Economic Study of the Burger Gas Discovery, Chukchi Shelf, Northwest Alaska

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Errata
Revisions to several cell formulas were made on 3/7/06 to allow the model to operate on Excel without @RISK as a platform. An error was also corrected, so Ad Valorem taxes are now included in the After Tax Cash Flow (DCF-AK, column CE). These revisions result in a small change in the calculated breakeven commodity prices (now $5.30/Mcf and $29.79/bbl; previously $5.22/Mcf and $29.34/bbl).

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Executive Summary

Purposes of Study

- To develop ranged estimates for discovered gas and condensate resources at the Burger prospect.
- To estimate the threshold prices for commercial viability of Burger gas resources under various economic assumptions.

Disclaimer: This study does not propose a single, well-constrained estimate for gas resources at Burger prospect. A single-well penetration of a 107-ft sandstone in a structure 25 miles in diameter does not provide sufficient information for an accurate resource determination. Given that some large quantity of gas resources exist at Burger structure, we attempted to establish a reasonable range of resources and to test for the gas prices that might allow the Burger gas resources to be monetized.

Results

Discovered gas resources at Burger prospect are estimated to range between 7.629 and 27.472 trillions of cubic feet (Tcf), with a most likely gas resource of 14.038 Tcf. Discovered condensate resources at Burger prospect are estimated to range between 393 and 1,404 millions of barrels (Mmb), with a most likely condensate resource of 724 Mmb.

Consideration of practical field economic life (22 years of production) yields estimates of producible and marketable resources for Burger structure of 11.5 Tcf gas and 587 Mmb condensate. A standard discounted-cash-flow (DCF) model yields "breakeven" prices (net present value at 12% discount rate [NPV_{12}] = 0.0) of $5.22/Mcf for gas delivered to U.S. domestic markets and $29.34/bbl for condensate sold with Alaska North Slope crude to West Coast markets. This is contingent on access to both the existing Trans-Alaska oil pipeline and a future gas transportation system from the Alaska North Slope.

Discovery of Gas at Burger Structure

The Burger well (OCS-Y-1413#1) was drilled by Shell Western Exploration and Production, Inc. (SWEPI) to test a large anticlinal prospect, originally referred to as the "Wainwright Dome" by Thurston and Theiss (1987). The prospect underlies all or parts of 50 OCS tracts and at maximum extent is 189,803 acres in area. Thirty-seven OCS tracts were leased on this prospect for a high bonus bid total of $169,694,200 at OCS Sale 109 held in May 1988. All of these leases were relinquished to the Federal government as of December 1996. No lands over Burger structure are under lease at present.

The Burger well was drilled to a total measured depth of -8,202 feet during a two-year program in the summers of 1989 and 1990. The well encountered two gas-bearing sandstones. The uppermost gas pay (top at -2,000 feet measured depth; located in pl. 1) was in a 36 foot thick Cretaceous (Albian) sandstone within the Nanushuk Group. The lower gas pay (top at -5,560 feet measured depth) was in a 107 foot thick Cretaceous sandstone equivalent in age to the Kuparuk River Formation, the principal oil reservoir in the 2.8 billion-barrel Kuparuk oil field near Prudhoe Bay. The lateral extent of the gas-bearing sandstone at –2,000 feet is not known but is probably very limited like most Nanushuk Group sandstones in that area. Therefore, we made no effort to evaluate potential gas resources associated with the gas-bearing sandstone at –2,000 feet. The sandstone at -5,560 feet in Burger well is referred to here as the "Burger sandstone" and the gas and condensate resources associated with this sandstone are the subject of the remainder of this report.

A drilling break at the top of the Burger sandstone at -5,560 feet (measured depth) was accompanied by a strong increase in the drilling mud gas. Gasification of drilling mud and possible gas flow into the well bore was handled in the standard manner by first shutting in the well, then increasing mud density from 10.0 pounds per gallon (ppg) to 11.3 ppg (8.5 to 9.0 ppg is the normal density), followed by circulating out the gas-charged drilling mud. (Excess formation pressure in deeper parts of the well ultimately required 13.9 ppg drilling mud.) Wire line geophysical logs indicated high gas saturations in the interval -5,560 to -5,667 feet (measured depth) and a wire line-sampling device (Repeat Formation Tester, or RFT) recovered gas and minor petroleum liquids from the Burger sandstone at -5,586 feet, -5,606 feet, and -5,648 feet (measured depths). The Burger gas reservoir was not production-tested and the well was plugged and abandoned. No additional delineation/appraisal wells were drilled on Burger structure.

Geological Habitat and Gas Resources at Burger Structure

The Burger prospect, over 189,800 acres in area, was mapped in 1987 and 1988 using conventional 2-D seismic data as part of preparations for Lease Sale 109 (in May of 1988). Burger well penetrated a sandstone 107 feet thick (in the measured depth interval -5,560 to -5,667 feet) with core porosity exceeding 29% and permeability values up to 447 millidarcies (md) (tbl. 3). The sandstone appeared to be saturated with gas, and possibly oil. Burger could represent the largest discovery to date in the Alaska OCS. Some quantification of the potential discovered resources is warranted.

The minimum fill model (fig. 13) assumes that Burger structure everywhere contains gas above the base of the sandstone at -5,625 feet subsea as penetrated in Burger well. The minimum pool area is 52,516 acres. The most likely fill model assumes that gas-bearing Burger sandstone is present within the entire area enclosed by a gas-water contact at -5,954 feet subsea projected from reservoir pressure data. The most likely pool area is 97,545 acres. The maximum fill model assumes that the productive area extends to the -6,360 feet subsea maximum closure or spill level identified by seismic mapping. That is, Burger structure is assumed to be completely filled with gas. The maximum productive area is 189,803 acres.

For the minimum fill model, we estimate mean resources of 7.629 Tcf gas and 393 Mmb condensate. For the most likely fill model, we estimate mean resources of 14.038 Tcf gas and 724 Mmb condensate. For the maximum fill model, we estimate mean resources of 27.472 Tcf gas and 1,404 Mmb condensate. These estimates are unrisked, or conditional. Risked estimates are reported in table 1, which also reports extreme ranges for the minimum, most likely, and maximum fill models for Burger structure.

Independent, practical consideration of models for field economic life (22 years of production) suggest that the entire resource (most likely case) at Burger will not be extracted and marketed. We estimate that of the most likely case resources of 14.038 Tcf gas and 724 Mmb condensate, 11.5 Tcf gas and 587 Mmb condensate will actually be lifted and sent to market. Revenue projections in our economic model for Burger structure are based on the latter estimates.

Engineering Simulation Model

The economic analysis was based on an engineering simulation of the offshore Burger gas pool. In contrast to province-wide oil and gas assessments, Burger was modeled as a standalone field and therefore did not have the cost-sharing benefits of other oil and gas fields in Chukchi province. Production of wet gas (gas plus condensate liquid) was transported via a 80-mile subsea pipeline to the Chukchi coastline and then by 320-mile pipeline overland across NPR-A to Prudhoe Bay on the central North Slope. The viability of the Burger project is entirely dependent on the existence of a future gas pipeline system connecting North Slope gas reserves to U.S. markets. We assumed that a new North Slope gas pipeline could accommodate additional gas delivery from the Burger field beginning in 2008[1], and the cost of conditioning and transporting Burger gas to U.S. markets would average $2.55/Mcf (2000$, including conditioning) over the life of the field. Condensate liquids could be blended with Alaska North Slope (ANS) crude and transported to the U.S. West Coast using the established TAPS and tanker routes.

Development and production costs were scaled to the available data from offshore gas fields in other difficult environments, although none are directly comparable to the Chukchi. A number of optimistic assumptions were made regarding year-round drilling, subsea technology, the accelerated schedule for development, and future North Slope gas infrastructure to carry Burger production to market. Optimizing the engineering plan and development schedule, and using an economic cut-off in the field life, led to a **modeled reserve volume of 11.5 Tcf of natural gas and 587 Mmb of condensate. At peak production the Burger field would produce 1.68 Bcf/d gas and 85,000 bbl/d condensate.**

Economic Analysis

A discount cash flow (DCF) method was used to define a breakeven price for Burger production under seven economic and market conditions ("scenarios"). We investigated flat and inflating costs and prices, sale and no-sale of the associated condensate liquids, different discount rates, and two BTU price-equivalency factors. The standard DCF analysis (Scenario 1) found **breakeven prices (NPV_{12}=0) for gas delivered to U.S. domestic markets of $5.22/Mcf and condensate sold with ANS to West Coast markets at $29.34/bbl.** The standard DCF analysis assumed that costs and commodity prices would increase at the rate of inflation (flat costs and prices in constant dollars) and that gas sales would be at BTU price parity with oil. BTU parity reflects recent trends to natural gas as a preferred energy fuel because of its clean-burning characteristics compared to oil or coal.

Six additional scenarios were modeled and the results are summarized in table 2. It is interesting that four scenarios had breakeven gas prices below the standard model. However, the lowest threshold price

[1] *Current estimates for completion of this gas pipeline are 2012-2015*

($4.56/Mcf, scenario 6) is still 24% higher than “high economic growth” prices forecast for the year 2020 by EIA (Outlook 2001; $3.68/Mcf in 1999$). Although domestic gas prices in many areas are higher today than these threshold prices, the volatility of domestic energy markets cannot be ignored. In 1998, wellhead gas prices averaged less than $2.00/Mcf in the U.S. market (EIA, 2004). Long-term price risks are a prevailing consideration in all projects of this scale.

Although it is impossible to accurately predict long-term future prices, some indication could be derived from OPEC who exerts a major control on world energy prices. OPEC’s stated objective is to maintain crude oil prices within a $22-$28/bbl range. Translating oil prices into natural gas prices would mean that expected gas prices could range from $3.91-$4.98 at BTU parity (BTU factor = 1.0). If environmental and regulatory forces do not continue to promote gas as the preferred energy fuel, BTU price discounts for gas could return to past levels averaging 0.66. Then gas prices would range from $2.74-$3.48/Mcf for oil prices in the $22-$28/bbl bracket. In either case, the expected threshold prices of $5.22/Mcf and $29.34/bbl are higher, thus making the Burger project marginal as a long-term investment opportunity.

Conclusions

- Burger potentially represents the largest discovery on the Alaska OCS. Current resource estimates range from 7.629 Tcf gas (mean, minimum fill case) to 27.472 Tcf gas (mean, maximum fill case), with a most likely (mean, most likely fill case) estimate of 14.038 Tcf of natural gas and 724 Mmb of condensate. The optimized engineering model, based on the resources for the most likely case, recovered 11.5 Tcf gas and 587 Mmb condensate.

- Natural gas production from Burger could make a significant contribution to gas deliveries from the North Slope to domestic markets via a future gas pipeline system. The Burger project could add 1.68 Bcfd of gas and 85,000 bopd to North Slope production. This production rate of condensate is equivalent to peak oil production from the Alpine field, the largest oil field discovered in the last decade on the North Slope. Gas production from Burger would represent 42% of the expected 4.0 Bcfd carried by a future North Slope gas pipeline.

- Because of its size and location, the development of the Burger gas discovery will be very costly. Development costs for the expected case total $11.24 billion (as-spent) and yearly operating costs average $781 million (as-spent). As modeled, development expenses for the Burger project would begin in year 2001, but payout (breakeven cash flow) would not occur until the year 2014. The maximum negative cash flow (exposed capital) during that 14-year period would be $5.158 billion.

- Even under optimistic assumptions, Burger is a risky investment opportunity. All scenarios result in threshold gas prices higher than forecast by EIA or set by market forces controlled by OPEC. The high transportation tariffs for Burger gas ($2.55/Mcf) to the U.S. makes this Alaskan project less attractive than gas reserves closer to market (Canada). The project is dependent on the existence and available capacity in a future North Slope gas pipeline.

- The Burger project faces formidable engineering hurdles. New technology, as yet untested under Chukchi shelf conditions, such as subsea wellheads, year-round operations in pack ice, and large-diameter high-pressure, dense-phase subsea pipelines, would be required. The accelerated schedules in our development models did not allow for costly delays associated with environmental studies, right-of-way issues, government agency coordination, or a host of legal obstacles normally faced by projects in Alaska.

- This Burger study offers a good perspective of the hurdles faced by offshore development projects in Alaska. Although petroleum assessments typically conclude that huge oil and gas resource potential exists in northern Alaska, the economic reality is that most of these resources will be non-commercial. Burger is perhaps the largest discovery made to-date on the Alaska OCS, yet its commercial potential is marginal even under optimistic assumptions.

Geological Analysis

Nature of Petroleum at Burger Prospect

Compositional data for most gas samples from the Burger sandstone show deficiencies in C_2 to C_5 (ethane, propane, butane, pentane) relative to C1 (methane) that suggest that the Burger pool is primarily gas. A Pixler-type plot for gas component ratios is shown in figure 17 and shows that most samples fall decisively within the "gas" domain, although some RFT 4 samples (in blue) seem to contain condensate. A plot for methane C13 isotopes and C1/(C2+C3) ratios shown in figure 18 shows that the Burger sandstone gas is of thermogenic origination.

The high ratios of methane to other gas components (fig. 17) suggest that it is unlikely that the gas pool in Burger prospect is now in contact with any significant, deeper oil column. However, relatively high oil saturations (up to 10.6% of pore space) were noted in sidewall core samples of gas-bearing Burger sandstone and the gravity of liquids recovered in RFT sampling devices ranged from 39.4° to 54.7° API. These residual saturations seem too high to be attributed to retrograde condensation (at reservoir pressure, 0.08% to 0.16% by volume, from Pressure-Volume-Temperature [PVT] studies reported in tbls. 11 and 12). The broad range in liquid gravities suggests that some liquids other than retrograde condensate are present. These observations suggest that oil may have once been pooled within Burger structure, but that movable fractions of oil were subsequently displaced out of reservoir pores by invading dry (methane-dominated) gas, leaving only a residual film of oil bound to sand grains and trapped in small pores and mixed geochemical signals (relatively dry gas, combined with residual oil saturations). These data do not preclude the existence of an oil "rim" below the single well penetration of the Burger sandstone.

1993 Model for Estimation of Burger Discovered Gas Resources

A preliminary study in early 1993 focused on reservoir properties and fluid contacts. Wireline geophysical log measurements suggested that a gas-oil contact was intersected at –5,620 feet measured depth, or 60 feet below the top of the sand. Using pressure gradient analysis, an oil-water contact was projected to –6,130 feet subsea. This preliminary study concluded that Burger structure contained a hydrocarbon column 991 feet in height, approximately half gas column and half oil column. A petrophysical description of the Burger sandstone reservoir was presented at the annual meeting of the American Association of Petroleum Geologists in New Orleans in April 1993 (Craig, Sherwood, and Hurlbert, 1993).

The interpretation of an oil column in the sandstone at Burger well bore is now believed to be incorrect. Further studies in late 1993 focused on "shaly sand" effects in the Burger sandstone and determined that increasing volumes of clay in the lower parts of the sandstone were falsely indicating the presence of oil rather than gas in the pore system. Specifically, a cross-over of the density-porosity and neutron-porosity log curves (fig. 6), normally an indicator of oil in clean sandstones, was instead attributable to a high amount of admixed clay in the lower part of Burger sandstone relative to the overlying, clay-free, gas-saturated sandstone unit. After correction for clay (or "shale") effects, it was determined that no gas-oil contact was present within the sandstone and that effective porosity within the sandstone was entirely saturated with gas, from top to base. This is confirmed by the recovery of gas (and water) into a sampling device from the lower sand unit.

Our late1993 study therefore modeled the Burger structure as filled with gas. A reservoir pressure gradient model (based on RFT pressure data) indicated a potential gas-water contact at -5,948 feet (subsea), or 323 feet below the base of the sandstone at the Burger well. Based on this work, three fill models (fig. 13) were developed for the gas resources in Burger structure. The 1993 minimum fill model assumed that Burger structure everywhere contained gas above the base of the sandstone at -5,625 feet subsea, but that the reservoir sandstone was absent within a 20,833 acre area near the crest of Burger structure. The sandstone was assumed to be absent in this area because seismic amplitudes for the reflection corresponding to the top of the sandstone are much reduced such that the reflection is virtually absent. This area is referred to here as the "dim spot." The area of the dim spot was excluded from the –5,625-foot closure area to obtain a minimum pool area. The dim spot was added back in to obtain the 1993 most likely fill model. For that case, it was assumed that the gas-bearing sandstone was present within the dim spot. The 1993 maximum fill model assumed that the productive area extended to the (-5,948 feet subsea) gas-water contact projected from pressure gradient analysis.

The productive areas, or "pool areas" resulting from these fill models were used to construct a probability distribution for pool area. The pool area distribution was aggregated with probability distributions for pay thickness and gas yield in the *PRASS* computer model to calculate a probability distribution for recoverable gas resources.

The 1993 Burger pool model calculated discovered gas resources ranging from 1.9 Tcf (95% probability) to 10.5 Tcf (5% probability), with mean recoverable gas resources of 5.2 Tcf**.**

2000 Models for Estimation of Burger Discovered Gas Resources

In 2000, all of the geological data for the Burger gas pool were reviewed and re-assessed. In general, the revised input data developed by the new study were not materially different from the data used in 1993. In 2000, pressure gradient analysis based on RFT pressure data from the Burger sandstone indicated a potential gas-water contact at -5,954 feet (subsea), or only 6 feet deeper than the projection used in the 1993 study. Pay thickness and gas yield models used in the 1993 and 2000 assessments were similar.

However, Burger well data were used to develop three very different fill models for Burger structure for the 2000 assessment. The 2000 minimum fill model (fig. 13) assumes that Burger structure everywhere contains gas above the base of the sandstone at -5,625 feet subsea in Burger well. The minimum pool area does not exclude the area of the "dim spot." The minimum pool area is thus 52,516 acres, or 21,266 acres larger than the minimum pool area in the 1993 study.

The 2000 model assumes that the seismic "dim spot" exists for reasons other than absence of reservoir formation. For example, gas-charging of the Pebble Shale that overlies the reservoir formation would act to reduce acoustic impedance and seismic amplitude. Compositional or physical changes within the Pebble Shale, like increasing silt content or development of gas-charged microfractures (common above large gas columns), would also tend to reduce acoustic impedance and create a seismic dim spot. Also, the development of a transitional upper contact for the reservoir formation might broaden the reflecting interface and reduce reflection coherence. Because there are several reasonable explanations for the coexistence of a dim spot with productive reservoir formation, we include the dim spot area in the minimum productive area for Burger pool.

The 2000 most likely fill model assumes that gas-bearing Burger sandstone was present within the entire area enclosed by the projected gas-water contact at -5,954 feet subsea. The most likely pool area is thus 97,545 acres, or 45,462 acres larger than the most likely pool area used in the 1993 study. The 2000 maximum fill model assumes that the productive area extends to the -6,360 feet subsea maximum closure or spill level identified by seismic mapping (allowed by uncertainties in pressure data that may permit a much deeper gas-water contact). That is, Burger structure is assumed to be completely filled with gas. The maximum productive area is thus 189,803 acres, or 109,803 acres larger than the maximum productive area in the 1993 study.

The 2000 Burger pool model held pool areas constant for the three fill models and aggregated the pool areas with probability distributions for pay thickness and gas yield factor. A probability distribution for recoverable gas resources was calculated (using the *@RISK* commercial software) for each fill model. This multiple-aggregation modeling approach differs from the single aggregation reported for the 1993 study. The results for the 2000 estimate for discovered gas and condensate resources at Burger structure are shown in table 1.

Stratigraphy and Genesis of Burger Structure

Burger structure is a dome-shaped uplift near the west edge of the Arctic platform and the north edge of Colville basin (fig. 1). Like Klondike structure, it is a culmination along a subdued arch that parallels the Barrow arch to the north. Together, these two arches create a broad, complex uplift that separates Colville basin on the south from the North Chukchi and Nuwuk basins on the north (fig. 1).

The earliest geological history of Chukchi shelf began with rifting and subsidence of Hanna trough, a north-trending basin of late Devonian to late Jurassic age that underlies the more subtle north-trending sag between Klondike and Burger wells in figure 1. Although the creation of Hanna trough formed structures that controlled subsequent deformations on Chukchi shelf, Hanna trough is not directly responsible for creation of Burger structure. Burger structure is more directly a product of flexures and narrow sag basins that extended south from the rift system that created North Chukchi and Nuwuk basins in late Jurassic and Cretaceous time.

A seismic section that crosses Burger structure from east to west is shown in figure 2. The sequence between "BU" and "JU", labeled "RS" is the Rift sequence and was deposited during the time of the rifting that created North Chukchi and Nuwuk basins. The gas-bearing sandstone discovered by Burger well at –5,560 feet is part of the Rift sequence and directly underlies the "LCU" in figure 2. A regional correlation panel for Chukchi shelf wells that shows the context of the Rift sequence and the Burger sandstone is presented in plate 1. The "RS" sequence in figure 2 thickens from 447 feet at Diamond well on the east to 2,615 feet at Burger well.

A seismic-based isopach map for the "RS" (or Rift) sequence in the area of the Burger structure is presented in figure 3. Burger structure is located on the east end of a west-trending rift-sag basin that was (at the time of subsidence) crossed by north-trending growth faults that trapped thick sequences of sediments against the downthrown sides of the faults. The Rift sequence across Burger structure thickens westward and isopach maxima occur on the downthrown sides of the growth faults.

The formation of the rift-sag basin (ca. 121-132 Ma) and influx of thick Rift sequence sediments set the stage for later uplift events that inverted the basin. Figure 2 shows that areas west of Burger were uplifted and eroded (creation of unconformity "MBU", minimum age 65 Ma) sometime following the conclusion of deposition of sequence "LB" (Lower Brookian rocks) in post-Cenomanian time (after 92 Ma). The post-"LB" uplift tilted the Burger rift-sag basin to the east, and the modern east dips on the east flank of Burger structure are a relict of this uplift. This uplift may have occurred along an ancestral Barrow arch that crossed or originated nearer to the Burger-Klondike arch (possibly driven by early thrust-related movements in the Brooks Range to the south). The east flank of Burger structure was created by the uplift event in the time period from 65 to 92 Ma.

Westward dip of the west flank of Burger structure did not develop until much later (ca. 35 Ma). Figure 2 illustrates that at the onset of deposition of sequence "UB" (early Tertiary time, ca. 65 Ma) the west flank of Burger structure began to subside beneath the developing north-trending trough that now separates Klondike and Burger structures (fig. 1). The older rift-era growth faults passing north through Burger structure were reactivated as the nodal line on the east that barred the spread of subsidence to the east and prevented any westward rotation of the east flank of Burger structure. The subsidence of the trough west of Burger structure coincides with a period of catastrophic faulting and collapse of North Chukchi basin on the north. This event probably represented renewed rifting in North Chukchi basin and was the driver for a host of regional deformations of northern Chukchi shelf. Popcorn well is located within the Tertiary trough northwest of Burger, and the stratigraphy of the trough fill in Popcorn well suggests that the trough was mostly filled (and by extension suggests that Burger structure achieved its present shape) by about late Eocene time (ca. 35 Ma).

Hydrocarbon Charging of Burger Structure

Pressure-Volume-Temperature (PVT) studies of RFT gas samples in the laboratory indicate that the Burger gas pool is a retrograde condensate. Typically, a retrograde condensate reservoir "fluid" (fluid in the general sense, either gas or liquid) exists as a gas in the reservoir, but with reduction in pressure experiences "retrograde condensation" and separation of liquids, often within the reservoir. With continuing reduction in pressure at fixed reservoir temperatures the liquid evaporates back into the gas and disappears. Typically, both gas and condensate are recovered at surface separators..

Laboratory studies of two Burger gas samples from 5,586 feet and 5,648 feet (measured depth; posted in fig. 6) show that above the dew point pressures from 4,518 to 4,269 pounds-per-square-inch (psi), the Burger reservoir fluid would be in a gaseous state. At the actual reservoir pressures (approximately 3,075 psi at well), both gas and liquids are present (maximum liquid fraction in PVT studies, 0.11 to 0.34 percent of sample volume). That is, the Burger reservoir fluid already lies in a state of over-saturation with liquids condensed into reservoir pore spaces.

As noted above, the gas in Burger structure is relatively deficient in natural gas liquids (C_2-C_5; fig. 17) and is probably not in contact with a significant underlying column of oil. However, irreducible oil saturations are widely observed in core samples. One explanation might be that oil once occupied Burger structure, but was later displaced by invading gas, primarily methane, that filled the crest and forced oil out of the structure through the spill point (on the northeast margin of the structure, located in pl. 2). Or, oil may have migrated through the Rift sequence at Burger before the trap was created in late Eocene time, leaving behind irreducible oil saturations (the oil clinging to pore walls and trapped in small pores) along the migration path. In any event, there appear to have been two discrete events of hydrocarbon movement through the Burger sandstone. Available data cannot preclude the existence of an oil "leg" or "rim" in the Burger structure below the Burger well.

Burger Sandstone Stratigraphy

The Burger sandstone is a marine sequence of Hauterivian to Barremian age (pl. 1). The sandstone is "regressive" in that it is shaly in its lower parts and becomes cleaner, more porous, and more permeable in its upper parts. Foraminifers indicate a middle neritic to upper bathyal environment. The Burger sandstone therefore seems to have been deposited far from shore near a shelf edge. As interpreted by us, the Burger sandstone directly underlies the "HRZ" or Pebble Shale (or correlative rocks) and probably the Lower Cretaceous unconformity (LCU).

We consider the Burger sandstone to be stratigraphically equivalent to the Kuparuk "C" sandstone in the Kuparuk River Formation in the Kuparuk oil field. Possible correlations between Burger and Kuparuk sandstones and bounding unconformities are illustrated in figure 4. The Kuparuk "C" sandstone in Kuparuk (and Niakuk, and Pt. McIntyre) field(s) is Hauterivian to Barremian in age and is interpreted by Masterson and Paris (1987, p. 96 and fig. 2) to overlie the regional Lower Cretaceous unconformity.

The upper parts of Kuparuk "C" sandstones are often clean well-sorted sandstones that record a higher energy environment than the transitional or muddy sandstones that they overlie. Masterson and Paris (1987) organized these uppermost "clean" sandstones into their "C-4" unit and placed an unconformity at its base. Possible relationships of the Burger and Kuparuk "C" sandstones to the regional Lower Cretaceous unconformity are illustrated in figure 4.

Figure 4 shows that the Burger sandstone shares clear similarities in stratigraphic context with the Kuparuk "C" sandstones. This analogy is important because the Kuparuk "C" sandstones are prolific petroleum reservoirs that thicken markedly into areas that actively subsided during Kuparuk sandstone deposition. The Kuparuk "C" sandstone is exceptionally thick in a syndepositional graben at Pt. McIntyre field (fig. 4). In Niakuk field, the Kuparuk "C" sandstones formed thick amalgamated bodies along a fault-controlled shoreline along the faulted northern edge of Prudhoe Bay structure (mapped by Masterson and Paris, 1987, fig. 11). At Burger, the sequence of rocks that contain the Burger sandstone (the Rift sequence) nearly triples in seismic thickness westward across the Burger structure (figs. 2 and 3). Our reservoir model speculates that the Burger sandstone could also thicken markedly in western parts of Burger structure, and this analogy is employed in the construction of the pay thickness model for Burger structure, discussed separately below.

Burger Sandstone Reservoir Properties

Core descriptions suggest that the Burger sandstone is composed of two units: 1) an upper "clean" sandstone unit (-5,560 to –5,620 feet measured depth) that is very fine- to fine-grained, well sorted, and mostly free of clay matrix; and 2) a lower "muddy" sandstone unit (-5,620 to –5,667 feet measured depth), very fine- to fine-grained, highly bioturbated, and rich in clay matrix. These units within Burger sandstone are illustrated in figures 6 and 7. The lower muddy unit probably represents a shelf sand that was initially highly intercalated with mud laminae or ripple mud drapes that were disrupted and mixed with the sands by burrowing organisms. The overlying "clean" sandstone represents a higher-energy environment—perhaps shallower water or a location along a new, energetic storm track—that acted to winnow clay and organic material from the sandstone and created sediment uninviting to burrowing organisms.

The compositional and textural differences between the two units of the Burger sandstone are reflected in the petrophysical data, particularly permeability measurements (fig. 7) and hydrocarbon saturations (fig. 10). The higher permeability of the upper "clean" sandstone is also evidenced by the greater drilling fluid invasion of the upper sand unit. Greater invasion is indicated by the greater spread between shallow (invaded by low-resistivity salt-water based drilling mud) and deep (gas-bearing, non-invaded) resistivity measurements in the upper sand unit relative to the lower sand unit, as shown in figure 6. Porosity and permeability data from rotary sidewall cores (percussion core data were not used owing to excessive sample disturbance) are given in table 3 and are shown graphically along with neutron-density crossplot porosity (POR_{ND}) in figure 7. In the "clean" sand unit, the (geometric) mean permeability is 369 millidarcies. In the "muddy" sand unit, the (geometric) mean permeability is an order of magnitude less, or only 39 md. The permeability of the "muddy" sandstone is degraded because the pore system of the muddy sandstone unit is clogged with clay, as can be seen in a comparison of microscopic views of representative samples from the clean and muddy sand units in figure 8. The dark streaks in the "C" view (left) of the muddy sandstone (fig. 8B) are probably individual burrows where feeding organisms introduced mud into the sands.

