CHARACTERIZATION AND QUANTIFICATION OF THE METHANE HYDRATE RESOURCE POTENTIAL ASSOCIATED WITH THE BARROW GAS FIELD

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ABSTRACT

The North Slope of Alaska has significant methane hydrate resource potential, and results of previous studies suggest that gas hydrates exist in the Barrow area. Currently, gas from three producing fields provides heating and electricity for Barrow, the economic, transportation, and administrative center of the North Slope Borough. As energy demands grow, it is important to characterize, quantify, and evaluate the potential impact of the postulated gas hydrate accumulation to guide future development, and assess the resource value of the hydrates. The Barrow Gas Fields (BGF) provide an excellent opportunity to study the interaction between a producing free gas reservoir and an overlying hydrate accumulation. A phased research program is underway, funded jointly by the U.S. Department of Energy- NETL and the North Slope Borough to: prepare a research management plan; establish a context for the study based on prior and ongoing research; model the hydrate stability zone associated with the three BGF's; characterize the reservoir properties; model production characteristics of the fields; and select an optimum hydrate test well location in Barrow. Modeling work completed in Phase 1A of the study supports the existence of methane hydrates in association with the BGF's. Phase 1A included sampling and analysis of produced gas; determination of temperature and pressure gradient; and modeling of hydrate stability. In Phase 1B, a detailed reservoir characterization will be completed to: support simulation of hydrate production methodologies; quantify the hydrate resource; and facilitate selection of an optimum location for a methane hydrate test well. If justified by results of Phase 1, Phase 2 of the study would include the design and drilling of a dedicated gas hydrate well near Barrow. This study will contribute to understanding the role of gas hydrate in recharging a producing gas field, while providing substantial commercial and social benefits for the NSB.

Keywords: gas hydrates, hydrate stability, reservoir characterization, reservoir simulation

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INTRODUCTION

The North Slope Borough (NSB) of Alaska comprises an area of 89,000 square miles. Eight communities are located in the NSB including Barrow, Point Lay, Point Hope, Wainwright, Atqasuk, Nuiqsut, Kaktovik, and Anaktuvuk Pass. Barrow is the largest city and serves as the economic, transportation and administrative center for the Borough.

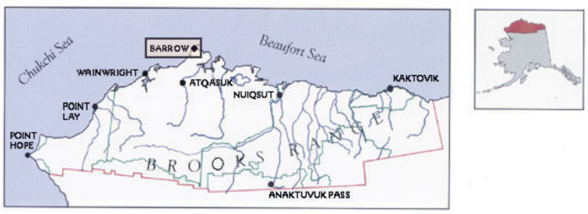

Figure 1. North Slope Borough Location Map

The NSB contains significant known and potential energy resources, including the National Petroleum Reserve-Alaska (NPR-A) and the Prudhoe Bay, Kuparuk, Endicott, Alpine and Milne Point oil fields. The NSB Department of Public Works Energy Management Group oversees production from the Barrow Gas Fields (i.e., East Barrow, South Barrow and Walakpa Fields) which provide heating and electricity for the approximately 4400 residents, businesses and government services in Barrow. Other NSB communities depend on importing fuel at great cost.

Based on current estimates of remaining reserves and consumption rates, the borough's gas supply should last for over 150 years. However, demand for energy is expected to grow in Barrow, and the prospect of distributing gas to outlying villages in the borough will create increasing pressure on the public utility to grow gas supply to meet demand.

The North Slope Borough Department of Public Works Energy Management Group commissioned a study of the remaining reserves in the Walakpa Gas Field in 2005, and has recently commissioned studies to:

- Develop a depletion plan for the Barrow Gas Fields,
- Identify possible infrastructure and operations upgrades to expand gas production,
- Increase surveillance activities at the Walakpa, East Barrow, and South Barrow Fields,
- Update the geologic model for the Barrow Gas Fields to support the planning and drilling of additional development wells,
- Characterize, quantify and evaluate the impact of a postulated gas hydrate accumulation associated with the Barrow Gas Fields.

The final bullet point above is the focus of this study. The depletion mechanism for the Barrow Gas Fields is primarily gas expansion, with potential contributions from edge water drive, and recharge from gas hydrate up dip of the free gas pool. Understanding the details of the drive mechanism is critical to field management, and will impact future development plans, particularly selection of new development well locations and future compression requirements.

The current study, funded jointly by the NSB and DOE-NETL (DOE project number DE-FC26-06NT42962) builds on the results and recommendations of a prior research effort (Glenn and Allen, 1991)

The objectives of this study are to:

- Determine whether or not methane hydrates are likely to exist in association with the Barrow Gas Fields through modeling of the methane hydrate stability zone in the Barrow Gas Field area.

- Characterization of the reservoir properties through integrated geological, geophysical, petrophysical, and production information.

- Reservoir modeling to determine the potential size of a methane hydrate resource, the possible depletion mechanisms associated with historic and future production, and optimal production parameters for the fields.

The project team adopted a phased approach to the study in order to allow for decision points at critical milestones. The results of the hydrate stability modeling determined whether or not the study would progress to the reservoir characterization phase. If the stability modeling indicated that the base of the hydrate stability zone was not likely to be deeper than the shallowest known free gas reservoir in any of the three Barrow Gas Fields, the study would be curtailed. Similarly, if the reservoir characterization effort indicated that the free gas was not interacting with a hydrate accumulation, the study would be shortened.

Phase 1A of this study aimed to establish the likelihood of a gas hydrate accumulation in contact with the Barrow gas fields through modeling of the hydrate stability zone. This modeling effort integrated the pressure and temperature gradients measured in the gas fields with the gas and formation water composition of produced gas and water from the fields to define the envelope of methane hydrate stability. The known phase behavior of methane hydrate, based on temperature, pressure (converted to subsea depth), gas composition, and formation water salinity allows for modeling of the hydrate stability envelope (Figure 2).

