Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay – Kuparuk River Area on the North Slope of Alaska

December 2003 Quarterly Technical Report
Fifth Quarterly Report: October 2003 – December 2003
Cooperative Agreement Award Number DE-FC-01NT41332

Submitted to the
United States Department of Energy
National Energy Technology Laboratory
ADD Document Control

by

BP Exploration (Alaska), Inc.
Robert Hunter (Principal Investigator)
P.O. Box 196612
Anchorage, Alaska 99519-6612
Email: hunterrb@bp.com
Tel: (907)-696-2124, (907)-301-9265

with
University of Alaska Fairbanks
Shirish Patil (Principal Investigator)
425 Duckering Building
P.O. Box 755880
Fairbanks, Alaska 99775-5880

and
Arizona Board of Regents
University of Arizona, Tucson
Robert Casavant (Principal Investigator)
Dept. Mining and Geological Engineering
Rm. 245, Mines and Metallurgy Bldg. #12
1235 E. North Campus Dr., POB 210012
Tucson, AZ 85721-0012

in collaboration with
United States Geological Survey
Tim Collett (Principal Investigator)
Denver Federal Center
Box 25046, MS939
Denver, CO 80225

March 3, 2003

DISCLAIMER

ABSTRACT

Interim results are presented from the project designed to characterize, quantify, and determine the commercial feasibility of Alaska North Slope (ANS) gas-hydrate and associated free-gas resources in the Prudhoe Bay Unit (PBU), Kuparuk River Unit (KRU), and Milne Point Unit (MPU) areas. This collaborative research will provide practical input to reservoir and economic models, determine the technical feasibility of gas hydrate production, and influence future development, field extension, and exploration of this potential ANS resource.

The large magnitude of unconventional in-place gas (40 – 100 TCF) and conventional ANS gas commercialization evaluation creates industry-DOE alignment to assess this potential resource. This region uniquely combines known gas hydrate presence and existing production infrastructure. Many technical, economical, environmental, and safety issues require resolution before enabling gas hydrate commercial production.

ANS gas hydrate and associated free gas reservoirs are being studied to determine reservoir extent, stratigraphy, structure, continuity, quality, variability, and geophysical and petrophysical property distribution. Phase 1 (October 2002 – October 2004) is characterizing reservoirs and fluids, leading to recoverable reserve and commercial potential estimates, and defining procedures for gas hydrate drilling, data acquisition, completion, and production. Phases 2 (November 2004 – December 2005) and 3 (January 2006 – December 2006) will integrate well, core, log, and production test data from additional wells, if justified by results from prior phases. The research program could lead to future ANS gas hydrate pilot development.

The gas hydrate-bearing Tertiary Sagavanirktok formation is characterized by stacked sequences of fluvial, deltaic and nearshore marine sands with interbedded terrestrial and marine shales. Facies changes, intraformational unconformities, and high-angle faults disrupt reservoir continuity and quality. Seismic attribute analyses and development of a new sequence stratigraphic framework reveal gas hydrate and gas-bearing sand-rich sequences and parasequences composed of river channel, point bar, mouth bar, and nearshore marine sandstones and shales. Seismic attribute and horizon interpretations, normalized log correlation, stratigraphic mapping, facies mapping, and net pay sand maps are used to assess reservoir continuity and estimate in-place gas hydrate and associated free gas. The reservoir and fluid characterization will be integrated into reservoir models to help define a range of recovery

factors, producible gas, and economic potential needed for evaluation of future development scenarios.

The Phase 1 study characterizes reservoirs and fluids, leads to recoverable reserve and resource potential estimates, and defines procedures for gas hydrate drilling, data acquisition, completion, and production. Phases 2 and 3 would integrate well, core, log, and production test data, if justified by results from prior phases. The research program could lead to future ANS gas hydrate pilot development.

This project will help solve technical and economic issues to enable government and industry to make informed decisions regarding the resource potential of unconventional gas hydrate accumulations. As this project enters into the second year of the 2-year Phase 1 research program, reservoir and fluid characterization within the Eileen trend area indicates significant stratigraphic and structural heterogeneity, causing compartmentalization of the gas hydrate accumulations. These interim research results highlight the importance of the resource characterization phase before any production testing might occur. Describing reservoir and fluid compartmentalization will help choose the best testing site for potential phase 2 operations.

TABLE OF CONTENTS

1.0 LIST OF TABLES AND FIGURES

2.0 INTRODUCTION

This project is helping to solve the technical and economic issues to enable government and industry to make informed decisions regarding potential future commercialization of unconventional gas-hydrate resources. The project is characterizing and quantifying in-place and recoverable gas-hydrate and associated free-gas resources initially in the Eileen trend area in the Prudhoe Bay Unit (PBU) – Kuparuk River Unit (KRU) – Milne Point Unit (MPU) areas on the Alaska North Slope (ANS). The project is also investigating gas hydrate phase equilibrium and relative permeability within porous media. Additional laboratory investigations include design of best practices for drilling, completion, and production operations within gas hydrate-bearing reservoirs.

Successful determination of the resource potential of gas hydrate and associated free gas resources could significantly increase current developable gas reserves available for reservoir energy support, secondary recovery, fuel gas, and commercial sales within and beyond current infrastructure on the North Slope of Alaska. Proving technical production feasibility and commerciality of this unconventional gas resource could lead to greater energy independence for the U.S., providing for future gas needs through an abundant, safe, secure, and stable domestic resource.

2.1 Project Open Items

Contracts and subcontracts were updated in December 2003, fully obligate Phase 1 project funding, and allow Phase 1 time extension for the full 2-year Phase 1 research program through end-October 2004. Phase 1 interim results, reservoir/fluid characterization, reservoir modeling, and economic modeling will contribute to a Phase 2 progression decision by summer 2004.

2.2 Project Status Assessment and Forecast

Project technical accomplishments from October 2003 through end-December 2003 are presented by associated project task. The attached milestone forms (Appendix A) present project tasks 1 through 13 with task duration and completion timelines.

2.3 Project Research Collaborations

Progress towards completing project objectives significantly benefits from continued DOE support and/or funding of the following associated projects and proposals. Section 5.4 provides additional detail on collaborative research accomplishments during the reporting period.

1. **LBNL Reservoir Modeling studies:** This research includes reservoir model code calibration to data collected during the 2002 Mallik gas hydrate test program as well as working with the BPXA project to evaluate potential development scenarios. DOE has apparently obligated project funds to continue LBNL reservoir modeling research through end-June 2004. BPXA and UAF met with LBNL on August 13-14, 2003. BPXA met with LBNL, Ryder-Scott Co., USGS, and DOE representatives on October 1, 2003 to determine how to best allocate project and DOE resources to gas hydrate reservoir modeling studies and to minimize potential duplication of gas hydrate reservoir modeling efforts between DOE-supported research projects. Previous actions from the August 13-14 meeting included:

1. LBNL: provide Beta-test reservoir model for BPXA team testing and use by January 2004. This has not been yet delivered as of the writing of this report (3/3/04).
    a. LBNL: Include model code calibration to 2002 Mallik testing (work regarding this objective was presented at 12/03 Mallik conference, Chiba, Japan)
    b. BPXA team: provide user input before and during model Beta-testing
    c. BPXA team: provide industry-standard assistance to LBNL for UA-UAF-developed reservoir/fluid scale-up and development plan optimization
    This is being worked through input from Ryder Scott Company.
2. LBNL-BPXA-DOE: collaboratively develop work plan and prioritize sensitivities. This is work in development.
3. DOE-BPXA: collaborate to minimize distractions to LBNL primary scope-of-work

2. **DE-FC26-01NT41248:** UAF/PNNL/BPXA studies to determine effectiveness of CO_2 as an enhanced recovery mechanism for gas dissociation from methane hydrate. Recent project status presentation updates and funding indicate a strong level of DOE support for this associated project. UAF has seconded a graduate student to PNNL to assist with this research. BPXA and UAF met with PNNL on August 11-12, 2003 to discuss project status, determine work progression, and discuss project synergies. PNNL and BPXA recently presented project research updates to Jim Slutz (DOE) in Anchorage.

3. **UAF/Argonne National Lab project:** This associated project was approved for funding by the Arctic Energy and Technology Development Lab (AETDL) and forwarded to NETL for review. The project is designed to determine the efficacy of Ceramicrete cold temperature cement to future gas hydrate drilling and completion operations. Evaluating the stability and use of a cold temperature cement will greatly enhance the ability to maintain the low temperatures of the gas hydrate stability field during drilling and completion operations, helping to ensure safer and more cost-effective operations.

4. **Precision Combustion – DOE collaborative research project:** Potential synergies from this DOE-supported research project with our gas hydrate research program were recognized during the reporting period by Edie Allison (DOE). Dialog and correspondence with Precision Combustion researchers indicate some significant potential synergies, particularly regarding potential in-situ reservoir heating. Successful modeling and lab work could potentially proceed into field application of gas hydrate thermal recovery enhancement testing if this project progresses into phases 2 and/or 3.

5. **UAF/McMillan-McGee/PNNL proposal:** This proposal was recently highly ranked during presentations to AETDL, but not forwarded to NETL for funding. The proposal also received strong letters of support from BPXA and Conoco-Phillips viscous oil development teams. The project would investigate in-situ electromagnetic (EM) heating as an enhanced recovery method for both viscous oil and gas hydrate production. In addition to depressurization of an adjacent free gas, this technology may thermally enhance gas dissociation from gas hydrate-bearing reservoirs and perhaps counteract any endothermic cooling reaction, thus providing greater flow assurance during gas production. A brief, independent assessment and first-principles numerical modeling of the EM methodology is being considered to determine whether or not to proceed with further proposals of this nature in support of potential Phase 2-3 operations procedures.

6. Progress toward completing the objectives of this project are aligned with a collaborative research agreement under evaluation between BPXA and Japan National Oil Corporation (JNOC). Execution of a BPXA – JNOC agreement could enable additional funding for technical studies, data acquisition, and/or potential Phase 2 operations.

7. India's Institute of Oil and Gas Production Technology (IOGPT) has also indicated an interest in participating with our research program. In September 2003, DOE replied to India's unsolicited expression of research collaboration interest and indicated support for India to participate as an observer if the project should proceed into Phase 2 research.

8. An additional collaborative research project under the Department of Interior (DOI) is providing significant benefits to this project. The BLM, USGS, and the State of Alaska recognize that gas hydrates are potentially a large untapped onshore energy resource on the North Slope region of Alaska. To develop a complete regional understanding of this potential energy resource, the BLM, USGS and State of Alaska (DGGS) have entered into an Assistance Agreement to assess regional gas hydrate energy resource potential in northern Alaska. This agreement combines the resource assessment responsibilities of the USGS and the DGGS with the surface management and permitting responsibilities of the BLM. As interest in the resource potential of Alaska gas hydrates continue to grow, information generated from this agreement will help guide these agencies to promote responsible development of this potential arctic energy resource. The DOI project is working with the BPXA – DOE project to assess the regional recoverable resource potential of onshore natural gas hydrate and associated free-gas accumulations in northern Alaska, initially within and eventually beyond current industry infrastructure.

9. A recently formed company in Europe, "Worldwide Gas Hydrates", has developed a potassium formate-based brine (Vapornet™GHF-164), which might provide an environmentally-safe and cost-effective gas hydrate stimulation fluid, to help initiate and maintain gas dissociation from gas hydrates during production. This fluid will be evaluated for possible application in phases 2 and/or 3 operations and production testing.

2.4 Project Performance Variance

Discussion with industry partners and BPXA operations groups in PBU and MPU continues to indicate that availability of shallow portions of PBU seismic data to the project is less certain. BPXA is working both internally and with industry partners to emphasize the importance of this data to gas hydrate reservoir and fluid characterization studies. PBU seismic data has not been provided to the project and is dependent upon industry partner approval. Future plans include presentation of project results to industry partners to help facilitate understanding of and potential future participation in the research program.

PBU will acquire a new seismic survey ("S-cubed") in early 2004. This seismic survey is specifically designed to enhance resolution of shallow oil resources and would also significantly enhance resolution of the shallow gas hydrate and associated free gas bearing shallow reservoirs within PBU and the Eileen trend area of interest. Before consideration of this 3D seismic survey for the latter purposes, the survey would require addition to the limited rights data defined within the BPXA – DOE contract in an amendment to that contract.

3.0 EXECUTIVE SUMMARY

This Quarterly report encompasses project work from October 1, 2003 through December 30, 2003. Sections 4 and 5 provide a detailed project activities report.

- Completed DOE-BPXA project contract extension for 2-year Phase 1 research program
  - Anticipate Phase 2 progression decision by summer 2004
  - Phase 1 research will continue through end-October 2004
  - Phase 2 research may continue through end-December 2005
  - Phase 3 research may continue through end-December 2006
- Continued gas hydrate research collaborations/discussions with many associated projects
- Began preparations for September 2004 project input to AAPG Hedberg Conference
  - Conference will provide a major opportunity to present Phase 1 study results
  - Anticipate 3-5 conference presentations and 5-10 attendees from this project
- Released additional industry shallow sand technical data to UA and USGS
- Prepared subcontract and scope-of-work for additional reservoir modeling work
  - Subcontract to Ryder Scott Company to help provide industry-standard modeling
  - Coordinated reservoir modeling plans with LBNL, UAF, and Ryder Scott Co.
- Compared and contrasted lithostratigraphic to sequence stratigraphic framework models
  - Study reveals more complex stratigraphic relationships in the Sagavanirktok
  - Affects lateral continuity and connectivity of gas hydrate and associated free gas
- Completed log-based fluid predictor and estimated gas hydrate/free gas saturations
- Normalized GR logs in all wells to calibrate net/gross reservoir sand sequence mapping
- Interpreted direct seismic detection of reservoir fluid transition from gas into gas hydrate
  - Seismic amplitudes decrease as trace reservoir into gas hydrate stability field
  - Sand facies changes can also significantly affect seismic amplitude response
  - Compared interpreted facies changes versus interpreted gas hydrate occurrence
  - Completed seismic waveform and attribute analyses and related to facies/fluids
  - Investigated fault controls on reservoir distribution and gas hydrate presence
- Calculated seismic horizon isopachs (11 seismic horizons) to assist in net sand mapping
- Generated preliminary fault-heave maps for 2 USGS horizons and 1 UA horizon
  - Fault heave maps show displacement transfer along laterally offset parallel faults
  - Fault heave maps may illustrate fault control of syndepositional sedimentation
  - Fault heave maps may help interpret fluid migration pathways and fault-sealing
- Estimated pore fluid concentrations using down-hole measurements of electrical resistivity, bulk density and compressional wave velocities using eight methodologies
  - Calculated ice, water, free gas, and gas hydrate saturations for net pay estimates
- Conducted dissociation experiments on bulk gas hydrates and gas hydrate-bearing sands
  - Measured effect of brine on dissociation using 2% and 4% NaCl concentrations
  - Discovered that a 2% increase in brine concentration within porous media decreases gas hydrate stability zone thickness by 20 to 30 meters
- Modified conventional relative permeability experimental apparatus for gas hydrate study
  - Conducted frost and sand, synthetic hydrate, and water displacement experiments
- Designed drilling fluid and formation damage experiments and procured lab equipment
- Assessed gas hydrate analytical reservoir modeling techniques and sensitivities
- Evaluated horizontal drilling methods, depressurization, and economic sensitivities

4.0 EXPERIMENTAL

During the time period from October through end-December 2003 encompassed by this report, primary experimental activities consisted of experiment apparatus design, setup, and execution as well as reservoir and fluid characterization studies using 3D seismic and well data.

4.1 TASK 5.0, Logging and Seismic Technology Advances – USGS, BPXA

The U.S. Geological Survey (USGS) analyzed seismic attributes within the Milne 3D dataset to investigate the potential for direct detection of pore fluid transitions between water to free gas to gas hydrate to permafrost from down-dip to up-dip within contiguous reservoir sand intervals. Previous USGS synthetic modeling studies suggested that the transition between a gas-bearing reservoir into a gas hydrate-bearing reservoir causes a seismic trace polarity reversal. Current USGS research confirms prior industry (BPXA and ARCO) and academic (UA) studies showing that seismic amplitudes can significantly decrease as continuous reservoir sands are traced up-dip from a gas-bearing reservoir into the gas hydrate stability field containing a gas hydrate bearing reservoir.

4.2 TASK 6.0, Reservoir and Fluids Characterization

The University of Arizona (UA) continued well and seismic data interpretation. Studies reveal shallow sand reservoir stratigraphic heterogeneity and structural compartmentalization. Section 5.6 provides additional details, results, and recommendations.

4.2.1 Subtask 6.1: Reservoir and Fluid Characterization and Visualization

Continued seismic and well log interpretation for reservoir and fluid characterization studies. Began bulk volumetrics calculations in MPU area. Updated project base map illustrating log curves and fluid saturations.

4.2.2 Subtask 6.2: Seismic Attributes and Calibration

Completed seismic waveforms and attribute analyses to compare and contrast interpreted sediment facies changes versus interpreted gas hydrate occurrence and relate to changing seismic wavelet character. Continued investigation of fault controls on reservoir distribution and gas hydrate presence. Assessed well-to-seismic correlations and calibrated synthetic seismograms. Assigned initial waveform classifications to gas hydrate bearing reservoir horizons and applied various seismic attribute analyses to detect facies and/or possible free gas to gas hydrate fluid transitions. Stratigraphic facies changes can also significantly affect seismic amplitudes; therefore, an understanding of both stratigraphic heterogeneity and potential reservoir fluid transitions is necessary to validate direct detection of reservoir fluids using seismic attributes.

4.2.3 Subtask 6.3: Petrophysics and Artificial Neural Net

Definitive correlation between self-organizing-mapping neural net classifications of chosen seismic attributes and the distribution and quality of gas hydrate occurrence remains inconclusive. Sediment facies relationships are being defined to help differentiate geologic facies and help ensure that any potential direct seismic indicators of gas and/or gas hydrate are not complicated by complex facies relations. Plan to refine classifications with improved time-depth conversions and geologic facies definition.

4.3 TASK 7.0: Laboratory Studies for Drilling, Completion, and Production Support

The University of Alaska Fairbanks (UAF) designed experiments and apparatus for gas hydrate phase equilibrium and relative permeability studies. Sections 5.7 through 5.12 provide additional details, results, and recommendations.

4.3.1 Subtask 7.1: Characterize Gas Hydrate Equilibrium

Conducted experiments on dissociation of bulk gas hydrates and gas hydrate-bearing sands using a 2% and 4% NaCl concentration by weight.

4.3.2 Subtask 7.2: Measure Gas-Water Relative Permeabilities

Gas hydrates were formed in the lab and the conventional experimental apparatus for measuring relative permeability was modified for forming gas hydrates.

4.4 TASK 8.0: Evaluate Drilling Fluids – UAF

Developed experiment plans and procured equipment.

5.0 RESULTS AND DISCUSSION

Project technical accomplishments from October 2003 through December 2003 are presented in chronological order by associated project task.

5.1 TASK 1.0: Research Management Plan – BPXA and Project Team

Task schedules are presented in the attached milestones forms (Appendix A). Expenditures by budget category and associated tasks are attached in Table 1.

