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

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ABSTRACT*

This cooperative project between BP Exploration (Alaska), Inc. (BPXA) and the U.S. Department of Energy (DOE) facilitates a high level of collaboration between industry, government, and university researchers. The mutually beneficial research activities would not otherwise have been independently conducted by industry. Project results will help identify technical and economic factors that must be understood for government and industry to make informed decisions regarding the resource potential of gas hydrate accumulations on the Alaska North Slope (ANS).

One of the important contributors to this effort is the U.S. Geological Survey, which has led ANS gas hydrate research for three decades. Dr. Timothy Collett of the USGS continues to promote the importance of this area to gas hydrate research and potential development. Shirish Patil of the University of Alaska Fairbanks (UAF) School of Mining and Engineering is leading reservoir and petroleum engineering research and supporting laboratory studies. Dr. Robert Casavant leads the reservoir and fluid characterization efforts at the University of Arizona (UA) with Dr. Roy Johnson. Associated projects at national laboratories include work on reservoir modeling by Dr. George Moridis at Lawrence Berkeley National Lab (LBNL) and on CO_2 injection potential by Dr. Pete McGrail at Pacific Northwest National Lab (PNNL).

Gas hydrates are present in many arctic regions and offshore areas around the world. In the U.S., notable deposits of gas hydrate occur in the offshore Atlantic, Gulf of Mexico (GOM), offshore Pacific, offshore Alaska, and also onshore Alaska regions beneath permafrost. Collett (1998) estimates that up to 590 TCF of in-place ANS gas resources may be trapped in clathrate hydrates. Of that total, an estimated 44 to 100 TCF of in-place gas resources may occur beneath existing ANS production infrastructure (Collett, 1993). However, much like conventional oil and gas resources, economic production of gas from gas hydrate resources will require a unique combination of factors, including all of the required petroleum system components (e.g., source, trap, seal, charge, reservoir, etc.), adequate industry infrastructure, industry access to acreage, familiar production technology, and favorable economics. In addition, industry must be able to estimate ultimate recovery potential, production rates, operating costs, and potential profitability within reasonable risk limits. Currently, the most likely areas for a favorable combination of these factors are the ANS and the Gulf of Mexico.

In this project, ANS gas hydrate and associated free gas-bearing reservoirs are being studied to determine reservoir extent, stratigraphy, structure, continuity, quality, variability, and geophysical and petrophysical property distribution. The objective of Phase 1 (Oct. 2002 – Oct. 2004) is the characterization of reservoirs and fluids, leading to estimates of recoverable reserve and commercial potential, and the definition of procedures for gas hydrate drilling, data acquisition, completion, and production. Phases 2 (Nov. 2004 – Dec. 2005) and 3 (Jan. 2006 – Dec. 2006) will integrate well, core, log, and production test data from additional wells, if justified by prior results. Ultimately, the program could lead to development of an ANS gas hydrate pilot project and determine whether or not gas hydrates can become a part of the overall ANS gas resource portfolio.

Interim results from this project have identified play areas within the Milne Point Unit (MPU) geologic system. Areas where gas hydrate and free gas appear to exist together have the most potential for production of hydrate-sourced natural gas, based on a preliminary understanding of the geology and potential production behavior investigated within reservoir model scenarios.

The shallow gas hydrate-bearing reservoirs of the Tertiary Sagavanirktok formation are part of a complex fluvial-deltaic system complicated by structural compartmentalization within the Eileen trend. Stacked sequences of fluvial, deltaic, and nearshore marine sands are interbedded with both terrestrial and marine shales. Facies changes, intraformational unconformities, and high-angle normal faults disrupt reservoir continuity. Phase 1 work related to volumetric assessment includes detailed well-log analyses and description of reservoir facies and fluids as integrated with the 3D seismic data. In conjunction with structural analyses, the identification and mapping of net pay in discrete sand bodies improves understanding of resource quality, quantity, distribution, and continuity. This work helps refine volume estimates, reservoir models, and forecasts of recovery factors and production.

Interpretations of gas hydrate and associated free-gas resources within the study area correlate with gas hydrates that were originally cored and tested in the 1972 NW Eileen State #2 well and also penetrated by many other wells targeting deeper reservoirs within the ANS development area. Geophysical attributes of gas hydrate occurrence are also under investigation. Seismic modeling of shallow (<950 ms) velocity fields suggests both amplitude and waveform variations may help locate gas hydrate-bearing reservoirs. Permafrost can also complicate seismic identification of gas hydrates due to its similar acoustic properties. Identification of gas hydrate prospects within the MPU 3D seismic volume are based on seismic interpretation and modeling, gas hydrate-similar waveform classes, fault-seal geometries, and well log-derived properties. Fault blocks with significant in-place volumes within identified gas hydrate-bearing reservoirs will be further delineated and/or production tested if the project proceeds into phases 2 and 3.

Understanding the nature of fluid flow and permeability is critical to assessing the productivity of gas hydrates. As part of this project, UAF has developed a new method for measuring gas-water relative permeability for laboratory synthesized gas hydrate in porous media. This work provides input to reservoir modeling and fluid flow. Although no laboratory method can approach the time required to form natural gas hydrate, the experiment design allows gas hydrate to form in porous media over relatively long periods of time and allows measurement of effective permeability and relative permeability for different saturation values. Although some dissociation of gas hydrate occurs due to differential pressure across the core, the low temperature decreases the rate of gas dissociation. Considerable additional experimental and theoretical work remains to develop an analytical or generalized model to predict relative permeability for gas hydrate reservoir simulation. The experimental data obtained from this work will allow identification of gas hydrate stability zones, determination of flow behavior, and development of techniques for safe production of natural gas from gas hydrates.

Under an associated project funded by NETL, Lawrence Berkeley National laboratory (LBNL) continues to develop the TOUGH2-EOSHYD2 reservoir model to evaluate gas hydrates. The preliminary reservoir model results based on this schematic characterization indicates that depressurization of a free gas reservoir adjacent to a gas hydrate accumulation can cause significant gas dissociation from the gas hydrate. However, cooling induced by this depressurization-induced gas hydrate dissociation decreases the temperature, a factor that could self-limit gas dissociation after the initial production years. Therefore, the depressurization production method may require some thermal stimulation assistance.

Within the BPXA project, UAF has adapted a commercial simulator (CMG-STARS) to model gas hydrate dissociation due to depressurization of an adjacent free gas accumulation in an ANS gas hydrate accumulation. Preliminary results also demonstrate the potential of the depressurization production method by dissociation of gas hydrate adjacent to free gas. UAF modeling indicates that as gas is produced at rates of up to 25 MMscfd per well, the free gas zone depressurizes and the adjacent gas hydrate accumulation begins to release significant additional gas.

Work is proceeding in the areas described above as well as on a number of other tasks as described below. Phase 1 of the project is currently scheduled for completion by November 2004.

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TABLE OF CONTENTS

1.0 LIST OF FIGURES AND TABLES 1
2.0 INTRODUCTION 2
2.1 Project Open Items 2
2.2 Project Status Assessment and Forecast 2
2.3 Project Research Collaborations 2
2.4 Project Performance Variance 4
3.0 EXECUTIVE SUMMARY 4
4.0 EXPERIMENTAL 5
4.1 TASK 5.0, Logging and Seismic Technology Advances – USGS, BPXA 5
4.2 TASK 6.0, Reservoir and Fluids Characterization 6
4.2.1 Subtask 6.1: Reservoir and Fluid Characterization and Visualization 6
4.2.2 Subtask 6.2: Seismic Attributes and Calibration 6
4.2.3 Subtask 6.3: Petrophysical and Neural Network Attribute Analyses 6
4.3 TASK 7.0: Laboratory Studies for Drilling, Completion, and Production Support 6
4.3.1 Subtask 7.1: Characterize Gas Hydrate Equilibrium 6
4.3.2 Subtask 7.2: Measure Gas-Water Relative Permeabilities 6
4.4 TASK 8.0: Evaluate Drilling Fluids – UAF 6
4.5 TASKS 11.0 and 13.0: Reservoir Modeling and Project Commerciality and Progression Assessment – UAF, BP, Ryder Scott Co. 7
5.0 RESULTS AND DISCUSSION 7
5.1 TASK 1.0: Research Management Plan – BPXA and Project Team 7
5.2 TASK 2.0: Provide Technical Data and Expertise – BPXA, USGS 7
5.3 TASK 3.0: Wells of Opportunity, Data Acquisition – BPXA 7
5.4 TASK 4.0: Research Collaboration Link – BP, USGS, Project team 8
5.5 TASK 5.0: Logging and Seismic Technology Advances – USGS, BP 8
5.6 TASK 6.0: Reservoir and Fluids Characterization – UA 10
5.6.1 Subtask 6.1: Reservoir and Fluid Characterization and Visualization – UA 10
5.6.1.1 Products and Interim Findings 10
5.6.1.2 Miscellaneous Project Activities 11
5.6.1.3 Research Publications and Presentations 12
5.6.1.4 Work In-Progress 12
5.6.1.5 Continuing Needs and Future Work 13
5.6.2 Subtask 6.2: Seismic Attribute Characterization and Fault Analysis – UA 13
5.6.2.1 Products 13
5.6.2.2 Work in Progress 14
5.6.2.3 Future Work 14
5.6.3 Subtask 6.3: Petrophysical and Neural Network Attribute Analysis – UA 15
5.6.3.1 Products 15
5.6.3.2 Work in Progress 16
5.7 TASK 7.0: Lab Studies for Drilling, Completion, and Production Support – UAF 16
5.7.1 Subtask 7.1: Characterize Gas Hydrate Equilibrium 16
5.7.1.1 Work in Progress 16
5.7.1.1.1 Initial Core Saturation 17
5.7.1.1.2 Hydrate Formations in Core Holder 17
5.7.1.1.3 Single Phase Flooding 17

5.7.1.1.4 The Displacement Experiment 18
5.7.1.2 Experimental Results 19
5.7.1.2.1 Gas Hydrate Formation Analysis 19
5.7.1.2.2 Permeability Results 19
5.7.1.2.3 Conclusion 20
5.7.1.2.4 Future Work 20
5.8 TASK 8.0: Evaluation of Drilling Fluid and Assess Formation Damage 20
5.8.1 Subtask 8.1: Design Integrated Mud System for Effective Drilling, Completion and Production Operation 20
5.8.1.1.1 Task 8 Objectives 20
5.8.2 Task 8.2, Assess Formation Damage: Testing, Analysis and Interpretation 20
5.8.2.1 Background 20
5.8.2.2 Key Testing Procedure Factors 21
5.8.2.3 Future Work 23
5.9 TASKS 11.0 and 13.0: Reservoir Modeling and Project Commerciality and Progression Assessment – UAF, BP, LBNL, Ryder Scott 23
5.9.1 Develop Analytical Model for Gas Hydrate: Modeling decomposition kinetics 23
5.9.2 Modeling gas hydrate decomposition in porous media 25
5.9.3 Production Modeling and Economic Evaluation of a Potential Gas Hydrate Pilot 28
5.9.3.1 Gas Hydrate Thermodynamics, Reservoir Model Considerations 34
5.9.3.2 UAF Preliminary Economic Assessment 35
5.9.4 Gas Hydrate Dissociation Reservoir Model Using ProCast 35
5.9.5 Future Work: 37
5.10 TASK 12.0: Select Drilling Location and Candidate – BP, UA, USGS 38
6.0 CONCLUSION 38
7.0 PROJECT AND RELATED REFERENCES 38
7.1 General Project References 38
7.2 Task 7, Gas Hydrate Phase Behavior and Relative Permeability References 40
7.3 Task 8, Drilling Fluid Evaluation and Formation Damage References 42
7.4 Task 10, Coring Technology References 45
7.5 Task 11, 13: Reservoir and Economic Modeling References 46
7.6 Short Courses 48
8.0 LIST OF ACRONYMS AND ABBREVIATIONS 49
9.0 APPENDICES 50
9.1 APPENDIX A: Project Task Schedules and Milestones 50
9.1.1 U.S. Department of Energy Milestone Log 50
9.1.2 U.S. Department of Energy Milestone Plan 51

1.0 LIST OF FIGURES

Figure 1: Gas hydrate – gas – water reservoir synthetic seismic model …………………...Page 9
Figure 2: Gas hydrate prospect in fault-bounded trap ………………….……………….......Page 9
Figure 3: Gas hydrate – free gas prospect fairway in seismic amplitude time slice ……...Page 10
Figure 4: The experiment apparatus for measuring relative permeability ……………….…Page 16
Figure 5: Schematic of laboratory apparatus for relative permeability measurements …...Page 18
Figure 6: Pressure decline gas hydrate formation confirmation ……………………….…Page 19
Figure 7: Volume change in methane cylinder, gas hydrate formation confirmation …... Page 19
Figure 8: Effective permeability for various gas hydrate saturation values……………....Page 19
Figure 9: Relative permeability curves for various gas hydrate saturation values..………Page 20
Figure 10: Formation damage experiment apparatus proposed to construct………………Page 23
Figure 11: Hydrate-gas phase equilibrium graph…………….…….…….….………....Page 25
Figure 12: Pressure profile for 300 SCMD gas production through 0.01 md reservoir……Page 26
Figure 13: Pressure profile for 1500 SCMD gas production through 10 md reservoir……Page 27
Figure 14: Position of gas hydrate decomposition front ……………….………………Page 27
Figure 15: Cumulative gas production versus time …......…………..……………………...Page 28
Figure 16: Pressure profile, gas production model after 15 years…………………….……...Page 29
Figure 17: Temperature profile, gas production model after 15 years …………………....Page 29
Figure 18: Horizontal and Multiple Well Production Rates…………………………….....Page 30
Figure 19: Water Production Rates – Horizontal and Multiple Well Cases ………………Page 30
Figure 20: Gas hydrate saturation profile, gas production model after 15 years……….....Page 31
Figure 21: Gas hydrate saturation profiles, gas production model over 8 years …………..Page 31
Figure 22: Water saturation profile, gas production model after 15 years……………......Page 32
Figure 23: Reduced permeability gas production profile, model after 15 years…………..Page 32
Figure 24: Reduced gas hydrate saturation gas production profile, model after 15 years . Page 33
Figure 25: Cumulative Production for different well cases and production rates……….…Page 33
Figure 26: Temperature rebound prediction after 4 years gas production ………………...Page 34
Figure 27: Gas hydrate dissociation input panel in ProCast reservoir simulator ………..…Page 36
Figure 28: Gas production forecasts from ProCast beta modeling ……..……..……….…Page 37

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 ANS gas-hydrate and associated free-gas resources, initially in the Eileen trend area in the Milne Point Unit (MPU) – Prudhoe Bay Unit (PBU) – Kuparuk River Unit (KRU) areas. 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 ANS reservoir energy support, enhanced oil recovery, fuel gas, and commercial sales within and beyond current infrastructure. 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.

1.1 Project Open Items

Contracts and subcontracts were updated in December 2003, fully obligate 109% of 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 during summer 2004. Incremental funding of $150,000 may be requested in May 2004 to accomplish unanticipated reservoir characterization, reservoir modeling, and Phase 2 planning scope-of-work in support of the Phase 2 progression decision.