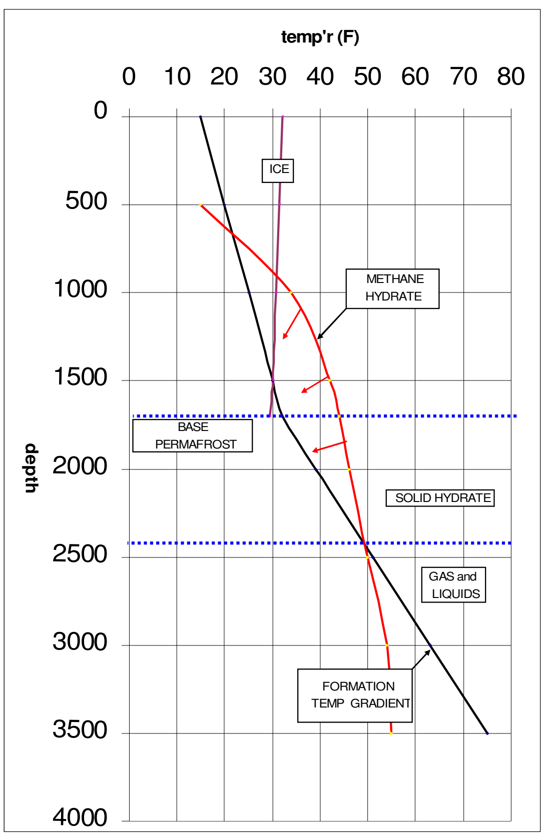

Figure 2. Example of hydrate stability envelope from Prudhoe Bay Unit Eileen Area

Phase 1B of the study incorporated all available well log, core, seismic, and production data to construct a 3D model of the hydrocarbon reservoirs. These detailed reservoir models were used to calculate free gas and hydrate resource volumes, as well as to perform dynamic reservoir simulations to evaluate potential depletion mechanisms, and to predict gas production performance.

Current State of the Art

<u>Physical conditions for formation of hydrates</u>

The pressure and temperature conditions under which gas hydrates exist are shown in Figure 3 for methane hydrates and also for gas with heavier components. North Slope hydrates are believed to contain mainly methane (Walakpa Field produced gas is 98% methane) but any heavier components would extend the pressure, temperature and hence depth range of hydrate stability. The salinity of the water in which hydrates form may also affect the range of hydrate stability as shown in Figure 4, with increasing salinity reducing the range. Since formation water salinities at shallow depths in this region of the North Slope are low this effect should be small.

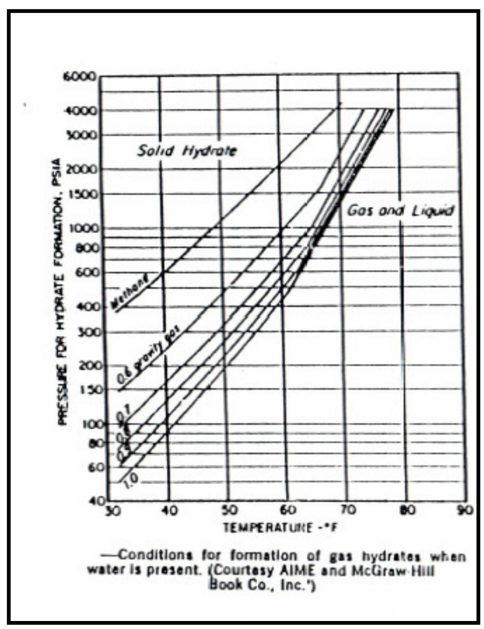

Figure 3. Conditions for formation of gas hydrates

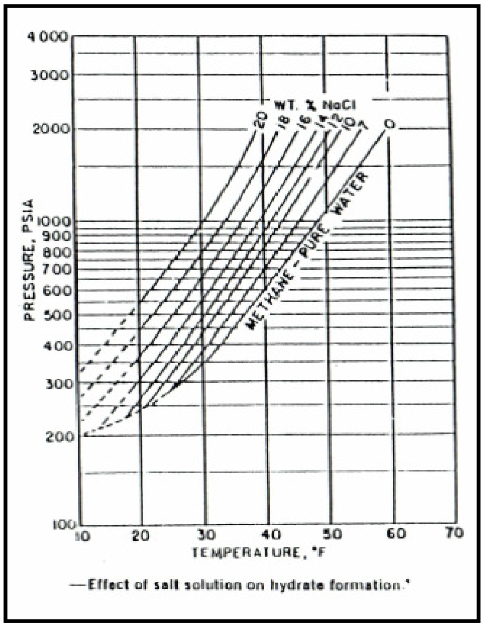

Figure 4. Effect of salinity on hydrate formation

Log Response to Methane Hydrates

Much of the published work on North Slope gas hydrates has been by Dr. Timothy Collett of the USGS. One of the more recent papers, Collett,1998, reviews the evaluation of gas hydrate saturations from logs and the following discussion of log responses and the interpretation of well NWEILEEN-2 are similar in general to those outlined in his paper.

The major issue in detecting hydrates from well logs is that gas hydrates and water ice permafrost have the same responses for the standard suite of logs. Hole conditions for logging can also be poor due to thawing by the drilling mud and subsequent enlargement of the hole in the unconsolidated formations. The gamma ray, neutron and density logs respond normally and can be interpreted for lithology and porosity.

The resistivity log sees both water-ice permafrost and gas hydrate as non-conductive and estimates of the amount of pore space filled by solid ice or hydrate can be attempted. The major source of error in this estimate is knowledge of the formation water salinity, assuming some remains unfrozen to provide the conductivity seen by the logging tool. Salinities are known to be low in this area at shallow depths and in the region of 2000 to 6000ppm. Figure 5 shows effects of salinity and temperature (depth) on Rw.

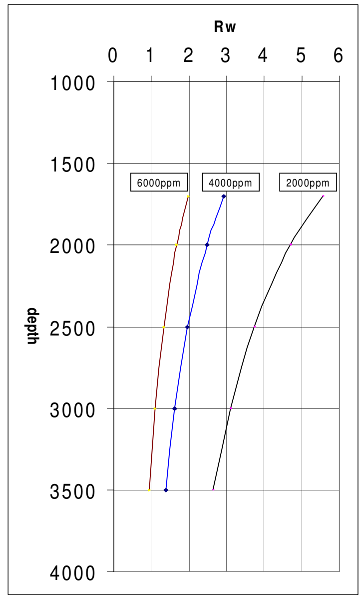

Figure 5. Effect of salinity and temperature (depth) on Rw

Hydrates below the base of the continuous permafrost can be identified by these high acoustic velocity and high resistivity log readings and saturation calculations attempted. Hydrates within the permafrost are very difficult to distinguish from water ice. Mud logs may give some indications and carbon/oxygen or nuclear-magnetic-resonance type logs might work if hole conditions are suitable.