Calculation of Burger Sandstone Gas Recovery Factor

The gas recovery factor for Burger reservoir was calculated using probability distributions as inputs to the standard yield equation:

Gas Recovery Factor (10^6 ft^3 gas per acre-foot) = [43,560 ft^3/acre-foot] [A . (1-B) . E . F] [D . (60 °F+460)G] [C/14.73] [$1/10^6$]

where:
- A = porosity, in decimal fraction
- B = water saturation, in decimal fraction
- C = reservoir pressure, in pounds per square inch (psi); 14.73 psi = standard surface (atmospheric) pressure
- D = gas formation volume factor (FVF), or 1/Z ("Z" is gas deviation factor)
- E = gas recovery efficiency, in decimal fraction
- F = gas "shrinkage factor", or fraction of gas volume surviving after loss of condensate and removal of non-combustible gas (carbon dioxide, etc.)
- G = reservoir temperature, in °Rankine (°F + 460). (60 °F + 460) = standard surface temperature, in °Rankine.

Using mean values for the input probability distributions, the calculation for mean gas yield may be illustrated as follows:

Mean gas recovery Factor = [43,560 ft^3/acre-foot] [0.265 (1-0.32) . 0.803 . 0.91] [1.209 (60°F + 460)/585] [3089/14.73] [$1/10^6$]
= 1.361 mmcfg/acre-foot

The actual calculations used a Monte Carlo aggregation process in *@RISK* with input data characterized by probability distributions, generally truncated normal distributions (for porosity, reservoir temperature, reservoir pressure, gas FVF, recovery efficiency, and shrinkage factor) or, in one instance, a truncated lognormal distribution (water saturation). The model aggregated certain input distributions as dependent, or varying in a related manner.

Porosity and recovery efficiency vary together in a positive manner but both should vary in a negative manner with water saturation (the complement to gas saturation). The model also used a positive dependency between reservoir temperature and reservoir pressure. Gas recovery factor input probability distributions are presented in tables 4 and 5, and the dependency model is presented in table 4. The calculated probability distribution for gas yield is reported in table 6. Some comments about each input variable follow.

Porosity

The rotary sidewall core data in table 3 were used to develop a probability distribution for porosity of the Burger sandstone. The 16 porosity measurements were entered as sample data into *BESTFIT* and fit with a normal (Gaussian) probability distribution that yielded a mean of 26.47% and a standard deviation of 2.35%. This probability distribution was entered as "porosity" in the gas yield model.

A separate issue is the probability for occurrence of porosity in sufficient quantity to be productive or "pay". A common minimum porosity limit for "pay" is 10 percent. Using a model that relates porosity to reservoir thermal maturity (Sherwood et al., 1998, figs. 13.10, 13.11), we estimated the probability for the existence of porosity exceeding 10% in the Burger sandstones across Burger structure. Vitrinite reflectance data from Burger well (Sherwood et al., 1998, tbl. 13.6) indicate that the depth range of the reservoir across Burger structure should correspond to a range in thermal maturity from 0.61% to 0.69% vitrinite reflectance. Overlaying this range in vitrinite reflectance on the multi-basin porosity model of Schmoker and Hester (1990), shown in figure 11A, we obtain a probability distribution for porosity, shown in figure 11B, that indicates a 75% probability for exceeding 10 percent. Reservoir continuity and porosity preservation are the chief geological risk elements for Burger pool (tbl. 7).

Water Saturations

The 1993 study modeled water saturations using a correction for shale content of the sandstones. The presence of shale in sandstones affects geophysical measurements and can mask true sandstone properties. The results of this work are shown in figures 9 and 10. The lowest water saturations, 17% to 25% (or highest gas saturations, 75% to 83%), are found in the upper clean sand unit. The gamma ray curve in figure 6 (and direct observations in fig. 8) reveal increasing shale content in the lower part of the Burger sandstone. The gamma ray recordings are used to calculate the sand-shale ratios shown in the "formation analysis" column of figure 10. Clearly, the lower sand unit is most subject to shale effects.

Shale (or clay minerals) contains water in its mineral structure that the neutron-logging device attributes to pore water (i.e., porosity). In addition, water clinging to clay size particles (bound water) cannot escape from the particles and flow through the pore system, but is nonetheless logged as porosity. The shale effect on porosity calculations can be corrected by estimating shale content (from gamma ray measurements) and then subtracting out the water (or apparent porosity) that is attributable to clay mineral structure or as water bound to clay-sized particles. The corrected porosity is termed "effective porosity" because fluids that occupy such pores are “movable” or can flow out of the pore and through the pore system. The calculated effective porosity profile is shown in the right column of figure 10.

Resistivity tools, which are used to calculate the mix of water and hydrocarbons in the pore system, include the non-movable clay-related water with movable pore water. The effect of shale-bound water on resistivity must be corrected to estimate the actual saturations of movable gas relative to movable water. A water-gas saturation model using a shale correction is shown in the right column of figure 10. We see that “effective” porosity (pores filled with movable fluids) declines with rising shale content in the lower muddy sand unit (below -5,620 feet). Significant gas saturations persist to the base of effective porosity within the sandstone at about 5,667 feet. Using a cutoff limit for “pay” of gas saturations exceeding 50%, the Burger sandstone has 86 feet of gas pay, posted as red blocks in the right column of figure 10.

In the “no shale correction” model (center column, fig. 10), uncorrected water saturations rise sharply near the base of the sandstone. Ordinarily, this would indicate a gas- water contact within the sandstone near the base. However, the apparent increase in water saturation in the “no shale correction” model is entirely attributable to shale-bound water. The shale-correction model in the right column does not support the interpretation of a gas-water contact within the sandstone penetrated by the well. The presence of gas-saturated reservoir in the lower part of the sandstone is confirmed by RFT recovery of gas (and water) at 5,648 feet measured depth (RFT 8, fig. 6). In the shale-corrected model, water saturations and gas saturations both decline near the base of the sandstone, entirely because of the decline (and eventual disappearance) of effective porosity.

Shale-corrected water saturation data were assembled as samples into *BESTFIT* and fit with a lognormal probability distribution with a mean of 0.32 and a standard deviation of 0.136. The probability distribution for water saturation for Burger sandstone is given in tables 4 and 5.

Reservoir Temperature

Reservoir temperatures for Burger pool were forecast using maximum bottom-hole temperatures recorded on successive logging runs (maximum temperature recorded when logging tool is lowered to the bottom of the well). At -5,467 feet subsea (-5,509 feet measured depth), 119°F was recorded; at -6,622 feet subsea (-6,664 feet measured depth), 145°F was recorded. The incremental gradient between these depth points is 22.5°F per thousand feet. Converting to °Rankine (°F + 460), we project the temperature at the crest (-5,139 feet subsea) of Burger structure to be 572°R and the temperature at spill (-6,360 feet subsea) to be 599°R. These limiting temperatures were posted at the F95 and F05 fractiles on a normal probability plot and joined with a straight line. The straight line is assumed to define the probability distribution for reservoir temperature. Probability/temperature-value pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (585 °R) and standard deviation (8.18 °R) for the distribution. The resulting probability distribution for reservoir temperature is given in tables 4 and 5.

Reservoir Pressures

Twenty-six pressure measurements were attempted within the Burger sandstone interval using a wireline device called a Repeat Formation Tester, or "RFT". Ten of these measurements were successful (others failed because of impermeable formation, seal failure, or plugging tool) and these are tabulated, graphed, and fit with a linear regression in figure 12. The RFT pressure measurements and the linear regression were used to forecast the reservoir pressures at the crest (3,038.2 pounds per square inch [psi]) and spill (3,139.0 psi) depths for Burger structure. These limiting pressures were posted at the F95 and F05 fractiles on a normal probability plot and joined with a straight line. The straight line is assumed to define the probability distribution for reservoir pressure. Probability-pressure value pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (3,089 psi) and standard deviation (30.641 psi) for the distribution. The resulting probability distribution for reservoir pressure is given in tables 4 and 5.

Gas Formation Volume Factor (FVF = 1/Z)

A probability distribution for the gas FVF (or 1/Z; Z = gas deviation factor—deviance from ideal [Boyle's Law] gas behavior) was developed from laboratory data on a sample of gas from the Burger sandstone that was captured during an RFT test at -5,648 feet measured depth. The determinations for "Z" on this sample were obtained during pressure-volume studies at a constant temperature of 132°F (592°R), the estimated reservoir temperature at the point of penetration by Burger well. From these data, and our estimates for the reservoir pressures at the crest and spill point of Burger structure, we interpolated a range in "Z" values of 0.825 to 0.829, corresponding to FVF ranging from 1.206 to 1.212. These limiting FVF values were posted at the F95 and F05 fractiles on a normal probability plot and joined with a straight line that is assumed to define the probability distribution for gas FVF in the reservoir. Probability/FVF-value pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (1.209) and standard deviation (0.002) for the distribution. The resulting probability distribution for gas FVF is given in tables 4 and 5.

Gas Recovery Efficiency

To estimate the fraction of pooled, in-place gas that might be recovered by production, we used White's (1989, p. 3-31) model for a gas-expansion drive, high-permeability gas reservoir. White noted that such reservoirs typically yield between 65 and 95 percent of the in-place gas, with a most likely recovery efficiency of 80 percent.

Some local examples are furnished by Bird (1991, tbl. 1), who published a table with estimates for in-place and recoverable oil and gas for several North Slope fields. This table forecasts a gas recovery factor of 87% for the Prudhoe Bay field (Sadlerochit), 14% for the Lisburne (carbonate) pool, 83% for the Point Thomson field, and 45% for the Endicott field. These local examples from undeveloped gas pools vary widely but seem consistent with the White (1989) model.

The three values suggested by the White model were used to construct a probability distribution for the gas recovery factor for Burger pool. The limiting gas recovery factor values (65%, 95%) were posted at the F100 and F00 fractiles on a normal probability plot and the most likely value (80%) was plotted at the F50 probability. The three plotted points were joined with a straight line that is assumed to define the probability distribution for gas recovery factor. Probability/gas-recovery-factor-value pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (0.803) and standard deviation (0.037) for the distribution. The resulting probability distribution for gas recovery factor is given in tables 4 and 5.

Gas Shrinkage Factor

When gas is produced, it shrinks in volume because associated liquids precipitate (condensates). Produced gas may shrink further in volume before it enters gas transmission pipelines because noncombustible gases like carbon dioxide, hydrogen sulfide, nitrogen, helium, and argon must be removed. For Burger pool, we estimated the potential losses attributable to both of these effects and merged them into a single factor that we term the "gas shrinkage factor." For calculation purposes in our model, the "gas shrinkage factor" is entered as the fraction of produced gas volume that is expected to survive removal of condensate and non-combustible gases and go to market.

Condensate yields for the Burger gas are estimated to range from 15 to 140 bbls/Mmcfg (discussed below), corresponding to a loss of 3 to 8 percent of produced gas volume. Gas samples that were recovered by RFT sampling devices were analyzed and found to contain non-combustible fractions (mostly nitrogen and carbon dioxide) ranging between 0.72 and 6.63 percent. Taken together, these effects yield an expected gas "shrinkage" factor ranging between 85 and 96 percent of produced gas volume. These limiting gas shrinkage factor values were posted at the F95 and F05 fractiles on a normal probability plot and joined with a straight line that is assumed to define the probability distribution. Probability/gas-shrinkage-factor-value pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (0.91) and standard deviation (0.032) for the distribution. The resulting probability distribution for gas shrinkage factor is given in tables 4 and 5.

@RISK Modeling of Gas Recovery Factor

Probability distributions for porosity, water saturation, reservoir pressure, reservoir temperature, gas FVF (1/Z), gas recovery factor, and gas shrinkage factor were aggregated in *@RISK* using Monte Carlo sampling. A dependency model, shown in table 4, was used in the aggregation. Porosity and recovery efficiency vary together (dependency = 0.8) in a positive manner and both should vary in a negative manner (dependency = -0.9) with water saturation (equivalent to varying in a positive manner (+0.9) with gas saturation). The model also used a positive dependency (dependency = 0.95) between reservoir temperature and reservoir pressure. Using dependencies in the aggregation model has the effect of increasing the range of outcomes for gas yield factor and the standard deviation of the calculated probability distribution. Table 6 shows the modeling results for gas yield factor, a probability distribution with a mean value of

1.361 Mmcfg/acre-foot, a standard deviation of 0.327 Mmcfg/acre-foot, and ranging from 0.544 to 2.477 Mmcfg/acre-foot.

Pay Thickness

The gross thickness of the Burger sandstone interval at Burger well is 107 feet (-5,560 to -5,667 feet measured depth). There is about 100 net feet of sandstone and 86 feet of gas pay. The Burger structure is quite large, 189,803 acres in area and 20 miles in diameter, and thus affords a great opportunity for lateral variation in thickness of the reservoir formation.

Regionally, sandstones that are stratigraphically equivalent to the Burger sandstone are observed to vary greatly in thickness, from several feet in parts of Kuparuk field to 290 feet at Pt. McIntyre No. 3 well in the Pt. McIntyre field. Unusually thick Kuparuk sandstones are found in areas of active synsedimentary subsidence, like the graben at Pt. McIntyre (fig. 4) or along the downthrown sides of growth faults, as in Kuparuk field (Masterson and Paris, 1987, fig. 11), indicating that they are inclined to fill any space created by subsidence. In other cases, the Kuparuk sandstones thicken regionally into the axial parts of rift-sag basins, but may transition to shale in the deepest parts of basins. Both effects are shown in the isopach map and stratigraphic cross section for the Kuparuk rift-sag basin by Masterson and Paris (1987, figs. 9,10, reproduced here as fig. 5). Here, we see that the Kuparuk "C" sandstones generally thicken northeastward into the central part of the rift basin that captured the Kuparuk Formation, but ultimately transition to shale. Masterson and Paris also show that both individual sandstones and the host Kuparuk Formation thicken abruptly at northwesterly growth faults that transect the basin axis (both effects mapped for the Kuparuk "C" sandstone by Masterson and Paris, 1987, fig. 11).

The seismic profile in figure 2 shows that the Rift sequence thickens westward across Burger structure. The isopach map shown in figure 3 shows that the Rift sequence triples in thickness from east to west across Burger structure. The Burger sandstone is part of the Rift sequence, and probably exhibits variations in thickness (factor of 3) that are comparable to those documented for the Rift sequence. Figures 2 and 3 both show that the Rift sequence achieves maximum thickness at sags along the downthrown sides of northeasterly growth faults that transect the west-trending sag basin that underlies Burger structure. This is precisely analogous to the structurally controlled thickness variations observed in Kuparuk basin (fig. 5). Completing the analogy, we note that the rift-sag basin beneath Burger (fig. 3) is comparable in scale (25 miles in rough diameter) to the Kuparuk Formation sag basin (25 X 30 miles) (fig. 5, shaded area in map).

We constructed a model for thickness variation of the Burger sandstone constrained by: 1) the recognized regional variations in absolute thickness (20 to 290 feet) of the Kuparuk "C" sandstone in the Prudhoe Bay area (fig. 4); 2) the strong similarities in stratigraphic context between these sandstones and Burger sandstone (fig. 4); and 3) the obvious structural controls on Rift sequence thickness variations across Burger (figs. 2, 3). We assumed a minimum thickness of 20 feet (easternmost Burger structure?), a most likely thickness of 90 feet (Burger well pay = 86 feet), and a maximum thickness of 400 feet (westernmost Burger structure?). On a lognormal probability plot, the extreme thickness values (20, 400 feet) were posted at the F100 and F00 probabilities, respectively, and the most likely value (90 feet) was posted at F50. Probability/pay-thickness-value pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (99 feet) and standard deviation (41.040 feet) for the pay thickness distribution. The resulting probability distribution for pay thickness at Burger pool is given in table 5.

The productive reservoir across Burger pool is assumed to mantle the structure at the same stratigraphic level as encountered at Burger well. The model is depicted schematically in figure 14. We acknowledge that sandstones not penetrated at the well may exist at deeper stratigraphic levels yet lie within the depth interval of the gas column between the crest of the structure at –5,139 feet (subsea) and the gas-water contact at –5,954 feet. Potential resources associated with such hypothetical additional sandstone reservoirs were not evaluated in this study.

Geological Risk Related to Reservoir Formation at Burger Prospect

Most of the geological risk associated with the Burger prospect is associated with the extent, continuity, and characterization of the reservoir formation. A gas pool clearly exists at the well location, indicating success in all critical areas of pool formation, and we note that the trap is reasonably simple and that the geophysical interpretation seems secure. However, the Burger sandstone may not be present in all parts of the mapped pool (for example the "dim spot" excluded from the productive area in the 1993 pool assessment [fig. 13, 1993 model]). Separately, the reservoir sandstone varies greatly in quality at the well and may not be productive at all sites. These are the two chief risk elements for the estimation of resources at Burger structure. Table 7 records our risk model for Burger pool.

Regionally, the Kuparuk "C" sandstones are quite continuous across much of the 170,000 acre Kuparuk production unit and extend beyond the developed area (area of wells, fig. 5) and across much (but not all) of the Kuparuk basin. The Kuparuk "C" sandstones mapped by Masterson and Paris (1987, fig. 11) continuously cover an area of at least 158,000 acres (our planimetry). We forecast comparable continuity for the Burger sandstone across the 189,803 acres Burger structure. We recognize that the Burger sandstone may be absent in some parts of Burger structure but estimate that reservoir-grade sandstone is present over 90% of the Burger structure.

A separate reservoir risk related to preservation of adequate porosity was also assessed. A porosity model based purely on reservoir thermal maturity, discussed above and shown in figure 11, predicts that a porosity of 10 percent—the minimum for productive formation or "pay"—will be exceeded 75 percent of the time (or, a 75% probability for adequacy). This model is reasonably consistent with the Burger sandstone at the well, where we observe 86 feet of pay in 100 net feet of sandstone.

When combined with the success factor for reservoir formation presence (0.75 . 0.9 = 0.675), we obtain an overall geologic success factor of 67.5% for Burger gas pool. In effect, this means that 67.5 percent of the potentially productive volume is expected to contain reservoir-grade sandstones.

Condensate Yield Factor

The probability distribution for condensate yield adopted for the Burger prospect resource assessment was drawn from literature references for typical condensate recoveries from developed fields. The condensate yield distribution is recorded in table 6. The condensate yield for Burger prospect was modeled as ranging from 15 to 140 bbl/Mmcfg (F100 to F00) and has a mean value of 51.271 bbl/Mmcfg.

Standing (1977, p. 57) and Craft and Hawkins (1991, p. 107) define a gas-condensate system as a gas-phase reservoir that produces gas and liquids at surface separators with gas-oil ratios between 5,000 and 100,000 cf/bbl. These gas-oil ratios equate to condensate yields ranging from 10 to 200 bbl/Mmcfg. This range in condensate recovery from gas is consistent with the production experience in gas and gas-condensate reservoirs in examples provided by Craft and Hawkins (1991, tbl. 4.2, figs. 4.2, 4.9; Standing, 1977, fig. 40).

Compositional data and pressure-volume (PVT) data for two Burger sandstone gas samples are presented in tables 11 and 12. These gas samples were obtained by formation tests RFT 4 and RFT 8 (posted in log display of fig. 6). At the temperatures of the Burger sandstone at the well (130-132ºF), the mean reservoir pressure (3,089 psi) is significantly less than the dew point[2] pressures (4,269 to 4,518 psi) established for the samples by the PVT analyses. This means that the *in situ* reservoir gas is oversaturated and that condensation has already dropped some liquids out of the gas and into the reservoir pore system. Therefore, the gas samples obtained by RFT are partially depleted of condensed liquids and are liquid-lean relative to the entirety of Burger reservoir fluids. A further complication is that some of the condensed liquids in the reservoir may have flowed to the RFT sampling device along with the gas. For these reasons, the RFT samples are unlikely to be truly representative of the full complement of reservoir fluids in the Burger sandstone.

The gas compositional data in tables 11 and 12 indicate total "liquids" (C2+) of about 57 bbl/Mmcfg. Ethane and propane form the bulk of these "liquids" but with boiling point temperatures below -43ºF would not condense at normal surface conditions. Pentanes (C5) and larger molecules can condense at surface conditions and this fraction of gas molecules in the Burger sandstone gas samples would yield 12 to 14 bbl/Mmcfg.

PVT data in tables 11 and 12 record maximum retrograde liquid volumes[3] of 0.11 to 0.34 percent, comprising 196 to 606 bbl/Mmcfg on a volume basis at corresponding pressures. In PVT studies (temperature held constant), these liquids re-vaporize at very low pressures. However, actual production would not re-vaporize all of these liquids and some would be swept to the production stream.

Our development model for Burger prospect assumes primary extraction and marketing of reservoir gas and condensate. Our model does not employ lean gas cycling, in which produced "wet" gas is stripped of liquids that are sent to market while residual "dry" gas is re-injected into the reservoir in order to maintain reservoir pressure and to help sweep "wet" gas to

[2] *Dew point: pressure and temperature at which liquids begin to condense out of a hydrocarbon gas fluid*

[3] *de-pressurization of retrograde gas-condensates causes condensation of liquids at intermediate pressures but these liquids are re-vaporized at lower pressures (1,450-2,000 psi for the Burger gas samples) because of the shape of the gas-liquid phase boundary in P-T relations.*

production wells. Lean gas cycling will sequester the gas for the early life of the field, followed by a period of "blow-down" production in which the gas is produced and marketed. Because lean gas cycling can achieve higher liquid recoveries, our condensate yield model may be overly optimistic. This is difficult to assess. De-pressurization of the Burger reservoir will certainly cause further condensation of liquids into the reservoir. If liquid saturations within the reservoir rise to a sufficiently high level (about 50%), some condensate might flow to production wells. However, this seems unlikely save within pressure-depleted cells in the reservoir surrounding production wells. At very low pressures, reservoir condensates may re-vaporize and rejoin the production stream. Because we have no long-term production tests and must rely upon small samples that may be biased, it seems best to rely upon the wider production experience with gas-condensates, as cited above, for the development of the Burger condensate yield model.

Using 15 and 140 bbl/Mmcfg as the range of possible values for condensate yield for Burger prospect, we plotted these values on a log-probability plot at the F100 and F00 fractiles and connected them with a straight line that then became the assumed probability distribution for condensate yield. Probability/condensate-yield pairs were picked from the graph and entered as a cumulative probability function in to *BESTFIT*, which calculated the mean (51 bbl/Mmcfg) and standard deviation (15.132 bbl/Mmcfg) for the distribution. The resulting probability distribution for condensate yield is given in table 6.

Fill Models for Burger Structure

Burger structure encompasses a maximum area of 189,803 acres. The crest of Burger structure occurs at a depth of –5,139 feet subsea about 2 miles southwest of Burger well (pl. 2). Burger well penetrated the Burger sandstone at a depth of –5,518 feet subsea, 379 feet below the crest. The spill point is located 9 miles northwest of Burger well at a depth of –6,360 feet subsea (pl. 2). The spill point is 1,221 feet below the crest and 842 feet below the gas-bearing sandstone at the well

For the 2000 assessment of Burger gas resources, we assumed that at minimum the Burger structure is filled with gas at mapped subsea depths equal to and shallower than the base of the gas-bearing sandstone at Burger well. This corresponds to –5,625 feet subsea (or –5,667 feet measured depth) in the well. Our fill model is shown in plate 2 and is compared to the 1993 fill model in figure 13. **The productive area for the minimum fill case is 52,516 acres.**

The analyses of geophysical logs for water saturations (discussed above and in figure 10) indicate that the Burger sandstone is gas-saturated to the base, implying that a gas-water contact lies deeper than the sandstone as penetrated at the well. For the most likely fill case, we used RFT pressure data from the Burger sandstone to project the depth to the gas-water contact. This concept is illustrated in a schematic cross section for Burger structure in figure 14. The pressure gradients for gas- and water-bearing parts of a shared reservoir must intersect at the gas-water contact, which is associated with a unique pressure. If one or more wells that penetrate the shared reservoir obtain multiple pressure measurements in both the gas and water column, these data can be combined with depths on a plot and the depth of intersection of the two gradients will correspond to the gas-water contact. The technique can identify the gas-water contact even if no well actually passes through the gas-water contact. In figure 14, the “red” pressure gradient, based on measurements in the gas-bearing sand, projects downward to an intersection at –5,954 feet (subsea) with the “blue” water column gradient that is based on pressure measurements in the water-saturated rocks below the gas pool. The gas-water contact is thus projected to –5,954 feet subsea. (A detailed discussion of Burger well pressure data is presented in a separate section below.) The projected gas-water contact is the fill level adopted as the most likely case for Burger structure, as shown in plate 2 and figure 13. **The productive area for the most likely fill model is 97,545 acres.**

The maximum fill model assumed that Burger structure is completely filled to the spill point at –6,360 feet subsea depth on the northeast flank of the structure (pl. 2). As discussed in the next section, uncertainties in the pressure data allow an interpretation that the structure is completely filled with gas. **The productive area for the maximum fill case is 189,803 acres.**

Analysis of Pressure Data from Burger Well

The basic assumption underlying the analysis of Burger pressure data is that the highly different pore fluid pressure gradients in the gas and water columns in a common reservoir must intersect at the gas-water contact. This is illustrated in the schematic of figure 14. The pressure gradients in the gas and water columns are much different because of the density contrast. Figure 12 shows that the pressure gradient in the Burger sandstone is 0.0826 psi/foot; in normally-pressured water-saturated rocks, the pressure gradient is typically 0.44 psi/foot, or 5 times higher. In “overpressured” or “geopressured” columns of water-saturated rock, where pore water is absolutely confined and the weight of the rock column is completely borne by pore fluids, pressure gradients can exceed 1.00 psi/foot, equivalent to the full lithostatic load. Pore pressure gradients exceeding 0.46 psi/foot are considered “overpressure” or “geopressure.”

At Burger, no explicit pressure measurements (using direct measurement methods, like the Repeat Formation Test [RFT] tool) were obtained above the gas-bearing Burger sandstone (at –5,560 feet measured depth). Our assessment of pore pressure conditions at shallower depths in Burger well depends upon analog methods, such as measurements of rock conductivity or velocity as obtained from geophysical logging tools.

Geophysical log data from the Burger well, illustrated in figure 15, show a trend of decreasing conductivity among shales in the well interval above –4,850 feet subsea. The progressive decrease in shale conductivity with increasing depth reflects the expulsion of pore waters that occurs with normal compaction. This suggests that the geologic column above –4,850 feet is “normally pressured.” The conductivity profile in figure 15 reverses trend at –4,850 feet, indicating that the shales have begun to retain excess pore waters. Pore water retention causes abnormally high pre fluid pressures. The excess pore water (a more electrically conductive material as compared to rock minerals) produces higher conductivity among geopressured shales. The geopressure zone encountered at Burger well is part of a regional cell that extends to most Chukchi shelf wells and east beneath the North Slope of Alaska.

Empirical curves published by McClure (1977) for pore pressure interpretation, scaled in pounds-per-gallon (ppg) are overlain on the shale conductivity data in figure 15. The empirical curves are based on the responses of geopressured shales in many different areas, but in any given well are subject to non-pressure effects related to shale composition. Therefore, although the conductivity trends clearly identify the presence of geopressure, the empirical curves must be calibrated to independently measured pore pressures in order to be used for explicit pressure evaluation. Two RFT pressure measurements of approximately 3,260 psi near –6,120 feet (subsea) indicate an equivalent pressure gradient of 10.4 ppg, and the empirical curves have been adjusted (slid vertically) to obtain a calibration match at that depth. Large variations in shale conductivity measurements within the geopressured section below –4,850 feet (subsea) may reflect the presence of distinct pressure cells, or possibly unrelated factors, such as variations in pore water salinity, conductive metallic minerals (like pyrite), or conductive clay minerals. A line connecting the RFT pressure measurements at –6,120 feet and the depth of geopressure onset at –4,850 feet is plotted as the overpressured zone gradient labeled "0.88 psi/ft" in figure 15. This line is also posted as the "geopressure" gradient of 0.8797 psi/ft in figure 16.

All RFT pressure data for Burger well are posted in figure 16. An inset diagram highlights the details of the intersection of the gas gradient (fully detailed for Burger sandstone in fig. 12) and the geopressure water gradient. The equations for the gas gradient and the geopressured water gradient are solved simultaneously for the common pressure at the gas-water contact (3,105.5 psi) to calculate the depth of the gas-water contact (–5,954 feet subsea):

<u>Gas Gradient</u> **<u>Geopressure Water Gradient</u>**

0.0826 (depth) + 2613.7 = **Common Gas/Water Contact Pressure** = 0.8797 (depth) – 2132.5
or,
2613.7 + 2132.5 = depth (0.8797 – 0.0826)
4746.2/0.7971 = depth = 5,954.3 feet subsea
∴
Gas-water contact depth = -5,954 feet subsea
Gas-water contact pressure = 3,105.5 psi

In several cases, the seals on the RFT devices did not seat properly and failed to isolate the internal pressure sensors from the pressure exerted by the column of drilling mud in the well bore. These are identified as "leaking seals" in figure 15 and lie along the "drilling mud hydrostatic gradient" with a pressure gradient to the surface of 0.619 psi/ft. This pressure gradient corresponds to 11.93 ppg drilling mud and compares favorably to the 11.65-ppg-mud density reported by surface measurement of a mud sample at the drill ship on the day the RFT pressure devices were run. Some of the pressure measurements that are intermediate in pressure between the drilling mud gradient and the geopressured water gradient are clearly instances of partial seal failure. In a few cases, the RFT tools were properly seated but recorded zero pressures (fig. 16). In these cases, the formation may have been impermeable, although tool plugging with drilling mud wall cake seems more likely.