1.2 Project Status Assessment and Forecast

Project technical accomplishments from January 2004 through end-March 2004 are presented by associated project task. The attached milestone forms (Appendix A) present project tasks 1 through 13 with task duration and completion timelines.

1.3 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. **Reservoir Model studies (Ryder Scott Co., LBNL, UAF)**: The LBNL Beta-test reservoir model for BPXA team testing and use was originally scheduled for release by January 2004. This still has not been delivered as of the writing of this report (5/6/04). This research includes reservoir model code calibration to data collected during the 2002 Mallik gas hydrate test program. Interim reservoir characterizations of MPU gas hydrate prospects are scheduled for evaluation in mid-May through June by Ryder Scott Company (RS), UAF, and LBNL. RS is providing industry-standard reservoir modeling for evaluation of gas hydrate prospects, input into the Phase 2 progression decision, and optimization of potential future development and delineation plans.
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 seconded a graduate student to PNNL to assist with this research. PNNL and BPXA presented project research updates to Jim Slutz (DOE) in January 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 in December 2003 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. BPXA provided a letter of support in April 2004 for progression of this project into phase 2: prototype tool design and possible surface testing.

5. **UAF/McMillan-McGee/PNNL proposal:** This proposal was highly ranked during 2003 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 gas hydrate research by Japan Oil, Gas, and Metals National Corporation (JOGMEC), formerly Japan National Oil Corporation (JNOC). BPXA remains in communication with JOGMEC regarding potential research collaboration, particularly if the project proceeds into Phase 2 operations.

7. India's Institute of Oil and Gas Production Technology (IOGPT) indicated an interest in participating with our research program in correspondence with DOE during September 2003.

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. UAF may request access to this fluid for formation damage studies, Task 8.2.

1.4 Project Performance Variance

Industry partners and BPXA continue to indicate that release of shallow portions of PBU seismic data under confidentiality constraints to the project is not currently possible. BPXA recognizes the importance of this data to additional gas hydrate reservoir and fluid characterization studies. However, as consistently recognized, provision of PBU seismic data to the project 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.

2.0 EXECUTIVE SUMMARY

This Quarterly report encompasses project work from January 1, 2004 through March 31, 2004. Sections 4 and 5 provide a detailed project activities report.

- Updated Phase 1 research program tasks, timelines, deliverables, and budget
  - Anticipate Phase 2 progression decision during summer 2004
  - Phase 1 research will continue through end-October 2004
  - Phase 2 may continue through end-December 2005, pending BPXA decision
  - Phase 3 may continue through end-December 2006, pending BPXA decision
- Continued gas hydrate research collaborations/discussions with many associated projects
- Planned and implemented input to 2004 conferences (5), meetings, and presentations
- Completed 9 abstracts for presentation at September 2004 AAPG Hedberg Conference
  - Conference will provide a major opportunity to present Phase 1 study results
- Reviewed, edited, and input required confidentiality to 2 UAF and 2 UA master's theses
- Initiated industry-standard gas hydrate reservoir modeling with CMG Stars and ProCast
  - Developed analytical model to simulate gas hydrate depressurization production
  - Modeled 1 by 4 mile gas hydrate-bearing area analogous to MPU play fairways

  - Evaluated permeability, spacing, production, and gas hydrate saturation variations
  - Incorporated beta release of a moving gas hydrate dissociation front into ProCast
  - Tuning reasonable dissociation behaviors to run ProCast models in only minutes
- Completed log-based estimations of gas hydrate/free gas saturations and net pay
  - Calculated second of two MPU log-based gas hydrate and free gas volumetrics
  - Completed preliminary comparative volumetric study/chart (under UA review)
  - Discussed influence of both seismic and well-log based facies on volumetrics
  - Determining gas hydrate/free gas net pay and reconciling with coal gas indicators
- Investigated seismic model and attribute analyses for direct gas-gas hydrate indicators
  - Developed synthethic models to illustrate seismic attribute response to fluid type
  - Interpreted potential MPU area gas hydrate/free gas play fairways and prospects
  - Began developing interim volumetrics and uncertainty ranges for these prospects
- Analyzed MPU seismic traverses from Simp32-14 to MPD-01 and others
  - Identified intraformational unconformities in sequence stratigraphic framework
  - Located reflector terminations at areas of potential downlap, onlap and erosion
  - Integrating seismic facies mapping with stratigraphic classifications
- Identified and characterized structural features which may influence net pay and fluids
  - Reconciling seismic versus well-log gross interval thicknesses near fault zones
- Extended major interpretable horizons into NW Eileen 3D survey and offshore MPU
- Completed post-stack wavelet processing on Milne and NW Eileen 3D seismic in MPU
  - Discovered significant enhancement of signal within gas-hydrate stability field
  - Modeled gas hydrate-bearing intervals: waveform response to thinner "fast zones"
- Improved time-depth conversion of Milne Point cube based on updated synthetic ties
- Calculated fault heaves, seal, and frequency across interpreted faults in 14 MPU horizons
- Created grid-illumination structure maps to interpret subtle structural features and faults
- Created preliminary interpolated surfaces of BIBPF and BGHSZ for amplitude extraction
- Redesigned and modified relative permeability experimental apparatus for porous media
  - Calculated relative permeability using JBN method for 3 gas hydrate saturations
  - Noted relative permeability reduction for higher gas hydrate saturations
- Designed specifications of formation damage experimental apparatus and procedure

3.0 EXPERIMENTAL

During the reporting time period from January through March 2003, primary experimental activities consisted of experiment apparatus design, setup, and execution at UAF as well as reservoir and fluid characterization studies using 3D seismic and well data at UA and USGS.

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

The U.S. Geological Survey (USGS) continues to analyze 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 studies showing that seismic velocity, amplitudes, and wavelet character respond to fluid and reservoir changes within the gas hydrate-bearing reservoir system (Figure 1).

3.2 TASK 6.0, Reservoir and Fluids Characterization

The University of Arizona (UA) continued resource characterization studies revealing shallow sand reservoir stratigraphic heterogeneity and structural compartmentalization. Considerable progress has been made on all geologic/geophysical project tasks. Most notable is the completion of a comprehensive and comparative volumetric assessment, improved understanding of seismic attributes in relation to expected gas hydrate occurrence, a preliminary assessment of fault seal properties, and an investigation of other structural elements (pull-apart basin, northwest depositional/structural hingeline) that may compartmentalize gas hydrate and free-gas resources. Section 5.6 provides additional details, results, and recommendations.

3.2.1 Subtask 6.1: Reservoir and Fluid Characterization and Visualization

Refined bulk volumetrics calculations in MPU area gas hydrate prospects.

3.2.2 Subtask 6.2: Seismic Attributes and Calibration

Completed post-stack wavelet processing and discovered signal enhancement within interpreted gas hydrate stability field. Calculated fault heaves, sealing potential, trends, and frequency. Concluded that waveform classification anomalies are primarily fault-controlled, particularly near faults with higher sealing potential.

3.2.3 Subtask 6.3: Petrophysical and Neural Network Attribute Analyses

Compared and contrasted 7 techniques for calculating pore fluid saturations. Selected Bulk Elastic Moduli and Compressional Wave Velocity as best techniques. Confirmed that available log data does not distinguish ice from gas hydrate.

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

The University of Alaska Fairbanks (UAF) refined apparatus and conducted experiments for gas hydrate relative permeability studies. Section 5.7 provides additional details, results, and recommendations.

3.3.1 Subtask 7.1: Characterize Gas Hydrate Equilibrium

Completed Jason Westervelt M.S. thesis draft during the reporting period.

3.3.2 Subtask 7.2: Measure Gas-Water Relative Permeabilities

A conventional experimental apparatus for measuring relative permeability was modified for forming gas hydrates within porous media. Several experiments were performed, effective permeability was measured, and relative permeability was calculated for gas hydrate saturations of 10%, 17%, and 29%.

3.4 TASK 8.0: Evaluate Drilling Fluids – UAF

Designed the experimental apparatus, procured and positioned components, and developed standard testing procedures. Section 5.8 provides additional details, results, and recommendations.

3.5 TASKS 11.0 and 13.0: Reservoir Modeling and Project Commerciality and Progression Assessment – UAF, BP, Ryder Scott Co.

Continued adaptation of commercially available reservoir simulator, CGM STARS, to gas hydrate-bearing reservoirs. Section 5.9 provides additional details, results, and recommendations.

4.0 RESULTS AND DISCUSSION

Project technical accomplishments from January 2004 through March 2004 are presented in chronological order by associated project task.

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

Task schedules are presented in the attached milestones forms (Appendix A). Project expenditures are reported separately on financial forms 269A and 272.

- Coordinated, compiled, and completed project technical and financial reports
- Reviewed, processed, and ensured budget consistency of subcontractor invoices
- Planned additional reservoir modeling work with Ryder Scott Company
- Planned additional reservoir characterization work with USGS and Interpretation Services
- Prepared and submitted cost-share update to DOE consistent with project budget
- Converted project manager subcontract from International Reservoir Technologies, Inc. to Arctic Slope Regional Corporation (ASRC) Energy Services (ASRC-AES)
- Updated ASAP financial authorities and authorization for U.S. Treasury funding
- Updated project tasks, timeline, deliverables, and budget for 2-year Phase 1 research
    - Phase 1 research will continue through end-October 2004
    - Phase 2 may continue through end-December 2005, pending BPXA decision
    - Phase 3 may continue through end-December 2006, pending BPXA decision
    - Cost extension effective October 2003, time extension effective December 2003

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

- Developed interim MPU gas hydrate prospect identification methods with USGS and UA
    - Determining prospective gas hydrate play areas within MPU
    - Establish methodology and calculating interim volumetrics
- Completed reservoir modeling scope-of-work plans
- Reviewed and provided interim edits to UAF master's thesis drafts
    - Stephen Howe: Reservoir and Economic modeling (in-progress)
    - Jason Westervelt: Determination of Gas Hydrate Stability Zones
- Reviewed and providing edits to UA master's thesis
    - Bo Zhao: Classifying Seismic Attributes
    - Casey Hagbo: Characterization of Gas Hydrate Occurrences
- Facilitated seismic data discussion with Kerr-McGee via contact through UA

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

- Monitored drilling schedule and operations

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

- Planned and implemented 2004 conferences, meetings, and presentations
  - Presented January update for DOE's Jim Slutz in Anchorage
  - Participated in February USGS and UA project meetings in Denver and Tucson
  - Presented February project summary at Colorado School of Mines
  - Presented March project update at Unconventional Gas Workshop in Anchorage
  - Planned and developed project presentation for April at AAPG in Dallas
  - Planned May project presentation at Alaska Geological Society in Anchorage
  - June project presentation, Canadian Society of Petroleum Geologists, Calgary
  - July project phase progression discussion meetings, likely Anchorage
  - September presentations (oral and poster), AAPG Hedberg, Vancouver
- Maintained communication with JOGMEC.
  - JOGMEC chose to not participate in the Phase 1 research.
  - JOGMEC may participate in Phase 2, if the project matures to this phase.
  - Responded to JOGMEC request for onshore well design/configuration query
- Committed to contribute project summary for DOE Fire/Ice Spring 2004 newsletter
  - Abstract for newsletter at beginning of this report
- Responded to media requests
- Considered study of in-situ combustion and 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 to determine feasibility of electromagnetic thermal recovery enhancement
  - Considered support and synergies with DOE-funded research with Precision Combustion, Inc. for potential enhanced recovery tool development
- Provided input to agenda, abstracts, 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 7-9 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 still did not provide Beta-test reservoir model for team development work by January 2004 as agreed in August 2003; may provide beta version to DOE in June 2004
  - LBNL did work to calibrate reservoir model code to 2002 Mallik testing program
  - UAF adapted alternative gas hydrate reservoir model through CMG STARS
  - Ryder Scott Co. assessed and developed CMG STARS gas hydrate modeling
  - Developed work plan and prioritized reservoir model variable sensitivities
- Monitored GOM gas hydrate research progress

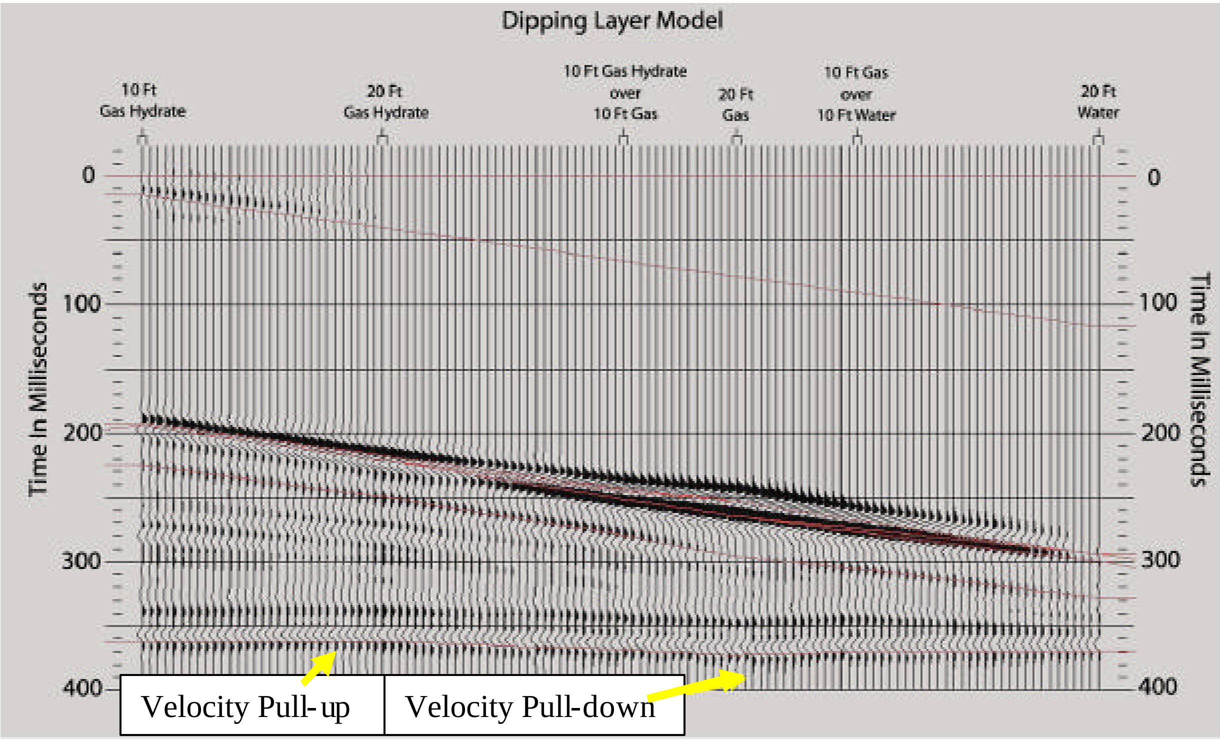
4.5 TASK 5.0: Logging and Seismic Technology Advances – USGS, BP

<u>United States Geological Survey</u>

USGS Principle Investigator: Timothy Collett

USGS Participating Scientists: David Taylor, Warren Agena, Myung Lee, Tanya Inks (IS)