- Coordinated, compiled, and completed project financial and technical reports
- Reviewed, processed, and ensured budget consistency of subcontractor invoices
- Prepared subcontract and scope-of-work for additional reservoir modeling work
    - Subcontract to Ryder Scott Company to help provide industry-standard modeling
- Completed DOE-BPXA project contract time extension for 2-year Phase 1 research
    - Phase 1 research will continue through end-October 2004
    - Phase 2 research may continue through end-December 2005
    - Phase 3 research may continue through end-December 2006
    - Cost extension effective October 2003, time extension effective December 2003

5.2 TASK 2.0: Provide Technical Data and Expertise – BPXA, USGS

- Working to release additional relevant seismic, drilling, and well file data to project
- Reviewed AOGCC well file data within MPU A, B, D, K pads
- Reviewed offsite storage well file boxes; extracted, copied, and distributed relevant project data to UA and USGS
- Released additional shallow sand technical data to UA and USGS

5.3 TASK 3.0: Wells of Opportunity, Data Acquisition – BPXA

- Monitored drilling schedule for potential data acquisition in wells-of-opportunity
- Met and worked with JNOC to identify potential base and stretch well of opportunity operations activities to support BPXA-DOE Phase 1 project activities if execute BPXA – JNOC collaborative research agreement within Phase 1

Table 1: Budget Period 1 DOE Cost Summary and Project Expenditures
DE-FC-26-01NT41332, December 2003 Quarterly Report

Cost Category	% Obligated	Year 0 Costs	Year 1 Costs	Other Year 1 Costs	Year 2 Costs	TOTAL DOE COSTS (GROSS)	Spent Costs	Balance Funds	Remaining %
U. Arizona, Labor	109.4%	$56,351	$372,589	$67,947	$440,537	$937,424	$428,941	$508,484	54%
U. Arizona, Travel	109.4%	$1,802	$5,713	$18,866	$24,579	$50,961	$7,515	$43,446	85%
U. Arizona, Third Party	109.4%	$7,853	$31,194		$31,512	$70,559	$39,047	$31,512	45%
U. Arizona, Operations	109.4%	$22,798	$16,507	$45,632	$62,139	$147,077	$39,305	$107,771	73%
U. AK Fairbanks, Labor	109.4%	$0	$149,318	$83,340	$232,658	$465,317	$149,318	$315,999	68%
U. AK Fairbanks, Travel	109.4%	$0	$627	$14,083	$14,710	$29,420	$627	$28,793	98%
U. AK Fairbanks, Third Party	109.4%	$0	$39,108		$22,065	$61,173	$39,108	$22,065	36%
U. AK Fairbanks, Operations	109.4%	$0	$11,631		$11,768	$23,399	$11,631	$11,768	50%
BPXA, Third Party Labor	109.4%	$128,599	$133,015		$328,312	$589,926	$261,614	$328,312	56%
BPXA, Travel	109.4%	$3,378	$12,358	$1,642	$14,000	$31,378	$15,735	$15,642	50%
BPXA, Operations	109.4%	$140	$3,375	$1,625	$5,000	$10,140	$3,515	$6,625	65%
*TOTAL**	109.4%	$220,922	$775,434	$233,137	$1,187,281	$2,416,774	**$996,356**	$1,420,417	59%
					TOTAL	**$2,416,774**			

* Includes only DOE funds

Table 2: BP Cost Categories Relation to Project Tasks

BP AFE #	Cost Category	Project Tasks*
GS2420H01	U. Arizona, Labor	Task 6.0, 6.1, 6.2, 6.3
GS2420H02	U. Arizona, Travel	Task 6.0, 6.1, 6.2, 6.3
GS2420H03	U. Arizona, Third Party	Task 6.0, 6.1, 6.2, 6.3
GS2420H04	U. Arizona, Operations	Task 6.0, 6.1, 6.2, 6.3
GS2420H05	U. AK Fairbanks, Labor	Tasks 7, 8, 9, 10, 11, 13
GS2420H06	U. AK Fairbanks, Travel	Tasks 7, 8, 9, 10, 11, 13
GS2420H07	U. AK Fairbanks, Third Party	Tasks 7, 8, 9, 10, 11, 13
GS2420H08	U. AK Fairbanks, Operations	Tasks 7, 8, 9, 10, 11, 13
GS2420H09	BPXA, Third Party Labor	Tasks 1, 2, 3, 4, 11, 12, 13
GS2420H10	BPXA, Travel	Tasks 1, 2, 3, 4, 11, 12, 13
GS2420H11	BPXA, Operations	Tasks 1, 2, 3, 4, 11, 12, 13

* Project Task 5.0 performed by USGS under separate funding and
Project Task 6.0 contains some overlap by USGS under separate funding

5.4 TASK 4.0: Research Collaboration Link – BP, USGS, Project team

- Coordinated reservoir modeling plans with LBNL, UAF, and Ryder Scott Co.
- Evaluated options and multiple contacts for study of electromagnetic (microwave and/or radiowave frequency) energy to enhance thermal recovery of gas from gas hydrate
    - May fund approximately 1-week first-principles thermodynamics modeling study
        - Study would determine feasibility of electromagnetic thermal recovery enhancement, likely through simple simulation of downhole mechanism
    - Circulated ideas through BP research and viscous oil communities for synergies
    - Considered support and synergies with DOE-funded research with Precision Combustion, Inc. for potential thermal enhanced recovery operations study
- Worked toward potential BPXA – JNOC collaborative research agreement
    - Met with JNOC to discuss project timing and potential technical research support
        - Emphasized BPXA unable to commit to Phase 2 operations until complete Phase 2 progression decision using Phase 1 interim reservoir/fluid characterization and modeling results

- Maintained dialog with DOE regarding India Ministry of Petroleum request to DOE for participation in project as observer
- Provided input to agenda and presentations for AAPG Hedberg Conference on gas hydrates planned for September 2004.
    - This conference will provide a major opportunity to present Phase 1 study results
    - Anticipate 3-5 conference presentations and 5-10 attendees from this project
- Continued cooperative project work with Pacific Northwest National Lab
    - Discussed gas hydrate research synergies and PNNL-UAF-BP research program: CO2 injection as potential enhanced gas recovery method from methane hydrates
- Continued cooperative reservoir model project work with Lawrence Berkeley National Lab, UAF, and Ryder-Scott staff
    - LBNL did not provide Beta-test reservoir model as agreed for team testing and use by January 2004
    - LBNL did work to calibrate reservoir model code to 2002 Mallik testing program
    - UAF assessed alternative gas hydrate reservoir modeling through CMG code
    - Ryder Scott Co. assessed simplified mechanistic gas hydrate reservoir modeling
    - LBNL-BPXA-Ryder Scott Co. will develop work plan and prioritize reservoir model variable sensitivities
- Participated in GOM JIP gas hydrate research program breakout sessions
- Presented project interim results and summary at NRC-sponsored conference in Houston
- Presented project interim results to BP GOM

5.5 TASK 5.0: Logging and Seismic Technology Advances – USGS, BP

- Provided input to potential wireline and LWD logging data acquisition plans
- Investigated seismic attributes for direct indicators of free gas to gas hydrate transition

5.6 TASK 6.0: Reservoir and Fluids Characterization – UA

<u>**University of Arizona**</u>
UA Principle Investigator: Robert Casavant
UA Co-Principle Investigator: Roy Johnson, Mary Poulton
UA Participating Scientists: Karl Glass, Ken Mallon
UA Graduate Students: Casey Hagbo, Bo Zhao, Andrew Hennes, Justin Manuel, Scott Geauner
UA Undergraduate Student Assistant: Greg Gandler

5.6.1 Subtask 6.1: Reservoir and Fluid Characterization and Visualization – UA

5.6.1.1 Products and Preliminary Findings

- Assessed well-to-seismic stratigraphic correlations (time-depth correlation) for wells containing appropriate check shot and/or VSP data (MPL-01, Cascade-01, Kavea32-25).
- Compared seismic picks with lithostratigraphic well picks in StratWorks. The latter were "well-behaved" relative to adjacent wells. Unfortunately, the quality and/or completeness of sonic log data for the Cascade-01 and Kavea 32-25 wells made the time-depth assessment questionable. A significant difference was noted in sonic log response between these two wells and adjacent wells. Thus, from a well log standpoint there exists a good time-depth conversion for only MPL-01.

- Completed log-based fluid predictor and tested against USGS and preliminary UA estimates of gas hydrate/free gas. In intervals where the sonic, density and resistivity log were absent, the predictor was adapted to work from a generated pseudo log of the missing curve. Completed a full report regarding the fluid predictor results.
- Normalized GR log in all wells based on a comprehensive synthesis of average GR log response in the marine shale interval, marker 36-36a. This unit represented the most lithologically consistent and continuous development of any unit within the AOI.
- Completed and compared/contrasted gross isopach maps using well log-based lithostratigraphic framework. Results compared favorably to prior USGS mapping. The computer-generated isopachs maps revealed an unrealistic solution in trend and distribution of net sands across the whole of the AOI. Recontoured and digitized well log-based lithostratigraphic-derived gross and net sand isopachs to use to develop total reservoir and net pay bulk volume calculations.
- Generated gross isopach maps from seismic volume within similar intervals (representing a more continuous and abundant data set) to help refine the distribution and morphology of net sand isopachs of which net pay is a subset.
- Generated a suite of net/gross and net sand isopachs based on well log data. It was hoped that a net-gross relationship, established from the well data, would help to refine net sand maps with incorporation of seismic gross isopach data. However, quick-look comparisons of well-based gross isopachs maps with seismic-based isopachs (assuming adequate time-depth conversion) revealed significant variation between the two grids for respective intervals. These preliminary results indicate caution in using the seismic gross isopachs to guide net sand mapping across the MPU area. Therefore, a proven well log-based bulk volumetric analysis was chosen for the preliminary volumetric calculations in MPU. The team is currently analyzing the issue and working to create better ties between well log and seismic data and a process flow chart.
- Produced two regional structure maps based on log data from the well-defined lithostratigraphic markers that include inferred gas hydrates; include base of Marker 36 (Eocene shale, equivalent to BPXA SV5 seismic marker) and top of Marker 33 (regionally correlative coarsening-up, mouth bar sequence). Geologic structure maps were in good agreement with a seismic structural map produced at the approximate level of USGS (Collett) "C" gas hydrate horizon (near lithostratigraphic Markers 34-33 created in the early lithostratigraphic framework).
- Developed spreadsheet relating depth relationship of USGS gas hydrate zones with UA lithostratigraphic framework. Some USGS gas hydrate zones discovered crossing some UA lithostratigraphic unit correlations.
- Completed spreadsheet showing average log values of each log type within each USGS-identified gas hydrate zone. Data used to compare and guide UA assessment of net pay in wells with and without USGS interpreted gas hydrate zones.
- Developed new sequence stratigraphic framework for MPU and northern part of NW Eileen block. Determined that this framework will guide final volumetric and mapping exercises in MPU. This pilot study reveals more complex stratigraphic relationships in the Sagavanirktok than those developed earlier. This complex stratigraphy will affect the lateral continuity and connectivity of gas hydrate and associated free gas resources.
- Planning to develop relationships of numerous intraformational unconformities to facies and reservoir sand distribution.

- Began calculation of fault heaves from seismic data interpretation.
  - Plan to combine this interpretation with shale thickness data from well logs to predict sealing/non-sealing nature of faults, sand body continuity, and connectivity of pore-fluids (gas hydrate, free gas, water).
- Familiarized staff and students with use of volumetric functions in Petra and LandMark.

5.6.1.2 Miscellaneous Project Activities

- Discussed project status, data correlation issues, provide inter-group strategy and feedback for Fall-Winter activities.
- Discussed progress with seismic work and well log correlation work and discussed intra group data needs and integration of activities for upcoming volumetric analysis.
- Held October UA meetings related to UA request to BPXA to initiate DOE no-cost/cost extension option in relation to UA-BP subcontract. Follow up of BPXA-DOE progress in November meetings. UA contracts personnel, MGE administrator, and researchers meet to plan necessary steps and implication of the subcontract in the event that DOE extension is not granted within the appropriate time frame as specified in the UA-BPXA subcontract.
- Held December meeting between UA Investigators and graduate students to discuss project status, data correlation issues, and provide inter-group strategy and feedback for UA Fall activities. Major topics included preliminary gross isopach discrepancies between well logs ground-truth data and tie to seismic interpretation.
  - Discussed data resolution, lack of well control and automated picking as possible errors. Outcome: wavelet processing to enhance resolution.
  - Discussed fault offset vs. resolution in response to NW trending structures.
- Held several intradepartmental meetings to discuss progress of MPU volumetric analyses and associated petrophysical challenges and data processing techniques.
- Contributed geologic/seismic maps for project presentation at Denver DOE conference.
- Familiarized researchers with UNIX-based Landmark and Windows-based Petra/PetraSeis software
- Scheduled software maintenance, backup and upgrades of database, lab software and hardware by IT staff.
- Completed project management, related administration activities, data compilation, and quarterly technical report draft.

5.6.1.3 Research Publications and Presentations

- Prepared MGE abstract and poster on student Alaska gas hydrate research activities.
  - Presented to 2003 AAPG Student Expo conference in Houston in October, 2003
- Presented results of Casey Hagbo MS thesis on waveform classification work in Special Gas Hydrates Session talk at AGU annual fall meeting in San Francisco, December 2004.
- Completed Casey Hagbo MS Thesis and delivered copies to BPXA and MGE.
  - Results not yet public subject to industry and DOE review.

5.6.1.4 Work In-Progress

- Developing petrophysical properties associated with interpreted USGS gas hydrate zones.

- Comparing the automated UA fluid prediction model to manual net pay calculations as identified across the MPU AOI.
- Comparing volumetric calculations/methodologies in MPU using the following data and methodology:
    1. USGS lithostratigraphic-based model
    2. UA seismic attribute method
    3. UA lithostratigraphic-based method
    4. UA sequence stratigraphic method
    5. UA automatic fluid predictor model
    6. UA manual net pay model for maximum and conservative interpretation cases
- Determining spatial analysis of coal-bearing units (and potential CBM contribution) to fault proximity/throw. A possible spatial connection of gas hydrate and oil zones to a particular facies and coal sequence has been noted.
- Developing a new seismic sequence_stratigraphic framework that will incorporate and be guided by the current log-based sequence stratigraphic framework developed for the MPU AOI. This seismic framework will be used to guide development of a new seismic facies classification scheme and to assess lateral and vertical continuity of sand bodies in the Sagavanirktok.
- Continuing the MPU log-based sequence stratigraphic framework and associated facies interpretation into the Eileen, PBU, and KRU areas.
- Determining spatial analysis of faults relative to porosity, facies development, reservoir orientation and dip slip (heave) estimates.
- Continuing research regarding the significance of the "NW-trending hingelines" (minimal dip slip/fracture zones/strike-slip component) as probable fluid barriers and influence on dip slip variations along NNE-trending fault zones.
- Continuing collaboration on NNE-trending fault typing, sealing vs. fault morphology, determination of the amount of heave and sand-shale juxtaposition.

5.6.1.5 Continuing Needs and Future Work

- Need more mudlog and sample log information related to any wells currently released to UA (provided in February 2004). If sample/core analysis not related to a well in the initial release, then the appropriate well log data should accompany any released mudlog, sample description data.
- Need any logs with full suite of caliper, resistivity, sonic and density logs for use in the sensitive UA fluid analysis and for current and upcoming activities related to the neural net and seismic attribute research.
- Spatial analysis/confirmation of structural control on the distribution of lakes, rivers, coastline and other surface features in the MPU area as indicated by previous morphotectonic analysis in the MPU, KRU areas (Casavant, 2001;: Rawlinson, 1993?).
- Spatial analysis/confirmation of structural control on the variation in permafrost thickness and character in the MPU area as indicated by previous morphotectonic analysis in the KRU and PBU areas (Casavant, 2001)
- Sequence stratigraphic characterization of ice-bearing permafrost above Marker 36a (mid Eocene shale) for fluid (and possible facies) prediction model.

5.6.2 Subtask 6.2: Seismic Attribute Characterization and Fault Analysis – UA

5.6.2.1 Products

- Developed waveform classification along known gas hydrate horizons on trace-equalized predictive deconvolution data (Figures 1-4; USGS Unit E, Unit D and Unit C horizons).
- Estimated preliminary volumetrics based on well-log correlated facies interpretations of waveform classification maps, known gas hydrate occurrence, and fault block geometries (Casey Hagbo MS thesis).
- Completed time-depth conversion of Milne Point 3D survey using improved synthetics and checkshots (Figure 5).
- Calculated seismic horizon isopachs from 11 seismic horizons to assist in net sand interpretations.
- Generated preliminary fault-heave maps for USGS Unit C and Unit D horizons and for Corr_mkr_29 horizon.
- Developed thorough working knowledge of Z-Map (Andrew Hennes MS thesis).
- Imported updated well-pick lists from MGE department to seismic project.
- Attempted to merge 3D surveys into one survey; unsuccessful due to acquisition discrepancies. Seisworks 3D-3D merge suitable for interpretation into NW Eileen Survey. Corr_mkr_34 and Corr_mkr_29 horizons successfully mapped across survey boundary.

5.6.2.2 Work in Progress

- Extending all interpreted horizons into NW Eileen and poorly constrained areas of Milne survey to take advantage of all available seismic data.
- Post-stack wavelet processing on Milne and NW Eileen seismic data to enhance data resolution that may yield better delineation of thin sand units and gas hydrate-bearing strata.
- Calculating fault heaves across all previously interpreted faults for each horizon to infer faulting history at particular intervals.
- Using fault heaves from seismic and shale thickness from well logs to predict sealing/non-sealing nature of faults as per CSP, GSP, SSF, SGR, etc. algorithms. Compare these to amplitude extractions along faults.
- Correlating fault heave magnitude, sealing nature and relative time of faulting to known/interpreted gas hydrate occurrence.
- Refining 3D ESP volumes to enhance data discontinuities – attention to small offset faults, deeper NW-trending faults and gas hydrate occurrence (Figure 6).
- Using grid illumination techniques on horizon structure maps to interpret subtle structural features and faults.

5.6.2.3 Continuing Needs

- Create or make available any additional velocity or synthetic data
- Make available seismic data or fault map from deeper Cretaceous or Permo-Penn horizons.
- Request additional processing on NW Eileen survey to increase Signal/Noise ratio.

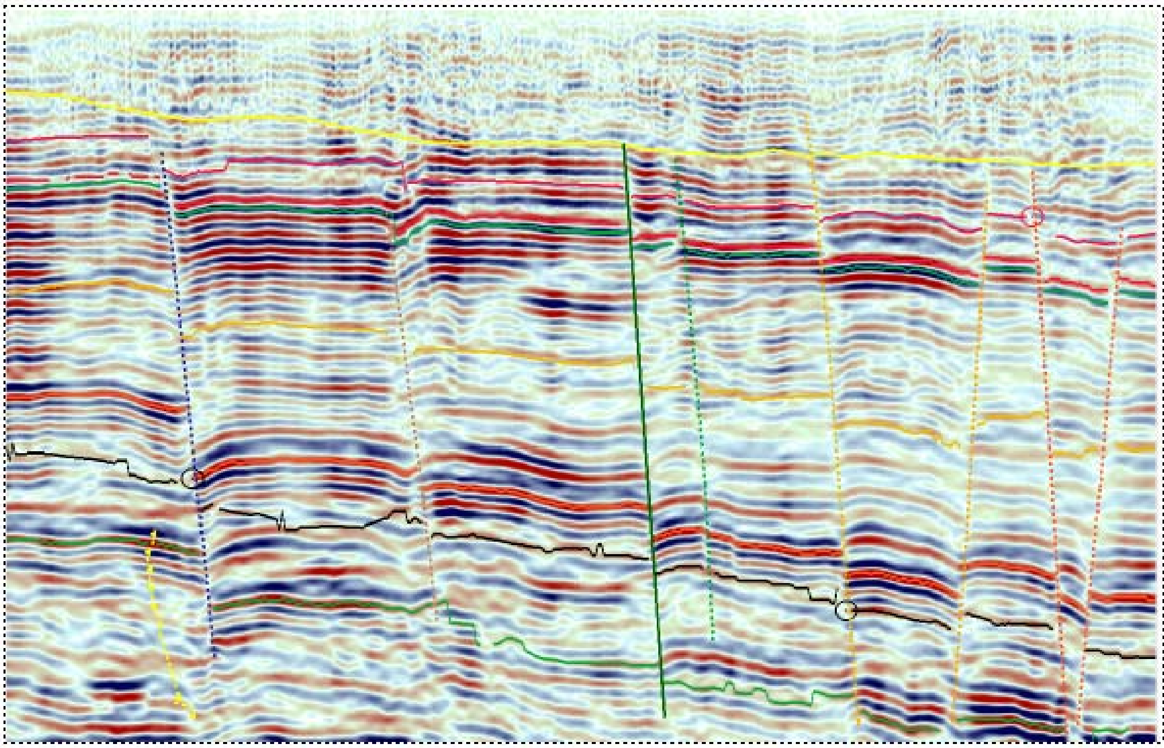

Figure 1a: Original seismic data example showing ringing multiples, masking real reflectors

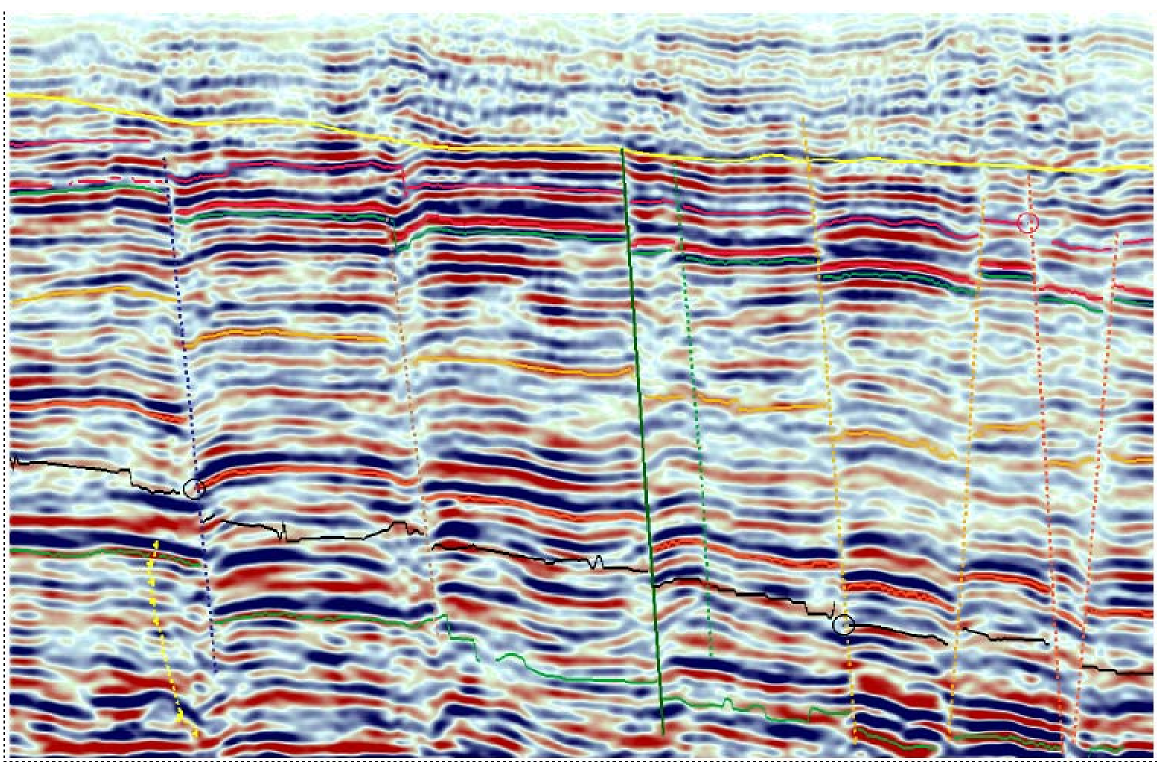

Figure 1b: Predictive deconvolution applied to same data to remove multiples and enhance ability to interpret seismic; image enhancement algorithm also applied (Hagbo, 2003).

