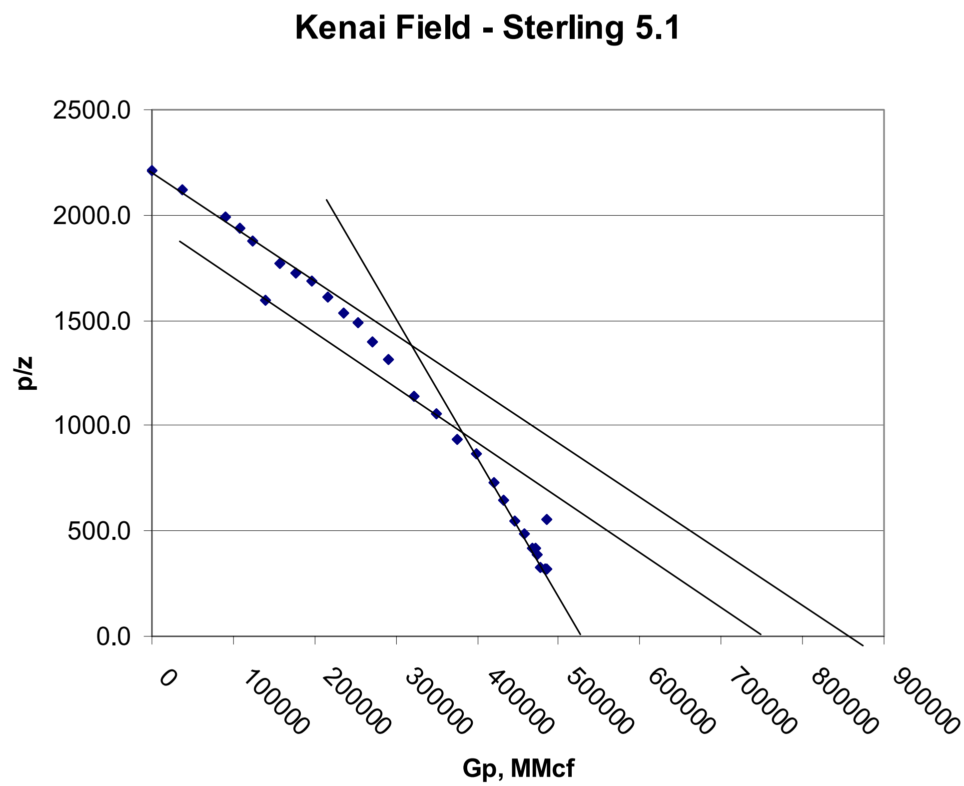


Figure 3.14. Kenai River Unit, Sterling 5.1 formation, P/Z versus cumulative recovery.

3.2.3.4 Sterling 5.2 formation

The Sterling 5.2 formation began producing in 1965 and continued until late 1981. Cumulative gas and water production over that time period totaled 44,031,635 Mcf and 12,700 bbls water. This performance is shown on Figure 3.15.

No reserves are assigned to the Sterling 5.2 formation.

3.2.3.5 Sterling 6 Formation

Initial production from the Sterling 6 formation began in 1961. Cumulative recovery for this formation is 511,978,304 Mcf and 100,347 bbls water. Production during December 2003 was 848,752 Mcf and 962 bbls water from 10 wells. This production history is shown in Figure 3.16.

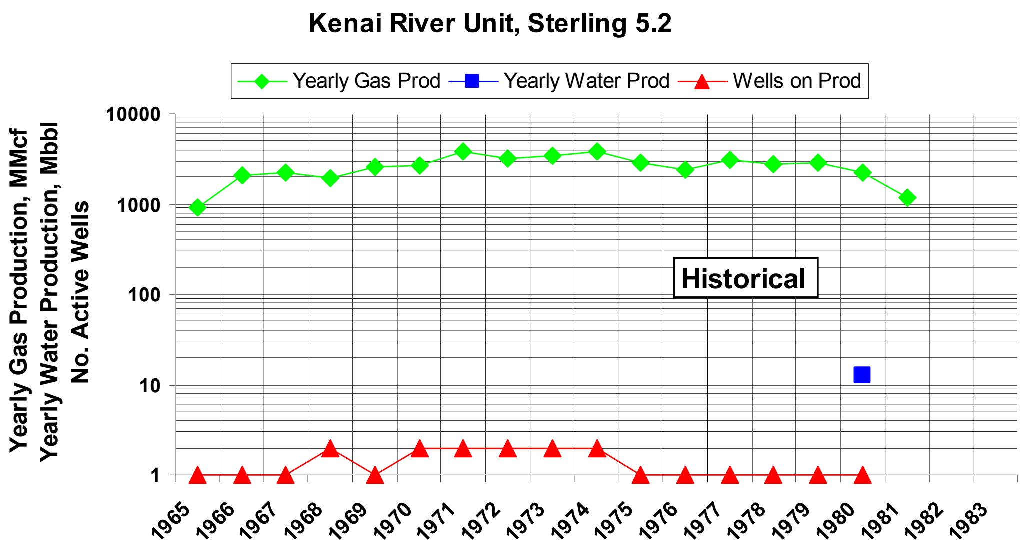


Figure 3.15. Kenai River Unit, Sterling 5.2.

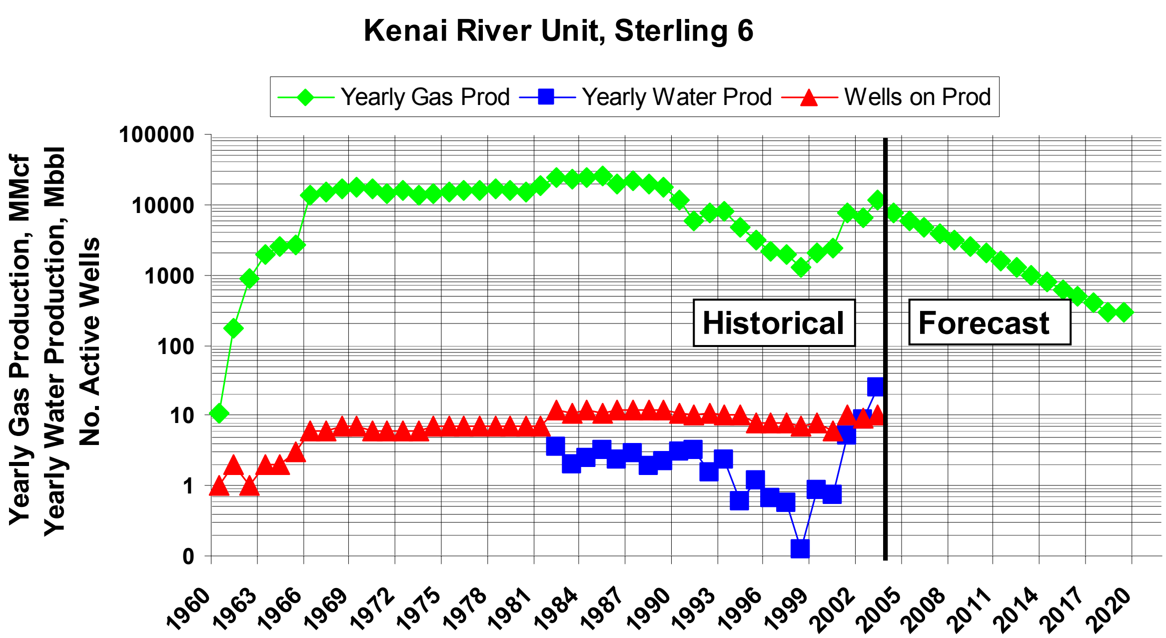


Figure 3.16. Kenai River Unit, Sterling 6, Production history.

Figure 3.17 is a plot of the P/Z data for this formation. Interpretation of these data ranges from 565 to 610 Bcf. The larger volume for OGIP is preferred based on reservoir performance to date.

Recent production performance, including the increased water production suggests the reservoir may start declining very soon. Future developed reserves after December 31, 2003,

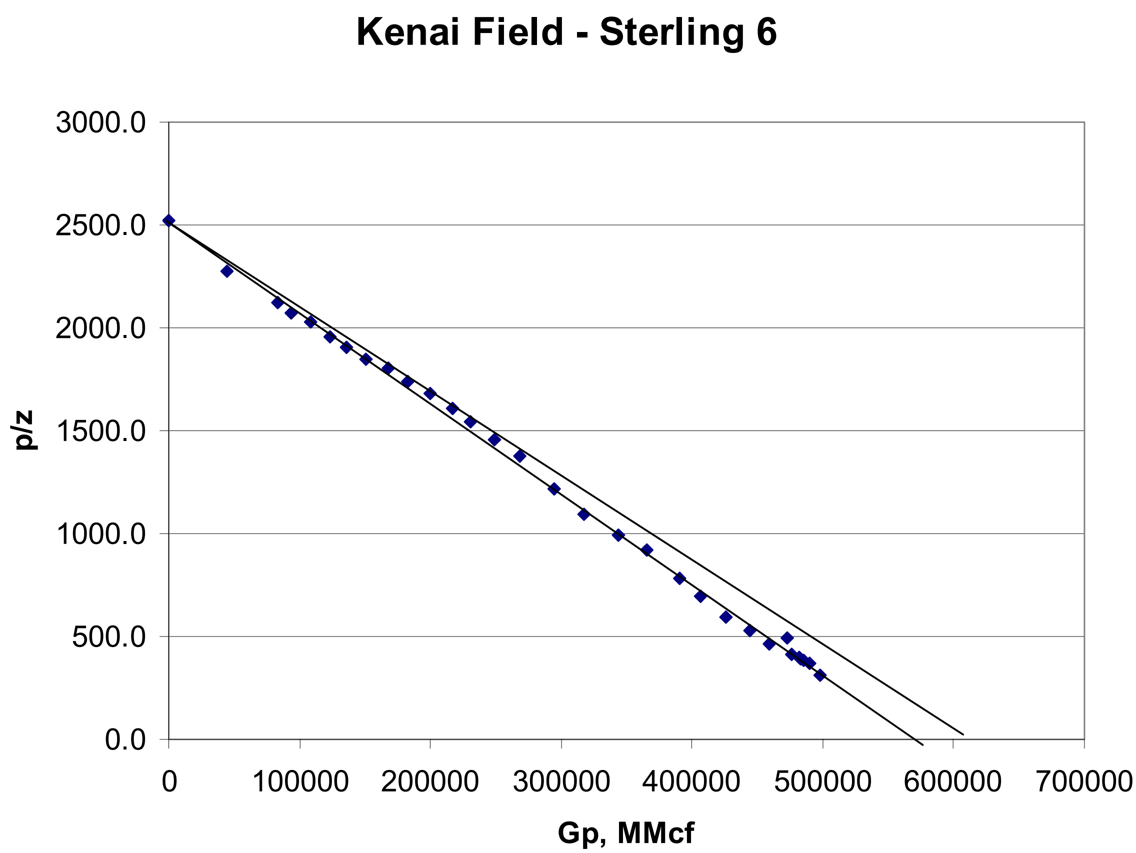


Figure 3.17. Kenai River Unit, Sterling 6, P/Z versus cumulative production.

are estimated using an initial rate of 700 MMcf/month, an abandonment rate of 20 MMcf/month, and a decline rate of 20% to account for wells being shut in due to increasing water influx.

Using the above parameters, estimated remaining reserves of 36.6 Bcf are determined. Estimated ultimate reserves are 549.3 Bcf. Using the higher of the OGIP volumes stated above, a recovery of 90% is obtained and is supported by the linear character of the P/Z data.

A forecast of future production is contained in Table 3.6. This forecast is shown on Figure 3.16.

Table 3.6. Kenai field, Sterling 6 formation production forecast.

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	7.5	2012	1.3
2005	6.0	2013	1.0
2006	4.8	2014	0.8
2007	3.9	2015	0.6
2008	3.1	2016	0.5
2009	2.5	2017	0.4
2010	2.0	2018	0.3
2011	1.6	2019	0.3

3.2.3.6 Beluga Formation

Initial production from the Beluga formation began in 1974. Cumulative recovery through December 31, 2003, was 171,812,177 Mcf gas and 69,730 bbls of water. Production during December 2003 was 747,571 Mcf gas and 479 bbls of water from eight wells.[9] Production history is shown on Figure 3.18.

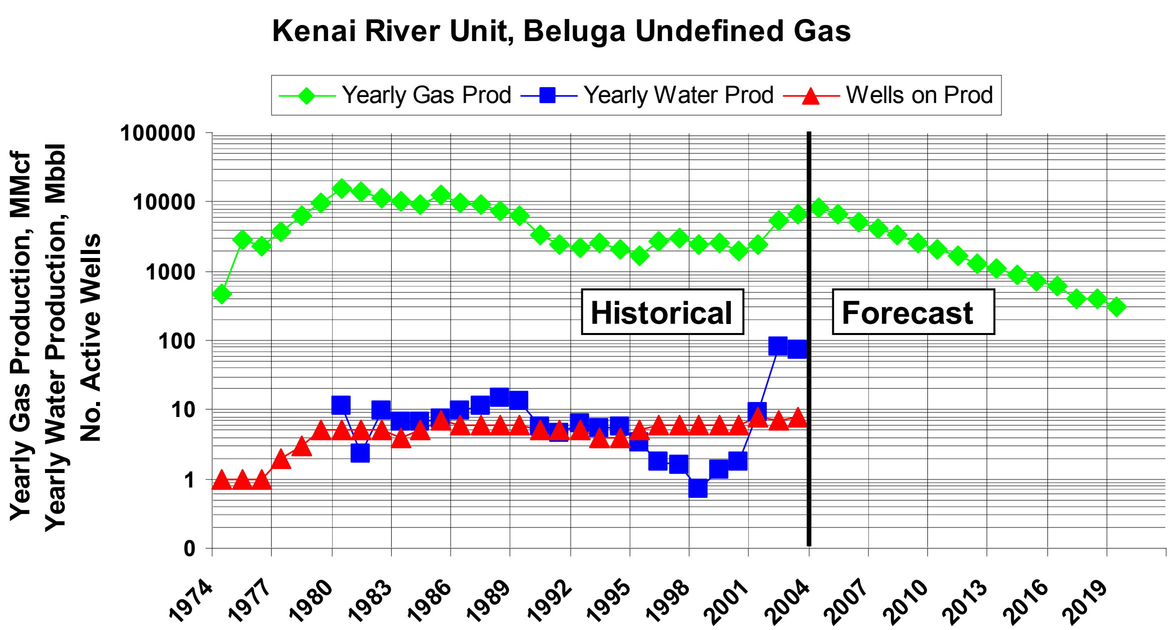


Figure 3.18. Kenai River Unit, Beluga Undefined Gas production history and forecast.

Figure 3.19 is a plot of P/Z data versus cumulative production. The plot shows a change in slope after recovery of about 85 Bcf. This may have resulted from newly drilled wells encountering partially drained reservoir intervals as well as opening new reservoir volume.

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[9] December 2003 volumes and wells reported by AOGCC appear to be incorrect. These volumes were adjusted between the Beluga and Tyonek formations to be in agreement with the previous values for 2003.

Although use of all the P/Z data may be questioned, Figure 3.19 shows three possible interpretations, which give OGIP volumes of 140 Bcf, 180 Bcf, and 235 Bcf. Based on cumulative gas recovery through December 31, 2003, the highest OGIP volume appears most reasonable. That volume is not used directly to estimate ultimate recovery, but is used to give an estimate of recovery percentage.

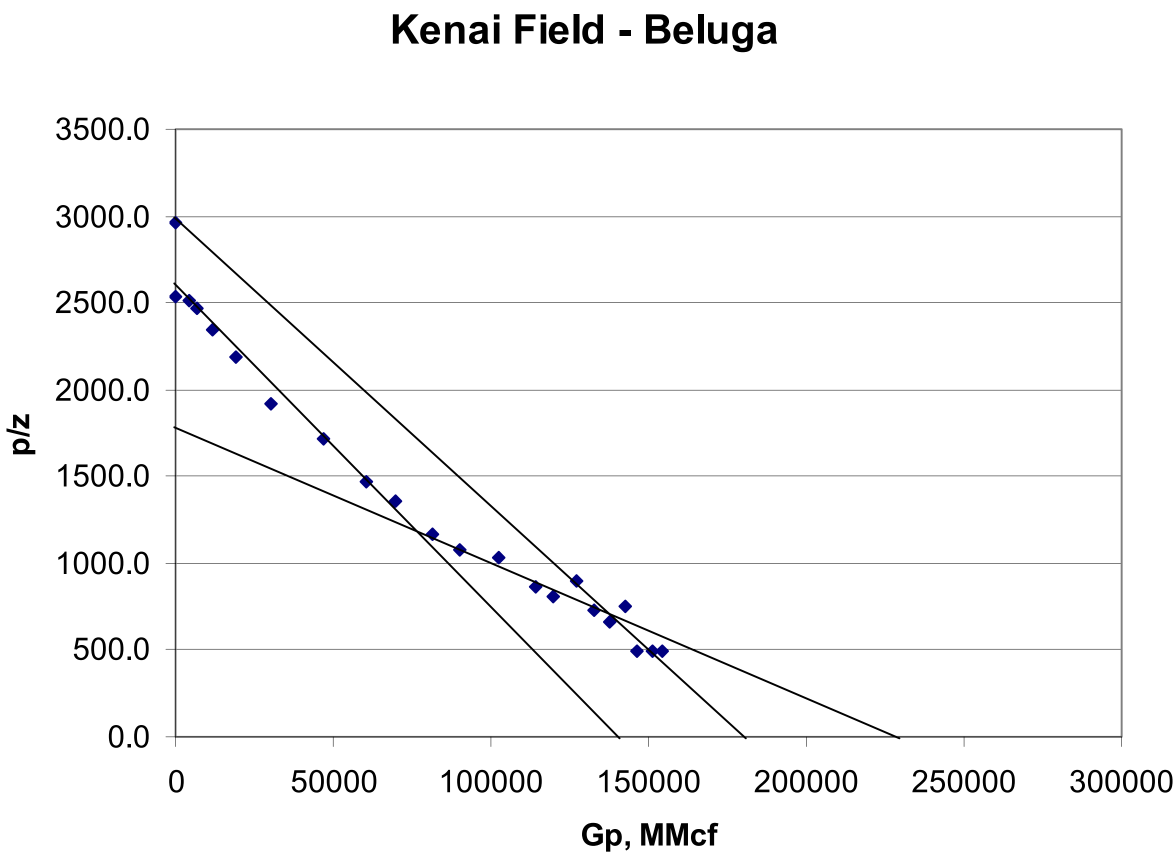

Figure 3.19. Kenai River Unit, Beluga Gas, P/Z versus cumulative production.

Future reserves are based on production performance. It is assumed that decline will begin immediately, because there is no evidence that production can be sustained at the present rate. A forecast is made using a decline rate of 20%, the December 2003 production of 747.6 MMcf/month as the initial rate, and an abandonment rate of 20 MMcf/month. This gives estimated remaining reserves of 39.3 Bcf. Estimated ultimate reserves are 211.1 Bcf or about 90% of the highest OGIP (235 Bcf) discussed above.

Table 3.7 contains the production forecast for the proven reserves determined above. This forecast is shown in Figure 3.18.

Table 3.7. Kenai field, Beluga formation -- Production forecast.

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	8.1	2012	1.3
2005	6.5	2013	1.1
2006	5.2	2014	0.9
2007	4.1	2015	0.7
2008	3.3	2016	0.6
2009	2.6	2017	0.4
2010	2.1	2018	0.4
2011	1.7	2019	0.3

3.2.3.7 Tyonek Formation

Initial production from the Tyonek formation began in 1968. Cumulative recovery through December 31, 2003, was 264,553,678 Mcf gas and 337,280 bbls water. Production during December 2003 was 533,230 Mcf gas and 3279 bbls water from seven wells. Production history is shown on Figure 3.20.

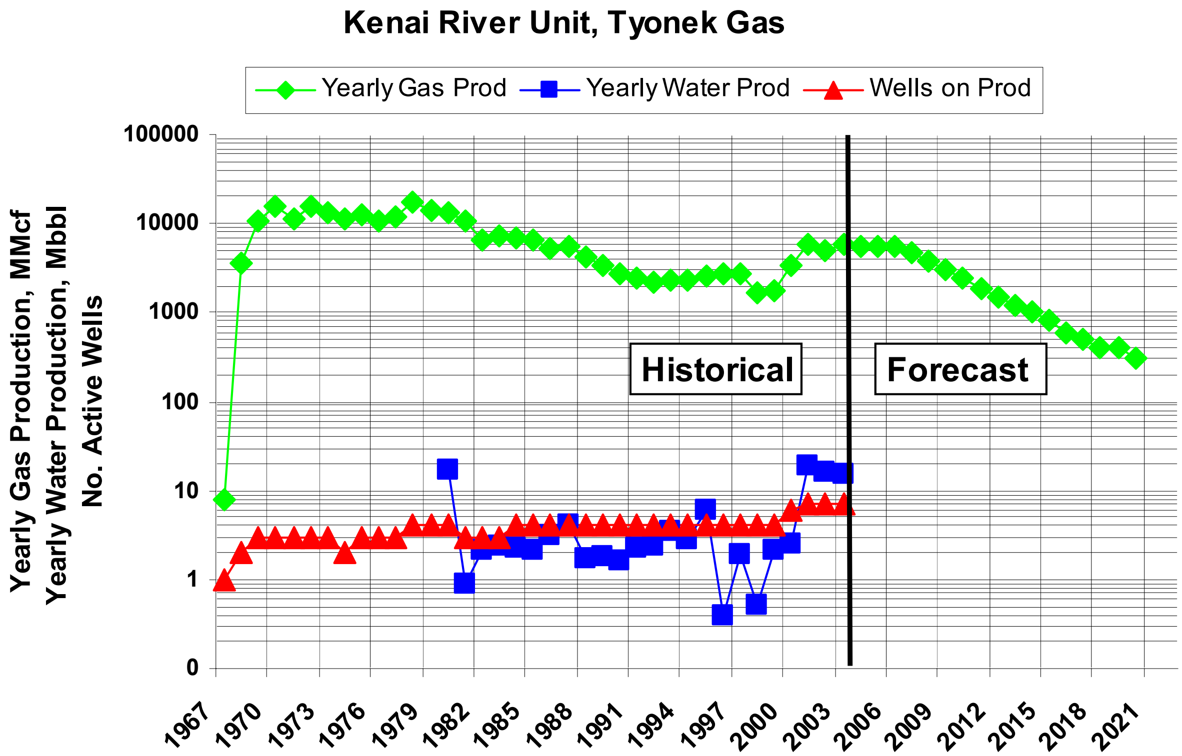

Figure 3.20. Kenai River Unit, Tyonek Gas, Production history and Forecast.

Figure 3.21 is a plot of P/Z data versus cumulative production. There is a change in the slope of the data at about 225 Bcf of recovery. This is prior to a redrill of an original well (October 1995) and the addition of three wells after September 2000. No bottomhole pressures are available after the new wells were drilled. Two possible interpretations of the data are shown in Figure 3.21; a low OGIP of about 260.0 Bcf and a higher one of about 290 Bcf. One possible interpretation is that aquifer influx is supporting reservoir pressure corresponding to the increase in water production shown in Figure 3.20. Based on production, neither of these interpretations appears to be valid. Additional bottomhole pressure data are required to estimate OGIP.