- Provided input to potential wireline logging data acquisition plans
- Investigated seismic model and attribute analyses for direct gas-gas hydrate indicators
  - Developed synthethic models to illustrate seismic attribute response to fluid (gas hydrate – free gas – water) and reservoir changes (Figure 1)
  - Interpreted multiple potential MPU area gas hydrate play fairways and prospects (Figures 2-3). Figure 2 shows a fault-bounded gas hydrate prospect within the gas-hydrate stability field (GHSZ). Figure 3 illustrates a time slice map contrasting seismic amplitude separated by the red line, which is coincident with the intersection of the GHSZ and a reservoir sand which likely contains gas hydrate within the GHSZ (on the left) and free gas below the GHSZ (on the right).
  - Began developing interim volumetrics and uncertainty analysis methods for specific MPU gas hydrate prospects for input into Phase 2 progression decision



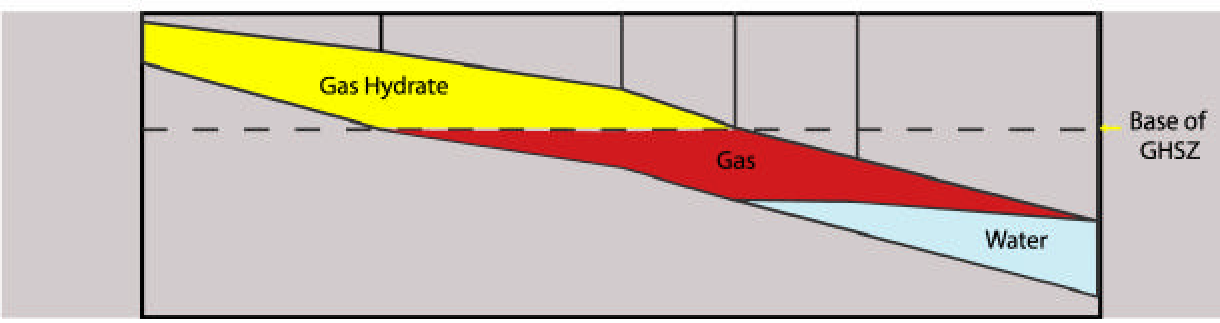


Figure 1: Gas hydrate – gas – water reservoir synthetic seismic model showing seismic velocity and amplitude anomalies associated with fluid and reservoir thickness changes

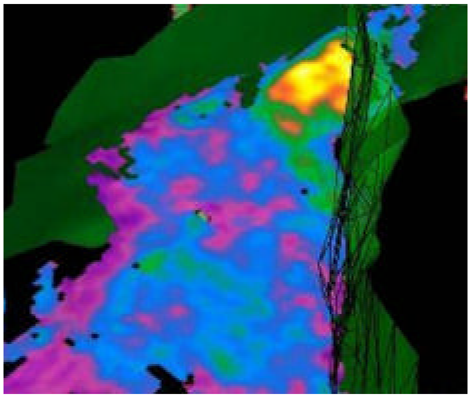
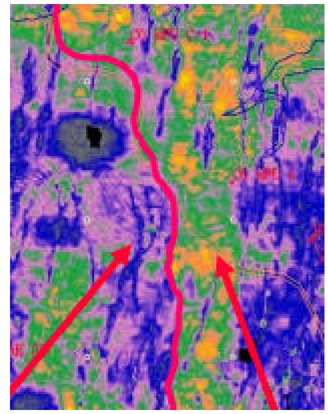


Figure 2: Gas hydrate prospect in fault-bounded trap.



Gas Hydrate Free Gas?

Figure 3: Gas hydrate (left) – free gas (right) prospect fairway in seismic amplitude time slice.

4.6 TASK 6.0: Reservoir and Fluids Characterization – UA

University of Arizona

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

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

4.6.1.1 Products and Interim Findings

- Received and entered key mudlog data into UA database.
- Completed preliminary analysis of MPU seismic traverse from Simp32-14 to MPD-01
  - Identified major intraformational unconformities and their relationship to current log-based sequence stratigraphic framework.
  - Located reflector terminations at areas of potential downlap, onlap and erosion.
  - Integrating seismic facies mapping with stratigraphic classifications
- Calculated second of two MPU gas hydrate and free gas volumetrics
  - Incorporated new probability predictor (expert system).
  - Created a second set of logs for gas hydrate, free gas, ice, petroleum and coal into PETRA for input to expert system.
  - Completed preliminary comparative volumetric study/chart (still under review).
  - Adjusting net pay calculations related to the base of the ice stability field and variations in gas hydrate stability zone (in progress).
  - Determined gas expansion factor and unit porosity on a per sequence basis (12), totaled and mapped in volumetric calculations.
- Discussed with Petra technical support re-converting data files and map files for transfer to LandMark's systems, especially StratWorks and ZMap-Plus.
- Discussed with Petra technical support re problems/solutions in plotting Petra map files.
  - Set-up & installed Petra off-site licensed software, update, and test for potential

use in Houston on Project work. Incorporated UA multiple site license for Petra/Petra Seis software.

- Confirmed spatial correlation between shoreline and some river trends with certain fault zones and structural trends
- Identified and characterized a northeast-trending pull apart basin in the central MPU.
  - Completed preliminary study of this structure and identified effects on location/prediction of syndepositional faults, permafrost thickness, net-gross sand ratios and locations of "gas chimneys".
- Identified another possible transtensional basin, the western margin of which is located in the vicinity of the MPK-38 and Cascade-01 wells.
  - Basin margins appear to be characterized by discontinuous narrow grabens. Result of this morphotectonic study will be presented at the Hedberg Conference.
- Reviewed (per the USGS-BP-UA meeting) GR log normalization based on a comprehensive synthesis of average GR log response in the marine shale interval, marker 36-36a and net sand cutoff to determine effects of cased-hole GR data.
  - The marker 36-36a represented the most lithologically consistent and regionally extensive sequence within the AOI.
  - Only a few wells exist in the database that only have cased-hole GR data over the interval of interest. These wells had in fact been omitted from the earlier analysis.
  - Field-wide statistics and log shifts remain unchanged and do not appear to adversely affect the use of case-hole data.
  - The 55 API GR cutoff for net sand remains valid. (Geauner and Manual, et al.)
- Compared gross interval and net sand isopach maps using lithostratigraphic and sequence stratigraphic frameworks
  - Show both normal and abrupt (between some zones) strike/dip interval changes
- Attempted to reconcile seismic gross interval thickness and well log interval thickness for several wells located near fault zones
- Compared MPU USGS gas hydrate zone thickness in relation to fault proximity
  - Results suggest a fair degree of correlation (Gandler, et al.) and suggest that these faults were syndepositional, and if sealing, continue to influence gas hydrate distribution.
  - Studying relationships with fault orientation and fault throws
- Determined a spatial correlation between interpreted thin gas and/or oil-bearing zones in the lower sequences of the Sagavanirktok F and discontinuous coal-bearing units in the upper portion of point bar parasequences.
  - Determined that coal units of varied thickness and extent are related to increases in total background gas in recently received mud log data.
- Used shale/sand thickness and ratio data and crossplots to determine the sealing/non-sealing nature of faults (Hennes et al.) and assess sand body continuity.

4.6.1.2 Miscellaneous Project Activities

- Met bi-weekly to discuss petrophysics and fluid/lithology prediction development
- Participated in BP-USGS-UA meeting in late February. USGS presented gas hydrate prospect site analyses in the MPU in preparation for Phase 2 progression decision.
  - Discussed current status of geologic mapping, volumetric analysis, coal gas, need for sequence stratigraphic correlation to go AOI-wide and methodology, expert

system for fluid prediction, seismic interpretation techniques, time-depth ties, and significance of anomalies.
    - Arranged for sharing of information about time-depth ties; USGS to get checkshots, UA to get USGS synthetic tie time-depth tables.
- Discussed progress, issues, and focus refining of Andrew Hennes' thesis
- Discussed data processing, interpretation, and presentation styles with Reflection Lab.
- Participated in SSCIL meetings on volumetrics, discussed impact of upcoming seismic facies study and well-log facies work on volumetrics, completion of comparative volumetric analysis, manual gas hydrate/gas net-pay determinations, misleading coal gas contributions, etc.
- Held several intradepartmental meetings to discuss progress of MPU volumetric analyses and associated petrophysical challenges and data processing techniques.
- 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.

4.6.1.3 Research Publications and Presentations

- Andrew Hennes presented results of data processing, visualization/interpretation techniques, and waveform analysis results as a poster at University of Arizona Geodaze
- Andrew Hennes presented results of fault throw, activity, seal analysis and recent waveform analyses at University of Arizona Geodaze Symposium
- Roy Johnson briefed Department of Geosciences Advisory Board on the broad scope and goals of the Gas Hydrate Project at the April 1, 2004 Annual Advisory Board Meeting in Tucson.
- Prepared the following extended abstracts of findings and activities related to geology and geophysical research in the MPU for submission to September Hedberg Conference, Vancouver, BC:
    - Andrew Hennes, Roy Johnson, and Bob Casavant—results of fault analysis and waveform classification analysis.
    - Greg Gandler, Bob Casavant, Karl Glass and Andrew Hennes, Casey Hagbo, and Roy Johnson—spatial analysis of faulting and gas hydrate occurrence
    - Scott Geauner, Justin Manual, Bob Casavant, Karl Glass and Ken Mallon—well log normalization and comparative volumetric analyses of gas hydrate and free-gas resources,
    - Bob Casavant, Andrew Hennes, Roy Johnson, and Tim Collett— Structural analysis of a proposed pull-apart basin: Implications for gas hydrate and associated free-gas emplacement,
    - Mary Poulton, Bob Casavant, Karl Glass, and Bo Zhao— model testing of methane hydrate occurrence with artificial neural networks

4.6.1.4 Work In-Progress

- Extending sequence stratigraphic framework developed for MPU into AOI.
- Using stratigraphic framework to guide volumetric and mapping in MPU.
- Relating intraformational unconformities to facies and gas hydrate and gas distribution.

- Interpreted a well-log correlation-based northeast-trending incised valley sequence within the lower Sagvanirktok in the KRU-Eileen area.
- Investigating relationship to coal occurrence with free-gas
  - Assessing possible effects on total gas volumes.
- Determined that average petrophysical properties associated with all USGS-interpreted gas hydrate zones across the MPU compare well with averages derived from the UA fluid prediction expert system and manual identification of non-USGS net pay.
- Constructing comparative table showing volumetric calculations and methodologies in MPU via the following:
  - USGS lithostratigraphic-based model
  - UA seismic attribute method
  - UA lithostratigraphic-based method
  - UA sequence stratigraphic method
    - UA auto. fluid predictor model (latest expert system)
    - UA manual net pay model, both maximum and conservative
- Assessing spatial analysis of coal-bearing units (and potential CBM contribution) to free-gas and location of intraformational unconformities within the lower sequences.
- Developing new seismic-based sequence stratigraphic framework that incorporates and is guided by the current log-based MPU sequence stratigraphic framework
- Plan to use this seismic framework will to guide development of a new seismic facies classification scheme and to assess lateral and vertical continuity of sand bodies in the Sagavanirktok formation (per Jan. 22, 2004 UA PI Meeting--Prelim. Agenda)
- Performing spatial analysis of faults relative to porosity, facies development, and reservoir orientation for prospect leads
- Researching significance of the "Northwest-trending hingelines" (minimal dip slip/fracture zones/strike-slip component, below seismic resolution) as probable fluid barriers and influence on dip slip variations along NNE fault zones.
- Continuing collaboration with GEOS on NNE fault typing, sealing vs. fault morphology, determination of the amount of heave and sand-shale juxtaposition.
- Spatial analysis now confirms significant structural control on the distribution of coastline and other surface features in the MPU area as indicated by previous morphotectonic analysis in the MPU, KRU areas (Casavant, 2001: Rawlinson, 1993).

4.6.1.5 Continuing Needs and Future Work

- Sequence stratigraphic characterization of ice-bearing permafrost above Marker 36a (mid Eocene shale) for fluid/facies predictor model.

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

4.6.2.1 Products

- Extended important, interpretable horizons into NW Eileen and off-shore areas of Milne survey to take advantage of all available seismic data.
- Completed post-stack wavelet processing on Milne and NW Eileen data.
  - Discovered significant enhancement of signal within gas-hydrate stability field.
  - Estimated tuning thickness of 25-50 feet.

- Finite-difference modeling of gas hydrate-bearing intervals shows a waveform response to “fast zones” below tuning thickness.
- Improved time-depth conversion of Milne Point cube based on updated synthetic ties.
- Calculated fault heaves across all interpreted faults for 14 MPU-area horizons
- Calculated fault frequency for four intervals within MPU. Trends in fault frequency reveal a distinctly lower frequency over NW trend in cube, through an extended period of geologic time, indicating a deep structure accommodating offset at depth, or many smaller faults below seismic resolution that accommodate offset.
- Calculated fault seal CSP (Clay Smear Potential) and SGR (Shale Gouge Ratio) across gas hydrate Unit-C horizon, using fault throws from seismic and shale thickness from well logs to predict sealing/non-sealing nature of faults.
- Created correlation volumes of extracted gas hydrate waveforms from known gas hydrate occurrences (from well logs) correlated with volume to determine distribution of “hydrate-similar” waveforms.
- Created additional waveform-classification maps on gas hydrate-bearing horizons from amplitude-normalized data cube.
- Correlated fault-heave magnitude, sealing nature and relative time of faulting to known/interpreted gas hydrate occurrences as interpreted from waveform classification.
  - Concluded that waveform-classification anomalies are fault controlled, specifically around faults with high sealing potential.
- Refined 3D ESP volumes to enhance data discontinuities with attention to small-offset faults, deeper NW-trending faults and gas-hydrate occurrence.
- Attempted to interpret subtle offsets along NW-trending structures in enhanced data.
  - Concluded that NW-trending vertical displacements are below seismic resolution.
- Created grid-illumination-horizon structure maps to interpret subtle structural features and faults. NW trends in shallow data become apparent as termini of N-NE-trending faults and zones of greater fault activity and seal.
- Created preliminary interpolated surfaces of BIBPF and BGHSZ for amplitude extraction and comparison to amplitude and waveform-classification anomalies.

4.6.2.2 Work in Progress

- Continuing fault-seal analyses.
- Investigating effects of permafrost on waveform classification.
- Studying supervised waveform classification based on gas hydrate and no-gas hydrate waveforms.
- Preparing prepublication manuscript and figures for masters thesis (Andrew Hennes).
- Preparing poster for presentation at September AAPG Hedberg Conference.
- Creating amplitude scan on BGHSZ surface for free-gas interpretation.

4.6.2.3 Future Work

- Compare USGS and UA time-depth ties.
- Perform additional processing on NW Eileen survey to further increase Signal to Noise ratio.
- Improve 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 interpreted facies.
- Classify waveforms of various attribute volumes such as 3D ESP.
- Continue search for gas hydrate and associated free-gas seismic attribute indicators and identify play fairways and prospective areas.
- Reconcile free gas interpretations in Cascade-01 well with NW Eileen 3D seismic survey; track and tie to MPU.
- Obtain GIS information from North Slope, if possible, to correlate surface features to anomalous events in the 3D seismic data. Determine whether or not:
  - Do lakes occur over gas chimney's?
  - Do lakes and or thin permafrost affect TDQ ?
  - Do lakes,/rivers/surface features trend with faults?
  - Did lakes/rivers affect acquisition and statics that may explain areas of anomalous seismic data?
- Obtain raw shot gathers (from BP) for additional processing
- Obtain cubes (from BP) for Amplitude versus Offset analysis.
- Obtain deeper seismic data to complete more comprehensive fault analysis.