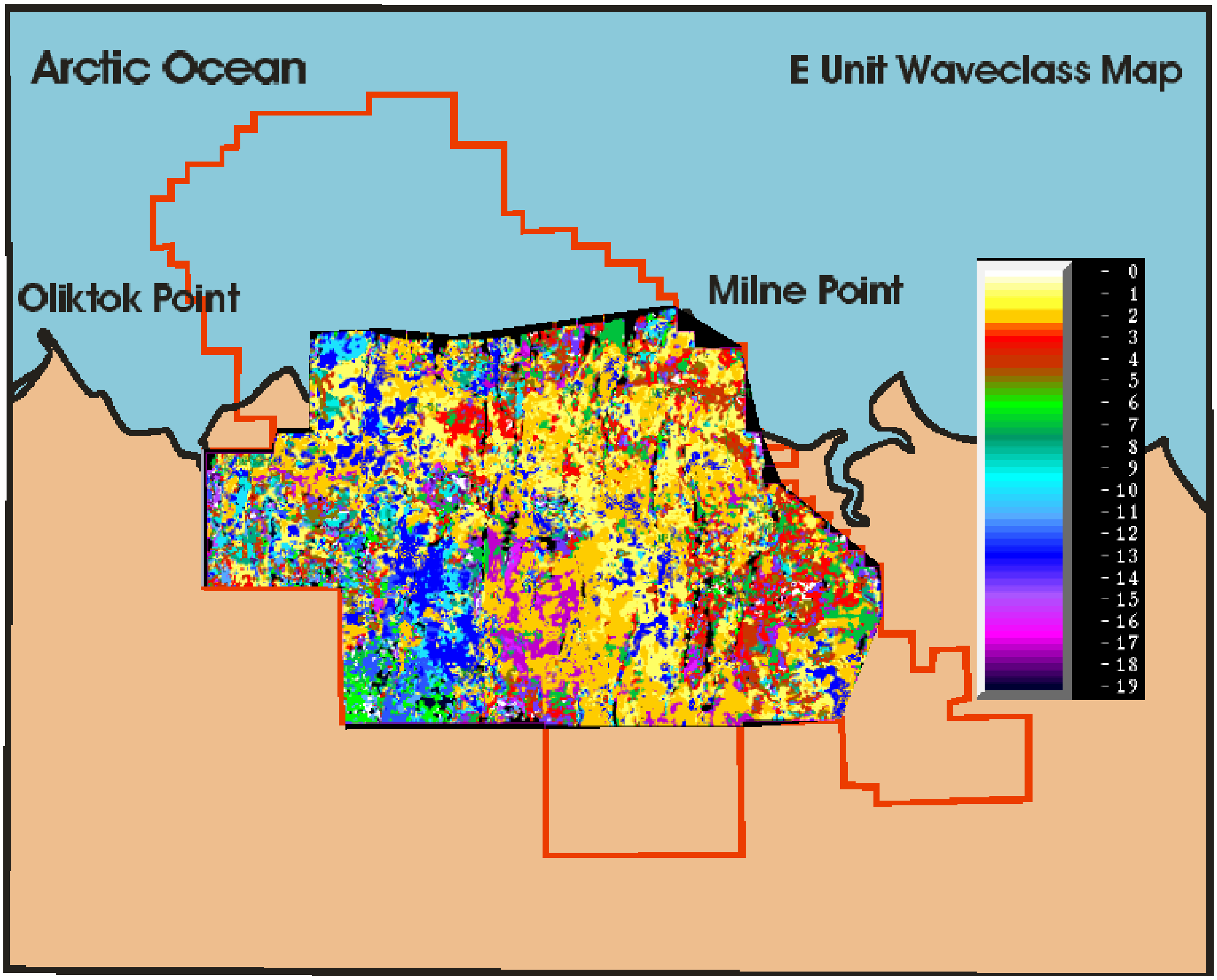

Figure 2: Unit E waveform classification map. This map was created using a 20 ms time window centered on the USGS E horizon and using a threshold of 0.10. This map shows a high level of heterogeneity due to either complex stratigraphy or noisy seismic data. Since stratigraphic interpretation indicates that the E horizon is not overly complex, the more likely explanation is greater levels of noise in the seismic data near the E horizon (Hagbo, 2003).

- In areas where unit thicknesses are greater than found for most of Milne area, seismic horizon interpretation of top and bottom of gas hydrate-bearing intervals (if increased resolution allows) to yield better volumetric estimates.
- Focus waveform classification efforts on supervised classification based on interpreted gas hydrate occurrence and/or stratigraphic facies.
- Classify waveforms of various attribute volumes such as 3D ESP.
- Model waveform responses to gas hydrate occurrence models based on well-log interpretation. Use in waveform classification.
- Use detailed fault analysis (above) to identify possible sealed blocks with gas hydrate occurrence as candidates for possible data acquisition and/or production testing.

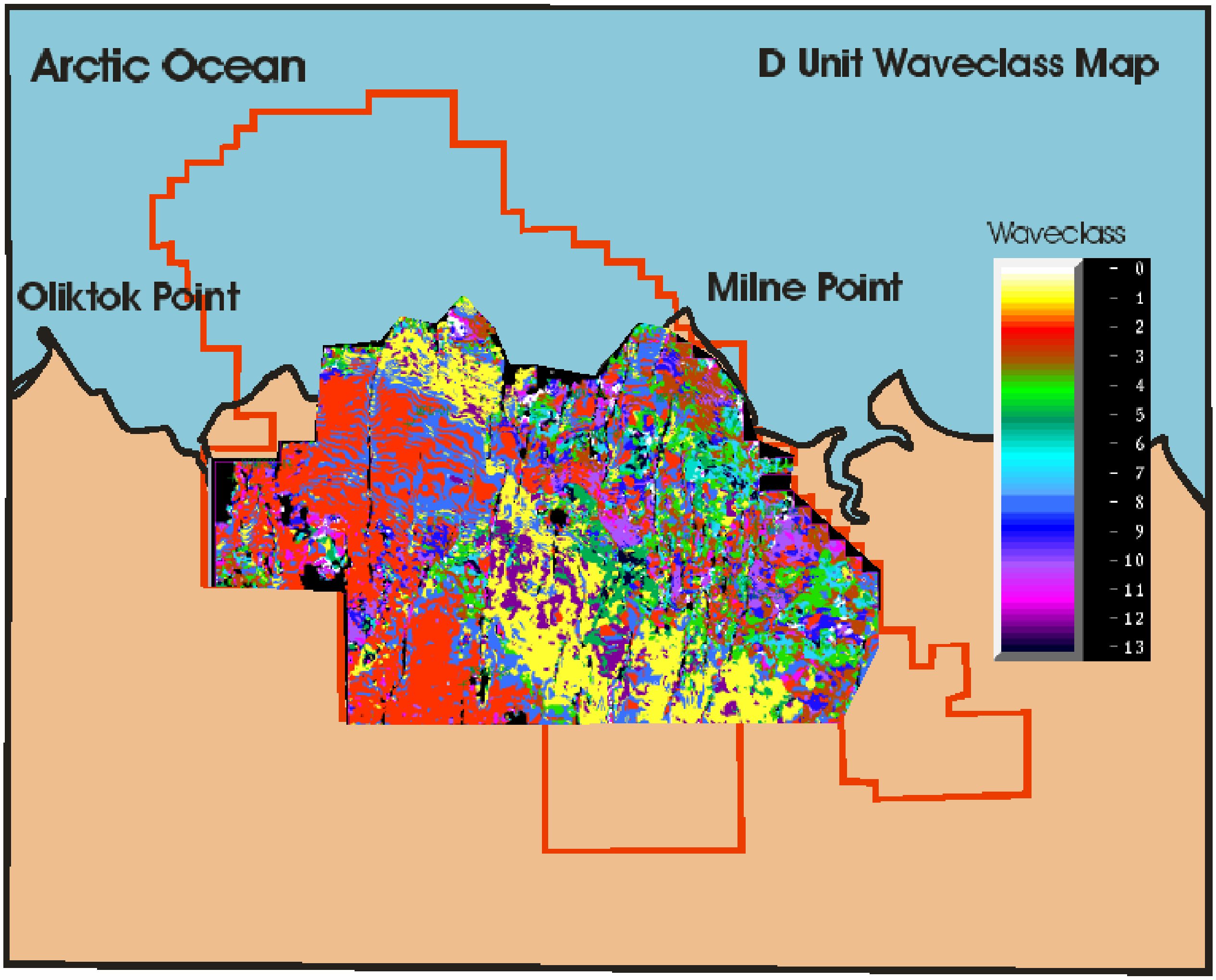

Figure 3: Unit D waveform classification map. This map was created using a 20 ms time window centered on the USGS D horizon and using a threshold of 0.10. The pattern of waveclass distribution reflects the patterns evident from the well log based stratigraphic interpretations (Hagbo, 2003).

- Analyze data for gas hydrate/free gas amplitude/polarity anomalies. These should form "ribbons" in 3D, which may be quite discontinuous.
- Obtain GIS information from North Slope, if possible, to correlate surface features to anomalous events in the 3D seismic data. Possible questions:
    1. Do lakes occur over gas chimneys?
    2. Do lakes thin permafrost affecting TDQ?
    3. Do lakes/rivers/surface features trend with faults (Casavant, 2001)?
    4. Did lakes/rivers affect acquisition and statics that may explain areas of anomalous seismic data?

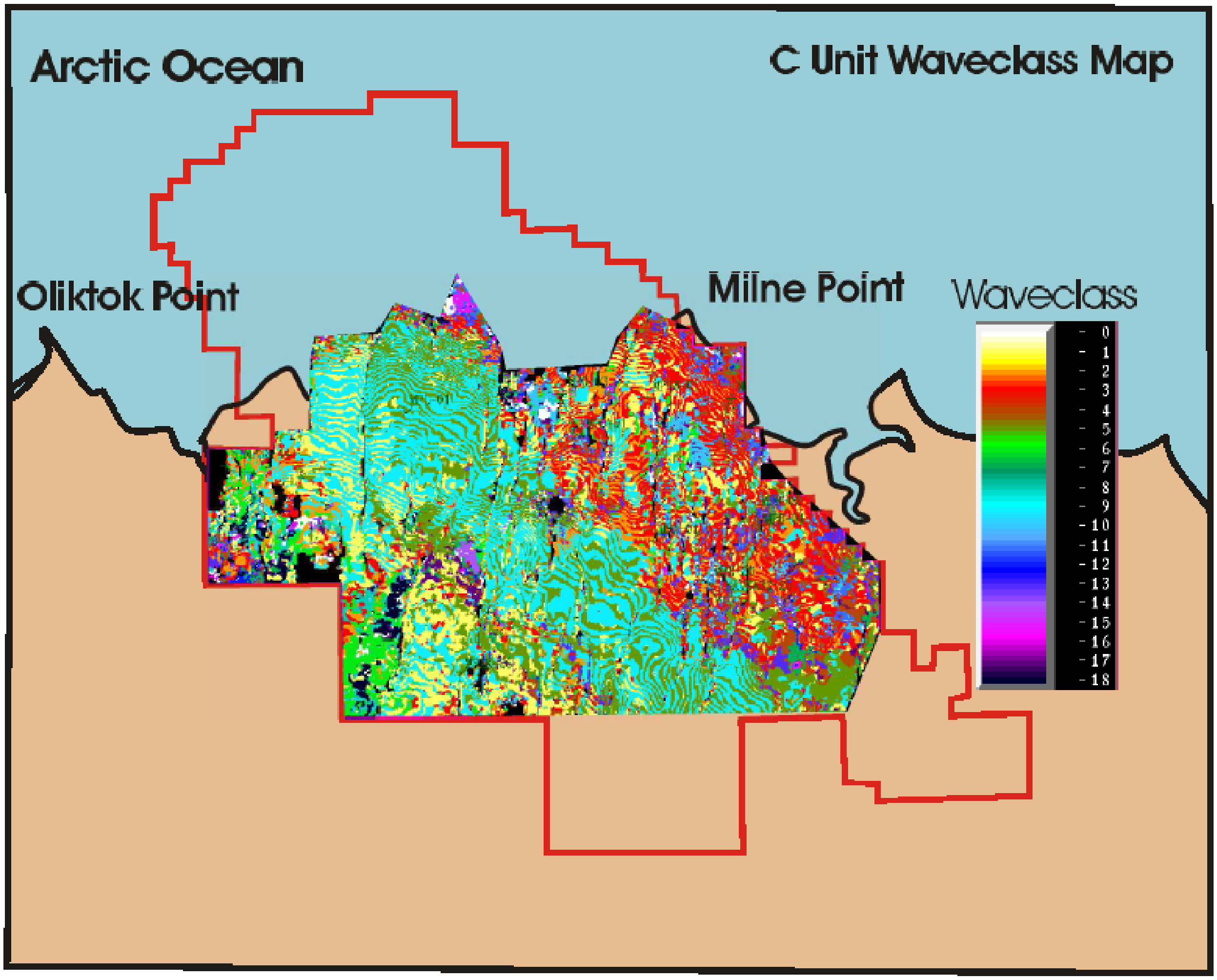

Figure 4: Unit C waveform classification map. This map was created using a 20 ms time window centered on the USGS C horizon and using a threshold of 0.10. The pattern of waveclass distribution reflects the patterns evident from the well log based stratigraphic interpretations and thus is likely caused by lateral variations in stratigraphic facies. These facies distributions will affect the lateral extent of gas hydrate-bearing reservoirs (Hagbo, 2003).

5.6.3 Subtask 6.3: Petrophysical and Neural Network Attribute Analysis – UA

5.6.3.1 Products

- Completed Zhoa Bo's MS thesis---*Classifying Seismic Attributes in the MPU area.*
- Completed Karl Glass's log-based fluid prediction algorithm: Estimating Pore Fluid Concentrations Using Seismic and Electrical Attributes
- Work done during the fall semester designed to provide estimates of pore fluid concentrations using down-hole measurements of electrical resistivity, bulk density and compressional wave velocities. Pore fluid concentrations comprise ice, free gas, water, and gas hydrate. Pore fluid concentration estimates are needed for net pay estimates, and are studied and accomplished using the following eight techniques:

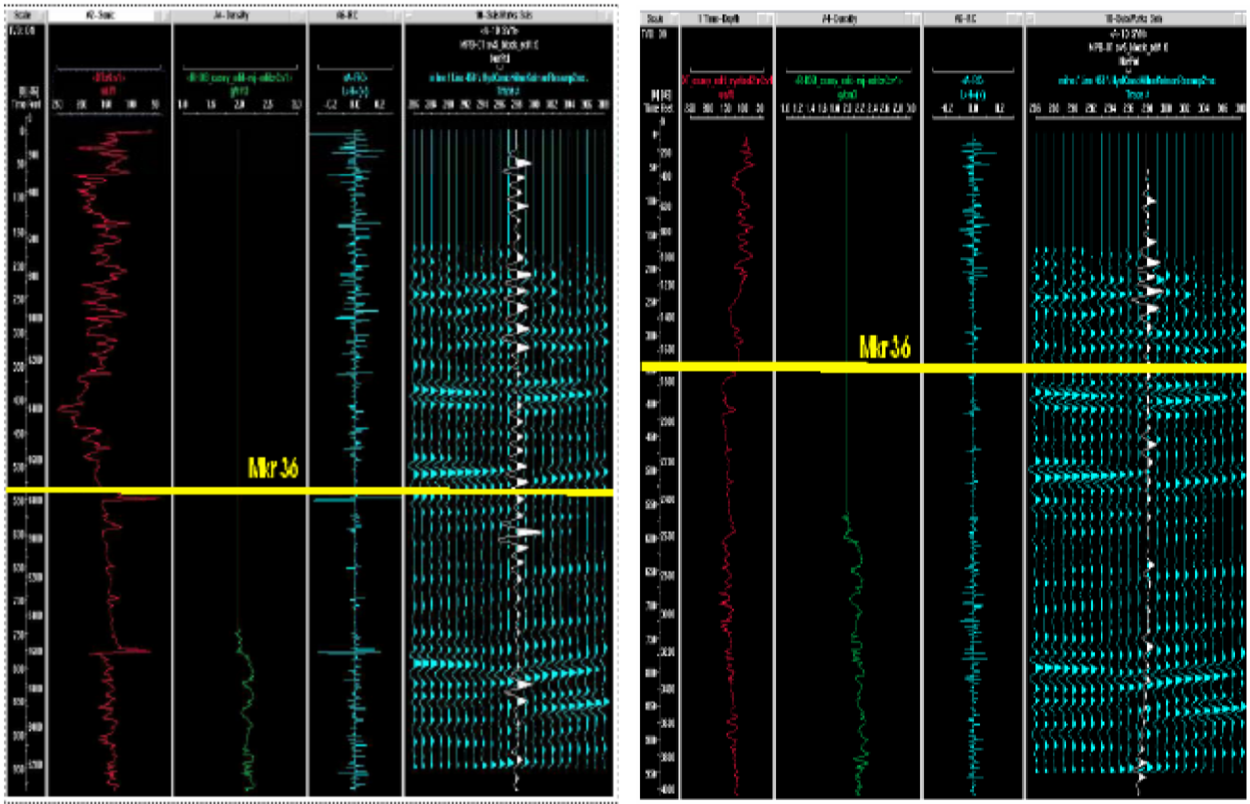

Figure 5: Milne Point Unit well MPB-01 synthetic comparing the synthetic match without a sonic correction (left) and with a sonic correction (right). The upper 1,700 feet of the sonic curve was bulk shifted to 102.5 us/ft to correct the sonic curve, provide a better synthetic match, and yield a better match to the BPXA SV5 stratigraphic marker (Hagbo, 2003).