At 2000 feet the possible error in calculated water saturations due to uncertainties in salinity and temperature could easily be a factor of two. There is a lack of core laboratory studies to quantify the range of hydrate saturations or the parameters suitable for use in log saturation calculations.

Gas hydrates and ice permafrost on the North Slope show high acoustic velocities, low transit time, compared with unfrozen formations. Base permafrost is usually picked where the resistivity reduces to a consistent value less than about 50ohmm and the sonic transit time at that point increases in the sands from around 100µs/ft to 140-150µs/ft.

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One result of drilling through hydrate-bearing strata is to thaw the hydrates in the near wellbore zone through the circulation of drilling fluids warmer than reservoir temperatures. Prior to the advent of MWD (Measurement While Drilling) techniques, wireline logging runs were typically not recording the effects of in situ hydrates due to significant thawing while the drill string was tripped out of the well, and wireline tools run in to the zone of interest. Only the most recent wells in the Barrow Gas Fields were logged with MWD tools, and direct evidence of in situ hydrates is weak or non-existent in the Barrow Gas Field wells.

Production of gas hydrates

While gas hydrates are estimated to represent a very significant resource on the North Slope (a 1995 USGS study estimated that gas hydrate in-place volumes approach 590 TCF across the North Slope), adequate production testing has not proven the feasibility of commercial production of this resource, and recovery factor has not been quantified.

The three approaches proposed for the production of gas hydrates are: depressurization; thermal injection; and chemical injection, as shown in Figure 6.

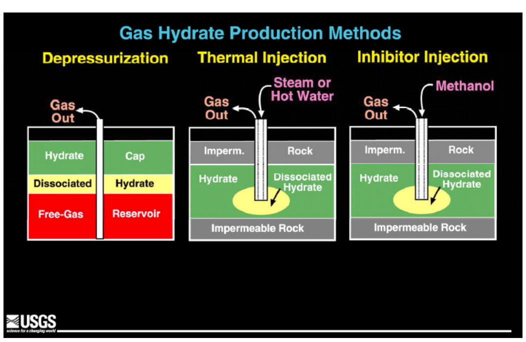

Figure 6. Proposed Gas Hydrate Production Methods (T. Collett)

At Mallik, a depressurization test was achieved by a series of MDT tests and a thermal method was successfully tested using circulation of a heated fluid and measuring the recovery of gas dissociated due to the addition of heat.

The results of the Mallik testing were used to develop and calibrate a methane hydrates production simulator. The simulator was used to make long term production predictions as shown in Figure 7.

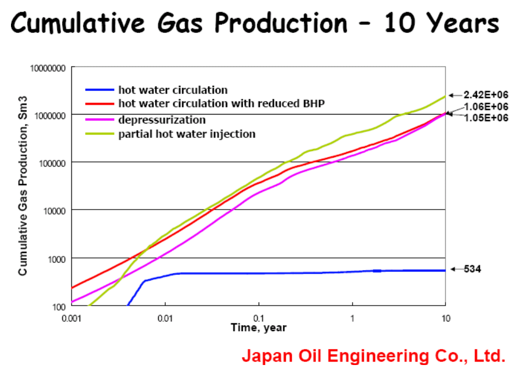

Figure 7 Modeled gas production based on Mallik well tests

Simulation results show that hot water injection will be possibly 2X higher than depressurization, but that depressurization could still recover significant amounts of gas potentially without the capital cost of thermal injection facilities.

The proposed production method in the Barrow Area gas fields test would be by depressurization, drilling horizontally through the up-dip methane hydrates zone and then horizontally down dip into the free gas zone.

PROCEDURE

The objectives of the study were met by carrying out three basic phases of investigation:

- Hydrate stability modeling
- Reservoir characterization
- Reservoir simulation modeling

The methane hydrate stability modeling effort involved: gathering of legacy subsurface temperature and pressure data, and gas and formation water composition analysis; collection of new temperature, pressure and fluid composition data; and integration of all of this data in the Colorado School of Mines CSM-Hyd modeling application to predict hydrate stability envelopes for the three Barrow Gas Fields. Results of this modeling indicated that the base of the hydrate stability zone would intersect the free gas reservoir in the East Barrow Gas Field, and the Walakpa Gas Field, but not the South Barrow Gas Field. The positive results for the two fields triggered commencement to the next phase of the study.

The reservoir characterization phase of the study involved: collection of all available seismic, well log, core, and reservoir fluid property information; interpretation and mapping of all of the data; and creation of an integrated 3D reservoir model for the fields. The completion of the detailed reservoir characterization allowed for calculation of volumetrics for the free gas pool, the hydrate accumulations, and the aquifers associated with the fields.

The final phase of the study involved material balance modeling of the reservoirs to screen the postulated depletion mechanisms associated with free gas production; and full-field reservoir simulation to model historical production, and to predict future production from the fields.

HYDRATE STABILITY MODELING

The methane hydrate stability models for the three BGF are based on the analysis of gas composition, formation water composition, and local pressure and temperature gradient of the individual fields. These parameters, along with the known phase behavior of methane gas hydrate, determine the existence and extent of the hydrate stability zone, postulated by previous researchers.

Historical temperature gradient surveys were collected from well files and field records. These were summarized to use for definition of the methane hydrate stability zone (HSZ).

<u>East Barrow Field HSZ Results</u>
Static temperature gradient surveys were made in wells E Barrow #15 and #21, which had been shut-in for 7+ months and the temperature data from these wells represents the best static reservoir temperature information available.