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

4.6.3.1 Products

- Prepared second report presenting estimates of pore fluid concentrations using down-hole logging measurements.
- Determined pore fluid concentrations comprising ice, free gas, water, petroleum and gas hydrate fluid phases.
- Estimated coal occurrences.
- Employed the following seven techniques to compare and contrast pore fluid concentration estimates. Combined the final two techniques to provide best pore fluid estimate

  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. **Bulk elastic moduli (BEM) estimation.** There were minor variations among the 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.

7. **Compressional wave velocity.** Estimates of gas hydrate concentrations are also affected by the compressional wave velocity bias (half of the six 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.

- Determined that distinguishing between ice and gas hydrate can not be accomplished with the available well-log data.
- Distinguished between ice and gas hydrate 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.

4.6.3.2 Work in Progress

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

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

<u>**University of Alaska Fairbanks**</u>
UAF Principle Investigator: Shirish Patil
UAF Co-Principle Investigator: Abhijit Dandekar
UAF Participating Scientists: David Ogbe, Godwin Chukwu and Santanu Khataniar
UAF Research Professional: Narender R Nanchary
UAF Graduate Students: Jason Westervelt, Stephen Howe, Namit Jaiswal, and Prasad Kerkar
UAF Undergraduate Student Assistant: Phillip Tsunemori

4.7.1 Subtask 7.1: Characterize Gas Hydrate Equilibrium

4.7.1.1 Work in Progress

In this quarter, the experimental apparatus was re-designed and modified to first form synthetic gas hydrate and then measure relative permeability across these cores by the unsteady state method. Gas hydrates are generally found in unconsolidated sediments, so coarse sand particles were used to form gas hydrates in the lab. Figure 4 is the schematic of experimental setup to perform flow experiments either by re-circulating the fluids, or by flowing them through the core only once. Temperature of core holder is maintained by circulating propylene glycol as coolant. The ISCO syringe pumps were used for core saturations with water, whereas top down

Figure 4: The experimental set-up picture constructed for forming gas hydrates and measuring relative permeability

gas injection was carried out using the gas cylinder under pressure. The re-circulator chiller was used to maintain the temperature of system. A backpressure regulator is used to maintain a fixed downstream pressure, avoiding gas hydrate dissociation. The dilute propylene glycol was used for maintaining confining pressure. The production of gas and water from the specimen as function of time is monitored using a mass flow meter and balance. The details of the experimental procedure are described below.

4.7.1.1.1 Initial Core Saturation

Cores were prepared by consolidating sand or mud samples obtained from the Anadarko Hot Ice #1 shallow non-gas hydrate-bearing cores. The dry weight of sand was measured and length of core inside the core holder was noted. Basically, the core is consolidated between the two distribution plugs. Overburden of around 150~200 psi was applied to ensure high porosity of core plug. Consolidated core is then flooded with water at low rate to completely remove air from the core. Approximately 10-15% pore volume of water is used to saturate the core plug.

4.7.1.1.2 Hydrate Formations in Core Holder

Gas hydrate formation and stability was a crucial and important aspect of this experiment. After trying several different techniques, the following technique was found to be successful in performing further displacement experiments. Saturated consolidated core was closed from both ends and overburden pressure was increased to approximately 1200 psig. This ensured the same initial pore volume. The valve leading to the upper distribution plug was opened to high pressure methane (approximately 900 psig), creating high pore pressure inside the core. After this ISCO pump was set to refill mode to collect predetermined amount of water from the core. The amount of water collected determines the gas hydrate saturation in the core plug. After this, the pump was switched off and temperature of core holder was reduced to approximately 1.5^{o} C. The temperature ramping rate was around 5-6^{o} C/hour. This temperature is just above ice formation temperature (around 30^{o} F) at high pressures. This facilitated the gas hydrate formation (gas hydrate formation is a cold temperature reaction) and avoided chances of ice formation. Apart from the above method, gas hydrate formation was also attempted using frost and sediment. This method was not efficient and time required for complete conversion was excessive. Moreover, the bulk gas hydrate formation was not initiated after some surface reaction in frost.

4.7.1.1.3 Single Phase Flooding

Gas and water flooding was carried out to measure the effective permeability for each gas hydrate saturation. This was an important step and required careful monitoring of gas flow rate. First gas flooding was carried for a differential pressure of approximately 300 psi. The backpressure was around 540 psi and it provides a crucial role to prevent any dissociation of gas hydrates due to differential pressure. The gas flooding was carried out to remove any free water during gas hydrate formation. Mobile water was collected in the vessel and monitored using electronic balance. The gas hydrate saturation value was determined using material balance for water (volume expansion for water to hydrate is 26%). The gas flooding was performed for around 5-8 hours. Due to permeability reduction the flow rate of gas was significantly small.

Water flooding was done at a constant flow rate (approximately 0.30 ml/minute) with backpressure of approximately 540 psi. Cold water (T= 5^{o} C) was injected from the bottom of the core, displacing the excess and free gas in the core plug. Low temperature and water flow rate retarded the gas hydrate dissociation. Gas hydrate dissociation was closely monitored using a gas flow meter. A sudden increase in flow rate of gas from the core plug indicated the dissociation of gas hydrates in core plug. Water from the core plug was collected in a collection vessel as shown in the schematic (Figure 5). Volume was monitored by electronic balance. The difference in injected and collected water amount was used to calculate the porosity of porous medium in presence of gas hydrate.

4.7.1.1.4 The Displacement Experiment

After measuring the effectively permeability of the core to water, cold methane gas was injected at a constant differential pressure of 310 psi for primary drainage displacement. The injection continued for about 10 to 12 hours, at which time the flow of water becomes almost zero and the flow rate across the core had stabilized. The cold methane gas was also injected at a constant flow rate in some experiments and injection was continued for 10 to 12 hours, at which time the fractional flow of water becomes almost zero and the pressure drop across the core had stabilized.

In order to confirm that the gas hydrates were not lost during the experiment in the core, the lower valve (Figure 5) was closed and the temperature of system was increased. The upper valve was opened to the methane cylinder and the volume change in the cylinder was monitored. As the temperature reaches approximately 8-9^{o} C, there is a sudden increase in the volume of the cylinder at approximately 1200 minutes (Figure 7), indicating dissociation of gas hydrates. This reaction confirmed the presence of gas hydrate in the core during the displacement experiment. After completion of the experiment, the core holder was dismantled and the weight of sediment was measured. The increase in weight of sand from initial dry weight was adjusted for an irreducible water saturation value.

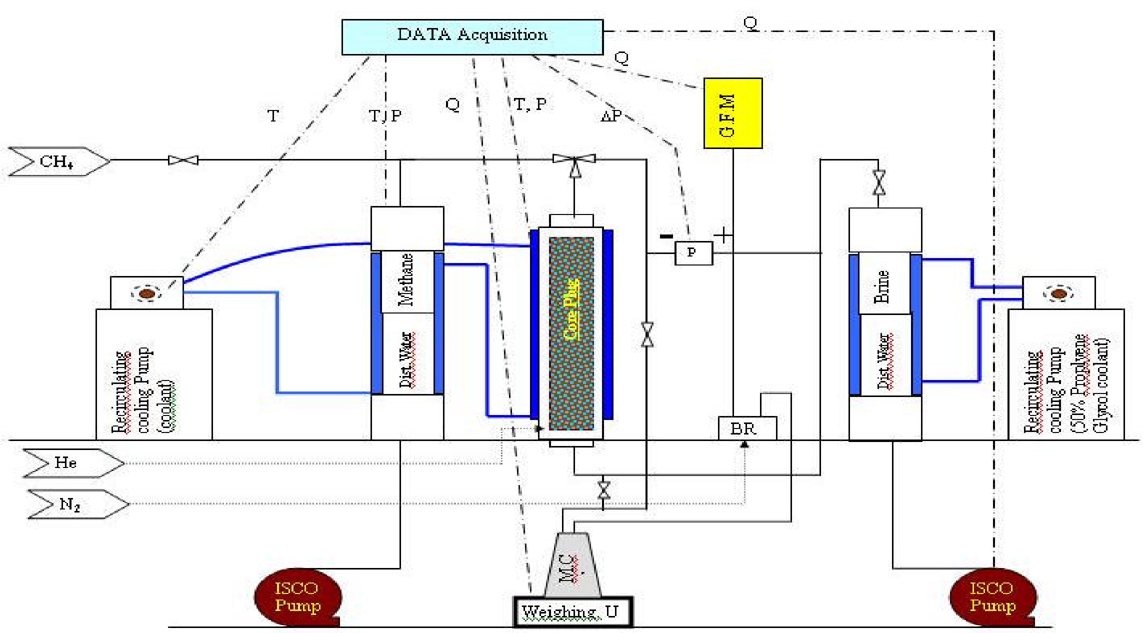


Figure 5: Schematic of laboratory apparatus for measuring relative permeability (Jan 2004).

4.7.1.2 Experimental Results

Study of gas hydrates formed within sediments and porous media is important in that gas hydrates exist in nature either within or below permafrost or within deep-sea sediments. Gas hydrates are not known to occur just within free water. In most of the studies carried out so far, massive gas hydrates have been formed in bulk or only within some vessel of sediment. Consequently, previous formation and decomposition studies and permeability studies performed on these gas hydrate samples do not likely exactly represent the actual behavior of gas hydrate samples existing in nature.

4.7.1.2.1 Gas Hydrate Formation Analysis

Gas hydrate formation and dissociation was monitored by the constant pressure (pore pressure) and constant volume (Methane cylinder) method and the results are presented in Figures 6-7. For the constant pressure (726 psia) case, the dissociation pressure was 7.5^{o} C, similar to that reported by Jason, 2004. Results confirmed that gas hydrates were actually formed within the core holder.

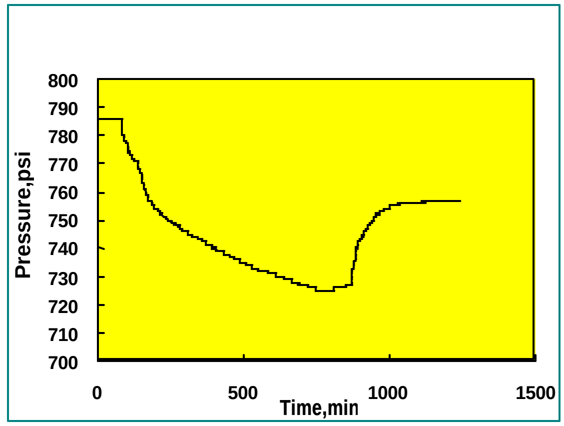


Figure 6: Pressure decline gas hydrate formation confirmation.

The cell was cooled while maintaining constant pressure via a regulating valve. The temperature ramping for gas hydrate formation was around 4-5^{o} C/hour and kept at 1^{o} C for 6-10 hours. After gas hydrate formation was complete, the cell temperature was increased and the plateau in pressure/volume of methane cylinder reappeared due to gas hydrate dissociation. The changes were rapid indicating rapid gas hydrate dissociation.

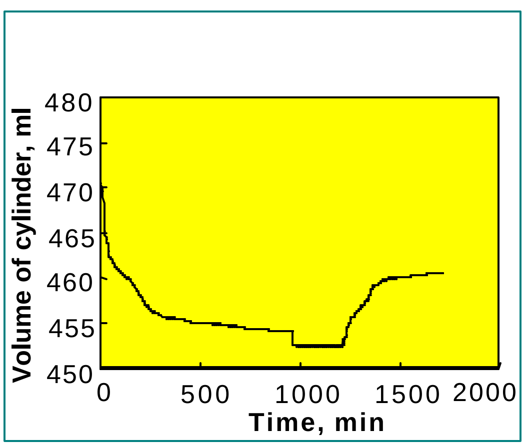


Figure 7: Volume change in methane cylinder (726 psi) gas hydrate formation confirmation

4.7.1.2.2 Permeability Results

The effective permeability results were plotted for gas flow through gas hydrate-bearing porous media formation. The results were compared with Mehrad's (1989) work (Figure 8). Mehrad conducted his experiment in unconsolidated medium (without any confining pressure), resulting in a higher value for permeability.

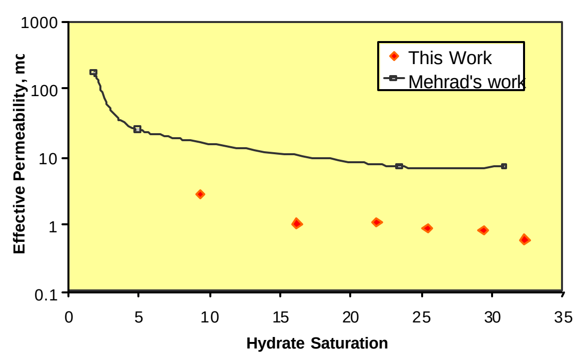


Figure 8: Effective permeability for various gas hydrate saturation values

The relative permeability was calculated using the JBN method for data reduction. Figure 9 displays relative permeability for various gas

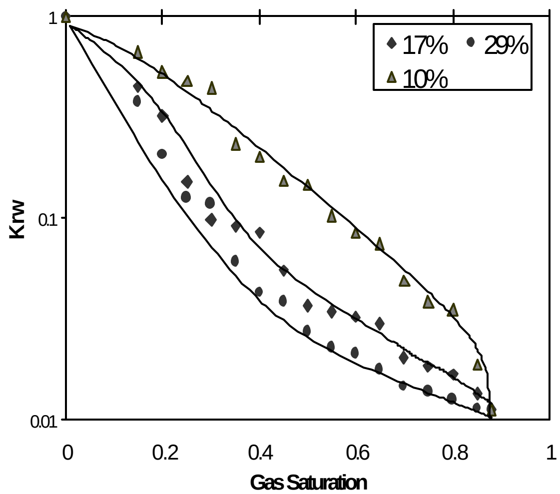


Figure 9: Relative permeability curves for various hydrate saturation values (S_h % = 10, 17, 29).

hydrate saturation values (irreducible water saturation of 0.12.).

4.7.1.2.3 Conclusion

Relative permeability and effective permeability for gas hydrates in porous media (coarse sand) was measured for three gas hydrate saturation values. For higher gas hydrate saturation values, there is a considerable change in relative permeability. This might be attributed to the distribution of gas hydrates in the core (i.e. for water flow there might be grain rearrangement in structure and we observe different relative permeability). There was no significant change in absolute permeability, probably due to a similar distribution of gas hydrates in the sand (likely cementing the core).

4.7.1.2.4 Future Work

- Measurement of relative permeability for different gas hydrate saturation values.
- Forming gas hydrates in different types of sediments.

4.8 TASK 8.0: Evaluation of Drilling Fluid and Assess Formation Damage

4.8.1 Subtask 8.1: Design Integrated Mud System for Effective Drilling, Completion and Production Operation

4.8.1.1.1 Task 8 Objectives

- Design fully integrated mud system for permafrost and gas hydrate bearing reservoirs.
- Determine mud contamination and formation damage risk.
- Evaluate mud chiller system such as one used in Mackenzie Delta program.