The two RFT pressure measurements from the geopressured water column at –6,120 feet subsea (fig. 16, inset) were used as described above to help construct the geopressured water gradient of 0.8797 psi/ft. However, these two critical measurements might, like several more obvious examples at the depth interval of the Burger gas sand, also reflect tool-seating failures and slowly leaking seals. If that is the case, then we have no explicitly reliable data to control the pressure gradient below –4,850 feet subsea. If the pore pressures recorded at –6,120 feet are partly due to leaking seals, then the actual formation pressures must be somewhat lower and the geopressure gradient must be steeper. A projected gas-water contact would then lie much deeper than the –5,954 feet subsea depth projected by using the 0.8797 psi/ft geopressure water gradient. As an extreme example, if we assume that the water gradient below –4,850 feet is actually "normal" (0.44 psi/ft), then the projected intersection of gradients locates a hypothetical gas-water contact at –7,313 feet subsea, fully 1,000 feet below the spill closure (-6,360 feet) for Burger structure. Given these uncertainties and the sparse water column pressure data, we conclude that the RFT pressure data do not preclude a model in which Burger structure is completely filled with gas. Therefore, we adopted a "full-to-spill" model as the maximum case for Burger pool. Figure 13 and plate 2 show that **when completely filled, Burger "pool" is 189,803 acres in area.**

Modeling Discovered Gas Resources at Burger Structure

Three separate aggregations, using the Monte Carlo sampling process in *@RISK*, were conducted to calculate probability distributions for Burger gas resources for each of the three fill models. Each aggregation used three inputs: 1) a fixed pool area (minimum pool = 52,516 acres; most likely pool = 97,545 acres; maximum pool = 189,803 acres; fig. 12, tbl. 5, or pl. 2); 2) the probability distribution for net pay (tbl. 5); and 3) the probability distribution for gas yield (tbl. 6). Pay thickness was entered as a truncated lognormal distribution bounded at 20 and 400 feet. Gas yield was entered as a truncated lognormal distribution bounded at 0.544 and 2.477 mmcf/acre-foot.

Each aggregation used a positive dependency of 0.8 between pay thickness and gas yield based on the assumption that a thick reservoir can be more efficiently drained. Probability distributions and descriptive statistics for the aggregations for the minimum, most likely, and maximum cases are given in table 6. The results can be generalized as follows:

- The mean outcome for the minimum case is 7.629 Tcf gas, and this assumed to be the minimum discovered gas resource for Burger prospect.
- The mean outcome for the most likely case is 14.038 tcf in discovered gas resources.
- The mean outcome for the maximum case is 27.472 Tcf, and this is assumed to be the maximum discovered gas resource for Burger prospect.

Modeling Discovered Condensate Resources at Burger Structure

Three separate aggregations using the Monte Carlo sampling process in *@RISK* were conducted to calculate the discovered condensate resources in Burger pool. Each aggregation used two inputs: 1) statistical descriptions (mean, standard deviation, and truncations) for lognormal probability distributions for gas resources (calculated as described above) for each of 3 fill models; and 2) a single statistical description of the probability distribution for condensate yield (all listed in tbl. 6). No dependency was recognized between the volume of gas resources and condensate yield.

Probability distributions for the results for discovered condensate resources for Burger pool are given in table 6. The results can be generalized as follows:

- The mean outcome for the minimum case is 393 Mmb condensate, and this is assumed to be the minimum discovered condensate resource for Burger prospect.
- The mean outcome for the most likely case is 724 Mmb condensate.
- The mean outcome for the maximum case is 3,370 Mmb condensate, and this is assumed to be the overall maximum discovered NGL resources for Burger pool.

Burger Fill Models and Leasing Patterns in Sale 109 (1988)

Total high bids in Sale 109 for leases on Burger structure clearly focused on the tracts near the crest of the structure, but bids were received for blocks as low as the spill point.

As summarized in table 8, the minimum pool model accounted for 80 percent of the total bids on Burger prospect and attracted, on average, 3 times the average per acre value received for the whole prospect.

Economic Analysis

Burger Evaluation vs. Regional Economic Modeling

Resource assessments conducted by MMS have encompassed the entire undiscovered petroleum endowment in the Chukchi shelf province (Sherwood et al., 1998; Sherwood and Craig, 2001). The *PRESTO* computer model, used to determine the economic portion of the resource endowment, simulates the discovery and development of all hydrocarbon pools in a province. Generalized engineering parameters and costs are estimated for pools, not specifically identified by size or location, to determine economic viability of groups of hypothetical fields in a province-wide development scenario. Fields that survive the economic screening are aggregated to determine the economically recoverable total volumes of oil and gas. The viability of individual fields is obscured by cost sharing of some components with other fields, and in particular, the viability of gas fields greatly benefits from the association with oil production that supports most of the cost of infrastructure. Because it is impossible to untangle the inter-relationships, a province-wide *PRESTO* model is not suited for defining the economic viability of single pools in known locations, particularly for non-associated gas pools.

The present study represents a more refined evaluation, focusing on the stand-alone development of the Burger gas discovery. We assume that gas production from Burger will be pipelined to a future gas pipeline system originating in Prudhoe Bay some 300 miles to the east. Burger gas would be carried with other North Slope gas reserves through Canada to U.S. domestic markets. Proven gas reserves available in developed oil fields on the North Slope amount to approximately 35 Tcf, and these reserves will be the target of the first gas commercialization plans in northern Alaska. Various gas projects now being evaluated generally call for project completion between 2007-2010[4]. For the present study, we assume that Burger gas production would feed into the future North Slope gas pipeline system in the year 2008.

Methodology

The economic evaluation of the Burger gas pool utilizes a spreadsheet model (written in *EXCEL 7.0*) as an interactive tool. The model displays all data in addition to a transparent accounting for the economic analysis. After engineering designs, costs, and time schedules were defined for the Burger project, a Discount Cash Flow (DCF) analysis of the project was used to determine the threshold gas and condensate prices required for economic viability. Key economic parameters are listed below:

- Base year, 2000
- Inflation rate, 3%
- Real Discount rate, 12% (actual discounting factor includes inflation; or 15.36%)
- BOE conversion factor, 5.62 Mcf/bbl
- BTU gas price factor, (1.0 equals parity with oil price on an energy equivalent basis)
- Federal tax rate, 35%
- State tax rate, 0% (Burger is located entirely on Federal OCS leases)
- Property tax rate, 2% (applied to infrastructure on State lands)
- Condensate price factor, 1.00 (parity with ANS market price on West Coast)

Modeling Assumptions

The Burger gas project faces many formidable hurdles. It is located 80 miles offshore in 165 feet of water typically covered for 9 months of the year by mobile pack ice 6 feet or more in thickness. The nearest infrastructure is nearly 300 miles away in the Prudhoe-Kuparuk complex. Many optimistic engineering assumptions were necessary to construct a feasible engineering simulation:

- We used the recoverable gas resource estimates for the Burger gas pool despite the uncertainty about the areal extent for the reservoir. The reservoir sand distribution cannot be directly mapped using available 2-D seismic data. Furthermore, no delineation wells were drilled to help define the productive area. We also note that the discovery well was not flow tested and there is therefore some uncertainty about reservoir productivity.
- We assumed that development activity would start immediately and there would be no significant delays caused by environmental impact studies, permitting, pipeline right-of-way, or other legal challenges. Few projects in Alaska have been so fortunate.
- We assumed that subsea technology would largely replace fixed production platforms. A single, centrally located production platform (large concrete, gravity-base design) would serve as the "hub" for subsea well templates and

[4] *The gas pipeline project is still under consideration (as of December 2004) by several sponsor groups. The current projection for pipeline completion is 2012-2015.*

flowline tie-backs over a seafloor area of 152 square miles (most likely case). Although subsea technology is proven in other areas of the world, it has not been used at this scale or under arctic ice pack conditions. Burger would be the largest offshore gas project based on subsea technology in one of the most difficult settings in the world.

- Development drilling would be from three new purpose-built drilling platforms capable of year-round operations. These bottom-founded drilling platforms are vital to the project's timetable because of the short open-water season (3 months). Year-round drilling in ice pack conditions has never been attempted in these water depths.
- We assume that a new North Slope gas pipeline system will be operational by 2007[5] to carry Alaska gas to domestic markets. We must also assume that this new gas pipeline will accept additional gas deliveries from other gas fields in northern Alaska. The modeled production rates from Burger amount to 42% of the likely 4.0 Bcfd initial capacity of the future pipeline system.

The cost estimates for this project are uncertain because of the scale and location of the Burger project. No comparable project has been completed, so there is no direct cost data. Consequently, indirect means were used to estimate development and operating costs.

- Total development costs are scaled in relation to recent offshore gas projects in other areas. Figure 19 shows a plot of offshore gas projects in Southeast Asia and the North Sea completed or planned within 5 years of the present date. Cost data were obtained from reports published in the Oil and Gas Journal (O&GJ). As many gas projects included minor proportions of crude oil or condensate production, all substances were converted to BOE and then plotted as costs relative to gas reserves ($/Mcf). Because the costs of materials, labor, and permitting, projects in Southeast Asia are considerably less expensive than equivalent-sized gas projects in the North Sea. Because conditions in the Chukchi Sea are more difficult, it is reasonable to expect costs somewhat higher than for projects in the North Sea. The closest analog for Burger in reserve size and logistical difficulty is the Asgard field offshore Norway. Asgard is the largest subsea development in the world, with 50 subsea wells and 300 km on in-field flowlines gathering to a central, bottom-founded platform in 300 m of water. The export subsea gas pipeline from Asgard is 42 inches in diameter and carries a sales gas volume of 670 Bcf/y. The development costs for Asgard were $0.44/Mcf. Excluding the 300-mile overland Burger gas pipeline across NPR-A ($1,716 B), the development cost for Burger is estimated to be $0.64/Mcf (45% higher). This is a reasonable comparison considering the ice conditions and remoteness of the Chukchi shelf location.

- After determining an overall development cost target for the Burger project, individual components were scaled using fractions typical of Alaska projects. We assumed minimal leasing and appraisal costs (minimum bids for tracts, delineation wells converted to

[5] *Completion of a major North Slope gas pipeline is projected for 2012-2015.*

producers, no dry holes) that amounted to 2.5% of the total. A new shore-base (with pipeline landfall and compressor station) built on the Chukchi coastline would cost 2.5% of the total. Production platforms (including mobile drilling platforms, central platform, and subsea manifolds) were estimated at 45% of the total. Offshore pipelines (including in-field flowlines and 80 mile gas line to the coast) are 15% of the total. Wells (drilling and completion of production and service wells, including subsea wellheads) were estimated at 30% of the total. Field abandonment and platform removal costs are 5% of the total. These target proportions were somewhat different in the final model because of the added cost of the overland gas pipeline from the Chukchi coast to the Prudhoe Bay area.

- Engineering and development well scheduling involve a great deal of balancing between many variables, and a full discussion of the steps will not be given here. A typical sequence of the steps might be:
  (1) Define productive area of field (most likely case),
  (2) Determine drainage area per well based on reservoir properties,
  (3) Well count equals productive area divided by average well drainage area,
  (4) Well completion rate determined by drilling time for each well and schedule of drilling platforms siting (platform movement during ice-free summers),
  (5) Subsea installations and tie-backs during open-water (summer),
  (6) Drilling and tie-backs progress across field with staggered group startups,
  (7) Aggregate the production rate from subsea wells through the main production platform and the overland pipeline to Prudhoe Bay.

Scheduling information is contained in each model file ("Schedule worksheet"). Although new technology was not assumed in the Burger engineering simulation, we adopted a very aggressive schedule for completion of this project.

- Based on the engineering design and scaling, the costs for individual components (such as subsea wells) are derived for model inputs in constant dollars. These costs were adjusted to fit proprietary MMS cost files used in recent sales and economic assessments. The costs for individual components were also compared to other high-cost settings (deepwater Gulf of Mexico and North Sea). As an example: production well costs on the North Slope to the same measured depths would cost $2.5 MM/well. We would expect offshore wells in the Beaufort Sea to cost 2-3 times more depending on location (or $5.0 to $7.5 MM/well). The average cost of a subsea gas well (drilling, completion, subsea tree) is estimated at $11.50 MM (2000$) or 4.6 times higher than North Slope onshore wells. Recent deepwater water wells in the Gulf of Mexico cost upwards of $20 MM/well to drill and complete, including subsea wellheads. The higher deepwater GOM costs are justified because the well produce at high rates and are sited in thousands of feet of water (water depth at Burger is 165 feet).

- Annual operating costs (“opcosts”) were also estimated using indirect methods. Opcosts were estimated as fractions of the total development cost (eg. 8% of capcost). Normally, opcosts are approximately equal to development costs on constant dollar/per-BOE basis. The second step allocates opcosts into fixed and variable (per-Mcf) components. Opcost inputs are in base year dollars (2000$) and they could be considerably higher in as-spent dollars because of inflation.

Economic Evaluation

Investments are judged by a variety of criteria, although the most common measure is Net Present Value (NPV). A discount cash flow (DCF) analysis is used to determine NPV, where future costs and income are discounted back to a base year (in this case 2000$). A discount factor (12%) reflects the real time value of money. The analysis was set up to evaluate the expected case (or risked mean NPV). Because the resource has been discovered, we assumed that the occurrence risk is zero. As discussed previously in the geologic models, there is a significant risk in regards to reservoir properties and continuity over the Burger structure. However, reservoir risk was not incorporated into the economic analysis. Commodity prices were adjusted to determine the breakeven price (NPV=0) under the modeled set of cost and scheduling assumptions. The breakeven price constitutes the economic threshold for a viable commercial project.

We acknowledge that there are numerous uncertainties with respect to costs in the model because a project of this size and location has never been attempted. However, it became apparent that the fundamental economic assumptions also play a very significant role in the outcome. A variety of economic assumptions (called “scenarios”) were tested to determine the threshold prices under different circumstances. The results are summarized in table 13 and discussed below.

Scenario 1 is a standard NPV analysis using the economic parameters listed above. This is the most common method of examining economic viability. The Burger project is profitable at a minimum starting gas price of $5.22/Mcf and a condensate price of $29.34/bbl (2000$). Assuming the market prices grow at the rate of inflation, the nominal threshold prices at production startup in 2008 are $6.61/Mcf and $37.16/bbl (tbl. 14). At abandonment (in year 2029) the nominal market prices rise to $12.30/Mcf and $69.13/bbl.

Scenario 2 evaluates the effects of flat nominal price and cost paths. This is easily accomplished by setting inflation rate to zero (normally it is 3%). While somewhat unconventional, there is some historical precedent for this assumption. Over most of the last century, oil and gas prices have deviated over short periods but have equilibrated to real prices of about $16/bbl and $2.00/Mcf. In the past 20 years, market prices have generally not kept pace with inflation, so industry has found ways to cut costs to remain in business. Although petroleum prices have recently stepped up to a higher base level (perhaps $25.00/bbl for oil and $4.50/Mcf for gas), there is no historical precedent for market prices to double or triple from today’s prices over the next few decades. Using a zero inflation rate for prices and costs, the threshold for economic viability is $4.88/Mcf gas and $27.43/bbl (2000$) oil (tbl. 15).

Scenario 3 evaluates the condition where the TAPS oil pipeline has been shutdown and condensate cannot be transported to outside markets. Income from condensate production is an important part of the viability equation for Burger. Using the expected reserve figure of 587 MMbbl and the average real price of $29.34/bbl, associated condensate production adds $17.22 billion to the future income stream. Because condensate is extracted as a by-product of gas production it is obtained at a relatively low cost. Without condensate sales, and allowing no costs for handling and disposal by other means, the threshold gas price for Burger would increase to $6.71/Mcf in 2000$ (tbl. 16).

Scenario 4 evaluates the effect of a price discount based on BTU equivalency to oil. Historically, the market value of gas on a BTU basis has been discounted by a factor of 0.66. The gas price discount is created by competition from other sources of energy (coal and residual oil) used for power generation. Because of the clean-burning properties of natural gas coupled with increasing electricity demands of a growing economy, many energy economists expect that the BTU price discount will decrease and eventually achieve parity (BTU factor = 1.0) with liquid petroleum fuels. Regulatory actions geared toward environmental concerns (eg. Kyoto Accord) could also cause a change in historic patterns so that gas would fetch at least price parity (if not a premium) compared to oil. Because oil and gas pricing is coupled in the model a lower BTU discount factor decreases the threshold gas price but increases the threshold oil price. Using a BTU discount factor of 0.66, the threshold gas prices are $4.68/Mcf and oil prices are $39.85/bbl (tbl. 17).

Scenario 5 evaluates the situation where oil and gas prices are flat in nominal terms (market prices) while costs increase at the rate of inflation (3%). In normal markets, readily available energy supplies place a downward pressure on energy prices. Inexpensive energy feeds a growing economy with consequent inflation of the cost of goods and services. Higher costs of materials and labor would raise operating costs, but production income is hampered by flat prices. The threshold gas price under these conditions increases to $8.00/Mcf and the corresponding oil price would be $44.96/bbl (tbl. 18).

Scenario 6 uses a lower discount factor (8%), reflecting lower expectations of the time value of money. A lower discount factor is appropriate in circumstances where financing costs are low and the investment risk is low. The investment risk could be minimized by the Federal government who could play a more active role in the Burger project because of a strategic need to increase gas supplies to domestic markets. Under very unlikely conditions, the Federal government could take on the responsibility for developing and operating the Burger gas field. The Burger gas project might be measured against other Federal projects (perhaps building dams) to evaluate the most efficient use of funds for energy development. Even without full Federal sponsorship, the aggressive development schedule would require some intervention in the permitting process, as the model did not allow for permitting and legal delays typically faced by projects in Alaska. Using a lower discount rate, the threshold price for gas is $4.56/Mcf and $25.63 for oil (tbl. 19).

Scenario 7 assumes a real increase in gas prices at 1% above inflation. This price path increases the value of the future income stream and alters the BTU price factor from parity (1.0) at the beginning of production to 1.36 at the economic conclusion of the Burger project. A real increase in gas prices relative to oil could be caused by an imbalance in supply/demand or political mandates to cleaner burning fuels (for example, the Kyoto Accord). This scenario finds threshold prices of $4.63/Mcf for gas and $26.02/bbl for oil (tbl.20). It is important to note that the nominal market price for gas increases to $14.56/Mcf (2029$) during the 22-year life of the field (tbl. 13). Energy prices at this level could dampen economic growth and act as a self-correcting factor in the gas supply/demand equation.

Many other economic assumptions can be envisioned, and the DCF model easily accommodates alternate scenarios. It is interesting that among the wide assortment of scenarios tested many of the threshold prices lie below the standard NPV scenario price of $5.22/Mcf (2000$). However, the lowest threshold price ($4.56/Mcf, scenario 6) is still 24% higher than "high economic growth" forecast by EIA for the year 2020 (EIA, 2000; $3.68/Mcf in 1999$). Although domestic gas prices are higher than these threshold prices today, the volatility of domestic energy markets assure that future cycles of reduced prices are inevitable. Low prices during the initial production of this expensive project would be devastating to future profits. Any group that would contemplate the development of Burger resources is probably aware of the historic volatility of the U.S. domestic natural gas market.

Although it is impossible to accurately predict long-term future prices, some indication could be derived from OPEC, which exerts a major control on world energy prices. OPEC's publicly-stated objective is to maintain crude oil prices within a $22-$28/bbl range. Translating oil prices into natural gas prices (5.62 Mcf/bbl times a BTU price factor) would mean that oil-equivalent gas prices would be $3.91-$4.98/Mcf (BTU price parity). A return to historical averages for BTU price factor ($ per gas BTU/$ per oil BTU = 0.66) would lower the oil-equivalent gas price range to $2.74-$3.48/Mcf. One could conclude that if a world oil price level is stabilized in the $22-$28/bbl range by OPEC, then future gas prices should average between $2.74 and $4.98/Mcf. The breakeven prices for an economic Burger project are $5.22/Mcf for the standard scenario (1) and $4.56/Mcf for the most optimistic scenario (6).

Conclusions

- Burger prospect potentially represents the largest discovery to date on the Alaska OCS. Discovered resources may range from 7.629 Tcf (mean, minimum fill model) to 27.472 Tcf (mean, maximum fill model), with a most likely (mean, most likely fill model) estimate of 14.038 Tcf of natural gas and 724 Mmb of condensate. The optimized engineering model based on the most likely gas resource estimate recovered 11.5 Tcf gas and 587 Mmb condensate.

- Natural gas production from Burger could make a significant contribution to gas delivery from the North Slope via a future gas pipeline system. The Burger project could add 1.68 Bcfd of gas and 85,000 bopd to North Slope production. The production rate of condensate is nearly as large as peak oil production (currently 100,000 bopd) from the Alpine field, the largest oil field discovered in the last decade on the North Slope. Gas production from Burger would represent 42% of the expected 4.0 Bcfd carried by a future North Slope gas pipeline.
- Because of its size and location, the development of the Burger gas discovery will be very expensive. Estimated development costs for the expected case total $11.24 billion (as-spent) and estimated operating costs average $781 MM (as-spent) annually. Expenses associated with development would begin in the year 2001, but payout (breakeven cash flow) would not occur until the year 2014. The maximum negative cash flow (exposed capital) during that 14-year period would be $5.158 billion.
- Even under optimistic assumptions, Burger is a risky investment opportunity. All scenarios require higher threshold gas prices than forecast by the EIA or expected from world energy markets controlled by OPEC. The high transportation tariff to the U.S. ($2.55/Mcf including conditioning on the North Slope) makes this project less attractive than Canadian gas reserves closer to market. The Burger project is dependent on construction and capacity in a future North Slope gas pipeline.
- The Burger project faces formidable engineering hurdles. It would be the world's largest offshore gas field developed using subsea technology. No other offshore field has been developed under environmental conditions equivalent to this remote setting in the Chukchi Sea. The accelerated schedule in our development models would require unprecedented cooperation between governments and the project sponsors, as no delays were assumed for permitting or legal problems.
- The Burger study provides a good perspective of the hurdles faced by large offshore developments in remote areas of Alaska. Although petroleum assessments commonly conclude that huge oil and gas potential exists in northern Alaska, the economic reality is that most of these resources will not be commercial to develop. Burger is perhaps the largest discovery made to-date on the Alaska OCS, yet its commercial potential is marginal even under very optimistic conditions.

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Table 1

BURGER CONDITIONAL* DISCOVERED RESOURCES-YEAR 2000							
	Pool Area	**Gas Resources (Tcf)**			**Condensate] (Mmb)**		
Fill Model	**(Acres)**	**F95**	**Mean**	**F05**	**F95**	**Mean**	**F05**
Minimum	52,516	2.389	7.629	17.256	107	393	925
Most Likely	97,545	4.335	14.038	31.384	203	724	1,700
Maximum	189,803	8.496	27.472	63.210	371	1,404	3,370

*No geological risk has been applied to these gas resource estimates. Success factors associated with reservoir presence (0.90) and sufficient (>10%) porosity for productive reservoir formation (0.75) yield an overall geologic chance of success of 0.675 for Burger pool discovered resources. **Risked** mean gas resources for the 2000 assessment would then be: 5.150 tcf (minimum case); 9.476 tcf (most likely case); and 18.544 tcf (maximum case). **Risked** mean NGL liquid resources for 2000 would be: 265 mmbo (minimum case); 489 mmbo (most likely case); and 948 mmbo (maximum case).

Table 2

Economic Scenarios (12% discount rate; 3% inflation; gas price BTU parity)	**Threshold Gas Price** ($/Mcf) (2000$)
1. Standard NPV model (tbl. 14)	$5.22
2. Zero inflation of prices/costs (tbl. 15)	$4.88
3. No condensate sales (tbl. 16)	$6.71
4. Use 0.66 gas price BTU factor (tbl. 17)	$4.68
5. Use flat nominal gas prices (tbl. 18)	$8.00
6. Use 8% discount rate (tbl. 19)	$4.56
7. Assume 1% growth in gas price above inflation (tbl. 20)	$4.63

Table 3: Porosity and Permeability Data for Burger Sandstone
(Rotary Sidewall Cores)

UNIT	SAMPLE NUMBER	MEASURED DEPTH[1] (feet)	POROSITY (Helium, %)	PERMEABILITY[2] (Horizontal, K_{AIR}, millidarcies)	SATURATIONS (% of Pore Volume)	
					OIL	WATER
CLEAN SAND UNIT	1	5572	29.5	447	4.3	64.2
	2	5577	28.7	446	8.4	58.6
	3	5581	28.0	314	7.9	64.3
	4	5586	28.8	305	4.8	65.7
	5	5594	27.2	347	5.4	74.9
	6	5606	28.1	403	2.9	72.0
	7	5610	29.2	347	5.5	65.2
	8	5617	27.6	222	3.8	73.8
MUDDY SAND UNIT	9	5624	26.8	139	5.2	78.0
	10	5629	25.0	67	5.3	81.1
	11	5633	24.3	32	8.5	77.2
	12	5636	24.5	24	10.6	71.8
	13	5644	24.2	61	8.3	81.3
	14	5646	22.5	18	9.0	76.9
	15	5647	26.8	56	7.2	74.5
	16	5651	22.3	11	10.6	81.6

[1]Burger sandstone (principal gas reservoir) 5,560 to 5,667 feet measured depth
[2]The mean (geometric) permeability for the clean sand unit is 369 md; for the muddy sand unit, the mean (geometric) permeability is 39 md

Table 4: *@RISK* Data Sheet for Gas Recovery Factor

CHUKCHI SHELF – BURGER GAS POOL

Gas Recovery Factor (mmcfg recoverable per acre-foot)

Input Constant and *@RISK* Equation "=**(**1.5378*a2*(1-b2)*c2*d2*e2*f2/g2)"

	MEAN	STANDARD DEVIATION	MINIMUM (LWR. TRUNC.)	MAXIMUM (UPPER TRUNC.)	*f(x) TYPE*
A. POROSITY	0.265	0.023539	0.10	0.373	***TNormal***
B. WATER SATURATION	0.320	0.13568	0.15	0.50	***TLNormal***
C. PRESSURE (PSI)	3089	30.641	2962	3209	***TNormal***
D. GAS FVF (1/Z)	1.209	0.0018239	1.202	1.216	***TNormal***
E. GAS REC. FACTOR	0.803	0.036828	0.65	0.95	***TNormal***
F. GAS "SHRINKAGE" FACTOR	0.91	0.032345	0.785	1.0	***TNormal***
G. TEMP. (°R)	585	8.1812	552	620	***TNormal***

Dependency or Correlation Matrix for Gas Yield Calculation:

	POROSITY	WATER SATURATION	PRESSURE	GAS FVF (1/Z)	GAS RECOVERY FACTOR	GAS SHRINKAGE FACTOR	TEMPER-ATURE (°R)
POROSITY	**1**	**-0.9**	**0**	**0**	**0.8**	**0**	**0**
WATER SATURATION	**-0.9**	**1**	**0**	**0**	**-0.6**	**0**	**0**
PRESSURE	**0**	**0**	**1**	**0**	**0**	**0**	**0.95**
GAS FVF (1/Z)	**0**	**0**	**0**	**1**	**0**	**0**	**0**
GAS RECOVERY FACTOR	**0.8**	**-0.6**	**0**	**0**	**1**	**0**	**0**
GAS SHRINKAGE FACTOR	**0**	**0**	**0**	**0**	**0**	**1**	**0**
TEMPERATURE (°R)	**0**	**0**	**0.95**	**0**	**0**	**0**	**1**

Logic Behind Dependency Relationships: *Factors Generally Related to Burial Depth*

Gas Yield: *High Porosity = Low Water Saturation = High Gas Recovery; High Pressure = High Temperature; additional depth-coincident dependencies produce a statistically incorrect matrix and numerically detract from the most significant dependency factors.*

f(x) types: *TNormal, truncated normal distribution*
TLNormal, truncated log-normal distribution

Table 5: Burger Prospect—Input Data for Estimates of Discovered Resources

ANALYSIS OF POTENTIAL GAS AND NATURAL GAS LIQUIDS DISCOVERED RESOURCES AT BURGER POOL

POOL DEPTH RANGE 5,139 ft – 6,360 ft (5,181-6,402 ft BKB)
RESERVOIR THERMAL MATURITY (%R_0) 0.61-0.69%

POOL AREAS (ACRES) AND HIGH BIDS FOR TRACTS IN POOL AREAS ($US1988)

Minimum Pool Area 52,516 Most Likely Pool Area 97,545 Maximum Pool Area 189,803
Total High Bids: Minimum= $136,157,300 Most Likely= $165,919,600 Maximum= $169,694,200

PAY THICKNESS (ft)

	F100	F99	F95	F90	F75	F50	MEAN	F25	F10	F05	F02	F01	F00
NET PAY	20	40	50	60	70	90	99	120	150	170	---	220	400
STATISTICS: MEAN = 99.348; STANDARD DEVIATION= 41.040; MINIMUM = 20 FT; MAXIMUM= 400 FT TLNORMAL DISTRIBUTION													

