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

June 2006 Quarterly Technical Report
Fifteenth Technical Quarterly Report: inclusive of January 2005 – June 2006
(Technical Quarterly Reports Ten through Fourteen Waived)
Cooperative Agreement Award Number DE-FC-01NT41332

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

by
BP Exploration (Alaska), Inc.
Robert Hunter (Principal Investigator)
P.O. Box 196612
Anchorage, Alaska 99519-6612
Email: hunterrb@bp.com
robert.hunter@asrcenergy.com
Tel: (907)-339-6377

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

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

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

July 31, 2006

DISCLAIMER

ABSTRACT

Methane hydrates may contain significant offshore and onshore arctic gas resources. The Phase 1-2 reservoir characterization, development scenario modeling, and associated studies indicate that 0-12 TCF gas may be technically recoverable from 33 TCF in-place Eileen trend gas hydrate beneath industry infrastructure within the Milne Point Unit (MPU), Prudhoe Bay Unit (PBU), and Kuparuk River Unit (KRU) areas on the Alaska North Slope (ANS). Modeled production methods involve subsurface depressurization and/or thermal stimulation of pore-filling gas hydrate into gas and water components.

Phase 2 studies included rate forecasts and hypothetical well scheduling, methods typically employed to evaluate potential conventional large gas development projects. This work helped quantify: 1. potential recoverable gas resource using conventional petroleum technologies and 2. range of potential outcomes that could be narrowed by acquiring specific recommended data and field testing. This systematic appraisal is designed to help determine whether or not gas hydrate can become a technically and economically recoverable gas resource.

Reference case forecasts with type-well depressurization-induced production rates of 0.4-2.0 MMSCF/D predict that 2.5 TCF of gas might be produced in 20 years, with 10 TCF ultimate recovery after 100 years (typical industry forecasts would not exceed 50 years). The downside case envisions research pilot failure and economic or technical infeasibility. Upside cases identify additional potential if future field testing confirms upside modeling results of pressure-induced, thermally enhanced, or chemically stimulated gas hydrate dissociation into movable gas. Phase 3a field studies to acquire data were formally approved in January 2006 to help mitigate uncertainty in potential gas hydrate productivity. A Phase 3a stratigraphic test was planned, permitted, and ready to drill by March 2006. However, third-party delays with the rig and approaching end-tundra travel ice season led to well deferral. A Phase 3b production test is not currently approved by DOE or BP.

Determining successful gas production from gas hydrate would yield both methane and fresh water for potential use in existing or planned developments. The gas could potentially provide fuel-gas to reduce consumption of richer conventional gas, provide lean injection-gas for reservoir energy, provide fuel for potential viscous oil thermal recovery, or supplement future export-gas. The fresh water could potentially be used in waterfloods and/or in association with produced gas for steam injection. The gas hydrate-bearing reservoirs may also provide a future option for CO_2-sequestration option during future gas and associated CO_2 production.

ACKNOWLEDGEMENTS

This cooperative DOE-BPXA research project has helped to rekindle industry interest in the resource potential of shallow natural gas hydrate deposits. The DOE and BPXA recognize that this research could help determine whether or not methane hydrate may become an additional unconventional gas resource and their support of these studies is gratefully acknowledged.

Efforts of DOE National Energy Technology Lab staff Brad Tomer, Ray Boswell, Tom Mroz, Kelly Rose, and others and of DOE Arctic Energy Office staff Jim Hemsath and Brent Sheets have enabled continuation of this and associated research projects. Scott Digert and others at BPXA continue to promote the importance of this cooperative research within industry. The State of Alaska Department of Natural Resources through the efforts and leadership of Dr. Mark Myers, Bob Swenson, Paul Decker, and others has consistently recognized the contribution of this research toward identifying a possible additional unconventional gas resource and actively supported the Methane Hydrate Act of 2005 to enable continued funding of these studies.

The collaborative research team for this project deserves specific acknowledgement. The USGS has led gas hydrate research on the ANS for 2 decades; Dr. Tim Collett continues to promote the importance of this area to gas hydrate research and potential future development. Seismic studies accomplished by Tanya Inks at Interpretation Services and by USGS scientists Tim Collett, Myung Lee, Warren Agena, and David Taylor identified potential gas hydrate prospects within the MPU. Scott Wilson at Ryder Scott Co. has progressed University of Calgary (Dr. Pooladi-Darvish) and University of Alaska Fairbanks (UAF) adaptations of CMG STARS to an industry-standard production model of gas hydrate-bearing reservoir behavior and assessed the regional development potential of Alaska North Slope gas hydrate (if proven as a resource). Shirish Patil and Dr. Abhijit Dandekar have helped redevelop the UAF School of Mining and Engineering into an arctic regions gas hydrate research center. The University of Arizona reservoir characterization studies led by Dr. Bob Casavant with Dr. Karl Glass, Ken Mallon, Dr. Roy Johnson, and Dr. Mary Poulton have improved understanding of the structural and stratigraphic architecture and compartmentalization of the gas hydrate-bearing reservoir sands on the Alaska North Slope.

Current related studies of gas hydrate resource potential are too numerous to mention here. National Labs studies include Dr. Pete McGrail, CO_2 Injection, and Dr. Mark White, reservoir modeling, at Pacific Northwest and Dr. George Moridis, reservoir modeling, at Lawrence Berkeley. The Colorado School of Mines under the leadership of Dr. Dendy Sloan and the University of Texas A&M under Dr. Stephen Holditch continue to progress laboratory and associated studies of gas hydrate. The significant efforts of international gas hydrate research projects such as those supported by the Directorate General of Hydrocarbons by the government of India and by the Japan Oil, Gas, and Metals National Corporation (JOGMEC) with the government of Japan are contributing significantly to a better understanding of the resource potential of natural methane hydrate. JOGMEC and the government of Canada support of the 2002 and current Mallik project gas hydrate studies in Northwest Territories, Canada are gratefully acknowledged. This cooperative DOE-BPXA research project builds upon the accomplishments of many prior government, academic, and industry studies.