4.8.2 Task 8.2, Assess Formation Damage: Testing, Analysis and Interpretation

4.8.2.1 Background

Well productivity can be significantly reduced by reservoir damage within the near wellbore area caused by drilling and mud contamination. The recent trend towards non-perforated completions as well as the number of highly deviated and horizontal wells drilled through hydrocarbon reservoirs has, from an economic perspective, increased the awareness for evaluating drilling fluids and completion techniques to assess potential reservoir damage. The suitability of a drilling or completion fluid for use in a particular reservoir can be determined using the measurement of return permeability or some other indication of formation damage. In the last quarter of the project, the following objectives have been accomplished:

- Sized and defined the specifications of some components in the experimental apparatus setup, including methane gas and drilling fluid separator, floating piston accumulator, gas mass flow meter, pressure gauges etc.
- Positioned items including back pressure regulators and gas-liquid separators in the experimental apparatus to allow for consideration of the possibility of compression of gas and the requirement to analyze and measure the gas flow with time.
- Procured critical parts of the testing apparatus, including Dynamic filtration core holder, dual action recirculation pump, floating piston accumulator, gas-drilling fluid and other gas and liquid measurement devices.
- Developed an understanding of a standardized testing procedure for formation damage assessment and defined the experiment parameters with methane gas and shallow sand and/or permafrost cores.

4.8.2.2 Key Testing Procedure Factors

The objective of any formation damage investigation is to determine the drilling fluid and formation interaction. The basic process involves the determination of the initial permeability of a sample of reservoir material or surrogate, the exposure the sample to drilling and/or completion fluids, and the subsequent re-measurement of permeability. The difference between the two measured permeabilities is taken as an indication of the suitability of the fluid under test for exposure to the reservoir. Marshall et.al. (1997) have given recommended practice for formation damage testing to overcome past repeatability or reproducibility concerns in such testing.

- In order to prevent damage in the sample due to fines mobilization during flow testing, a separate critical velocity test will be performed to determine the flow rates that can be applied without causing permeability reductions due to fines migration.
- Testing should ideally be done using reservoir material where care to use representative and preserved reservoir core is critical in order to correctly evaluate the drilling fluid. In native state material the plugs will have reservoir connate brine saturation and the samples can be analyzed with drilling fluid directly.
- The cores of analogous sedimentary deposits from the ANS are provided by Anadarko Petroleum Corporation. The "Hot Ice-1" location is about two miles south of the present boundary of Kuparuk River Unit. The cores are available from 107 feet to a total depth of 1400 feet.
- The prepared sample for evaluation should be loaded into a core holder capable of attaining reservoir in-situ conditions. The core sample should be mounted in the horizontal position for analysis. The confining stress on the sample should be gradually increased while at the same time the pore pressure of the fluid in place is also increased to maintain a net confining stress ratio equivalent to the in-situ reservoir stress conditions. The rate of increase of net stress on the sample should not exceed 1000 psi per hour.
- In the traditional core-holders, there is considerable turbulence at the mud inlet and mud outlet ports and this turbulence may alter results by causing excessive mud invasion into the core in the rubber sleeve and can give a boundary flow effects around the core. To compensate for this condition, we plan to use a special "Dynamic Filtration Core Holder" (DFCH) with an available maximum mud flowing pressure of 2500 psi. In this particular core holder the mud flow will be passed on the face of the core and due to absence of curved paths, possible turbulence and boundary flow effects are minimized.

- The test apparatus and sample should be heated and the sample should be allowed to stabilize at the test temperature and pressure before testing begins.
- The JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate research well was drilled in February and March 1998, in the Mackenzie Delta, Northwest Territories, Canada, to a depth of 1150 m. (Dallimore S.R. et.al.; 1999). Drilling and coring of the permafrost section (0-670 m) at Mallik 2L-38 well proved to be challenging, with significant borehole erosion in some zones, affecting core recovery. Mud temperatures during drilling of the main hole beneath the permafrost casing (670-1150 m) were maintained near 2^{o} C, using a plate type heat exchanger in an effort to minimize permafrost thawing and to depress the mud temperature lower than the in-situ formation temperatures while drilling through the gas hydrate zones. We plan to circulate the coolant in the jacket around the DFCH as well as around the Drilling Fluid Recirculation Unit.
- Formation fluid should be flowed in the production direction (from 'formation' to 'wellbore') by at constant rate until the pressure drop stabilizes. The flow rate will be <50% of the critical rate and ceased once the initial permeability is established.
- Based on the research conducted in Japan, a KCl/polymer drilling mud-containing drilltreat, a chemical mud additive recognized to have properties which can stabilize gas hydrate cuttings, was selected to help maintain cold temperature. The basic composition of the mud used in the main hole intervals including the gas hydrate layers consisted of 50 kg/m3 of KCl (antifreeze agent and shale inhibitor), 1-3 kg/m3 of Xanvis (viscosifiers), 0.5 kg/m3 of KOH (pH control), 6 L/m3 of lecithin (62% Drilltreat; gas hydrate promoter), 10 kg/m3 of Dextrid LT (filtration control), 5 kg/m3 of Drispac (filtration control), 0.3 kg.m3 of Na2SO3, and barite (weighing material). We plan to analyze the compatibility of this drilling fluid with methane gas and permafrost core.
- The drilling fluid heated pre-heated (cooled in this case to 2^{o} C) should be applied to the sample face at the same overbalance pressure as that in the reservoir and should be dynamically circulated over the face of the test sample for a minimum of 4 hours. During the circulation the drilling fluid pressure and the pore pressure should be recorded to ensure the values remain stable (less than 5% variation).
- During dynamic drilling fluid circulation, the amount of fluid invasion into the test sample should be monitored at the 'formation' end of the sample. The invasion volume as a function of time should be recorded to allow the evaluation of spurt loss as the mud cake builds up and to determine the effectiveness of the mud cake to prevent filtrate invasion into the test sample (leak off).
- Static drilling fluid placement, where the mud pressure should be maintained without flowing fluid over the 'wellbore' face of the sample should follow the dynamic placement for 16 hours. As in the dynamic placement, recording of invasion volume as a function of time measured at the 'formation' face of the sample. Following the static placement the mud should be dynamically circulated for a minimum of 1 hour.
- We believe that the equipment advances, such as a dual action drilling fluid recirculation system (capable of pumping at maximum 7400 cc/min, against maximum differential pressure of 250 psia, at a line pressure of 2500 psi maximum) and floating piston cylinder (2500 ml) arrangement will be invaluable additions in prolonging the cycle of dynamic and static filtration cycle over 20 hours if necessary.

4.8.2.3 Future Work

Recent experiences indicate that the biggest challenge to progress in gas hydrate research is to match to the time scale available or to be followed. Also, the specific experimental items or equipment are critical and may require some modification to enable the best performance. Temperature, pressure, and chemistry are the fundamental parameters controlling the stability of gas hydrate, and the addition of suitable drilling fluid is a critical step toward developing a mud compatible with methane hydrate and gas. We anticipate having a special drilling fluid and all analytical tools procured to:

- Establish the mud rheology at in-situ conditions.
- Build the experimental apparatus (Figure 10).
- Test the experimental apparatus for leaks and attained pressure with water and N_2 and calibrate the analytical tools.
- Perform critical velocity test to get flow rates that can be applied without causing excessive permeability reductions due to fines migration.
- Measure the return permeability with specific underbalance and overbalance pressure drops.
- Calibrate the results obtained with different approaches in an effort to quantify the significance of drilling fluid on the formation damage.

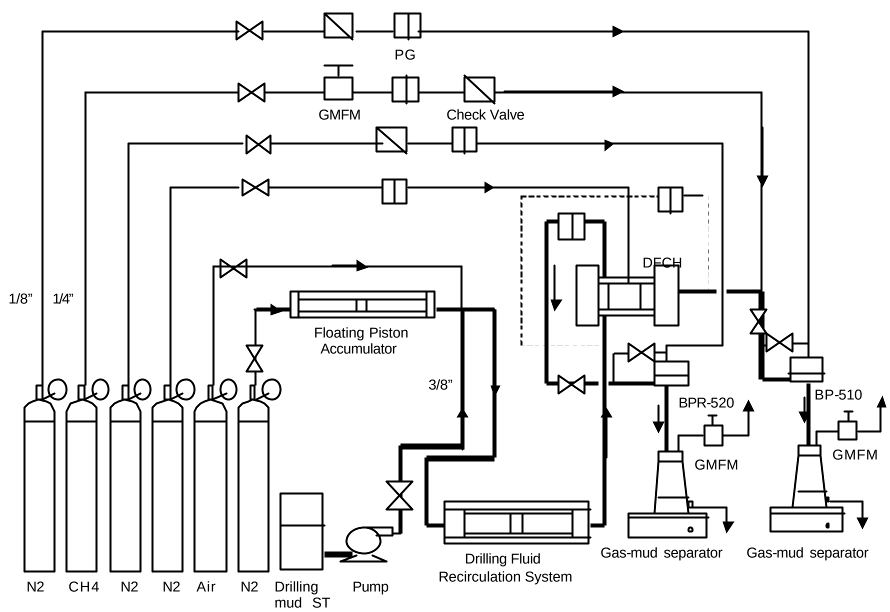


Figure 10: Formation damage experiment apparatus proposed to construct.

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

4.9.1 Develop Analytical Model for Gas Hydrate: Modeling decomposition kinetics

As documented in the fifth quarterly report, an analytical model was developed to study gas hydrate well design by depressurization methods with equilibrium method of gas hydrate decomposition. In this quarter, efforts were completed in predicting the performance of gas production by depressurization methods by combining generalized material balanced equations with kinetics of gas hydrate decomposition.

McGuire (1982) and Tsypkin (1992) neglected the gas hydrate dissociation kinetics in their respective studies on gas production from in-situ gas hydrates. Ji et al. (2001) developed an analytical model for studying depressurization-induced gas hydrate dissociation in porous media. In this model, they did not consider dissociation kinetics. Most reservoir models assume equilibrium decomposition (Ji et al., 2001; Tsypkin, 1991). In these prior models, gas hydrate is assumed to dissociate instantaneously once the equilibrium condition is reached. Many authors today simulate the performance of gas hydrate reservoirs by incorporating the dissociation of kinetics by an energy balance. This type of numerical technique is a complex process that involves simultaneous multi phase fluid and heat flows in dissociated zone. These simulators require an empirical correlation to determine gas hydrate surface area for dissociation kinetics calculations, and it commonly predicts a large pressure drop in a small region of the gas hydrate core, for which Yousif et al. (1991) do not adequately account.

The literature survey shows that there is not a publicly available reservoir model which can couple the dissociation kinetics to the gas flow in the porous media, does not require empirical correlation and yet, can predict gas production from in-situ gas hydrates. Shell conducted significant gas hydrate modeling research using an in-house 3D thermal reservoir simulator which incorporated gas hydrate phase behavior, heat flow, and reservoir compaction (Swinkles and Drenth, 1999).

This work is undertaken to develop a reservoir model to predict the performance of a naturally occurring in-situ gas hydrate reservoir. This task is accomplished by adapting the decomposition kinetics model and using an interface–related surface area. The kinetic model is incorporated into the radial diffusivity equation using a gas mass balance at the gas hydrate-gas zone interface. The model is then solved analytically. Numerical solution of the resulting system has been obtained by the Newton method of iteration. The calculations have been made for the available range of data parameters as listed in nomenclature. This simulator is fast, self-standing and can be used for matching laboratory experiments quickly. It can also be used for determining sensitivity to key parameters for anticipated development scenarios.

The proposed model is used to describe the gas potential of a hypothetical semi-infinite reservoir based upon predicted and interpreted MPU-area reservoirs and fluid types. The model compares effects of various gas production rates on gas hydrate decomposition behavior. The gas hydrate reservoir is represented on a pressure-temperature equilibrium graph in Figure 11. For different production rates and given reservoir pressure and temperatures, distributions of pressure in the porous layer of methane hydrate and in the gas region are illustrated in Figures 12-13. The distance of the gas hydrate decomposition front from the well as functions of time are shown in Figure 14. Time variations of mass flux and total mass flow are also shown in Figure 15. Time evolutions of resulting pressure profiles in the gas hydrate reservoir for different permeabilities are displayed. In addition to the above-described capabilities, the present model can also predict gas hydrate reservoir performance when multiple gas production rates are used. In case of multiple gas rates, a well is operated with one-flow rate up to t_1 years and another flow rate beyond t_1 years.

This model predicts relatively low gas production rates and very low cumulative gas production if the depressurization mechanism is used for the dissociation of in-situ gas hydrates. This slow dissociation rate suggests that techniques, such as enhancers or thermal stimulation, must be investigated to enhance gas production from the in-situ gas hydrates. This model assumes isothermal gas hydrate dissociation with no volume change and gas hydrate dissociation at an interface between the dissociated and undissociated region only. Work is in progress to predict the performance of naturally occurring gas hydrates non-isothermally.

4.9.2 Modeling gas hydrate decomposition in porous media

Pressure distribution in the reservoir is governed by:

$$\left(\frac{\partial^2 p_n^2}{\partial r^2} + \frac{1}{r}\frac{\partial p_n^2}{\partial r}\right) = \frac{1}{a_n}\frac{\partial p_n^2}{\partial t}$$

where a is the hydraulic diffusivity constant. In the subsequent analysis, subscript n identifies the regions, with n=1 or 2 corresponding to the gas zone or the gas hydrate zone respectively. The following initial and boundary conditions are employed:

$$p_2(\infty, t) = p_2(r,0) = p_e$$

$$p_1(R(t),t) = p_o$$

$$p_2(R(t),t) = p_D$$

$$q_1 - q_2 = q_{released}$$

In addition to the above boundary conditions, a constant gas withdrawal is considered at the well bore. For the constant gas withdrawal condition, the solution of the gas hydrate dissociation model is analogous to the heat flow in an ice-water decomposition system. Thus, the model solution for the dissociated zone and undissociated zones are respectively,

$$p_1^2 = p_o^2 - \frac{q_{sc} p_{sc} zTm}{phkT_{sc}}\left(\int_{l_1}^{\infty}\frac{e^{-l^2}}{l}dl - \int_{a_1}^{\infty}\frac{e^{-l^2}}{l}dl\right)$$

$$p_2^2 = p_e^2 + (p_D^2 - p_e^2)\frac{\int_{l_2}^{\infty}\frac{e^{-l^2}}{l}dl}{\int_{a_2}^{\infty}\frac{e^{-l^2}}{l}dl}$$

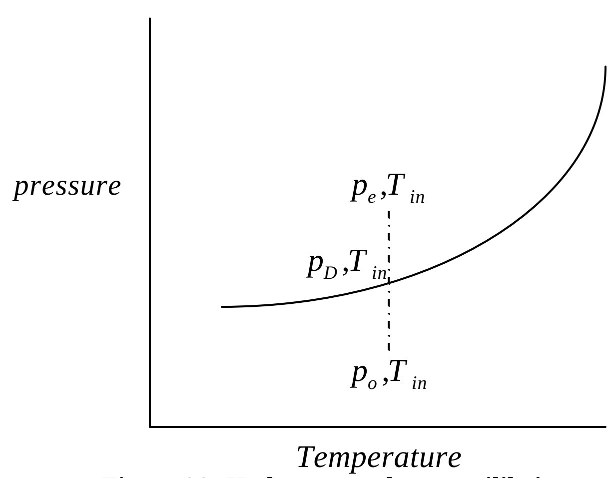


Figure 11: Hydrate-gas phase equilibrium graph

Mass balance equation at the interface

$$\frac{q_{sc} p_{sc} ZT}{phT_{sc}} e^{-a_1^2} - \frac{k_2((p_D^2 - p_e^2)}{m}\frac{e^{-a_2^2}}{\int_{a_2}^{\infty}\frac{e^{-l^2}}{l}dl} = Ag$$

where, $A = zT\Phi S_H (\frac{B_H p_{sc}}{T_{sc}})$

The above set of equations completely describes the process of gas production from the dissociation of gas hydrates. These equations predict the performance of a gas hydrate reservoir. An iterative scheme has to be employed to determine unknown pressure, p_o, and gas compressibility, c_g, and the constant g, which determines the position of the front for given set of conditions.