1. Lee equation for seismic compressional wave velocity.
2. Archie equation for electrical resistivity.
3. Fuzzy membership functions using seismic compressional wave velocity.
4. Maximum likelihood probability using seismic compressional wave velocity.
5. Mixing modeling using seismic compressional wave velocity and electrical resistivity.
6. Expert System using seismic compressional wave velocity and electrical resistivity.
7. Reister Model using seismic compressional and shear wave velocity and porosity.
8. Pore fluid density estimation as predicted from resistivity logs (dependent upon porosity and saturations).

- Determined variations among the eight approaches, but all produced essentially the same overall pattern. Estimates of free gas concentrations are dominated by the reliance on compressional wave velocities, hence, free gas concentration estimates tend to be high even where electrical resistivity values do not support the existence of free gas. To remedy this situation a second probability was computed for free gas that ensures that estimates of free gas concentrations occur only where electrical resistivity values are suitably high.

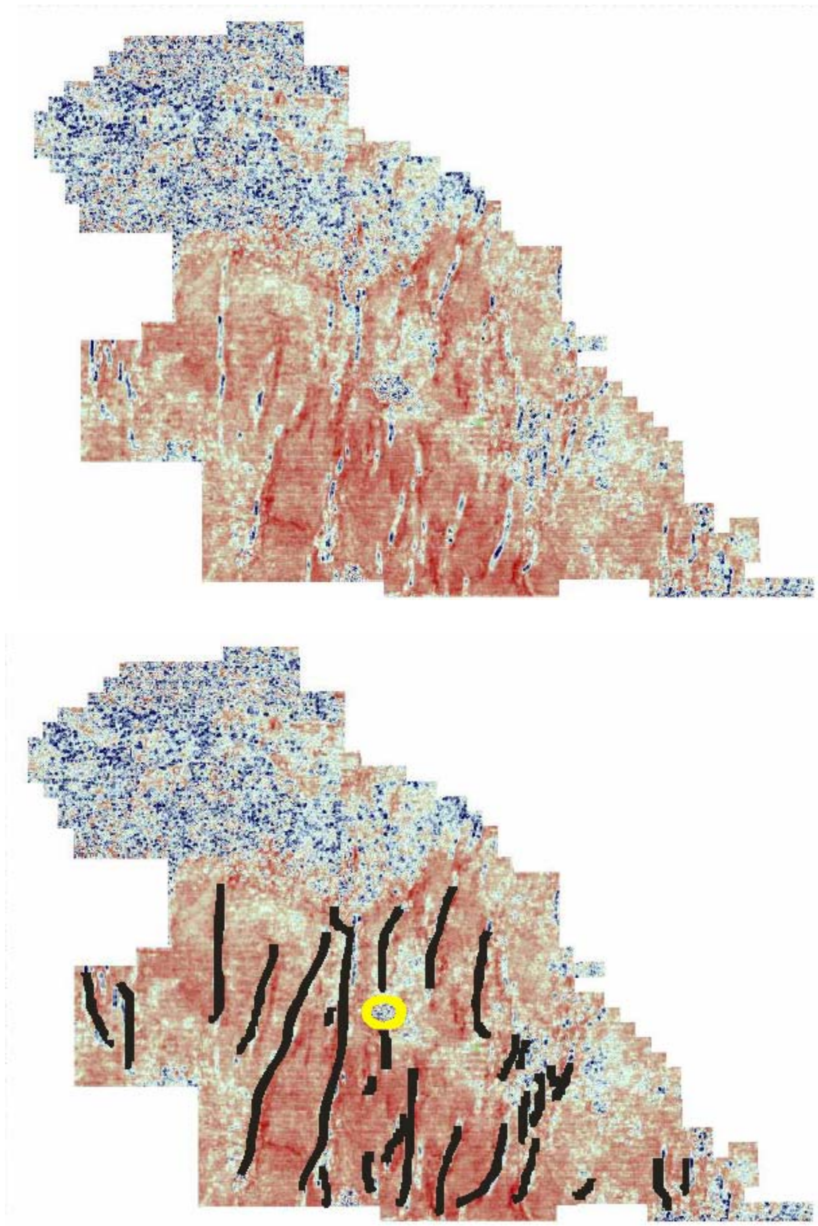

Figure 6: Event Similarity Prediction (ESP) time-slice view to enhance data for structural interpretation. A 400 ms time slice is illustrated through the ESP-processed data. Dissimilar data is shown in blue, similar data is shown in red. The top image is uninterpreted; the lower image is shown with some interpreted faults to illustrate the usefulness of viewing the ESP data to enhance fault interpretation capability and show data discontinuities (Hagbo, 2003).

- Determined that estimates of gas hydrate concentrations are also affected by the compressional wave velocity bias (half of the techniques rely solely on compressional wave velocity). This is especially apparent near the base of the gas hydrate stability field where gas hydrate is estimated to occur without support of high resistivity measurements. In the areas near the base of the gas hydrate stability field, the expert system approach provides a more realistic estimate of the concentration of gas hydrate.
- Noted that distinguishing between ice and gas hydrate cannot be accomplished with the measured data available in the wells. This distinction was performed using estimates of the locations of the ice stability field and the gas hydrate stability field. Where these fields overlap, no distinction is possible at the current time and with the currently available information.
- Estimated pore water concentrations using the Archie equation, Equation 8.

5.6.3.2 Work in Progress

- Analyzing automated fluid prediction accounting for poor log sections and washouts.
- Characterizing reservoir intervals within ice-bearing permafrost above Marker 36a (mid Eocene shale)
- Initiating log-based and seismic-based predictors for facies classification

5.7 TASK 7.0: Lab Studies for Drilling, Completion, and Production Support – UAF

University of Alaska Fairbanks
UAF Principle Investigator: Shirish Patil
UAF Co-Principle Investigator: Abhijit Dandekar
UAF Participating Scientists: David Ogbe, Godwin Chukwu and Santanu Khataniar
UAF Graduate Students: Jason Westervelt, Stephen Howe, Namit Jaiswal, and Prasad Kerkar
UAF Undergraduate Student Assistant: Phillip Tsunemori

5.7.1 Subtask 7.1: Characterize Gas Hydrate Equilibrium

5.7.1.1 Experimental Results

Experiments on dissociation of bulk gas hydrates and gas hydrate-bearing sands have been conducted using a 2% and 4% NaCl concentration by weight. These data were then used along with the geothermal gradients from five different wells (Figure 7) to produce gas hydrate stability curves. The wells chosen are WK-11, WK-14, WK-17, NWEN, and NHST (Table 3). They were chosen because temperature log data was available for depths below the permafrost, which allowed the geothermal gradients to be determined. Figure 8 illustrates an example of the type of gas hydrate stability curves that were produced. These curves were produced by using the dissociation pressures and temperatures along with an average pressure gradient of 0.433 psia/ft. The intersections of the geothermal gradient and the gas hydrate stability curve determined the depth to the top and base of the gas hydrate stability zone (HSZ).

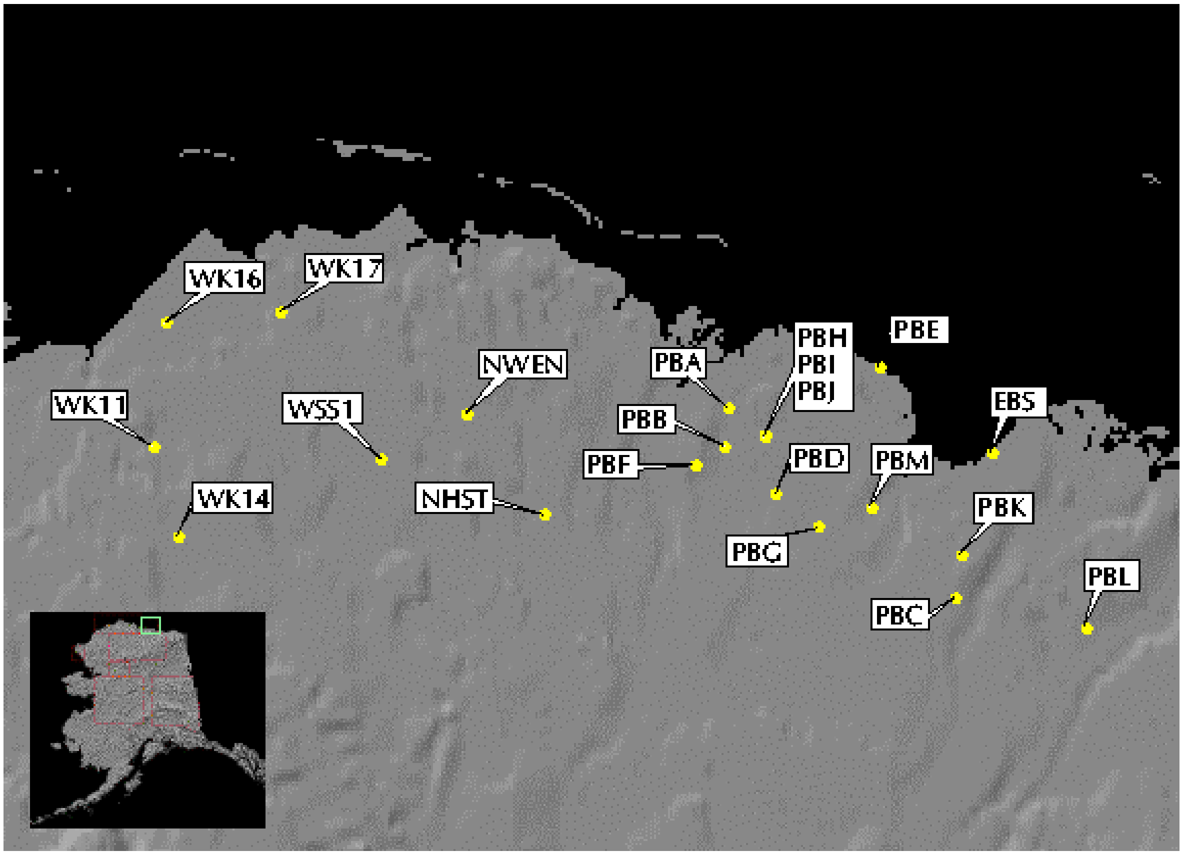

Figure 7: Location of Wells (USGS website)

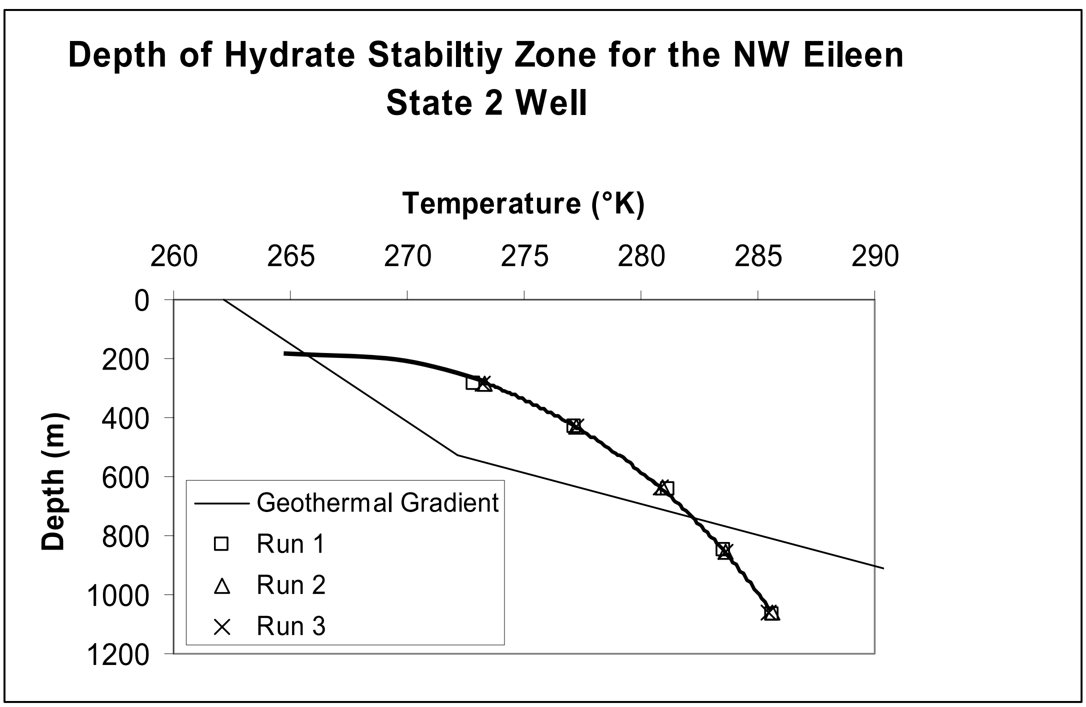

Figure 8: Example of Gas Hydrate Stability Curves

5.7.1.1.1 Sapphire Cell Experiment

The sapphire cell experiment was conducted without the presence of a porous media. Bulk gas hydrates were formed in the cell and then dissociated in order to determine the equilibrium pressure and temperature. The results obtained in this experiment are given in Table 4. The depth to top and base of the HSZ is also presented in Table 3. Figure 9 shows how the zone of gas hydrate stability (ZHS) varies between the different wells. It also shows the influence that different NaCl concentrations can have on the ZHS. It is interesting to note that in both concentrations the ZHS increases as moving eastward and northward.

Lachenbruch et al (1987), has analyzed the thickness of the HSZ from well logs for wells WK-11, WK-14, WK-17, and NHST. He determined the HSZ to be approximately 561, 568, 657, and 718 meters respectively. These results assume zero salinity and the uncertainty ranges from $\pm$ 30-50 m. The thicknesses obtained in this study are all within approximately 100 m of Lachenbruch's et al (1987) work. These results also show that a 2% brine increase, can decrease the thickness of the gas hydrate stability zone by as much as 90 m when a porous media is not present, which coincidently is the approximate difference between Lachenbruch's et al (1987) work and the results presented here. Increasing the brine by 2% typically decreases the thickness of the HSZ by 30 to 45 m (Table 3).

Table 3: Depths to the Top and Base of the Gas Hydrate Stability Zone

Well Name		2% Bulk Gas Hydrates			4% Bulk Gas Hydrates		
Well	**Well**	**Top (m)**	**Bottom (m)**	**Thickness (m)**	**Top (m)**	**Bottom (m)**	**Thickness (m)**
WK-11	WSak-11	140	660	520	175	605	430
WK-14	WSak-14	145	625	480	190	590	400
WK-17	WSak-17	140	690	550	170	650	480
NW Eileen	NWEileen-02	125	765	640	175	710	535
NHST	N.HighlandSt-01	115	790	675	150	760	610

Table 4: Raw Data from Sapphire Cell Experiment

Bulk Gas Hydrate Testing Results

2% Brine	
Temp. (°F)	**Pressure (psia)**
29.9	300
42.7	600
49	892
51	1195
54.2	1497

4% Brine	
Temp. (°F)	**Pressure (psia)**
52.5	1499.7
52.4	1499.7
48.3	1200.7
49	1194.7
44	900.7
42.9	895.7
37.3	614.7
36	611.7
26.4	315.7

5.7.1.1.2 Sand Experiment from Anadarko Hot Ice #1 Sample

These experiments were also conducted by analyzing pressure maintenance during the gas hydrate dissociation. The results for each of the experiments are listed in Table 5. The information provided by these results best mimics rock properties typically found on the North Slope of Alaska. The Anadarko sample showed the same general trend as the previous experiment. Table 6 shows the depths to the top and bottom of the HSZ. Both the 2% and 4% brines showed an increase in the HSZ thickness to the east and north (Figure 10). In wells WK-11, WK-14, WK-17, and well NHST the thickness of the HSZ is approximately 160 m less than the work conducted by Lachenbruch's et al (1987).

Problems arose in achieving reliable results when conducting experiments below 400 psia. This was also assumed to be attributed to the formation/dissociation temperature being below the freezing point of water. For this reason, the results obtained below 400 psia were disregarded. Disregarding these results did not allow accurate determination of the top of the HSZ. Comparing the effects of 2% and 4% brine on the depth of the HSZ, there is only a difference of 15 to 25 m. The top of the gas hydrate stability zone does not vary by more than 5 m except in well NHST where it varies by 20 m, when comparing the 2% and 4% NaCl experiments. In 1972, ARCO and Exxon recovered a core from the NW Eileen State 2 well at a depth between 664 and 667 m that contained gas hydrates. From well log data, Collett (1993) has inferred that gas hydrate exist between a range of 575 and 675 m. In this study, the HSZ for the NW Eileen State 2 well ranges from 190 m to 740 m. In all experiment cases the ranges for the HSZ are in agreement.

5.7.1.1.3 Experiment Conclusions

The five wells examined in this study show that as moving eastward and northward the gas hydrate stability zone increases in thickness and depth. These results were all similar for each of the three experiments. Experiments conducted without a porous media present show that a 2% NaCl brine increase can decrease the thickness of the gas hydrate stability zone by 65 to 105 m. When a porous media is present a 2% NaCl brine increase only decreases the thickness of the gas hydrate stability zone by 0 to 30 m. In the presence of a porous media typically found on the North Slope of Alaska, the maximum depth of the gas hydrate stability zone was 780 m and was at the eastern most well (NHST). The minimum depth was located at the northern most well (WK-14) and had a depth of 585 m. Overall the thickness of the gas hydrate stability zone can vary by as much as 200 m on the North Slope of Alaska. It should be noted that 99% pure methane was being used and this analysis is only valid for this gas composition. Changing the gas composition may cause major variations in the depth of the gas hydrate stability zone. However, compositional analyses of ANS gas hydrates from NW Eileen-02 indicate nearly pure methane.

Much of this gas hydrate stability zone thickness variation is dependent on the local variations of the geothermal gradient and the type of porous media in which gas hydrates are found. The thickness and depths coincide with actual gas hydrate cores recovered by ARCO in 1972. Also the results coincide with the work done by Lachenbruch et al (1987). It is also important to note that the depths and thickness of the gas hydrate stability zones determined in this study are only possible ranges in which gas hydrate could exist.