TABLE OF CONTENTS

1.0 LIST OF TABLES AND FIGURES

Appendix B Figures:

2.0 INTRODUCTION

The cooperative research between BP Exploration (Alaska), Inc. (BPXA) and the U.S. Department of Energy (DOE) is helping to characterize and assess Alaska North Slope (ANS) methane hydrate resource potential and is helping to identify technical and commercial factors that could enable government and industry to make more informed decisions regarding this possible unconventional energy resource. Results of Phase 1-2 reservoir characterization, reservoir modeling, schematic future development, and associated studies indicate sufficient potential to enable approval to proceed into an initial data acquisition Phase 3a stratigraphic test. A future production testing Phase 3b is a key goal of the Federal Research and Development program and may follow, but this remains to be evaluated. Collaborative research partners include U.S. Geological Survey (USGS), Arctic Slope Regional Corporation Energy Services, Ryder Scott Company, APA Engineering, University of Arizona, University of Alaska Fairbanks, and Pacific Northwest National Lab.

Methane hydrate may contain a significant portion of world gas resources within offshore and onshore arctic regions petroleum systems. In the United States, deposits of gas hydrate occur within pressure-temperature stability regions in both offshore and also onshore near-permafrost regions. The USGS estimates that clathrate hydrates may contain up to 590 TCF of in-place ANS gas resources (Figure 1). Over 33 TCF in-place potential gas hydrate resources are interpreted within shallow sand reservoirs beneath ANS production infrastructure within the Eileen trend (Figure 2). Gas hydrate accumulations require the presence of all petroleum system components (source, migration, trap, seal, charge, and reservoir). Future exploitation of gas hydrate would require developing feasible, safe, and environmentally-benign production technology within areas of industry infrastructure. In the United States, the ANS onshore and Gulf of Mexico (GOM) offshore are currently known to favorably combine these factors. The information and technology being developed in this onshore ANS program will be an important component to assessing the possible productivity of the potentially much larger marine hydrate resource.

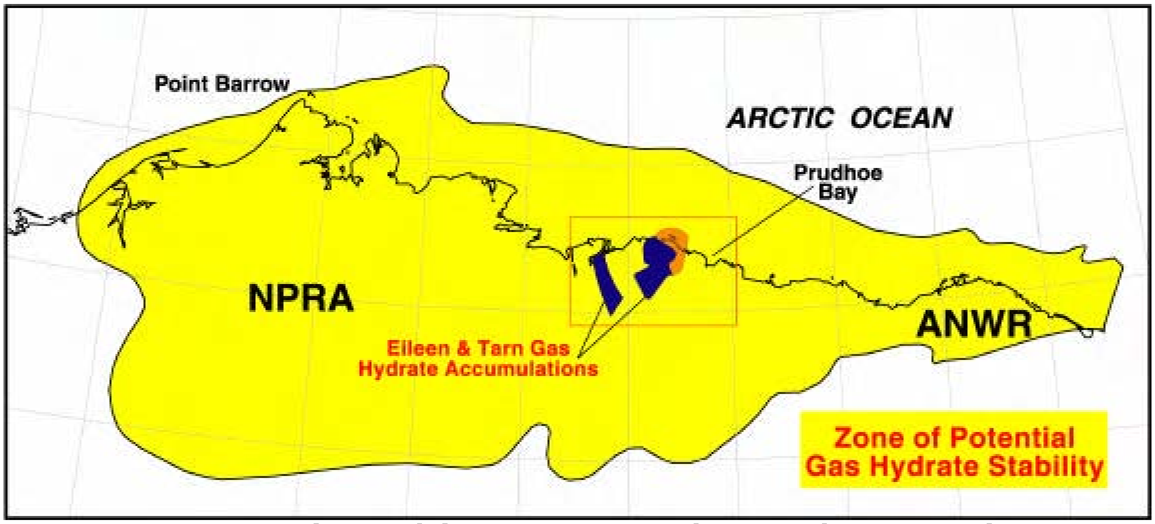


Figure 1: ANS Gas Hydrate Stability Zone Extent. The USGS has estimated 590 TCF methane in place in hydrate form in this region (Courtesy USGS).

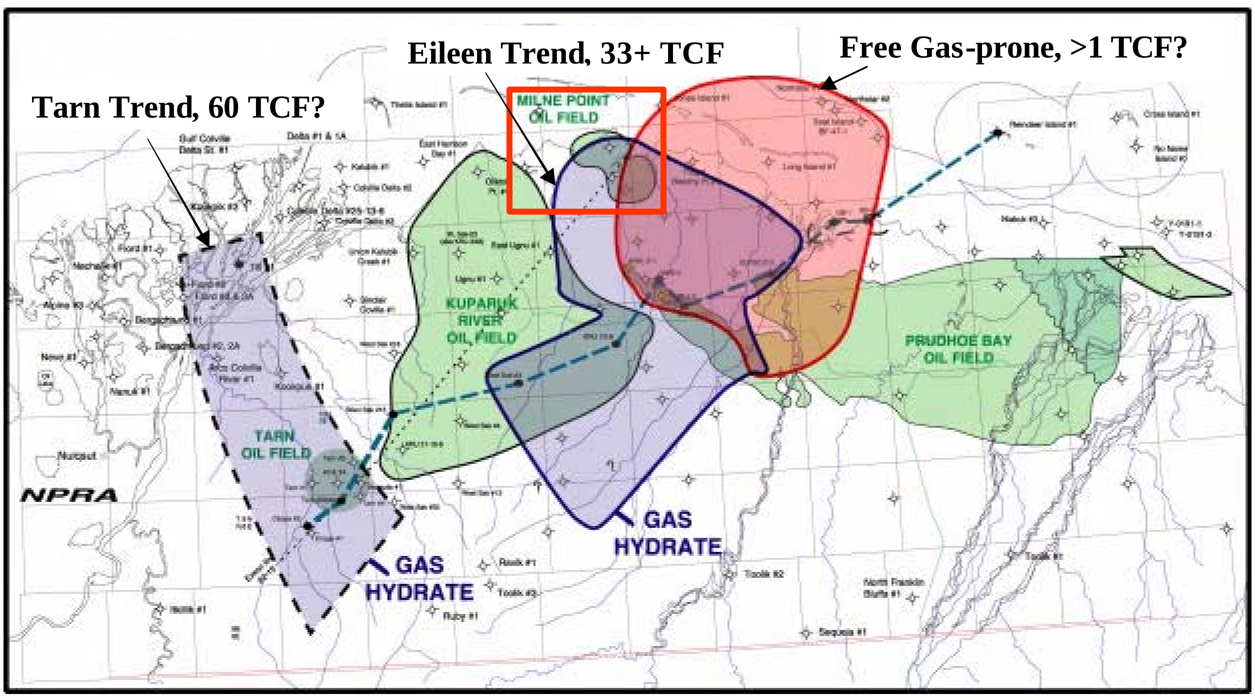


Figure 2: Eileen and Tarn Gas Hydrate Trends and ANS Field Infrastructure (modified after Collett, 1998).