GAS RECOVERY FACTOR: INPUT STATISTICS AND REPORTED DISTRIBUTIONS

	F100	F99	F95	F90	F75	F50	MEAN	F25	F10	F05	F02	F01	F00
A. POROSITY	0.10	---	0.227	0.235	0.250	0.266	0.266	0.282	0.296	0.304	--	--	0.373
INPUT STATISTICS: MEAN= 0.265; STANDARD DEVIATION= 0.023539; MINIMUM= 0.10; MAXIMUM= 0.373; DISTRIBUTION= TNORMAL													
B. WATER SATURATION	0.150	---	0.170	0.185	0.226	0.287	0.297	0.363	0.430	0.456	---	----	0.50
INPUT STATISTICS: MEAN= 0.320; STANDARD DEVIATION= 0.13568; MINIMUM= 0.15; MAXIMUM= 0.50; DISTRIBUTION= TLNORMAL													
C. RESERVOIR TEMP. °RANKINE	556	---	572	575	580	585	585	591	596	599	---	----	617
INPUT STATISTICS: MEAN= 585; STANDARD DEVIATION= 8.1812; MINIMUM= 552; MAXIMUM= 620; DISTRIBUTION= TNORMAL													
D. RESERVOIR PRESSURE (PSI)	2975	-----	3039	3050	3068	3089	3089	3110	3128	3138	----	-----	3190
INPUT STATISTICS: MEAN= 3089; STANDARD DEVIATION= 30.641; MINIMUM= 2962; MAXIMUM= 3209; DISTRIBUTION= TNORMAL													
E. GAS FVF (1/Z)	1.203	-----	1.206	1.207	1.208	1.209	1.209	1.210	1.211	1.212	----	-----	1.216
INPUT STATISTICS: MEAN= 1.209; STANDARD DEVIATION= 0.0018239; MINIMUM= 1.202; MAXIMUM= 1,216; DISTRIBUTION= TNORMAL													
F. GAS RECOVERY FACTOR (FRAC)	0.677	----	0.743	0.756	0.778	0.803	0.804	0.829	0.852	0.864	----	----	0.930
INPUT STATISTICS: MEAN= 0.803; STANDARD DEVIATION= 0.036828; MINIMUM= 0.65; MAXIMUM= 0.95; DISTRIBUTION= TNORMAL													
G. GAS SHRINKAGE FACTOR (COMBUST. FRAC. + FRAC. VOL. AFTER COND. LOSS)	0.789	------	0.857	0.869	0.888	0.910	0.910	0.931	0.950	0.961	-----	------	1.000
INPUT STATISTICS: MEAN= 0.910; STANDARD DEVIATION= 0.032345; MINIMUM= 0.785; MAXIMUM= 1.000; DISTRIBUTION= TNORMAL													

GAS YIELD (MMCFG/AC-FT)=[43560 ft^3/ac-ft] [A · (1-B) · F · G] [E (60°F+460)/C] [D/14.73] [1/1000000]

Table 6: Results for Gas Recovery Factors and Discovered Resources
BURGER PROSPECT

RECOVERY FACTOR AND YIELD DISTRIBUTIONS (GAS, CONDENSATE)

	F100	F99	F95	F90	F75	F50	MEAN	F25	F10	F05		F01	F00
GAS RECOVERY (10^6 FEET^3/ACRE-FOOT)	0.544	-----	0.842	0.933	1.119	1.352	1.361	1.593	1.794	1.912		---	2.477
STATISTICS: MEAN= 1.361; STANDARD DEVIATION= 0.327; MINIMUM= 0.544; MAXIMUM= 2.477. DISTRIBUTION TLNORMAL													
CONDENSATE YIELD (BBL/10^6 CFG)	15	25	30	33	40	50	51	60	70	77		92	140
STATISTICS: MEAN= 51.271; STANDARD DEVIATION= 15.132; MINIMUM= 15; MAXIMUM= 140. DISTRIBUTION TLNORMAL													

RESULTS FOR DISCOVERED GAS RESOURCES (Tcf)

	F100	F99	F95	F90	F75	F50	MEAN	F25	F10	F05	F02	F01	F00
MINIMUM GAS RESOURCES	0.708	---	2.389	2.948	4.200	6.368	7.629	9.547	13.853	17.256	--	--	40.630
STATISTICS: MEAN= 7.629; STANDARD DEVIATION= 4.98121; MINIMUM= 0.708; MAXIMUM= 40.630; DISTRIBUTION= TLNORMAL													
MOST LIKELY GAS RESOURCES	1.696	--	4.335	5.429	7.953	11.744	14.038	17.655	25.266	31.384	--	--	83.047
STATISTICS: MEAN= 14.038; STANDARD DEVIATION= 9.048; MINIMUM= 1.696; MAXIMUM= 83.047; DISTRIBUTION= TLNORMAL													
MAXIMUM GAS RESOURCES	2.853	--	8.496	10.564	15.137	22.803	27.472	34.415	50.174	63.210	--	--	185.275
STATISTICS: MEAN= 27.472; STANDARD DEVIATION= 17.920; MINIMUM= 2.853; MAXIMUM= 185.275; DISTRIBUTION= TLNORMAL													

RESULTS FOR CONDENSATE (Mmb)

	F100	F99	F95	F90	F75	F50	MEAN	F25	F10	F05	F02	F01	F00
MINIMUM COND. RESOURCES	28	--	107	136	203	315	393	497	732	925	--	--	2677
STATISTICS: MEAN= 393; STANDARD DEVIATION= 286; MINIMUM= 28; MAXIMUM= 2677; DISTRIBUTION= TLNORMAL													
MOST LIKELY COND. RESOURCES	62	--	203	256	378	577	724	912	1349	1701	--	--	6234
STATISTICS: MEAN= 724; STANDARD DEVIATION= 524; MINIMUM= 62; MAXIMUM= 6234; DISTRIBUTION= TLNORMAL													
MAXIMUM COND. RESOURCES	114	---	371	471	724	1121	1404	1777	2656	3370	---	---	10719
STATISTICS: MEAN= 1404; STANDARD DEVIATION= 1025; MINIMUM= 114; MAXIMUM= 10719; DISTRIBUTION= TLNORMAL													

Table 7: Burger Pool Risk Analysis Form

Assessor: Kirk W. Sherwood — Burger Reserves Calculation –November 2000

EXPLORATION SUCCESS RATIO = _____ (From exploration success rate within play, exploration success rate in productive analog, or prospect grading)

PLAY CHANCE FACTORS (Complete and enter to PRASS only if play is not known to be successful, or, if Overall Play Level Chance is less than 1.0)		CONDITIONAL PROSPECT CHANCE FACTORS (Complete and enter to PRASS only if Exploration Success Ratio Not Available. Must assume success of same factor at play level. No entry needed if equal to 1.0)
	TRAP - SEAL - TIMING	
1.0	CLOSURE PRESENCE (reliability of map size or definition)	**1.0**
1.0	SEAL PRESENCE (top, lateral; role of faults; number of seals required)	**1.0**
1.0	TIMING (relative to petroleum migration)	**1.0**
	RESERVOIR - POROSITY	
1.0	RESERVOIR PRESENCE (areal distribution as limited by deposition, facies changes, truncation at regional unconformities)	**0.9**
1.0	POROSITY (primary, secondary, fracture; not plugged or cemented)	**0.75***
	SOURCE - MATURATION - MIGRATION	
1.0	SOURCE PRESENCE (organic quantity and quality, areal extent, thickness, total organic carbon)	**1.0**
1.0	MATURATION (sufficient time, temperature)	**1.0**
1.0	MIGRATION (primary (expulsion) and(?) secondary (source to trap); migration route vs. prospects; migration distance)	**1.0**
	PRESERVATION/HC QUALITY - RECOVERY	
1.0	PRESERVATION (risk of flushing, biodegradation, diffusion, thermal overmaturation of pooled oil and cracking to gas; processes yielding viscous, high-sulfur, possibly unproducible oil)	**1.0**

****

Calculate the Following as a Check on Results

A. 1.0 OVERALL PLAY LEVEL CHANCE (Product of all play chance factors)

B. 0.675 OVERALL PROSPECT LEVEL CHANCE (Exploration Success Ratio, **or** product of all Conditional Prospect Chance Factors. Must be ≤ Overall Play Level Chance.)

A X B = 0.675 = EXPLORATION CHANCE

* ***based on relationship between porosity and reservoir thermal maturity; reservoir porosity has a 75% probability of exceeding 10% porosity (minimum for successful reservoir)***

Table 8: Burger Prospect Bidding Patterns, 1988 Lease Sale

Total Bids Received for Fill Models for Burger Structure in OCS Lease Sale 109 (1988)		
Fill Model	**Total High Bids**	**Average Paid Per Acre**
Minimum Pool (52,516 acres)	$136,157,300	$2,596/acre
Most Likely Pool (97,545 acres)	$165,919,600	$1,701/acre
Maximum Pool (189,803 acres)	$169,694,200	$894/acre

Table 9: Conditional* Discovered Gas Resources, Burger Prospect

Comparisons of Results of 1993 and 2000 Assessments

Case	Assessed Gas Resources (tcf)		Specific Statistic from Results	
	1993	2000	1993	2000
Minimum Gas Resource	1.974	7.629	F_{95} Value from Results Distribution for Single Aggregation	Mean, Minimum Fill Case Aggregation
Most Likely Gas Resource	5.176	14.038	Mean, Results Distribution for Single Aggregation	Mean, Most Likely Fill Case Aggregation
Maximum Gas Resource	10.485	27.472	F_{05} Value from Results Distribution for Single Aggregation	Mean, Maximum Fill Case Aggregation

*no geological risk has been applied to these gas resource estimates; success factors associated with reservoir presence (0.90) and sufficient (>10%) porosity for productive reservoir formation yield (0.75) an overall geologic chance of success of 0.675 for Burger pool discovered resources. Risked gas resources for the 2000 assessment would then be: 5.150 tcf (minimum case); 9.476 tcf (most likely case); and 18.544 tcf (maximum case)

Table 10: Differences and Similarities in 1993 and 2000 Estimates for Discovered Resources at Burger Prospect

PARAMETER	YEAR 1993	YEAR 2000
Pay (ft), Mean	74	99
Gas Yield (mmcf/ac--ft), Mean	1.345	1.361
Minimum Pool Area (acres)	31,250	52,516
Most Likely Pool Area (acres)	52,083	97,545
Maximum Pool Area (acres)	80,000	189,803
Minimum Gas Reserves (tcf)	1.974 (F95)	7.629 (Mean)
Most Likely Gas Reserves (tcf)	5.176 (Mean)	14.038 (Mean)
Maximum Gas Reserves (tcf)	10.485 (F05)	27.472 (Mean)

Most of the difference between the 1993 reserve estimate (by Jim Craig) and the 2000 reserve estimate (by Kirk Sherwood) extends from much larger pool areas used in the later assessment. This reflects a change in the model assumptions rather than any new data.

Minimum pool area: In 2000, the minimum pool area (52,516 acres) was assumed to correspond to the area of the pool that is structurally higher than the point of penetration at —5,625 ft subsea by Burger well. In the 1993 assessment, a "dim spot" on the crest of the structure (~11,500 acres in present mapping) was apparently subtracted from this area on the rationale that the sandstone might be absent. However, there might be other explanations for the dim spot, such as facies changes in the seal (more silty and partly gas--saturated) or reservoir (more firmly cemented) so as to reduce acoustic impedance across the surface of the reservoir and to reduce reflection amplitude. Accordingly, in the 2000 assessment, the "dim spot" was treated as productive pool area.

Most Likely pool area: In 2000, the most likely pool area (97,545 acres) was assumed to be the area of the pool that is structurally higher than a gas--water contact projected to —5,954 ft subsea from reservoir pressure data and a model for supercharging. In 1993, the most likely pool area (52,083 acres) was assumed to correspond to the area of the pool that is structurally higher than the point of penetration at —5,625 ft subsea by Burger well.

Maximum pool area: In 2000, the maximum pool area (189,803 acres) was assumed to be the entire structure as filled to spill at —6,360 ft subsea. Existing data are permissive for this model. In fact, the reservoir pressure data and supercharging model project to a gas--water contact at —7,313 ft subsea, or a thousand feet below spill, if one assumes a normal hydrostatic pore pressure gradient in the rocks outside the reservoir. In 1993, the maximum pool area (80,000 acres) was defined to correspond to a gas-water contact projected to —5,948 ft subsea from reservoir pressure data and a model for supercharging and did not include parts of Burger structure above this datum in the faulted west flank of the structure.

Table 11

Burger Sandstone Reservoir Fluid Properties, RFT 4, 5,586 ft (md)

Core Lab Report File RFL 900364. Cylinder Number PSRD-995 (Top)

Reservoir Fluid Composition						
Component	**Mole Percent**	**Liquids (gallons per Mcfg) (3)**	**Liquids (bbl per Mmcfg) (4)**	**Molecular Weight(1)**	**Density (g/cc @ 60ºF)(1)**	**Boiling Point (ºF) (2)**
Hydrogen Sulfide	0.00			34.080	0.80064	
Carbon Dioxide	0.22			44.010	0.81720	
Nitrogen	0.31			28.013	0.80860	
Methane (C1)	91.75			16.043	0.29970	-258.7
Ethane (C2)	4.11	1.093	26.024	30.070	0.35584	-127.5
Propane (C3)	1.60	0.483	11.500	44.097	0.50648	-43.7
iso-Butane (C4)	0.22	0.072	1.714	58.123	0.56231	31.1
n-Butane (C4)	0.45	0.141	3.357	58.123	0.58343	31.1
iso-Pentane (C5)	0.15	0.055	1.310	72.150	0.62408	96.9
n-Pentane (C5)	0.27	0.097	2.310	72.150	0.63049	96.9
Hexanes (C6)	0.23	0.089	2.119	84	0.685	155.7
Heptanes (C7)	0.20	0.084	2.000	96	0.722	209.2
Octanes (C8)	0.20	0.090	2.143	107	0.745	258.2
Nonanes (C9)	0.10	0.050	1.190	121	0.764	303.4
Decanes (C10)	0.06	0.033	0.786	134	0.778	345.5
Undecanes (C11)	0.03	0.018	0.429	147	0.789	384.6
Dodecanes (C12)	0.02	0.013	0.310	161	0.800	421.3
Tridecanes (C13)	0.02	0.014	0.333	175	0.811	
Tetradecanes (C14)	0.01	0.007	0.167	190	0.822	
Pentadecanes (C15)	0.01	0.008	0.190	206	0.832	519.1
Hexadecanes (C16)	0.01	0.008	0.190	222	0.839	
Heptadecanes (C17)	Trace	Trace	Trace	237	0.847	
Octadecanes (C18)	Trace	Trace	Trace	251	0.852	
Nonadecanes (C19)	Trace	Trace	Trace	263	0.857	
Eicosanes (C20) plus	0.03	0.031	0.738	336 (3)	0.883 (3)	648.9+
Totals	100	2.386	56.810			
Totals for Pentanes +	1.34	0.597	14.214			

Molecular Weight	18.65
Molecular Weight C7+	132
Gas Gravity (Air=1)	0.644
Gross BTU/scf dry gas	1132

(1) Assigned properties from literature
(2) McCain, 1973, tbl. 1-5
(3) Calculated by Core Laboratories
(4) 42 gallons/barrel

Pressure-Volume Relations at 130º F (Constant Composition Expansion)				
Pressure (psig)	**Relative Volume**	**Deviation Factor (Z)**	**Retrograde Liquid Volume (%)**	**Comment**
5000	0.9109	0.977		
4900	0.9210	0.968		
4800	0.9315	0.959		
4700	0.9425	0.950		
4600	0.9547	0.942		
4500	0.9674	0.934		
4400	0.9808	0.926		
4300	0.9949	0.918		
4269	1.0000	0.916	0.00	Dew Point
4200	1.0103	0.911	Trace	
4100	1.0259	0.903	Trace	
4000	1.0432	0.896	Trace	
3900	1.0617	0.889	Trace	
3800	1.0814	0.882	Trace	
3700	1.1021	0.876	Trace	
3600	1.1247	0.869	Trace	
3500	1.1491	0.864	Trace	
3450	1.1612	0.860	Trace	
3350	1.1892	0.856	0.06	
3200	1.2346	0.849	0.12	
3089				Mean Reservoir Pressure
3070	1.2778	0.843	0.16	
2850	1.3632	0.835	0.24	
2600	1.4867	0.831	0.30	
2300	1.6774	0.830	0.34	
2079	1.8652	0.835	0.34	
1735	2.2629	0.847		
1330	3.0317	0.872		
1081	3.8054	0.892		
879	4.7551	0.909		
741	5.6994	0.921		

Table 12

Burger Sandstone Reservoir Fluid Properties, RFT 8, 5,648 ft (md)

Core Lab Report File RFL 900453. Cylinder Number PSRD Not Specified (Core Lab Report of 31 Dec 1990)

Reservoir Fluid Composition

Component	Mole Percent	Liquids (gallons per Mcfg) (4)	Liquids (bbl per Mmcfg) (5)	Molecular Weight(1)	Density (g/cc @ 60ºF)(1)	Boiling Point (ºF) (2)
Hydrogen Sulfide	0.00			34.080	0.80064	
Carbon Dioxide	0.36			44.010	0.81720	
Nitrogen	0.36			28.013	0.80860	
Methane (C1)	91.38			16.043	0.29970	-258.7
Ethane (C2)	4.14	1.101	26.214	30.070	0.35584	-127.5
Propane (C3)	1.75	0.528	12.571	44.097	0.50648	-43.7
iso-Butane (C4)	0.24	0.091	2.167	58.123	0.56231	31.1
n-Butane (C4)	0.60	0.188	4.476	58.123	0.58343	31.1
iso-Pentane (C5)	0.13	0.048	1.143	72.150	0.62408	96.9
n-Pentane (C5)	0.23	0.083	1.976	72.150	0.63049	96.9
Hexanes (C6)	0.21	0.081	1.929	84	0.685	155.7
Heptanes (C7)	0.17	0.071	1.690	96	0.722	209.2
Octanes (C8)	0.19	0.086	2.048	107	0.745	258.2
Nonanes (C9)	0.10	0.050	1.190	121	0.764	303.4
Decanes (C10)	0.06	0.033	0.786	134	0.778	345.5
Undecanes (C11)	0.03	0.018	0.429	147	0.789	384.6
Dodecanes (C12)	0.02	0.013	0.310	161	0.800	421.3
Tridecanes (C13)	0.01	0.007	0.167	175	0.811	
Tetradecanes (C14)	0.01	0.007	0.167	190	0.822	
Pentadecanes (C15)	0.01	0.008	0.190	206	0.832	519.1
Hexadecanes (C16)	Trace	Trace	Trace	222	0.839	
Heptadecanes (C17)	Trace	Trace	Trace	237	0.847	
Octadecanes (C18)	Trace	Trace	Trace	251	0.852	
Nonadecanes (C19)	Trace	Trace	Trace	263	0.857	
Eicosanes (C20) plus	Trace	Trace	Trace	336 (3)	0.883 (3)	648.9+
Totals	100.00	2.413	57.452			
Totals for Pentanes +	1.17	0.505	12.024			

Molecular Weight	18.58	
Molecular Weight C7+	119	
Gas Gravity (Air=1)	0.643	(Reported for Separate Sample in PSRD 1878)
Gross BTU/scf dry gas	1130	(Reported for Separate Sample in PSRD 1878)

(1) Assigned properties from literature
(2) McCain, 1973, tbl. 1-5
(3) Calculated by Core Laboratories
(4) Calculated by KWS using constants estimated from RFT 4 compositional analysis
(5) 42 gallons/barrel

Pressure-Volume Relations at 132º F (Constant Composition Expansion)

Pressure (psig)	Relative Volume	Deviation Factor (Z)	Retrograde Liquid Volume (%)	Gas Viscosity (centipoise)	Comments
5000	0.9419	0.950		0.03	
4700	0.9766	0.926		0.0285	
4600	0.9894	0.919		0.0281	
4518	1.0000	0.912	0.00	0.0277	Dew Point
4450	1.0092	0.907	Trace		
4350	1.0241	0.899			
4200	1.0477	0.888	0.01		
4000	1.0827	0.875	0.02		
3800	1.1225	0.861	0.03		
3600	1.1692	0.850	0.04		
3400	1.2224	0.840	0.06		
3200	1.2841	0.831	0.07		
3089					Mean Reservoir Pressure
3000	1.3568	0.823	0.08		
2800	1.4447	0.818	0.10		
2600	1.5475	0.814	0.10		
2400	1.6775	0.815	0.11		
2250	1.7930	0.817	0.11		
2100	1.9260	0.819	0.11		
1900	2.1434	0.826	0.10		
1661	2.4882	0.839	0.10		
1450	2.8892	0.852			
1273	3.3326	0.864			
1018	4.2538	0.884			
880	4.9836	0.897			

Table 13

Threshold Commodity Prices for Economic Viability of Burger

Economic Scenario	Gas Price (2000$)	Oil Price (2000$)	Gas Price (2008)	Gas Price (2029)	Oil Price (2008)	Oil Price (2029)
1	$5.22	$29.34	$6.61	$12.30	$37.16	$69.13
2	$4.88	$27.43	$4.88	$4.88	$27.43	$27.43
3	$6.71	$0.00	$8.50	$15.81	$0.00	$0.00
4	$4.68	$39.85	$5.93	$11.03	$50.48	$93.11
5	$8.00	$44.96	$8.00	$8.00	$44.96	$44.96
6	$4.56	$25.63	$5.78	$10.75	$32.46	$60.39
7	$4.63	$26.02	$6.35	$14.56	$32.96	$61.32

Gas prices are given in dollars per thousand cubic feet at market (U.S. Midwest). Oil prices are given in dollars per barrel at market (U.S. West Coast). (2000$) indicate real (constant) prices in base year dollars. (2008) and (2029) indicate nominal (inflation adjusted) market prices in dollars of the day.

Scenario Description

1. Standard case (3% inflation, 12% discount rate, gas BTU-price parity, 11.5 Tcf gas, 587 MMbbl condensate)
2. Same as Scenario 1, but with no inflation for prices and costs.
3. Same as Scenario 1, but with no condensate sales (TAPS not operational)
4. Same as Scenario 1, but change gas BTU-price factor to 0.66 (the historical average for domestic markets)
5. Same as Scenario 1, but hold commodity prices flat in nominal terms while increasing costs at 3% inflation.
6. Same as Scenario 1, but with lower discount factor (8%)
7. Same as Scenario 1, keep oil prices constant but increase gas prices at 1% above rate of inflation (3%).

Table 14
Economic Scenario No. 1: Standard Case With Gas Price Parity

INPUTS

Project:	Burger	**Case (Alternative):**	Scenario 1
Planning Area:	Chukchi	**Analyst:**	Jim Craig
Company:	?	**Date of Analysis:**	12/10/04

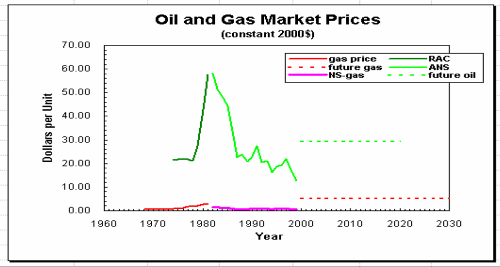
Economic Parameters

Base Year:	2000	
Geologic Probability (1- Risk):	100.0%	
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl
gas price - BTU discount factor:	1.00	

	Suggested Distribution			to be used
Inflation Rate	1.50%	3.00%	4.50%	3.00%
Real Discount Rate:	7.00%	10.00%	15.00%	12.00%

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	$29.34
Real	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Price	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Growth	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$5.22		$5.22
Real	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Price	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Growth	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC
Lease (bonus bid):	0%	0%
Delineation/Appraisal (wells & seismic):	0%	0%
Exploration well converted to producer:	51%	30%
On-Platform Production Well:	51%	30%
Subsea Well:	51%	30%
Exploration Platform:	83%	75%
Platform & Production Equipment:	72%	60%
Shorebase:	83%	75%
Pipelines (flowlines & salesline):	83%	75%
Abandonment:	0%	0%

ACRS Schedule:	
Year 1:	14.29%
Year 2:	24.49%
Year 3:	17.49%
Year 4:	12.49%
Year 5:	8.93%
Year 6:	8.92%
Year 7:	8.93%
Year 8:	4.46%

Federal Tax Rate:	35.00%	
State Tax Rate:	0.00%	
Property Tax Rate	2.00%	(use AdValorem sheet)
Royalty Rate:	12.50%	

Infrastructure Costs

Sunk Costs ($MM):	
Lease:	$2.88
Surveys:	$20.00
Appraisal wells:	$75.00
Well Costs ($MM/well)	
Development (from platform):	$13.33
Subsea (tie-backs):	$11.50
Shorebase ($MM):	$150.00

Platform Cost ($MM):

type	minimum	most likely	maximum	to be used
drill rig	$150	$250.00	$300.00	$273.95
production	$200	$270.00	$340.00	$450.00
Subsea	$225	$300.00	$375.00	$114.11

Pipeline Cost ($MM):		
flowlines ($MM/mi):	$5.84	
infield (mi)	105.0	(from Schedule)
sales line ($MM/mi):	$5.50	
overland (miles):	432.0	(from Schedule)

As-Spent Costs ($MM):	
Appraisal:	$191
Shorebase:	$177
Platform:	$3,953
Pipeline:	$3,703
Wells:	$2,800
Abandonment:	$421
Total Development Cost :	
As-spent ($/boe):	$4.27
Constant ($/boe):	$3.30

Production Scenario

Operating Costs:		
Variable (per-unit):		
Oil:	$1.00	$/bbl
Gas:	$0.36	$/Mcf
Fixed (facility):		
(per-well basis)	$1.24	$MM/well/yr
Total Operating Cost:		
As-spent	$6.52	($/boe)
Constant$:	$3.60	($/boe)

Transportation Costs:		
Oil feeder pipelines:	$0.05	$/bbl
TAPS:	$2.88	$/bbl
tanker:	$1.58	$/bbl
total oil tariffs:	$4.51	$/bbl
Gas main line to AK-NS:	$0.00	$/Mcf
NS gas processing:	$0.20	$/Mcf
AK-NS to US midwest:	$2.35	$/Mcf
total gas tariffs:	$2.55	$/Mcf

Field Life:	22	years
Abandonment ($MM	$170.00	
National Stockpile		
Imported oil expected to be embargoed (	45.40%	
Percent of year embargo lasts:	83.33%	
NPV Stockpile Reserve Value ($MM):	$4,227.74	

Notes

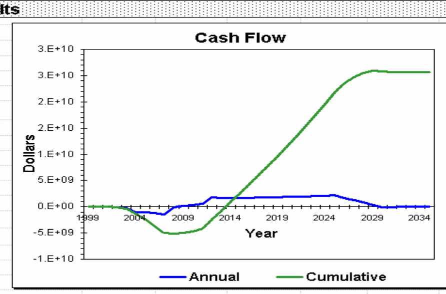
User inputs are in cells with colored font. Cells with black fonts show calculation results or suggested guidelines.
Data in cells with blue fonts are constant parameters.
Cells with bold blue fonts have @RISK distributions for variable parameters

(1) All inputs are in constant base year dollars. Input parameters are inflated to as-spent dollars according to the Schedule worksheet.
(2) End-of-year accounting is used for all expenses and income variables.
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$14,280.30	$14,280.30
Royalties:	$9,632.79	$9,632.79
Income to governments:	$23,913.09	$23,913.09
Net Income (BFIT):	$48,632.78	$48,632.78
Net Present Value (MM$):		
NPV of Taxes:	$379.07	$379.07
NPV of Royalties:	$639.65	$639.65
NPV Income to governments:	$1,018.72	$1,018.72
NPV of Net Income (BFIT):	$934.39	$934.39
NPV of Cash Flow:	$8.79	$8.79



Standard case: (3% inflation, 12% discount rate, gas BTU-price parity, sales of 11.5 tcf gas and 587 mmb condensate and natural gas liquids). Threshold prices are $5.22/mcf (gas) and $29.34/bbl (condensate).