Gas and water compositions and temperature and pressure gradients were modeled in the Colorado School of Mines methane hydrate stability modeling application (CSMHYD). The modeling results are sensitive to formation water salinity, and the best information available for the East pool indicates salinities in the range of 2.1-2.4% NaCl, based on analysis of samples from the Barrow Sand interval in the SB #15 and SB #17 wells.

Model results indicate that the East Barrow Field is in communication with a methane hydrate zone, as the base of the hydrate stability zone intersects the shallowest known free gas reservoir (Figure 8).

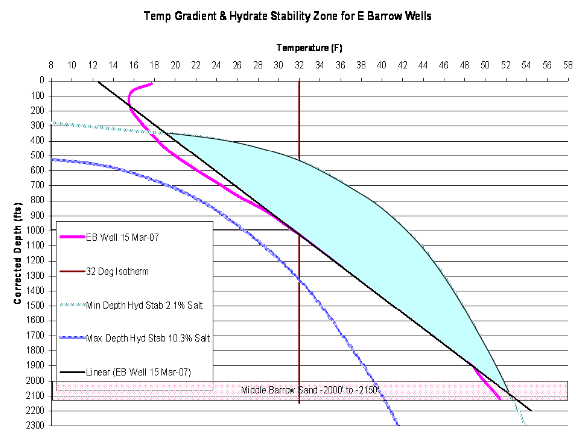

Figure 8. Hydrate Stability Envelope for E. Barrow Field

These model results aid in explaining the apparent pressure support in the reservoir, with no appreciable water production or watering out of wells, as would be expected if a water drive was providing support to the reservoir. The East Barrow Field was suspected to be a reservoir with strong aquifer support from initial material balance work, based on P/Z response (Figure 9) and the field was expected to water-out by now, having produced over 8 BSCF of gas from an original reserve estimate of 6 BSCF.

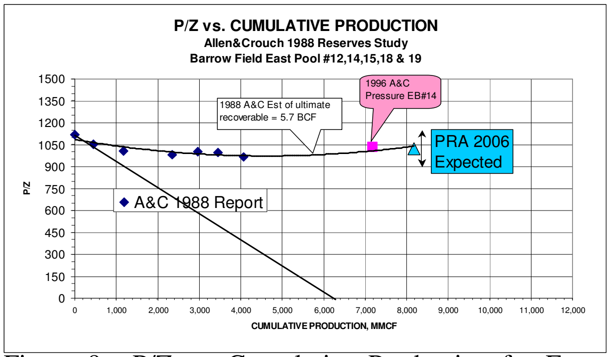

Figure 9. P/Z vs. Cumulative Production for E. Barrow Gas Field

Pressure support from hydrate dissociation could possibly explain the pressure response and production characteristics of this field. The other indicator that may support hydrate dissociation occurring in the East Barrow Field is the cooler temperature gradient at equivalent depths compared to the South Barrow Field. Figure 3 shows the temperature gradients for East Barrow and South Barrow Fields at equivalent subsea depths. The cooler temperatures in the East Barrow Field may be due to the endothermic cooling from the dissociation of methane hydrates. In any case, the lower geothermal gradient at East Barrow promotes a deeper base to the methane hydrate stability zone than that in the South Barrow pool.

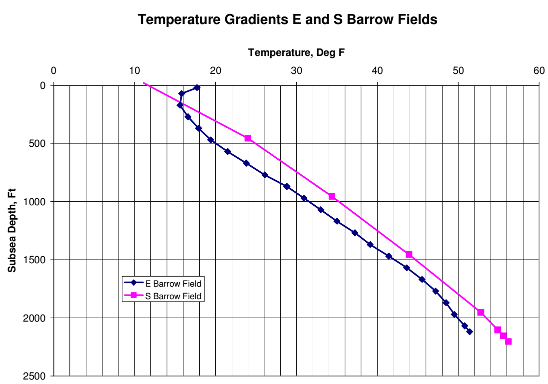

Figure 10. Temperature Gradients for East and South Barrow Gas Fields

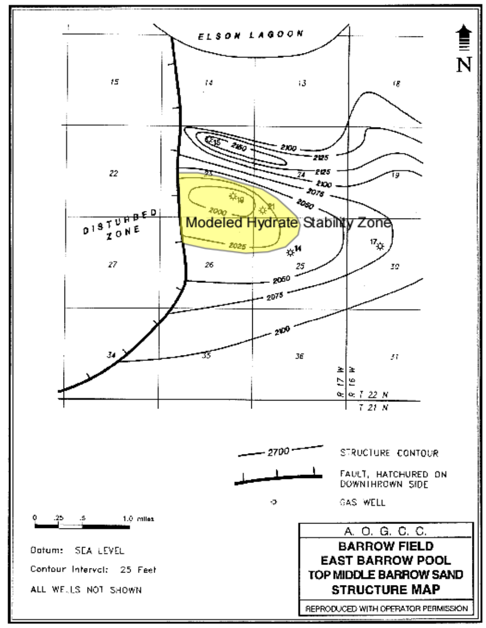

Figure 11. Modeled Hydrate Stability Zone for East Barrow Gas Field

Walakpa Field HSZ Results

Analysis of the pressure, temperature, gas and fluid data for the Walakpa Field similarly support the presence of a hydrate stability zone which is potentially in communication with the free gas reservoir in this field. The base of the modeled hydrate stability zone at Walakpa (Figure 12) coincides with the shallowest well penetration of the free-gas sand.

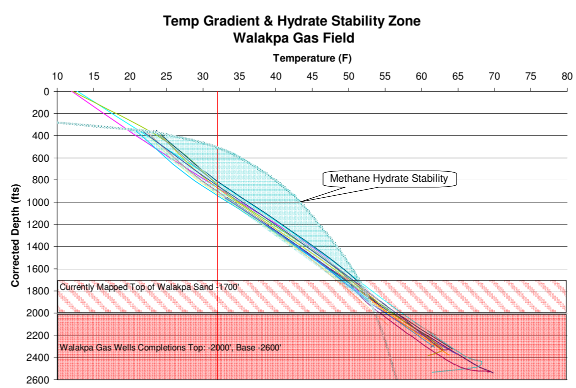

Figure 12. Walakpa Field Modeled Hydrate Stability Zone

The Walakpa Gas Field is believed to represent an extensive reservoir, with a significant downdip aquifer to the south and west of the free gas pool, and an extensive hydrate accumulation updip to the north and east of the free gas pool (Figure 13).