In 1972, the existence of natural methane hydrate within ANS shallow sand reservoirs was confirmed by data acquired in the Northwest Eileen-02 well. Although up to 100 TCF in-place gas may be trapped within the gas hydrate-bearing formations beneath existing infrastructure areas, it has been primarily known as a shallow gas drilling hazard to the hundreds of well penetrations targeting deeper oil-bearing formations and has drawn little resource attention due to no ANS gas export infrastructure and unknown potential productivity. Characterization of ANS gas hydrate-bearing reservoirs and improved modeling of potential gas hydrate dissociation processes led to increasing interest to study gas hydrate production feasibility.

If gas can be technically produced from gas hydrate and if studies help prove production capability at economically viable rates, then methane dissociated from ANS gas hydrate could help supplement fuel-gas, provide additional lean-gas for reservoir energy pressure support, sustain long-term production of portions of the geographically-coincident 20-25 billion barrels viscous oil resource, and/or potentially supplement conventional export-gas in the longer term.

As part of a multi-year effort to encourage these feasibility studies, the DOE also supports significant laboratory and numerical modeling efforts focused on the small scale behaviors of gas hydrate. Concurrently, the USGS has assessed the potential in-place resource potential and participated in field operations with DOE and others to acquire data within many naturally occurring gas hydrate accumulations throughout the world. There remain significant challenges in quantifying the fraction of these in-place resources that might eventually become a technically-feasible or possibly a commercial natural gas reserve. This study estimates this potential ANS prize within the Eileen trend to help recommend future research, data acquisition, and field operations.

A “chicken and egg” problem has hindered unproven resource research and development in the past; an “unconventional” resource commonly requires a few positive examples before it can generate stand-alone interest from industry. This was true for tight gas resources in the 1950-1960’s, Coal-Bed-Methane plays in the 1970-1980’s and the shale gas resources in the 1990-2000’s. In each case, the resource was thought to be technically infeasible and uneconomic until the combination of market, technology (new or newly applied), and positive field experience helped motivate widespread adoption of unconventional recovery techniques in an effort to prove whether or not the resource could be technically and commercially produced. In an attempt to bridge this gap, the gas hydrate reservoir modeling efforts were coupled with a series of possible future development scenarios to quantify a suite of potential recoverable reserve outcomes.

These hypothetical development scenarios indicate that 0-12 TCF gas may be technically recoverable from 33 TCF in-place Eileen trend gas hydrate beneath industry infrastructure within the Milne Point Unit (MPU), Prudhoe Bay Unit (PBU), and Kuparuk River Unit (KRU) areas on the ANS. Reference case forecasts with type-well depressurization-induced production rates of 0.4-2.0 MMSCF/D predict that 2.5 TCF of gas might be produced in 20 years, with 10 TCF ultimate recovery after 100 years (typical industry forecasts would not exceed 50 years). The downside case envisions research pilot failure and economic or technical infeasibility. Upside cases identify additional potential recoverable resource. Additional static data acquisition and possible future production testing could help validate whether or not these upside model results might occur in a future potential development using pressure-induced, thermally enhanced, and/or chemically stimulated dissociation of gas hydrate into movable gas. Modeled production methods involve subsurface depressurization and/or thermal stimulation of pore-filling gas hydrate into gas and water components. Phase 2 studies included rate forecasts and hypothetical well scheduling, methods typically employed to evaluate potential conventional large gas development projects. This work helped quantify: 1. potential recoverable gas resource using conventional petroleum technologies and 2. range of potential outcomes that could be narrowed by acquiring specific recommended data during field operations.

Determination of the resource potential of gas hydrate and associated free gas resources could increase ANS gas resources. Proving technical production and commercial feasibility of this possible unconventional gas resource could lead to greater U.S. energy independence.

2.1 Project Open Items

Review of regional resource potential and field operations recommendations based on Phase 1 and 2 studies resulted in the January 2006 decision to proceed into field operations in the Phase 3a stratigraphic test. Quarterly reports 10-14 (January 2005 through end-March 2006) were delayed by preparations for this Phase 3a decision and associated well planning, permitting, data acquisition planning, and subcontracting. A topical report was submitted on the primary drilling prospect in June 2005. Status and Technical reports will be brought into contractual compliance by end-July 2006. Financial reports will be finalized by mid-August 2006. Third-party delays with the drilling rig selected to accomplish the Phase 3a stratigraphic test operation and approaching end-tundra travel ice season caused the mid-March 2006 decision to defer the stratigraphic test until early 2007 since no other qualified rig was available. Phase 3a stratigraphic test budget and scope-of-work definitization is in-progress. Contract amendments 10-11 initiated funds necessary for Phase 3a operations and associated studies following the mid-September 2005 Continuation Application.

2.2 Project Status Assessment and Forecast

Project technical accomplishments from January 2005 through end-June 2006 are presented by associated project task. The attached milestone forms (Appendix A) present project Phase 1 tasks 1 through 13 with task duration and completion timelines. Individual project status reports for each quarter will be submitted by end-July 2006 to enable tracking progress.

2.3 Project Research Collaborations

Project objectives significantly benefit from DOE awareness, support, and/or funding of the following associated collaborations, projects, and proposals. Section 5.4 provides additional detail on collaborative research accomplishments during the reporting period.