Table 15
Economic Scenario No. 2: No Inflation for Prices or Costs

INPUTS

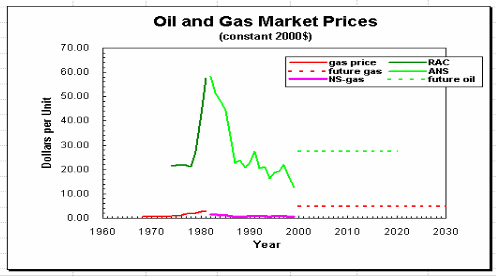
Project:	Burger	**Case (Alternative):**	Scenario 2
Planning Area:	Chukchi	**Analyst:**	Jim Craig
Company:	?	**Date of Analysis:**	12/10/04

Economic Parameters

				Suggested Distribution			to be used
Base Year:	2000		**Inflation Rate**	1.50%	3.00%	4.50%	0.00%
Geologic Probability (1 - Risk):	100.0%		**Real Discount Rate:**	7.00%	10.00%	15.00%	12.00%
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl					
gas price - BTU discount factor:	1.00						

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	$27.43
Real	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Price	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Growth	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$4.88		$4.88
Real	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Price	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Growth	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC	**ACRS Schedule:**			
Lease (bonus bid):	0%	0%			**Federal Tax Rate:**	35.00%
Delineation/Appraisal (wells & seismic):	0%	0%	Year 1:	14.29%	**State Tax Rate:**	0.00%
Exploration well converted to producer:	51%	30%	Year 2:	24.49%	**Property Tax Rate**	2.00% (use AdValorem sheet)
On-Platform Production Well:	51%	30%	Year 3:	17.49%		
Subsea Well:	51%	30%	Year 4:	12.49%	**Royalty Rate:**	12.50%
Exploration Platform:	83%	75%	Year 5:	8.93%		
Platform & Production Equipment:	72%	60%	Year 6:	8.92%		
Shorebase:	83%	75%	Year 7:	8.93%		
Pipelines (flowlines & salesline):	83%	75%	Year 8:	4.46%		
Abandonment:	0%	0%				

Infrastructure Costs

Sunk Costs ($MM):		**Platform Cost** ($MM):					**As-Spent Costs ($MM):**	
Lease:	$2.88	type	minimum	most likely	maximum	to be used	Appraisal:	$173
Surveys:	$20.00	drill rig	$150	$250.00	$300.00	$273.95	Shorebase:	$150
Appraisal wells:	$75.00	production	$200	$270.00	$340.00	$450.00	Platform:	$3,098
		Subsea	$225	$300.00	$375.00	$114.11	Pipeline:	$2,989
Well Costs ($MM/well)							Wells:	$2,107
Development (from platform):	$13.33	**Pipeline Cost** ($MM):					Abandonment:	$168
Subsea (tie-backs):	$11.50	flowlines ($MM/mi):	$5.84					
		infield (mi)	105.0 (from Schedule)				**Total Development Cost :**	
Shorebase ($MM):	$150.00	sales line ($MM/mi):	$5.50				As-spent ($/boe):	$3.30
		overland (miles):	432.0 (from Schedule)				Constant ($/boe):	$3.30

Production Scenario

Operating Costs:			**Transportation Costs:**				
Variable (per-unit):			Oil feeder pipelines:	$0.05	$/bbl	**Field Life:**	22 years
Oil:	$1.00	$/bbl	TAPS:	$2.88	$/bbl		
Gas:	$0.28	$/Mcf	tanker:	$1.58	$/bbl	**Abandonment** ($MM	$170.00
Fixed (facility):			**total oil tariffs:**	$4.51	$/bbl		
(per-well basis)	$0.97	$MM/well/yr					
			Gas main line to AK-NS:	$0.00	$/Mcf	**National Stockpile**	
Total Operating Cost:			NS gas processing:	$0.20	$/Mcf	Imported oil expected to be embargoed (	45.40%
As-spent:	$2.86	($/boe)	AK-NS to US midwest:	$2.35	$/Mcf	Percent of year embargo lasts:	83.33%
Constant$:	$2.86	($/boe)	**total gas tariffs:**	$2.55	$/Mcf	NPV Stockpile Reserve Value ($MM):	$4,070.94

Notes

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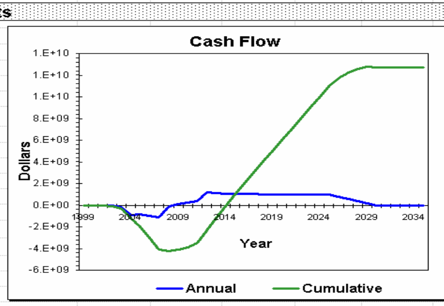
(1) All inputs are in constant base year dollars. Input parameters are inflated to as-spent dollars according to the Schedule worksheet.
(2) End-of-year accounting is used for all expenses and income variables.
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$7,282.70	$7,282.70
Royalties:	$5,032.90	$5,032.90
Income to governments:	$12,315.59	$12,315.59
Net Income (BFIT):	$24,039.73	$24,039.73
Net Present Value (MM$):		
NPV of Taxes:	$364.68	$364.68
NPV of Royalties:	$616.25	$616.25
NPV Income to governments:	$980.93	$980.93
NPV of Net Income (BFIT):	$854.37	$854.37
NPV of Cash Flow:	$18.12	$18.12



Similar to Scenario 1 (Standard Case: 12% discount rate, gas BTU-price parity, sales of 11.5 tcf gas and 587 mmb condensate and natural gas liquids), but with no inflation for prices and costs. Threshold prices are $4.88/mcf (gas) and $27.43/bbl (condensate).

Table 16
Economic Scenario No. 3: No Condensate Sales (TAPS Not Operational)

INPUTS

Project:	**Burger**	**Case (Alternative):**	**Scenario 3**
Planning Area:	**Chukchi**	**Analyst:**	**Jim Craig**
Company:	**?**	**Date of Analysis:**	**12/10/04**

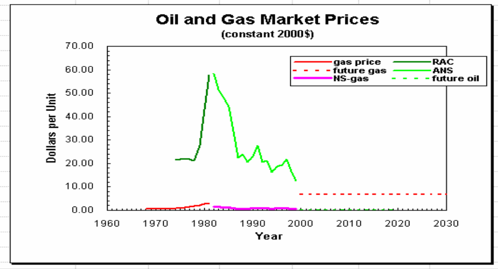
Economic Parameters

Base Year:	2000	
Geologic Probability (1- Risk):	100.0%	
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl
gas price - BTU discount factor:	**1.00**	

	Suggested Distribution			to be used
Inflation Rate	1.50%	3.00%	4.50%	**3.00%**
Real Discount Rate:	7.00%	10.00%	15.00%	**12.00%**

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	**$0.00**
	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Real	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Price	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
Growth	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$0.00		**$6.71**
	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Real	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Price	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
Growth	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC
Lease (bonus bid):	0%	0%
Delineation/Appraisal (wells & seismic):	0%	0%
Exploration well converted to producer:	51%	30%
On-Platform Production Well:	51%	30%
Subsea Well:	51%	30%
Exploration Platform:	83%	75%
Platform & Production Equipment:	72%	60%
Shorebase:	83%	75%
Pipelines (flowlines & salesline):	83%	75%
Abandonment:	0%	0%

ACRS Schedule:	
Year 1:	14.29%
Year 2:	24.49%
Year 3:	17.49%
Year 4:	12.49%
Year 5:	8.93%
Year 6:	8.92%
Year 7:	8.93%
Year 8:	4.46%

Federal Tax Rate:	35.00%	
State Tax Rate:	0.00%	
Property Tax Rate	2.00%	(use AdValorem sheet)
Royalty Rate:	12.50%	

Infrastructure Costs

Sunk Costs ($MM):	
Lease:	$2.88
Surveys:	$20.00
Appraisal wells:	$75.00
Well Costs ($MM/well)	
Development (from platform):	$13.33
Subsea (tie-backs):	$11.50
Shorebase ($MM):	$150.00

Platform Cost ($MM):

type	minimum	most likely	maximum	to be used
drill rig	$150	$250.00	$300.00	**$273.95**
production	$200	$270.00	$340.00	**$450.00**
Subsea	$225	$300.00	$375.00	**$114.11**

Pipeline Cost ($MM):		
flowlines ($MM/mi):	**$5.84**	
infield (mi)	105.0	(from Schedule)
sales line ($MM/mi):	**$5.50**	
overland (miles):	432.0	(from Schedule)

As-Spent Costs ($MM):	
Appraisal:	$191
Shorebase:	$177
Platform:	$3,953
Pipeline:	$3,703
Wells:	$2,800
Abandonment:	$421
Total Development Cost :	
As-spent ($/boe):	$4.27
Constant ($/boe):	$3.30

Production Scenario

Operating Costs:		
Variable (per-unit):		
Oil:	$1.00	$/bbl
Gas:	$0.36	$/Mcf
Fixed (facility):		
(per-well basis)	$1.24	$MM/well/yr
Total Operating Cost:		
As-spent:	$6.52	($/boe)
Constant$:	$3.60	($/boe)

Transportation Costs:		
Oil feeder pipelines:	$0.05	$/bbl
TAPS:	$2.88	$/bbl
tanker:	$1.58	$/bbl
total oil tariffs:	**$4.51**	$/bbl
Gas main line to AK-NS:	$0.00	$/Mcf
NS gas processing:	$0.20	$/Mcf
AK-NS to US midwest:	**$2.35**	$/Mcf
total gas tariffs:	**$2.55**	$/Mcf

Field Life:	22	years
Abandonment ($MM	$170.00	
National Stockpile		
Imported oil expected to be embargoed (		45.40%
Percent of year embargo lasts:		83.33%
NPV Stockpile Reserve Value ($MM):		$0.00

Notes

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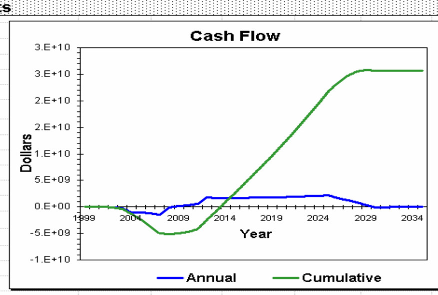
Data in cells with blue fonts are constant parameters.
Cells with bold blue fonts have @RISK distributions for variable parameters

(1) All inputs are in constant base year dollars. Input parameters are inflated to as-spent dollars according to the Schedule worksheet.
(2) End-of-year accounting is used for all expenses and income variables.
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$14,242.59	$14,242.59
Royalties:	$9,617.40	$9,617.40
Income to governments:	$23,859.99	$23,859.99
Net Income (BFIT):	($85,703.28)	($85,703.28)
Net Present Value (MM$):		
NPV of Taxes:	$376.57	$376.57
NPV of Royalties:	$638.63	$638.63
NPV Income to governments:	$1,015.20	**$1,015.20**
NPV of Net Income (BFIT):	($7,986.00)	($7,986.00)
NPV of Cash Flow:	$4.14	**$4.14**



Similar to Scenario 1 (Standard Case: 3% inflation, 12% discount rate, gas BTU-price parity, sales of 11.5 tcf gas), but with no condensate sales (TAPS not operational).The threshold price is $6.71/mcf (gas only).

Table 17
Economic Scenario No. 4: Gas Price Per BTU Discount Factor = 0.66
(Historic U.S. Market Average Relative to Oil)

INPUTS

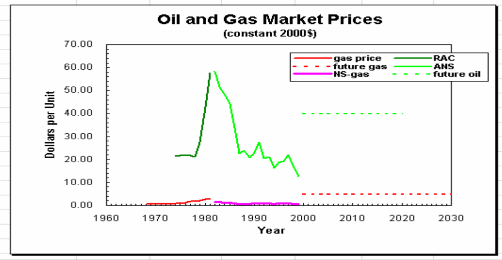
Project:	**Burger**	**Case (Alternative):**	**Scenario 4**
Planning Area:	**Chukchi**	**Analyst:**	**Jim Craig**
Company:	**?**	**Date of Analysis:**	**12/10/04**

Economic Parameters

				Suggested Distribution			to be used
Base Year:	2000		**Inflation Rate**	1.50%	3.00%	4.50%	**3.00%**
Geologic Probability (1- Risk):	100.0%		**Real Discount Rate:**	7.00%	10.00%	15.00%	**12.00%**
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl					
gas price - BTU discount factor:	**0.66**						

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	**$39.85**
Real Price Growth	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$4.68		**$4.68**
Real Price Growth	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC	**ACRS Schedule:**			
Lease (bonus bid):	0%	0%			**Federal Tax Rate:**	35.00%
Delineation/Appraisal (wells & seismic):	0%	0%	Year 1:	14.29%	**State Tax Rate:**	0.00%
Exploration well converted to producer:	51%	30%	Year 2:	24.49%	**Property Tax Rate**	2.00% (use AdValorem sheet)
On-Platform Production Well:	51%	30%	Year 3:	17.49%		
Subsea Well:	51%	30%	Year 4:	12.49%	**Royalty Rate:**	12.50%
Exploration Platform:	83%	75%	Year 5:	8.93%		
Platform & Production Equipment:	72%	60%	Year 6:	8.92%		
Shorebase:	83%	75%	Year 7:	8.93%		
Pipelines (flowlines & salesline):	83%	75%	Year 8:	4.46%		
Abandonment:	0%	0%				

Infrastructure Costs

Sunk Costs ($MM):		**Platform Cost** ($MM):					**As-Spent Costs ($MM):**	
Lease:	$2.88	type	minimum	most likely	maximum	to be used	Appraisal:	$191
Surveys:	$20.00	drill rig	$150	$250.00	$300.00	**$273.95**	Shorebase:	$177
Appraisal wells:	$75.00	production	$200	$270.00	$340.00	**$450.00**	Platform:	$3,953
		Subsea	$225	$300.00	$375.00	**$114.11**	Pipeline:	$3,703
Well Costs ($MM/well)							Wells:	$2,800
Development (from platform):	$13.33	**Pipeline Cost** ($MM):					Abandonment:	$421
Subsea (tie-backs):	$11.50	flowlines ($MM/mi):	**$5.84**					
		infield (mi)	105.0 (from Schedule)				**Total Development Cost :**	
Shorebase ($MM):	$150.00	sales line ($MM/mi):	**$5.50**				As-spent ($/boe):	$4.27
		overland (miles):	432.0 (from Schedule)				Constant ($/boe):	$3.30

Production Scenario

Operating Costs:			**Transportation Costs:**				
Variable (per-unit):			Oil feeder pipelines:	$0.05	$/bbl	**Field Life:**	22 years
Oil:	$1.00	$/bbl	TAPS:	$2.88	$/bbl		
Gas:	$0.36	$/Mcf	tanker:	$1.58	$/bbl	**Abandonment** ($MM)	$170.00
Fixed (facility):			**total oil tariffs:**	**$4.51**	$/bbl		
(per-well basis)	$1.24	$MM/well/yr					
			Gas main line to AK-NS:	$0.00	$/Mcf	**National Stockpile**	
Total Operating Cost:			NS gas processing:	$0.20	$/Mcf	Imported oil expected to be embargoed (	45.40%
As-spent:	$6.52	($/boe)	AK-NS to US midwest:	**$2.35**	$/Mcf	Percent of year embargo lasts:	83.33%
Constant$:	$3.60	($/boe)	**total gas tariffs:**	**$2.55**	$/Mcf	NPV Stockpile Reserve Value ($MM):	$5,743.01

Notes

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Cells with bold blue fonts have @RISK distributions for variable parameters

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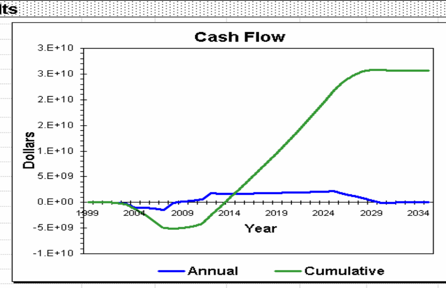
(2) End-of-year accounting is used for all expenses and income variables.
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$14,257.27	$14,257.27
Royalties:	$9,623.39	$9,623.39
Income to governments:	$23,880.66	$23,880.66
Net Income (BFIT):	$48,557.57	$48,557.57
Net Present Value (MM$):		
NPV of Taxes:	$377.54	$377.54
NPV of Royalties:	$639.03	$639.03
NPV Income to governments:	$1,016.57	**$1,016.57**
NPV of Net Income (BFIT):	$929.40	$929.40
NPV of Cash Flow:	$5.95	**$5.95**



Similar to Scenario 1 (Standard Case: 3% inflation, 12% discount rate, sales of 11.5 tcf gas and 587 mmb condensate and natural gas liquids), but with gas prices only 66% of oil prices on a BTU-equivalent basis (historic U.S. market norm). Threshold prices are $4.68/mcf (gas) and $39.85/bbl (condensate).

Table 18
Economic Scenario No. 5: Nominal Gas Prices Flat With 3% Inflation in Costs

INPUTS

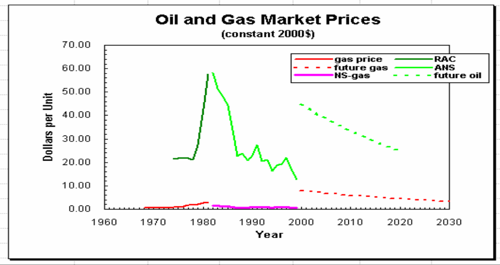
Project:	**Burger**	**Case (Alternative):**	**Scenario 5**
Planning Area:	**Chukchi**	**Analyst:**	**Jim Craig**
Company:	**?**	**Date of Analysis:**	**12/10/04**

Economic Parameters

Base Year:	2000			Suggested Distribution			to be used
Geologic Probability (1- Risk):	100.0%		**Inflation Rate**	1.50%	3.00%	4.50%	**3.00%**
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl	**Real Discount Rate:**	7.00%	10.00%	15.00%	**12.00%**
gas price - BTU discount factor:	**1.00**						

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	**$44.96**
	Period 1 Rate	3.30%	3.40%	4.10%	-2.90%
Real	Period 2 Rate	0.00%	1.80%	2.10%	-2.90%
Price	Period 3 Rate	0.00%	0.70%	0.80%	-2.90%
Growth	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$8.00		**$8.00**
	Period 1 Rate	3.30%	3.40%	4.10%	-2.90%
Real	Period 2 Rate	0.00%	1.80%	2.10%	-2.90%
Price	Period 3 Rate	0.00%	0.70%	0.80%	-2.90%
Growth	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC	**ACRS Schedule:**			
Lease (bonus bid):	0%	0%			**Federal Tax Rate:**	35.00%
Delineation/Appraisal (wells & seismic):	0%	0%	Year 1:	14.29%	**State Tax Rate:**	0.00%
Exploration well converted to producer:	51%	30%	Year 2:	24.49%	**Property Tax Rate**	2.00% (use AdValorem sheet)
On-Platform Production Well:	51%	30%	Year 3:	17.49%		
Subsea Well:	51%	30%	Year 4:	12.49%	**Royalty Rate:**	12.50%
Exploration Platform:	83%	75%	Year 5:	8.93%		
Platform & Production Equipment:	72%	60%	Year 6:	8.92%		
Shorebase:	83%	75%	Year 7:	8.93%		
Pipelines (flowlines & salesline):	83%	75%	Year 8:	4.46%		
Abandonment:	0%	0%				

Infrastructure Costs

Sunk Costs ($MM):		**Platform Cost** ($MM):					**As-Spent Costs ($MM):**	
Lease:	$2.88	type	minimum	most likely	maximum	to be used	Appraisal:	$191
Surveys:	$20.00	drill rig	$150	$250.00	$300.00	**$273.95**	Shorebase:	$177
Appraisal wells:	$75.00	production	$200	$270.00	$340.00	**$450.00**	Platform:	$3,953
		Subsea	$225	$300.00	$375.00	**$114.11**	Pipeline:	$3,703
Well Costs ($MM/well)							Wells:	$2,800
Development (from platform):	$13.33	**Pipeline Cost** ($MM):					Abandonment:	$421
Subsea (tie-backs):	$11.50	flowlines ($MM/mi):	**$5.84**					
		infield (mi)	105.0 (from Schedule)				**Total Development Cost :**	
Shorebase ($MM):	$150.00	sales line ($MM/mi):	**$5.50**				As-spent ($/boe):	$4.27
		overland (miles):	432.0 (from Schedule)				Constant ($/boe):	$3.30

Production Scenario

Operating Costs:		**Transportation Costs:**			
Variable (per-unit):		Oil feeder pipelines:	$0.05 $/bbl	**Field Life:**	22 years
Oil:	$1.00 $/bbl	TAPS:	$2.88 $/bbl		
Gas:	$0.36 $/Mcf	tanker:	$1.58 $/bbl	**Abandonment** ($MM	$170.00
Fixed (facility):		**total oil tariffs:**	**$4.51** $/bbl		
(per-well basis)	$1.24 $MM/well/yr				
		Gas main line to AK-NS:	$0.00 $/Mcf	**National Stockpile**	
Total Operating Cost:		NS gas processing:	$0.20 $/Mcf	Imported oil expected to be embargoed (	45.40%
As-spent:	$6.52 ($/boe)	AK-NS to US midwest:	**$2.35** $/Mcf	Percent of year embargo lasts:	83.33%
Constant$:	$3.60 ($/boe)	**total gas tariffs:**	**$2.55** $/Mcf	NPV Stockpile Reserve Value ($MM):	$5,787.86

Notes

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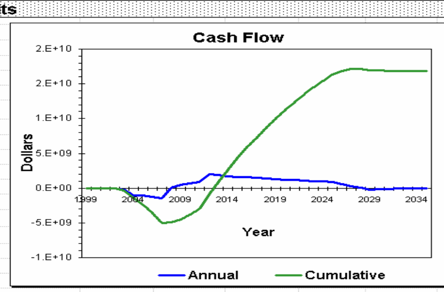
(2) End-of-year accounting is used for all expenses and income variables.
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$9,501.93	$9,501.93
Royalties:	$7,682.44	$7,682.44
Income to governments:	$17,184.36	$17,184.36
Net Income (BFIT):	$33,029.92	$33,029.92
Net Present Value (MM$):		
NPV of Taxes:	$373.72	$373.72
NPV of Royalties:	$637.47	$637.47
NPV Income to governments:	$1,011.19	**$1,011.19**
NPV of Net Income (BFIT):	$916.92	$916.92
NPV of Cash Flow:	($1.14)	**($1.14)**



Similar to Scenario 1 (Standard Case: 12% discount rate, gas BTU-price parity, sales of 11.5 tcf gas and 587 mmb condensate and natural gas liquids), but with gas prices held nominally flat while costs inflate by 3% per year. Threshold prices are $8.00/mcf (gas) and $44.96/bbl (condensate).

Table 19

Economic Scenario No. 6: Lower Assumed Discount Rate (8%)

INPUTS

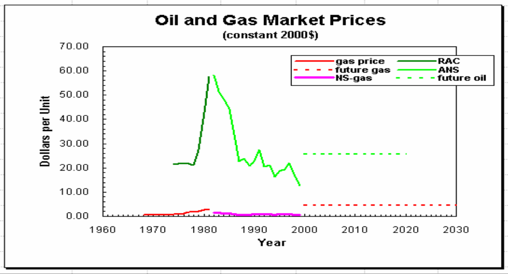
Project:	**Burger**	**Case (Alternative):**	**Scenario 6**
Planning Area:	**Chukchi**	**Analyst:**	**Jim Craig**
Company:	**?**	**Date of Analysis:**	**12/10/04**

Economic Parameters

					Suggested Distribution			to be used
Base Year:	2000		**Inflation Rate**		1.50%	3.00%	4.50%	**3.00%**
Geologic Probability (1- Risk):	100.0%		**Real Discount Rate:**		7.00%	10.00%	15.00%	**8.00%**
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl						
gas price - BTU discount factor:	**1.00**							

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	**$25.63**
	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Real	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Price	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
Growth	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$4.56		**$4.56**
	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
Real	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
Price	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
Growth	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC	**ACRS Schedule:**			
Lease (bonus bid):	0%	0%	Year 1:	14.29%	**Federal Tax Rate:**	35.00%
Delineation/Appraisal (wells & seismic):	0%	0%	Year 2:	24.49%	**State Tax Rate:**	0.00%
Exploration well converted to producer:	51%	30%	Year 3:	17.49%	**Property Tax Rate**	2.00% (use AdValorem sheet)
On-Platform Production Well:	51%	30%	Year 4:	12.49%		
Subsea Well:	51%	30%	Year 5:	8.93%	**Royalty Rate:**	12.50%
Exploration Platform:	83%	75%	Year 6:	8.92%		
Platform & Production Equipment:	72%	60%	Year 7:	8.93%		
Shorebase:	83%	75%	Year 8:	4.46%		
Pipelines (flowlines & salesline):	83%	75%				
Abandonment:	0%	0%				

Infrastructure Costs

Sunk Costs ($MM):		**Platform Cost** ($MM):					**As-Spent Costs ($MM):**	
Lease:	$2.88	type	minimum	most likely	maximum	to be used	Appraisal:	$191
Surveys:	$20.00	drill rig	$150	$250.00	$300.00	**$273.95**	Shorebase:	$177
Appraisal wells:	$75.00	production	$200	$270.00	$340.00	**$450.00**	Platform:	$3,953
		Subsea	$225	$300.00	$375.00	**$114.11**	Pipeline:	$3,703
Well Costs ($MM/well)							Wells:	$2,800
Development (from platform):	$13.33	**Pipeline Cost** ($MM):					Abandonment:	$421
Subsea (tie-backs):	$11.50	flowlines ($MM/mi):	**$5.84**					
		infield (mi)	105.0	(from Schedule)			**Total Development Cost :**	
Shorebase ($MM):	$150.00	sales line ($MM/mi):	**$5.50**				As-spent ($/boe):	$4.27
		overland (miles):	432.0	(from Schedule)			Constant ($/boe):	$3.30

Production Scenario

Operating Costs:			**Transportation Costs:**					
Variable (per-unit):			Oil feeder pipelines:	$0.05	$/bbl	**Field Life:**	22	years
Oil:	$1.00	$/bbl	TAPS:	$2.88	$/bbl			
Gas:	$0.36	$/Mcf	tanker:	$1.58	$/bbl	**Abandonment** ($MM	$170.00	
Fixed (facility):			**total oil tariffs:**	**$4.51**	$/bbl			
(per-well basis)	$1.24	$MM/well/yr						
			Gas main line to AK-NS:	$0.00	$/Mcf	**National Stockpile**		
Total Operating Cost:			NS gas processing:	$0.20	$/Mcf	Imported oil expected to be embargoed (		45.40%
As-spent:	$6.52	($/boe)	AK-NS to US midwest:	**$2.35**	$/Mcf	Percent of year embargo lasts:		83.33%
Constant$:	$3.60	($/boe)	**total gas tariffs:**	**$2.55**	$/Mcf	NPV Stockpile Reserve Value ($MM):		$4,433.78

Notes

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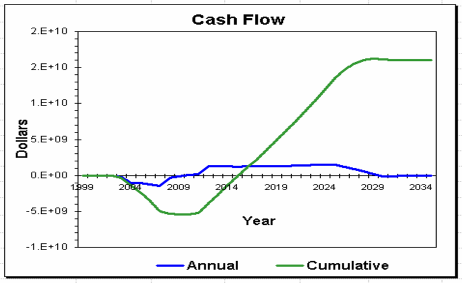
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$9,078.64	$9,078.64
Royalties:	$7,509.66	$7,509.66
Income to governments:	$16,588.30	$16,588.30
Net Income (BFIT):	$31,647.76	$31,647.76
Net Present Value (MM$):		
NPV of Taxes:	$438.35	$438.35
NPV of Royalties:	$939.49	$939.49
NPV Income to governments:	$1,377.84	**$1,377.84**
NPV of Net Income (BFIT):	$1,223.95	$1,223.95
NPV of Cash Flow:	$6.68	**$6.68**



Similar to Scenario 1 (Standard Case: 3% inflation rate, gas BTU-price parity, sales of 11.5 tcf gas and 587 mmb condensate and natural gas liquids), but with a lower (8% as opposed to 12%) discount rate. Threshold prices are $4.56/mcf (gas) and $25.63/bbl (condensate).