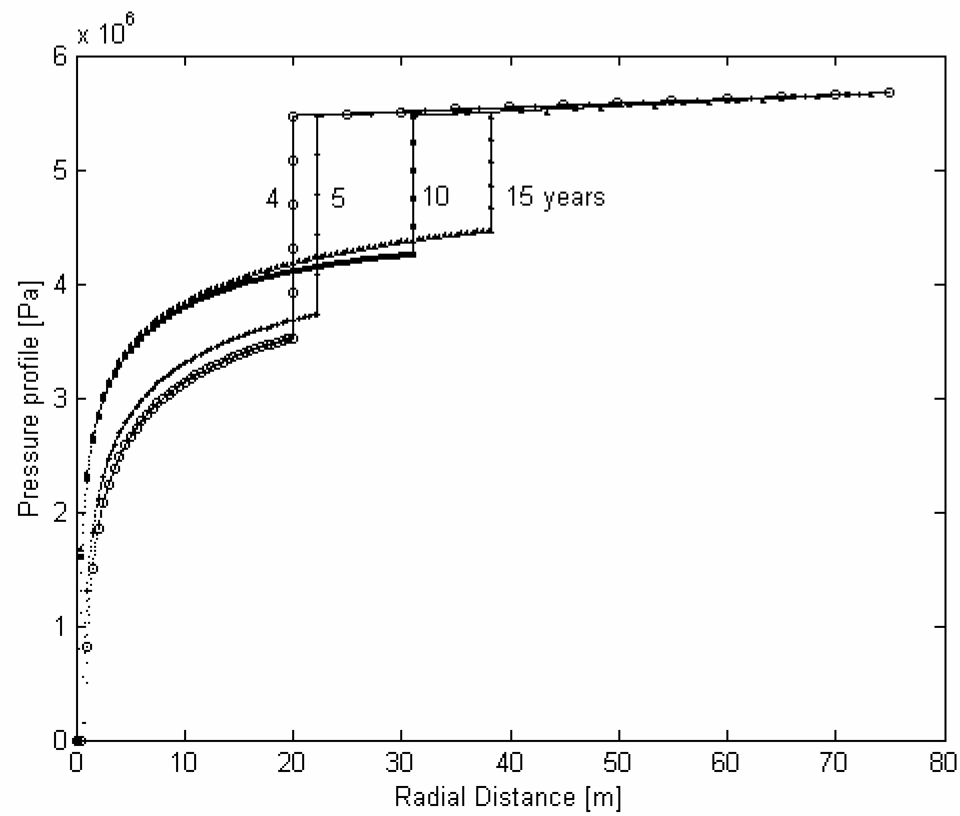


Figure 12: Pressure profile for 300 SCMD gas production from a reservoir of 0.01 md

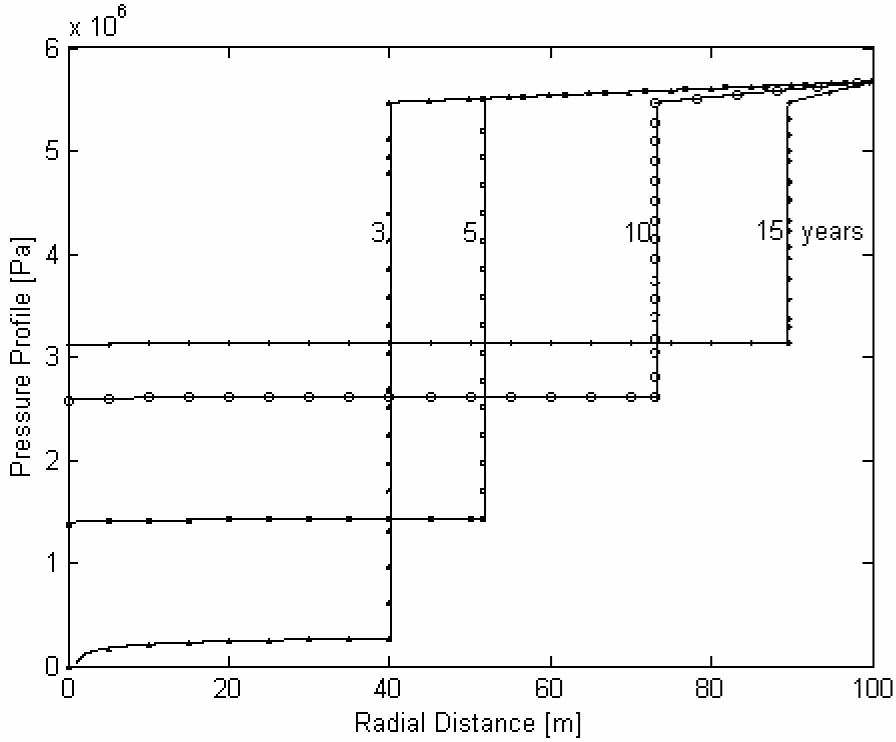


Figure 13: Pressure profile for 1500 SCMD gas production from a reservoir of 10 md

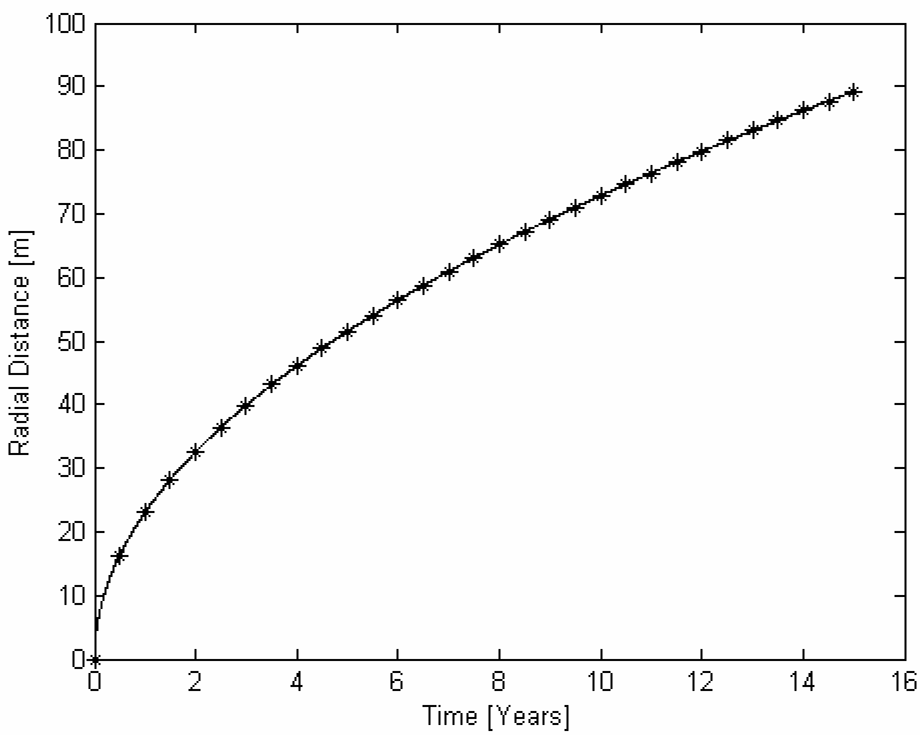


Figure 14: Position of gas hydrate decomposition front

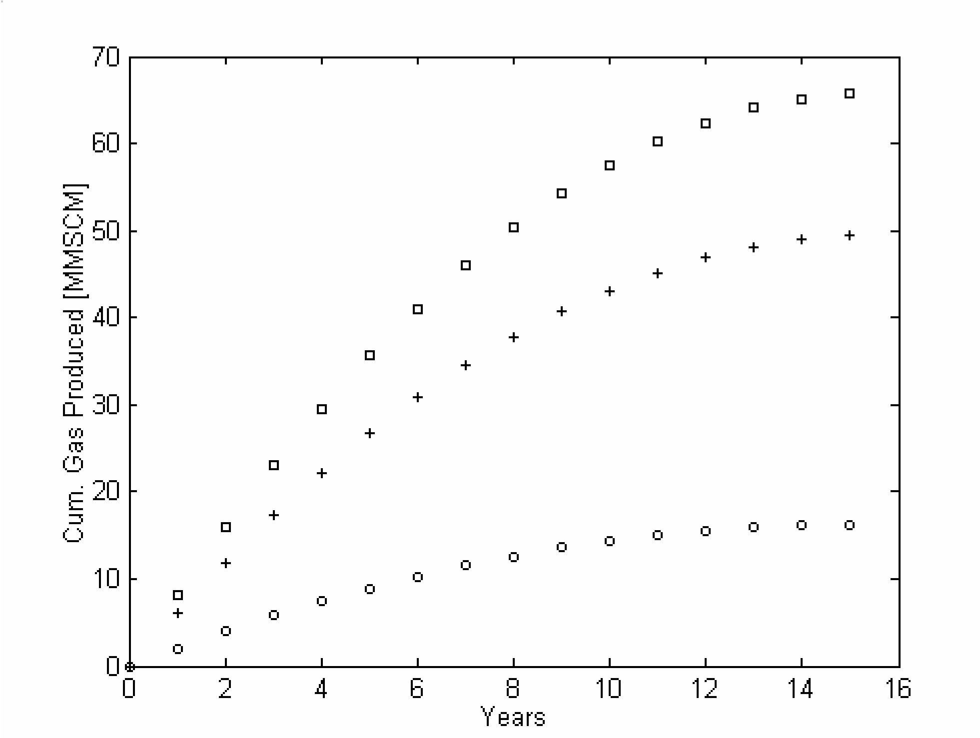


Figure 15: Cumulative Gas Production versus time

----------- Cumulative Gas production
+ + + + ----------- Free Gas Only
o o o o ----------Hydrate Dissociation Gas

4.9.3 Production Modeling and Economic Evaluation of a Potential Gas Hydrate Pilot

Simulations were run using a commercially available simulator, CMG STARS. A 1-mile by 4-mile fault block was simulated using parameters analogous to the gas hydrate accumulations being interpreted within the MPU. Various cases were run with variations in absolute permeability, well spacing, production rate and gas hydrate saturations. The simulation period encompassed 15 years. While recognizing this study has limitations due to the small amount of definitive input data and the approximations used, coupled with the imprecision of the gas hydrate dissociation simulator, useful conclusions can still be drawn from the study. Production profiles generated from the simulations indicate that an accumulation of methane hydrate in a reservoir will begin to dissociate when the reservoir pressure is lowered. Reservoir pressure, temperature and production profiles are displayed in Figures 16-17 and 18-19 after 15 years of gas production. Gas hydrate and water saturation profile schematic for modeling gas production is also presented in Figures 20-22 at 15 years. The gas production profile schematic after 15 years of production for different gas hydrate saturations and permeabilities are shown in Figures 23-24. A comparison of gas production rates for different operating wells is presented in Figure 25.