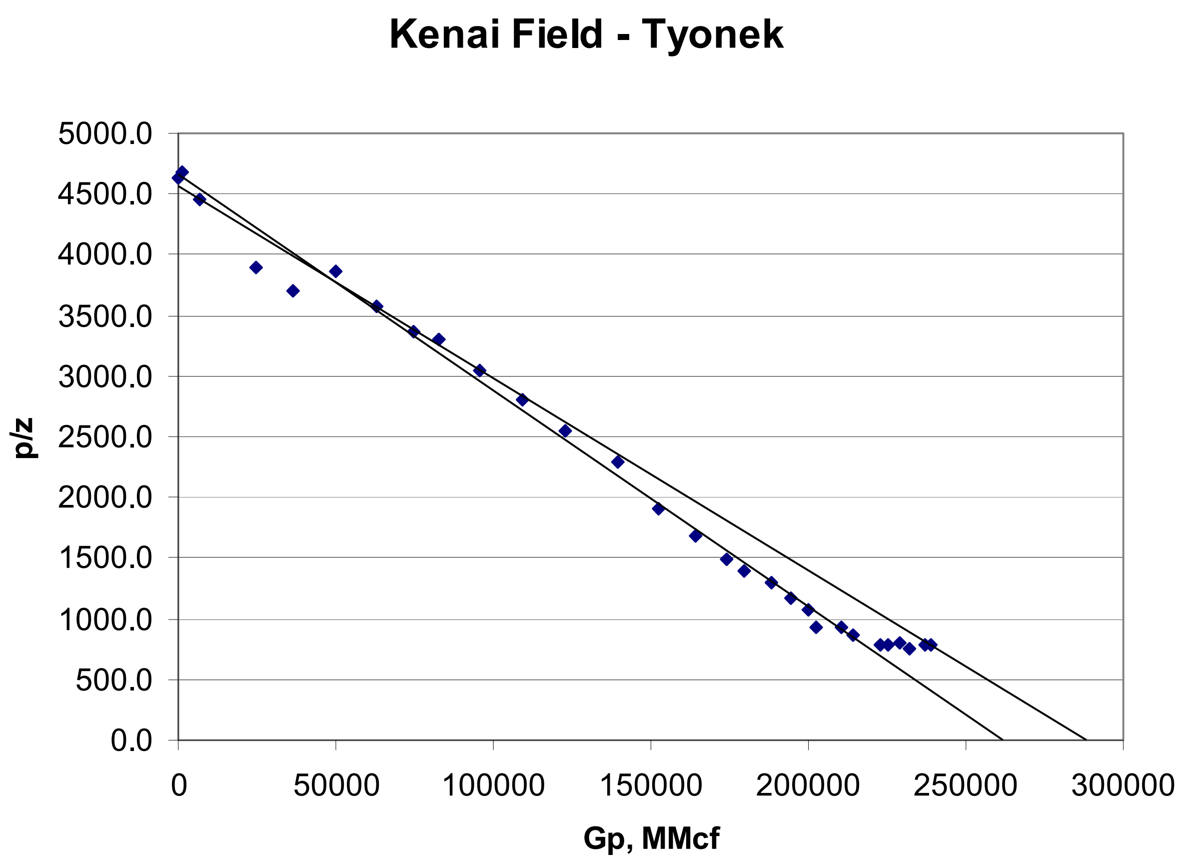

Figure 3.21. Kenai River Unit, Tyonek, P/Z versus cumulative production.

These data were used to determine the future rate forecast for the Tyonek formation shown in Table 3.8. This forecast is shown in Figure 3.20.

3.2.3.8 Kenai Field Reserves and Production Rates

The total estimated remaining reserves from the Sterling 3, Sterling 4, Sterling 6, Beluga, and Tyonek formations at the Kenai field is 139.2 Bcf. Table 3.9 gives the total forecast of production rates for the Kenai field.

Table 3.8. Kenai field, Tyonek formation -- Production forecast.

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	5.6	2013	1.2
2005	5.6	2014	1.0
2006	5.5	2015	0.8
2007	4.8	2016	0.6
2008	3.8	2017	0.5
2009	3.0	2018	0.4
2010	2.4	2019	0.4
2011	1.9	2020	0.3
2012	1.5		

Table 3.9. Kenai field summary of production rates (Bcf/yr)

Year	Sterling 3	Sterling 4	Sterling 6	Beluga	Tyonek	Total
2004	2.6	2.6	7.5	8.1	5.6	26.4
2005	2.1	2.1	6	6.5	5.6	22.3
2006	1.7	1.7	4.8	5.2	5.5	18.9
2007	1.3	1.3	3.9	4.1	4.8	15.4
2008	1.1	1.1	3.1	3.3	3.8	12.4
2009	0.9	0.9	2.5	2.6	3	9.9
2010	0.7	0.7	2.0	2.1	2.4	7.9
2011	0.6	0.5	1.6	1.7	1.9	6.3
2012	0.4	0.4	1.3	1.3	1.5	4.9
2013	0.4	0.3	1.0	1.1	1.2	4.0
2014	0.3	0.3	0.8	0.9	1.0	3.3
2015			0.6	0.7	0.8	2.1
2016			0.5	0.6	0.6	1.7
2017			0.4	0.4	0.5	1.3
2018			0.3	0.4	0.4	1.1
2019			0.3	0.3	0.4	1.0
2020					0.3	0.3
Total	**12.1**	**11.9**	**36.6**	**39.3**	**39.3**	**139.2**

3.2.4 McArthur River (Trading Bay Unit)

The McArthur River gas field is a part of the Trading Bay Unit and is produced from the Steelhead platform. It is located offshore near the west side of the Cook Inlet. The McArthur River gas field began producing from the Mid-Kenai formation in 1969. Cumulative production from this formation is 966,749,564 Mcf gas and 350,617 bbls of water through December 31, 2003. Production in December 2003 was 3,261,618 Mcf gas and 2,180 bbls of water from 15 wells. Production performance is shown on Figure 3.22.

No reservoir pressure data are available so production performance is used to forecast reserves for this field. Although recent production shows a decline of about 16%, a decline of

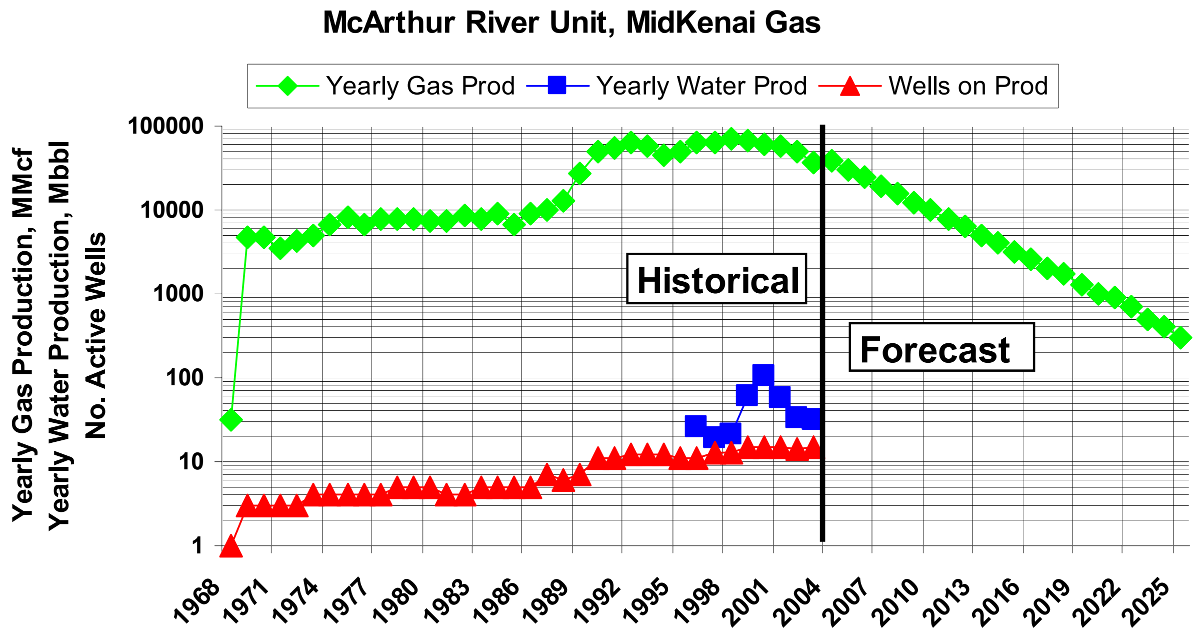

Figure 3.22. McArthur River Unit, Mid-Kenai Gas, Production history and forecast.

20% is used as water influx is expected to affect the late-life recovery. The production rate was low for a portion of 2003 when two wells were not on production. Both wells were on production by December 2003. It is assumed that gas will be produced at the December 2003 rate of 3,262 MMcf/month through April 2004 at which time it will continue to decline. An abandonment rate of 20 MMcf/day is used.

Estimated remaining reserves after December 31, 2003, are 187.1 Bcf. The production forecast is shown in Table 3.10 and on Figure 3.22.

Table 3.10. McArthur River Mid-enai gas production forecast. (Bcf/yr)

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	37.2	2016	2.6
2005	30.2	2017	2.0
2006	24.1	2018	1.7
2007	19.3	2019	1.3
2008	15.4	2020	1.0
2009	12.4	2021	0.9
2010	9.9	2022	0.7
2011	7.9	2023	0.5
2012	6.3	2024	0.4
2013	5.0	2025	0.3
2014	4.0	2026	0.3
2015	3.2	Total	187.1

3.2.5 North Cook Inlet Unit

The North Cook Inlet field was discovered in 1962. The field is located offshore in the northern part of the Cook Inlet about eight miles from the western shore. Production began in 1969 from the Sterling and Beluga formations. Cumulative production through December 31, 2003, was 1,621,586,748 Mcf of gas and 573,809 bbls of water. Production during December 2003 was 4,321,652 Mcf of gas and 2,827 bbls of water. Production history is shown in Figure 3.23.

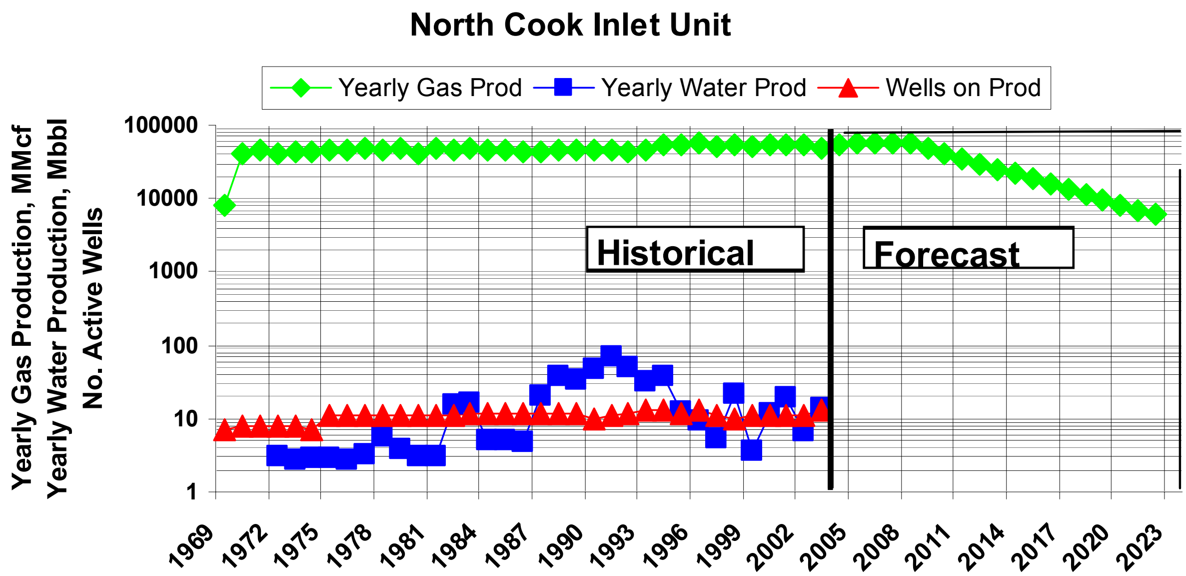

Figure 3.23. North Cook Inlet Unit production history and forecast.

Figure 3.24 is a plot of the P/Z values versus cumulative gas production. The plot shows a downward deviation of the data points at about 1,300 MMcf of gas recovery in 1998. This is believed to have been caused by workovers performed in the early 1990s. Many producing intervals were blanked off by packers or were squeeze cemented, reducing reservoir volume. As can be seen in Figure 3.24, the apparent reservoir volume being drained prior to the workovers was about 2,525 Bcf and the reservoir volume after the workovers is about 2,000 Bcf.

Evidence supporting a reduced reservoir volume is shown by the production performance during 2003 on Figure 3.23. The unit's production capacity dropped below the delivery requirement of about 4.775 Bcf/month during the last half of 2003. After redrilling one well and returning shut-in wells to active status, production remained below the delivery requirement. The operator plans additional workovers that must increase production by about

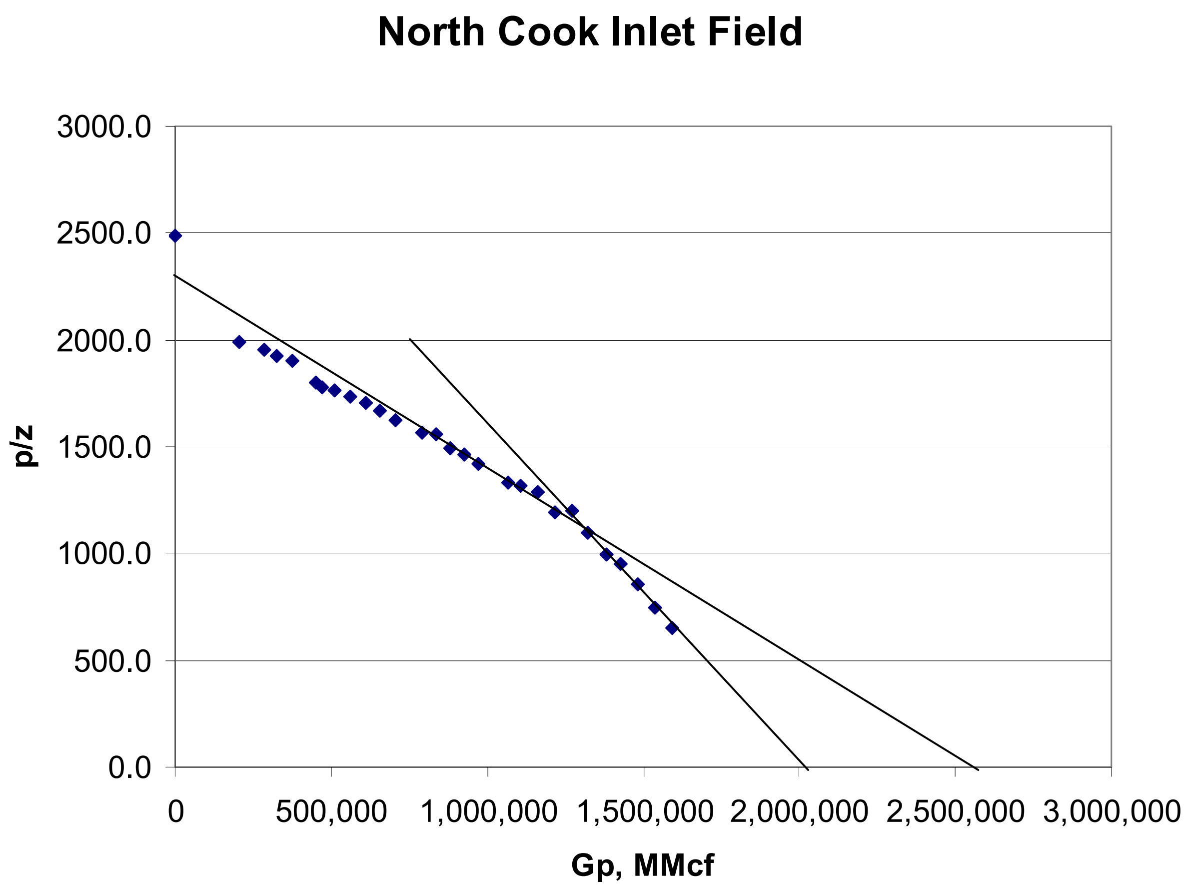

Figure 3.24. North Cook Inlet Field, P/Z versus cumulative production.

20 MMcf/day to meet delivery requirements at the current time. This increased volume would only allow the delivery requirement to be met for about one year. The operator must be successful in increasing recovery and deliverability to meet the delivery requirement through the first quarter of 2009. Options include increasing water handling capacity, performing additional workovers, restoring shut-in reservoir volume to production, and perhaps redrilling some wells.

It is assumed the operator will take all possible steps to return the production capacity to the level necessary to meet the 57.3 Bcf/yr delivery requirement through the first quarter of 2009. If this is accomplished, the reservoir performance will be defined by the upper projection line of the P/Z plot in Figure 3.24, which is used to estimate total recoverable reserves for the field. Abandonment reservoir pressure is assumed to be 250 psia. Estimated ultimate recovery is about 2,220 Bcf, with estimated remaining reserves of 598.4 Bcf as of December 2003.

If no additional remedial work is performed on North Cook Inlet Unit wells, estimated remaining reserves would be about 358 Bcf gas. The remaining 240 Bcf of the future reserve estimate are considered proven undeveloped reserves.

Both proven developed and undeveloped reserves are included in the production forecast. The December 2003 production rate of 4.322 Bcf/month is used for the initial rate during 2004. Production is assumed to increase during 2004 until the required delivery rate of 4.775 Bcf/month is reached. That production rate is assumed to be maintained until early 2009. Production is then declined at about 15%/yr until it reaches 2 Bcf/yr at abandonment. This forecasted volume is 598.4 Bcf giving a total recovery of 2,220 Bcf. The resulting forecast is shown in Table 3.11. It is also shown in Figure 3.23.

The total estimated recovery of 2,220 Bcf is 88% of the OGIP determined above.

Table 3.11. North Cook Inlet field production forecast. (Bcf/yr)

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	54.5	2016	15.7
2005	57.3	2017	13.2
2006	57.3	2018	11.3
2007	57.3	2019	9.6
2008	57.3	2020	8.2
2009	48.7	2021	6.9
2010	41.4	2022	6.0
2011	35.2	2023	5.0
2012	29.9	2024	4.2
2013	25.4	2025	3.7
2014	21.6	Remaining	10.4
2015	18.3	Total	598.4

3.2.5 Swanson River Unit

The Swanson River Unit is located onshore on the east side of the Cook Inlet. The Swanson River Hemlock Oil Pool was discovered in 1957 and began producing in October 1958. Reinjection of produced gas began in 1962 for pressure maintenance. Gas from other fields was also injected in this project.

Production from an Undefined gas reservoir began in July 1960. Five wells have been completed in this reservoir and produced intermittently until July 1987. Cumulative gas production through December 31, 2003, was 41,097,349 Mcf gas and 733,255 bbls of water.

Production during December 2003 was 179,414 Mcf gas and 1 bbl of water from four wells. The production history is shown in Figure 3.25.

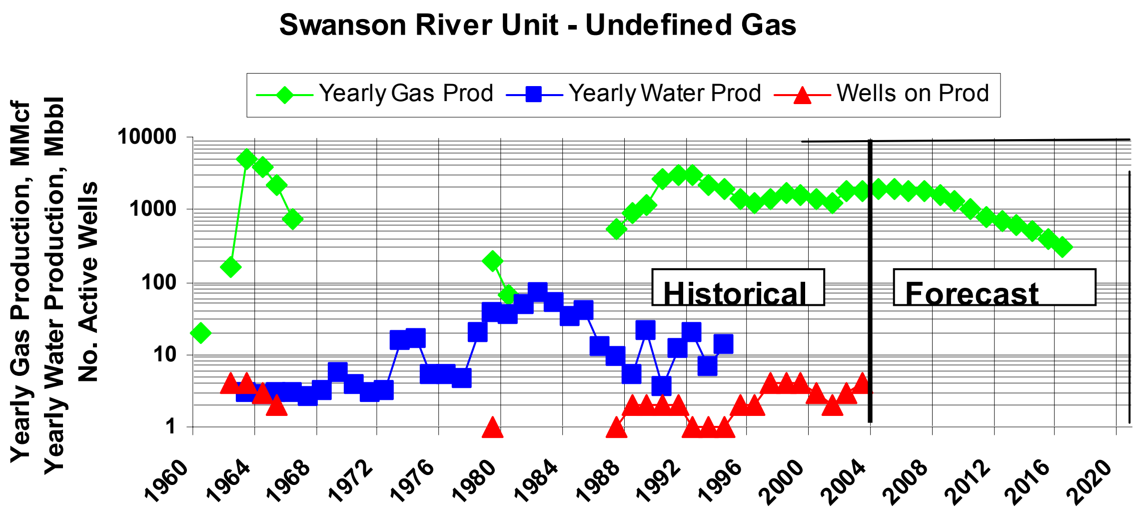

Figure 3.25. Swanson River Unit Undefined gas production history and forecast.

The future reserves forecast is based on the following assumptions: a 20% decline rate, abandonment volume of 20 MMcf/month, and a field capacity of 320 MMcf/month. The assumed production capacity is taken as the monthly average for the four months beginning October 1, 2002, through January 31, 2003. The remaining reserves determined are 14.6 Bcf.

The production forecast is determined by assuming production will average about 153,500 Mcf/month until decline begins. The forecast for the 14.6 Bcf is shown in Table 3.12 and in Figure 3.25.

Table 3.12. Swanson River Unit, Undefined gas production forecast. (Bcf/yr)

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	1.9	2011	0.8
2005	1.9	2012	0.7
2006	1.8	2013	0.6
2007	1.8	2014	0.5
2008	1.6	2015	0.4
2009	1.3	2016	0.3
2010	1.0	Total	14.6 Bcf

3.2.6 Newly Discovered Fields – Ninilchik Unit/Falls Creek PA and Happy Valley/Deep Creek PA

The Ninilchik Unit began producing in September 2003 and is made up of three participating areas (PA): Falls Creek, PA; Grassim Oskolkoff, PA; and Susan Dionne, PA. Through December 31, 2003, production was 3.06 Bcf gas and 704 bbls of water. There is very little publicly available information on the extent and characteristics of this field.

The Happy Valley field discovery was announced in November 2003 (Petroleum News, 2003c). The discovery well reported to have 110 feet of natural gas pay and was followed by a successful appraisal well. Three development wells are expected to be drilled in 2004 and first production is planned for fourth quarter 2004 with average production expected to be 20 to 25 MMcf/day.

Advanced production decline curve methods based on analogous formation characteristics were used to develop an estimated production forecast to produce the approximate 100 Bcf reserves. The advanced production decline methods (Fetkovich, 1980) are reservoir engineering analytic tools to estimate reservoir properties (permeability, hydraulic fracture characteristics, and decline parameters) from historical production data. These methods are applicable to the entire life of a well (transient production response through depletion) and can be used to forecast production. The transient production response was matched using the reported test results for discovery wells at Ninilchik and Happy Valley. From the history matched reservoir parameters, production forecasts were prepared for an "average" well.

The Ninilchik discovery test results (OGJ, 2003) by Marathon reported the initial test results that a 39-foot interval at 9,822 feet flowing 11.2 MMscf/day at tubing pressure of 1656 psi. Assuming an initial reservoir pressure of 3500 psia, a 22% porosity, a 320-acre spacing, and a permeability of 75 md, results in an initial transient deliverability of 11.85 MMscf/day. A 22% exponential decline was used. The base production profile was replicated for each of five development wells, staggered from 2004 to 2005. The resulting production forecast is shown in Figure 3.13.

Similarly, a Happy Valley production forecast for an average well was made using information derived from press release (Peninsula Clarion, 2003). It was noted that Happy

Valley 1 and 2 were capable of gas flows greater than 5 MMscf/day from 110 feet of net pay. The finding and development costs were estimated to average around $0.50/Mcf. Assuming an initial reservoir pressure of 3000 psi, a producing wellhead pressure of 750 psi (pipeline operating pressure), 160-acre spacing, 22% porosity, and reservoir permeability of 13 md results in an initial transient deliverability of 5.6 MMscf/day. At the end of transient flow, the production is declined using a 20% exponential decline. This base production was replicated for each of ten development wells, using a staggered development schedule starting in 2004 and finishing by year-end 2005. The resulting production forecast is shown in Figure 3.13.

Table 3.13. Ninilchik and Happy Valley production forecasts.

Year	Ninilchik Production (Bcf/Yr)	Happy Valley Production (Bcf/Yr)	Year	Ninilchik Production (Bcf/Yr)	Happy Valley Production (Bcf/Yr)
2004	12.1	1.0	2015	1.9	2.8
2005	15.7	12.2	2016	1.5	2.3
2006	13.5	16.3	2017	1.2	1.9
2007	10.9	13.4	2018	1.0	1.5
2008	8.8	11.0	2019	0.8	1.3
2009	7.0	9.0	2020	0.6	1.0
2010	5.7	7.4	2021	0.5	0.8
2011	4.6	6.1	2022	0.3	0.7
2012	3.7	5.0	2023	0.1	0.6
2013	3.0	4.1	2024	0.0	0.5
2014	2.4	3.4	2025	0.0	0.3
			Total	95.3	102.6

3.3 All Other Fields

The production forecast for the small fields included in the All Other Fields group is based on the gas production forecast for this combined group of fields prepared by the ADNR and presented in the 2003 Annual Report (ADNR 2003, pg. 4-23). ADNR's forecast includes the Beaver Creek Unit, which is forecasted separately in Section 3.2.1; therefore, the All Other Fields forecast was modified by reducing its annual gas volumes by the gas volumes determined in Section 3.2.1 for the Beaver Creek Unit. The resulting forecast for All Other Fields group is shown in Table 3.14.

Table 3.14. Cook Inlet All Others combined production forecast.