Table 20
Economic Scenario No. 7: Nominal Oil Prices Flat With 1% Real Growth in Gas Prices (Nominal Growth 4%/Year)

INPUTS

Project:	**Burger**	**Case (Alternative):**	**Scenario 7**
Planning Area:	**Chukchi**	**Analyst:**	**Jim Craig**
Company:	**?**	**Date of Analysis:**	**12/10/04**

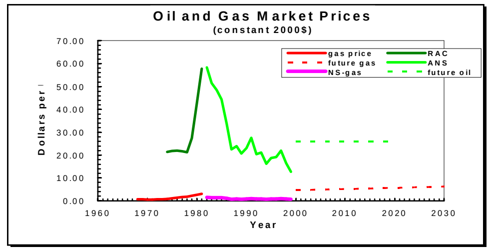
Economic Parameters

Base Year:	2000	
Geologic Probability (1- Risk):	100.0%	
BOE Conversion Factor (Mcf/bbl):	5.62	Mcf/bbl
gas price - BTU discount factor:	**1.00**	

	Suggested Distribution			to be used
Inflation Rate	1.50%	3.00%	4.50%	**3.00%**
Real Discount Rate:	7.00%	10.00%	15.00%	**12.00%**

Oil Price:		Suggested Distribution			to be used
Landed Starting Price ($/bbl):		$11.51	$15.78	$20.31	**$26.02**
Real Price Growth	Period 1 Rate	3.30%	3.40%	4.10%	0.00%
	Period 2 Rate	0.00%	1.80%	2.10%	0.00%
	Period 3 Rate	0.00%	0.70%	0.80%	0.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011

Gas Price:		Suggested Distribution			to be used
Wellhead Starting Price ($/Mcf):			$4.63		**$4.63**
Real Price Growth	Period 1 Rate	3.30%	3.40%	4.10%	1.00%
	Period 2 Rate	0.00%	1.80%	2.10%	1.00%
	Period 3 Rate	0.00%	0.70%	0.80%	1.00%
	Period 1 Begin Year				2000
	Period 2 Begin Year				2005
	Period 3 Begin Year				2011



Tax and Royalty Inputs

Tangible Portion of Costs:	with IDC	w/o IDC
Lease (bonus bid):	0%	0%
Delineation/Appraisal (wells & seismic)	0%	0%
Exploration well converted to producer:	51%	30%
On-Platform Production Well:	51%	30%
Subsea Well:	51%	30%
Exploration Platform:	83%	75%
Platform & Production Equipment:	72%	60%
Shorebase:	83%	75%
Pipelines (flowlines & salesline):	83%	75%
Abandonment:	0%	0%

ACRS Schedule:	
Year 1:	14.29%
Year 2:	24.49%
Year 3:	17.49%
Year 4:	12.49%
Year 5:	8.93%
Year 6:	8.92%
Year 7:	8.93%
Year 8:	4.46%

Federal Tax Rate:	35.00%
State Tax Rate:	0.00%
Property Tax Rate	2.00% (use AdValorem sheet)
Royalty Rate:	12.50%

Infrastructure Costs

Sunk Costs ($MM):

Lease:	$2.88
Surveys:	$20.00
Appraisal wells:	$75.00

Well Costs ($MM/well)

Development (from platform):	$13.33
Subsea (tie-backs):	$11.50

Shorebase ($MM): $150.00

Platform Cost ($MM):

type	minimum	most likely	maximum	to be used
drill rig	$150	$250.00	$300.00	**$273.95**
production	$200	$270.00	$340.00	**$450.00**
Subsea	$225	$300.00	$375.00	**$114.11**

Pipeline Cost ($MM):

flowlines ($MM/mi):	**$5.84**
infield (mi)	105.0 (from Schedule)
sales line ($MM/mi):	**$5.50**
overland (miles):	432.0 (from Schedule)

As-Spent Costs ($MM):

Appraisal:	$191
Shorebase:	$177
Platform:	$3,953
Pipeline:	$3,703
Wells:	$2,800
Abandonment:	$421

Total Development Cost:

As-spent ($/boe):	$4.27
Constant ($/boe):	$3.30

Production Scenario

Operating Costs:

Variable (per-unit):		
Oil:	$1.00	$/bbl
Gas:	$0.36	$/Mcf
Fixed (facility):		
(per-well basis)	$1.24	$MM/well/yr

Total Operating Cost:

As-spent:	$6.52	($/boe)
Constant$:	$3.60	($/boe)

Transportation Costs:

Oil feeder pipelines:	$0.05	$/bbl
TAPS:	$2.88	$/bbl
tanker:	$1.58	$/bbl
total oil tariffs:	**$4.51**	$/bbl
Gas main line to AK-NS:	$0.00	$/Mcf
NS gas processing:	$0.20	$/Mcf
AK-NS to US midwest:	**$2.35**	$/Mcf
total gas tariffs:	**$2.55**	$/Mcf

Field Life: 22 years

Abandonment ($MM $170.00

National Stockpile

Imported oil expected to be embargoed	45.40%
Percent of year embargo lasts:	83.33%
NPV Stockpile Reserve Value ($MM):	$3,749.89

Notes

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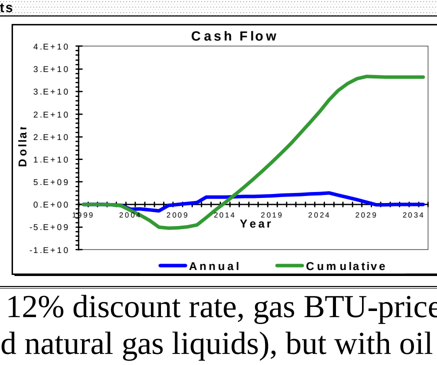
(1) All inputs are in constant base year dollars. Input parameters are inflated to as-spent dollars according to the Schedule worksheet.
(2) End-of-year accounting is used for all expenses and income variables.
(3) Expenses prior to the Base Year (Sunk costs) should be adjusted to total dollars in at year-end preceeding the Base Year.
(4) Development costs include all expenses associated with activities: management, engineering, permitting, materials, labor, installation, financing.
(5) Operating costs include all expenses associated with logistics, transportation, communication, maintenance, repair, project management, well workovers, supplies.
(6) Property tax should be included for all project infrastructure located on State lands (use Ad Valorem sheet).

RESULTS

Summary of Results

	Unrisked	Risked
Petroleum Resources:		
Oil (MMbbl):	587	587
Gas (Bcf):	11,508	11,508
BOE (MMbbl):	2635	2635
Actual Values (MM$):		
Taxes:	$15,639.59	$15,639.59
Royalties:	$10,187.60	$10,187.60
Income to governments:	$25,827.19	$25,827.19
Net Income (BFIT):	$33,449.20	$33,449.20
Net Present Value (MM$):		
NPV of Taxes:	$374.84	$374.84
NPV of Royalties:	$637.92	$637.92
NPV Income to governments:	$1,012.76	**$1,012.76**
NPV of Net Income (BFIT):	($73.85)	($73.85)
NPV of Cash Flow:	$0.93	**$0.93**



Similar to Scenario 1 (Standard Case: 3% inflation rate, 12% discount rate, gas BTU-price parity, sales of 11.5 tcf gas and 587 mmb condensate and natural gas liquids), but with oil prices nominally flat while gas prices grow nominally at 4% per year (or real growth of 1% over 3% inflation). Threshold prices are $4.63/mcf (gas) and $26.02/bbl (condensate).

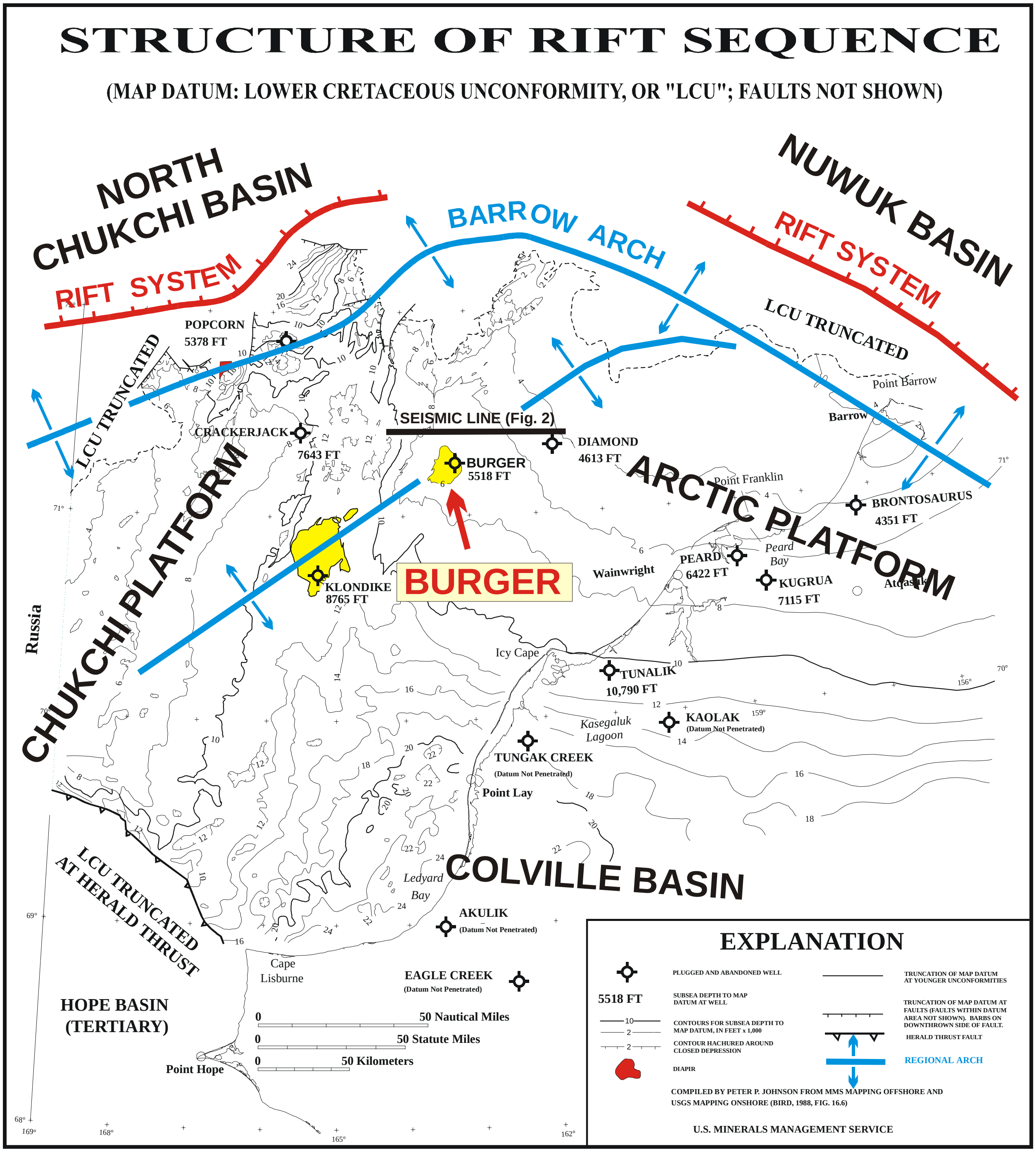


Figure 1: Regional structure map on Lower Cretaceous (Hauterivian-Barremian) unconformity, showing location of Burger structure along a regional arch between North Chukchi rift basin and Colville basin. A companion structure to the southwest, “Klondike”, was drilled and found to contain oil pay in a sandstone correlative to the Burger gas sandstone. The seismic line posted north of Burger structure is shown in figure 2.

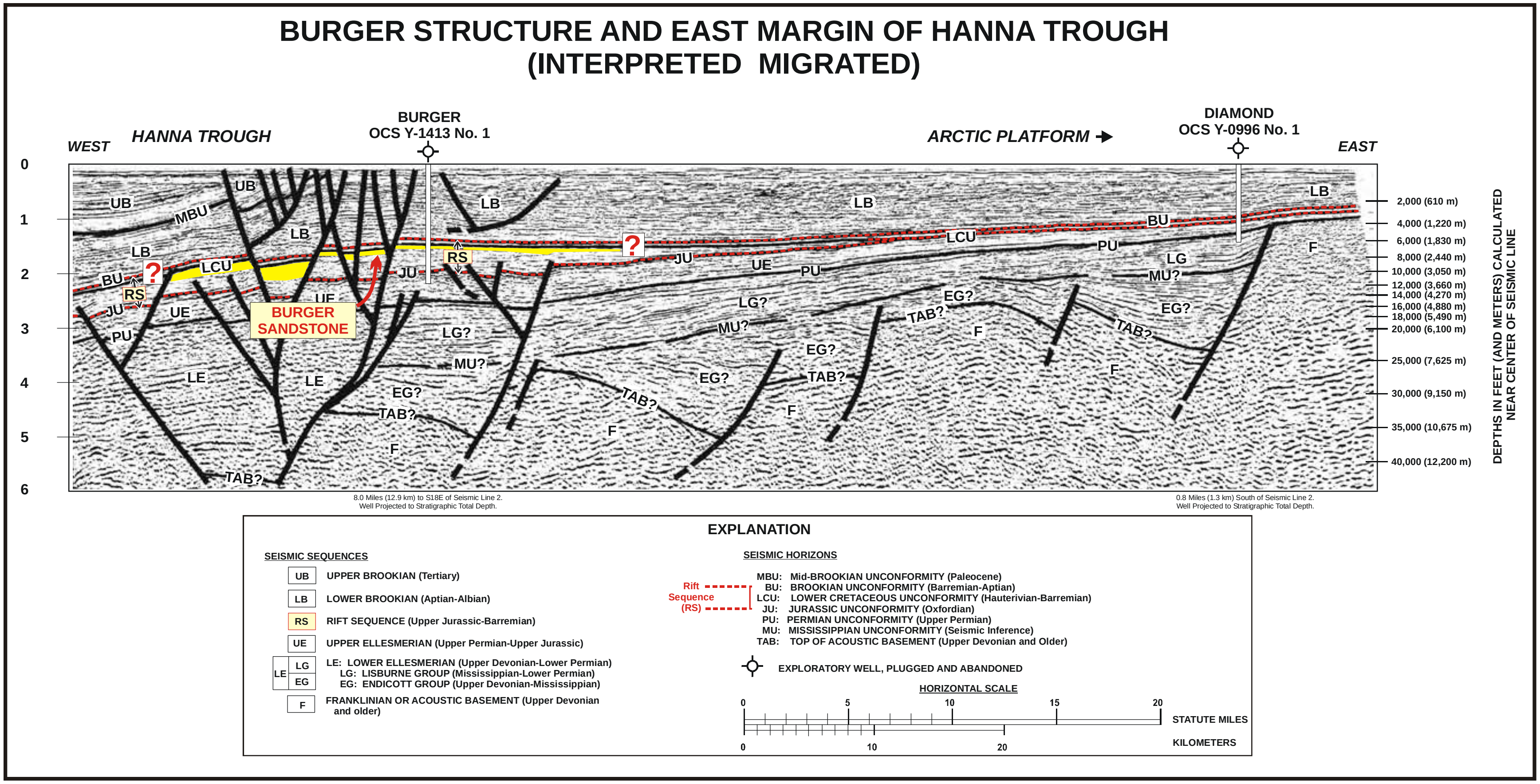


Figure 2: East-west migrated seismic profile (located in fig. 1) illustrating Burger structure. The Burger gas-bearing sandstone lies directly beneath the LCU and is speculatively highlighted in yellow away from the Burger well. Seismic record adapted from Sherwood et al. (2002, plate 5).

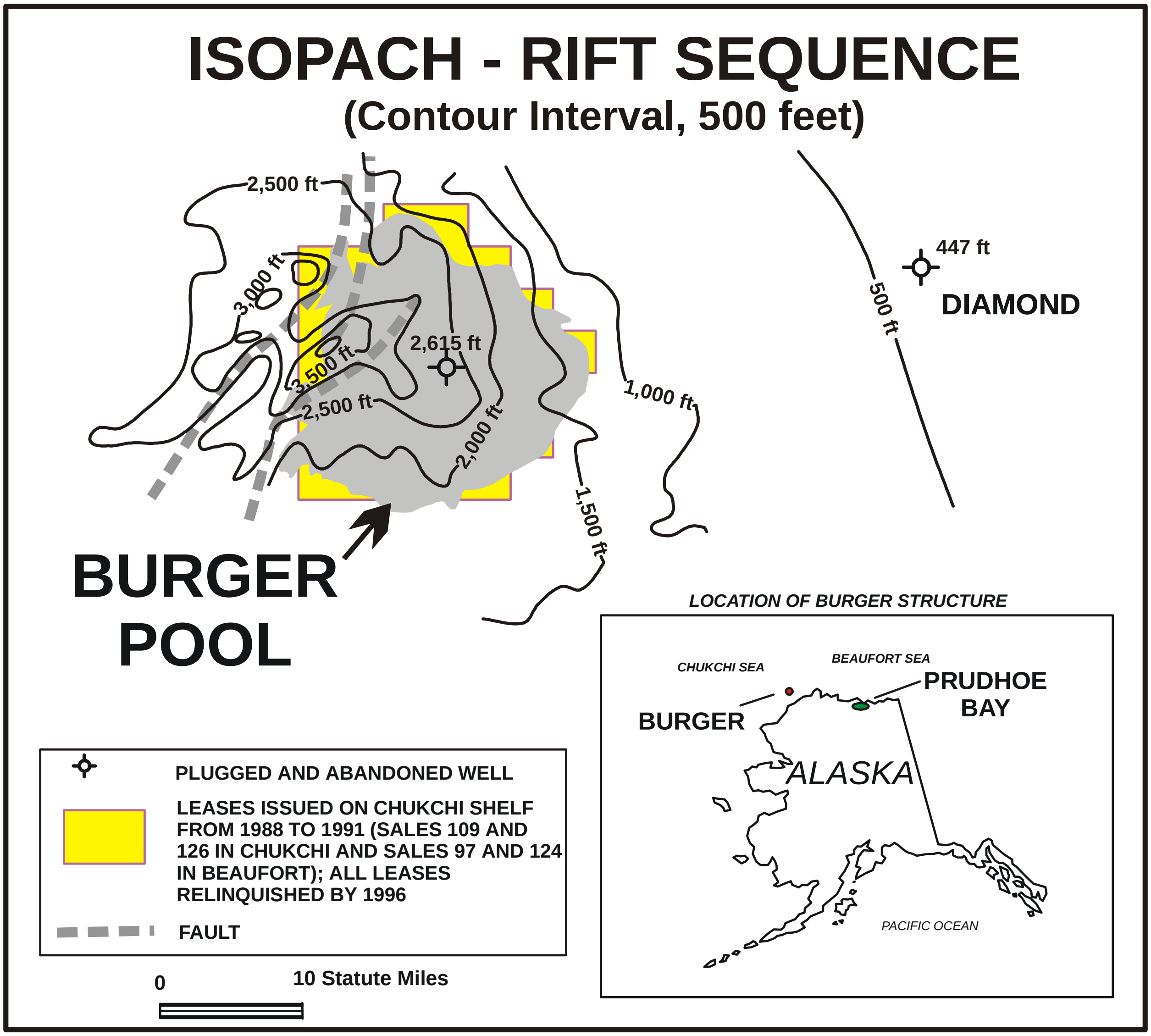


Figure 3: Isopach map for Rift sequence (between Brookian unconformity [BU] and Jurassic unconformity [JU]) in area of Burger structure, showing that the sequence nearly triples in thickness from the east flank to the west flank of the structure. Burger structure is sited in a west-trending rift-sag basin cross cut by north-trending growth faults. The rift-sag basin formed in Late Jurassic to Early Cretaceous time, with basin inversion and uplift of Burger structure occurring somewhat later in Tertiary time. The gas-bearing "Burger" sandstone at 5,560 feet in Burger well is part of the Rift sequence and may likewise greatly expand in thickness in western parts of Burger prospect.

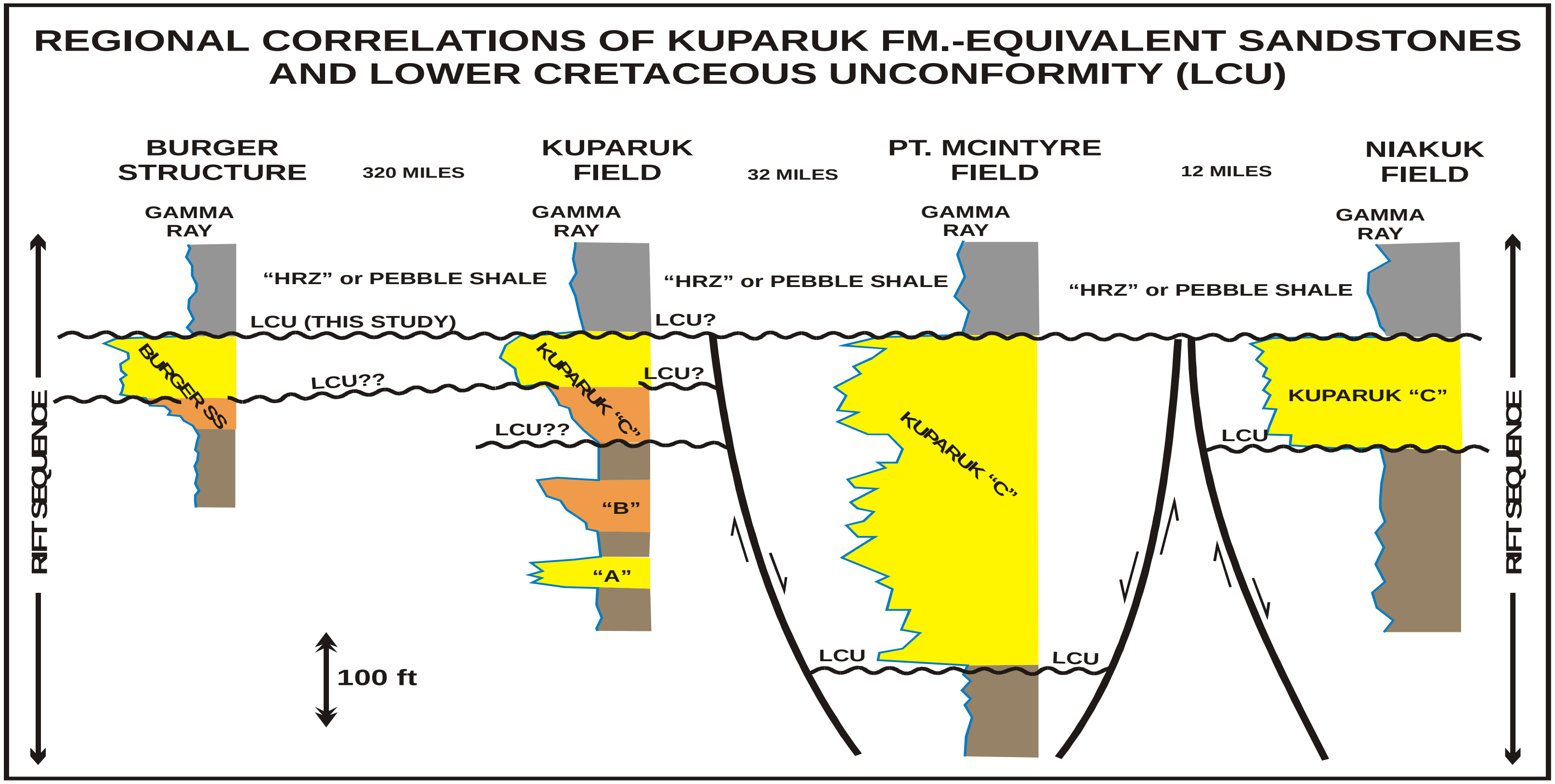


Figure 4: Regional stratigraphic context of Burger sandstone relative to the Kuparuk Formation of the central North Slope. Yellow denotes clean sand facies; orange denotes upward-coarsening, bioturbated, muddy sandstone. Brown and gray denote shales. At Niakuk and Pt. McIntyre fields, the Lower Cretaceous unconformity, or "LCU", clearly lies at the base of the Kuparuk "C" sandstone. At Kuparuk field, some place the LCU at the base of the sandstone, within the sandstone, or at the top of the sandstone. Unconformities may be present at all three levels at Kuparuk field. At Burger, we place the unconformity at the top of the Burger sandstone (pl. 1), although it could also be justifiably located in the middle the Burger sandstone at the base of the upper clean sand unit at 5,620 feet. In any case, the context of the Burger sandstone is clearly analogous to the Kuparuk "C" sandstone, which thickens markedly into areas of subsidence, like the graben at Pt. McIntyre or the low-side fault sag at Niakuk. Burger sandstone is hypothesized to become thicker on the west side of Burger structure, where the Rift sequence nearly triples in thickness (fig. 3).

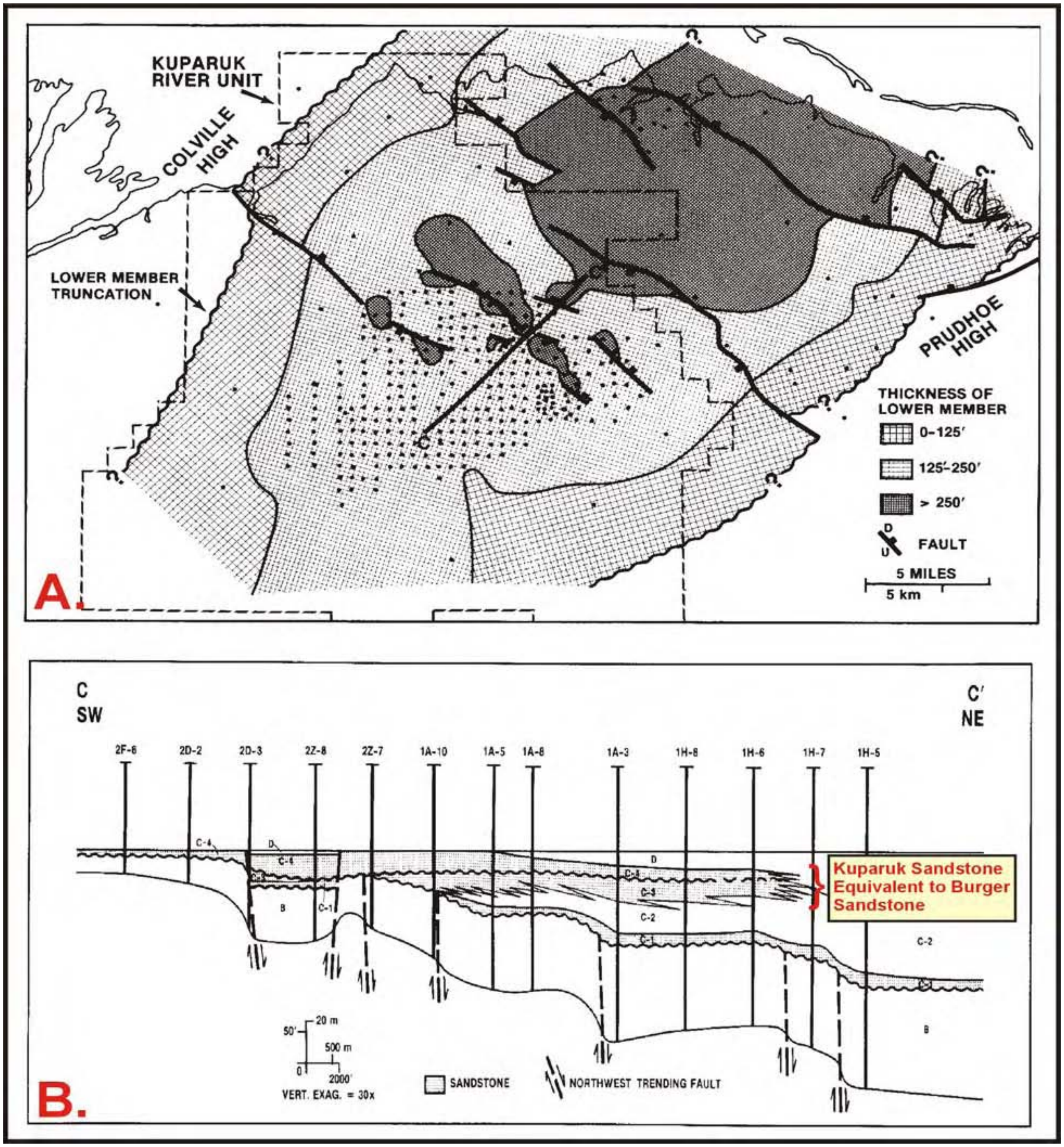


Figure 5: Map and stratigraphic cross section for Kuparuk rift-sag basin west of Prudhoe Bay between Colville high on the northwest and Prudhoe Bay high on the southeast. A., Map showing regional isopach for lower member ("B") of Kuparuk Formation across sag basin. Area of numerous dots is the area of Kuparuk field oil production. B., stratigraphic cross section showing progressive thickening of Kuparuk Formation and Kuparuk "C" sandstone unit northeastward into axis of sag basin. Major unconformities occur at the bases of Kuparuk units C-1 and C-4. The unconformity at the base of C-1 is correlated by some to the regional Lower Cretaceous unconformity. Diagrams adopted from Masterson and Paris (1987, figs. 9, 10).

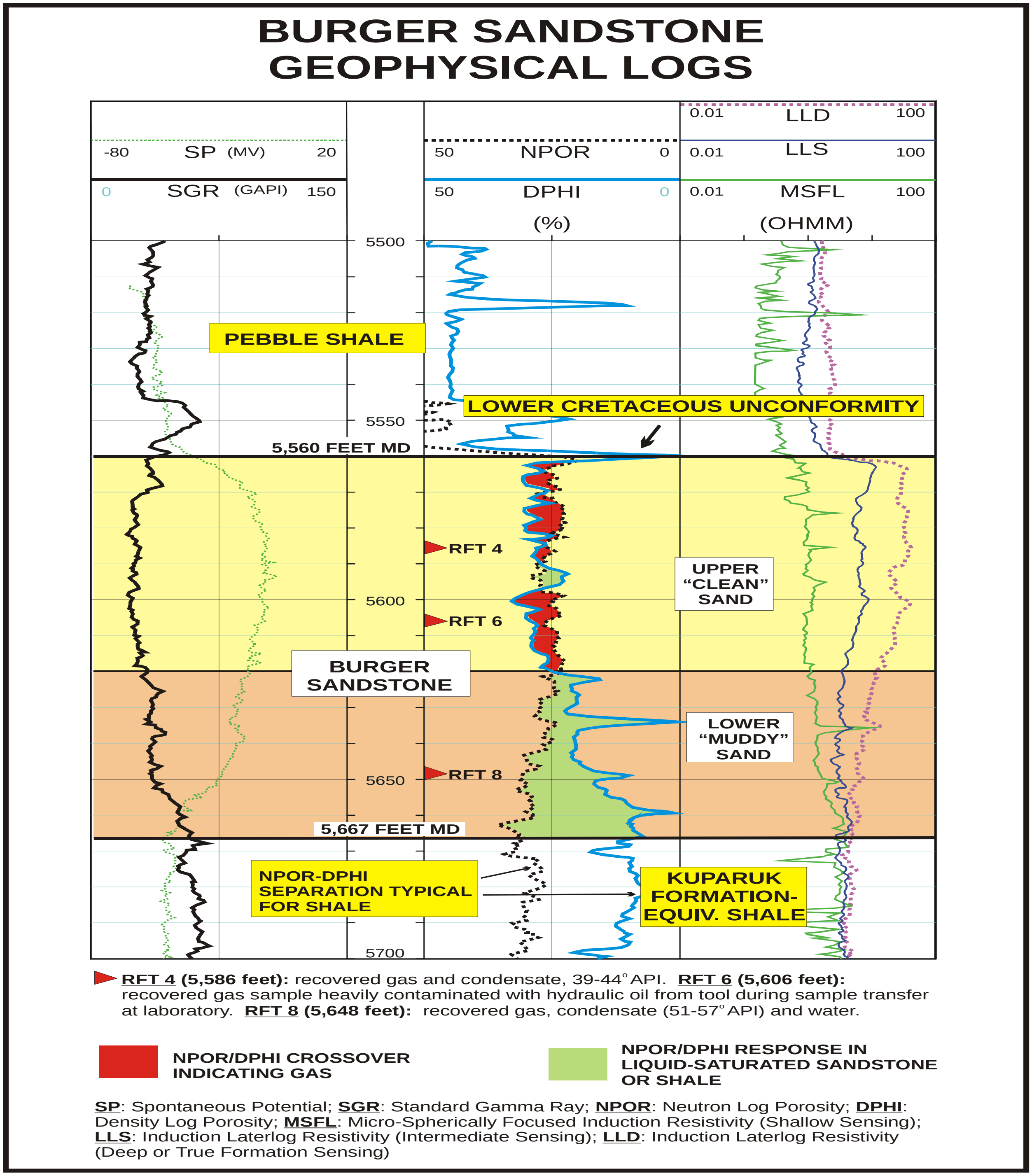


Figure 6: Log data for Burger sandstone. The lower part of the sandstone shows NPOR-DPHI relationship that typifies either liquid-saturated sandstone or shale. Detailed analysis indicates that this part of the sandstone is actually gas-saturated, but the normal crossover effect of the gas on the NPOR and DPHI logs is reversed and masked by the high shale content of the lower part of Burger sandstone. RFT 8 recovered gas and water from the lower part of the sandstone.