1. **Reservoir Model studies:** DOE NETL coordination of reservoir modeling through the efforts of Dr. Joseph Wilder and others significantly increased collaborative reservoir modeling efforts between this project, Japan, Lawrence Berkeley National Lab (LBNL), and Pacific Northwest National Lab (PNNL). This very important work should continue into simulation of field-scale gas hydrate bearing reservoirs. The studies to-date have facilitated a common understanding of how these different gas hydrate reservoir models handle the basic physics of gas hydrate dissociation processes within gas hydrate-bearing formations. Contributors to this effort include: Masanori Kurihara (Japan Oil Engineering Co., Ltd.), Yoshihiro Masuda (The University of Tokyo), Pete McGrail (Pacific Northwest National Laboratory), George Moridis (Lawrence Berkeley National Laboratory, University of California), Hideo Narita (National Institute of Advanced

Industrial Science and Technology), Mark White (Pacific Northwest National Laboratory), Joseph W. Wilder (National Energy Technology Laboratory, U.S. Department of Energy), Scott Wilson (Ryder Scott Company, Consultant to BP-DOE project), Timothy Collett (U.S. Geological Survey), and Robert Hunter (ASRC Energy Services; BP Exploration (Alaska), Inc.),. PNNL has adapted the reservoir modeling package STORM to model gas hydrate dissociation behavior.

2. **DE-FC26-01NT41248:** UAF/PNNL/BPXA studies to investigate the effectiveness of CO_2 as an enhanced recovery mechanism for gas dissociation from methane hydrate. DOE currently supports this associated project research which may help facilitate a future field test of this technology.
3. **UAF/Argonne National Lab project:** This associated project was approved for funding by the Arctic Energy and Technology Development Lab (AETDL), forwarded to NETL for review, and was funded in mid-2004. The project is designed to determine the efficacy of Ceramicrete cold temperature cement for possible future gas hydrate drilling and completion operations. Evaluating the stability and use of a cold temperature cement may enhance the ability to maintain the low temperatures of the gas hydrate stability field during drilling and completion operations and help ensure safer and more cost-effective operations. In early 2006, the Ceramicrete material was approved for field testing at the BJ Services yard in Texas (primary contact Lee Dillenbeck). Although Ceramicrete was not yet field tested in time to be evaluated for use in 2006 Alaska operations, successful future yard testing of the material may enable limited testing in Alaska project operations. We remain in communication with ANL and BJ Services. A meeting to discuss yard testing of Ceramicrete is scheduled in Tomball, Texas (north of Houston) on August 8, 2006. Our UAF PI will participate in the meeting.
4. **Precision Combustion, Inc. (PCI) – DOE collaborative research project:** Potential synergies from this DOE-supported research project with the BPXA – DOE gas hydrate research program were recognized in December 2003 by Edie Allison (DOE). Communications 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 applications in either viscous oil or future gas hydrate operations. BPXA provided a letter in April 2004 in support of progression of PCI's project into their phase 2: prototype tool design and possible surface testing; limited communications are continuing.
5. **UAF shallow resource (gas hydrate and viscous oil) research initiatives:** UAF proposed that AETDL fund Alaska shallow resource research initiatives. This associated research could provide benefits to this project. It should be noted that industry could take a leadership role in these initiatives, similar to the approach taken in this project.
6. **Japan gas hydrate research:** Progress toward completing the objectives of this project remain aligned with gas hydrate research by Japan Oil, Gas, and Metals National Corporation (JOGMEC), formerly Japan National Oil Corporation (JNOC). JOGMEC remains interested in research collaboration, particularly if this project proceeds into production testing operations. Communications with JOGMEC were limited during the reporting period, but recently reinitiated in June 2006, to inform JOGMEC that the BP-DOE project is proceeding into Phase 3a stratigraphic test field operations. JOGMEC may proceed into future (2007-2008?) production test operations at the Mallik field site.
7. **India gas hydrate research:** India's Institute of Oil and Gas Production Technology

(IOGPT) indicates a continued interest in participating with the BPXA – DOE research program in correspondence/discussion with DOE. BPXA has not initiated contact with IOGPT. However, Dr. Tim Collett, partner in the BPXA research team, and Ray Boswell, DOE gas hydrate program lead are currently leading and participating in, respectively, certain aspects of the data acquisition at multiple offshore India field sites. The value of international research collaboration is recognized.

8. **Korea gas hydrate research:** Korea may be developing a gas hydrate research program. They have discussed potential participation in future Alaska gas hydrate research with USGS. BPXA has not initiated contact with Korea.
9. **U.S. Department of Interior, USGS, BLM, State of Alaska DGGS:** An additional collaborative research project under the Department of Interior (DOI) provides significant benefits to this project. The BLM, USGS, and the State of Alaska recognize that gas hydrate is potentially a large untapped onshore energy resource on the ANS. To develop a more complete regional understanding of this potential energy resource, the BLM, USGS and State of Alaska Division of Geological and Geophysical Surveys (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. Information generated from this agreement will help guide these agencies to promote responsible development if this potential arctic energy resource becomes proven. 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 current industry infrastructure.

2.4 Project Performance Variance

Detailed project performance variance is noted by quarter in the Project Status Reports on standard forms 4600. BPXA and DOE decided in mid-January 2006 to acquire additional data in Phase 3a stratigraphic test well operations. However, this well was deferred in mid-March 2006 due to third-party rig delays and approaching end-tundra travel ice limits.

3.0 EXECUTIVE SUMMARY

This Quarterly report encompasses project work from six quarters from January 1, 2005 through end-June 2006. Coverage of research during this reporting period is comprehensive and this report is submitted in lieu of individual quarterly reports for this timeframe. Project communications between BP-DOE during the reporting period were accomplished via alternative means including June 30, 2005 Drilling and Data Acquisition Planning Topical Report; July 25, 2005 Quarterly report covering July 2004 through end-December 2005; regularly scheduled teleconferences; electronic and paper correspondence; scheduled meetings; internal project conferences; external conferences; and regularly weekly scheduled Phase 3a stratigraphic test well planning meetings. Future quarterly reports will be submitted within 30-60 days of the end of each quarter. Sections 4 and 5 provide detailed project tasks report. The below bulleted summary highlights project accomplishments during the reporting period:

- Submitted combined Quarterly technical report through end-December 2004 in July 2005
- Submitted Drilling and Data Acquisition Planning Topical Report in June 2005
- Submitted Status and Financial reports through March 2005