Year	Production (Bcf/year)	Year	Production (Bcf/year)
2004	16.5	2013	6.9
2005	16.3	2014	6.3
2006	12.2	2015	6.4
2007	13.5	2016	5.6
2008	12.6	2017	5.8
2009	11.5	2018	3.2
2010	9.9	2019	2.3
2011	7.4		
2012	6.7	Total	143.0

3.4 Proven Undeveloped Reserves

An independent determination of the proven undeveloped reserves in the Cook Inlet Area was not made for this report. The ADNR's Division of Oil and Gas forecast of these reserves, presented in the Division of Oil and Gas Annual 2003 Report (ADNR 2003, Table IV.10), was ".... based primarily on gas prospectively in the Ninilchik and Kasilof exploration units and other exploration areas on the Kenai Peninsula." The total Proven Undeveloped gas from ADNR's forecast is 341 Bcf. We have assumed that Ninilchik and Happy Valley each have about 100 Bcf of reserves, Table 2.5. The remaining undeveloped reserves are considered part of reserves growth and exploration, which are discussed in Section 4.5.

3.5 Cook Inlet Coalbed Natural Gas Resources

Coalbed natural gas resources were discussed in Section 2.6.3. The estimates for technically recoverable resources for the accessible Cook Inlet coalbed natural gas are about 7 Tcf.

The only production to date is from the Evergreen Resources operated Pioneer Unit in the Mat-Su Valley (see Figure 2.9). Evergreen initiated a pilot testing program in June 2003 involving two four-well pilots consisting of three wells forming an equilateral triangle (600 to 700 feet on a side) with a fourth well in the center. The wells are reported to contain up to 160 feet of coal thickness in an approximate gross section of 600 to 1000 feet.[10] The objective is to de-water the coal seams as rapidly as possible without damaging the wells to determine the gas production rates. The target de-watering rate was about 100 BWPD. Five of the eight wells had

[10] Personal communication, John Tanagawa, Evergreen Resources (Alaska) Corporation, August 21, 2003.

been completed by October 2003 (Petroleum News, 2003c). Total production from the Pioneer Unit from June 2003 through January 2004 from four wells was 2,427 Mcf and 69,001 bbl water. The reported January 2004 production was 271 Mcf and 6,660 bbl water.[11]

Evergreen's president, Mark Sexton, announced in November 2003 (Petroleum News, 2003d) that "initial production results indicate that the wells in the first two pilot projects are probably not capable of commercial production." He went on to say, "While we are disappointed with our initial drilling results on the Pioneer Unit we're not down on the Alaska project." Evergreen in now involved in drilling five stratagraphic core holes to provide scientific data. These core holes are being drilled north of the Castle Mountain fault. The coals are encountered at 700 feet on the north side of the fault compared to 3,700 feet south side of the fault (Petroleum News, 2003d). The purpose of this coring program is to obtain geological information on coal-bearing rock formations penetrated during drilling and to recover coal cores for further laboratory testing of their mineralogical, geological, and engineering properties (Petroleum News, 2003e).

The cost of the pilot wells was about $750,000 per well.[12] The five stratagraphic core holes are expected to be about $2.3 million or $460,000 per well (Petroleum News, 2004a). For comparison, the cost to drill and complete coalbed methane wells in the Powder River Basin in Wyoming is from about $85,000 to $125,000 per well depending on depth. Evergreen also performed fracture stimulations on the wells involving nitrogen foam using up to 500 Mscf nitrogen and 150 to 250 thousand pounds of frac sand. At the present time, nitrogen and frac sand have to be imported to Alaska, resulting in a cost two to three times greater than in Evergreen's operations in Colorado. In addition to the production well cost, it is anticipated that water disposal wells will be required in Alaska to dispose of the water in an acceptable manner. Also anticipated are gas processing to remove water vapor from the gas and gas compression to raise the pressure from about 30 psi wellhead pressure to ENSTAR pipeline pressure of about 800 psi.

[11] AOGCC - http://www.state.ak.us/local/akpages/ADMIN/ogc/production/pindex.htm
[12] Personal communication, John Tanagawa, Evergreen Resources (Alaska) Corporation, August 21, 2003.

Gas and water production rates for typical coalbed natural gas wells in several basins in the Lower 48 are shown in Table 3.15.[13] These results show the high variability of coalbed natural gas basins, which affect the economics in each basin. Until the Cook Inlet Basin coalbed natural gas resources are better characterized geologically, production characteristics are better known, and costs are reduced, it is not possible to make a technically sound evaluation of the coalbed natural gas economics for the Cook Inlet Basin. A parametric study could be made to bracket the spread in the price of gas required to encourage development. However, such an assessment is premature at this time and could send incorrect signals to policymakers and stakeholders.

Table 3.15. Typical coalbed natural gas well production data for several Lower 48 basins.

Typical Coalbed Natural Gas Well Production Data			
Basin	**Gas (Mcf/d)**	**Water (bbl/d)**	**TDS (mg/l)**
Greater Green River Basin (WY)	280	71	22,000
Powder River Basin (WY)	145	400	500
San Juan Basin (CO & NM)	806	25	8,000
Unita Basin (Utah)	511	215	15,000

3.6 Cook Inlet Basin Estimated Remaining Reserves and Production Forecasts

The remaining reserves for all the non-associated dry gas fields in the Cook Inlet were reviewed, including those in the All Other Fields group. The estimated remaining reserves and the estimated ultimate recovery are shown in Table 3.16. The estimates for the eight fields in Section 3.2 are highlighted in Table 3.16. The fields in the All Other Fields group were reviewed where sufficient production data existed and the remaining reserves estimated by using a 20% decline rate. The total remaining reserves were adjusted to match the total contained in the ADNR 2003 Report (ADNR 2003, p. 4-23) by adjusting the Wolf Lake remaining reserves. An independent production forecast was not prepared for these fields; the ADNR (2003, p. 4-23) production forecast is used.

The estimated remaining reserves in Table 3.16 are for non-associated dry gas fields only and total 1,784.9 Bcf compared to the ADNR estimate of 1,713.6 described in Table 2.5. The total estimated ultimate recovery estimate is 7,926.8 Bcf as shown in Table 3.16 compared to the total discussed in Table 2.5 of 8,403.4 Bcf; however, the total from Table 2.5 and ADNR (2003)

[13] John Boysen, presentation at University of Alaska Fairbanks 2004 Alaska Unconventional Gas Workshop, March 9-11, 2004, Anchorage, AK.

Table 3.16. Estimated remaining reserves and estimated ultimate recovery for Cook Inlet basin non-associated dry gas fields.

Gas Fields[1]	Production Discovery thru 2003 (Bcf)[2]	Proven Reserves as of Jan. 1, 2004 (Bcf)[3]	Estimated Ultimate Recovery (Bcf)
Albert Kaloa	0.119	0.000	0.119
Beaver Creek	170.149	51.800	221.949
Beluga River	847.163	452.800	1299.963
Birch Hill	0.065	11.000	11.065
Cannery Loop	110.770	29.309	140.079
Falls Creek/ Ninilchik[1]	3.063	95.300	98.363
Granite Point	0.800	0.355	1.155
Happy Valley	0.000	102.600	102.600
Ivan River	74.049	8.604	82.653
Kenai	2245.565	139.200	2384.765
Lewis River	10.882	2.370	13.252
Lone Creek	1.011	8.012	9.023
McArthur River	966.750	187.100	1153.850
Middle Ground Shoal	16.383	1.927	18.310
Moquawkie	0.988	20.000	20.988
Nicolai Creek	2.207	0.890	3.097
North Cook Inlet	1621.587	598.400	2219.987
North Fork	0.105	12.000	12.105
Pretty Creek	8.273	3.764	12.037
Sterling	4.058	2.082	6.140
Stump Lake	5.643	0.000	5.643
Swanson River	41.097	14.600	55.697
Trading Bay	5.265	0.040	5.305
West Foreland	1.059	8.833	9.892
West Fork	4.212	0.645	4.857
Wolf Lake	0.654	33.169	33.823
Totals	**6141.917**	**1784.860**	**7926.777**

(1) Production and reserves estimates for Cook Inlet non-associated gas fields only.
(2) Data from ADNR (2003, Table VI-6) plus production from AOGCC Production statistics for 2003 (http://www.state.ak.us/local/akpages/ADMIN/ogc/production/Dec03gas.pdf).

total include associated gas as well as non-associated gas. Most of the associated gas produced is used to produce oil and not to meet the gas demand of primary interest for analysis (see Section 4.3.3 for additional discussion).

The production forecasts for eight fields in the Cook Inlet basin and the "All Other Fields" are shown in Table 3.17. The All Other Fields forecast in Table 3.17 has been adjusted from the DOG forecast by subtracting the Beaver Creek forecast from the DOG forecast in 2003a, p

4-23. The Swanson River field forecast is for the Undefined Gas zone only and is aggregated with the All Others Fields forecast for the economic analysis in Section 4.

Table 3.17. Cook Inlet Basin Production Forecast (Bcf)

Year	Beaver Creek	Beluga River	Happy Valley	Kenai	McArthur River	Ninilchik	North Cook Inlet	Swanson River[1]	All Other Fields[2]	TOTAL
2004	7.7	53.2	1.0	26.4	37.7	12.1	54.5	1.9	16.5	211.0
2005	7.7	53.2	12.2	22.3	30.2	15.7	57.3	1.9	16.3	216.8
2006	7.5	53.2	16.3	18.9	24.1	13.5	57.3	1.8	12.2	204.8
2007	6.0	53.2	13.4	15.4	19.3	10.9	57.3	1.8	13.5	190.8
2008	4.8	48.3	11.0	12.4	15.4	8.8	57.3	1.6	12.6	172.2
2009	3.8	38.6	9.0	9.9	12.4	7.0	48.7	1.3	11.5	142.2
2010	3.1	30.8	7.4	7.9	9.9	5.7	41.4	1.0	9.9	117.1
2011	2.4	24.7	6.1	6.3	7.9	4.6	35.2	0.8	7.4	95.4
2012	2.0	19.7	5.0	4.9	6.3	3.7	29.9	0.7	6.7	78.9
2013	1.6	15.8	4.1	4.0	5.0	3.0	25.4	0.6	6.9	66.4
2014	1.3	12.7	3.4	3.3	4.0	2.4	21.6	0.5	6.2	55.4
2015	1.0	10.1	2.8	2.1	3.2	1.9	18.3	0.4	6.4	46.2
2016	0.8	8.1	2.3	1.7	2.6	1.5	15.7	0.3	5.6	38.7
2017	0.6	6.5	1.9	1.3	2.0	1.2	13.2	0.0	5.8	32.5
2018	0.5	5.2	1.5	1.1	1.7	1.0	11.3	0.0	3.2	25.5
2019	0.4	4.1	1.3	1.0	1.3	0.8	9.6	0.0	2.3	20.8
2020	0.3	3.3	1.0	0.3	1.0	0.6	8.2	0.0	0.0	14.7
2021	0.3	2.6	0.8	0.0	0.9	0.5	6.9	0.0	0.0	12.0
2022	0.0	2.1	0.7	0.0	0.7	0.3	6.0	0.0	0.0	9.8
2023	0.0	1.6	0.6	0.0	0.5	0.1	5.0	0.0	0.0	7.8
2024	0.0	1.3	0.5	0.0	0.4	0.0	4.2	0.0	0.0	6.4
2025	0.0	1.1	0.3	0.0	0.3	0.0	3.7	0.0	0.0	5.4
Remainder	0.0	3.4	0.0	0.0	0.3	0.0	10.4	0.0	0.0	14.1
Total	**51.8**	**452.8**	**102.6**	**139.2**	**187.1**	**95.3**	**598.4**	**14.6**	**143.0**	**1784.9**

1. Swanson River Field forecast is for the Undefined Gas zone only. The Hemlock pressure maintenance project is not included.
2. All Other Fields forecast is the ADNR 2003 forecast for All Others less the Beaver Creek forecast in the first column.

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4. ECONOMIC ANALYSIS OF COOK INLET GAS SUPPLY

An analysis of the short-term and long-term outlook (through 2025) for natural gas supply from Cook Inlet basin to meet expected demand for south-central Alaska is included in this section and options for maintaining an adequate gas supply are examined. The focus is on conventional natural gas resources from the upper Cook Inlet basin and is not a comprehensive analysis of all possible energy sources,such as coalbed natural gas, coal, and renewable energy sources.

4.1 Goals and Approach

The goals of the economic study are to:

- describe the economic performance of existing gas fields using price and production forecasts and estimated operating cost structure by field
- estimate capital costs for future development of additional gas reserves from the existing fields (reserves growth) and exploration for new gas reserves from the undiscovered gas endowment in the Cook Inlet basin
- estimate the minimum economic field size for three operating environments
- evaluate gas supply costs from a North Slope gas pipeline and spur to the south-central Alaska region
- develop a supply–cost curve for current and future demand
- estimate future state revenue from royalty, severance tax, ad valorem tax, and state income tax from Cook Inlet natural gas production
- provide an overview of the interactive gas market and supply options and the likely impacts of the various choices.

The demand estimates rely on prior work from several references that contain reviews and analysis of south-central Alaska natural gas demand (Dismukes et al., 2002; Beck, 2004; ADNR 1997, Sproule Associates, 1998). This prior work reviewed the economic and demographic components of natural gas demand: industrial (LNG and fertilizer production); electric power generation; and commercial/residential. The economic models are designed to provide estimates of potential outcomes of natural gas demand, supply, price and investment over the study time horizon through 2025.

The results produced by the models are dependent on many factors including the structure and architecture of the models; the level of detail in the models; the mathematical algorithms used; and the input assumptions, which rely on publicly available data. The results produced by the models should not be viewed as precise forecasts of any future level of supply, demand, or price. Instead, they should be viewed as estimates of trends and ranges of possible outcomes from the specific assumptions made. The model results provide guidance regarding the likely impacts of pursuing particular choices relative to the south-central Alaska natural gas market.

The economic evaluations do not include risk. Risk comes from several sources, including subsurface resource related uncertainties, price, regulatory and environmental risk, and the overall level of macroeconomic activity. The decision not to include risk in the evaluation is predicated on several observations. A first study of the complex Cook Inlet natural gas market is best served by focusing on a deterministic analysis to understand the market fundamentals, supply-demand relations, characteristics of the producing fields, nature of the resource endowment, and existing price relationships. Additional study and research would be required to collect the data that are needed to perform a more robust stochastic study to identify and quantify the risks present in the Cook Inlet supply and demand future and was beyond the scope of the current analysis.

4.2 Economic Review

The historical Cook Inlet gas market and demand are described and analyzed in this section. This history provides a necessary foundation for understanding the current concerns and issues surrounding the future of the gas supply for south-central Alaska.

4.2.1 Historical Cook Inlet Gas Market - Demand

As described in Section 2, natural gas was discovered in the Cook Inlet as a result of exploration for oil in the 1950s and 1960s. By 1970, about 8 Tcf had been discovered and it resulted in a large oversupply of gas compared to the then-existing local demand. Gas consumption in 1971 for power generation and utility use was 26.8 Bcf/yr and the gas used in oil and gas field operations was 57 Bcf/yr or 83.8 Bcf/yr for a reserves-to-production ratio of 95 (a 95-yr supply). To monetize the large stranded gas discoveries, two large industrial facilities were constructed by the operators to utilize the abundant supplies of cheap natural gas; an ammonia/urea facility in 1968 by Unocal and a LNG export facility in 1969 by Phillips (now ConocoPhillips) and Marathon, (ownership 70%/30%, respectively). These two industrial facilities consumed 83 Bcf in 1971 (19.5 Bcf by the ammonia/urea facility and 63.2 Bcf by the LNG facility). Hence, the total gas use for 1971 was 167 Bcf for a reserves-to-production ratio of 50.

Industrial usage increased with the addition of a second train at the ammonia/urea plant in 1978 to 48.9 Bcf. LNG usage averaged 62.8 Bcf from 1971 through 1993, at which time the LNG export license was renewed and consumption increased to an average of 77.7 Bcf from 1994 through 2001. Current capacity of the two facilities is estimated at 78 Bcf/yr for the LNG facility and 52 Bcf/yr for the ammonia/urea plant. Gas production to support these two large industrial users has been primarily from three large fields: Kenai, McArthur River, and North Cook Inlet, with incremental supply from the other fields on an as-needed basis to balance short-term gas demand.

Residential and commercial demand consists of natural gas for power generation and utility gas and has increased with population and economic growth in the south-central Alaska region. Chugach Electric (Chugach) and Anchorage Municipal Light & Power (ML&P) use natural gas to drive combustion turbines to generate electricity. Installed capacity has increased over time to a total of 831 MW, of which 495 MW and 336 MW are operated by Chugach and ML&P, respectively. Power generation gas demand in 2001 was 31.6 Bcf, supplied primarily from the Beluga River field.

The residential and commercial gas demand is supplied by the gas utility, ENSTAR Natural Gas Company (ENSTAR). Gas utility demand has increased from 10.2 Bcf in 1971 to 34.9 Bcf in 2001. Gas demand has increased at an annual average of 2.95% from 1991 through 2001 due to economic and population growth.

Natural gas consumed by field and lease operations is used for compression, space heating, fluid separation, flared, or used for purging of gas lines and is not available for sales. Lease consumption from all Cook Inlet production operations (oil and gas) has decreased from 57.5 Bcf in 1971 to 15.2 Bcf in 2001 as conservation measures have decreased the flaring of excess gas, primarily from oil production operations. A majority of the lease usage of natural gas is associated with oil production with almost all gas associated with oil production consumed by lease operations. Lease usage by non-associated dry gas fields averaged 6.9 Bcf in 2002 or 3.7% of total gas production from the non-associated dry gas fields.[14]

Historical gas consumption by segment, excluding lease consumption is shown in Figure 4.1.

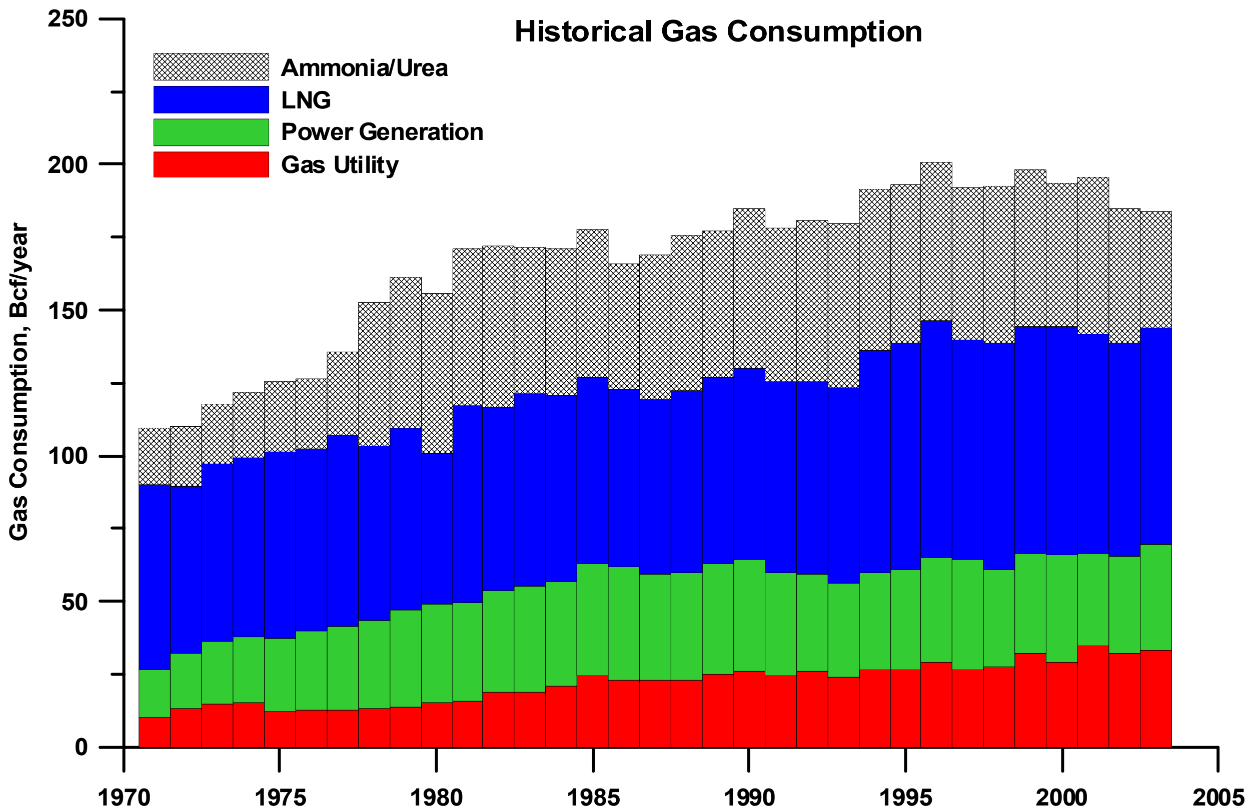

Figure 4.1. Historical gas consumption, excluding lease operations. (ADNR, 2004)

4.2.2 Historical Gas Prices

Historically, Cook Inlet gas prices have reflected this over-supply situation with prices significantly below Lower 48 prices. The price of gas sold to a utility is regulated by the Regulatory Commission of Alaska (RCA) and is a public record. The Alaska Department of Revenue (ADOR) is required under 15 AAC 55.173(b) to publish quarterly the prevailing value for gas delivered in the Cook Inlet area. The prevailing value is the weighted average price of significant gas sales to publicly regulated utilities in the Cook Inlet.[15] The prevailing value is the royalty basis for gas sold. The royalty for gas sold under contract at a price less than prevailing

[14] Non-associated gas – natural gas that is in reservoirs that do not contain significant quantities of crude oil (SPE 1998). Dry gas is a petroleum fluid classification defined as primarily methane with some intermediate hydrocarbons (McCain, 1990).
[15] State of Alaska code 15 AAC 55.173(b).

value is determined by the prevailing value. The contract terms for gas sold by company intersegment transfers (i.e., from exploration and production to the industrial plants) is not public information. Historical gas prices are shown in Figure 4.2, with the gas prices prior to 1994 compiled by the ADNR (1996) and prices after 1994 posted by the ADOR.[16] U.S. average wellhead price is included for comparison and shows that Cook Inlet prices have been consistently lower than the U.S. average.[17]

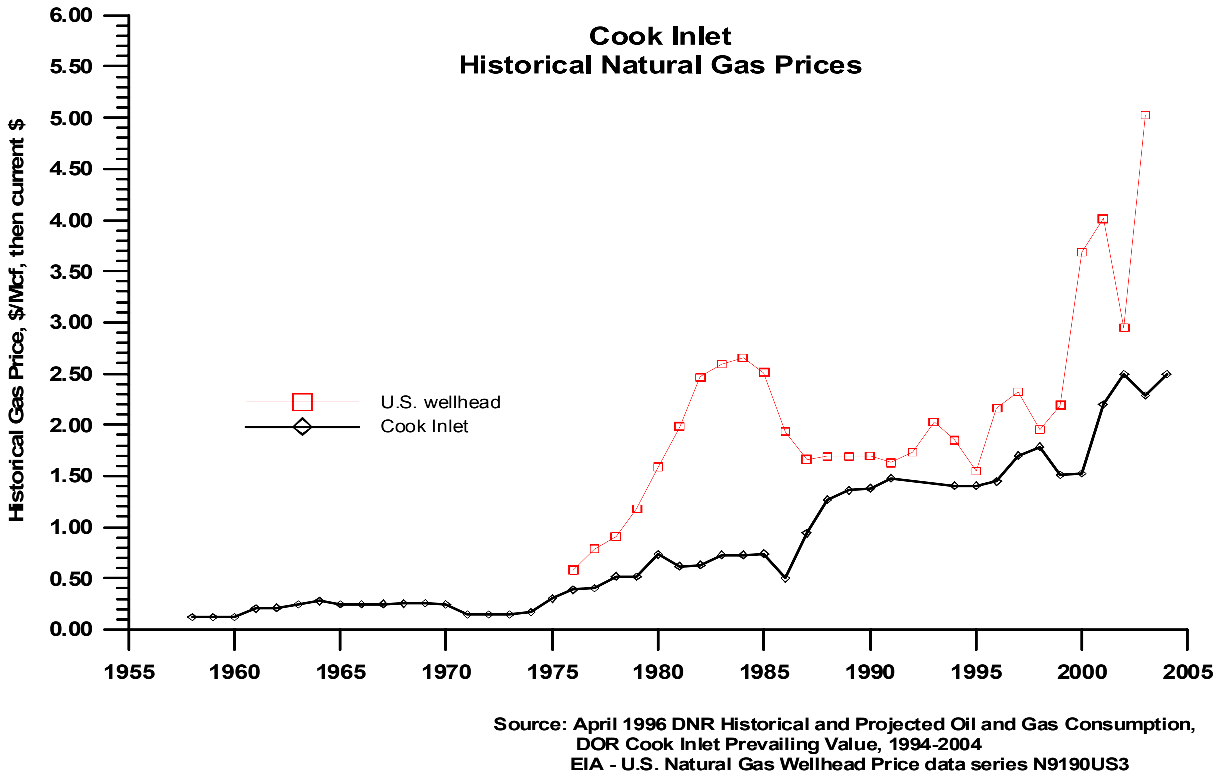

Figure 4.2. Cook Inlet historical natural gas prices compared to Lower 48.