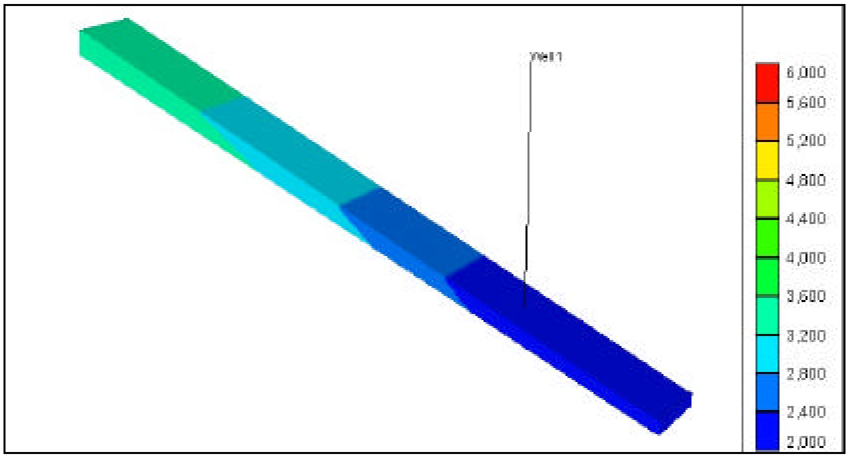


Figure 16: Pressure profile, gas production model after 15years

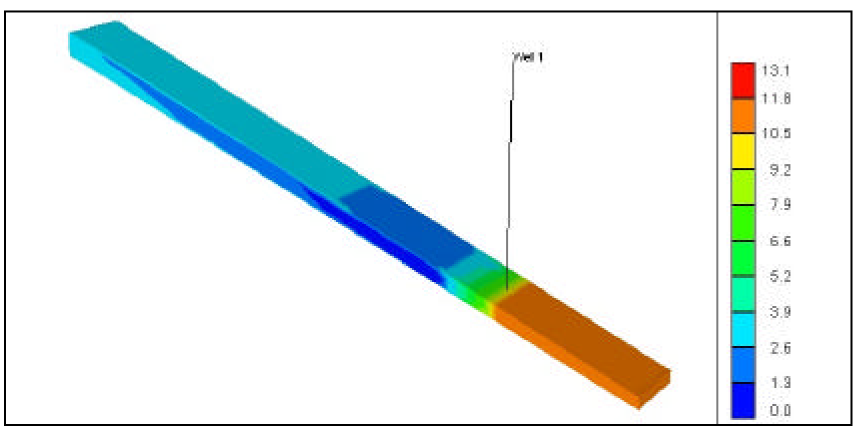


Figure 17: Temperature profile, gas production model after 15years

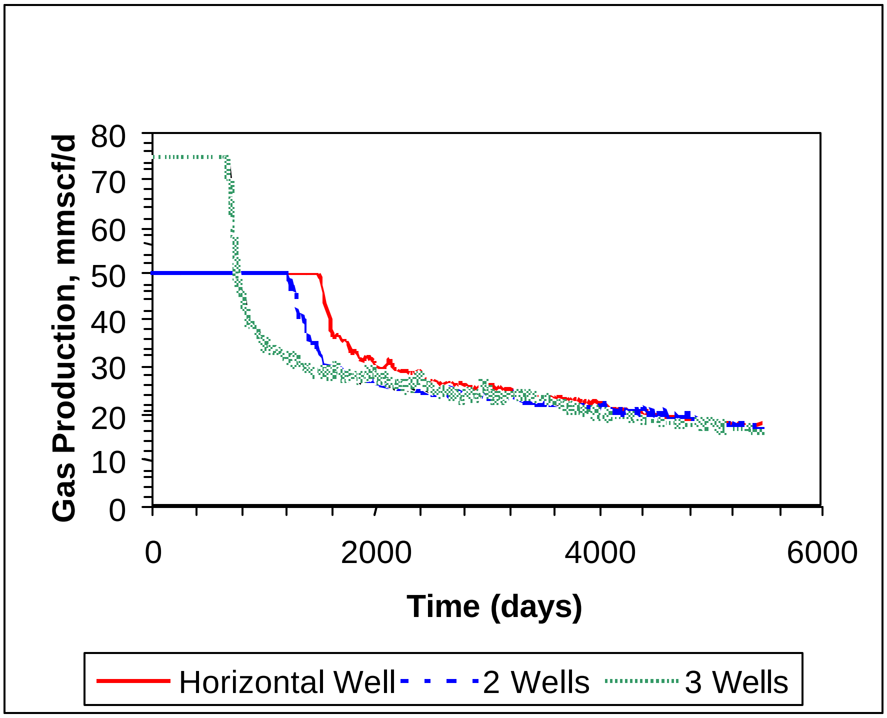


Figure 18: Horizontal and Multiple Well Production Rates

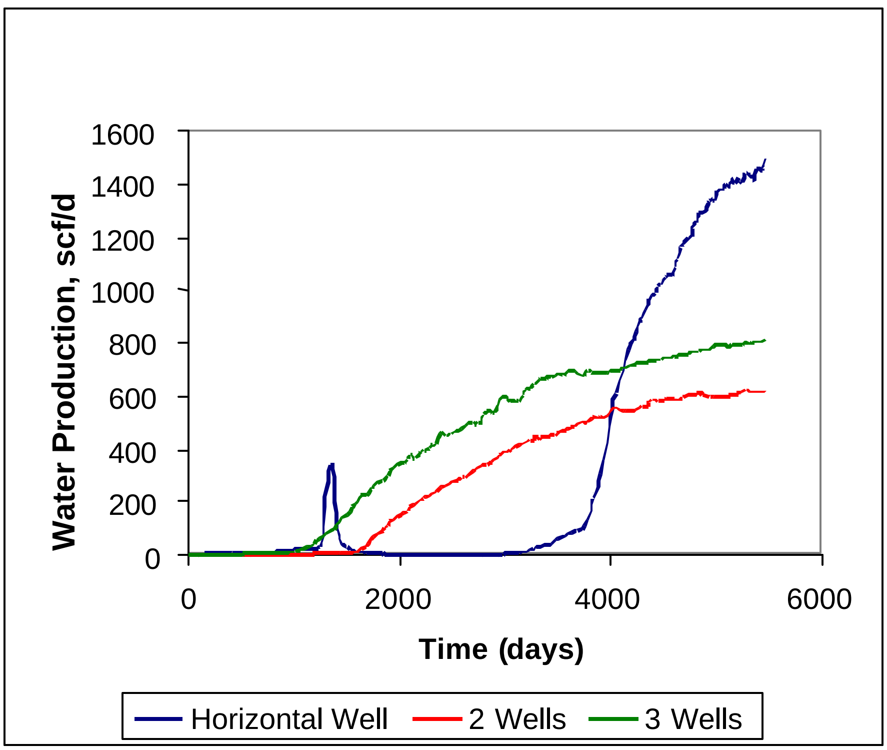


Figure 19: Water Production Rates – Horizontal and Multiple Well Cases (Conversion Factor is 5.61 scf per barrel)

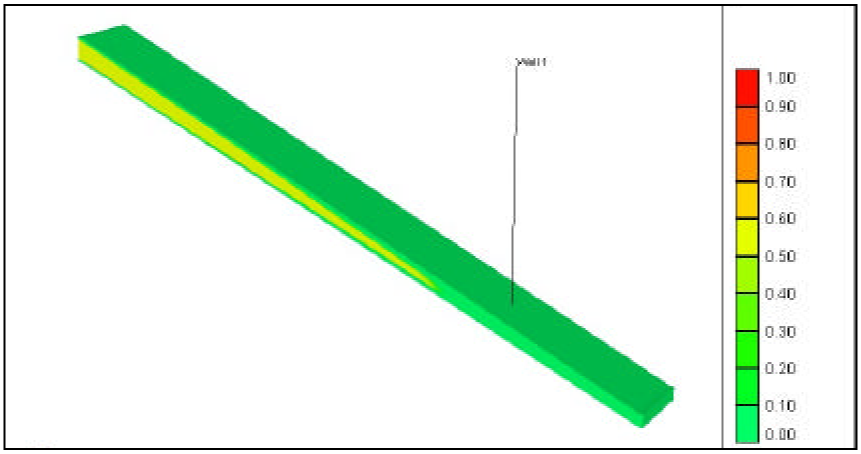


Figure 20: Gas hydrate saturation profile, gas production model after 15years

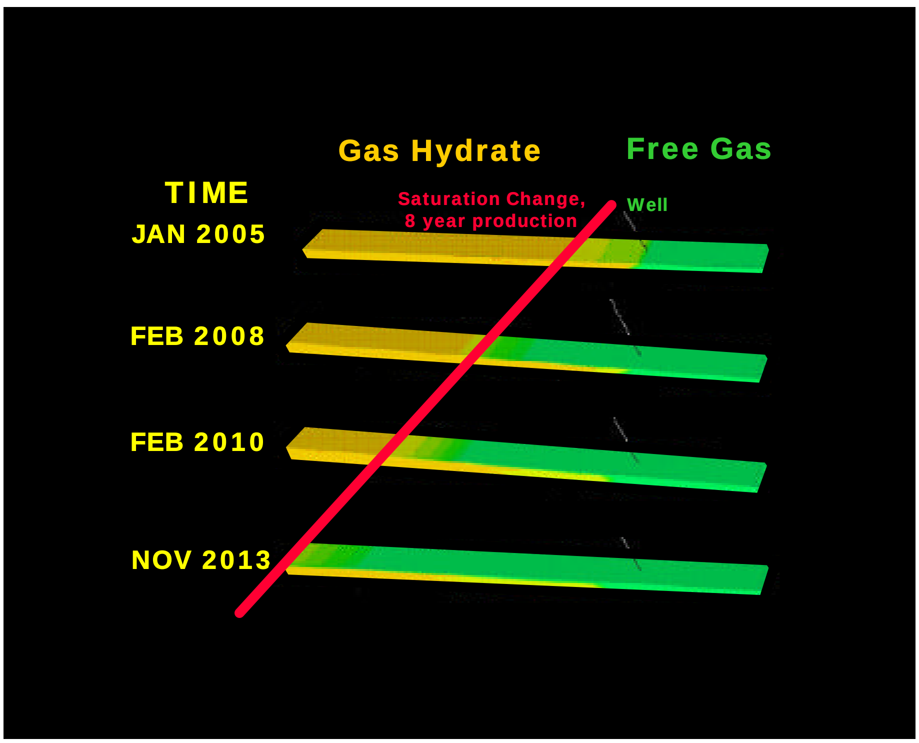


Figure 21: Gas hydrate saturation profiles, gas production model over 8 years.

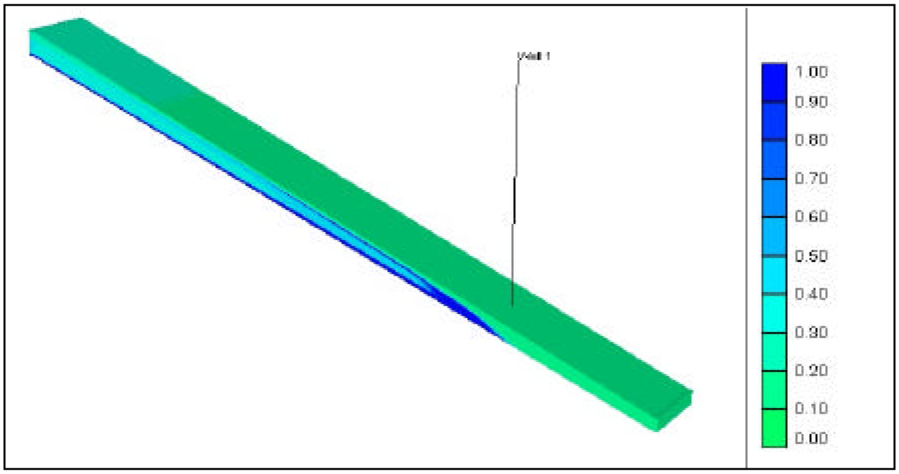


Figure 22: Water Saturation profile, gas production model after 15years

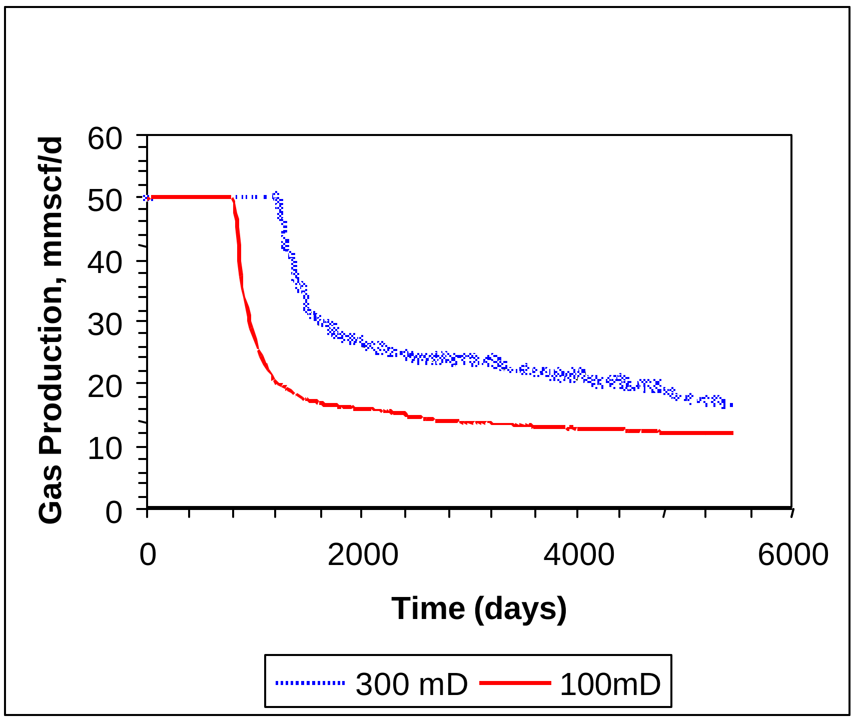


Figure 23: Reduced permeability gas production profile, model after 15 years

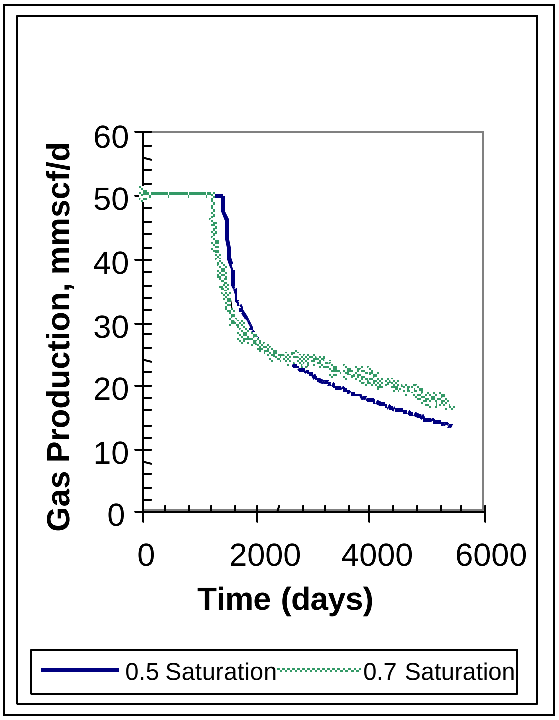


Figure 24: Reduced gas hydrate saturation gas production profile, model after 15 years

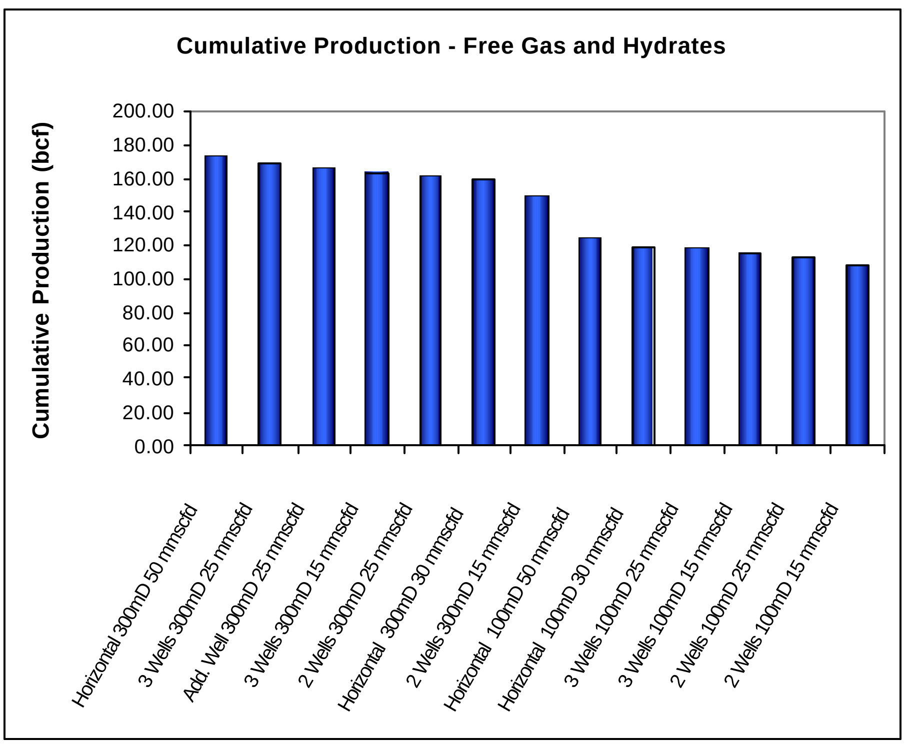


Figure 25: Cumulative Production for different well cases and production rates

4.9.3.1 Gas Hydrate Thermodynamics, Reservoir Model Considerations

Cooling of the reservoir during gas hydrate dissociation was noted. An area of concern is the lowering of the reservoir temperature due to the endothermic nature of the dissociation reaction and a Joule-Thomson effect. A reduction in temperatures may lead to freezing of water in the reservoir, plugging the formation and preventing efficient depressurization. Limitations of the model meant that the full impact of temperatures below 0^o C could not be simulated and further work is required to investigate reservoir cooling.