- Maintained project electronic and hardcopy files, documentation, and backups
- Updated project contracts for phases 2 and 3a and modified scope-of-work and budget
  - Modified scope-of-work to assess potential regional resource development scenarios and to plan and implement stratigraphic test well operations
  - Reviewed Draft Phase 2 SOW/budget with BP and DOE
  - Input scope-of-work and budgets to Amendments 8-12 and updated subcontracts
- Presented and discussed Phase 1 and 2 project summary and Phase 3a project plans, budget, and issues at DOE NETL in Morgantown in April 2006
- Prepared agendas, briefed management, and held meetings with DOE, industry, Alaska State, and Federal government in Houston and Anchorage (June 2005)
- Contributed to April 2006 meetings on Barrow, Alaska gas hydrate research proposal
  - Identified gas hydrate presence risk and discussed phased program to mitigate risk
  - Identified potential synergies to BP-DOE Alaska North Slope research program
- Responded to multiple media inquiries on project results, significance, and future plans
- Maintained limited project communications with JOGMEC gas hydrate research program
- Reviewed downhole heating methods for application to potential production testing
  - Included electromagnetic, radio-frequency, electrical, and downhole combustion
- Evaluated value of and participated in multiple invited technical conferences
  - Provided project input to State Department gas hydrate conference (April 2005)
  - Presented project summary for DOE Advisory Committee meeting (June 2005)
  - Prepared and presented 3-panel project poster, AAPG Calgary (June 2005)
  - Helped plan, presented project summary, and contributed to gas hydrate workshop, co-sponsored by State of Alaska and USGS (August 2005)
  - Presented project summary for DOE Advisory Committee meeting (April 2006)
  - Presented project summary to AAPG/SPE Pacific Section Conference (May 2006)
  - Declined participation in several non-essential invited technical conferences
- Presented project results and plans to BP Technical Advisory Committee (August 2005)
  - Project was one of six Alaska "emerging technology" areas of interest
- Submitted project to BP-internal Helios awards program (June 2005 and June 2006)
- Participated in viscous oil technology development meetings with BP and Schlumberger
  - Worked potential synergies of viscous oil to gas hydrate technology development
- Reviewed and responded to Federal and State initiatives designed to encourage gas hydrate testing, research, and development
  - Responded to Federal (BLM/MMS) Rulemaking on royalty relief incentives
  - Testified to State of Alaska "challenged" gas/oil resource development incentives
- Presented MPU seismic study and gas hydrate prospects to MPU staff and management
- Planned and coordinated Phase 2 reservoir modeling and regional resource assessments
  - Completed gas hydrate regional development scenario assessment to help facilitate decision to proceed into Phase 3a stratigraphic test
- Initiated long-lead well permit discussions to allow potential future well operations
- Developed long-lead materials and rig plans to allow possible future well operations
- Prepared Continuation Application, Budget, Decision Support Package, and Authority to Negotiate documents to support January 11, 2006 Phase 3a stratigraphic test approval
- Provided operational integrity and HSE requirements for stratigraphic test operations
- Completed NEPA Environmental Questionnaire with inputs from BP HSE and Drilling

- Prepared initial procedures, plans, and cost estimates for stratigraphic test well operations
- Planned Stratigraphic Test Well and held regular weekly meetings with BP/DOE/team
  - Developed and implemented task schedules for well permits, materials, plans
  - Identified critical tasks and path for well permits, materials, contracts, and rig
  - Documented risks, addressed concerns, and developed plans to mitigate risks
  - Developed contacts and contracts with appropriate operations subcontractors
  - Prepared and checked surface ice pad/road and well bottom hole location (BHL)
  - Developed agenda, convened, and moderated weekly well planning meetings
    - Provided task status updates and coordinated well operations plans
  - Selected ice road route to ensure safe access within existing infrastructure
  - Developed logging-during-drilling, wireline, and MDT evaluation program
  - Evaluated cement program options and initiated discussions with Schlumberger
  - Evaluated mud program and incorporated DrillCool, Inc. mudchilling system
  - Planned core program and procedures with Corion (ReedHycalog)
  - Planned core handling and processing program with OMNI and others
  - Initiated and reviewed detailed plan of operations for well permits
  - Initiated and reviewed drilling and data acquisition time and cost plans
    - Determined inability to drill well due to third party rig delays and approaching end-of-tundra travel and ice season drilling (March 14, 2006)
    - Notified DOE and subcontractors of drilling delay and test deferral
  - Developed, reviewed, and submitted detailed Phase 3a program drilling, data acquisition, and data evaluation budget
- Initiated review of potential alternative gravel pad options for future Phase 3 test site(s)
  - Evaluated potential gas handling options for possible future production test well
    - Evaluating potential GTL facility synergy with Alchem Field Services, Inc
- Completed Phase 1 and 2 stratigraphic and structural studies within MPU and expanded these studies into Eileen trend area-of-interest within PBU and KRU
- Initiated facies analysis, paleodepositional reconstruction, and AOI volumetrics
- Completed formation damage assessment experimental setup and studies

4.0 EXPERIMENTAL

During the reporting time period from January 2005 through end-June 2006, primary experimental activities were:

1. UAF studies limited to minor experiment apparatus design, setup, and execution,
2. Continuation of UA reservoir and fluid characterization using 3D seismic and well data,
3. Continued reservoir and development scenario modeling.

4.1 TASK 5.0, Logging and Seismic Technology Advances

Prior quarterly reports and the June 30, 2005 topical report document seismic attribute study within the Milne 3D seismic data and the interpreted relation between seismic amplitude and gas hydrate-bearing zone thickness and saturation within 20-50 foot thick (relatively thin-bedded) gas hydrate-bearing formations. The Mt Elbert-01 stratigraphic test well (Phase 3a) data acquisition wireline logging and coring program was designed to delineate this direct seismic detection of thickness and pore fluid saturation within these interpreted gas hydrate-bearing reservoirs. Seismic modeling and interpretation confirm that seismic velocity, amplitudes, and wavelet character may respond to fluid and reservoir changes within the gas hydrate-bearing reservoirs. Multiple gas hydrate-bearing prospects have been interpreted within fairways of the Eileen gas hydrate trend within the MPU. The Mt Elbert-01 stratigraphic test well is designed to delineate the highly-ranked Mt Elbert gas hydrate prospect. Sections 5.8 and 5.11 provide additional details on data acquisition planned within this well.