An econometric review was made of time series data from 1987 through 2002, using prevailing gas prices, yearly remaining reserves, annual production, reserves/production ratio, and utility and power generation demand. No relationship was found explaining the historical price behavior as a function of supply and demand fundamentals. This leads to the observation that historically there has not been a functioning gas market in the Cook Inlet; i.e., as demand increases, prices increase and additional supply is added in response. This observation is not

[16] http://www.tax.state.ak.us/programs/oil/prices/prevailingvalue/cookinlet.asp
[17] EIA data series N9190US3, file name ng_pri_sum_nus_m_d.xls)

surprising given the large quantity of stranded gas, the closed market, and gas consumption by large industrial users.

A second analysis of market concentration was made using the Herfindahl-Hirschman Index (HHI) used by the Federal Trade Commission (FTC) to determine market concentration. Markets with an index in excess of 1800 are considered to be concentrated. The HHI for Cook Inlet gas exploration and production operations is 2512, implying a concentrated market. This is not surprising given the dominate position by the three major operators: ConocoPhillips, Marathon, and Unocal. This situation was a result of the large initial gas discoveries made over 35 years ago, requiring no further gas exploration and development for the last 30 years and is not a reflection of market collusion or monopolistic behavior. Quite the contrary, by simply noting that monopolistic behavior would have resulted in natural gas prices greater than Lower 48, not significantly less as has been the case. See Appendix A for details of this analysis.

These results demonstrate that, historically, natural gas pricing in the Cook Inlet was not a supply and demand driven market, but instead a market that relied on large industrial uses to monetize an 8 Tcf stranded gas asset. The Cook Inlet natural gas market is currently in transition due to the decline of the large stranded gas reserves as the two industrial facilities have used this gas to create valued added-products for export, coupled with increased power generation and gas utility consumption so that today the current reserves/production ratio is nine.

This market transition is further supported by the recent Unocal and ENSTAR gas supply agreement. On December 21, 2001, the RCA approved a gas sales agreement between Unocal and ENSTAR using a 36-month daily average of the Henry Hub natural gas futures and a floor price of $2.75/Mcf adjusted for one-half the inflation rate after 2002 (RCA, 2001). Both Unocal and ENSTAR characterized this GSA as an exploration contract because the focus and intent was on the exploration for new gas sources. The RCA noted that “investment capital in Cook Inlet must compete with investment opportunities worldwide” and “risk associated with exploration must be compensated or exploration will go elsewhere.” These two observations are important to understanding the natural gas market transition currently underway in the Cook Inlet; i.e., the current natural gas pricing regime, and project capital decisions by Cook Inlet producers.

4.3 Forecasts of Cook Inlet Economic Performance

Economic forecasts of the Cook Inlet natural gas fields depend on a number of factors that by necessity must be estimated. These estimates are based on publicly available information, the level of overall economic activity, and conditions specific to Cook Inlet operations. This section presents the basis for the economic models and the resulting estimates. Specific parameters include:

- remaining reserves and yearly production
- natural gas prices
- operating costs
- capital costs
- cost of capital
- book property value
- inflation rate
- demand for natural gas

4.3.1 Proved Reserves from Existing Fields

Reserves and production forecasts used as the basis for economic modeling are presented in Section 3. Individual field production and remaining reserves were reviewed and the remaining reserves were forecast for year-end 2003. Production forecasts were developed using standard reservoir engineering approaches, including material balance methods or empirical decline curve methods, or both.

The reserves estimates for Happy Valley and Ninilchik units reflect publicly available information based on recent press releases. These two units are currently the focus of an active exploration, delineation, and development program and future information will likely increase the reservoir size and hence reserves. Thus, the estimates presented are conservative.

4.3.2 Natural Gas Prices

Natural gas prices in the Cook Inlet reflect a mixture of different contracts between the field operators and the various purchasers, including intersegment transfers from E&P operations to industrial uses (i.e., ConocoPhillips/Marathon LNG facility). Natural gas pricing reflects differing consumers' needs for firm supply, interruptible supply, and peaking demand with different price arrangements reflecting these supply needs. Several contracts, each with different pricing formulas, are in place for pricing of Cook Inlet natural gas:

- gas sales from the North Cook Inlet Unit to the LNG facility
- gas sales from the Kenai River Unit to the LNG facility
- gas sales from the McArthur River field (Trading Bay Unit) to the ammonia/urea facility
- gas sales from the Beluga River Unit to Chugach and ML&P for power generation
- sales from the other fields to ENSTAR Natural Gas.

The remaining gas is purchased under bilateral short-term agreements to balance incremental supply and demand. Given the differing arrangements for gas sales, a variety of information was reviewed to infer the gas price basis at which gas is sold to the industrial consumers from the Kenai, McArthur River, and North Cook Inlet fields, because the actual contract terms are proprietary.

The prevailing value is the weighted average price of significant gas sales to publicly regulated utilities in the Cook Inlet reported by ADOR on a quarterly basis. This value is essentially the volume weighted average for gas purchased from Beluga River Unit by Chugach and Anchorage ML&P and gas purchased by ENSTAR under several approved contracts.

The RCA approved gas contracts in November 2003 are the APL-4 contract for gas purchases from Marathon, the Beluga contract, the Moquawkie contract (no gas currently being sold), and the Unocal contract (RCA, 2003a). The APL-4 contract price for 2004 is $2.6868/Mcf and the Moquawkie contract price is $2.9778/Mcf. The Railbelt Contract Summary (RCA, 203b) describes the Fuel Supply Contracts between Chugach and the Beluga field producers (Chevron, ConocoPhillips, and ML&P), which are indexed to reference prices for natural gas, fuel oil, and crude oil and with differing weights for the three working interest owners. The RCA approved weighted average price for gas purchases for 2004 is $2.7763/Mcf for gas from Beluga.

As noted above, on December 21, 2001, the RCA approved a gas sales agreement between Unocal and ENSTAR using a 36-month daily average of the Henry Hub natural gas futures and a floor price of $2.75/Mcf adjusted for one-half the inflation rate after 2002 (RCA, 2001). Historical monthly average Henry Hub prices from January 1995 through November 2003 and the December 8, 2003 futures prices are used to construct a Henry Hub price forecast. Natural gas price is assumed to be flat ($4.484/Mcf) after the last futures contract and is used for the economic evaluation of new gas supplies from the Cook Inlet. The RCA approved price for 2004 is $4.7421/Mcf. The ENSTAR weighted average gas supply price from all sources in the first quarter of 2004 is $3.1123/Mcf.

No public data are available concerning the contract terms for natural gas sold to the two industrial facilities by E&P operations as private party gas sales are not regulated. However, basic information was obtained by reviewing information reported to the Security and Exchange Commission (SEC). A review of a recent 8-K filing by ConocoPhillips provides information on the intersegment transfer price for gas sold to the LNG facility. This filing provides specific information on the Alaskan business unit and the average prices received for Alaskan natural gas sold by ConocoPhillips. All Alaskan gas production sold by ConocoPhillips is from the Cook Inlet basin and specifically excludes gas processing and reinjection operations at the Prudhoe Bay oil field for enhanced oil recovery. Prudhoe Bay operations and gas consumed by lease operations is not included as gas sold for financial reporting. The 8-K filing lists quarterly and annual values for the average Alaska gas price, Alaska gas production, and Kenai Alaska LNG sales volume and sales price per Mcf, shown in Table 4.1(ConocoPhillips, 2004). The reported values represent a mix of gas sales (2002) from primarily the North Cook Inlet field (79.5%) and Beluga River field (20.5%). Based on the price ConocoPhillips received for gas from Beluga, this would indicate the intersegment value (gas sold by E&P operations to the LNG facility) from the North Cook Inlet field of $1.50/Mcf. This price was used for the gas produced from the North Cook Inlet field and for gas supplied by Marathon from the Kenai field to the jointly owned LNG facility.

A press release from Unocal (2004) states the base sales price of natural gas supplied from the McArthur River (79.7% of Unocal's Alaska production) field to Agrium was $1.20/Mcf in 2002 (see Table 4.2). The 2002 weighted average combined price from Ivan River (13.3% of Unocal's Alaska production), Lewis River (2.8% of Unocal's Alaska production), and Pretty Creek (4.2% of Unocal's Alaska production) is calculated to be about $2.28/Mcf, which compares very well to the average 2001 Cook Inlet prevailing value of $2.20/Mcf, which varies quarterly.

Table 4.1. ConocoPhillips Alaska segment operations, from 8-K filing.

	2002					2003				
	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	YTD
Natural gas (MMcf/d)	168	160	183	186	**175**	189	162	180	205	**184**
Sales price, $/Mcf	2.13	1.80	1.58	1.95	**1.85**	1.97	1.88	1.33	1.88	**1.76**
Kenai LNG facility net back from gas sales in Japan.										
Volume (MMcf/d)	117	114	128	128	**122**	130	91	121	140	**121**
Sales price, $/Mcf	4.00	3.74	4.21	4.30	**4.07**	4.38	4.56	4.46	4.44	**4.45**

Table 4.2. Unocal Alaska segment operations from 8-K filing.

	Three months		Twelve months	
	Ended December 31			
	2002	2003	**2002**	**2003**
Natural gas (MMcf/d)	68	50	**75**	**57**
Sales price, $/Mcf	1.20	1.46	**1.42**	**1.31**

The gas price received by the Cook Inlet producers varies; the estimates are shown in Table 4.3. These prices are escalated at the inflation rate to obtain then-current prices for economic modeling.

Table 4.3. Natural gas prices for Cook Inlet fields.

Field	$/Mcf (2003$), Price Model	Remaining Reserves Year End 2003 (Bcf)[1]
Beaver Creek	$2.6868, APL-4	51.8
Beluga River	$2.7763	452.8
Happy Valley	$4.7421, Henry Hub	102.6
Kenai	$1.50	139.2
McArthur River	$1.20	187.1
Ninilchik	$4.7421, Henry Hub	95.3
North Cook Inlet	$1.50	598.4
Other Fields	$3.1123, ENSTAR average	157.6
Total		**1784.9**
1. From Table 3.17.		

Historical and forecast gas prices from several sources are presented in Figure 4.3 for comparison, including the recent DOE Energy Information Agency (EIA) forecast from the 2004 Annual Energy Outlook for Gulf Coast wellhead prices.

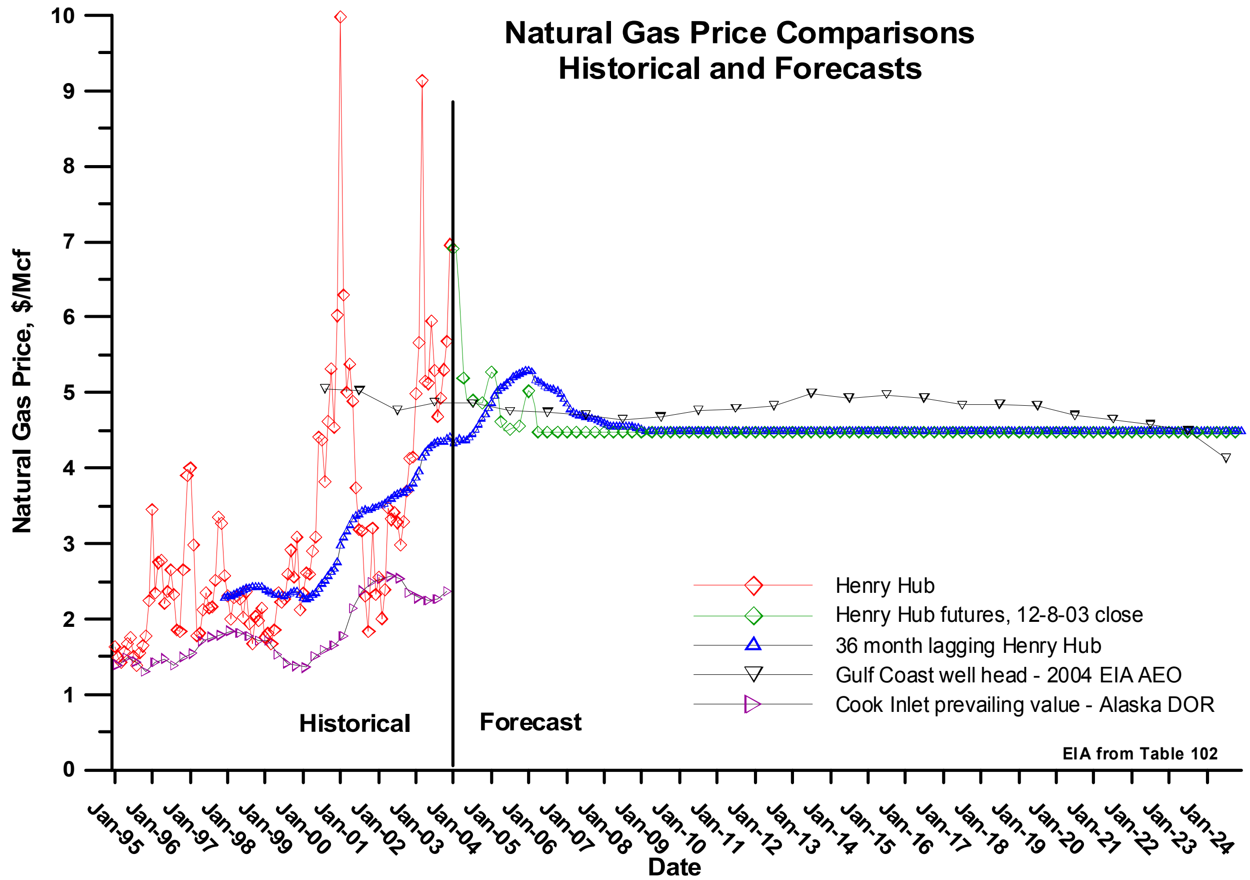

Figure 4.3. Gas prices – Henry Hub actual and futures prices, EIA Gulf Coast Wellhead, and Cook Inlet Prevailing Value.

4.3.3 Operating Costs

No lease operating expense reports were available to determine operating cost structure (fixed and variable operating costs) of the Cook Inlet gas fields as this is company proprietary data. In the absence of actual data, several assumptions were made to estimate operating costs. Fixed costs were estimated at $1,500/well/month. The number of producing completions, shown in Table 4.4, is from the December 2003 well counts in the AOGCC production reports for each field (AOGCC, 2004).

Variable operating costs consists of two components, direct operating cost per Mcf and the cost to dispose of produced water. Energy Information Agency (EIA) data was used to estimate operating costs as a function of flowrate (DOE/EIA, 2003).[18] This extensive dataset is available in spreadsheet form and contains operating cost information by regions, by depth, and by gas flowrate. The Rocky Mountain cost data for 8,000 feet well depth was assumed to be

[18] http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/cost_indices/c_i.ht

Table 4.4. Cook Inlet December 2003 producing well completions, (AOGCC, 2004).

Field	Producing completions
Beaver Creek	6
Beluga River	13
Happy Valley	0
Kenai	37
McArthur River	15
Ninilchik	5
North Cook Inlet	13
Swanson River	4
Other Fields	16
Total	**118**

representative for Cook Inlet operating conditions because of similar severe winter conditions and well depths. The variable operating cost as a function of flowrate is shown below in Figure 4.4. This relationship agrees with the expected functional form with the operating cost per Mcf decreasing rapidly as flowrate increases.

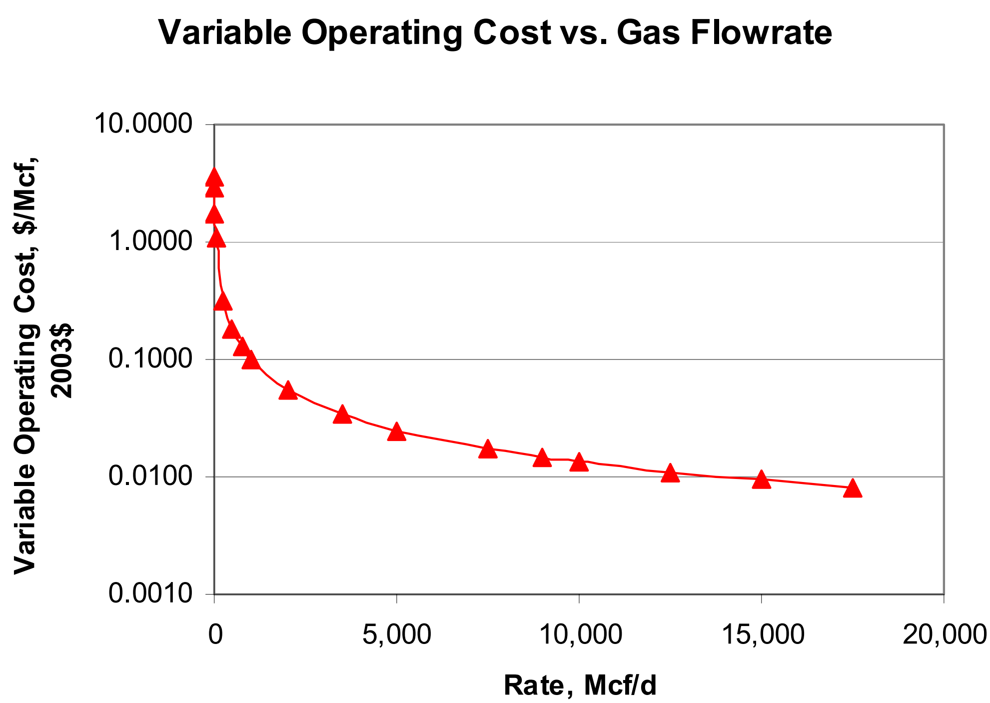

Figure 4.4. Variable operating cost.

Water disposal costs are the product of gas production, water production per Mcf, and water disposal costs. No hard data were found in the public domain for water disposal costs, which vary by field due to differences in the overall level of water production, water handling capacity, and available disposal options. Water production is modeled as a function of depletion resulting in rapidly increasing water production as a field nears the estimated ultimate recovery. This is based on the observation (see section 3) that water encroachment increases as producing zones in Cook Inlet fields are depleted. Water disposal costs were estimated at \$2/bbl (2003\$). An algorithm was developed to estimate water production as a function of percent of estimated ultimate recovery, with a sharp increase in water production per Mcf as a field nears depletion. This relationship is shown in Figure 4.5.

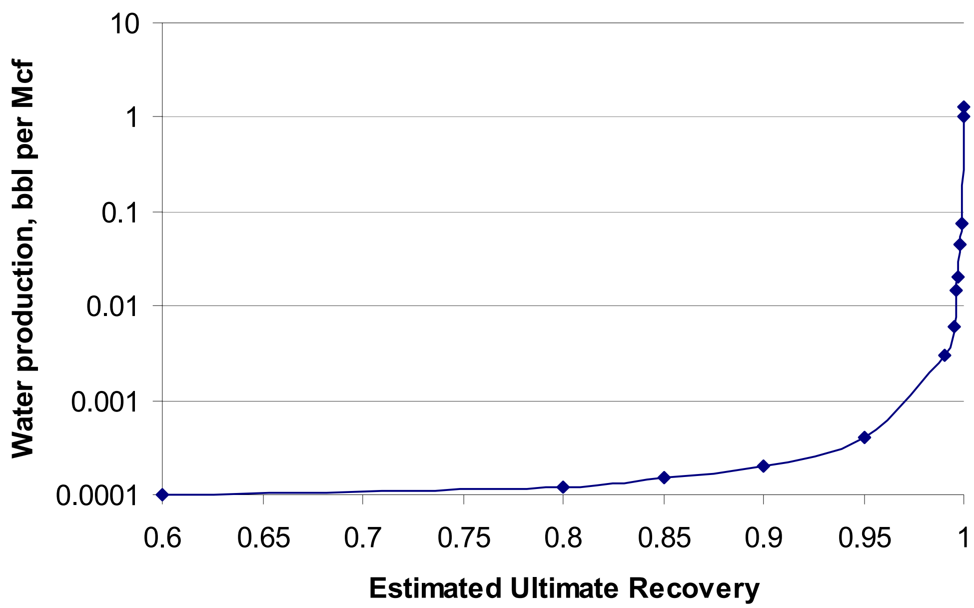

Figure 4.5. Water production algorithm as a function of depletion.

While not a direct monetary operating cost, lease gas consumption reduces the volume of gas available for sale. Lease consumption is gas used for lease activities including water separation, facility space heating, flowline purging, and gas compression. Actual lease consumption by field was reviewed using the 2002 gas disposition reports and varies by field. The average lease usage of all dry gas fields in the Cook Inlet is 3.3%. The lease usage at Kenai River field, McArthur River field, and North Cook Inlet field is largely due to compression to maintain reservoir deliverability. When the producing wellhead pressure approaches and goes below pipeline operating pressure, compression is added, which reduces the reservoir abandonment pressure and increases recovery. The Swanson River field operations have high lease consumption due to compression required for gas reinjection and for oil production operations. The Swanson River Undefined Gas is a dry gas zone and is assumed to have similar lease consumption as other Cook Inlet dry gas fields and is included in the All Other

Fields aggregation for economic modeling. No attempt is made to estimate future lease usage as reservoir pressures decline, which will require more compression, and a corresponding increase in lease usage as well as capital investment to install the additional compression. Thus the leas usage factors may be low. The two new fields, Happy Valley and Ninilchik, were estimated to have low initial lease consumption due to the lack of pressure depletion. The lease consumption used is shown in Table 4.5.

Table 4.5. Lease gas consumption in 2002.

Field	Lease consumption, %
Beaver Creek	1.0
Beluga River	0.4
Happy Valley	0.4
Kenai	3.3
McArthur River (Steelhead platform)	4.1
Ninilchik	0.4
North Cook Inlet	4.1
Other Fields	1.1

4.3.4 Capital Costs

Implemented project costs will differ due to a number of factors, including greater level of project planning and detail, the ability to negotiate terms with suppliers, and superior information. However, the cost estimates presented are reasonable estimates for economic evaluation. Sensitivity analyses can be performed to examine the impact of cost uncertainty.

Exploration costs include geological and geophysical expenses (GG&E), lease acquisition and bonus, lease rentals, seismic and exploration studies, and exploratory drilling costs. Exploration costs are capitalized and amortized under successful-efforts-accounting. Seismic costs per square mile for 3-D acquisition and processing for offshore Cook Inlet, onshore, and the inter-tidal transition zone are estimated at $45,000/sq mile, $85,000 to $90,000/sq mile, and $110,000 to $115,000/sq mile, respectively. Exploration wells are estimated to cost from $10 to $20 million, depending on location, well trajectory, depth, and target.

Development wells are estimated to cost from $3.9 million for a straight well to $7.5 million for a horizontal or extended reach well. The published cost for the recent Osprey platform at the Redoubt Shoal field is $30 million, excluding drilling and production facilities (OGJ, 2002a). That project uses a multi-phase pipeline to deliver produced fluids to shore for further separation and processing for an additional $80 million. Gas handling facilities costs are related to processing capacity and are estimated at $0.025/Mcf/d for peak throughput capacity.[19]

Onshore field gas pipeline costs are based on the recent Kenai-Kachemak pipeline (KKPL) that entered service September 2003. KKPL, a 33-mile, 12-inch diameter pipeline, cost approximately $25 million, equating to $11.96/diameter-inch/ft [$63,000/diameter-in/mi]. This construction factor can be scaled and compression added for other similar pipeline projects.

4.3.5 Book Property Values

The economic models include depreciation of tangible assets and ad valorem taxes. While property tax valuations are based on market valuation and depreciation is a book value, tax valuations are used as a proxy for the current depreciable basis. This is a good approximation for recent projects as the tax valuation closely reflects the project cost basis but is less so for the older fields. However, in the absence of other data, this approach is used. The 2003 property tax rolls for the Kenai Peninsula Borough were used for the depreciation basis and for ad valorem tax calculations. Property tax line items included wells, facilities, platforms, and gas pipelines for the gas fields. Warehouse materials and fuel stocks (inventory) were excluded. The property tax valuations used are listed in Table 4.6.

4.3.6 Inflation Rates

An inflation rate of 2.4%, based on the average for the last 10 years of the gross domestic product (GDP) deflator, is used for drilling and capital costs, as well as gas price inflation. Separate inflation rates could be used for each cost component, if detailed data are available. A separate inflation rate is used for the gas operating cost inflation, which was estimated using the EIA operating cost data (DOE/EIA, 2003, Table ES1). From 1996 to 2002, the average gas operating cost inflation was 2.05% annually, slightly less than the domestic product deflator.

[19] Personal communication, Dudley Platt, D.D. Platt and Associates, Eagle River, Alaska.

Table 4.6. Assessed property valuations from the Kenai borough.