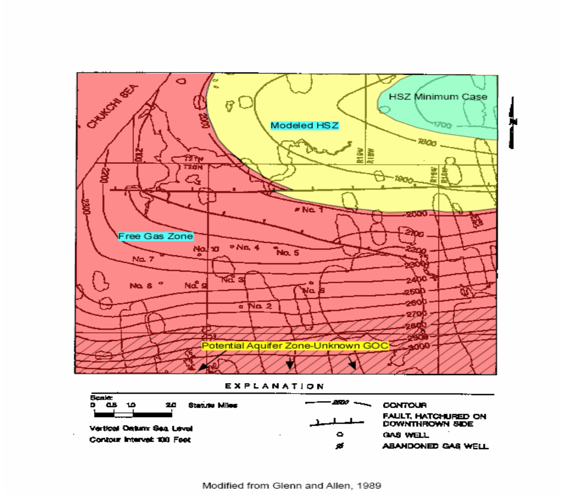

Figure 13. Modeled Hydrate Stability Zone in Walakpa Field

RESERVOIR CHARACTERIZATION

Updated seismic mapping work was undertaken across the Barrow High area, including 1) the Barrow Gas Fields, in which the Jurassic Barrow sandstone is the primary reservoir unit, and 2) the Walakpa Gas Field, which produces from a Neocomian sandstone that was deposited on the Lower Cretaceous Unconformity (LCU) surface. A depth structure map on the LCU was produced for the entire region, and a sub-regional depth structure map on the top of the Barrow sandstone was produced covering the East Barrow, South Barrow, and Sikulik field areas. In addition, individual field maps were produced for all four fields.

All available well data files and reports were reviewed and incorporated into the interpretation, and an updated well pick data set was created from log correlation work. The well picks were used as control for the depth conversion of corresponding seismic horizons and for the generation of isochore maps. Structure and thickness grids, together with the well picks that resulted from this study, were used to build the framework for subsequent gas and methane hydrate reservoir modeling work within and near the field areas.

Careful tying of the seismic data with existing well control, incorporation of all available seismic lines, and phase and time matching of seismic data sets has resulted in improved structural maps for the region. Detailed stratigraphic interpretation of the key reservoir intervals through seismic modeling and attribute work has not been undertaken to date, due to the limited and inconsistent quality of available seismic data. Seismic isochore mapping of the HRZ to LCU interval was undertaken and may provide some insight into the distribution of Walakpa sandstone to the north and east of the existing Walakpa Field area.

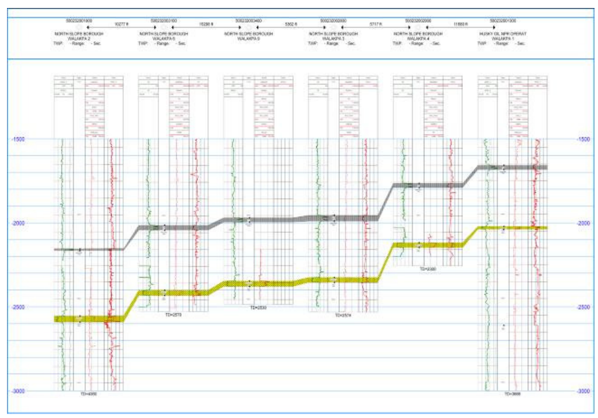

Figure 14. Structural Well Cross-Section, SW-NE Through Walakpa Gas Field

Extensive well log interpretation and correlation was integrated with the seismic interpretation to create depth and thickness maps for the Walakpa and Barrow Sandstone reservoirs. Figure 14 shows a SW-NE well cross-section through the Walakpa Gas Field, from the Walakpa #2 well to the updip Walakpa #1 well. Correlation of the Walakpa reservoir updip of the Walakpa #1 well indicates that the Walakpa reservoir extends tens of miles to the northeast, and well into the hydrate stability zone.

<u>Seismic Interpretation</u>
Seismic interpretation work was undertaken on both regional and local field scales. The regional work covered all of the onshore area shown in Figure 1 and was undertaken for two main purposes: 1) to assure that the interpretations in the separate field areas were consistent and 2) to identify areas outside the field limits where

Walakpa and/or Barrow sandstone members might be present at depths consistent with methane hydrate occurrence. Local field mapping focused on currently producing reservoir units and was done in more detail than the regional work.

The key regional horizons are described below:

Top HRZ – This is the youngest horizon interpreted and is associated with the top of a "highly radioactive shale" which, together with the underlying pebble shale, forms the lowest unit of the Brookian succession.

LCU – The Lower Cretaceous Unconformity is a regional surface of erosion and angular truncation. The Walakpa sandstone immediately overlies this surface.

UJ – This is an Upper Jurassic marker horizon that is truncated by the LCU in the Walakpa field area. It is important because of its subcrop amplitude effects on the Walakpa sandstone response.

LJ – This is a Lower Jurassic marker horizon which typically overlies the Barrow sandstone horizon by one or two legs (cycles). The Barrow sandstone is not an acoustically strong event in the area.

Top Shublik – The top of the Shublik Fm. Is one or two cycles below the Barrow sandstone event and provides a high quality deep marker bed for the area.

Two additional horizons were mapped locally across the field areas:

Top Walakpa ss - The top of the Walakpa sandstone was picked within the 1989 NSB seismic grid covering the Walakpa field area. In this area the top of the sandstone is expressed as a peak, and the base (LCU) is near the next trough below this peak (Figure 15).