Table 5: Results from Anadarko Sample Experiments

Anadarko Sample 2%			**Anadarko Sample 4%**		
1500 psia			**1500 psia**		
	Temp. (°F)	Pressure (psia)		Temp. (°F)	Pressure (psia)
Run 1	54.5	1511.7	Run 1	52.3	1505.7
Run 2	54.4	1509.7	Run 2	52.7	1505.7
Run 3	54.2	1509.7	Run 3	53.6	1508.7
1200 psia			**1200 psia**		
	Temp. (°F)	Pressure (psia)		Temp. (°F)	Pressure (psia)
Run 1	50.7	1206.7	Run 1	49.1	1203.7
Run 2	50.9	1210.7	Run 2	49.2	1207.7
Run 3	50.9	1209.7	Run 3	49.2	1208.7
900 psia			**900 psia**		
	Temp. (°F)	Pressure (psia)		Temp. (°F)	Pressure (psia)
Run 1	46.4	910.7	Run 1	44.6	905.7
Run 2	46	904.7	Run 2	44.9	908.7
Run 3	45.8	904.7	Run 3	44.8	906.7
600 psia			**600 psia**		
	Temp. (°F)	Pressure (psia)		Temp. (°F)	Pressure (psia)
Run 1	39.2	608.7	Run 1	37.8	604.7
Run 2	39.3	607.7	Run 2	37.8	601.7
Run 3	39.4	608.7	Run 3	37.9	603.7
400 psia			**400 psia**		
	Temp. (°F)	Pressure (psia)		Temp. (°F)	Pressure (psia)
Run 1	31.5	403.7	Run 1	30.7	301.7
Run 2	32.3	405.7	Run 2	30.5	398.7
Run 3	32.2	401.7	Run 3	30.5	397.7

Table 6: Depths to the Top and Base of the Gas Hydrate Stability Zones

Well	**2% Anadarko**			**4% Anadarko**		
Well	Top (m)	Bottom (m)	Thickness (m)	Top (m)	Bottom (m)	Thickness (m)
WK-11	205	640	435	200	615	415
WK-14	200	600	400	205	585	380
WK-17	200	675	475	205	660	455
NW Eileen	190	740	550	195	715	520
NHST	220	780	560	200	760	560

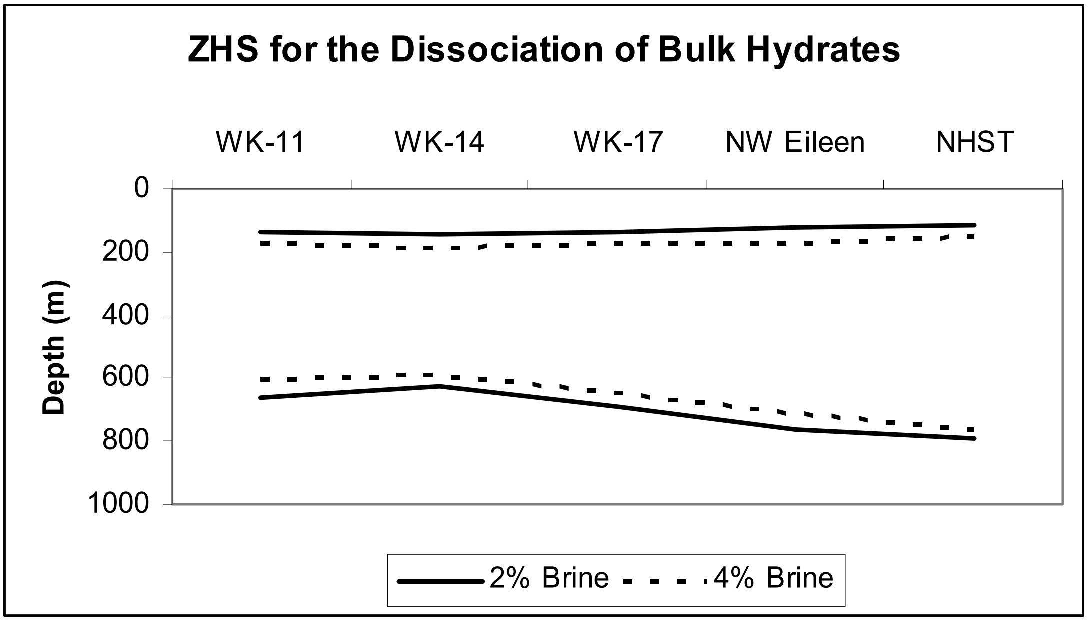

Figure 9: Zone of Gas Hydrate Stability (ZHS) for Bulk Hydrates

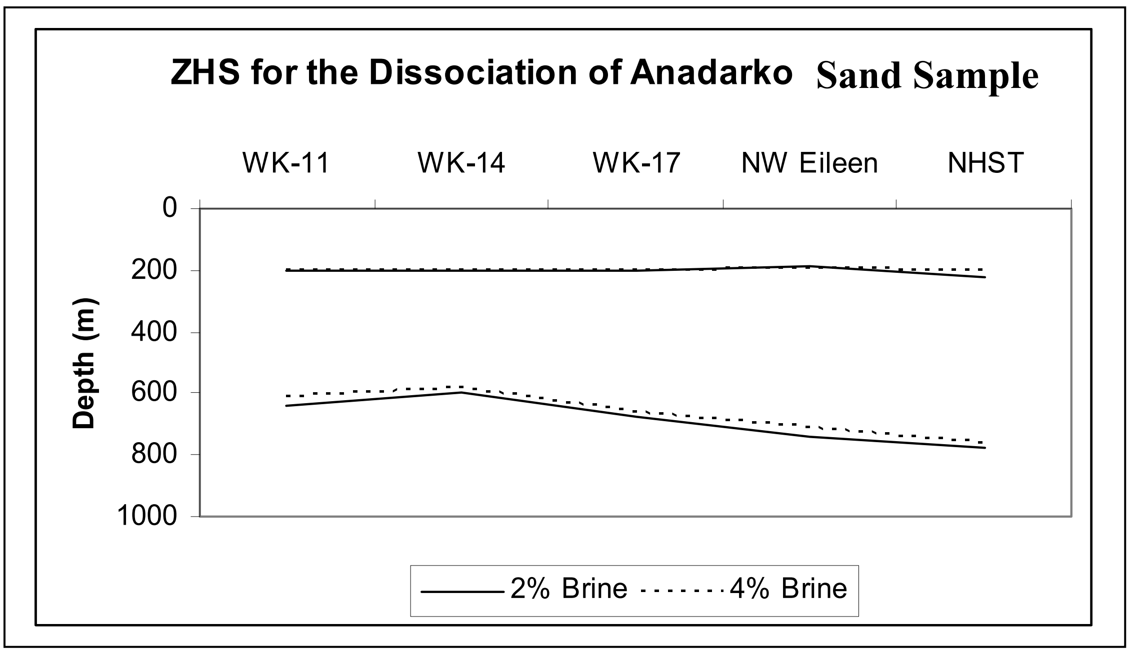

Figure 10: ZHS for Anadarko Sand Sample

Subtask 7.2: Measure Gas-Water Relative Permeabilities

5.7.1.2 Subtask 7.2 Objective

The objective of the project is to measure the relative permeability function relationships by conducting two phase relative permeability experiments and to assess gas productivity from gas hydrate bearing porous media. The current research plays important role in the simulation studies for future gas hydrate zone drilling, completion, and production. The simulation study is one of the important tasks to be carried out in ongoing research.

5.7.1.3 **Experimental Progress**

The current quarter was mostly used for forming gas hydrates in the lab. The conventional experimental set-up for measuring relative permeability was modified for forming gas hydrate. Figure 11 gives the modified schematic of experimental set up.

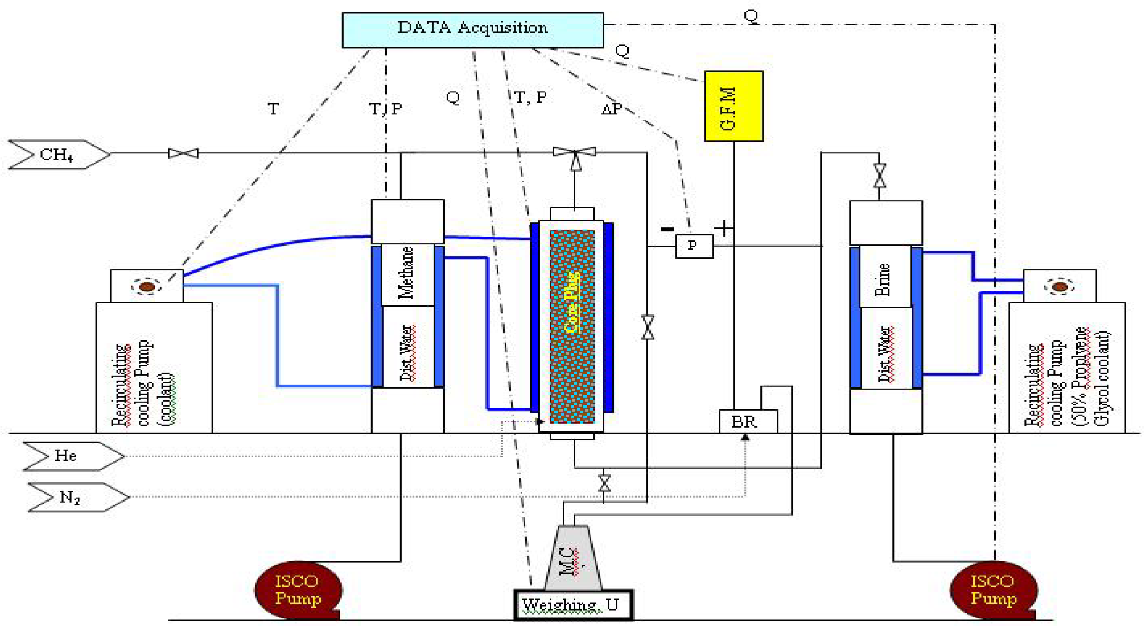

Figure 11: Schematic of laboratory formation of gas hydrates and relative permeability measurements (Jan 2004).

The relationship between natural gas hydrates and the sediments in which they reside is as important as their bulk properties. This is particularly true because gas hydrates are generally found in less consolidated sediments. The mechanical stability of the wellbores in gas hydrate–affected regions crucially depends on whether gas hydrate cements mineral grains or merely resides in the pore space between the grains. Scenarios for the production of natural gas from gas hydrates depend on how gas hydrate saturation affects hydraulic permeability, which in turn depends on the pore geometry.

There are several distinct ways in which gas hydrate can interact with an unconsolidated packing of mineral grains. If gas hydrate forms preferentially at grain contact, it can act as a cementing agent; in this scenario a small amount of gas hydrate can substantially affect sediment properties, for example, the compressional velocity, mechanical strength and volume and this cementing effect that increases steadily with increasing gas hydrate volume. Gas hydrate that grows in the interior of pores will affect mechanical and transport properties, but only modestly until substantial saturations are reached.

5.7.1.4 Gas Hydrates and Ice

There is large literature on the freezing of ordinary water ice in porous media. It is well established that hydrophilic porous media such as sands and sandstone remain liquid-water-wet in the presence of water ice. It can be concluded that the growth habits of ice and gas hydrate may be similar because many of their physical properties are similar [Dvorkin et al. 2000]. Density, Poisson's ratio, and heat capacity indeed are very similar. [Wilder et al. 2001]. On the other hand, the heat of fusion per unit mass is substantially different, and the thermal conductivity of ice is four and a half times larger than that of gas hydrate. [Dvorkin et al., 2000]

5.7.1.5 Laboratory Preparation of Gas Hydrates

Sample integrity can be assured in laboratory experiments performed on artificial samples at controlled temperatures and pressures. However it is difficult to create methane hydrate in the laboratory under conditions similar to those in nature. Realistic fluxes of dissolved or gaseous methane are difficult to simulate in small laboratory core holder, at gas hydrate forming conditions, particularly in porous media, the easiest approach is perhaps the U.S Geological Survey GHASTLI technique [Winters et al. 2000]. A more convenient technique for making laboratory samples of methane hydrate involves reaction of methane gas with melting granulated water ice [Stern et al., 2000], but this process occurs in nature only over limited range of conditions. Other methods are reviewed by Sloan [1998] and Makogon et al. [1998]. Three distinct cases have been identified useful for relative permeability measurements. 1) gas hydrate replaces water as a pore space constituent 2) gas hydrate coats the grains, becoming part of the solid phase, and 3) gas hydrate grows preferentially at grain contact, effectively cementing an otherwise unconsolidated sediment.

Many researchers have grown gas hydrate by dynamic methods e.g. 1) bubbling a hydrate forming gas through fresh water saturated sediment columns, simulating sub-ocean conditions. 2) production of gas hydrate from water and gas mixture [Jason, 2004] by vigorous agitation, shaking, or rocking procedures that continually renew fresh ice surfaces for gas hydrate growth. Such processes are not possible in our experimental set up and primarily meant for phase equilibria, formation processes and formation kinetics studies. There remain some inherent problems, such as low methane content and free water availability, which affect relative permeability measurement. The present quarter was used for selecting methods for forming gas hydrate and their suitability for further relative permeability measurements.

5.7.1.5.1 Method 1: Frost and Sand

Initially the core holder temperature was reduced to -15^{o} C to prevent any melting of frost, used in gas hydrate formation. Frost and sand was mixed and compacted uniformly in the core holder. The core was evacuated and the system was subjected to methane under pressure and gas hydrate was allowed to form. Ice grains subjected to gas hydrate forming conditions showed surface reaction (Figure 12) at temperatures well below the H_2O liquidus, almost immediately after exposure to CH_4 gas. But at low temperatures in the ice subsoilidous field, gas hydrate formation on ice grains virtually halts (on the laboratory time scale) after initial surface reaction unless the grains are vigorously agitated to renew fresh surfaces for gas hydrates formation. The process of converting the unreacted core to gas hydrate by raising the temperature, however, is less well understood. Another problem encountered was measuring the gas hydrate saturation and type of gas hydrate saturation for such conditions.

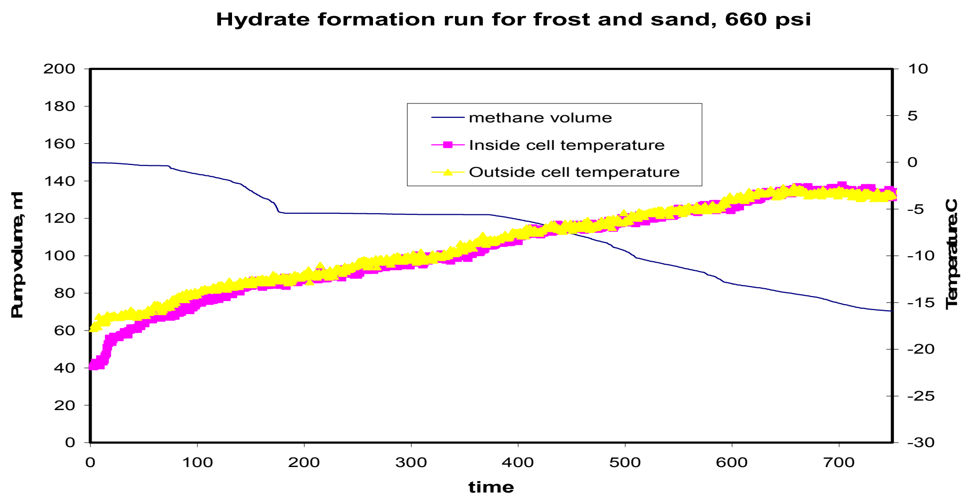

Figure 12: Gas hydrate formation run for sand and frost mixed

5.7.1.5.2 Method 2: Synthetic Methane Hydrate

Samples of poly crystalline methane hydrate can be efficiently synthesized by promoting the general reaction

$$CH_{4(gas)} + (5.5 \sim 6)H_2O_{(solid \sim liguid)} \longrightarrow MethaneHydrate_{(solid)}$$

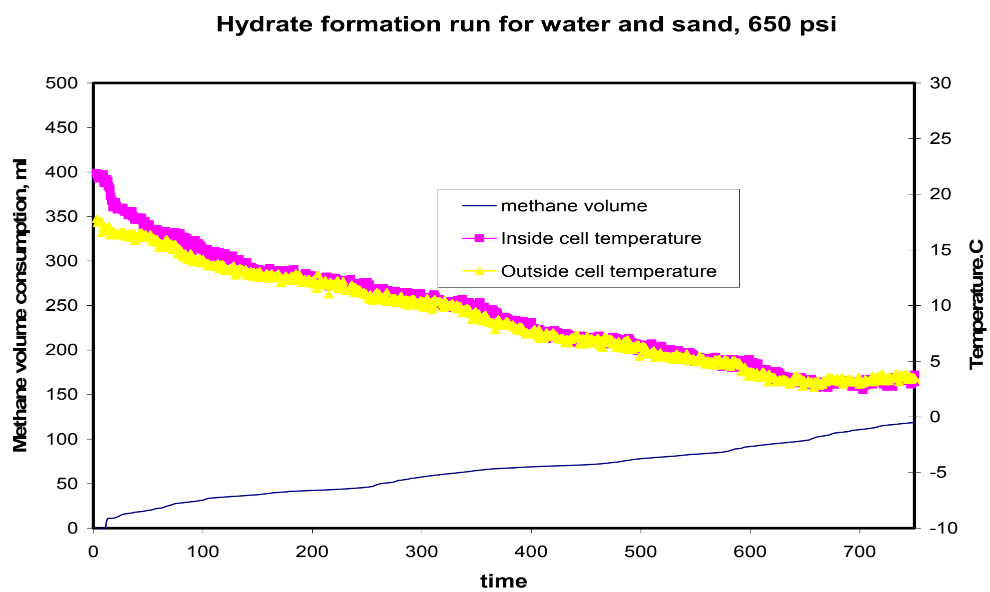

Figure 13: Gas hydrate formation run from saturated sediment

The product in this method was achieved by raising the frost sand mixture or saturated sand (method 1) temperature to ice melting temperature and exposing to cold, pressurized methane gas. Although some initial reactions were observed due to gravity segregation (vertical core holder), the gas hydrate formation was not completed (Figure 13). This method had some success but then in our present equipment set up we still cannot determine the type of saturation.

5.7.1.5.3 Method 3: Water Displacement

In some literature it is cited that rapid formation of gas hydrates is promoted by raising the temperature well above the melting point of ice, in the absence of measure bulk melting and melt segregation, and allowing the reaction to continue by an essential solid state transport or diffusion controlled reaction. In order to simulate in situ conditions, typically, water saturated sediment was initially brought to overburden pressure around 1100 psia. Consolidation was allowed until excess pore pressure was dissipated. The difference between internal pore pressure and the confining pressure is related to the simulated overburden stress. Methane is percolated up through the sediment at desired pressure, until desired amount of water, measured by the collector is pushed out. The temperature of the coolant flowing to the cell is lowered until the P-T conditions are within the gas hydrate stability zone.

The absolute permeability in gas hydrates can be determined by water flooding. The water will be injected at constant differential pressure to make sure there is no gas dissociation from gas hydrates. And later cold gas flooding, at above the dissociation pressure can give us relative permeability for given gas hydrate saturation. Figure 14 shows the gas hydrate formation in presence of overburden pressure of 1100 psi; the UAF experiment was done at 700 psi with temperature ramping of 4.5 C/hr. [Stern, 2000].

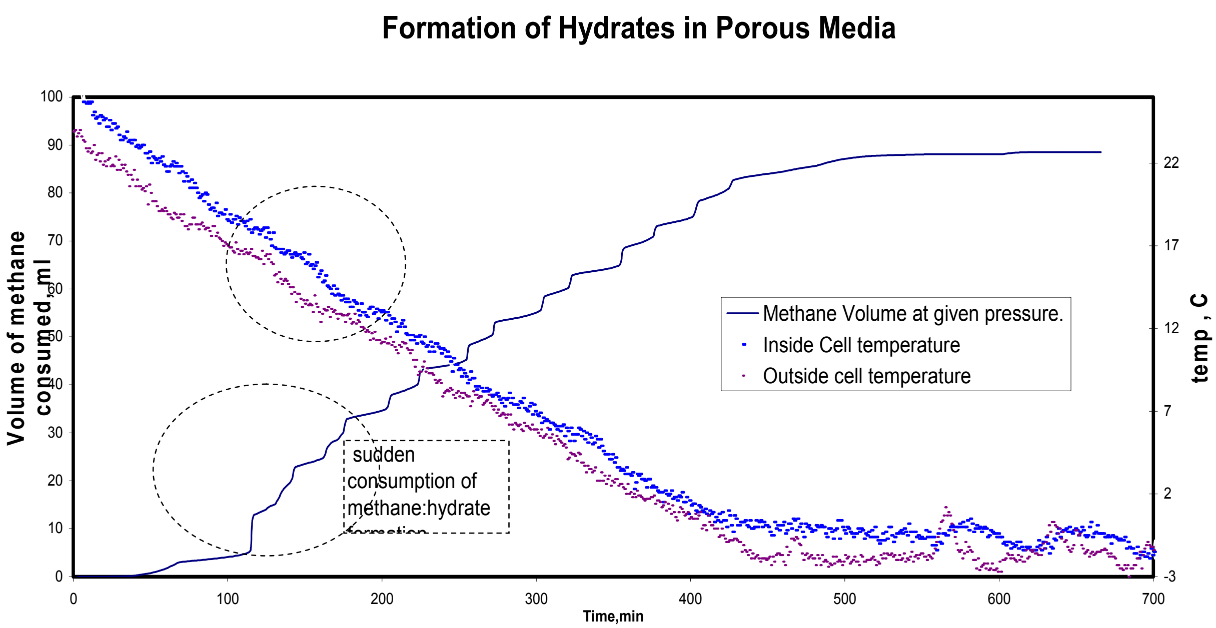

Figure 14: Gas hydrate formation run from saturate sediment with some water displaced

5.7.1.6 Conclusion

For gas hydrate formation in sediment, unconsolidated core should have large porosity (50 % and more) for expansion of water to ice (about 9%) and water to gas hydrate (about 26 %), which is difficult to achieve with large overburden. This can be one of the reasons for significant reduction extent of completion of reaction. Temperature ramping of core holder also plays an important role for gas hydrate formation in porous media.

5.7.1.7 Future Work

- Forming gas hydrate in different types of sediments.
- Measurement of relative permeability in gas hydrate-bearing sediments.