Field	2003 Property valuation, $
Beaver Creek	6,772,344
Beluga River	26,207,030
Happy Valley	N/A
Kenai	16,475,260
McArthur River (Steelhead platform)	48,483,950
Ninilchik	1,937,190
North Cook Inlet	46,087,590
Swanson River	835,360
Other Fields	6,770,940
Total	**153,569,664**

4.3.7 Discount Rate

A discount rate of 15% is used for mid-year discounting of future cash flows for present value analysis. No risk adjustment is made to the discount rate. The 10-year United States Treasury bond has a current risk-free yield of 3.98%.[20] The weighted average cost of capital (WACC) for ENSTAR was 9.97% in 2002 (RCA, 2002a). The WACC for ENSTAR, a regulatory rate of return on the installed capital base, is a low-risk return on the regulated capital base. Natural resource exploration and development activities do not enjoy this risk reduction on investment and must accept additional risk commensurate with additional return. Therefore, the project discount rate should be greater than 14% (9.97% plus 3.98%); 15% was chosen as a standard benchmark.

Discounted cash flow modeling using unrisked discount rates provide a starting point for modern asset pricing tools, including stochastic variables, components discounting, option pricing theory, and portfolio optimization. These advanced asset pricing techniques were not used in this study. Use of these modern asset valuation methods would provide a more robust and richer picture of the internal market drivers for the Cook Inlet gas fields and should be conducted in future studies.

[20] February 27, 2004 close, http://www.stockcharts.com/charts/YieldCurve.html

4.3.8 Future Demand Forecast

Future demand for Cook Inlet gas is estimated for power generation, gas utilities, LNG, and ammonia/urea. Demand for power generation and gas utility use is fairly inelastic to price, while the industrial demand for LNG and ammonia/urea is price elastic. Specific demand elasticity values were not estimated.

The forecast power generation demand is based on a recent study assessing future generation needs and options (Beck, 2004). Gas utility demand has increased over the last three decades with an annual average increase in demand from 1991 through 2001 of 2.95% (ADNR, 2003, page 6-10). This value is used to forecast future demand, with the implicit assumption that population and economic growth will continue along the same trajectory as the long-run average.

LNG is sold to Japan on a BTU-equivalent basis referenced to a 'basket' of imported liquid hydrocarbons (DOE, 1996). The U.S. Department of Energy export license (1999) for LNG expires at the end of the first quarter of 2009. The currently estimated remaining proved reserves, as discussed in Section 3, for the two fields (Kenai and North Cook Inlet) supplying natural gas for the LNG facility are insufficient to continue LNG sales beyond 2009 at the current level. An option might be to use LNG as an alternative to diesel in some locations in rural and bush Alaska or ship to the West Coast of North America. Numerous issues, such as the requirement that Jones Act tankers be used for transport of LNG between U.S. ports and establishing adequate markets in Alaska, will have to be solved for this option to be viable.

Agrium has stated that at a feedstock price greater than $2.00/Mcf the finished products are not competitive in international markets where the fertilizer is sold. This threshold may result in the plant being shut-in by year-end 2005 (ADN, 2004a; ADN 2004b). Gas usage by Agrium in 2003 was 40 Bcf and is assumed to continue at this level through year-end 2005, for the base case. Due to the price sensitivity for feedstock gas and a mix of prices for industrial gas, actual gas consumption may be less than forecast.

The resulting base demand forecast is shown in Figure 4.6.

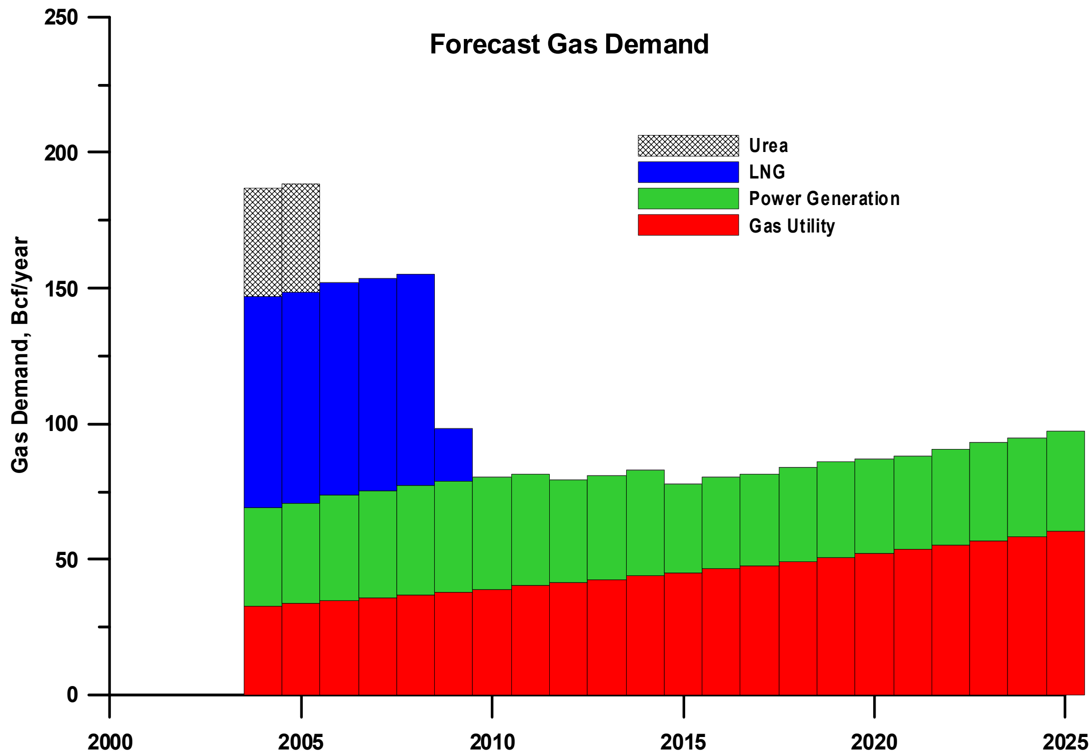

Figure 4.6. Base case gas demand forecast.

A summary of the Cook Inlet gas supply and demand dynamics, showing the four largest fields and their primary delivery, is presented in Figure 4.7. The LNG facility is primarily supplied with gas from the North Cook Inlet field and the Kenai River field. The Agrium facility is primarily supplied by the McArthur River field, while power generation is primarily supplied by the Beluga River field. Gas utility demand is supplied by the other remaining fields plus gas from the fields primarily dedicated to industrial or power generation use. This figure summarizes the gas demand at capacity for the LNG and Agrium facilities (in 2003 Agrium averaged 40 Bcf/year) and estimated 2004 gas demand for power generation and gas utility use. The supply column summarizes the gas sales price, 2002 and 2003 dry gas production (AOGCC, 2003b, pp. 28-33, AOGCC, 2004c, pp. 34-39) and field ownership. The colored arrows show the primary disposition. However, gas is a fungible commodity and fields not totally dedicated to a particular market may provide secondary supply to meet incremental demand on an as-needed basis. The numerous dashed arrows indicate that all these fields may provide secondary supply to meet incremental demand by other users under various conditions, particularly during short high demand periods associated with severe winter conditions.

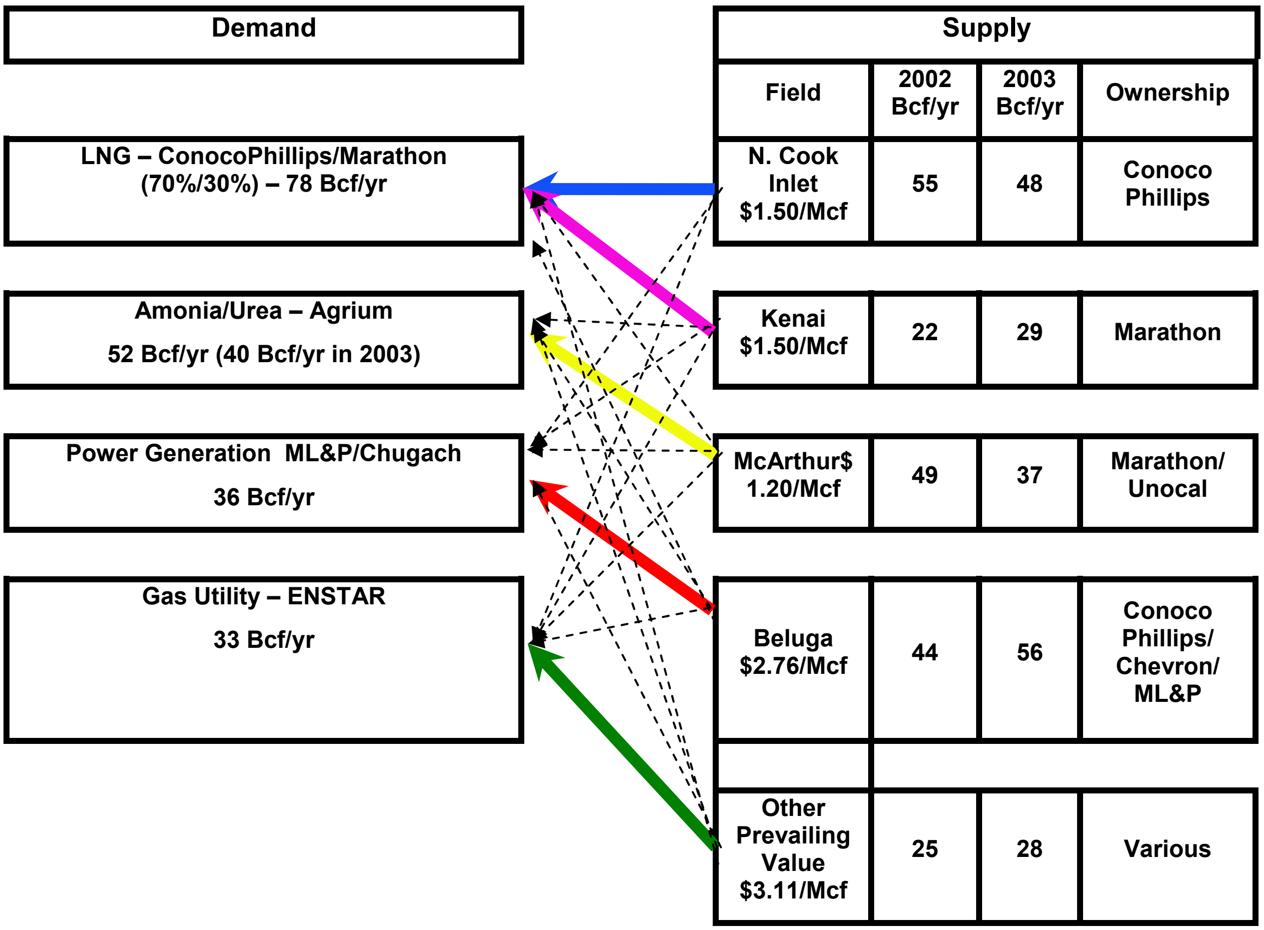

Figure 4.7. Cook Inlet supply and demand dynamics.

4.4 Economic Model

The economic model used is based on earlier economic studies of Alaska's hydrocarbon resources (DOE, 1991, 1993, and 1996). All these studies use commercially available software[21] and a deterministic discounted cash flow methodology. No attempt is made to model the economic performance of an individual working interest owner; instead the focus is on the economic performance of each field at 100% ownership. Economic models were created for seven large natural gas fields and the other 10 fields are aggregated and treated economically as one field, as shown in Table 4.7.

Thus, 94% of the OGIP of the discovered non-associated gas fields have a dedicated economic model and the Other Fields comprise 10 fields that were in production December 2003 (Granite Point, Ivan River, Lewis River, Lone Creek, Nicolai Creek, Pretty Creek,

[21] Interactive Financial Planning System, IFPS.

Table 4.7. Economic models of non-associated dry gas fields.

Field	Estimated Ultimate Recovery (Tcf)[2]	OGIP (Tcf)
Beaver Creek	0.22	0.26
Beluga River	1.30	1.53
Happy Valley[1]	0.10	0.12
Kenai	2.38	2.80
McArthur River	1.15	1.35
Ninilchik	0.10	0.12
North Cook Inlet	2.22	2.61
Other Fields	0.46	0.54
Total[3]	**7.93**	**9.33**

1. Happy Valley anticipated start of production is fourth quarter 2004.
2. Section 3.6, Table 3.16
3. The total volumes discussed in Section 2, Table 2.5 include approximately 0.6 Bcf of Estimated Ultimate Recovery (EUR) from Associated gas fields and zones. This increases the EUR to 8.53 Tcf and the estimated OGIP to 10.03 Tcf.

Swanson River, Trading Bay, West Foreland, and Wolf Creek). The Other Fields had a total December 2003 production of 832.0 MMcf compared to 17,786.0 MMcf for the seven fields with explicit economic models or 4.5% of the current production from the dry gas fields in the Cook Inlet. See Table 3.1 for ownership of the Other Fields.

The discounted cash flow models are constructed to provide a high level of financial detail and the determination of economic rents. The models are used to evaluate various scenarios for the currently developed fields, the known undeveloped fields, reserves growth, exploration, and to estimate the minimum economic field size.

Historical geophysical, geologic, exploration, (GG&E) and lease acquisition costs for the current producing fields are sunk costs and are excluded from economic modeling and amortization. GG&E costs are project specific and difficult to estimate without access to proprietary company financial and lease data. Hypothetical economic scenarios include estimates of GG&E and are amortized and capitalized under successful efforts accounting structure. Project capital is assumed to be 100% equity with no debt financing or financial leverage.

4.4.1 Resource Parameters

Primary resource parameters are the original-gas-in-place (OGIP) and the estimated recovery factor. The recovery factor averages approximately 85% but varies by field depending on natural water influx into the reservoir, increased water production, workover activities to shut-off water zones, control sand production, and other operational factors, as discussed on a field-by-field basis in Section 3.

The number of active production wells at year-end 2003 uses state production records (AOGCC, 2004). The number of future development wells is calculated using a development drilling investment schedule and the cost per development well. New wells are added to the number of active production wells. The average well production rate is calculated by the yearly production divided by the number of active production wells and is used for the gas economic limit factor (ELF), the determination of severance taxes (discussed below), and variable operating costs. Field production terminates when the specified reserves have been depleted or net revenue (gross revenue less royalty) does not cover direct field operating costs.

4.4.2 Capital Investment

Project investment includes costs for exploration, delineation, and development drilling wells; offshore platforms; production facilities; and field pipelines. Investment costs are year-end 2003 costs and inflated to the then-current year using the appropriate inflation rate.

Capital costs are either tangible or intangible[22] and are treated differently for tax purposes. Tangible costs are 100% for platforms, production facilities, and pipelines. Intangible costs are 70% for development wells and 90% for exploration and delineation wells and the balances are tangible costs. Tangible and intangible drilling costs have different tax treatment as discussed in Section 4.4.6.1.

4.4.3 Inflation

All costs are inflated to then-current (nominal) dollars from a year-end 2003 base using mid-year escalation. Specific types of inflation are the following:

- General
- Drilling
- Operating costs
- Gas price.

[22] Intangible costs are those costs incurred during a drilling operation that are consumed during drilling: bits, drilling fluid, fuel, rig rental, equipment rental, rig mobilization and demobilization, etc.

A forecast inflation rate of 2.4% is used for general, drilling, and gas price, consistent with the average GDP deflator for the last 10 years. Operating cost inflation is estimated at 2.05%, as discussed in Section 4.3.6. The inflation rate can be varied individually for all these variables if specific information is available, but for simplicity is set to the same value for all costs except operating costs.

4.4.4 Royalty

Royalty is a fraction of the gross wellhead value that is paid by the lessee to the lessor for production from a lease. The customary royalty for natural gas production in the Cook Inlet is 12.5% (1/8). The state of Alaska is the lessor for most of the land in the Cook Inlet with the Federal government and CIRI having an interest in some fields. Royalty to the state is paid on the greater of the contract sales price or the prevailing value. This is an additional cost burden for those fields with a sales price less the prevailing value.

In 1996, Alaska enacted a law that permits the granting of discovery royalty for previously undiscovered oil or gas pools in the Cook Inlet sedimentary basin, providing the pools are capable of producing in paying quantities. The discovery royalty for state lands is 5% for 10 years following the discovery of a pool and applies to all oil or gas from a pool that is attributable to the lease (ADNR, 2003).

In 1998, the state passed HB 380 granting a 5% temporary royalty on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first 10 years of production from six specified fields in the Cook Inlet sedimentary basin. The six fields eligible for royalty reduction were discovered before January 1, 1988, and were undeveloped or shut-in. The fields specifically identified by HB 380 are Falls Creek; Nicolai Creek; North Fork; Point Starichkof; Redoubt Shoal; and West Foreland. Production from these fields had to begin before January 1, 2004. The gas fields receiving the royalty reduction are Falls Creek (Ninilchik Unit), Nicolai Creek, and West Foreland.

4.4.5 State of Alaska Taxes

4.4.5.1 Depreciation

Depreciation is a capital recovery deduction and is calculated using a units-of-production basis (consistent with successful efforts accounting) on the total investment (tangible and intangible) once an asset has been placed in service. The units-of-production factor used is the yearly production divided by the year-end remaining reserves. The depreciable basis is the total investment less cumulative depreciation. This is a deduction for the determination of the state income tax liability and is a non-cash expense.

4.4.5.2 Property Tax

The property tax base is the cumulative tangible investment, less the prior year's property tax base divided by the remaining project life. This balance is adjusted for the current year inflation plus the prior year's tangible investment. The property tax (ad valorem) is 2% of the current year property tax base.

4.4.5.3 Severance Tax

The state gas severance tax is calculated on the wellhead value less royalty payment. The severance tax paid is the greater of either $0.064/Mcf or an alternative calculation at 10% of the net wellhead value, multiplied by a gas economic limit factor (GELF). The GELF is calculated by:

GELF = (1-(3000/Daily average well rate)) in Mcf/d.

4.4.5.4. Income Tax

Alaska uses a form of unitary taxation for state income taxes based on weighted fraction of a company's Alaskan portion of worldwide sales, production, and assets. The statutory tax rate is given as:

$$9.3\% * 1/3 \left[\frac{\text{Alaska sales}}{\text{Worldwide sales}} + \frac{\text{Alaska production}}{\text{Worldwide production}} + \frac{\text{Alaska assets}}{\text{Worldwide assets}} \right]$$

Since it is difficult to independently determine a company's Alaska segment operations compared to worldwide operations, a nominal effective tax rate of 3% is used.

State income tax is calculated before Federal tax. Operating cost, severance and property tax, and state depreciation are deductions from net revenue. The net income after the state income tax adds back state depreciation before the calculation of Federal taxable income.

4.4.6 Federal Taxes

4.4.6.1 Depreciation, Depletion and Amortization

Federal depreciation is calculated using a 10-year, 150% declining balance of tangible assets with no switch-over. Intangible drilling costs (IDC) are 70% expensed in the current year and the balance amortized over 60 months. Intangible portions of exploration and development wells are 90% and 70%, respectively. No depletion deductions are used.

4.4.6.2 Federal Income Taxes

The federal income tax rate is 34% of the federal taxable income. Federal tax loss-carry-forward is available and no federal taxes are paid until the loss-carry-forward balance is recovered.

4.4.7 Cash Flow Analysis

Non-cash deductions, depreciation, depletion, and amortization (DD&A) are added to the net income for annual operating cash flow. Investments are subtracted from operating cash flow for annual total project cash flow. Annual operating and total cash flow are discounted using mid-year discounting. Discount rates of 10% and 15% are used for comparison.

4.5 Economic Modeling Scenarios

The historical Cook Inlet natural gas market can be characterized as a closed market using an abundant stranded gas resource (8 Tcf) of cheap gas for two distinct markets: residential and commercial demand and a large industrial demand. The industrial demand is price elastic while the residential and commercial demand is comparatively more price inelastic. Thus, project scenarios must consider this difference in demand elasticity in allocating demand and supply between these two distinct consumers of Cook Inlet gas resources. The historically abundant gas reserves have been reduced to a reserves-to-production ratio of nine due to production of historic reserves and the lack of exploration to replace produced reserves. The Cook Inlet is a market in transition, where critical decisions made in the near-term will impact the gas availability in the future and the portfolio of gas supply options available to the south-central Alaska gas market. Scenarios were chosen to illuminate this critical nature.

The geologic analysis in Section 2 infers a large natural gas endowment with additional conventionally recoverable resources of 12 to 17 Tcf. The actual location, land status, and size of the undiscovered gas fields are unknown but will be located in three general physiographic locations: offshore, in the inter-tidal zone, and onshore. Minimum economic field size will be influenced by the different operating environments.

4.5.1 Scenarios Analyzed

Several different scenarios are examined:

- A base case with the projected demand and supply from the existing, reasonably proven gas reserves through 2025
- Reserves growth of 1.4 Tcf from the large existing fields (unspecified)
- Successful exploration for USGS class 6, 7, and 8 onshore reservoirs
- Minimum economic field size for offshore, inter-tidal, and onshore environments
- A spur pipeline from a North Slope gas pipeline at Fairbanks or Glenallen to Wasilla to connect to the existing south-central Alaska pipeline system.

These five economic scenarios are evaluated using the economic model and methodology described and the estimated future capital expenditures. The aggregated analysis will be used to estimate economic rents for the producers and state and federal governments.

4.5.1.1 Base Case

Future supply is constrained to the current proven reserves from the non-associated dry gas fields determined in the reservoir engineering review (Section 3). The fields supplying the primary gas supply to the industrial operations (Kenai River Unit, McArthur River Unit, and North Cook Inlet Unit). All Other Cook Inlet dry gas fields (Beaver Creek, Beluga River, Happy Valley, Ninilchik, and the All Other Fields group) are available to supply the residential and commercial users. Surplus gas deliverability from the fields supplying industrial users is currently used to meet incremental residential and commercial demand during times of high demand. Natural gas prices reflect the sales agreements discussed in Section 4.3.2. This supply curve is compared to demand and the investment, net present value, and cash flows are estimated.

The gas supply is compared to the base case demand forecast in Figure 4.8. The top curve is the total dry gas production forecast for the Cook Inlet from Table 3.17 less the lease consumption shown in Table 4.5. The bottom curve is for all the fields except for the three fields, Kenai, McArthur River, and North Cook Inlet, dedicated primarily to industrial use. These results indicate that demand will exceed supply between 2009 and 2012 depending on the allocation of supply between industrial and residential and commercial use. All these supply and demand data are yearly average rates and do not account for seasonal variations. Seasonal variations and the lack of gas storage capacity to draw upon in times of very high demand, such as long cold spells, may make the supply-demand issue more critical than indicated by this analysis based on yearly average rates. No attempt is made in this study to analyze the supply and demand to that level of sophistication. Such an analysis would require specific reservoir and deliverability information for gas storage reservoirs as well as a review of monthly gas production and consumption. This study attempts to account for peak demand by surplus annual deliverability. Monthly supply and demand is more volatile, adding an additional complication to the overall Cook Inlet market.

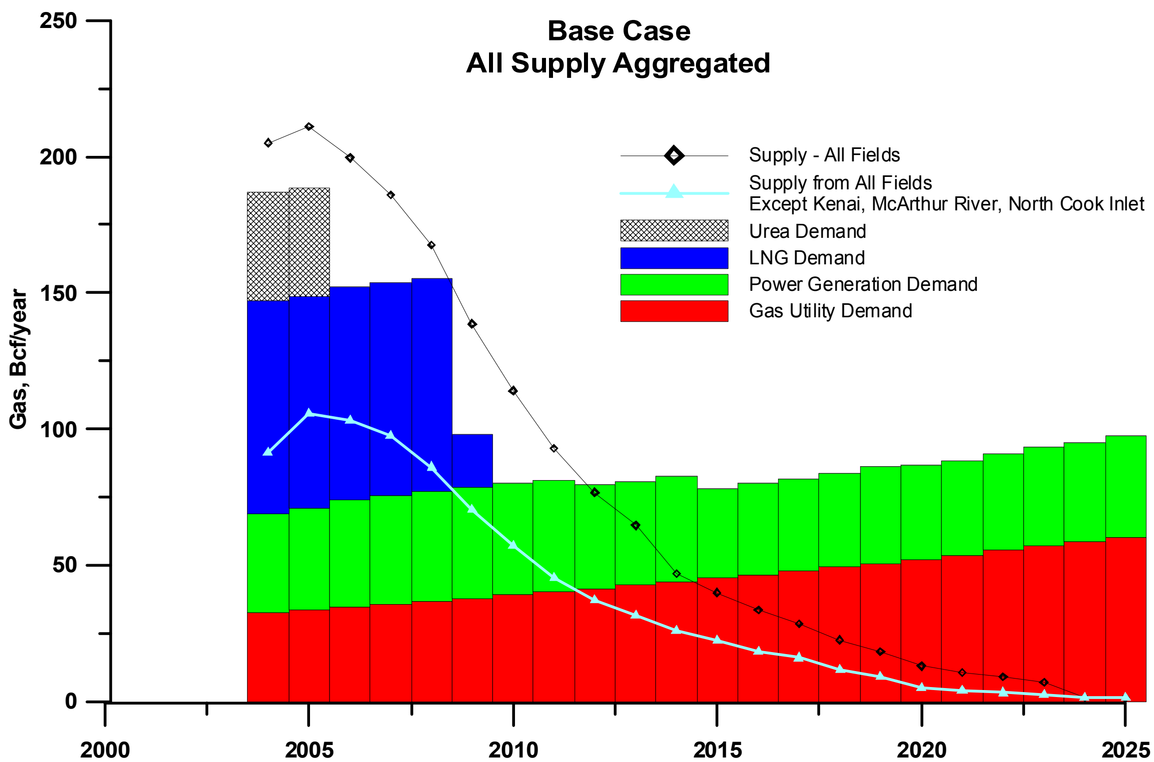

Figure 4.8. Base Case total aggregated supply and demand.