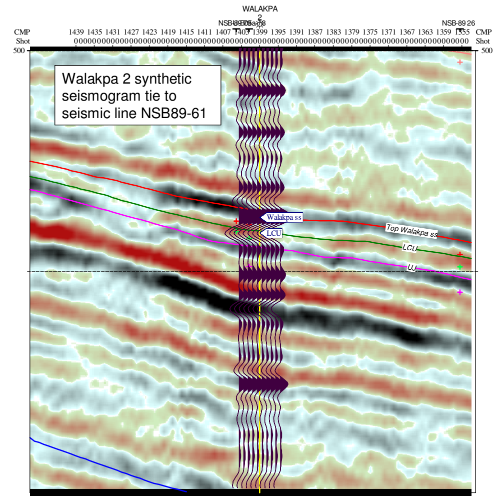

Figure 15. Top Walakpa SS. Seismic Horizon Tie

Top U. Barrow sandstone – The top of the Barrow sandstone was picked sub-regionally across the East Barrow, South Barrow, and Sikulik field areas. It is most closely associated with a broad, low amplitude trough on USGS seismic lines. On the higher resolution NSB lines in the South Barrow and Sikulik areas a peak is resolved at the Top Barrow, but the event is still weak and difficult to pick. In areas of uncertainty the event was picked so as to best preserve the isochron thickness of intervals above and below.

Faults were interpreted, and correlated fault surfaces were created where faults could be confidently mapped across multiple seismic lines. In the East Barrow area faults could be identified on several seismic lines, but could not be confidently traced between lines, so they were not included in the mapping.

The South Barrow, East Barrow, and Sikulik gas fields are located on the northwest, east, and south sides of the Avak crater, respectively, and are structural traps associated with that feature. The Walakpa gas field is located on the south flank of the Barrow High. The trapping mechanism for this field is not clearly understood, but it is quite possible that the trapping mechanism is hydrate and permafrost updip of the free gas field.

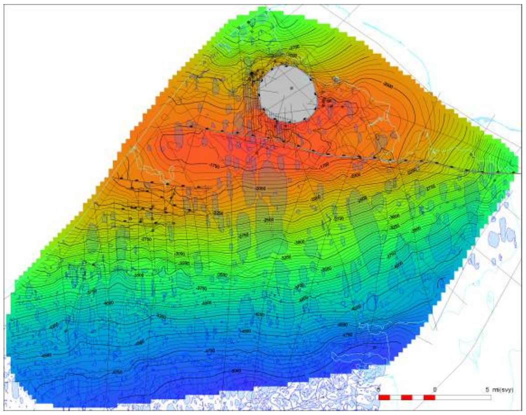

Figure 16. Regional Depth Structure Map on the LCU Horizon

Field scale depth structure maps for producing reservoirs were created for the four gas fields. Figure 17 shows Top Walakpa sandstone depth structure for the Walakpa field area.

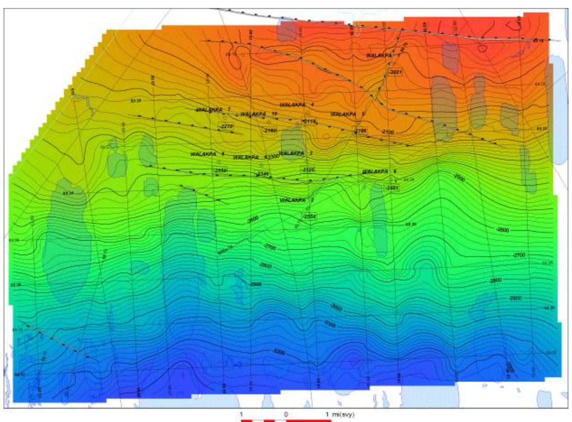

Figure 17. Top Walakpa Depth Map

One of the objectives of the seismic evaluation was to gain insight into the distribution, thickness, and quality of the Walakpa sandstone away from current well control. Updip of the Walakpa Field the sandstone, if present, is at depths prognosed to be within the gas hydrate stability zone. To date, detailed seismic modeling work has not been undertaken on the unit, primarily because of limited seismic data quality outside of the Walakpa Field area and because of LCU subcrop effects. Figure 18 shows maximum amplitude (gridded and smoothed) on the peak associated with the top of the Walakpa sandstone. The low amplitude region trending northwest-southeast through the Walakpa 8, 9, and 2 wells appears to be associated with truncation of the UJ horizon, rather than with thickness changes or other reservoir property variations within the Walakpa sandstone. Any modeling effort would have to account for subcrop acoustic impedance variations and associated side-lobe effects, as well as Walakpa sandstone impedance and thickness variations, and the results would likely be ambiguous. More detailed seismic to well correlation work together with zero-offset and AVO response modeling could be undertaken, if desired, but may be of limited value.

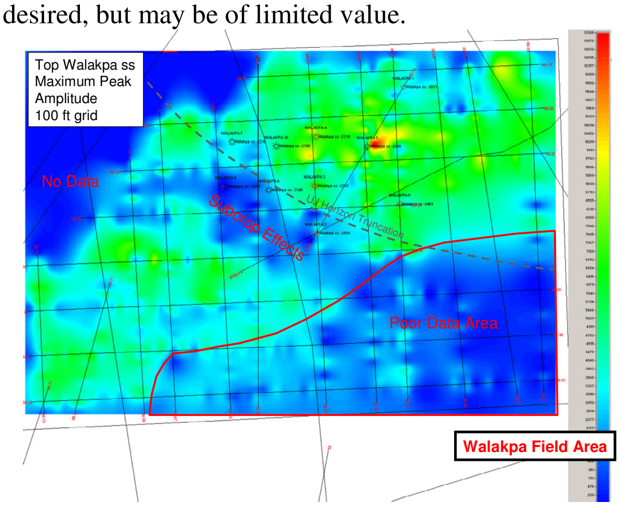

Figure 18. Walakpa SS Maximum Peak Amp

Direct mapping of Walakpa sandstone isochron thickness is not possible on a regional basis because the unit is below seismic resolution in all areas updip of the Walakpa Field and in all data sets except the 1989 NSB seismic lines. However, from the Walakpa Field area south to the Brontosaurus 1 well there appears to be a close correspondence between Walakpa sandstone thickness values from well control and HRZ to LCU isochron values. The HRZ to LCU interval consists mainly of the pebble shale unit, which is anomalously thick in the northwest portion of NPR-A compared to areas to the east.