5.8 TASK 8.0: Evaluate Drilling Fluids and Assess Formation Damage – UAF

5.8.1 Subtask 8.1: Design Integrated Mud System for Effective Drilling, Completion and Production Operations

- Design fully integrated mud system for permafrost and gas hydrate-bearing section
- Assess mud contamination risk
- Evaluate mud chiller system for Alaska North Slope, such as one used in Mackenzie Delta Mallik research program

5.8.1.1 Future Work

Future work will assess incompatibility between brine and injection water in the drilling mud simulator. Current Alaska North Slope drilling fluid properties may change if circulated through a mud chiller.

5.8.2 Subtask 8.2: Assess Formation Damage: Testing, Analysis and Interpretation

5.8.2.1 Future Work

Low in-situ pressure gas reservoirs pose unique challenges associated with the drilling and completion practices required in order to obtain economic production rates. Formation damage mechanisms affecting these very low permeability gas hydrate-bearing reservoirs, with a particular emphasis on permeability and capillary pressure effects will be assessed through proposed experimental setup shown in Figure 15.

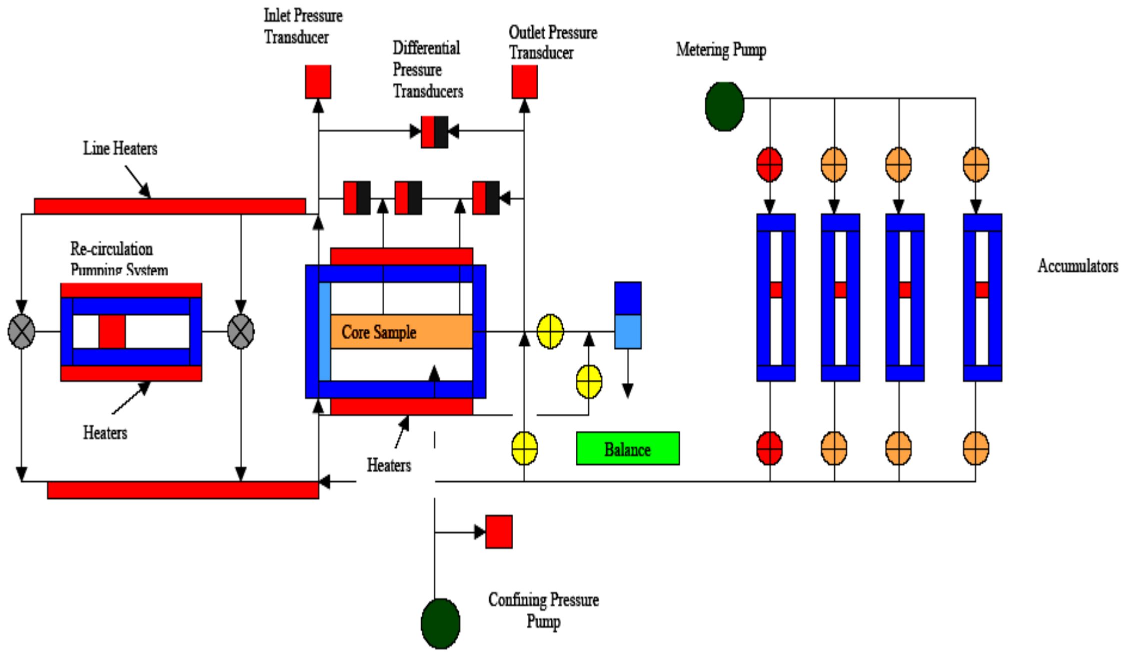

Figure 15: Proposed experimental apparatus to assess drilling fluid and formation damage

5.8.2.2 Experiment Plan

For this experimentation, the initial pressure at the bottom of the gas hydrate zone will be taken as 1000 psi (Pooladi-Darvish, M. and Hong H.; 2003). The flow of methane gas will maintain this pressure on one face of the core sample. The chilled drilling fluid consisting of 50 kg/m^3 of KCl (antifreeze agent and shale inhibitor), 1-3 kg/m^3 of Xanvis (viscosifiers), 0.5 kg/m^3 of KOH (pH control), 6 L/m^3 of lecithin (62% Drilltreat; gas hydrate promoter), 10 kg/m^3 of Dextrid LT (filtration control), 0.3 kg/m^3 of Na_2SO_3, and barite (weighting material) will flow on the other side of the core at varied pressures to provide measurements of the permeabilities at underbalanced as well as overbalanced drilling conditions. The example of a typical underbalanced mud leak off permeability summary with methane gas as a reservoir fluid is shown below.

Table 7: Underbalanced Mud Leak off with Mackenzie Delta Drilling Mud and Permafrost cores with methane gas as a reservoir fluid

Test Phase	Permeability (md)	%Change in Permeability
Gas Permeability at 600 psi Underbalanced Pressure		
Gas Permeability at 400 psi Underbalanced Pressure		
Gas Permeability at 200 psi Underbalanced Pressure	Proposed Experiments	
Gas Permeability at balanced Conditions		
Regain Permeability at 100 psi Drawdown at 200 psi Drawdown at 400 psi Drawdown at 600 psi Drawdown		

Table 8: Overbalanced Mud Leak off with Mackenzie Delta Drilling Mud and Permafrost cores with methane gas as a reservoir fluid

Test Phase	Permeability (md)	%Change in Permeability
Initial Gas Permeability		
Overbalanced Leak off	Proposed Experiments	
Final Regain Permeability to gas		

Such observations will be made for overbalanced drilling pressure conditions and for one set of pressure drawdown. The amount of time will be monitored so as to observe any kind of a permeability change. Also, parameters such as fluid leakoff, filter cake build up, physical depth of invasion of filtrate and solids will be subsequently measured. The cores with depth from 200 ft to 1400 ft from the sedimentary deposits of North Slope of Alaska from the Anadarko Hot Ice #1 well will be utilized for this experimentation.

5.8.2.3 Procured Experiment Equipment

1. Dynamic Filtration Core Holder
   (maximum pressure 2500 psi.; Core Diameter 3 inch; Core Length 6 inch)
2. Differential Pressure Transducer
   (pressure range from 0-1250 psi)
3. Back Pressure regulators (BPR-50-ss and BP-50-ss) (working pressure 5000 psi; temperature 200° F)
4. Drilling Fluid Recirculation System (pressure 2500 psi; temperature -10 to 400° F; volume 500 cc; ¼" NPT)
5. Digital Transducer Indicator
6. Floating Piston Accumulator (with Teflon seals, 2500 psi, 2000 cc volume, 316 ss body, 350° F temperature, ¼"NPT)
7. Mass Flow meter (GFM, 10 l/min, Viton seals, ¼" NPT, LCD display)
8. I/O Signal Conditioner (I/O-232-C, w/RS232, 0-5 VDC)
9. Power Supply Plug (PS-GFM-110NA, 110V/12V DC)
10. Flow meter for Methane Gas (FMA-871A-V-CH4, 1000 PSI, 0-15 SLPM)
11. Power Supply (EPW-D15, +/- 15 V DC 200 mA)
12. Channel Temperature Scanner (CN612TC1)
13. Refrigerated Fluid Circulator (9300650-13, FP50-HP 230V/60Hz; -50 to 200° C, RS232/RS485; 20Lpm or 5psi)

5.8.2.4 Future Work

- Build-up of experimental plan
- Test Trials at limiting pressure and temperature conditions.
- Underbalanced and Overbalanced Mud Leak off tests.
- Measurement of time for distinct permeability change for various sets.

5.9 TASK 9.0: Design Cement Program – UAF

No significant work was accomplished during the reporting period.

5.9.1 Future Work

- Continue literature survey and assess current permafrost cements
- Work with AETDL and DOE to fund cooperative research program with Argonne National Lab (ANL) to study efficacy of Ceramicrete as arctic conditions and chilled drilling cement
    - Proposal presented to AETDL review panel in July 2003
    - Proposal ranked second and to be forwarded to NETL for funding by AETDL
    - Project co-funding and participation commitments by Bindan Corporation (Ceramicrete manufacturer) and BJ Drilling (mud company)
- Design experiments to assess cements and conduct preliminary experiments at ANL

5.10 TASK 10.0: Study Coring Technology – UAF

5.10.1 Coring Technology Summary

No significant work was accomplished during the reporting period. The various methods for recovering, preserving, and transporting gas hydrate cores at in-situ conditions were reviewed in the June 2003 Quarterly Report.

5.10.2 Future Work

- Continue literature survey
- Assess coring technologies and recommend best core methods for ANS application

5.11 TASKS 11.0 and 13.0: Reservoir Modeling and Project Commerciality and Progression Assessment – UAF, BP, LBNL, Ryder Scott

5.11.1 Gas Hydrate Analytical Model Development

Mathematical formulations proposed by Makogon [1] for time evolutions of pressure and temperature fields are considered in developing the axisymmetric model. To be able to obtain the similar solutions, transport and energy equations must be first linearized. Self-similar solutions are obtained when the conductive heat transfer in the porous medium is neglected compared to convective heat transfer term. Linearization method is derived for fixed natural gas output and constant well pressure. In this context, constant well pressure, pg, is treated as BC1 whereas fixed production rate, Q, as BC2. The resulting nonlinear-coupled equations are solved at each gridpoint with the Newton-Raphson method. For different well pressures (BC1), production rates (BC2) and reservoir temperatures, distribution of pressure and temperature in the porous layer of methane hydrate and in the gas region are evaluated. The distance of the decomposition front from the well as functions of time are computed. Time variations of mass flux and total mass flow are also studied. Time evolutions of resulting pressure and temperature profiles in the gas hydrate reservoir under various conditions are displayed. Effects of reservoir porosity and zone permeability are presented. Effects of boundary conditions on production profile are also studied.

The Linearization method formulated by Makogon [1] assumes that the heat convection dominates the conduction in the entire reservoir. While this assumption is reasonable away from the front, it does not allow for the energy balance at the dissociation front to be enforced. Despite this important limitation of the approach this semi-analytical method is a convenient means for studying many features of the natural gas production from gas hydrate reservoirs.

The model is evaluated for various sensitivity parameters (Table 9). The simulation results showed that the natural gas production is a sensitive function to the reservoir temperature and zone permeability. Change in gas hydrate zone permeability has a remarkable effect on gas output even though the dissociation front moves at slower pace. Increase of gas zone permeability has no significant effect on gas productivity as shown in Table 10. Effect of boundary conditions on the gas production has a significant effect on long run. It is shown that the movement of dissociation front in case of BC2 is faster than in case of BC1 and also natural gas production is higher in case of BC1 over BC2. The simulation results presented in the below tables for constant well output case are quite different from the published paper by Ji et al. Their simulation results are inconsistent when observed carefully. The dissociation pressure, temperature, and the movement of the dissociation front listed in Table 9 are quite different from figures 16-18. In this work, effect of reservoir porosity on the gas flow is also presented and compared the model performance for possible different boundary conditions.

Table 9: Dissociating temperature, pressure, and parameter γ for given reservoir conditions

p_{in} (MPa)	T_{in} (K)	p_W (MPa) BC1	Q (Kg/S) BC2	T_D (K)	p_D (MPa)	γ (m^2/s)
15	287	2		279.89	5.418	$1.629*10^{-6}$
			0.04	279.334	5.1409	$1.538*10^{-5}$
15	287	3		280.078	5.5125	$7.8*10^{-7}$
			0.03	279.801	5.3704	$2.421*10^{-6}$
15	287	4		280.3	5.631	$1.9*10^{-7}$
			0.02	280.471	5.722	$6.423*10^{-8}$
15	287	5.5		280.96	6.006	$3*10^{-8}$
			0.01	281.274	6.1811	$4.457*10^{-8}$
15	285	2		277.963	4.535	$1.3*10^{-7}$
			0.03	277.505	4.3535	$1.642*10^{-6}$
15	283	2		276.02	3.826	$1*10^{-8}$
			0.03	275.347	3.6137	$1.302*10^{-6}$

Table 10: Dissociating temperature, pressure, and parameter γ for different zone permeabilities

p_{in} (MPa)	T_{in} (K)	k_1 md	k_2 md	p_W (MPa) BC1	Q (Kg/S) BC2	T_D (K)	p_D (MPa)	γ (m^2/s)
15	287	5.2	0.4	2		279.89	5.418	$1.629*10^{-6}$
					0.04	279.334	5.1409	$1.538*10^{-5}$
15	287	5.2	1	2		280.53	5.75	$3.94*10^{-8}$
					0.04	280.698	5.8484	$1.043*10^{-8}$
15	287	5.2	3	2		280.97	6.003	$3.94*10^{-10}$
					0.04	281.673	6.4185	$1.245*10^{-8}$
15	287	1	1	2		281.3	5.945	$8.335*10^{-9}$
					0.04	280.698	5.8484	$1.043*10^{-8}$

Table 11: Dissociating temperature, pressure, and parameter γ for different reservoir porosities

p_{in} (MPa)	T_{in} (K)	p_W (MPa) BC1	k_1 md	k_2 md	ϕ	T_D (K)	p_D (MPa)	γ (m^2/s)
15	287	2	5.2	0.4	0.2	279.89	5.418	$1.629*10^{-6}$
15	287	2	17.55	1.35	0.3	278.21	4.639	$3.968*10^{-7}$
15	287	2	41.6	3.2	0.4	276.95	4.151	$1.141*10^{-7}$

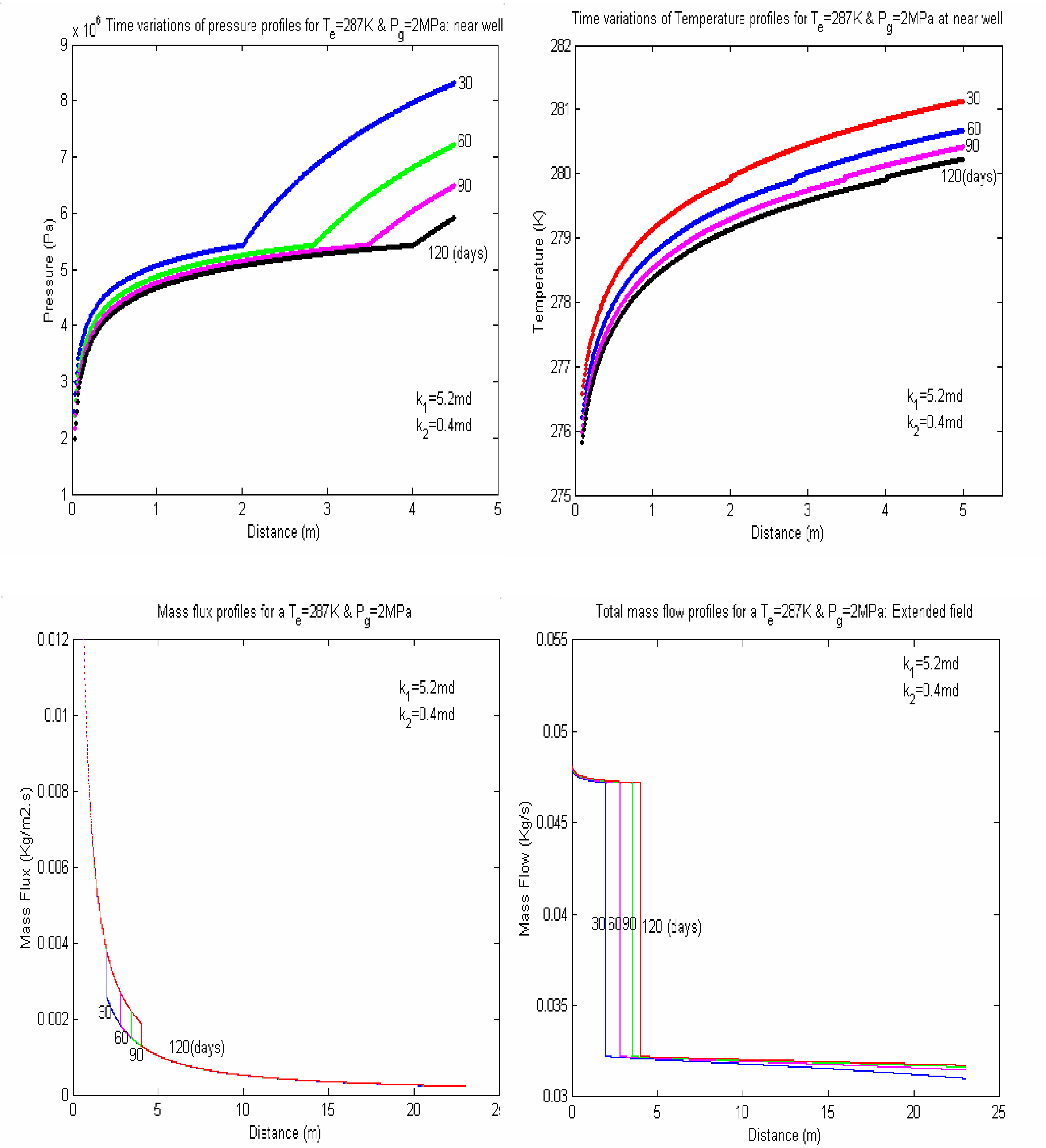

Figure 16: Comparative pressure, temperature, and movement of the gas dissociation front

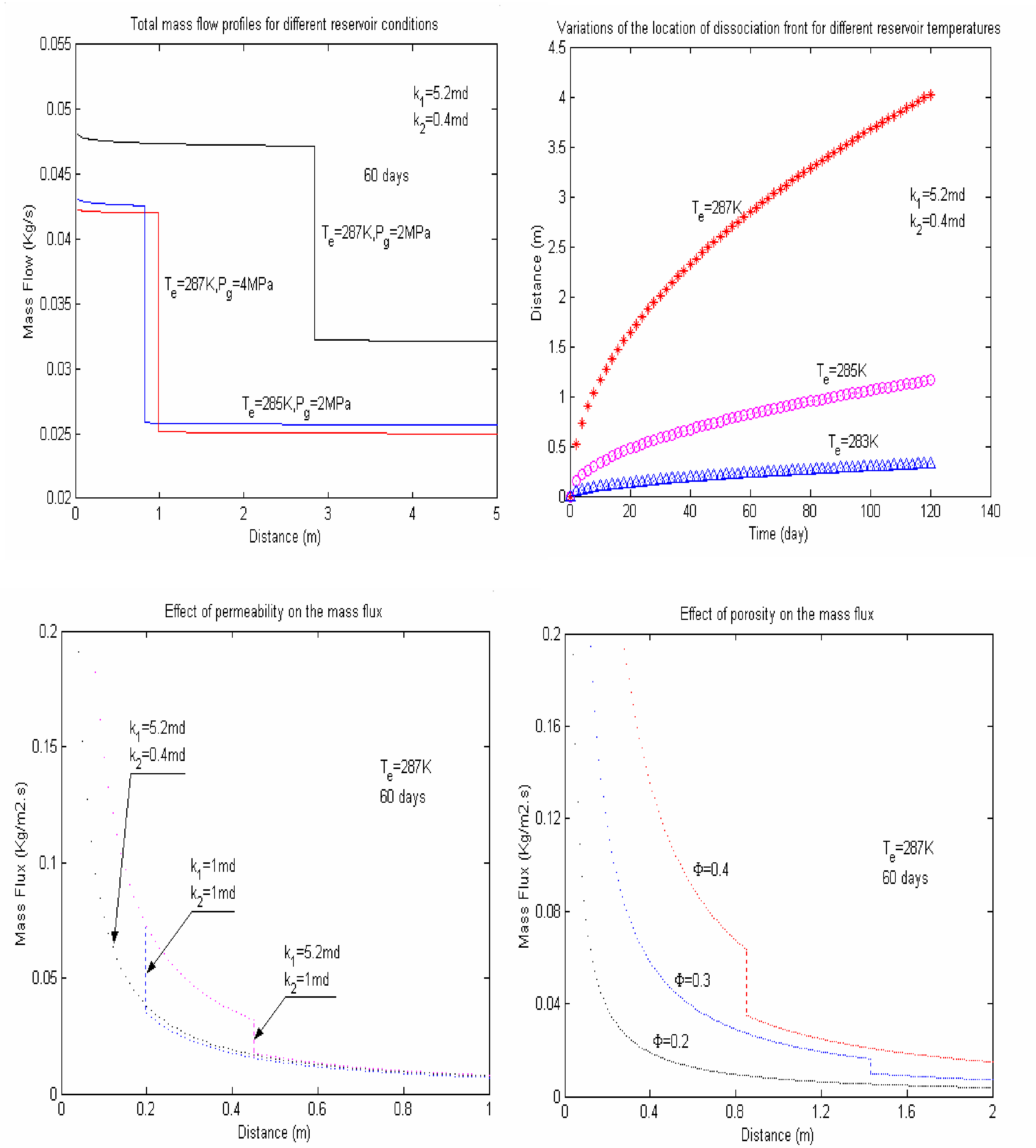

Figure 17: Reservoir condition sensitivities and movement of the gas dissociation front