Although years of theoretical work have helped define relationships for conductive heating and cooling of reservoir rock, predicted heat influx from the surrounding strata continue to be an area of significant uncertainty. Preliminary results from the TOUGH2 gas hydrate reservoir modeling (Moridis and Collett, 2004 in press) do not show a temperature rebound that is on the order of those experienced in field temperature logging measurements. In fact, the TOUGH2-predicted temperature rebound at the wellbore is so small it is not noticeable at the center of the gas productive zone after 500 days. For reference, standard production logging practice is to cease repetitive logging passes after only 48 hours (2 days) since the bulk of the temperature response will have already occurred. The disparity in these two sources is extreme.

To generate a 3rd measurement to reconcile this difference, Stephen Howe from UAF ran a case where a gas production well in the dissociation model was allowed to rebound to ambient conditions after 4 years of production. These results are shown in Figure 26.

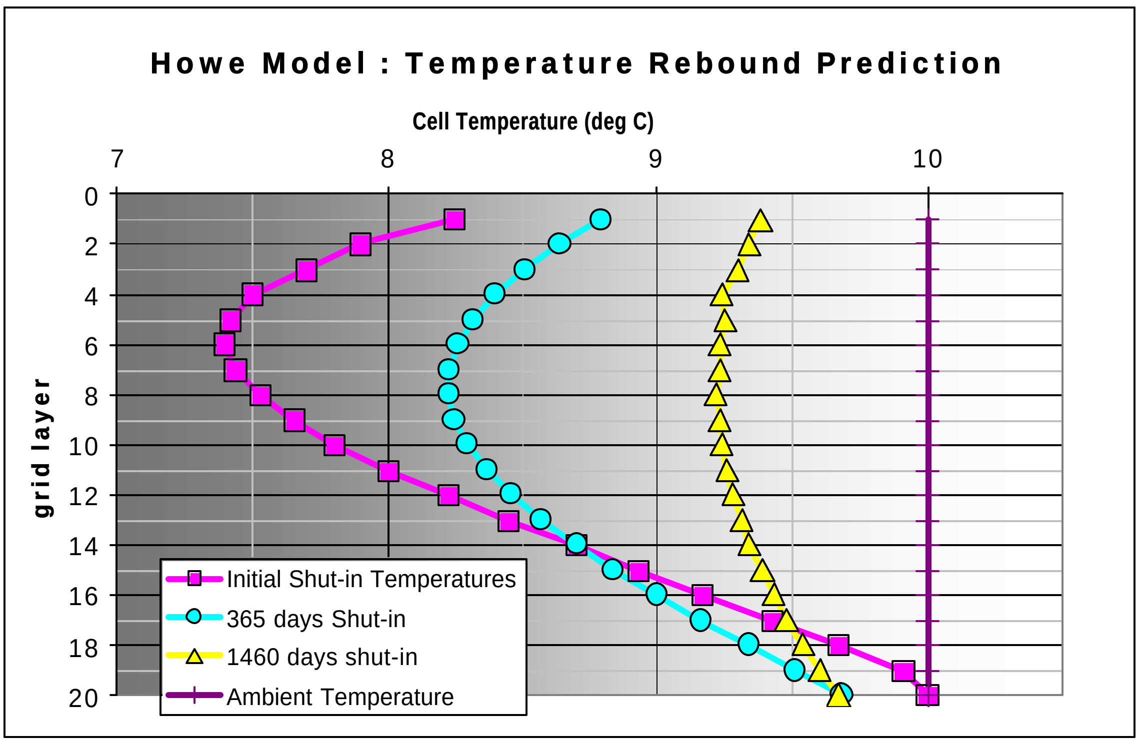


Figure 26: Temperature rebound prediction after 4 years of gas production from a well in the gas hydrate depressurization and gas dissociation model

These temperature rebound predictions from the STARs model are closer to the production logging expectations, but still less than typically experienced in the field. Perhaps this is due to the relatively small temperature disturbance created by the dissociation process. If this small temperature differential is sufficient to slow dissociation, but not sufficient to drive a significant heat flux back into the gas hydrate zone, then the steady state gas evolution will be adversely affected and will be a critical behavior to measure and fully define.

Unfortunately, in the cases of both TOUGH2 and STARS, default values were used to represent heat flux constants of surrounding strata. One of the few examples available to calibrate heat flux constants is the Mallik data. But to date, the data from the Mallik temperature cool-down following hot-water circulation has not been matched in order to calibrate heat flux values.

Since the pressure dissociation process remains the simplest and most viable gas hydrate production option, it is imperative that the widely divergent views on the ability to sustain dissociation in the face of vaporization-induced cooling be reconciled with actual field testing.

4.9.3.2 UAF Preliminary Economic Assessment

UAF performed a preliminary economic assessment and sensitivity analysis using the generated production profiles. The volumes of gas produced in the base case scenario are sufficient to produce a positive rate of return on the assumed investment costs of the project, though this is very dependent upon facilities cost, gas price, and transportation tariff. A reduced permeability results in an economic loss, though this can be overcome by expanding the project to reduce the burden of assumed local pipeline capital costs. The high permeability of the reservoir means that one horizontal or two vertical wells are sufficient in the test case. Additional wells increase gas production, but the high cost of drilling the extended reach wells is not compensated for by an increase in gas sales. The UAF work concluded that a base case of a 300-mD reservoir with a peak production rate of 25-50 MMscfd would be feasible and that (given the assumed project investment costs) could achieve a net present value of just under $5 million.

It was noted that the project economics were very leveraged to gas price and the tariff for transport to the lower 48 gas markets. Economic analysis for different well designs and for various cases is performed in Howe (2004, in-press thesis). The depressurization method of dissociation was found to be feasible and the results give encouragement that further research into gas hydrate resource potential may be beneficial.

Total recovery of the potential gas volumes from the gas hydrate over 15 years is relatively low, under 50%. Substantial depletion of a reservoir using depressurization alone could be a lengthy process and as such, methods to increase the rate of dissociation should be investigated for effectiveness and economic impact.

4.9.4 Gas Hydrate Dissociation Reservoir Model Using ProCast

A beta release of a moving front gas hydrate dissociation model was incorporated into ProCast during the quarter (Figure 27). This model uses a material balance treatment of the connected gas zone to create a moving dissociation front. The dissociation front is defined as a horizontal rectangular surface area connected to a free gas structure. The surface area can be changed as a function of depth to represent varying exposed free gas-gas hydrate interface sizes. The basic rate of dissociation is controlled by two parameters that mirror the Kim-Bishnoi constants but on a larger scale. These two values can be tuned to match virtually any reasonable dissociation behaviors and, once tuned, can be used to generate production forecasts in a manner of minutes as opposed to days or weeks (Figure 28). Final debugging and interface testing are in progress on this new feature incorporated into ProCast. The program is generally available free to the public at www.ryderscott.com\download2\setupprocast.exe. The installer password "Procast2004" will enable the program for full use throughout 2004.

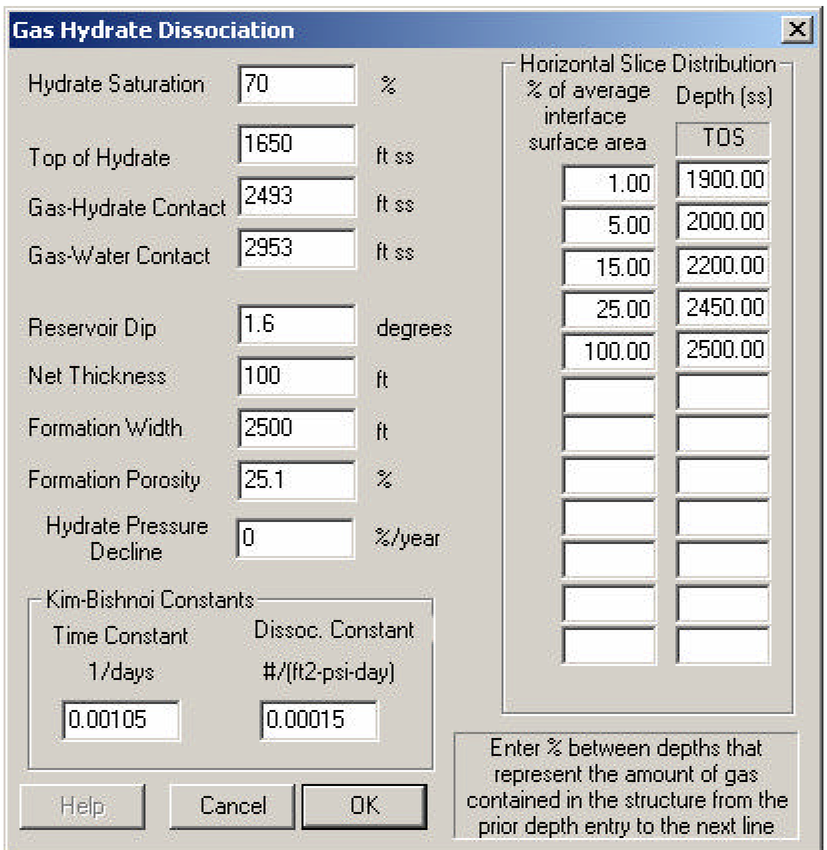


Figure 27: Gas hydrate dissociation input panel in ProCast reservoir simulator

A sample dataset with gas hydrate dissociation test parameters is included in the example datasets. This example results in the following production profiles that closely mirror those of Howe's work. The conventional reservoir is included for reference as well as a more detailed gas hydrate reservoir description for a case with a dissociating gas hydrate surface.

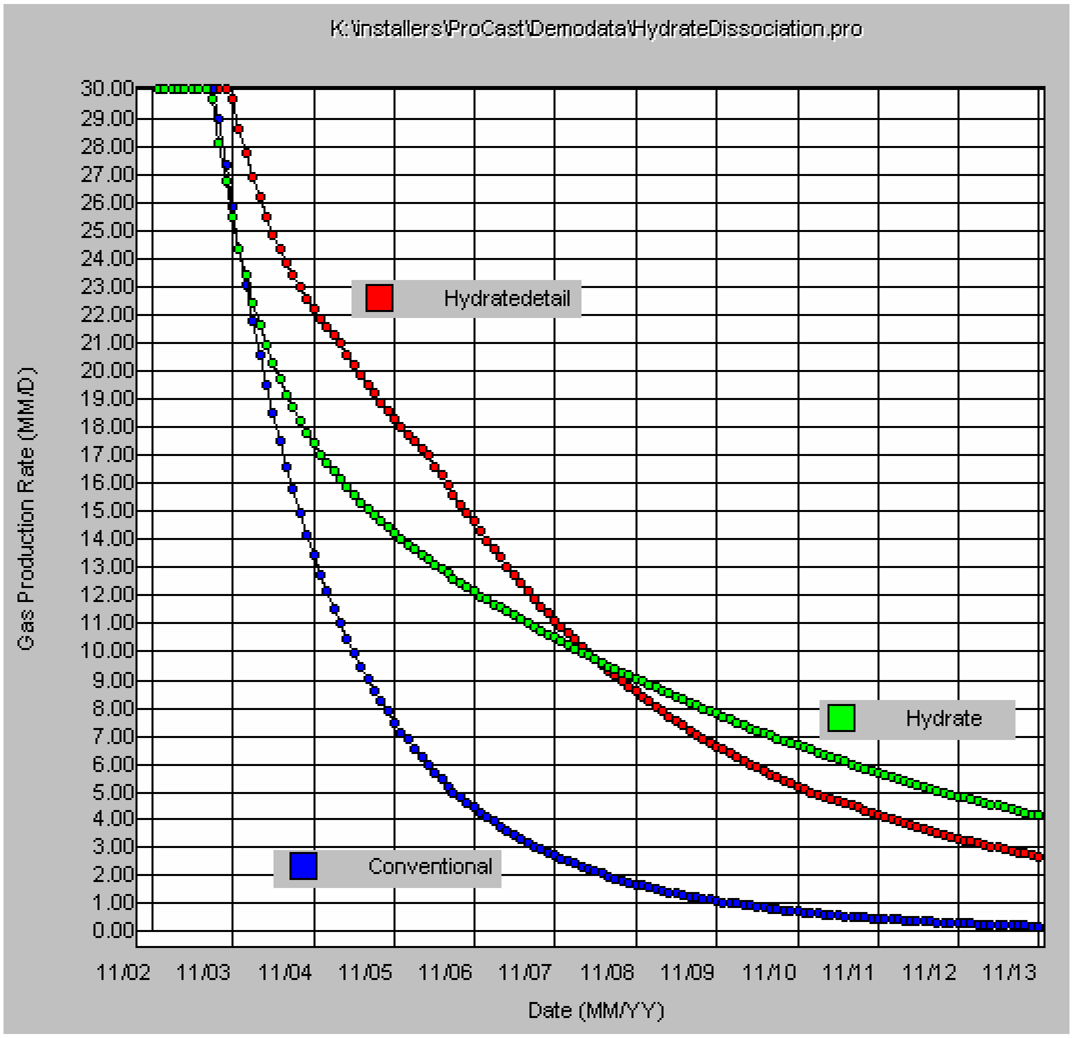


Figure 28: Gas production forecasts from ProCast beta modeling

Final improvements to the model will include the pressure decline experienced as pore space is exposed by the dissociating gas hydrate. Although tracking of water volumes released by the gas hydrate is possible, the lack of areal definition in the material balance treatment will preclude prediction of wellbore produced water volumes.

4.9.5 Future Work:

- Predict gas production performance by depressurization methods incorporating kinetics of gas hydrate decomposition non-isothermally.
- Calculate the water volume released from gas hydrate dissociation in "tank" and compare to Ryder Scott model water evolution of 20-30,000 BWPD versus projected gas rates.
- Run simulation scenarios using the Lawrence Berkeley National Laboratory's *EOSHYD2-TOUGH2* simulator, if available. *EOSHYD2* is specifically designed to model the dissociation of gas hydrates and would add more certainty to the results, while also allowing more flexibility in simulations, permitting experiment on the changes in kinetic values for instance. A *UAF* hydrate model will be revised and calibrated using modeling results and code from *LBNL*.

4.10 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 prospective areas within MPU for gas hydrate data acquisition and/or production testing operations. The associated project study by USGS as funded by the regional ANS BLM-USGS research has identified seismic attribute anomalies potentially associated with changes in pore fluid types (water, free gas, and gas hydrate) within reservoir (sand-prone) intervals. These studies will help BPXA determine whether or not to proceed into Phase 2 research.

5.0 CONCLUSION

Interim conclusions are presented at this stage in the research program. The first dedicated gas hydrate coring and production testing, NW Eileen State – 02, was drilled in 1972 within the Eileen gas hydrate trend by Arco and Exxon. Since that time, methane hydrates have been 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 potential commerciality of gas production from gas hydrate across a broad regional contact from adjacent free gas depressurization is demonstrated by 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) and corroborated by the results of the UAF and Ryder Scott Co. reservoir model research in presented in Section 5.9 of the December 2003 Quarterly report and herein. This collaborative research project will verify the size of the potential resource, determine the extent of reservoir/fluid compartmentalization, and validate potential production techniques.

6.0 PROJECT AND RELATED REFERENCES

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6.6 Short Courses

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7.0 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
JOGMEC	Japan Oil, Gas, and Metals National Corporation (reorganized from JNOC 1/04)
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

8.0 APPENDICES

8.1 APPENDIX A: Project Task Schedules and Milestones

8.1.1 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

8.1.2 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 March 2004 technical progress report.

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