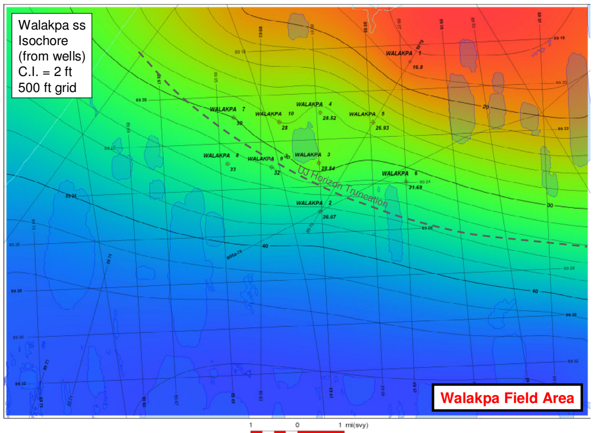

Figure 19. Walakpa SS Isochore from Well Data

Reservoir depth-structure maps, isochores, N/G, porosity, permeability, and Sw calculated curves were loaded to Roxar RMS modeling application to build a geostatistical model of the East Barrow and Walakpa Fields. Selected realizations of the geostatistical models were then used for reservoir simulation modeling.

RESERVOIR MODELING

Material balance modeling was carried out as a screening-level study to compare relative impacts of volumetric expansion, aquifer support, and hydrate dissociation as potential drive mechanisms for gas production in the East Barrow Gas Field. This simple "tank" modeling was undertaken prior to building a full-field reservoir simulation model to indicate whether or not there was enough evidence in the production history to support further investigation of the hydrate dissociation drive mechanism.

Reservoir performance history matching using material balance models was done progressively as follows:

- a volumetric reservoir with an iterative technique that was developed for tight shallow gas reservoirs by West and Cochrane, 1994 called Extended Material Balance (EMB).
- a volumetric reservoir with aquifer support with an analysis technique developed by Pletcher, 2002 and Ahmed & McKinney, 2005.
- a volumetric reservoir with methane hydrate dissociation model used was developed by Gerami & Darvish, 2006.

Volumetric Reservoir Analysis

The EMB methodology was applied to East Barrow gas reservoir. Several iterations were carried out to obtain a constant deliverability coefficient (C). Z-factor and gas viscosity calculations were also undertaken to provide accurate gas property. The best case (constant C) was obtained by assuming an initial gas in place, *G* of 90 std bcf. The initial reserve obtained using this model is exceptionally high compared to volumetric estimates of 15 std bcf (Gruy 1978).

P/Z vs. Gp relationship obtained for the best case and the actual production data is compared in Figure 20. As it is clearly evident from the plot, the profile obtained from EMB model follows a typical volumetric reservoir profile. The model incorporates the deliverability equation in the material balance equation by considering the fact that for a shallow gas reservoir, like East Barrow, the pressure decline is primarily under the influence of pseudo steady state condition.

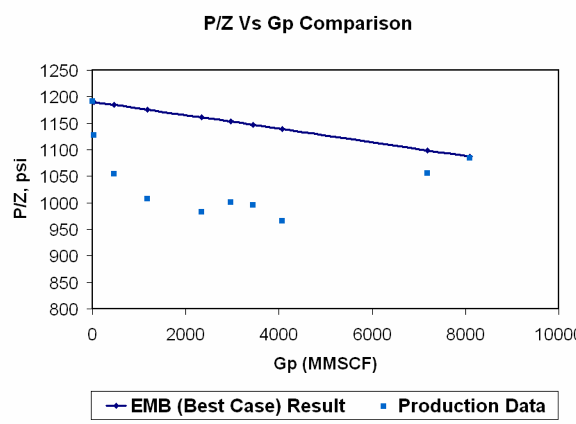

Figure 20. EMB Model – P/Z vs. Gp plot for East Barrow gas reservoir

P/Z vs. *Gp* relationship obtained for the base case is used to obtain reservoir pressure *P* vs. monthly Time (t) (refer Figure-21). The plot is compared with the production profile. Extremely low production rates keeps the bottom hole pressure essentially equal to the reservoir pressure and hence the EMB model matches the production history data in later times, but cannot simulate early pressure draw down.

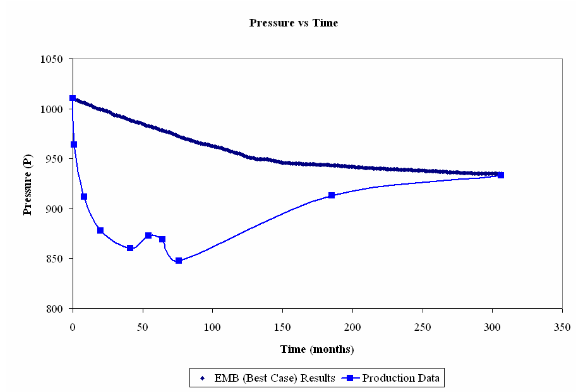

Figure 21. EMB Model – Pressure (P) vs. Time plot for East Barrow gas reservoir

A maximum error of 20% was observed between the EMB model results and production data. Figures 20 and 21 clearly show that the production history data taken from East Barrow gas reservoir never followed the EMB results. This marked deviation confirms that the East Barrow gas reservoir is not volumetric.

The actual reservoir performance for E Barrow pool was not even close to the prediction for a volumetric reservoir drive. This can be seen in Figure 20. The flattening of the P/Z vs. Cum curve is the classic sign of water influx or other replacement of voidage as gas is produced.

Water Influx Analysis

East Barrow production data is utilized to develop material balance model considering a waterdrive mechanism. Figure 22 shows a plot between $(GpBg + WpBw)/(Bg - Bgi)$ and cumulative gas production Gp. A slope is constructed passing through points lying in early production times. Following are the observations and inferences drawn from the plot.

1. The data points clearly show a positive buildup of slope thereby confirming the hypothesis that the reservoir is not volumetric.

2. The steep slope observed in early production time confirms the fact that the reservoir was dominated by gas expansion accompanied with considerable water influx.