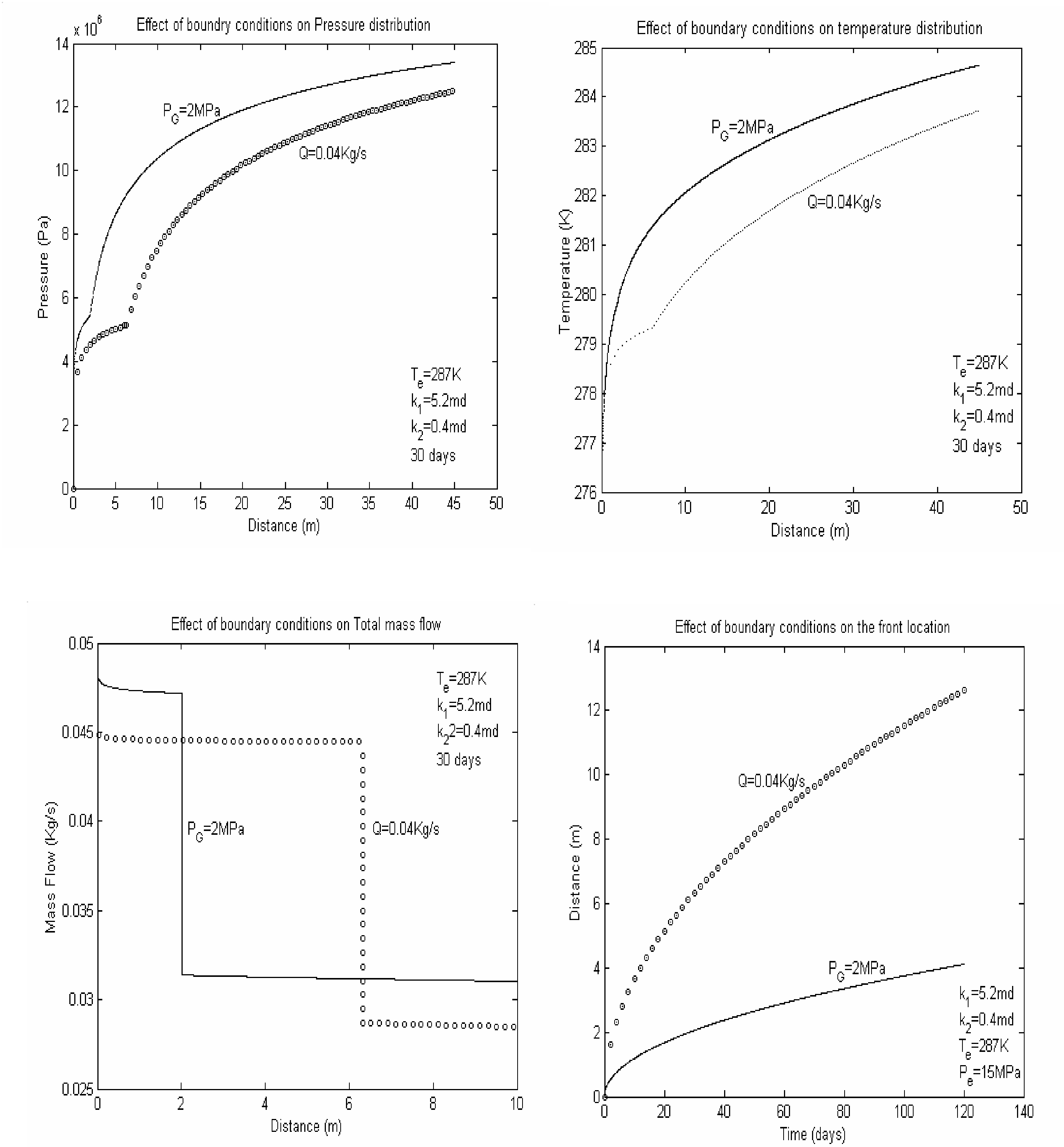

Figure 18: Reservoir boundary conditions and movement of the gas dissociation front

5.11.2 Simulation Model Development

Work towards modeling a gas hydrate pilot production scheme has been directed to two areas. Further efforts have been directed into modifying a commercial simulator to model gas dissociation from gas hydrate. A valid model has not been produced as yet, however, many trial runs and guidance from the software developers mean that success is anticipated shortly. Focusing on the depressurization of the underlying free-gas area, various well configurations were simulated to compare the efficiency of different well trajectories and the rate and distribution of depressurization. A sinusoidal well was found to be most efficient, but the practicality of employing this in the field has not been considered.

5.11.3 Use of Horizontal and Designer Wells for Gas Hydrate Production

In addition, consideration has been given to the use of horizontal and designer wells in the production of gas hydrate accumulations and how these may benefit a pilot production scheme. The stage of methane hydrate research and development is presently largely confined to the development of analytical and modeling techniques and small pilot projects such as the Mallik well. For this reason, little has been written about the practical nature of methane hydrate exploitation. Any such studies, such as McGuire (1982) and Moridis & Collett (2003) assume the use of conventional horizontal wells with no new innovations. However, taking the nature of gas hydrate dissociation into account, several of the specific advantages of horizontal and multi-lateral wells can be applied.

5.11.4 Constrained Gas Hydrates

With constrained gas hydrates, the area for depressurization is small. Formations containing gas hydrates are generally thought to be highly impermeable as the hydrate effectively blocks the pores with ice. Effectively, gas dissociation only occurs at the gas hydrate face. The initial area of depressurization is only as large as the effective wellbore radius area. Early work carried out by McGuire (1982) recognized that fracturing would be necessary in such confined gas hydrate accumulations. McGuire suggests fracturing using a hot, super-saturated solution of salt (calcium chloride). This hot solution is pumped into the wellbore at high rates and pressure to create the long fractures perpendicular to the well-bore. As the brine cools, some of the salt crystals will precipitate out and act as the proppant. The high salt content also helps prevent re-freezing of the fracture.

Whilst this procedure may have its technical merits, whether it's actual use is feasible, from environmental grounds is debatable. Certainly in Alaska, there are strict guidelines for the injection of substances in to the sub-surface. Normally, the injection zone has to be shown to be isolated from the other formations and certainly have no chance of migrating into the fresh water table. As such, the injection of large quantities of super-saturated brine into comparatively shallow depths may cause problems. However, if we consider that a large fracture from a vertical well is analogous to a horizontal well, a possible alternative emerges. A horizontal well, drilled though the gas hydrate zone will present a larger area for depressurization. As the depressurization occurs and the gas hydrate interface moves into the formation, this area will grow substantially quicker than if a vertical well had been drilled.

5.11.5 Gas Hydrate and Free-Gas accumulations

With gas hydrates that overlie a free-gas accumulation, the gas hydrate dissociates at the gas-hydrate interface as the pressure of the gas below descends below the pressure necessary for stability at the formation temperature. As such the main uses of horizontal and designer well technology would be to facilitate the production of gas from the reservoir, leading to a reduced reservoir pressure. As in conventional gas reservoirs, horizontal and multilateral wells can help overcome problems due to compartmentalization, low permeability and thin pay zones. An additional advantage may arise when it is considered that dissociation of free gas from gas hydrate produces great quantities of water (each mole of methane hydrate releasing 6 moles of water when dissociated). In typical formations containing gas hydrate, Moridis and Collett (2003) suggest that low capillary pressures lead to rapid drainage of the water from the dissociation zone. This is likely to accumulate at the bottom of the reservoir. In thin reservoirs, coupled with high production rates, water coning could occur. The use of horizontal wells, known to be effective at reducing coning could be advantageous.

5.11.6 Economic Considerations

The nature of methane hydrates means that onshore, the conditions needed for stability are generally found in arctic regions. These areas, such as the Alaska North Slope, are remote from the locations of demand for gas and so any produced gas needs to be transported great distances, either by pipeline, LNG or possibly GTL. With current, typical gas prices, the added burden of gas transportation costs means the economics of a gas hydrate development are marginal at best, unless lined to a conventional gas pipeline. A development scheme is unlikely to be able to shoulder the costs of new field development infrastructure, especially as the cost of new-build schemes in remote environments tends to be a factor higher than in more benign locations. In the case of the North Slope gas hydrate accumulations, fortunately, much of the gas hydrate underlies existing infrastructure that was installed for oil development. This has the dual advantages of saving money, plus adding little additional environmental impact, which can be as important as financial considerations. However, the existing infrastructure foot print does not cover all the gas hydrate areas, nor are all the existing gravel drilling pads located in the optimum positions for the gas and gas hydrate depressurization. Therefore extended reach drilling (ERD) wells may be needed to access some of the gas hydrate. Wells at Milne Point and Niakuk have proved the feasibility of ERD on the North Slope and reduced costs to an acceptable level, although ERD technology within less consolidated shallow sands is less proven.

5.11.7 Future Work

- Develop the mechanistic and numerical model for gas hydrate.
- Develop Depressurization production model and conditional simulation reservoir model
- Study economic Analysis/Feasibility of gas production from gas hydrate.
- Progress research collaborations with LBNL regarding EOSHYDR2 reservoir model.
- Incorporate suggestions from CMG Group into simulator initialization
- Achieve a valid and stable simulation

5.12 TASK 12.0: Select Drilling Location and Candidate – BP, UA, USGS

Reservoir and fluid characterization studies in Task 6.0 and investigation of seismic technologies in tasks 5.0 and 6.0 are helping to identify potential areas within MPU for additional gas hydrate data acquisition and/or production testing operations. The associated project study by USGS as funded by the regional ANS BLM research has retained a geophysical consultant. The consultant is working with USGS geologic and geophysical staff to identify seismic attribute anomalies potentially associated with changes in pore fluid types (water, free gas, and gas hydrate) within reservoir (sand-prone) intervals.

6.0 CONCLUSION

Interim conclusions are presented at this stage in the research program. Establishing this collaborative research agreement culminates nearly three decades of hundreds of well penetrations through methane hydrate during ANS oil production operations following the first dedicated gas hydrate coring and production testing in NW Eileen State – 02, drilled in 1972 within the Eileen gas hydrate trend by Arco and Exxon. During this time, methane hydrates were known primarily as a drilling hazard. Industry has only recently considered the resource potential of conventional ANS gas during industry and government efforts in working toward an ANS gas pipeline. Consideration of the resource potential of conventional ANS gas created the industry – government alignment necessary to reconsider the resource potential of the potentially huge (40 – 100 TCF in-place) unconventional ANS methane hydrate accumulations beneath or near existing production infrastructure.

The BPXA – DOE collaborative research project is designed to enable industry and government to make informed decisions regarding the resource potential of this ANS methane hydrate petroleum system through comprehensive regional shallow reservoir and fluid characterization utilizing 3D seismic data, implementation of methane hydrate experiments, and design of techniques to support potential methane hydrate drilling, completion, and production operations.

The results of the collaborative BPXA-LBNL pre-Phase 1 scoping reservoir model and economics study (presented in the March 2003 Quarterly report and recent technical conferences) demonstrate first-ever potential commerciality of gas production from gas hydrate across a broad regional contact from adjacent free gas depressurization. This collaborative research project will verify the size of the potential resource, determine the extent of reservoir/fluid compartmentalization, and validate potential production techniques.

7.0 PROJECT AND RELATED REFERENCES

7.1 General Project References

Casavant, R.R. and others, 2003, Geology of the Sagavanirktok and Gubik Formations, Milne Point Unit, North Slope, Alaska: Implications for neotectonics and methane gas hydrate resource development, AAPG Bulletin, in prep.

Casavant, R.R. and Gross, E., 2002, Basement Fault Blocks and Subthrust Basins? A Morphotectonic Investigation in the Central Foothills and Brooks Range, Alaska, at the SPE-AAPG: Western Region-Pacific Section Conference, Anchorage, Alaska, May 18-23, 2002.

Casavant, R.R. and Miller, S.R., 2002, Tectonic Geomorphic Characterization of a Transcurrent Fault Zone, Western Brooks Range, Alaska, at the SPE-AAPG: Western Region-Pacific Section Conference, Anchorage, Alaska, May 18-23, 2002.

Collett, T.S., "Natural Gas Hydrates of the Prudhoe Bay and Kuparuk River Area, North Slope, Alaska", The American Association of Petroleum Geologist Bulletin, Vol. 77, No. 5, May 1993, p. 793-812.

Collett, T.S., 2001, Natural-gas hydrates: resource of the twenty-first century? In M.W. Downey, J.C. Treet, and W.A. Morgan eds., Petroleum Provinces of the Twenty-First Century: American Association of Petroleum Geologist Memoir 74, p. 85-108.

Collett, T.S., 12/6/2001, MEMORANDUM: Preliminary analysis of the potential gas hydrate accumulations along the western margin of the Kuparuk River Unit, North Slope, Alaska (unpublished administrative report).

Collett et al., 2001, Modified version of a multi-well correlation section between the Cirque-2 and Reindeer Island-1 wells, depicting the occurrence of the Eileen and Tarn gas hydrate and associated free-gas accumulations (unpublished administrative report).

Collett et al., 2001, Modified version of a map that depicts the distribution of the Eileen and Tarn gas hydrate and associated free-gas accumulations (unpublished administrative report).

Collett, T.S., 2002, Methane hydrate issues – resource assessment, In the Proceedings of the Methane Hydrates Interagency R&D Conference, March 20-22, 2002, Washington, D.C., 30 p.

Collett, T.S., 2002, Energy resource potential of natural gas hydrates: Bulletin American Association of Petroleum Geologists, v. 86, no. 11, p. 1971-1992.

Collett, T.S., and Dallimore, S.R., 2002, Detailed analysis of gas hydrate induced drilling and production hazards, In the Proceedings of the Fourth International Conference on Gas Hydrates, April 19-23, 2002, Yokahama, Japan, 8 p.

Geauner, J.M., Manuel, J., and Casavant, R.R., 2003, Preliminary subsurface characterization and modeling of gas hydrate resources, North Slope, Alaska, , in: 2003 AAPG-SEG Student Expo Student Abstract Volume, Houston, Texas

Hunter, R.B., Casavant, R. R. Johnson, R.A., Poulton , M.., Moridis, G.J., Wilson, S.J., Geauner, S. Manuel, J., Hagbo, C., Glass, C.E., Mallon, K.M., Patil, S.L., Dandekar, A., And Collett, T.S., Reservoir-fluid characterization and reservoir modeling of potential gas hydrate resource, Alaska North Slope, 2004 AAPG Annual Convention Abstracts with Program, in press.

Hunter, R.B., Digert, S.A., Casavant, R.R., Johnson, R., Poulton, M., Glass, C., Mallon, K., Patil, S.L., Dandekar, A.Y., and Collett, T.S., "Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay-Kuparuk River Area, North Slope of Alaska", Poster Session at the AAPG Annual Meeting, Salt Lake City, Utah, May 11-14, 2003. Poster selected as EMD 2nd place, President's Certificate for Excellence in Presentation (posters).

Hunter, R.B., Pelka, G.J., Digert, S.A., Casavant, R.R., Johnson, R., Poulton, M., Glass, C., Mallon, K., Patil, S.L., Chukwu, G.A., Dandekar, A.Y., Khataniar, S., Ogbe, D.O., and Collett, T.S., "Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay-Kuparuk River Area on the North Slope of Alaska", presented at the Methane Hydrate Inter-Agency Conference of US Department of Energy, Washington DC, March 21-23, 2002.

Hunter, R.B., Pelka, G.J., Digert, S.A., Casavant, R.R., Johnson, R., Poulton, M., Glass, C., Mallon, K., Patil, S.L., Chukwu, G.A., Dandekar, A.Y., Khataniar, S., Ogbe, D.O., and Collett, T.S., "Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay-Kuparuk River Area on the North Slope of Alaska", at the SPE-AAPG: Western Region-Pacific Section Conference, Anchorage, Alaska, May 18-23, 2002.

Lachenbruch, A.H., Galanis Jr., S.P., and Moses Jr., T.H., (1988) "A Thermal Cross Section for the Permafrost and Hydrate Stability Zones in the Kuparuk and Prudhoe Bay Oil Fields", Geologic Studies in Alaska by the U.S. Geological Survey during 1987, p. 48-51.

Lee, M.W., 2002, Joint inversion of acoustic and resistivity data for the estimation of gas hydrate concentration: U.S. Geological Survey Bulletin 2190, 11 p.

Lewis, R.E., Collett, T.S., and Lee, M.W., 2001, Integrated well log montage for the Phillips Alaska Inc., Kuparuk River Unit (Tarn Pool) 2N-349 Well (unpublished administrative report).

Khataniar, S, Kamath, V.A., Omenihu, S.D., Patil, S.L., and Dandekar, A.Y., "Modeling and Economic Analysis of Gas Production from Hydrates by Depressurization Method", The Canadian Journal of Chemical Engineering, Volume 80, February 2002.

Zhao, B., 2003, Classifying Seismic Attributes in the Milne Point Unit, North Slope of Alaska, MS Thesis, University of Arizona, 159 p.

7.2 Task 7, Gas Hydrate Phase Behavior and Relative Permeability References

ASTM: "Standard Test Method for Permeability of Granular Soils (constant head) D 2434-68", American Society for Testing and Materials, Annual Book of ASTM Standards, West Conshohocken, PA, (2000), 202-206.

Dvorkin, J., Helgerud, M.B., Waite, W.F., Kirby, S.H. and Nur, A., "Introduction to Physical Properties and Elasticity Models", in Natural Gas Hydrate in Oceanic and Permafrost Environments, edited by M.D. Max, pp 245-260, Kluwer, Dordrecht, 2000.

Gash, B.W.: "Measurement of Rock Properties in Coal for Coalbed Methane Production", Paper 22909 presented at the 1991 SPE annual Technical conference and Exhibition, Dallas, October 6-9.

Johnson, E.F., Bossler, D.P., and Neumann, V.O.: "Calculation of Relative Permeability from Displacement Experiments", Trans. AIME, (1959), 216, 370- 372.

Jones, S.C. and Roszelle, W.O.: “Graphical Techniques for Determining Relative Permeability from Displacement Experiments”, JPT, (May 1978), 807-817.

Joseph W. W. and Duane H.S.: “Upper Limits on the Rates of Dissociation of Clatharate Hydrates to Ice and Free Gas”, J. Phys. Chem. B., (May 2002), 106, 6298-6302.

Makogon, Y.F., Makogon, T.Y. and Holditch, S.A., “Several Aspects of the Kinetics and Morphology of Gas Hydrates”, Proceedings of the International Symposium on Methane Hydrates: Resources in the Near Future?, Chiba City, Japan, 20-22, October 1998.

Masuda, Y., Ando, S., Ysukui, H., and Sato, K.: “Effect of Permeability on Hydrate Decomposition in Porous Media”, International Workshop on Gas Hydrate Studies, Tsukuba, Japan, Mar 4-6, 1997.

Owens, W.W., Parrish, D.R., and Lamoreausx, W.E.: “An Evaluation of Gas Drive Method for Determining Relative Permeability Relationships”, Trans., AIME (1956) 207, 275-280.

Scheidegger, A.E., The Physics of Flow Through Porous Media, Macmillan, New York, 1998.

Sloan, E.D., Clatharate Hydrates of Natural Gases, Mercel Dekker, New York, 1998.

Spangenberg,W., : “Modeling of the influence of gas hydrate content on the electrical properties of porous sediments”, J of Geophys. Res B., (2001), 106, 6535-6549.

Stern, L.A., Kirby, S.H., Durham, W.B., Circone, S. and Waite, W.F., “ Laboratory synthesis of pure methane hydrate suitable for measurement of physical properties and decomposition behavior” in Natural Gas Hydrate in Oceanic and Permafrost Environments, edited by M.D. Max, pp 323-348, Kluwer, Dordrecht, 2000.

Tooth, J., Bodi, T., et al: “Analytical Techniques for Determination of Relative Permeability from Displacement Experiments”, Progress in Mining and Oilfield Chemistry, (2000), Vol-2, 91-100.

Wastervelt, Jason., M.S thesis in preparation at University of Alaska Fairbanks, 2004.