4.2 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 throughout the MPU, KRU, and PBU Eileen trend area-of-interest. Progress continues on geologic/geophysical project tasks. Full integration of well and seismic data interpretations remains incomplete. Section 5.6 provides additional details, results, recommendations, and conclusions.

4.3 TASK 7.0: Drilling, Completion, and Production Lab Studies

The University of Alaska Fairbanks (UAF) gas hydrate phase behavior and relative permeability laboratory studies were presented in Quarterly Report 9 (July 25, 2005). Further experimental studies were suspended during the reporting period pending decision to acquire additional field data in Phase 3a studies. The phase behavior and relative permeability experiments conducted on gas hydrate-bearing porous media would be setup to study core samples collected within the Eileen trend within the proposed Mt Elbert-01 stratigraphic test well. Additional experiments are planned pending collection of data from this well. UAF refined standard testing procedures to evaluate formation damage using completed experimental apparatus. Section 5.7 provides additional details, results, and recommendations.

5.0 RESULTS AND DISCUSSION

Project technical accomplishments from January 2005 through end-June 2006 are presented in chronological order by associated project task.

5.1 TASK 1.0: Research Management Plan

Task schedules for phases 1, 2, and 3a are presented in attached milestones forms (Appendix A). Project expenditures are reported separately on financial forms 269A and 272. Project status reports for each quarter are reported separately on forms 4600.

- Updated project contracts and modified scope-of-work and budget as needed
    - Prepared, reviewed, and approved Phase 2 Statement of Work and budget
        - Designed to assess regional resource potential and develop operations plan
        - Input project Statement of Work and budgets into Amendments 8-12
        - Updated subcontracts accordingly
    - Executed contract amendments 8, 9, 10, and 11
    - Received contract amendment 12 for additional Phase 3a funds allocation
    - Submitted Continuation Application (9/12/05)
    - Implemented scope-of-work and budget to initiate stratigraphic test operations plans
    - Prepared project budget estimates and tracked subcontracts spend/invoices
- Participated in project teleconference discussions with DOE project manager
- Prepared agenda, briefed management, and held DOE Anchorage meetings 6/9-10/05
    - BP: Discussed well operations decision and contract timing
    - AOGCC, DNR, ExxonMobil, ASRC Energy Services, ConocoPhillips

- Coordinated, compiled, and wrote project status, technical, and financial reports
  - Submitted combined Quarterly technical report encompassing project work period from July 1, 2004 through end-December 2004 (in July 2005)
  - Submitted Drilling and Data Acquisition Planning Topical Report (June 2005)
  - Submitted Status and Financial reports through March 2005
  - Updated U.S. Treasury ASAP protocols as-needed
- Prepared project briefs and coordinated Phase 2 results and Phase 3a plans documentation
  - Presented project summary for DOE NETL at Morgantown, April 2006
  - Discussed budget, Phase 3a plans, and outstanding issues with CO and COR
- Monitored scope-of-work task accomplishments and coordinated change modifications
- Maintained current contacts and specifications for U.S. Treasury ASAP system
- Prepared and presented Phase 1 and 2 resource characterization, modeling, and regional resource development scenario study results
- Developed well operations plans and procedures for stratigraphic test well (Phase 3a)

5.2 TASK 2.0: Provide Technical Data and Expertise

- Planned and coordinated reservoir modeling work, meetings, teleconferences with DOE NETL reservoir modeling cooperative studies
- Prepared and executed project electronic file backups and maintained hardcopy files
- Provided and reviewed maps for reservoir and regional development modeling studies
- Transferred and reviewed gas hydrate zone polygon maps for regional development study
- Reviewed university publications and theses and recommended modifications
- Participated in meetings, teleconferences, and correspondence regarding Barrow, Alaska gas fields area gas hydrate research proposal
  - Met with research proposal team and USGS in Barrow (April 4-5, 2006)
  - Identified gas hydrate presence risk and discussed phased program to mitigate risk
  - Identified potential synergies to BP-DOE Alaska North Slope research program
  - Recommended inclusion of UAF research team for increased research synergy
  - Reviewed pre-proposal and proposal prior to submission by North Slope Borough

5.3 TASK 3.0: Wells of Opportunity, Data Acquisition

- Monitored BP drilling schedules and communicated with BP operations groups
- Discussed potential wells of opportunity with ConocoPhillips within the KRU prior to 2005-2006 exploration ice pad drilling season

5.4 TASK 4.0: Research Collaboration Link

- Reviewed, edited, wrote, and approved specific external publications
  - Reviewed gas hydrate literature and recent developments
    - Maintained and transferred knowledge of relevant other-project research
  - Edited relative permeability publication with University of Alaska Fairbanks
  - Prepared, reviewed, and compiled team input to 2006 Pacific Section SPE manuscript draft for presentation and publication
    - Draft was not approved, but essential results are included in this report
    - Changed presentation venue from SPE poster/publication to AAPG oral
    - Presented project to AAPG/SPE Anchorage meeting on May 9, 2006