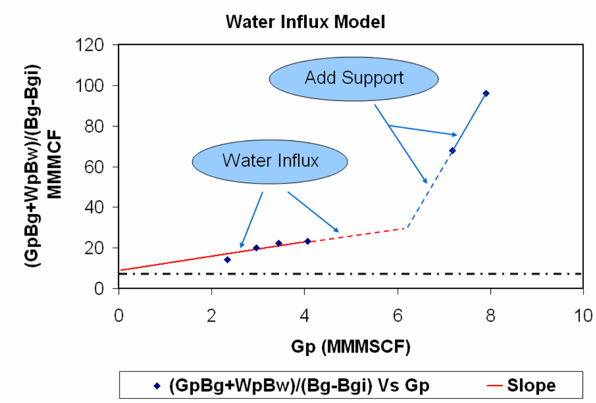

Figure 22. Water in Influx Model - $(GpBg + WpBw) / (Bg - Bgi)$ vs. Gp plot

3. However during later stages of production, the data points shows a vertical jump. Such behavior cannot be explained with water influx model.

4. Hence, due to the limitation with water influx model, the study is now limited to early time periods only. The slope developed through the data points results into an OGIP estimate of 9 Std BCF. Based on this information cumulative water influx, *We* calculations are also performed. At the end of 76 month about 6.83 MMBBLS of water influx has taken place.

5. Interestingly, while estimating aquifer size, it was observed that the aquifer size tends to increase with time and never remained constant as expected. This observation confirms that the size of associated aquifer may not be large enough to support observed reservoir pressures. Nevertheless, after 76th month of production, the size of the aquifer was estimated in the range of 6 MMMBBLS. In other words one will require 6 MMMBBLS of aquifer size to supply water to the gas reservoir in order to achieve the observed reservoir pressure after 76 months of gas production.

To summarize, water influx study confirmed the existence of an aquifer in contact with the gas reservoir. During early production time, the reservoir was producing under moderate to active water drive. However, the model failed to explain the observed shift/jump in the slope (Figure 22) in later time periods.

Methane Hydrate Material Balance Analysis

The Darvish hydrate model and modified version constructed during this study provides a powerful tool to compare the performance of the East Barrow reservoir in presence of hydrate zone.

1. Modifications to Darvish model were made to handle gas reservoir (with no associated hydrates). The result obtained from modified Darvish model was validated by comparing the performance of a volumetric reservoir (no hydrates). The P/Z vs. Gp and P vs. Time plots were constructed and responses were compared. The results show a close agreement between the results obtained using two different models. The exercise validates the effectiveness of modified Darvish model in representing no hydrate condition in a gas reservoir.
2. The modified Darvish model is now applied to East Barrow type reservoir. The reservoir is produced at a constant production rate of 1600 MSCF/Day. The reservoir is considered to be of volumetric type (no associated hydrates). Actual production data is compared with the performance of modified Darvish model.

   As expected the production data and modified Darvish results never matched during the entire production life of the reservoir. Thus, we conclude that the reservoir is under constant pressure support from either water influx and/or associated hydrates.
3. **To study the impact of hydrate layer on reservoir performance, original Darvish model is used and performance of East Barrow type reservoir model is evaluated. The reservoir performance is then compared for several hydrate thicknesses as shown in Figures 23 & 24. The plot shows that as the thickness of hydrate zone is increased, the reservoir pressure stabilizes.**
4. The Darvish model is proposed for a volumetric gas reservoir system with a layer of hydrates. It has no provision to include the effect of water influx into the overall material balance and therefore the two external pressure support mechanisms (water influx and hydrate supports) cannot be modeled together with simple material balance method.

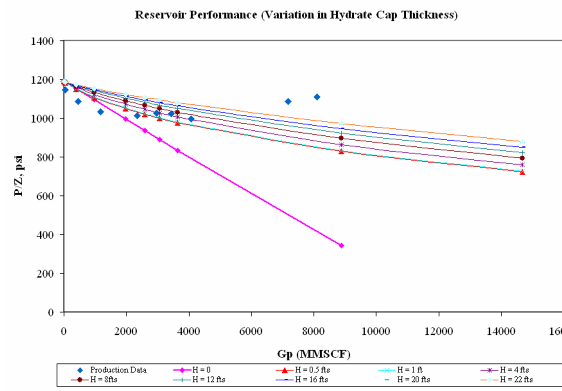

Figure 23. Hydrate Model: P/Z vs. Gp comparison for Darvish model

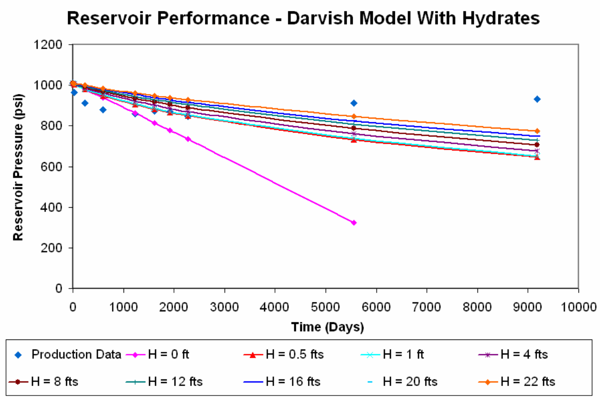

Figure 24. Hydrate Model : Pressure vs. Time comparison for Darvish model

Material Balance Modeling Conclusions

The reservoir performance is not volumetric and therefore has external pressure support either from an aquifer, methane hydrate dissociation or a combination of both.

The water influx model did not match the reservoir performance, as matching the pressure history required an increasing size of aquifer.

The hydrate model came close to matching the reservoir performance with thicknesses of 22' of hydrates, but it still did not fully explain the pressure history.

Based on the material balance investigation with the volumetric model, the water influx model and the methane hydrate model, it is apparent that the pressure history can be explained by a combination of water influx and methane hydrate dissociation. The material balance modeling justifies the next step in modeling this reservoir using a three dimensional reservoir and thermodynamic model. This will also allow varying the strength of the aquifer and the thickness of the hydrate zone to better match the reservoir performance.

Based on the results of the material balance modeling, a full-field reservoir simulation model was run using CMG-STARS to extend the history match work and to facilitate planning for potential drilling and production of the methane hydrate reservoir. The results of this modeling were not finalized at the time of submission of this paper.

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