The investment and net present value results are shown in Table 4.8. Total gas available through 2025 is 1,770.8 Bcf (see Table 3.17) and the net gas remaining for sale after lease use is 1,687.0 Bcf as shown in Table 4.8.

Table 4.8. Net present value and investment.

Field	NPV at 10%, Thousand $	NPV at 15%, Thousand $	Investment, Thousand $	Net Sales Gas Bcf
Beaver Creek	53,288	46,151	0	50.7
Beluga River	453,824	380,033	0	447.6
Happy Valley	155,850	122,793	49,927	101.2
Kenai	62,315	56,239	0	124.2
McArthur River	58,128	52,795	0	161.3
Ninilchik	183,829	157,023	15,362	94.9
North Cook Inlet	227,058	188,900	11,996	556.3
All Other Fields	169,037	139,361	0	155.9
Total	**1,363,328**	**1,143,295**	**77,285**	**1,687.0**

Figure 4.9 shows industrial demand for the base case and the production forecast for the Kenai River, McArthur River, and North Cook Inlet fields. The forecast for the McArthur River field is less than the 40 Bcf/yr needed by Agrium for 2004 and 2005. The forecast production from North Cook Inlet and Kenai is not adequate to fully supply the LNG requirements through the end of the contract without additional capacity. It is anticipated that reserves will added at both the Kenai River Field and the North Cook Inlet field based on ongoing activity at those fields. Marathon Oil Company applied to the AOGCC to define a new gas pool, Beluga/Upper Tyonek Gas Pool, Kenai River field. This order was approved February 11, 2004.

If the excess supply shown by the top curve in Figure 4.10 from all fields is available after 2012, supply could meet demand until about 2017 for this case. However, these curves only show yearly averages and do not show the seasonal demand variations. ENSTAR's swing is 2.7 to 1. Hence, some excess production capacity is essential to meet seasonal variations and peaking demand that occurs in cold periods in the winter. A more detailed analysis of this variation and the potential need for gas storage sufficient to meet emergency needs as excess production capacity is used up, is needed.

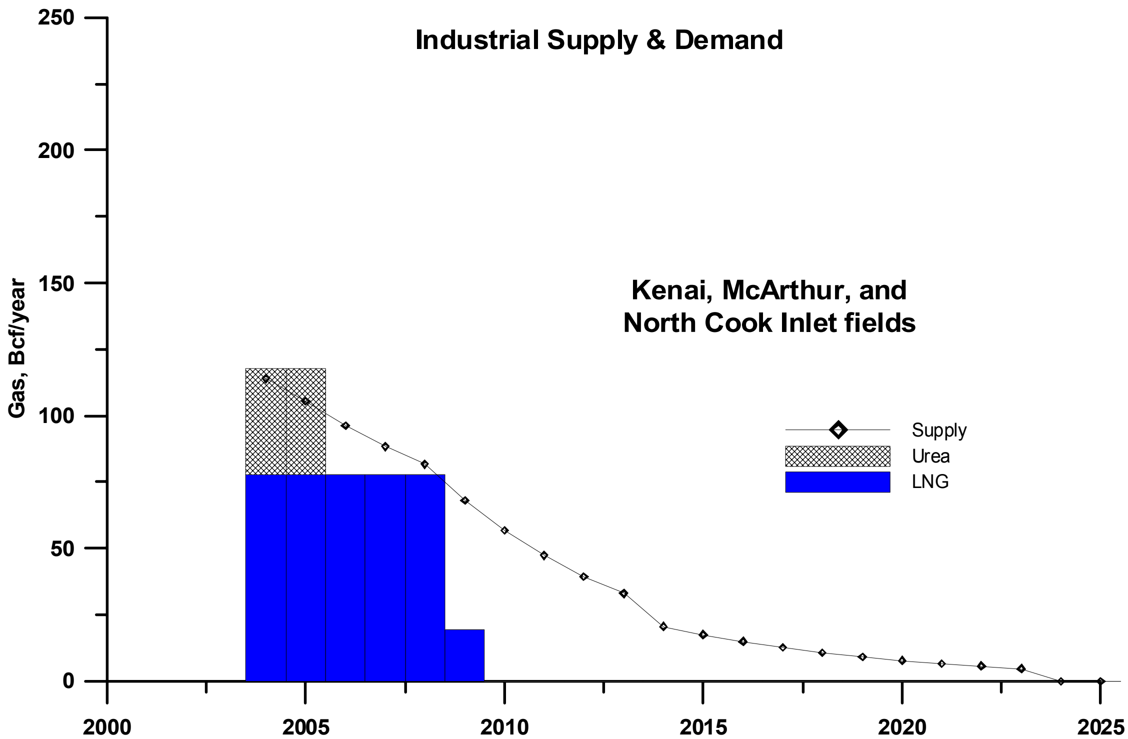

Figure 4.9. Base Case industrial supply and demand from Kenai River, McArthur River, and North Cook Inlet Units.

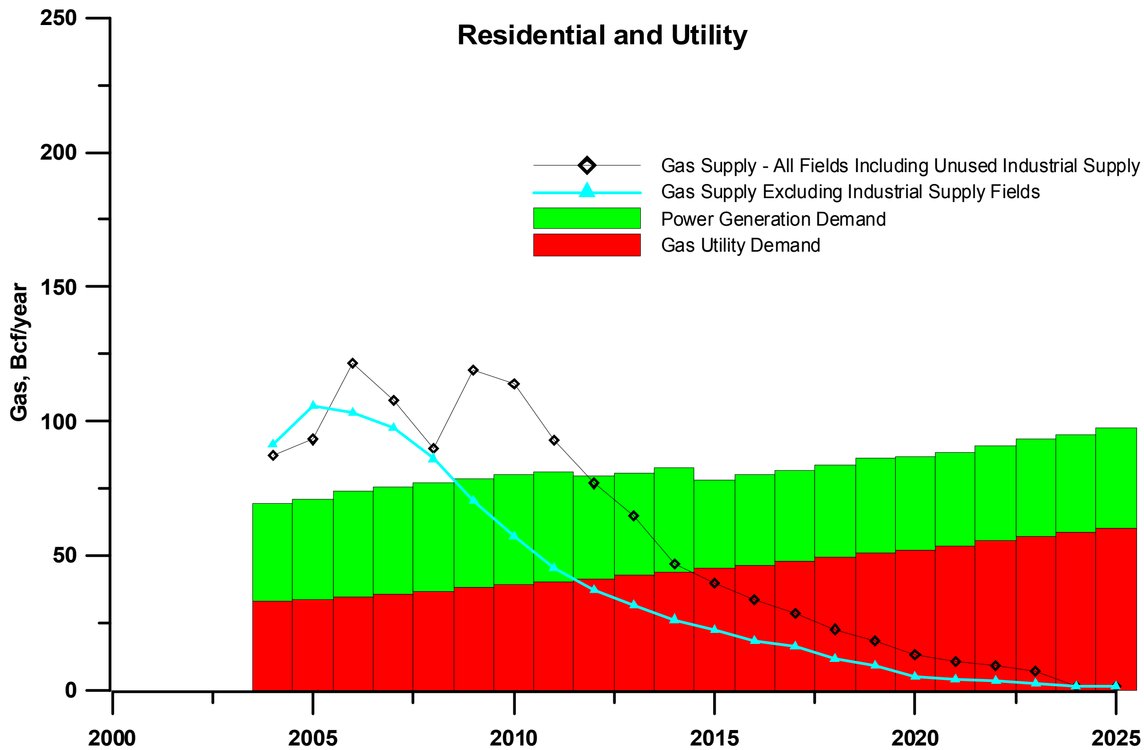

Figure 4.10. Base case commercial and residential demand with supply from all fields including unused gas from the Kenai, McArthur River, and North Cook Inlet Fields.

4.5.1.2 Reserves Growth

Reserves growth of 1.4 Tcf is assumed to occur among the larger existing fields (Beluga, Happy Valley, Kenai River, North Cook Inlet, Nicolai Creek, and Ninilchik fields) using their respective cost structure. No attempt is made to specify which fields and the expected reserves additions in each. Access to proprietary data would be needed and detailed well by well analysis would be needed to estimate reserves growth in each field and is not appropriate for this study.

The capital investment required to support reserves growth of 1.4 Tcf is estimated to be about $500 million. The Henry Hub pricing basis is used under the assumption that higher gas pricing will be needed to attract capital from other competing opportunities a company may have in it's world-wide opportunity set. The resulting reserves growth is available to meet base commercial and residential demand and the remaining gas would be available to supply industrial marginal demand. The supply curve in Figure 4.11 includes the base production forecast plus the 1.4 Tcf reserves growth forecast.

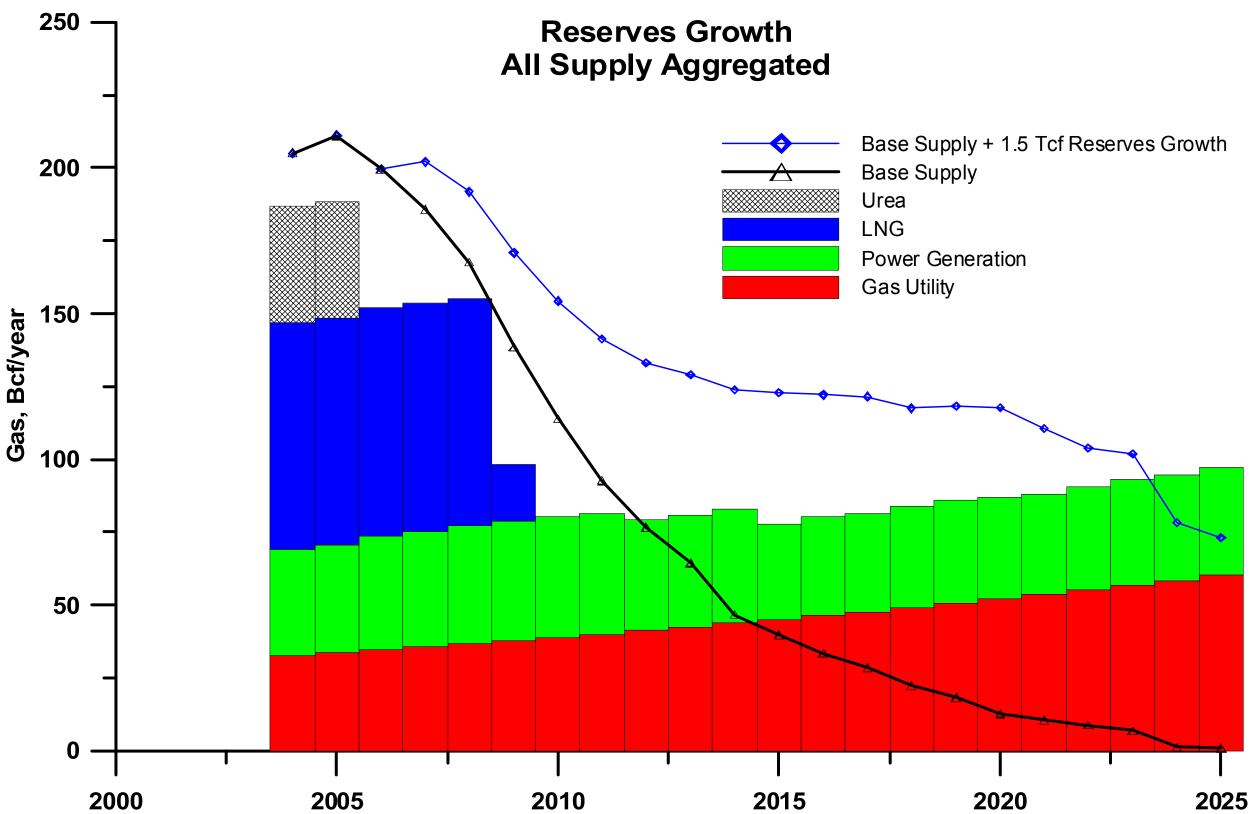

Figure 4.11. Reserves Growth of 1.4Tcf in known fields.

A recent application by Marathon to the AOGCC (2004a) to define a new gas pool in the Kenai gas field is an example of contemporaneous reserves growth as field operators continue to reevaluate geologic and reservoir information to maximize the asset value and increase recovery from the existing gas fields. The new gas pool is defined as the Beluga/Upper Tyonek gas pool, located below the base of the Sterling pool 6 and above the Deep Tyonek gas pool.

Approximately six new wells are planned for 2004 in the Kenai field, with two wells already permitted for this new reservoir interval.[23,24] The Kenai River field had produced 2.245 Tcf as of year-end 2003 from approximately 37 wells or an average recovery per well of over 60 Bcf. The rates of the years in the new untested zone are unknown and may not produce as well as the other zones. However, if they produce at 50% of the average recovery in the other zones, these six new wells would add 180 Bcf to the estimated ultimate recovery from this field. Actual well recoveries will be determined by reservoir performance. However, an example such as this demonstrates significant reserves growth potential still exists in the Cook Inlet and is an ongoing process driven by the potential for higher prices to meet demand. Depending on the performance of these new wells, additional development wells may be drilled in the future in all the existing fields, further continuing reserves growth.

It can be seen from Figure 4.11 that with reserves growth on the same order of magnitude as has occurred historically in the Cook Inlet, sufficient gas may be available to meet power generation and gas utility demand and limited industrial usage through 2025. However, such an increase in reserves will require an estimated $500 million in capital investment to achieve.

4.5.1.3 Exploration

An exploration case investment assumes a successful effort and the cost to explore and develop, ignoring risk. Actual exploration entails risk, however the examples presented here can be used as the basis for risked economics. Three onshore exploration cases are examined for the successful discovery and development of a field at the mid-point of Class 6 (192 to 384 Bcf OGIP), or Class 7 (384 to 768 Bcf OGIP), or Class 8 (768 to 1,536 Bcf) fields. Production forecasts were developed using the advanced production type curve models and a well development schedule was established to provide additional gas supplies as needed to meet demand with some surplus deliverability. The Henry Hub prices model was used and resulting

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[23] Alaska Oil and Gas Conservation Commission, http://www.state.ak.us/admin/ogc/drilling/ddec03.pdf.
[24] Alaska Oil and Gas Conservation Commission, http://www.state.ak.us/admin/ogc/drilling/dfeb04.pdf.

economically producible reserves are shown in Table 4.9 and in Figure 4.12. The production forecasts shown in Figure 4.12 are for individual fields at the fields and are not cumulative

Table 4. 9. Economic results for exploration cases.

Exploration Class	NPV at 10% (1000$)	NPV at 15%, (1000$)	Investment (1000$)	Net Reserves, (Bcf)	Investment ($/Mcf)
Class 6	277,731	197,445	152,215	228	$0.668
Class 7	612,391	452,986	250,659	464	$0.540
Class 8	1,124,864	784,507	384,394	912	$0.421

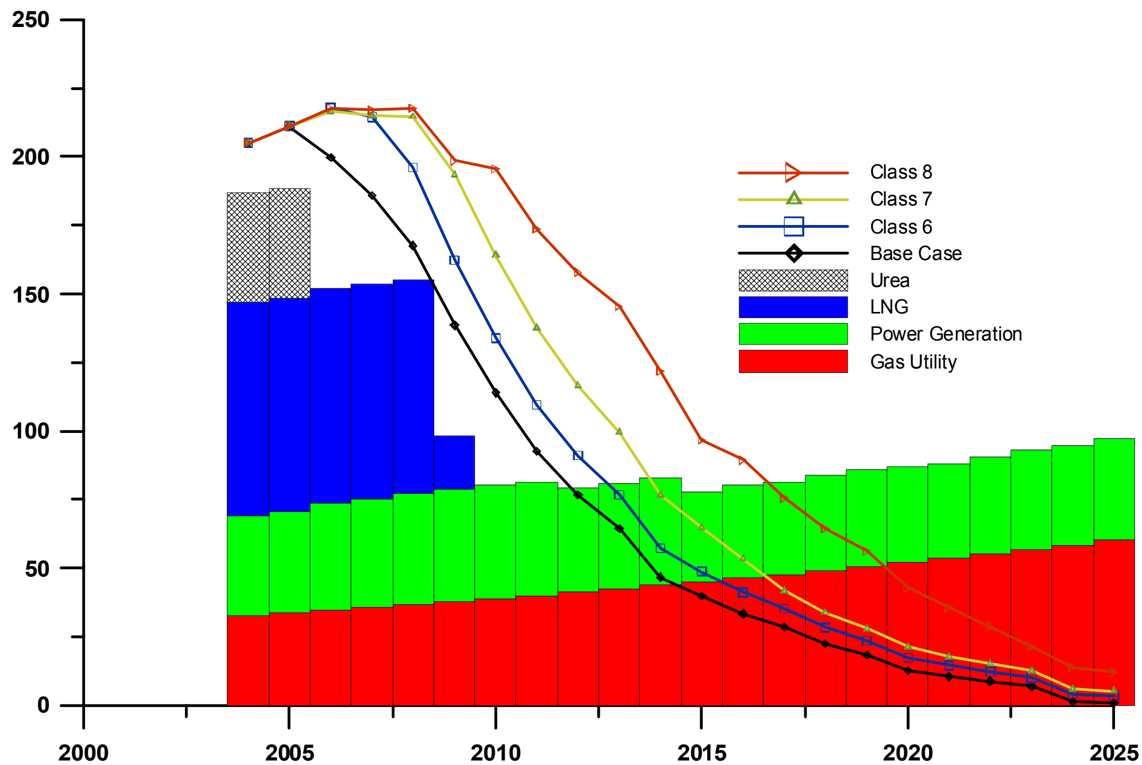

Figure 4.12. Exploration cases.

The last column in Table 4.9 is analogous to a finding, development, and acquisition cost (FD&A) that petroleum companies typically report as a measure of resource exploration efficiency. As an efficiency measure, typically finding smaller quantities are more capital intensive than finding larger quantities. Unocal reported their 2003 FD&A costs for the Alaska business unit (Cook Inlet) was $4.71/barrel of oil equivalent (BOE) or $0.78/Mcf for six million BOE (about 36 Bcf) from discoveries and extensions. Under full cost accounting, FD&A would include lease acquisition and bonus, lease rentals, seismic acquisition and processing, geologic staff analysis and prospect identification, and other costs preparatory to exploration drilling.

Not all of these internal costs are estimated in this analysis and the investment in $/Mcf shown may be lower than actual because the investment costs do not include environmental and regulatory costs. This is shown below in Figure 4.13 and compared to Unocal's reported results.[25]

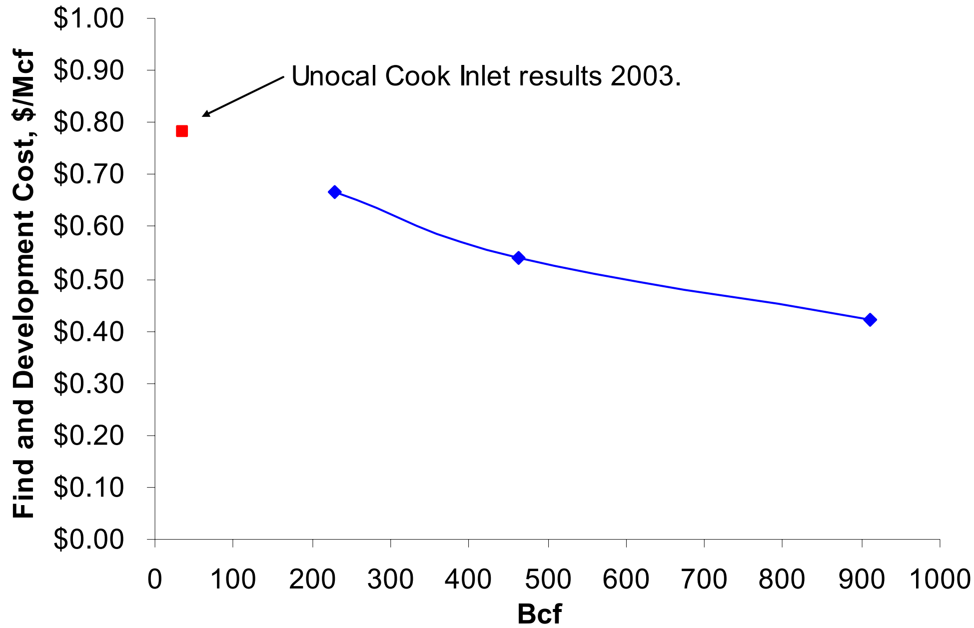

Figure 4.13. Finding and development costs for Class 6, 7, and 8 fields compared to 2003 results for Unocal Corporation.

4.5.1.4 Minimum Economic Field Size

The minimum economic field size is evaluated for three operating environments -- onshore, offshore, and the inter-tidal zone -- across a range of prices from $1.00 to $6.00/Mcf. The fields benefit from a discovery royalty reduction (see Section 4.4.4). A base field production schedule is scaled to achieve the target rate of return of 15% and the resulting production summed to determine the minimum economic field size using an 85% recovery factor. The results are shown in Table 4.10 and on Figure 4.14.

The results of the minimum economic field size (MEFS) analysis show that the higher capital costs of offshore development (platforms, more expensive wells, and pipelines) require a MEFS approximately 2.5 times larger than onshore. The onshore MEFS corresponds to the

[25] http://www.unocal.com/uclnews/2004news/020204.htm, Preliminary 2003 E&P Segment Reserves and Cost Information.

upper end of the Class 3 field size for a $4.50/mcf gas price, transition MEFS corresponds to a Class 4 field, and the offshore MEFS corresponds to a Class 5 field size for the $4.50/Mcf price.

Table 4.10. Minimum economic ield size as a function of gas prices.

Environ - ment	Price $/Mcf	OGIP Bcf	Total Invest-ment, $million	Environ-ment	Price $/Mcf	OGIP Bcf	Total Invest-ment, $million	Environ-ment	Price $/Mcf	OGIP Bcf	Total Invest-ment, $million
Off-shore	$1.00	517	125.8	Trans-ition	$1.00	240	63.0	On-shore	$1.00	193	44.9
	$1.50	389			$1.50	158			$1.50	126	
	$2.00	250			$2.00	115			$2.00	93	
	$2.50	199			$2.50	92			$2.50	73	
	$3.00	165			$3.00	75			$3.00	61	
	$3.50	141			$3.50	65			$3.50	52	
	$4.00	122			$4.00	57			$4.00	45	
	$4.50	108			$4.50	49			$4.50	40	
	$5.00	98			$5.00	45			$5.00	37	
	$5.50	88			$5.50	40			$5.50	33	
	$6.00	81			$6.00	38			$6.00	31	

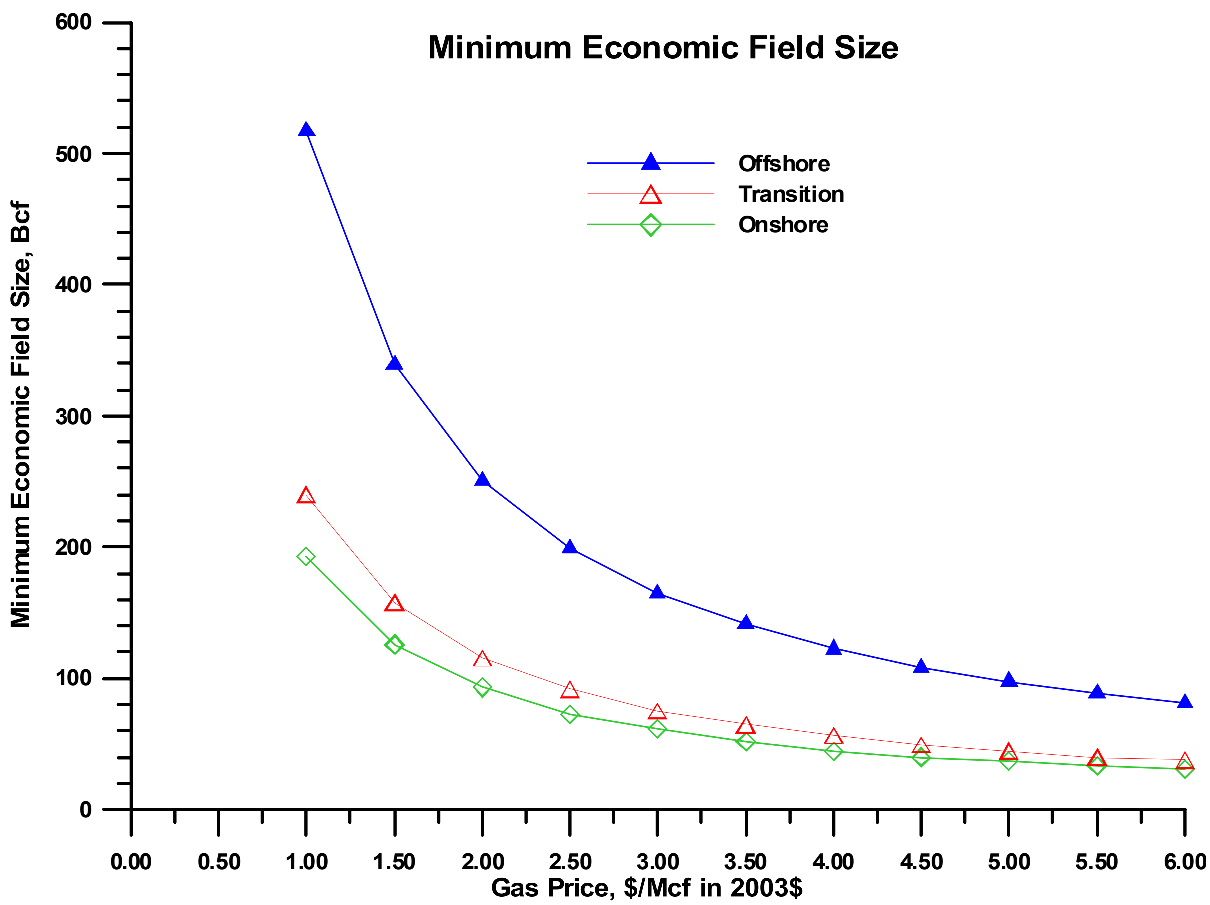

Figure 4.14. Minimum economic field size price sensitivity.