- Responded to multiple media inquiries on project results, significance, and future plans
  - BP-approved responses help manage external expectations
- Maintained project electronic and hardcopy files, documentation, and backups
- Reviewed downhole heating methods for application to potential future production test(s)
  - Included electromagnetic, radio-frequency, electrical (conduction & induction)
    - Note JOGMEC initiated and dropped earlier EM initiative
  - Downhole combustion; maintained dialog with Precision Combustion, Inc. (PCI)
    - Initiated dialog between PCI and BP-led viscous oil development team for potential future technical field trials
    - Presented separate proposal to AETDL; proposal not funded
    - Alaska viscous oil team may consider future application or test
    - Considered application at Alberta Research Council test site
- Wrote carbon sequestration demonstration proposal related to gas hydrate project
  - Discussed proposal with potential CO_2 Sequestration Partnerships
  - Proposal did not pass BP-internal review
  - Proposal would have studied potential to sequester CO_2 within ANS gas hydrate
  - Difficulty in CO_2 source; current ANS CO_2 not separated (no export line for gas)
    - Would have required trucking CO_2 from Washington state
- Evaluated value of participation in multiple invited technical conferences
  - Selected technical conferences in which to present project interim results & plans
    - Prepared, reviewed with BP, and presented project summary for DOE Advisory Committee meeting, Galveston (June 2005)
    - Prepared and presented 3-panel project poster, AAPG Calgary (June 2005)
      - Participated in AAPG Gas Hydrate Subcommittee meeting
    - Provided project input to but not direct participation in April 2005 State Department gas hydrate conference
    - Helped plan and participated in August 2005 gas hydrate workshop
      - Co-sponsored and results published by State of Alaska and USGS
      - Successfully attracted multiple industry/government stakeholders
    - Provided input to and approved AAPG Rocky Mountain Section presentation, September 2005 in Jackson, Wyoming for MPU gas hydrate prospect study
    - Prepared, reviewed with BP, and presented project summary for DOE Advisory Committee meeting, Washington D.C. (April 2006)
    - Presented project summary to well-attended joint AAPG/SPE Pacific Section Conference, Anchorage (May 2006)
  - Declined participation in multiple invited technical conferences
    - March 2005 Intercontinental Drilling Program in Germany
    - May 2005 Victoria, Canada gas hydrate conference
    - October 2005 CanCon (Catalyst Group) "Catalysis for Future Energy and Fuel Demands" meeting in Philadelphia
    - December 2005 American Geophysical Union meeting in San Francisco
    - March 2006 Science and Technology Issues in Methane Hydrate R&D in Hawaii (conflict with stratigraphic test planned operations); NETL presented on behalf of BP-DOE project

        - April 2006 GOM Hydrate JIP/DOE Drilling Data & Hydrate Tool & Protocol Development Workshop (conflict with stratigraphic test planned operations)
- Presented project results and plans with DOE NETL to Exxon (June 2005; Houston upstream research and Alaska) and ConocoPhillips (June 2005) and maintained dialog with staff from both companies
- Presented project results and plans to BP Technical Advisory Committee (August 2005)
    - Project 1 of 6 Alaska technology areas presented to this prestigious committee
    - Wrote 1 page summary and 15 page extended abstract pre-read for Committee
    - Positive reaction of Committee to research results and plans; caution to manage external expectations and recognize timeline to potentially identify new resource
    - Presented project summary PowerPoint slides to BP management and Committee
    - Updated and presented 3-panel poster to BP management and Committee
- Submitted project to BP-internal Helios awards program (June 2005 and June 2006)
    - Enabled increased corporate awareness of research program goals and potential
- Participated in viscous oil technology development meetings with BP and Schlumberger
    - Worked potential synergies of viscous oil to gas hydrate technology development
    - Evaluated viscous oil production technologies & potential synergies to possible future gas hydrate production technology
        - Attended presentation by Farouq Ali and discussed analogy to gas hydrate
        - Recognized major issue of lead time to develop or test new technologies
        - Recognized Cyclic Steam Injection and SagD technologies most applied
- Evaluated Worldwide Gas Hydrate (WWGH) proposal for potential future application to gas hydrate production test (Phase 3b)
    - Held meeting, brainstormed, and recorded notes from 6/7/06 teleconference
- Reviewed and responded to Federal and State initiatives designed to encourage gas hydrate testing, research, and development
    - Prepared, coordinated review, and submitted response to Federal (BLM/MMS) Rulemaking on royalty relief incentives for gas hydrate development
    - Emphasized early research given some positive preliminary indications, but that production potential remains unknown (reason for this research)
    - Prepared gas hydrate testimony, coordinated review, and testified to State of Alaska unconventional ("challenged") gas and oil resource development incentives
- Maintained limited project communications with JOGMEC gas hydrate research program

5.5 TASK 5.0: Logging and Seismic Technology Advances

United States Geological Survey

USGS Principle Investigator: Timothy Collett

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

This project continued to fund a portion of consultant studies during the reporting period. The major portion of the research and contributions of USGS staff were funded internally by the U.S. Department of Interior. Major results of this study were reported in the June 30, 2005 Topical Report and the July 25, 2005 Quarterly Report for the period of June 2004 through December 2004. February 2005 presentation of this MPU seismic study and gas hydrate prospects to MPU staff and management resulted in an improved understanding of significance of project results.

5.6 TASK 6.0, Phase 1, 2 and 3a: Reservoir and Fluids Characterization

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

This section discusses gas hydrate research activities that were completed or are in progress between January 1, 2005 through June 30, 2006 at the University of Arizona (UA). The report documents significant progress in the regional MPU, KRU, and PBU reservoir characterization of the gas hydrate and associated free gas resources.

5.6.1 Phase 1 Reservoir Characterization Summary and Accomplishments

All of the UA subtasks designated for Phase 1 have been addressed and/or completed. Activities related to specific Phase 2 (e.g. Subtasks UA 2.1.1.1; UA2.1.1.2). are in progress. Structural-stratigraphic studies and multidisciplinary evaluations of gas hydrate and free-gas prospective areas and preliminary assessments of resource volumes within MPU have been completed. Preliminary seismic attribute analyses of gas hydrate and free-gas resources throughout the MPU area have been completed (figures 3-4) and await full integration with completed log-based evaluations. Structural-stratigraphic linkages will guide predominantly log-based assessments throughout the remaining (beyond MPU) Area-of-Interest (AOI) in Phases 2 and 3.

5.6.1.1 Regional AOI Stratigraphic Correlation, Facies, and Fluid Studies

5.6.1.1.1 Phase 1 Stratigraphic Studies (Subtasks 1.1.1A.1; 1.1.1A.3; 1.1.3.1)

The Phase 1 stratigraphic analyses and mapping concentrated on an interval from the mid-Eocene shale/siltstone unit (UA marker L_37-36) down to the top of the heavy-oil prone Ugnu sandstone formation (noted as correlation marker L_24 or T/Ugnu Ss) where gas hydrate resources and associated free-gas have been interpreted from earlier USGS studies. The Ugnu sands equate to USGS marker 11.

Independent lithostratigraphic sequence correlation markers (20+ surfaces) relating to the Gubik and Sagavanirtok (Sag) formations have been completed across the whole of the AOI within the MPU, KRU, PBU Eileen areas. Approximately 10 other correlation markers are defined beneath the Sag (e.g. Upper and Lower Ugnu sands, Upper and Lower WSak sands, etc.).