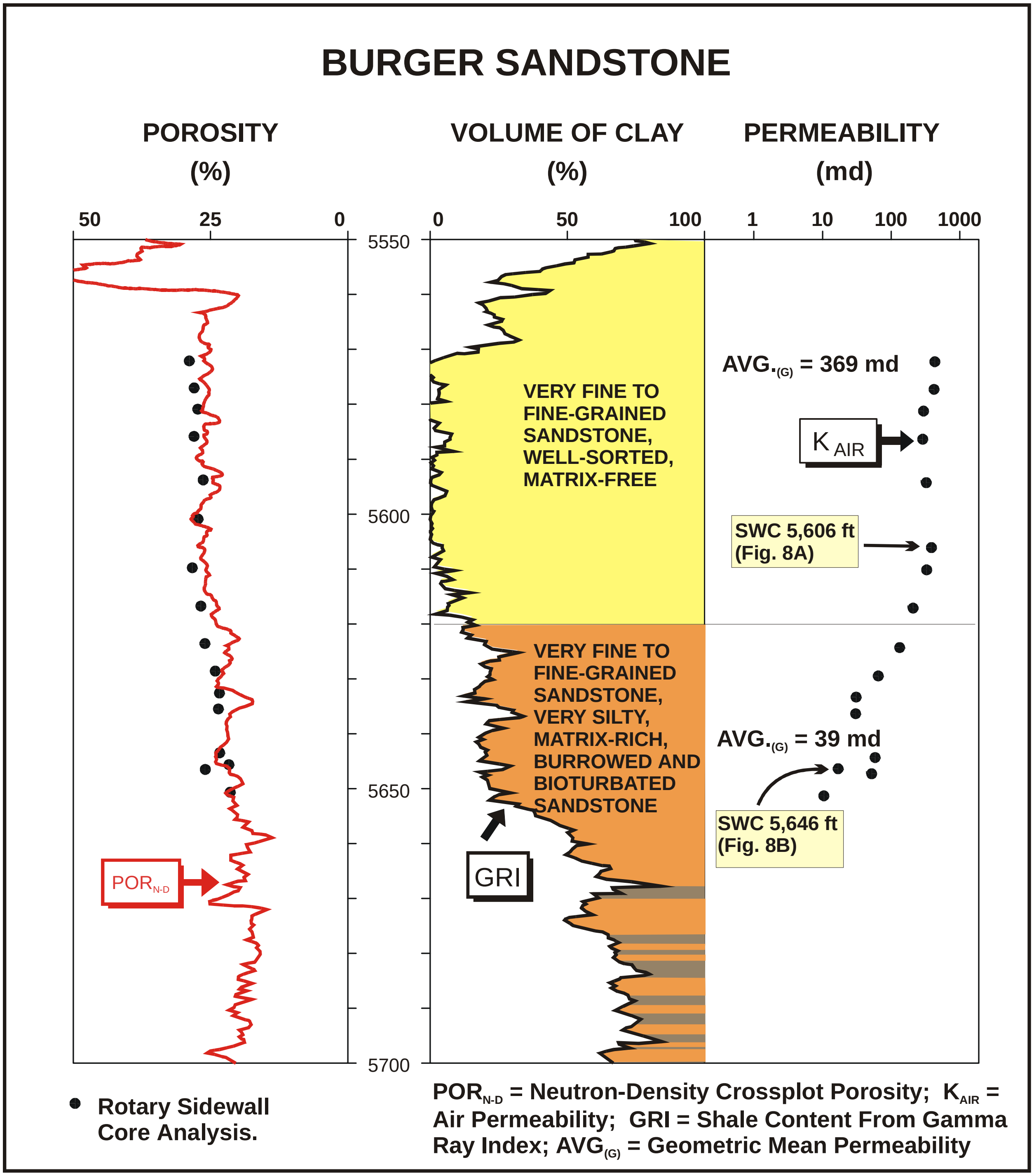


Figure 7: Lithologic and log data for Burger sandstone, with rotary sidewall-core data for porosity and permeability. The sandstone consists of two major units, with a lower muddy and bioturbated sandstone overlain by a clean, well sorted sandstone that probably reflects shoaling and greater sifting by wave action or storm events. The best reservoir quality is associated with the upper sandstone unit. The age of the sequence is Hauterivian to Barremian (Early Cretaceous, ca. 121-132 Ma) and foraminifers indicate a middle neritic to upper bathyal environment of deposition (far offshore near a shelf edge).

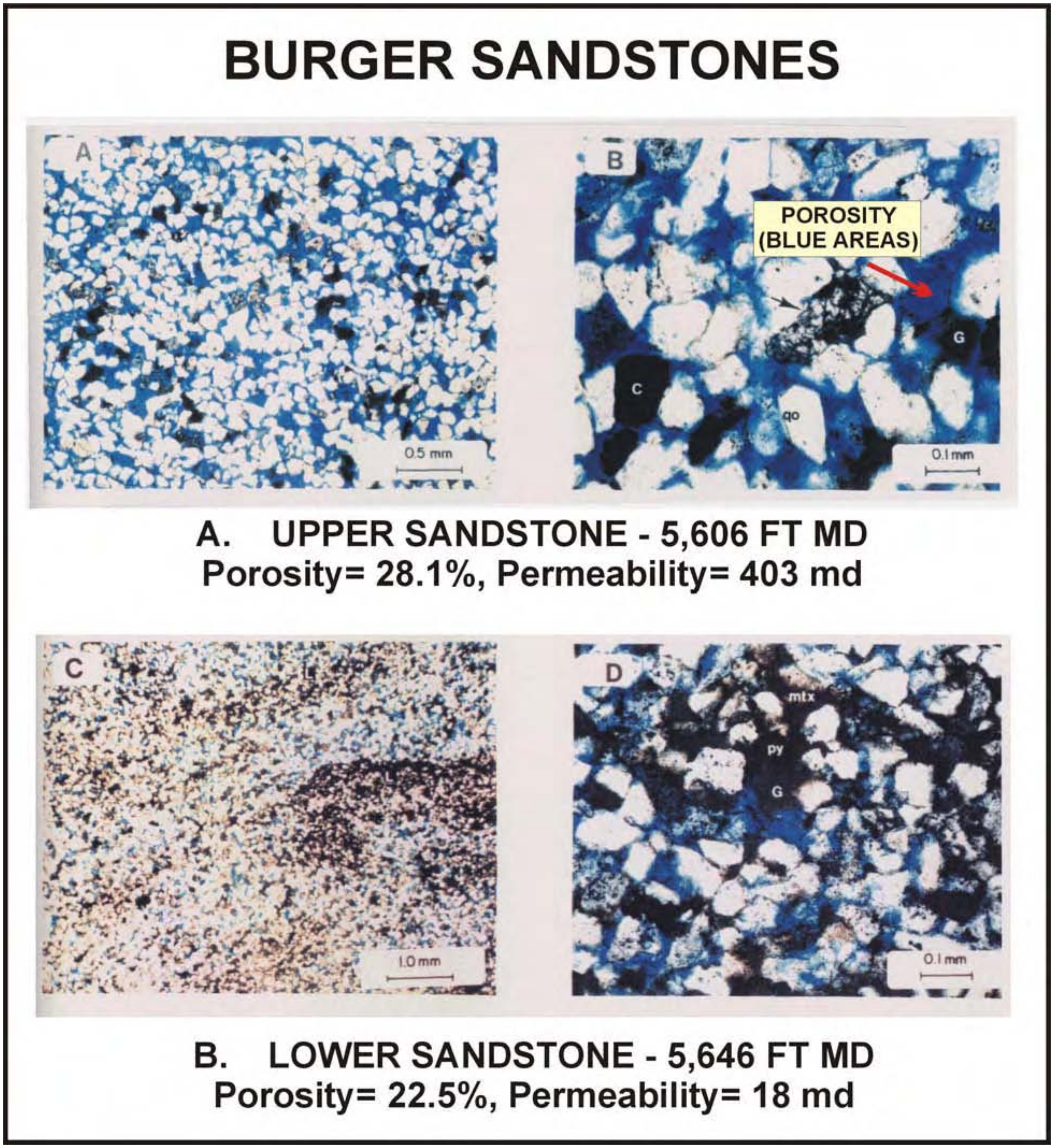


Figure 8: Photomicrographs (microscopic views of thin slices of samples) of two units comprising Burger sandstone sequence, Burger well, Chukchi shelf, Alaska. Blue areas are pores that were injected with blue epoxy prior to photomicrograph preparation. G: glauconite; C: carbonaceous material; qo: quartz overgrowth; mtx: clay matrix; py: authigenic pyrite.

A: upper clean, well-sorted, high-permeability sandstone unit (-5,560 to -5,620 feet); representative sample from rotary sidewall core at 5,606 feet measured depth.

B: lower muddy, bioturbated, low-permeability sandstone unit (-5,620 to -5,667 feet); representative sample from rotary sidewall core at -5,646 feet measured depth.

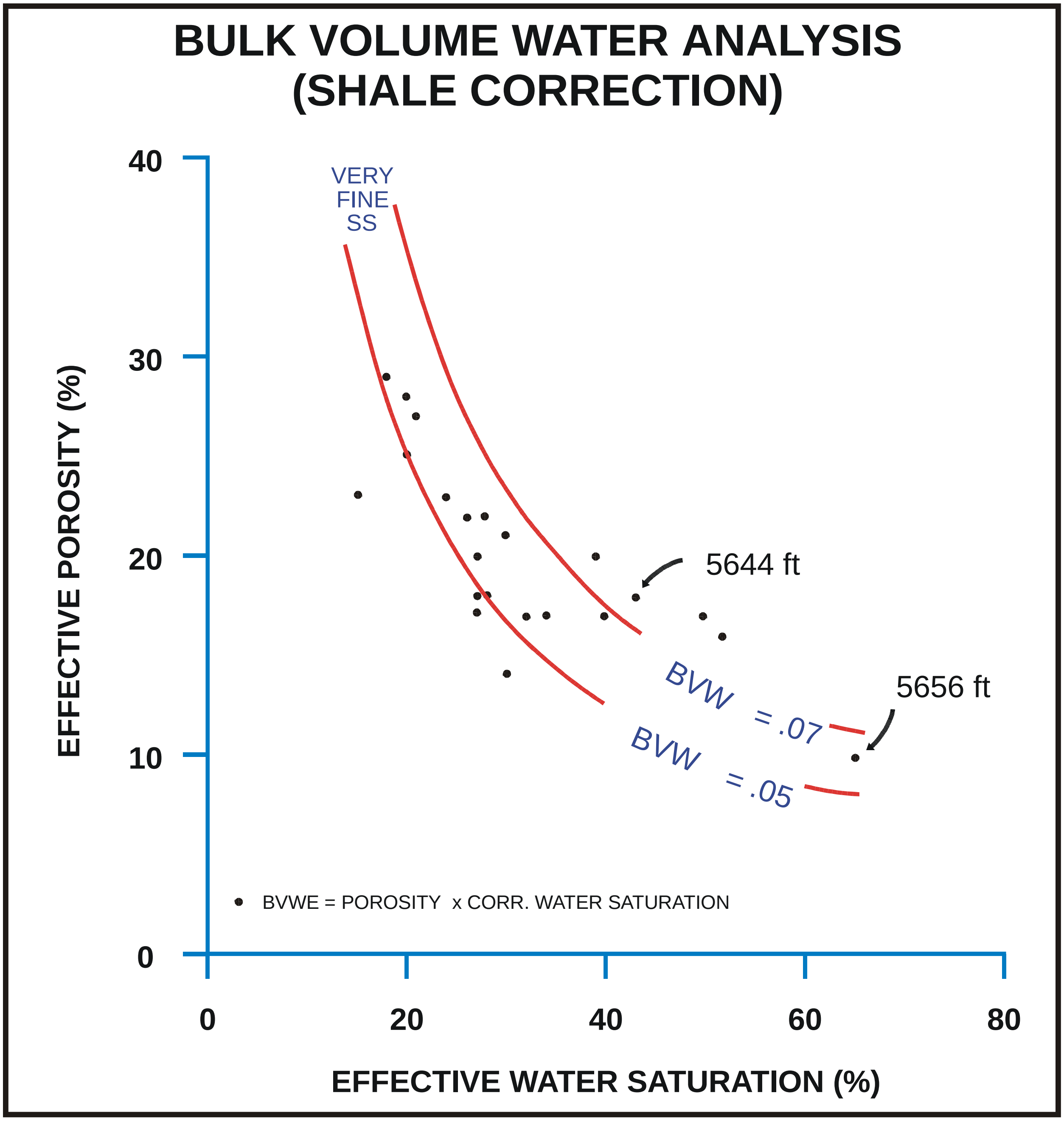


Figure 9: Water saturation model for Burger sandstone, with corrections for shale (mineralogically bound water). The minimum water saturation is 0.17 (maximum gas saturation = 0.83).

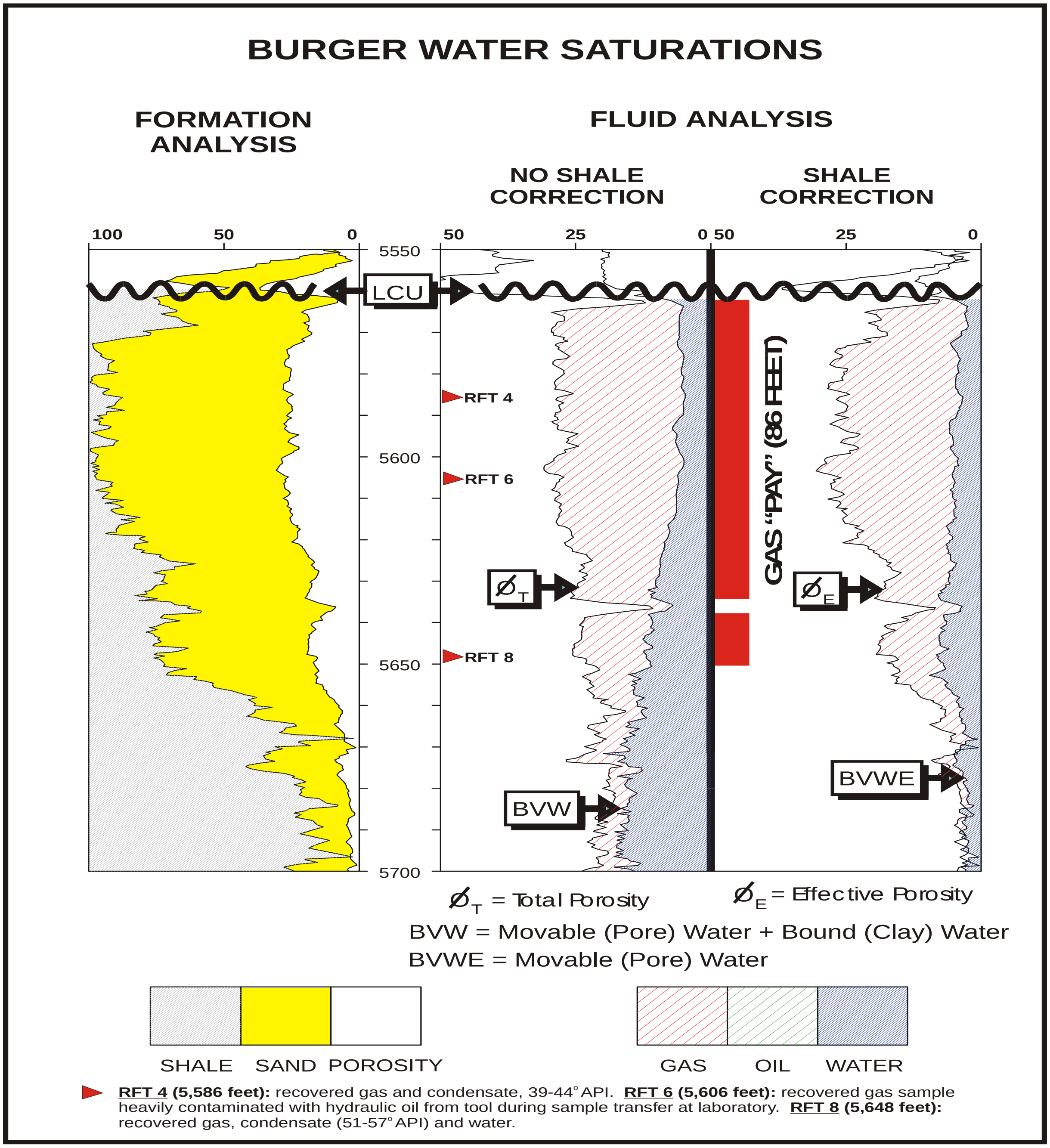


Figure 10: Water saturation model for Burger sandstone, Burger well. The shale correction model (right column) is preferred because it accounts for increasing shale content and mineralogically bound water in the lower, shaly unit of the Burger sandstone. Porosity measurements that are affected by shale are also corrected (shown as "effective" porosity). The shale correction model also shows that significant gas saturations and relatively constant water saturations persist to the base of effective porosity (porosity < 10%) within the sandstone. The presence of gas in the lower sand unit is confirmed by the gas recovery by RFT 8. This suggests that a gas-water contact was not penetrated in the Burger sandstone at Burger well.

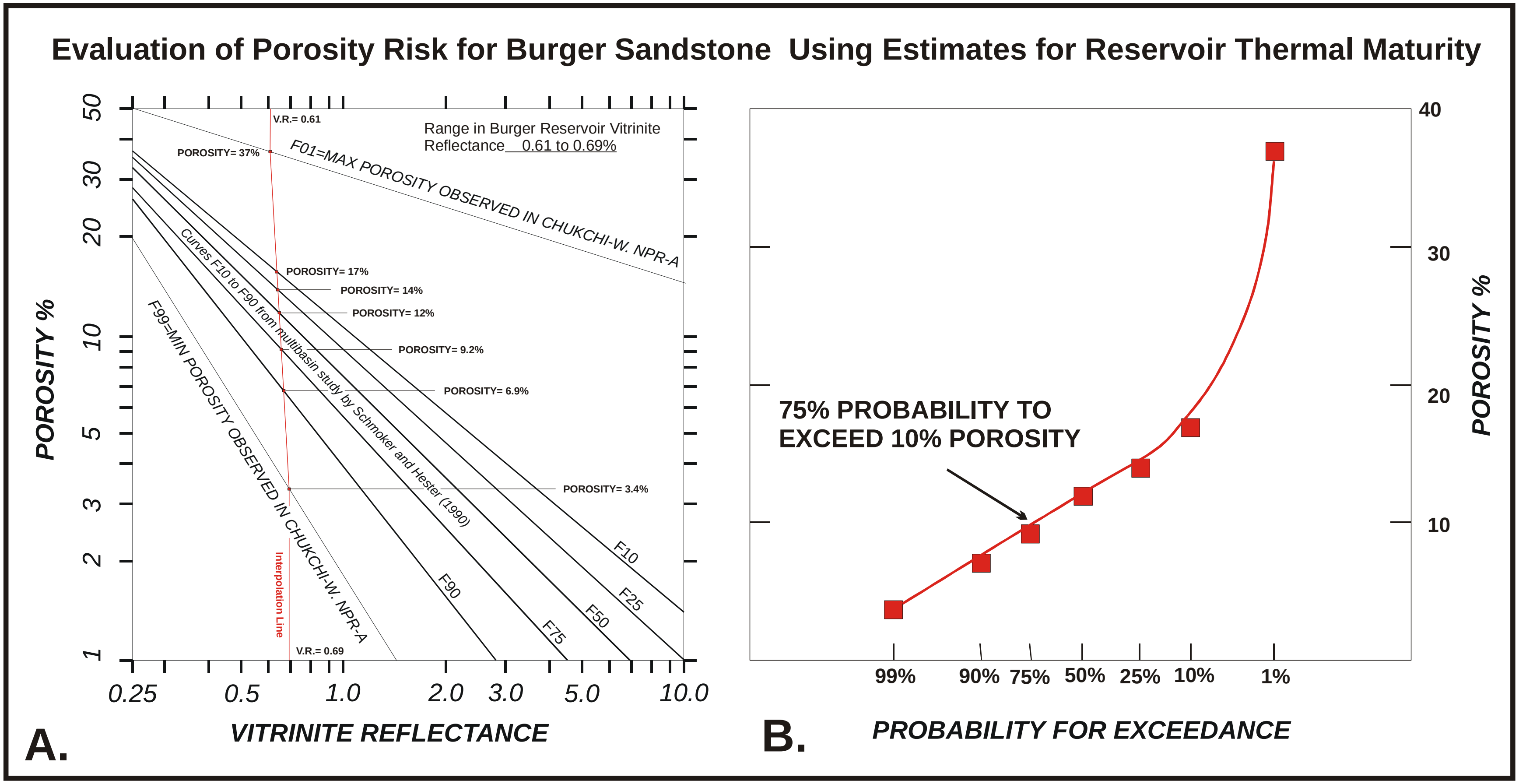
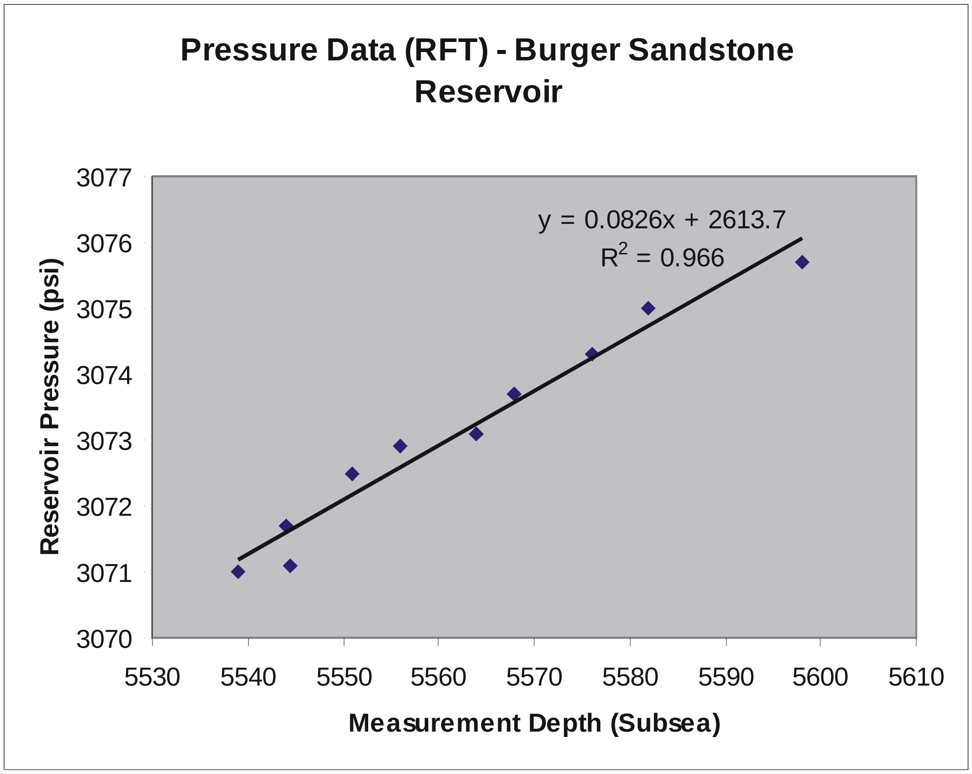
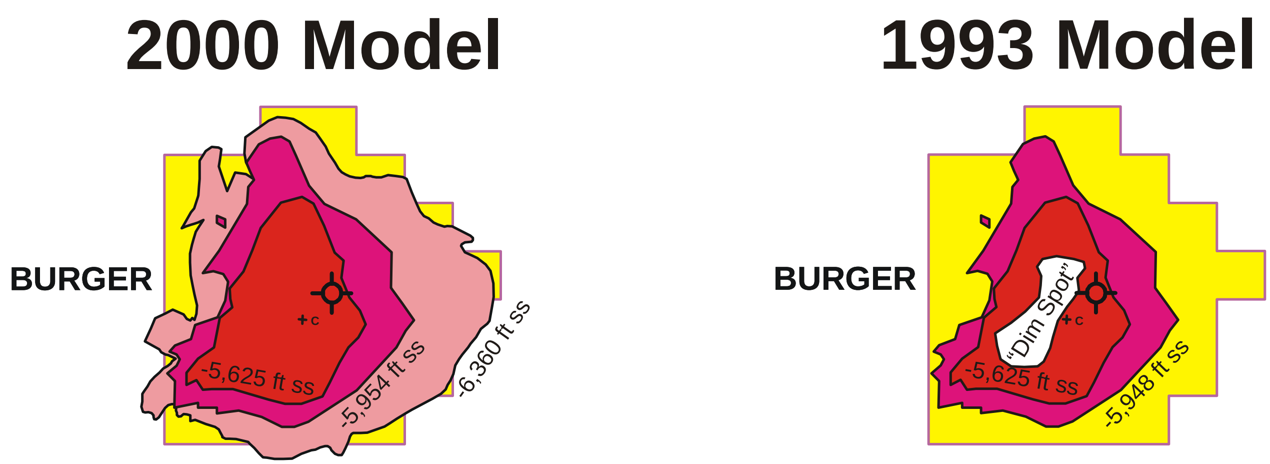


Figure 11: Porosity model for Burger sandstone reservoir based on predicted range in thermal maturity (vitrinite reflectance) of reservoir within Burger structure. The thermal maturity model shown here was created to examine pool risk related to insufficient porosity for productive reservoir, here assumed to be any porosity less than 10%. The thermal maturity model predicts that the probability for exceeding 10% porosity is 75%. That is, 75% of the time the sandstone will be sufficiently porous to be productive. The thermal maturity model ***was not*** used to quantify the input porosity for calculation of the gas resources of Burger pool. The porosity data from rotary sidewall cores (tbl. 3) were used to develop a probability distribution for Burger pool porosity.



Subsea Depth	RFT Pressure
5598	3075.7
5582	3075
5576	3074.3
5568	3073.7
5564	3073.1
5555.9	3072.9
5551	3072.5
5544.5	3071.1
5544	3071.7
5539	3071

Figure 12: Reservoir pressure data from Burger sandstone used to estimate reservoir pressures across Burger structure. The linear regression to plotted data was used to project gas pool pressures at the crest of Burger structure and the base of the gas column. This pressure gradient for the gas pool was also used to project the depth of the gas-water contact (figs. 14-16).



2000 FILL MODELS

Minimum Fill: -5,625 feet subsea (depth to base of gas-bearing sandstone in Burger well)--total 52,516 acres

Most Likely Fill: -5,954 feet subsea (depth to gas-water contact projected from pressure gradient analysis)--total 97,545 acres

Maximum Fill: -6,360 feet subsea (depth to spill contour on Burger structure)--total 189,803 acres

+C: Crest of Burger structure, -5,139 feet subsea

1993 FILL MODELS

Minimum Fill: -5,625 feet subsea (depth to base of gas-bearing sandstone in Burger well), subtracting the 20,833-acre "dim spot" based on the assumption that the sandstone reservoir is absent--total 31,250 acres

Most Likely Fill: -5,625 feet subsea and including area of "dim spot" (20,833 acres)--total 52,083 acres

Maximum Fill: -5,948 feet subsea (depth to gas-water contact projected from pressure gradient analysis)--total 80,000 acres

+C: Crest of Burger structure, -5,139 feet subsea

Figure 13: Fill models used in years 2000 and 1993 assessments of discovered gas resources at Burger structure.