4.5.1.5 North Slope natural gas pipeline and spur to south-central Alaska

It is assumed that natural gas from a North Slope gas pipeline through Fairbanks will be available in to connect to the south-central Alaska distribution system at Wasilla, Alaska. The timing for a North Slope pipeline remains uncertain with a range of 2011 to 2013 (Mid-America, 2004;ConocoPhillips, BP, ExxonMobil, 2004). Pipeline operations for the North Slope and spur pipelines are modeled as a common carrier charging a regulatory tariff structure for capital and cost recovery. The assumptions used are: annual O&M costs are 2.5% of the installed capital investment, gas consumption is 1.1% of the throughput volumes, and the regulatory cost of capital is 9.97%.

North Slope Pipeline--Capital costs are based on a North Slope gas pipeline to the Yukon border using the Mid-American proposal for cost estimates.[26] This 745-mile, 48-inch pipeline is estimated to cost a total of $8.72 billion (2003$), all a tangible investment: $4.72 billion for the pipeline, compression facilities at $1.6 billion, and $2.4 billion for a gas conditioning facility on the North Slope with a gas throughput of 4.5 Bcf/day. The estimated average tariff charges for the first 10 years are $0.99 per Mcf to the Yukon border. The tariff, pro-rated for the 530 miles from the North Slope to Fairbanks, is $0.704/Mcf.

Spur Pipeline--Preliminary capital costs, basic operating parameters, and gas flow rates at different levels of compression were provided by ENSTAR to estimate tariffs.[27] The pipeline capital cost is estimated at $300/foot for a 24-inch line ($12.50 per diameter inch-foot) and would be approximately 300 miles long, although the actual distance will depend on the exact route chosen. At the takeoff from the North Slope pipeline, a measurement and pressure reduction station would be required for a cost of $2 million. Throughput on the line without compression would be 330 MMscf/d assuming 1,400 psi in and 800 psi out. Increased throughput with one compressor station at 1.75 compression ratio (discharge pressure/inlet pressure) would be 465 MMscf/d and with two compressor stations at 1.75 compression ratio would be 670 MMscf/d. Each compression station would require two compressors at $10 million each (primary and backup) and for the 670 MMscf/d case would require two active compressors at each station (2 stations required) and one backup compressor. Installed compressor capital costs are estimated at $10 million for 6,000 horsepower.

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[26] Alaska Department of Revenue, http://www.revenue.state.ak.us/GasLine/index.asp
[27] Personal communication, John Lau, ENSTAR Natural Gas Company.

The tariff calculation allows for capital recovery at the regulatory rate of return plus cost recovery for operating cost, ad valorem taxes, depreciation, a dismantlement charge, and state and federal income taxes. The tariff charge per Mcf is thus dependent on the transported volumes of gas, with larger volumes resulting in lower tariffs, as shown in Table 4.11. Due to the nature of the tariff calculation, capital cost overruns scale almost directly; i.e., a 25% overage results in a 25% increase in the tariff.

Table 4.11. Spur pipeline tariff at different throughput rates.

Case	Capital Investment, then current $	Average 10-year Tariff, $/Mcf	25% Increase In Capital, Tariff, $/Mcf	50% Increase In Capital, Tariff, $/Mcf
330 MMcf/day	$541.5 million	0.751	0.940	1.128
465 MMcf/day	$577.4 million	0.563	0.695	0.829
670 MMcf/day	$613.2 million	0.411	0.503	0.596

These results indicate the tariff for gas transported from the North Slope to south-central Alaska vary from $1.12 to $1.46/Mcf, depending on the volumes, with greater volumes having a lower tariff; i.e., tariff from North Slope to Fairbanks estimated at $0.704/Mcf plus values from Table 4.11 ranging from $0.411/Mcf for 670 MMcf/d to $0.751/Mcf for 330 MMcf/d). The proposed delivery point for the North Slope gas pipeline is the Chicago city gate. Tariff estimates by the operator consortia for gas delivered from the North Slope to Chicago are $2.25 to $2.50/Mcf (ADN, 2004c). A $2.50 tariff results in a net back to the well head $2.50 less than Chicago city gate. The price differential between Chicago and Henry Hub varies and, for simplicity, we assume no Chicago – Henry Hub differential. The wellhead netback and a $1.50 tariff from the North Slope to Anchorage provide approximately a $1.00/Mcf market advantage over Henry Hub prices. This analysis implicitly assumes static gas markets. Any differential between Chicago and Henry Hub reduces this cost advantage between Anchorage and Henry Hub.

The potential for a price advantage over Henry Hub prices provides an opportunity to encourage large industrial users to relocate to Alaska. One major requirement for feasibility of a spur pipeline is large industrial demand, as even the lowest rate of 330 MMscf/day, equates to 120 Bcf/yr (the combined industrial demand for LNG and Agrium facilities at capacity is 130 Bcf/yr). This potential structural price advantage may be attractive to Gulf Coast industrial users looking for a price arbitrage opportunity. This price arbitrage potential warrants further investigation and analysis, but is beyond the scope of this static analysis.

The preceding analysis (Section 4.5.1.2) indicates that Cook Inlet reserves are sufficient with the assumed reserves growth for the power generation and utility needs to 2025; therefore, initially, the primary market to be served by a spur pipeline would be large industrial users. If the spur pipeline option is to maintain viability, it is necessary to either continue operations of one or both of the current industrial users or attract new, large users.

For example, ConocoPhillips owns approximately 37% of the gas resources at Prudhoe Bay and the ability to use a portion of their Prudhoe Bay gas to continue operation of the Kenai LNG facility may have economic merit. However, there is a narrow time window for this to occur, as the export license expires at the end of the first quarter of 2009 and the earliest gas delivery from the North Slope is expected to be 2012 to 2015 (ConocoPhillips, BP, ExxonMobil, 2004). Economic, regulatory, and policy signals can encourage continued operation of this facility, as well as attract other industrial users to create value-added products with the natural gas.

If these tariff estimates are reasonable and Henry Hub prices remain at $4/Mcf or above, the price advantage for North Slope gas to south-central Alaska does not appear likely to provide gas at a price low enough to meet Agrium’s target of $2/Mcf at the plant in Nikiski based on market forces alone. Policy decisions by the state would likely be required to provide special pricing of state royalty gas or other support options to meet this target.

This potential price advantage for the users of natural gas over Henry Hub prices has a possible downside. This structural price differential also applies to the sale of gas produced in the Cook Inlet basin and could be seen as a disincentive (all things being equal) for producers to continue to explore and develop new reserves, especially if there is major uncertainty on the timing of a North Slope pipeline and spur line in the long term. For example, if the North Slope netback wellhead value is $2.00/Mcf, gas could be delivered for $3.40/Mcf to $3.08/Mcf, depending on the capacity of the spur pipeline. This delivered price would vary up or down depending on the North Slope netback wellhead price and throughput volumes. Even at the lowest throughput rate of 330 MMcf/day (120 Bcf/yr), these results suggest a spur pipeline could supply gas at a price less than a Henry Hub price basis, thus discouraging Cook Inlet exploration and development. However, the demand for this additional gas must exist from continued or expanded industrial use, new industrial users or both, the economics of which are yet to be determined and require additional study.

4.5.2 Gas Cost – Supply Relationship

Development of new reserves or building a spur pipeline will require prices for natural gas that are adequate to encourage large investments. Table 4.12 shows the cost-supply data for three time period, 2004, 2010, and 2015, in then-current dollars for the contract prices (see Table 4.3) and the forecast production for all fields except the fields dedicated to industrial use. The reserves growth from the reserves growth scenario is included because without reserves growth or successful exploration, demand would be higher than supply in 2010 without gas from the fields dedicated to industrial use and before a spur pipeline can be built. The utility and power generation demand is included in Table 4.12 for reference. These data are shown graphically in Figure 4.15 and illustrate the variation in supply with the existing contract prices and the increase in gas prices that have occurred to date with the recent Unocal/ENSTAR contract on a Henry Hub price basis.

Table 4.12. Cook Inlet gas cost-supply data for fields not dedicated to industrial use.

	2004			2010			2015		
Field	**Price** ($/Mcf)	**Field Prod.** (Bcf/yr)	**Cum. Prod.** (Bcf/yr)	**Price** ($/Mcf)	**Field Prod.** (Bcf/yr)	**Cum. Prod.** (Bcf/yr)	**Price** ($/Mcf)	**Field Prod.** (Bcf/yr)	**Cum. Prod.** (Bcf/yr)
Swanson River	2.72	1.88	1.88	3.25	0.99	0.99	3.53	0.39	0.39
Beaver Creek	2.72	7.623	9.503	3.25	3.07	4.06	3.53	0.99	1.38
Beluga River	2.82	52.99	62.49	3.25	30.48	34.54	3.66	10.05	11.44
Other	3.15	16.32	78.81	3.63	9.79	44.33	4.09	6.33	17.77
Happy Valley	4.80	0.99	79.80	5.23	7.38	51.71	5.89	2.75	20.52
Ninilchik	4.80	12.05	91.85	5.23	5.65	57.36	5.89	1.91	22.43
Reserves Growth	4.80	0.00	91.85	5.23	40.00	97.36	5.89	83.00	105.43
Utility and Power Generation Demand		2004 – 69 Bcf/yr		2010 – 80 Bcf/yr			2015 – 78 Bcf/yr		

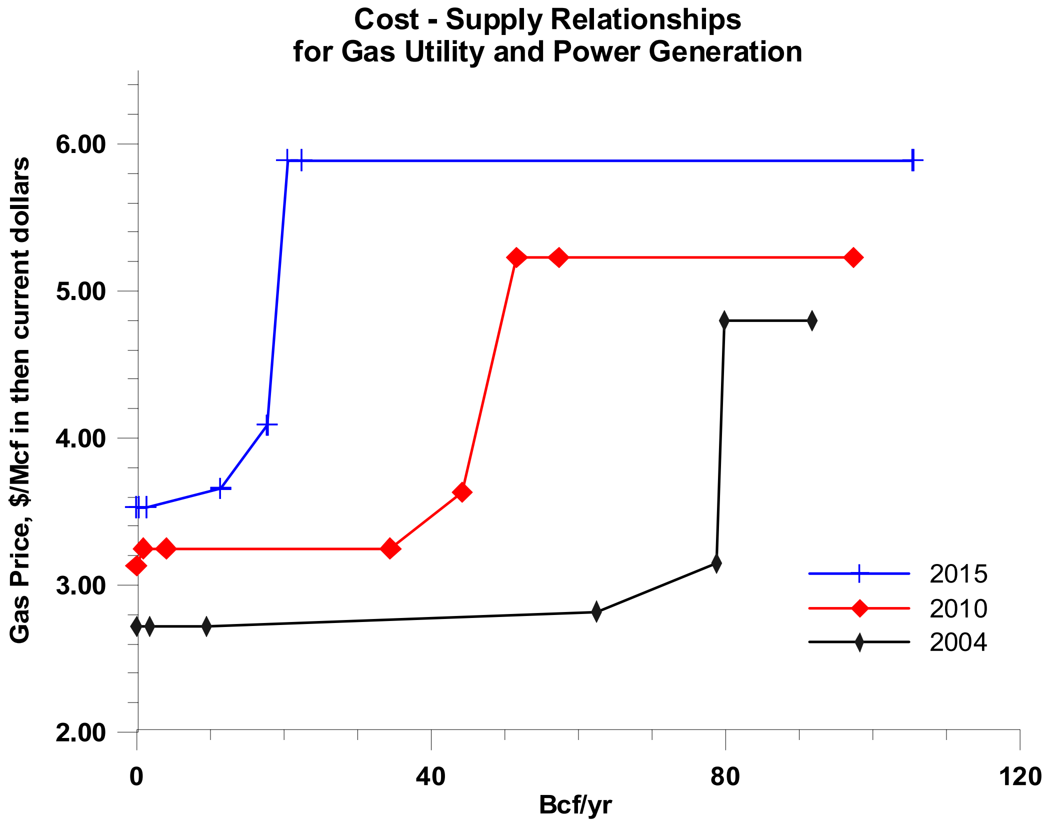

Figure 4.15. Cook Inlet gas price in then-current $/Mcf versus gas supply in

If a spur pipeline is built and a Henry Hub price basis is used, the structural cost advantage to the south-central Alaska region is estimated to be about $1.00/Mcf as discussed in Section 4.5.1.5. This price advantage over Henry Hub is likely to remain as prices escalate due to inflation but the amount is dependent on timing, final costs of pipelines, and world LNG and gas prices. Thus, a spur pipeline has the potential to moderate gas prices in the south-central Alaska region. Additionally, if all of the current industrial demand can be preserved, delivery volumes of 330 MMscf/day (120 Bcf/yr) would be insufficient to meet all the demand requirements, requiring the additional compression to increase volumes to the next increment of 465 MMscf/day (170 Bcf/yr), providing additional price advantage over Henry Hub prices in the region (see Table 4.11).

4.5.3 Economic Rents from Cook Inlet Gas Production

The stream of revenues from continued Cook Inlet gas production flows to the producers, the state of Alaska and the federal government. Economic rents for three scenarios were prepared: the proven reserves case, reserves growth, and the exploration for a Class 6, or 7, or 8 size discovery. The results for the reserves growth case and the discovery of a Class 6, or 7, or 8 filed are incremental to the base case, which is for remaining proven reserves. These components of economic rents are estimated for each stakeholder through 2025 in cumulative then-current-dollars and are shown in Table 4.13.

Table 4.13. Economic rents from Cook Inlet natural gas production through 2025 (thousands of then-current dollars).

Stakeholder	Proven reserves (1000$)	Reserves growth (1000$)	Exploration, Class 6 (1000$)	Exploration, Class 7 (1000$)	Exploration, Class 8 (1000$)
State of Alaska					
Royalty	500,749	1,074,685	86,122	171,046	372,206
Severance tax	162,338	262,874	24,864	46,900	80,184
Ad valorem	35,020	22,028	8,766	17,086	26,075
Income tax	95,464	198,895	29,395	59,686	125,492
Total state	**793,571**	**1,558,482**	**149,147**	**294,718**	**603,957**
Federal income tax	**1,103,229**	**2,194,650**	**325,450**	**662,816**	**1,389,946**
Producer net income (pro forma)	**2,137,563**	**4,260,197**	**631,758**	**1,286,644**	**2,698,128**
Total	**4,034,363**	**8,013,329**	**1,106,355**	**2,244,178**	**4,692,031**
Net reserves, Bcf	**1,744**	**1,517**	**227.9**	**464.2**	**912.1**

The results for the proven reserves show the state of Alaska derives a large fraction of the economic rents from royalty and severance taxes and, to a lesser degree, income and ad valorem taxes. For the proven reserves scenario, the producer's share of the economic rents is 53%, the federal government 27%, and the state is 20%. Similar proportions are present for the reserves growth case, although the absolute amounts are greater due to the higher gas prices assumed (Henry Hub model) for future years. The state fraction of the economic rents for the three exploration cases is reduced by the discovery royalty reduction, with the federal government receiving approximately one-third and the producers two-thirds of the royalty difference. The mix of revenue derived by the state from natural gas production provides policy makers flexibility to provide incentives for new gas reserves (reserves growth and exploration).

4.6 Summary and Conclusions

The Cook Inlet gas market is clearly in transition as a result of the utilization and monetization of stranded gas found in the 1960s to meet the needs of two large industrial facilities, and a growing commercial and residential market. The reserves-to-production (R/P) ratio is now at about nine years, which is approaching the R/P ratio in the Lower 48. The Lower

48 gas supply has repeatedly responded to increasing real price signals with the transfer of probable and possible reserves to proven reserves in existing fields (reserves growth) through development and active exploration in frontier exploration; e.g., exploration in deep water in the Gulf of Mexico, and the continuing development and application of new technology such as deep water drilling, horizontal wells, and 3-D seismic. Cook Inlet is clearly at a turning point in its history, with the exploration focus on natural gas rather than exclusively on oil and the recent success in adding new gas reserves. In response to increased real prices, Cook Inlet projects can compete for capital with other investment opportunities worldwide.

Reserves growth in the Cook Inlet is expected to be a major component of new proven reserves with recent operator activity and dramatically increased spending to increase proven reserves through workovers, opening previously undeveloped zones, new wells, and redrills into existing and new reservoirs identified by modern 3-D seismic. Significant past reserves additions resulted from detailed geologic and reservoir engineering analysis of existing data. Future reserves growth will occur as the operators continue to reevaluate existing fields with the new technology. The recent increase in 3-D seismic activity is further evidence that the operators are responding to the increased value of their proven reserves. Delineation drilling using extended reach and horizontal wells will be used to expand the search for satellite accumulations, similar to what has occurred on the North Slope. The continued high prospectively of the Cook Inlet bodes well for increased industry interest to add reserves and find a ready market for natural gas.

The economic analysis conducted was a deterministic evaluation of the south-central Alaska supply of conventional gas from three sources: (1) proven reserves, (2) reserves growth, and (3) exploration in the Cook Inlet basin, and (4) examined the potential of a spur gas pipeline to bring North Slope gas from Fairbanks to the south-central Alaska region. The analysis did not examine the impact of public funding or other non-market-based price incentives. Other options such as coalbed natural gas; electricity from coal plants; alternatives such as wind power and hydropower; and conservation were not analyzed but could play a role in meeting energy needs in the future.

The analysis relies on several assumptions concerning the two industrial facilites as discussed below.

Base Case:

The base case demand assumes the Agrium fertilizer plant stops operations at the end of 2005, the LNG plant stops operations at the end of the current export contract in the first quarter of 2009, and increasing demand for utility gas and for electric power generation.. The proven reserves are forecast to meet the commercial and residential needs until 2012 based on yearly average demand volumes. If *all* unused gas from industrial consumers, fertilizer, and LNG plants, becomes available for utility and power generation use, the supply could meet demand for several years beyond 2012 based on the yearly average volumes shown. However, the yearly average volumes include seasonal swings in demand (e.g., the ENSTAR demand swing is 2.7:1) and the production capacity could be less than required to meet peak demand without gas storage or additional fields to provide production capacity to meet peak demands.

A shortage could occur by 2009 or before unless new reserves are found and developed, or industrial use is curtailed. Large seasonal swings in demand and very limited gas storage could lead to shortages before 2009 in periods of very high demand.

Reserves Growth Case:

A potential reserves growth of 1.4 Tcf in the existing fields, including field extensions, was examined in response to the increase in real prices indexed to Henry Hub prices. Reserves growth of this magnitude is not an unreasonable assumption in and around the existing fields but will require significant new investment to support aggressive development programs through workovers, redrills, and new wells drilled to targets identified by 3-D seismic programs.

The addition of 1.4 Tcf through reserves growth is sufficient to supply the basic commercial and residential consumer's gas demand through 2025. A limited amount of gas remaining after supplying commercial and residential demand would be available to continue industrial activity at reduced levels.

Reserves growth will require an estimated investment of up to $500 million. The actual investment required may be more as reserves growth will require the application of emerging and new technologies whose cost in the Cook Inlet region is uncertain. However, the estimated cost of \$0.36/Mcf should be highly attractive to operators, compared to historical finding and development costs in the Lower 48 and even the Cook Inlet.

Minimum Economic Field Size:

The minimum field size (MEFS) for offshore, transition zone, and onshore locations, each having different exploration, development, and operating cost structures was examined for a range of prices from \$1.00/Mcf to \$6.00/Mcf. For a \$4.50/Mcf price, (similar to long-term average Henry Hub prices) the offshore field MEFS was 108 Bcf OGIP, 49 Bcf OGIP for the transition zone, and 40 Bcf OGIP for the onshore fields. Finding and development costs are estimated to vary from about \$0.75/Mcf for the smaller fields, Class 3 to 4, to about \$0.30/Mcf for Class 7 and 8 sized fields. Finding and development costs for the Class 7 and 8 fields are approximately the same as for reserves growth. Thus, it is likely new reserves will come from a combination of both reserves growth and exploration activities. Such a combination of natural gas sources was not modeled, but illustrates the potential of each source to supply new reserves for the future.

Exploration Case:

Potential new fields in the class sizes 6, 7, and 8 were analyzed as unrisked, grass roots exploration projects and using the Henry Hub prices basis. The finding and development cost varied by the amount of gas discovered and developed. New capital investments are about \$152 million for a Class 6 field, \$251 million for a Class 7, and \$384 for a Class 8.

The total unrisked capital required to explore for and develop 7.5 Tcf (out of the 13 to 17 Tcf) of the estimated remaining potential undiscovered reserves in the Cook Inlet would require in investment of at least \$5.6 billion at \$0.75/Mcf finding and development costs. This cost estimate excludes lease acquisition, lease bonus, and environmental and regulatory costs, which may be significant depending on the overall level of operator interest and competition. However, given the high level of geologic prospectivity and the potential magnitude of the remaining resource base, finding and development costs at this level or somewhat greater should be very attractive to the industry. Exploration and development requires lease access to the prospective exploration areas.

Spur Pipeline Case:

A spur pipeline from a North Slope gas pipeline to the Anchorage area and connection to the existing gas distribution system was examined to determine its potential as a cost effective gas supply option. While a number of issues need to be resolved, the estimated tariffs are $1.46/Mcf to $1.12/Mcf, with the higher tariff for a lower pipeline capacity of 330 MMcf/day (120 Bcf/yr) throughput rate and the lower tariff for a higher rate of 670 MMcf/day (245 Bcf/yr). These are first estimates only and are based on preliminary design estimates made by ENSTAR based on its experience in building pipelines in south-central Alaska. The tariff calculation for the North Slope gas pipeline is based on the Mid-American pipeline proposal to the state of Alaska for a North Slope pipeline to the Canadian border. The Mid-American pipeline proposal has a higher cost structure than some of the other proposals for the North Slope to the Yukon border, thus the estimated tariff for this segment may be on the high side.

The actual delivered price for gas to south-central Alaska would include the wellhead price for gas on the North Slope and may be less than forecast. The uncertainty in tariff estimates illustrates the complexity of this topic and the need for additional, detailed study on just this aspect of future gas supply for south-central Alaska. The wellhead price would likely be set by prices in the Lower 48 less the tariff to Chicago city gate or a negotiated price contract with the owners of the gas, which includes the state of Alaska and its royalty gas. A more detailed conceptual study of a spur pipeline options, economics, and North American gas markets is required to confirm and refine the estimates made in this analysis.

The spur pipeline tariff analysis indicates North Slope gas can be delivered to south-central Alaska at a structural price advantage of approximately $1.00/Mcf below Lower 48 prices. However, for a spur gas pipeline of this size to be viable there must be an established long-term market for at least 120 Bcf/yr of natural gas. This large demand will require industrial users. Benefits of a spur pipeline include opportunities to continue operation of the existing LNG plant, the fertilizer plant, or new value-added industrial activities such as petrochemicals, ore processing, and other industries seeking lower cost energy than can be obtained in the Lower 48.