Wilder, J.W., Seshadri, K. and Smith, D.H., “Modeling Hydrate Formation in Media With Broad Pore Size Distributions”, Langmuir 17, 6729-6735, 2001.

Winters, W.J., Dillon, W.P., Pecher, I.A. and Mason, D.H., “GHASTLI-Determining physical properties of sediment containing natural and laboratory formed gas hydrate” in Natural Gas Hydrate in Oceanic and Permafrost Environments, edited by M.D. Max, pp 311-322, Kluwer, Dordrecht, 2000.

7.3 Task 8, Drilling Fluid Evaluation and Formation Damage References

Anselme, M.J., Reijnhout, M.J., Muijs, H.M., Klomp, U.C.; World Pat. WO 93/25798, 1993.

Belavadi, M.N.; "Experimental Study of the Parameters Affecting Cutting Transportation in a Vertical Wellbore Annulus"; M.S.Thesis, UAF; Sept., 1994.

Bennion D.B., Thomas F.B., Bietz R.F.; "Low permeability Gas Reservoirs: Problems, Opportunities and Solution for Drilling, Completion, Simulation and Production"; SPE 35577; May 1996.

Bennion D.B., Thomas F.B., Bietz R.F.; "Formation Damage and Horizontal Wells- A Productivity Killer?" SPE 37138; International Conference on Horizontal Well Technology, Calgary; Nov. 1996.

Bennion D.B., Thomas F.B., Bietz R.F.; "Underbalanced Drilling and Formation Damage- Is it a Total Solution?"; The Journal of Canadian Petroleum Tech.; Vol. 34 (9); Nov. 1995.

Bennion D.B., Thomas F.B., et al.; "Advances in Laboratory Core Flow Evaluation to minimize Formation Damage Concerns with Vertical/Horizontal Drilling Application"; CAODC; Vol. 95 (105); 1995.

Bennion D.B., Thomas F.B, Jamaluddin, K.M., Ma T.; "Using Underbalanced Drilling to Reduce Invasive Formation Damage and Improve Well Productivity- An Update"; Petroleum Society of CIM; PTS 98-58.

Chadwick J.; "Exploration in permafrost"; Mining Magazine; February, 1995.

Chen, W., Patil S.L., Kamath, V.A., Chukwu, G.A.; "Role of Lecithin in Hydrate Formation/Stabilization in Drilling Fluids"; JNOC; October 20, 1998.

Chilingarian G.V., Vorabutr P.; "Drilling and drilling fluids"; Elsevier; NY; 1983.

Cohen J.H., Williams T.E.; "Hydrate Core Drilling Tests: Topical Report"; Maurer Technology Inc., Houston, Texas; November 2002.

Crowell, E.C., Bennion, D.B., Thomas, F.B., Bennion, D.W.; "The Design & Use of Laboratory Tests to Reduce Formation Damage in Oil & Gas Reservoirs"; 13th Annual Conference of the Ontario Petroleum Institute; 1991.

Dallimore S.R., Uchida T., Collett T.S.; "Scientific Results from JAPEX/JNOC/GSC Mallik 2L-38 Gas Hydrate Research Well, Mackenzie Delta"; Geological Survey of Canada Bulletin 544; Canada; 1999.

Drill Cool Systems Canada Inc., www.drillcool.com.

Duncum, S.N., Edwards, A.R., Osborne, C.G.; Eur. Pat. 536,950,1993.

Francis P.A., Eigner M.R.P., et. al.; "Visualization of Drilling-Induced Formation Damage Mechanisms using Reservoir Conditions Core Flood Testing"; paper SPE 30088 presented at the 1995 European Formation Damage Conference, The Hague, May 15-16.

Fu, S.B., Cenegy, L.M., Neff C.S., "A Summary of Successful Field Application of A Kinetic Hydrate Inhibitor"; SPE 65022; 2001.

Hammerschmidt E.G.; Ind.Eng.Chem.; 26, 851; 1934.

Howard S.K.; "Formate Brines for Drilling and Completion: State of the Art"; SPE 30498; 1995.

I.F.P. patents: Fr.Pats. 2,625,527; 2,625,547; 2,625,548; 2,694,213; 2,697,264: Eur. Pats. 594,579; 582,507323,775; 323307: US Pat. 5,244,878. Can.Pat. 2,036,084.

Jamaluddin A.K.M., Bennion D.B., et. al.; "Application of Heat Treatment to Enhance Permeability in Tight Gas Reservoirs"; Petroleum Society of CIM; Paper No. 98-01.

Kalogerakis N., Jamaluddin, et. al.; "Effect of Surfactants on Hydrate Formation Kinetics"; SPE 25188; 1993.

Kamath V.A., Mutalik P.N., et. al; "Experimental Study of Brine Injection and Depressurization Methods for Dissociation of Gas Hydrate"; SPE Formation Evaluation; December 1991.

Kastube T.J., Dallimore S.R., et. al.; "Gas Hydrate Investigation in Northern Canada"; JAPEX; Vol. 8; No. 5; 1999.

Kelland, M.A., Svartaas, T.M., Dybvik, L.A.; "Control of Hydrate Formation by Surfactants and Polymers"; SPE 28506; p. 431-438; 1994.

Kotkoskie T.S., AL-Ubaidi B., et. al.; "Inhibition of Gas Hydrates in Water-Based Drilling Mud"; SPE 20437; 1990.

Kutasov I.M.; "Salted drilling mud helps prevent casing collapse in permafrost"; Oil & Gas Journal; July 31, 1995.

Maury V., Guenot A.; "Practical Advantages of Mud Cooling Systems for Drilling"; SPE Drilling & Completion, March 1995.

Max M.D.; "Natural Gas Hydrate in Oceanic & Permafrost Environments"; Kluwer Academic Publishers; Boston; 2000.

Muijs, H.M., Beers, N.C., et al.; Can. Pat. 2,036,084, 1990.

Oort E.V., Friedheim J.M., Toups B.; "Drilling faster with Water-Base Mud"; American Association of Drilling Engineers – Annual Technical Forum; Texas; March 30-31, 1999.

Paez, J.E., Blok, R., Vaziri, H., Islam M.R., "Problems in Hydrates: Mechanisms and Elimination Methods"; SPE 67322; 2001.

Pooladi-Darvish M., Hong, H.; "A Numerical Study on Gas Production From Formations Containing Gas Hydrates"; Canadian International Petroleum Conference 2003, Calgary, June 10-12, 2003.

Reijnhout, M.J., Kind, C.E., Klomp, U.C.; Eur. Pat. 526,929, 1993.

Robinson L.; "Mud equipment manual, Handbook 1: Introduction to drilling mud system"; Gulf Publishing Company; Houston; 1977.

Sasaki K., Akibayashi S., Konno S.; "Thermal and Rheological properties of Drilling Fluids and an Estimation of Heat Transfer Rate at Casing pipe"; JNOC-TRC, Japan; October 20-22, 1998.

Schofield T.R., Judis A., Yousif M.; "Stabilization of In-Situ Hydrates Enhances Drilling Performance and Rig Safety"; SPE 32568 ; Drilling & Completion; 1997.

Sira J.H., Patil S.L., Kamath V.A.; "study of Hydrate Dissociation by Methanol and Glycol Injection"; SPE 20770; 1990.

Sloan, E.D.; World Pat. WO 94/12761, 1994.

Spence G.D., Hyndman R.D.; "The challenge of Deep ocean Drilling for Natural Gas Hydrate"; Geoscience Canada; Vol.28 (4); December, 2001.

Sumrow Mike; "Synthetic-based muds reduce pollution discharge, improve drilling"; Oil & Gas Journal; Dec. 23, 2002.

Szczepanski R., Edmonds B., et. al; "Research provides clues to hydrate formation and drilling-hazard solutions"; Oil & Gas Journal; Vol. 96(10); Mar 9, 1998.

Toshiharu O., Yuriko M., et. al; "Kinetic Control of Methane Hydrates in Drilling Fluids"; JNOC-TRC; October 20-22, 1998.

Urdahl, O., Lund, A., Moerk, P., Nilsen, T-N; "Inhibition of Gas Hydrate Formation by means of Chemical Additives: Development of an Experimental Set-up for Characterization of Gas Hydrate Inhibitor Efficiency with respect to Flow Properties and Deposition"; Chem. Eng. Sci.; 50(5), 863; 1995.

Vincent M., Guenot Alain; "Practical Advantages of Mud Cooling System for Drilling"; SPE Drilling & Completion; March 1995.

Weidong C., Patil S.L., Kamath V.A., Chukwu G.A.; "Role of Lecithin in Hydrate Formation/Stabilization in Drilling Fluids"; JNOC-TRC; October 20-22, 1998.

Yuliev, A.M.; Gazov. Delo; 10, 17-19, 1972. Russ.

Zakharov A.P.; "Silicon-based additives improve mud Rheology"; Oil & Gas Journal; Aug. 10, 1992.

7.4 Task 10, Coring Technology References

1. Carroll, John. "Natural Gas Hydrates: A Guide for Engineers". Gulf Professional Publishing. October 30, 2002.

2. "Methane Hydrates: A US Department of Energy Website". www.fossil.energy.gov

3. "Natural Gas Demand". [www] www.naturalgas.org/business/demand.asp.

4. Shukla, K., et al. "Overview on Hydrate Coring/Handling/Analysis". Westport Technology Center International. Prepared for DOE on December 12, 2002 under award No. DE-PS26-NT40869-1.

5. Rack, Frank R, "In-Situ Sampling and Characterization of Naturally Occurring Marine Hydrate Using the D/V JOIDES Resolution". Joint Oceanographic Institute, Cooperative Agreement DE-FC26-01NT41329.

6. Dickens, Gerald R. et al. "Detection of Methane Gas Hydrate in the Pressure Core Sampler (PCS): Volume-Pressure-Time Relations During Controlled Degassing Experiments". *Proc. of the Ocean Drilling Program*, Vol. 164. (2000).

7. Francis, T.J.G. "The HYACINTH project and pressure coring in the Ocean Drilling Program". Internal Document: Geotek, Ltd. July 2001.

8. "HYACE". [www] http://www.tu-berlin.de/fb10/MAT/hyace/description/describe.htm. Accessed June 15th, 2003.

9. Amann, H. et al. "First Successful Deep-Sea Operations of OMEGA-MAC, the Multiple Auto Corer, during the OTEGA-I campaign on Hydrate Ridge". Fachgebiet Maritime Technik. August 2002.

10. Hohnberg, H.J. et al. "Pressurized Coring of Near-Surface Gas Hydrate Sediment on Hydrate Ridge: The Multiple Autoclave Corer, and First Results from Pressure Core X-Ray CT Scans". Geophysical Research Abstracts, Vol. 5. European Geophysical Society. (2003).

11. "Methane Hydrate Recovery". JNOC Website. [www] http://www.mh21japan.gr.jp/english/mh/05kussaku.html#e.

12. “Patent No. 6,214,804: The Pressure-Temperature Coring System”. U.S. Patent Office. [www]http://patft.uspto.gov/netacgi/nph-Parser?Sect1=PTO1&Sect2=HITOFF&d=PALL&p=1&u=/netahtml/srchnum.htm&r=1&f=G&l=50&s1=6,216,804.WKU.&OS=PN/6,216,804&RS=PN/6,216,804. Viewed July 14, 2003

7.5 Task 11, 13: Reservoir and Economic Modeling References

Chuang Ji, Goodarz Ahmadi, Duane H.Smith.; ”Constant rate natural gas production from a well in a hydrate reservoir”; Energy Conversion and Management 44 (2003) 2403-2423.

Chuang Ji, Goodarz Ahmadi, Duane H.Smith.; “ Natural gas production from hydrate decomposition by depressurization”; Chemical eng. science 56 (2001) 5801-5814.

McGuire, Patrick L; “Methane hydrate gas production by thermal stimulation”; proceedings of the 4th Canadian Permafrost Conference, 1982, pp.356-362.

Moridis, G., Collett, T.S., Dallimore, S.R., Satoh, T., Hancock, S. and Weatherill, B.; “Numerical simulation studies of gas production scenarios from hydrate accumulations at the Mallik site, Mackenzie Delta, Canada”. In, Mori, Y.S., Ed. Proceedings of the Fourth International Conference on Gas Hydrates, May 19-23, Yokohama, Japan, 2003, pp 239-244.

7.6 Short Courses

“Natural Gas Hydrates”, By Tim Collett (USGS) and Shirish Patil (UAF), A Short Course at the SPE-AAPG: Western Region-Pacific Section Conference, Anchorage, Alaska, May 18-23, 2002, Sponsored by Alaska Division of Geological and Geophysical Surveys and West Coast Petroleum Technology Transfer Council, Anchorage, Alaska.

8.0 LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	Denotation
2D	Two Dimensional (seismic or reservoir data)
3D	Three Dimensional (seismic or reservoir data)
AAPG	American Association of Petroleum Geologists
AETDL	Alaska Energy Technology Development Laboratory
ANL	Argonne National Laboratory
ANN	Artificial Neural Network
ANS	Alaska North Slope
AOGCC	Alaska Oil and Gas Conservation Commission
AOI	Area of Interest
AVO	Amplitude versus Offset (seismic data analysis technique)
ASTM	American Society for Testing and Materials
BLM	U.S. Bureau of Land Management
BP	British Petroleum (commonly BP Exploration (Alaska), Inc.)
BPXA	BP Exploration (Alaska), Inc.
DOI	U.S. Department of Interior
DGGS	Alaska Division of Geological and Geophysical Surveys
DNR	Alaska Department of Natural Resources
EM	Electromagnetic (referencing potential in-situ thermal stimulation technology)
ERD	Extended Reach Drilling (commonly horizontal and/or multilateral drilling)
GEOS	UA Department of Geology and Geophysics
GOM	Gulf of Mexico (typically referring to Chevron Gas Hydrate project JIP)
GR	Gamma Ray (well log)
GTL	Gas to Liquid
GSA	Geophysical Society of Alaska
HP	Hewlett Packard
JBN	Johnson-Bossler-Naumann method (of gas-water relative permeabilities)
JIP	Joint Industry Participating (group/agreement), ex. Chevron GOM project
JNOC	Japan National Oil Corporation
KRU	Kuparuk River Unit
LBNL	Lawrence Berkeley National Laboratory
LNG	Liquefied Natural Gas
MGE	UA Department of Mining and Geological Engineering
MPU	Milne Point Unit
NETL	National Energy Technology Laboratory
ONGC	Oil and Natural Gas Corporation Limited (India)
PBU	Prudhoe Bay Unit
PNNL	Pacific Northwest National Laboratory
Sag	Sagavanirktok formation
SPE	Society of Petroleum Engineers
TCF	Trillion Cubic Feet of Gas at Standard Conditions
TCM	Trillion Cubic Meters of Gas at Standard Conditions
UA	University of Arizona (or Arizona Board of Regents)
UAF	University of Alaska, Fairbanks
USGS	United States Geological Survey
USDOE	United States Department of Energy
VSP	Vertical Seismic Profile

9.0 APPENDICES

9.1 APPENDIX A: Project Task Schedules and Milestones

9.1.1 U.S. Department of Energy Milestone Log

Program/Project Title: DE-FC26-01NT41332: Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay - Kuparuk River Area on the North Slope of Alaska

Identification Number	Description	Planned Completion Date	Actual Completion Date	Comments
Task 1.0	Research Management Plan	12/02	12/02	Subcontracts Completed Research Management ongoing
Task 2.0	Provide Technical Data and Expertise	MPU: 12/02 PBU: * KRU: *	MPU: 12/02 PBU: * KRU: *	Ongoing, See Technical Progress Report Description
Task 3.0	Wells of Opportunity Data Acquisition	Ongoing to 12/03-10/04	Ongoing	Ongoing, See Technical Progress Report Description
Task 4.0	Research Collaboration Link	Ongoing to 12/03-10/04	Ongoing	Ongoing, See Technical Progress Report Description
Subtask 4.1	Research Continuity	Ongoing	Ongoing	
Task 5.0	Logging and Seismic Technology Advances	Ongoing to 12/03-10/04		Ongoing, See Technical Progress Report Description
Task 6.0	Reservoir and Fluids Characterization Study	10/04		Interim Results to also be presented
Subtask 6.1	Characterization and Visualization	10/04		Interim Results to also be presented
Subtask 6.2	Seismic Attributes and Calibration	10/04		Interim Results to also be presented
Subtask 6.3	Petrophysics and Artificial Neural Net	10/04		Interim Results to also be presented
Task 7.0	Laboratory Studies for Drilling, Completion, Production Support	6/04		
Subtask 7.1	Characterize Gas Hydrate Equilibrium	6/04		
Subtask 7.2	Measure Gas-Water Relative Permeabilities	6/04		
Task 8.0	Evaluate Drilling Fluids	6/04		
Subtask 8.1	Design Mud System	11/03		
Subtask 8.2	Assess Formation Damage	5/04		

Task 9.0	Design Cement Program	10/04		
Task 10.0	Study Coring Technology	2/04		
Task 11.0	Reservoir Modeling	10/04		Interim Results to also be presented
Task 12.0	Select Drilling Location and Candidate	10/04		
Task 13.0	Project Commerciality & Progression Assessment	10/04		Interim Results to also be presented

* Date estimate dependent upon industry partner agreement for seismic data release

9.1.2 U.S. Department of Energy Milestone Plan

(DOE F4600.3)

DOE F 4600.3#

U.S. DEPARTMENT OF ENERGY FEDERAL ASSISTANCE MILESTONE PLAN

1. Program/Project Identification No. DE-FC26-01NT41332	2. Program/Project Title Resource Characterization and Quantification of Natural Gas-Hydrate and Associated Free-Gas Accumulations in the Prudhoe Bay - Kuparuk River Area on the North Slope of Alaska
3. Performer (Name, Address) BP Exploration (Alaska), Inc., 900 East Benson Blvd, P.O. Box 196612, Anchorage, Alaska 99519-6612	4. Program/Project Start Date 10/22/02* 5. Program/Project Completion Date 12/31/06 (through Phase 3)

6. Identification Number	7. Planning Category (Work Breakdown Structure Tasks)	8. Program/Project Duration (Currently illustrates 2002-2004) O N D J F M A M J J A S O N D J F M A M J J A S	9. Comments (Primary work Performer)
Task 1.0	Research Management Plan	>>>>>>>>>>>>>>>!	BPXA
Task 2.0	Technical Data and Expertise	>>>>>>----->>>>------>>>>>>>>------------>>>>>>!>>------->>>>>>>------------	BPXA
Task 3.0	Wells of Opportunity - Data	------>>>>>-------------->>>>>--------->>>>>>>>>>!>>>>>---------->>>>>>>>>>>>>>	BPXA
Task 4.0	Research Collaboration Link	>>>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>	BPXA, USGS, UAF, UA
Task 5.0	Logging/Seismic Technology	>>>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>	USGS, BPXA
Task 6.0	Characterize Reservoir/Fluid	------->>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>	UA
Task 7.0	Lab Studies: Ph Behav, Rel k	-- ----->>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>!>>>>>>>>>>>>>>>>>>>>	UAF
Task 8.0	Evaluate Drilling Fluids	------->>>>>>>>>>>>>>>>>>>>>>>>>>>>>>--->!>>>>>>>>>>>>>>>>>>>>	UAF
Task 9.0	Design Cementing Program	---!---->>>>>>>>>>>>>>>>>>>>>>>>>	UAF
Task 10.0	Study Coring Techniques	-------->>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>-!	UAF, RyderScott
Task 11.0	Reservoir Modeling	>>>>------------------------>>>>>>>>>------------!----->>>>>>>>>>>>>>>>>>>>>>>>	UAF
Task 12.0	Drilling Candidate Selection	>>>------ ----->>>>>-----!--->>>>>>>>>>>>>>>---->>>>>>>	BPXA, UA
Task 13.0	Commerciality Assessment	>>>>>>-------------------------------->>>>>>>>---!----------->>>>>>>---->>>>>>>>	BPXA, UAF

10. Remarks * Official Contract Date 10/22/02; Funded reduced-cost pre-Phase 1 from 10/01-10/02. Phase 1 project from 10/02 through 10/04.
Explanation of Symbols: (> = Major Task Work); (- = Minor Task Work); (! = current time).
Additional significant milestones presented in December 2003 technical progress report.

11. Signature of Recipient and Date	12. Signature of U.S. Department of Energy (DOE) Reviewing Representative and Date