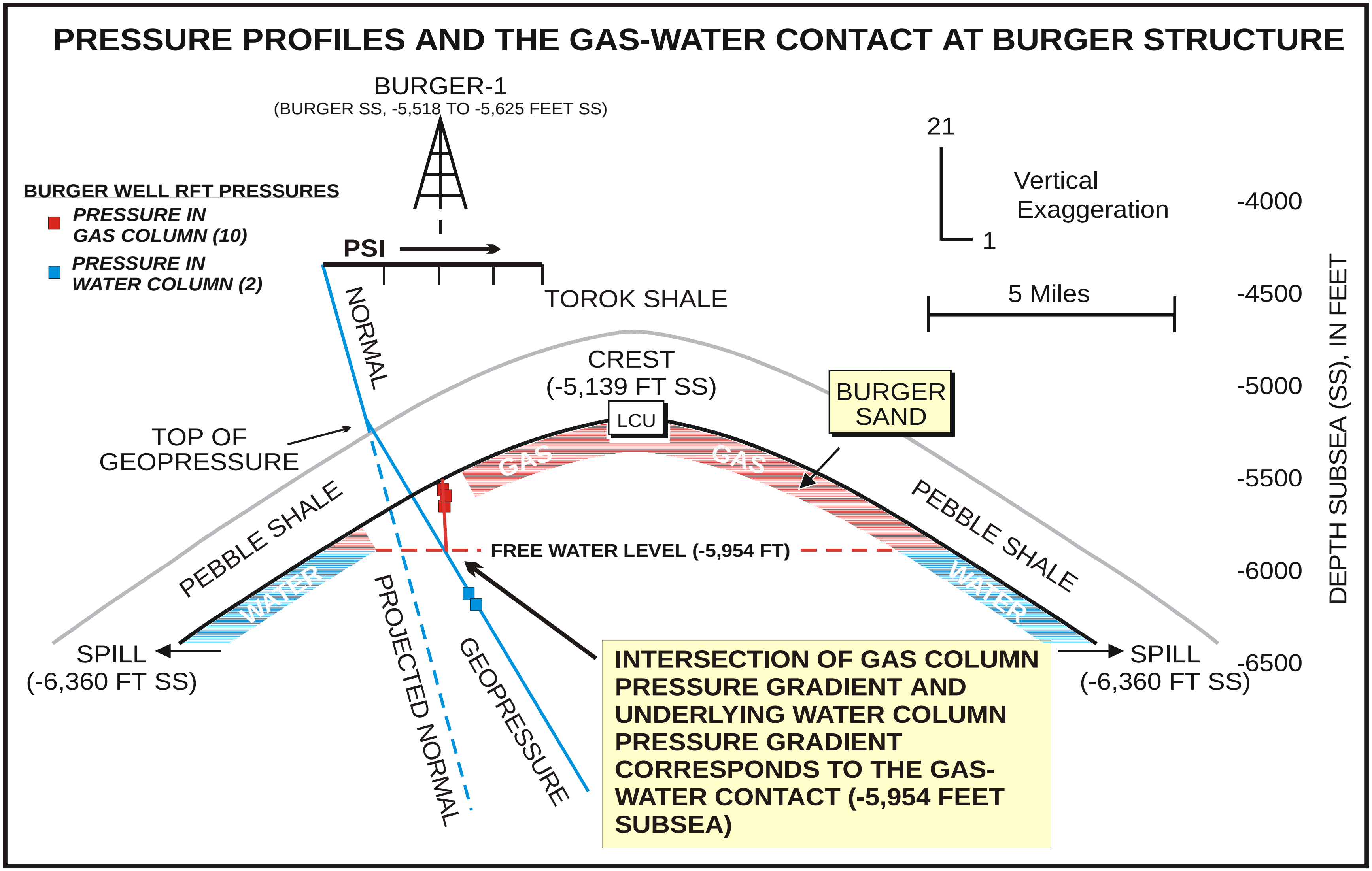


Figure 14: Schematic cross section showing hypothetical disposition of gas and water columns within Burger sandstone across Burger structure. The practice of using pressure gradients derived from RFT pressure measurements to project the depth of the gas-water contact is also illustrated.

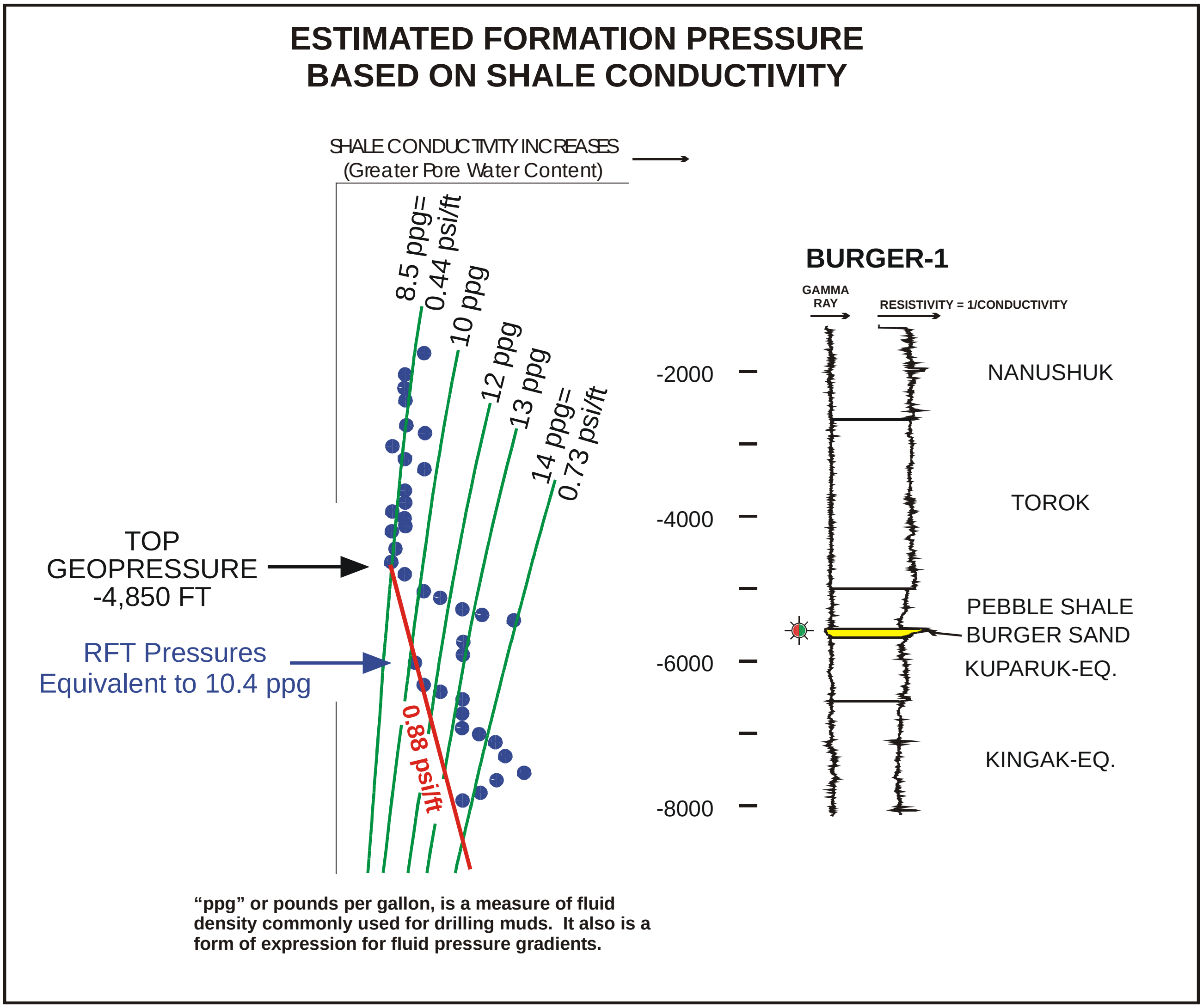


Figure 15: Shale conductivities reveal onset of excess pore pressure or "geopressure" at -4,850 feet subsea in Burger well. Above –4,850 feet, the conductivity of shale declines with greater depth, reflecting normal compaction and expulsion of pore fluids and normal water column pressure gradients of 8.5 ppg (or 0.44 psi/ft). Below –4,850 feet, shale conductivity is abnormally high for the depth of burial. Apparent water pressure gradients (values for data points read from evaluation curves) vary widely, perhaps because of pore water salinity variations, mineralogical variations, or the presence of isolated pressure cells. Pore pressure gradients in the geopressured interval could exceed 14 ppg (or 0.73 psi/ft (projected to the surface). Two RFT-based pressure measurements of approximately 3,260 psi near –6,120 feet sampled pore pressures in the geopressured water column (see fig. 16). These yield a fluid pressure gradient of 10.4 ppg (or 0.53 psi/ft) and serve to calibrate the interpretive curves. In figure 16, a line connecting the RFT pressure measurements at –6,120 feet to the point of onset of geopressure at –4,850 feet yields an interval gradient of 0.8797 psi/ft. A similar line, in red, connects the same pressure points above. This gradient corresponds to the geopressured water gradient in figures 14 and 16.

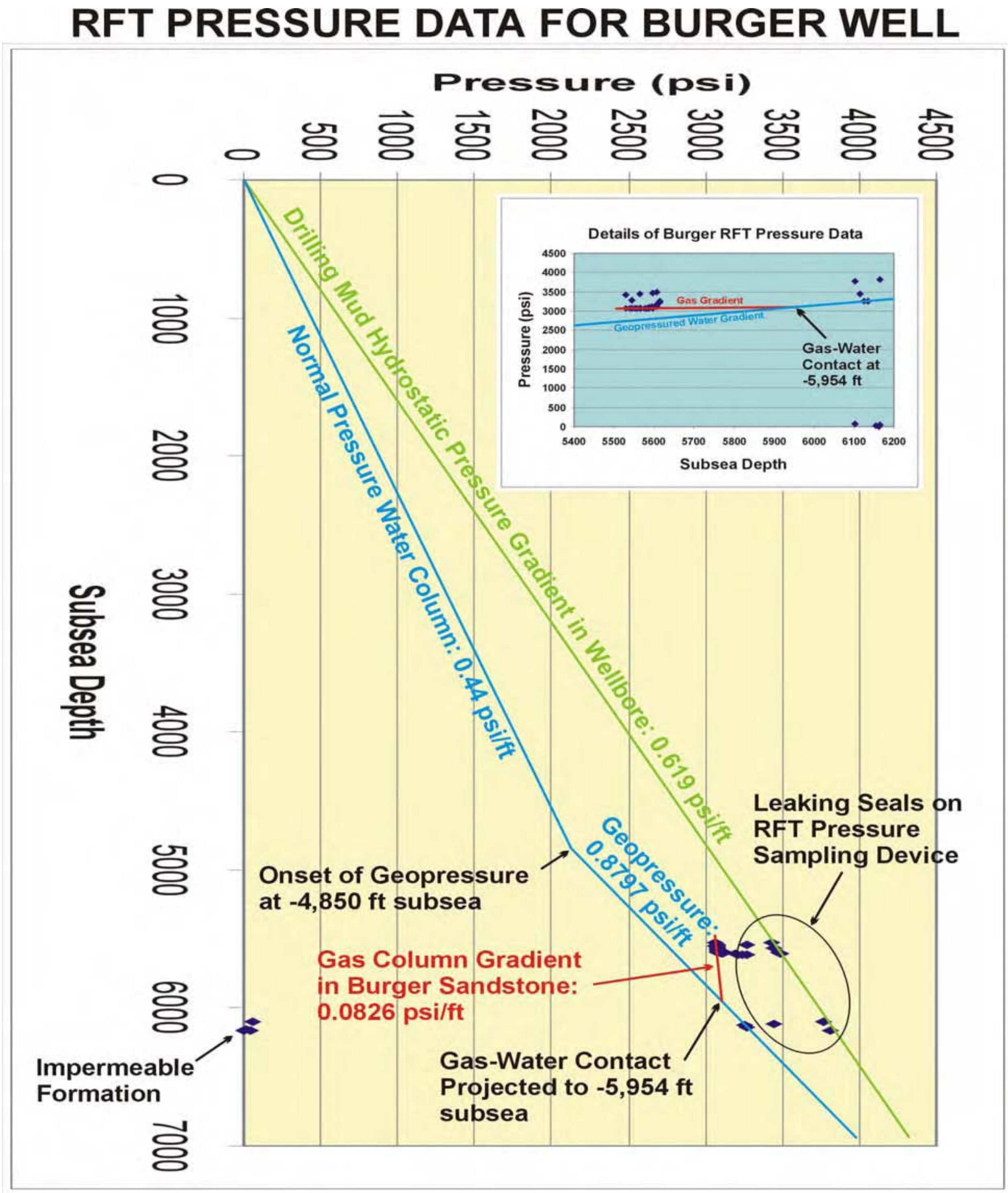


Figure 16: Pressure data obtained by RFT devices in Burger well and projection of gas-water contact to –5,954 feet subsea on Burger structure. The equations for the gas gradient (pressure at gas water contact = 0.0826 (depth) + 2613.7) and the geopressured water gradient (pressure at gas-water contact = 0.8797 (depth) – 2132.5) were solved simultaneously to calculate the gas-water contact at –5,954 feet subsea.

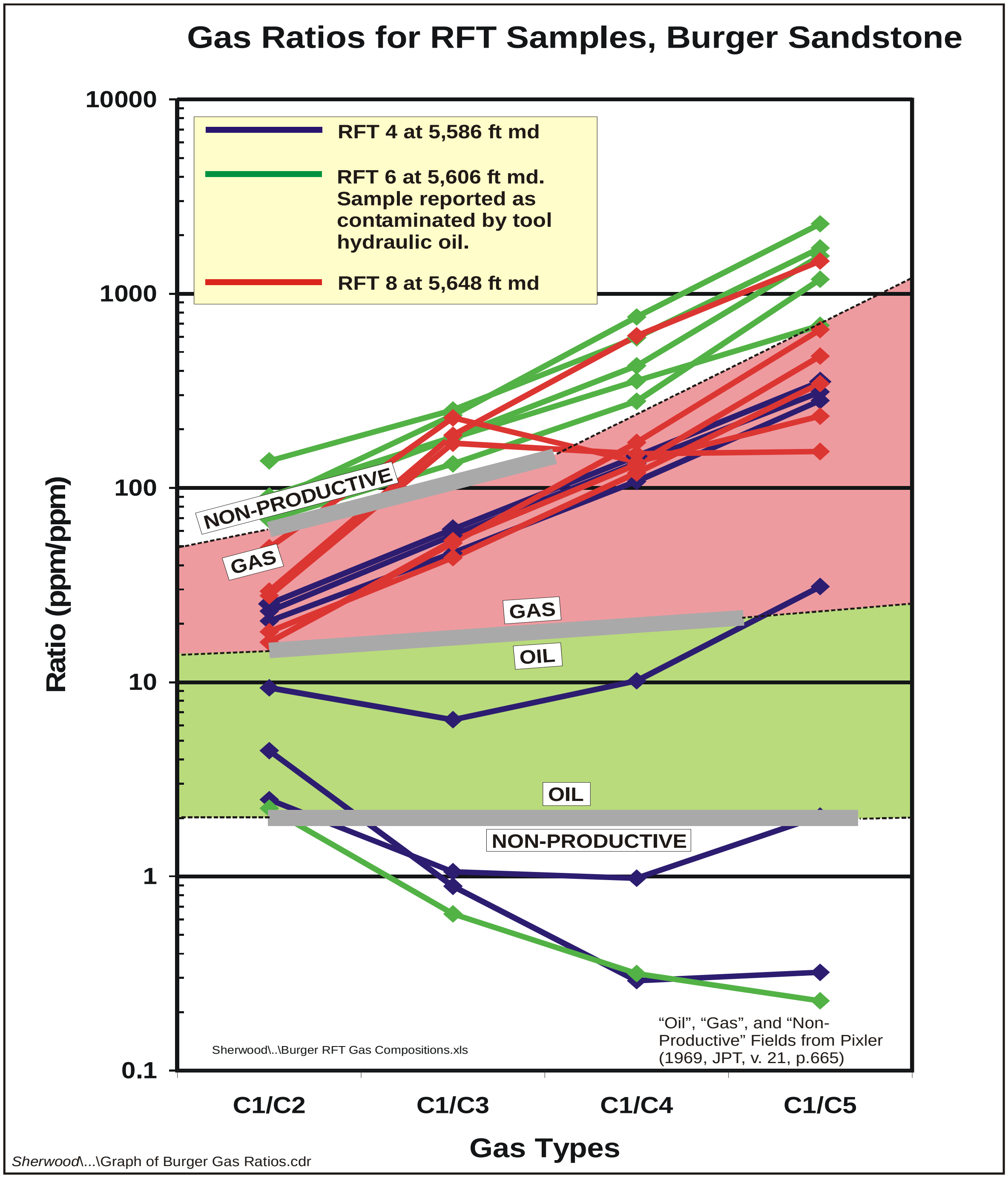


Figure 17: "Pixler" (Pixler, 1969) plot for 18 gas samples recovered from RFT (repeat formation tester) tests of Burger sandstone in measured depth interval 5,586 to 5,648 feet. RFT 6 fluids were contaminated with hydraulic oil during laboratory transfer and yield suspect profiles for C1-C5. Most other samples are consistent with a gas-bearing reservoir. Three samples from RFT 4 yield anomalous C1-C5 profiles and may be condensate liquids.

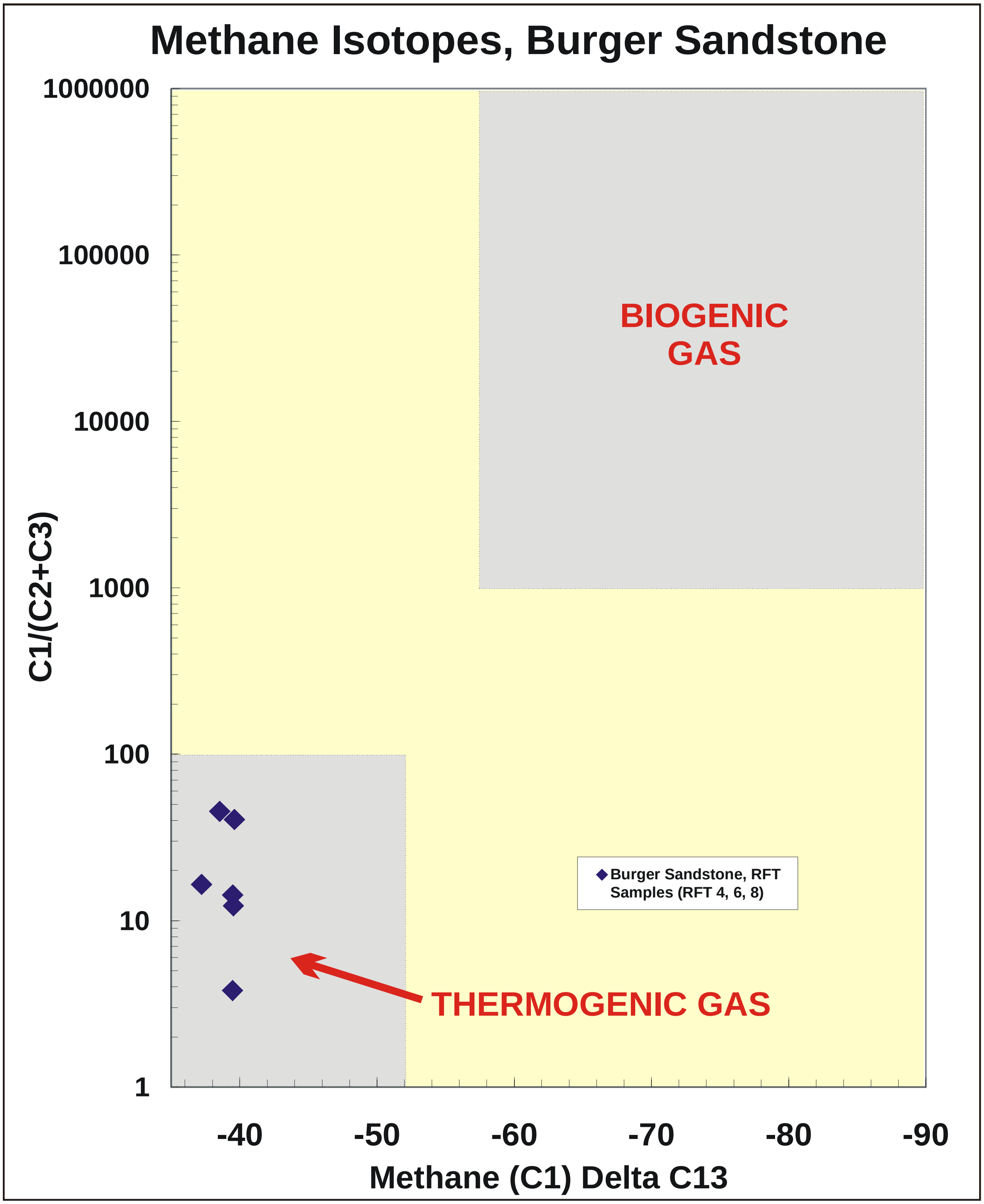


Figure 18: Methane C13 isotope data for gas samples recovered by RFT from Burger sandstone. The Burger methane data plot decisively within the field for thermogenic gas. Plot fields adopted from Schoell (1984) and Claypool and Kvenvolden (1983).

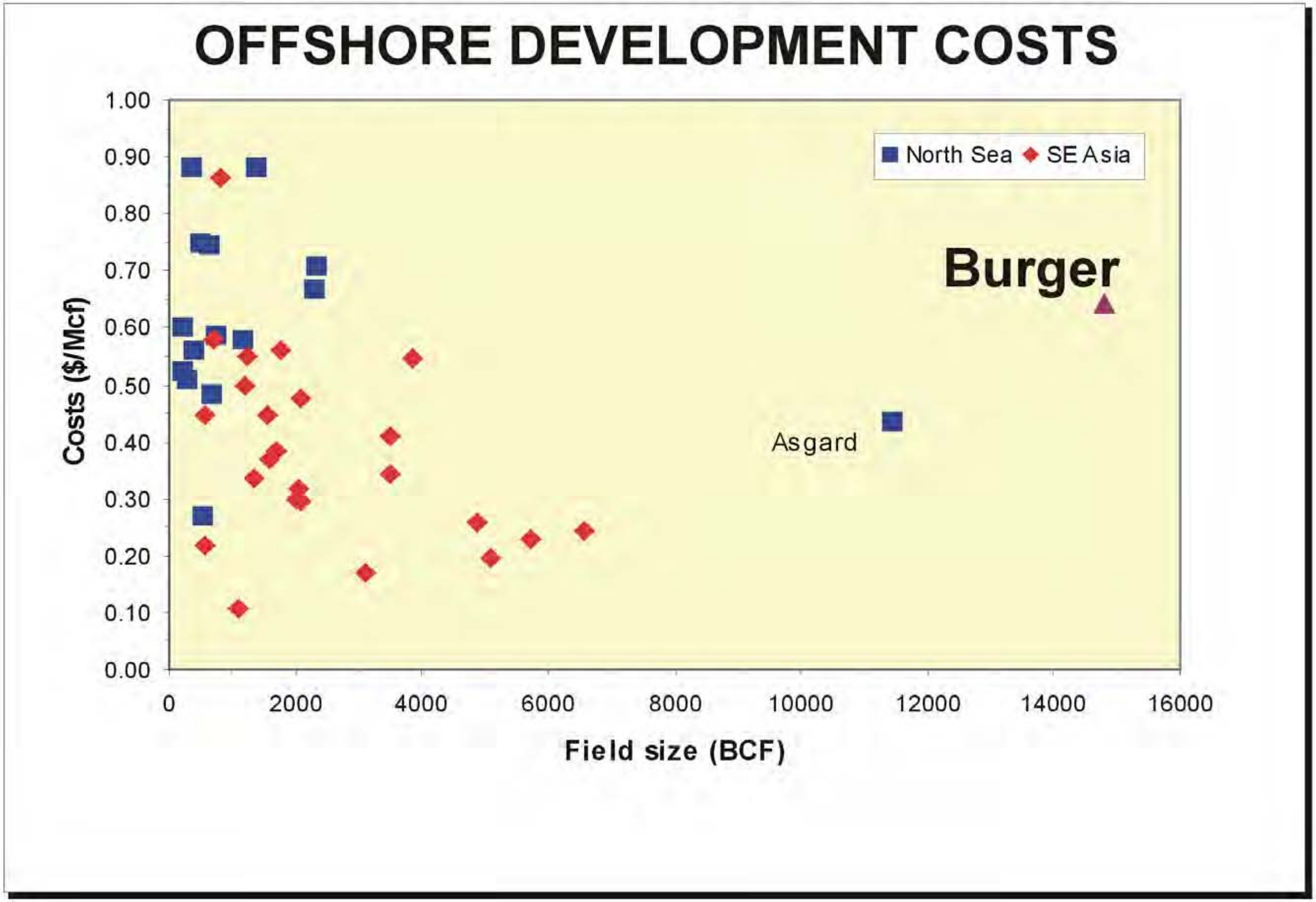


Figure 19: Offshore development costs for projects in North Sea, Southeast Asia and for hypothetical development of Burger pool.

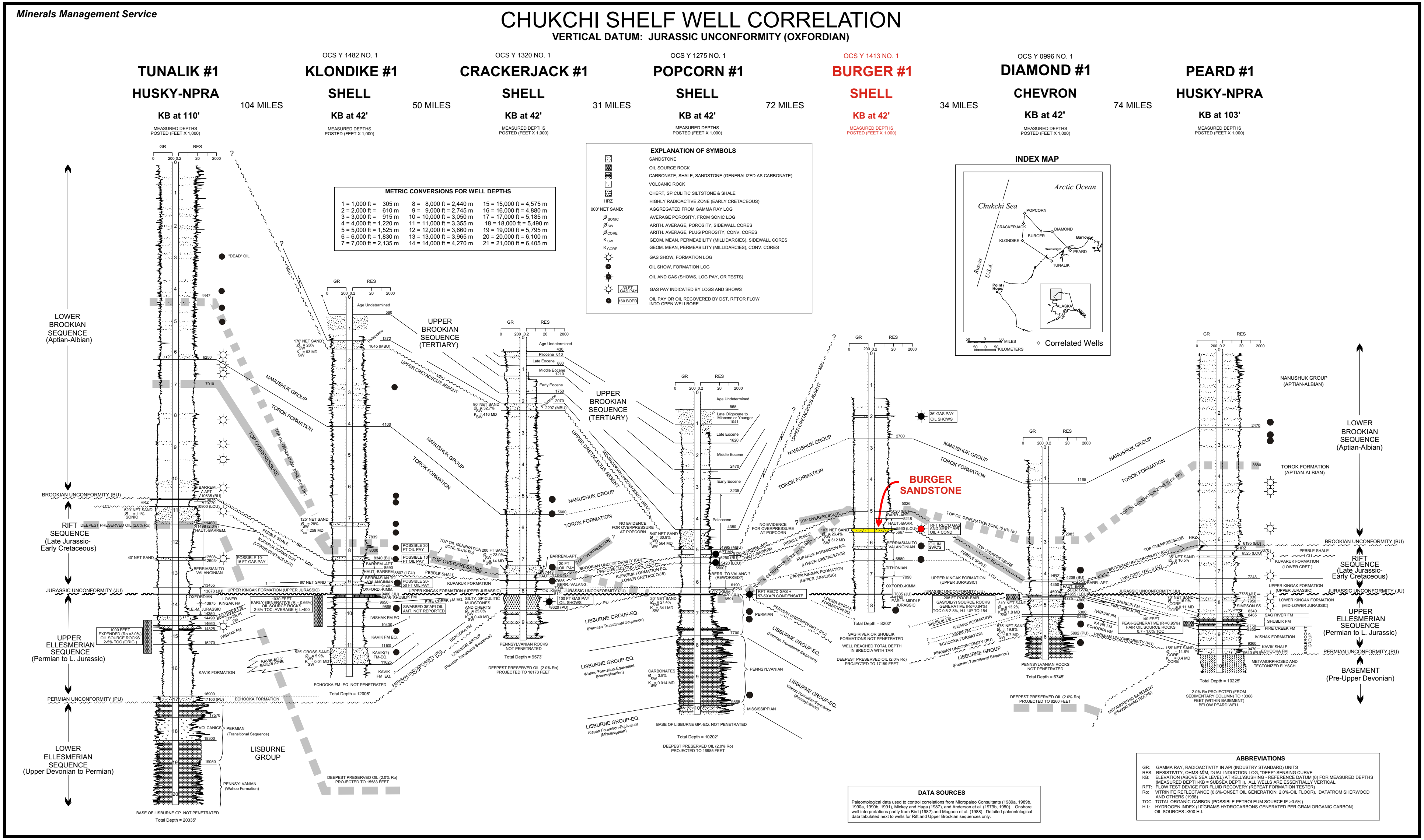


PLATE 1: CHUKCHI SHELF WELL CORRELATION

BURGER GAS POOL, CHUKCHI SHELF

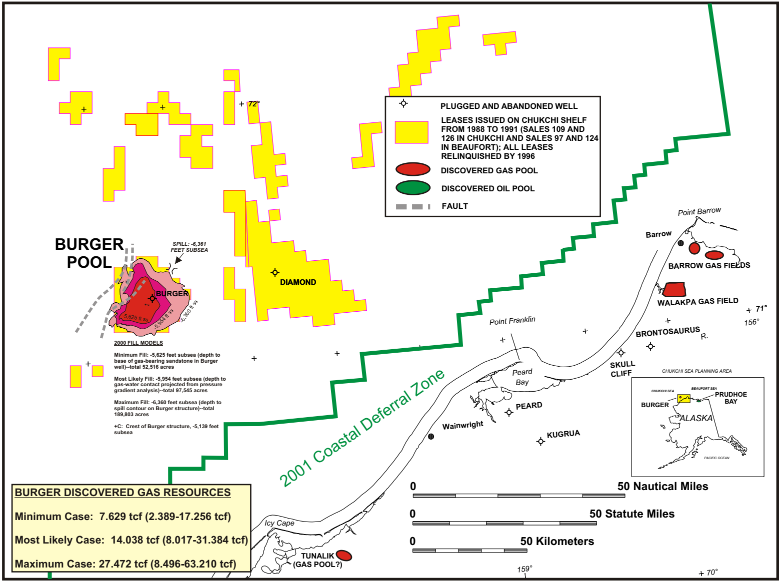


PLATE 2: BURGER POOL AND REGIONAL GAS FIELDS