Such industrial operations must be able to be profitable at prices higher than the historically low Cook Inlet prices. Agrium's operations are very price sensitive and it has indicated that it needs gas at around $2.00/Mcf or less to be competitive in the Asian fertilizer markets. This price threshold seems unlikely unless large gas discoveries are made in the very near future, creating stranded gas pricing again for Cook Inlet gas to drive the prices below the prevailing prices being paid by non-industrial users; i.e., Cook Inlet Prevailing Value published by the Alaska Department of Revenue for First Quarter 2004 is $2.49/Mcf.

A potential downside to a spur pipeline, from an operator point-of-view, is that a large supply of gas from the North Slope at a structural price below the Lower 48 prices may establish a price cap for new Cook Inlet reserves in the 10- to 15-year time frame. This could have a dampening effect on exploration and development for new gas reserves in the Cook Inlet. Hence, it is urgent that decisions such as the North Slope pipeline be made soon so that all options for south-central Alaska region can be determined in a timely manner.

The income to the industry through profits and the return to the state and federal government from taxes and royalties were estimated to be as follows: 53% to industry, 27% to the federal government, and 20% to the state of Alaska.

Coalbed natural gas is a major potential resource for south-central Alaska with estimated technically recoverable resources of about 7 Tcf. However, the economic viability of those resources is highly uncertain.

LNG Import:

A final alternative for south-central Alaska would be to import LNG from foreign sources into the existing export facilities at Kenai. A regasification plant would be required and the gas would have to be purchased at world LNG prices in competition with Lower 48 west coast markets. The existence of this option does provide knowledge that south-central Alaska will not run out of gas for basic needs but the price will be high to the economy.

APPENDIX A. - ECONOMETRIC MODEL OF COOK INLET NATURAL GAS RESERVES

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The goal of this analysis was to build an econometric model for Cook Inlet natural gas reserves. A normal market-driven situation leads to the expectation that natural gas prices would be strongly influenced by wellhead price, exploration drilling activities, and the reserves-to-production ratio. However, the Cook Inlet of Alaska has had a different history than most U.S. oil and gas basins because of the huge gas discoveries made in the 1950s and 1960s and a small local demand to make use of the gas.

The normal expectation is incorrect for the Cook Inlet (south-central Alaska) region to the present time. The Cook Inlet historical data are best represented using the reserves-to-production ratio as the dependent variable and the following form:

R/P = f(Year) (1)

The data used in this analysis are presented in Table A.1 below.

Average natural wellhead gas prices for the United States and Cook Inlet appear in columns A and C, respectively. The nominal prices in Columns A and C were converted to 2002 real prices using the PPI (Purchasing Power Index for all commodities) in Column F. The real prices in 2002 dollars are shown in columns B and D. The ratio of Cook Inlet to U.S. natural gas price appears in column E. The R/P (reserves-to-production), yearly production, and reserves values are in columns G, H, and I. The number of exploratory wells drilled each year is shown in column J. The number of exploration wells has been shifted one year to allow for the time it takes to develop the discovery and bring the production to market.

Crossplots were used to make a preliminary determination of possible relationships between reserves and the Cook Inlet price; reserves and the Cook Inlet-to-U.S. price ratio; reserves and lagged exploratory wells; and reserves and R/P ratio.

Table A.1. Cook Inlet historical production, reserves and price data.

Year	A. US NG Wellhead Price ($/MCF)	B. US NG Wellhead Price ($/MCF 2002$)	C. Cook Inlet Avg. NG Wellhead Price ($/MCF)	D. Cook Inlet Avg. NG Wellhead Price ($/MCF 2002$)	E. Ratio of Cook Inlet to US NG Wellhead Price	F. PPI (All Commodities)	G. Cook Inlet Reserves /Production Ratio	H. Cook Inlet Yearly Production	I. Cook Inlet Reserves	J. Cook Inlet Lagged Expl Wells
1987	$1.663	$2.121	$0.940	$1.199	0.301	102.8	22.9	189.3	4,158	2
1988	$1.682	$2.063	$1.270	$1.558	0.559	106.9	22.0	196.6	3,906	0
1989	$1.690	$1.975	$1.360	$1.589	0.751	112.2	19.9	198.4	3,619	1
1990	$1.698	$1.914	$1.380	$1.556	0.801	116.3	18.2	205.5	3,417	0
1991	$1.629	$1.833	$1.480	$1.665	0.847	116.5	16.6	203.1	3,215	1
1992	$1.733	$1.939	$1.500	$1.678	0.854	117.2	15.8	204.5	2,827	3
1993	$2.028	$2.236	$1.460	$1.610	0.690	118.9	13.8	200.5	2,187	4
1994	$1.850	$2.014	$1.405	$1.530	0.757	120.4	10.9	214.0	1,887	4
1995	$1.549	$1.628	$1.405	$1.477	0.907	124.7	8.8	214.5	2,842	0
1996	$2.163	$2.221	$1.447	$1.485	0.650	127.7	13.2	223.0	3,281	0
1997	$2.322	$2.386	$1.700	$1.747	0.623	127.6	14.7	214.7	3,066	1
1998	$1.954	$2.059	$1.787	$1.883	0.870	124.4	14.3	215.0	2,843	5
1999	$2.192	$2.290	$1.510	$1.577	0.815	125.5	13.2	212.6	2,564	3
2000	$3.687	$3.643	$1.526	$1.508	0.410	132.7	12.1	215.8	2,348	0
2001	$4.022	$3.929	$2.197	$2.146	0.379	134.2	10.9	219.7	2,241	1
2002	$2.950	$2.950	$2.497	$2.497	0.745	131.1	10.2	194.4	2,020	2

Figure A.1 is a crossplot showing the relationship between reserves and the Cook Inlet price. The expectation was a positive relationship; i.e., as the price increased, the additional reserves would have been developed and reserves would have increased. The relationship as demonstrated in Figure A.1 appears negative; i.e., as prices increased, reserves decreased.

In Figure A.2, the relationship between the ratios of Cook Inlet to U.S. average natural gas price versus reserves is shown. The relationship is expected to be positive. As the Cook Inlet price improves in relation to the U.S. average wellhead price, the expectation is for the competitiveness of Cook Inlet to increase and, therefore, drilling activity would increase and reserves would follow. However, the relationship between reserves and price ratio is not positive as expected.

It is not clear what the relationship is. For the time period of study, 1987 to 2002, Cook Inlet natural gas wellhead prices were consistently below the average United States natural gas wellhead prices. On average, Cook Inlet natural gas wellhead prices were 68% of U.S. natural

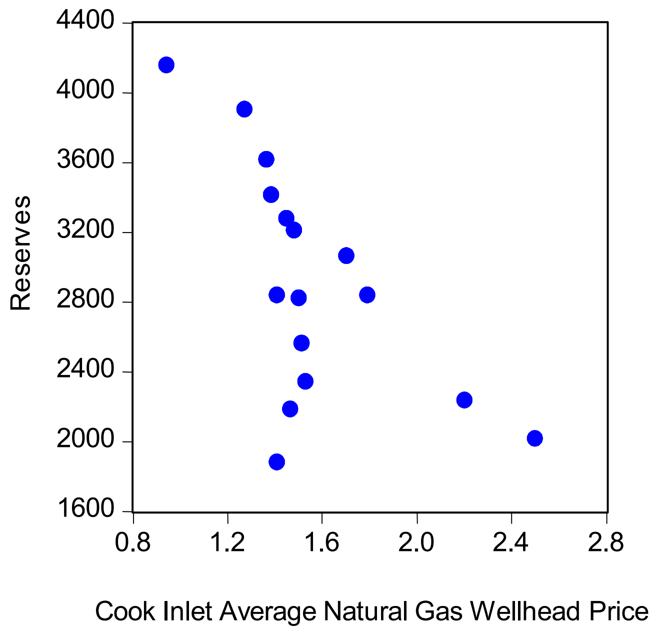

Figure A.1 Cook Inlet reserves versus average wellhead price.

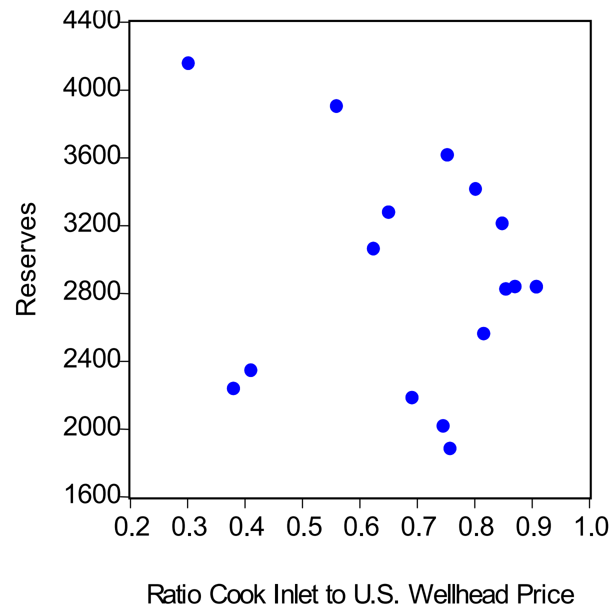

Figure A.2 Cook Inlet reserves versus ratio of Cook Inlet to U.S. wellhead prices.

gas prices. Figure A.3 is a plot showing this price comparison. U.S. natural gas wellhead prices have been normalized to 1.

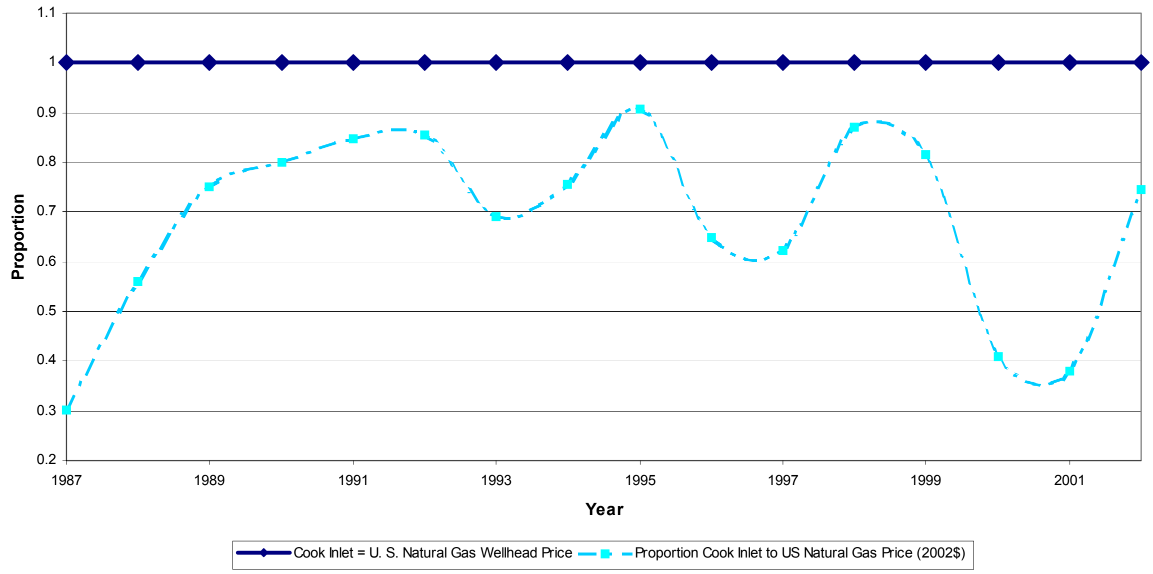

Figure A.3. Comparison of normalized Cook Inlet wellhead price to U.S. wellhead price.

In Figure A.4, the number of lagged exploration wells versus reserves is studied. The expectation is positive, but no clear relationship is demonstrated by the data. The final crossplot, Figure A.5, examines the relationship between reserves and R/P. The expectation was a variable relationship; instead it shows a marked positive slope.

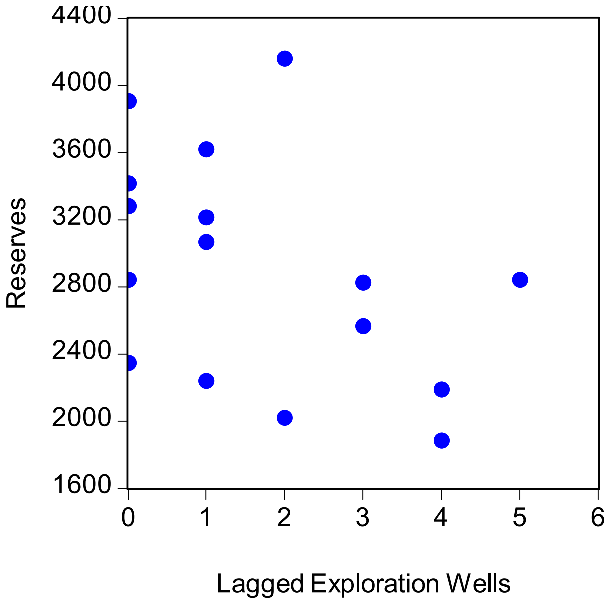

Figure A.4. Cook Inlet exploration wells versus reserves.

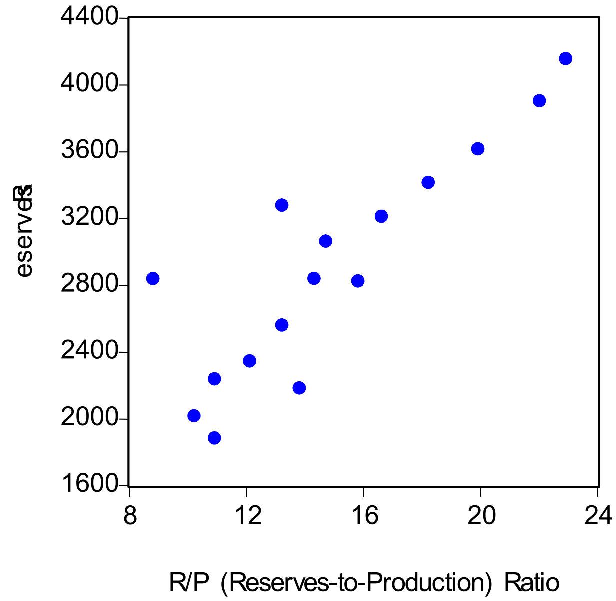

Figure A.5. Cook Inlet reserves to production ratio (R/P) versus reserves.

Because the relationships demonstrated in the crossplots in Figures A.1, A.2, A.4, and A.5 were not as expected the type of market exhibited in the Cook Inlet area was analyzed next. The United States Department of Justice uses the Herfindahl-Hirschman Index (HHI) to examine market concentration.[28] Markets in which the HHI exceed 1,800 are considered to be concentrated; i.e. few producers bringing products to market. However, a high HHI does not mean a non-competitive market.

Using 2001 Cook Inlet production data, shown in Table A.2, three producer's control 85% of the yearly production.

The HHI is calculated by summing the squared percentages for the largest producers.

$$\mathbf{HHI = 31.62^2 + 32.72^2 + 21.02^2 = \underline{2512}}$$

[28] http://www.usdoj.gov/atr/public/testimony/hhi.htm'

Using the percentages of the three largest producers, the HHI for Cook Inlet equals 2,512, which exceeds the 1,800 cutoff. Therefore, the Cook Inlet market is concentrated.

Table A.2. Cook Inlet 2001 production data by producer.

Company	**Field**	**2001 Field Production Volumes (Bcf/yr)**	**Percentage of Total Production**
ConocoPhillips	Cook Inlet	55.53	
	Beluga River	13.93	
	Company total:	**69.46**	**31.62%**
Marathon	Beaver Creek, Sterling Unit, Cannery Loop	9.66	
	Kenai River	20.06	
	McArthur River	31.13	
	Swanson River	11.025	
	Company total:	**71.875**	**32.72%**
Unocal	Ivan River, Lewis	4.02	
	Swanson River	11.025	
	McArthur River	31.13	
	Company total:	**46.175**	**21.02%**
ChevronTexaco	Beluga River	13.93	6.34%
Municipal Light & Power	Beluga River	13.93	6.34%
Other		4.33	1.96%
Total Production		**219.7**	**100.00%**

Concentrated markets can be competitive. For example, in a 1990 dissertation,[29] the West Virginia gas market was determined to be concentrated but competitive as a result of economic and policy incentives. An analysis to determine whether the Cook Inlet market is competitive and what economic and policy incentives might be required was beyond the scope of this study. According to Porter,[30] in general terms, five factors impact competition:

1) Rivalry among the existing firms

[29] Omowunmi O. Iledare, "Modeling the Supply Response of Energy Resources: The Case of Non-Associated Natural Gas in West Virginia," Dissertation, West Virginia University, 1990.
[30] Michael E. Porter, "How Competitive Forces Shape Strategy," ***Harvard Business Review***, March-April 1979 (reprinted in Michael E. Porter, ***On Competition***, Boston, Harvard Business School Publishing, 1998).

2) Threat of entry
3) Threat of substitution
4) Bargaining power of suppliers
5) Bargaining power of consumers

Figure A.5, a plot of R/P versus reserves, provides a starting point for building a model to explain Cook Inlet reserves.

Figures A.6, A.7, and A.8 are yearly plots of production, remaining reserves, and R/P. Although Figure A.6 shows some variability, production appears to increase at a gradual rate over the time period of this analysis, 1987 to 2002.

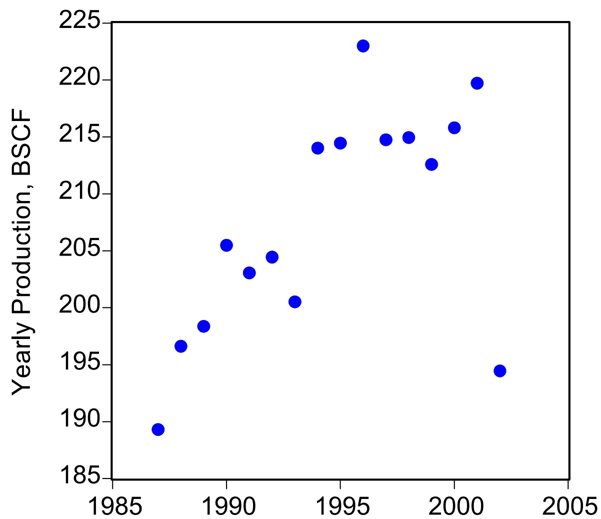

Figure A.6. Cook Inlet yearly production.

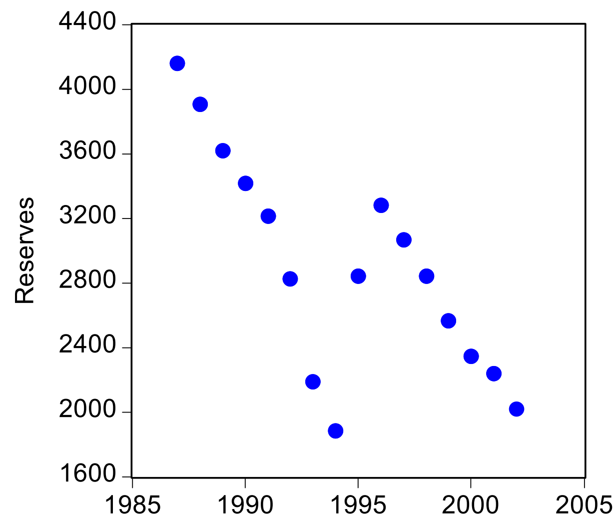

Figure A.7. Cook Inlet reserves by year.

Figure A.7 is a plot of reserves versus year. The data show two steady, negatively sloped trends. The first is from 1987 through 1995. The second trend is from 1997 through 2002. This corresponds to the time frame when ConocoPhillips, then Phillips Petroleum, needed additional proven reserves to extend its LNG contract with Japan. This was accomplished through detailed geological and petroleum reservoir engineering analysis, which commonly results in an addition to proven reserves; i.e., reserves growth. The reserves increase, which started in 1996, shifted the curve right. With a relatively steadily increasing production volume and the only significant change in the reserve base occurring in 1996, reserves-versus-year plots as two approximately straight lines.

Figure A.8 further demonstrates this point by combining reserves and production into R/P versus year. Note the two approximately straight, negatively sloped lines.

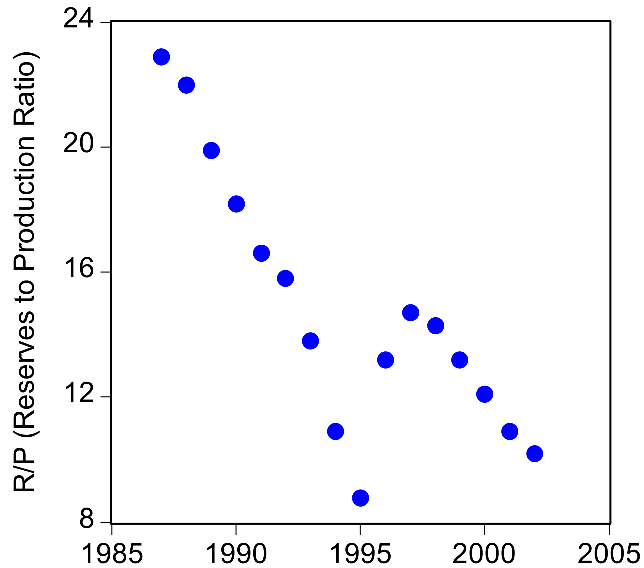

Figure A.8. Cook Inlet reserves to production ratio by year.

Therefore, the econometric model to explain Cook Inlet natural gas reserves uses R/P and two equations, one for the time period 1987 through 1995 and the other for the time period 1997 through 2002. For the first time period, 1987 through 1995, the Cook Inlet Econometric Model is defined by the following equation:

$$\mathbf{R/P = 3477.57 - 1.74 * (Year);\ Adjusted\ R^2 = .983} \qquad \mathbf{(2)}$$

For the second time period, 1997 through 2002, the Cook Inlet Econometric Model is defined by the following equation:

$$\mathbf{R/P = 1943.51 - 0.97 * (Year);\ Adjusted\ R^2 = .982} \qquad \mathbf{(3)}$$

The adjusted R^2's are extremely high and indicate a strong relationship between the dependent and independent variable. In each of the two time periods, R/P versus year dropped by a constant amount. During the first time period, the R/P relationship dropped 1.74 each year; during the second time period, R/P dropped 0.97 each year.

Figures A.9 and A.10 are plots of the actual R/P versus the fitted R/P calculated using Equations (2) and (3), respectively. They exhibit an almost perfect fit. The small residuals represent the difference between the actual R/P values per year and those calculated using one of the equations.

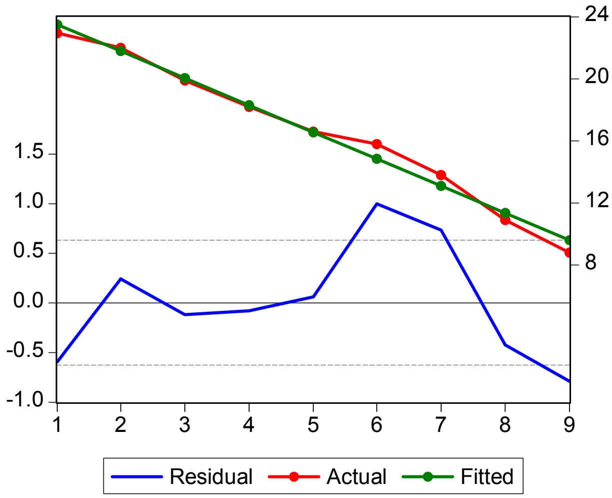

Figure A.9. R/P actual versus fitted R/P, Eq. 2.

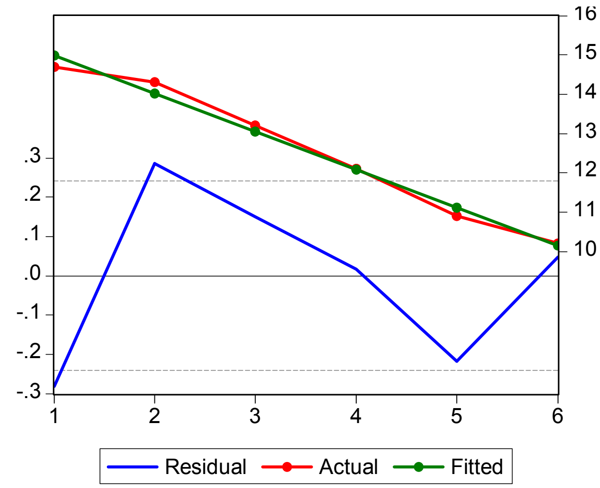

Figure A.10. R/P actual versus R/P fitted, Eq. 3.

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