Good agreement was observed with USGS correlation units below USGS marker 16 (mid-Eocene thick marine siltstone unit) down to USGS marker 13. These lithostratigraphic (lithostrat) markers translated to the independent UA correlation scheme as marker L_36 through L_33. The UA scheme identified more units within the lower portion of the Sag. This marker defines the top of the uppermost sand member of the “Staines tongue” reservoirs within the AOI. Above this zone, stacked marine mouth bar sequences dominate the section and exhibit considerable “apparent” stratigraphic continuity and geographic extent based on net sand and net/gross isopach maps across the AOI and also within the MPU. This interval contains the majority of USGS and UA inferred gas hydrate-prone occurrences.

Between marker L_33 and the underlying L_31 marks a rapid transition from dominantly marine to fluvial-deltaic deposition. From zones L_31 down to the top of the L_24 (top Ugnu Sand), available mudlog descriptions and well log patterns reveal that thin-bedded mixed fluvial-deltaic sand units, and shallow reworked marine sand-rich units are the dominant reservoir facies types. This lower half of the Sagavanirktok is dominated by a major sequence of stacked coarse-grained channels and point bar deposits with associated intervening thin coals and fine-grained mudstone and siltstone units of varying thickness. Although these lithostratigraphic sequences appear to be fairly correlative across the AOI, detailed stratigraphic correlations and thicknesses of individual sands units within these sequences indicate limited reservoir continuity and extent are likely characteristic of the lower Sagavanirktok interval.

Regional structure, gross isopach, net sand, and net-gross sand maps have been completed for all lithostratigraphic sequences throughout the MPU and the whole of the AOI. These maps have been integrated with fault maps and fault-seal integrity studies, and are being used to guide the development of automated fluid and facies predictors, volumetric analyses, and support on-going and upcoming reservoir characterization studies.

All structural and stratigraphic mapping done to-date has been constrained to relatively thick intervals defined by lithostratigraphic markers. Within the MPU, however, a chronostratigraphic correlation framework has also been derived that links genetic, but variable reservoir sand distribution and quality within unconformity-bound intervals. The apparent value of this framework will be best realized in planned reservoir connectivity studies and associated reservoir modeling (non UA-task) to be accomplished within Phase 3. Planned for the first half of Phase 2 (2005) is a systematic slice-mapping of these units at the finer parasequence scale. This planned progression will provide a more robust and accurate characterization of the stratigraphic and structural elements that provide control on the distribution of gas hydrate and associated free-gas resources. Geologic mapping along with cross-section analysis have clearly shown that, in addition to faulting, stratigraphic pinchouts and intraformational truncations of reservoir units will play a definitive role in defining gas hydrate and associated free gas occurrence. Much of this phenomenon likely remains below the resolution of the 3D seismic. However, structural control may still play a significant role in gas trapping mechanisms as discussed in sections 5.6.2.1 and 5.6.2.4.

Enhancements of fluid and facies classifiers and the completion of the full-field stratigraphic-structural framework anticipated to be completed during Phase 2 studies will be instrumental in providing adequate prospect evaluation, given the lack of available shallow seismic data throughout the KRU and PBU Eileen areas. Reservoir modeling at the well scale would be able to take full advantage of the reservoir description derived from the seismic- and log-based characterization in the MPU and log-based derivatives throughout the KRU and PBU Eileen regions.

Phase 2 studies should complete the classification and mapping of reservoir facies, which was commenced in Phase 1 within the MPU, portions of the KRU, and across the rest of the AOI. Facies classes, derived from diagnostic log-patterns and validated by available mud log and core log descriptions, will be used to train and strengthen interpretation of outputs from on log-based expert systems and artificial neural network algorithms that may be used to help accurately identify facies and fluids in future prospective regions. These approaches are planned to be extended to interrogation of facies and fluids via seismic waveform analysis in Phase 2-3 studies. This attempt to develop a different seismic-based interwell analysis would be coupled with standard seismic waveform attribute studies currently in progress via the Landmark workstations. Resulting maps would be used to develop paleodepositional reconstructions of the gas hydrate-bearing sediments within the MPU and be related to the structural trends observed in sequence stratigraphic interpretations of MPU 3D seismic. This pilot work would be used to guide mapping throughout the AOI-wide gross interval, net sand, and net/gross isopach maps of selected lithostratigraphic intervals in the pursuit of understanding first-order structural-stratigraphic linkages.

5.6.1.1.2 Phase 1 MPU AOI Study (Subtask 1.1.1A.4)

Within only the MPU 3D seismic area, both litho- and chronostratigraphic sequences were defined, completed, and contrasted with the lithostratigraphic framework. Maps were generated, which demonstrate caution in evaluating in the extent of resource volumes and modeled reservoir extent and sand continuity. UA chronostratigraphic sequences throughout the MPU were based on log-based cross section interpretation of intraformational unconformities whose surfaces extended across the AOI and were identified by the truncation of individual sand units below the chronostratigraphic marker and the downlap or onlap of sand members and packages above the chronostratigraphic marker. Several of the upper marine dominated sequences were subdivided into 2-3 subunits represented by parasequence sets. Preliminary study of intraformational unconformities on the MPU 3D seismic data set was started in Phase 2 studies (2005). Continuation of the seismic sequence analysis is scheduled for Phase 2 activity as proposed. Data and study needed to confirm earlier UA time-depth conversions have been slow to materialize. Seismic sequences have been noted on some MPU seismic lines. Phase 2 will see better definition and mapping of interpreted seismic sequence units. They are thicker and less abundant than what is identified from well logs due to seismic resolution limits. In Phase 2, we hope to define and fully illustrate major seismic sequences across not only the MPU, but within the greater Eileen trend AOI (although no seismic data outside the MPU area is currently available to project studies).

5.6.1.2 Phase 1 Coal Study (Subtask 1.1.1A2 through 1.1.1A.4)

Preliminary analyses indicated that thin coal seams were often noted below some of the gas hydrate-bearing zones. This led to preliminary review of coal (lignitic, subittuminous) occurrence and thicknesses by lithostratigraphic interval to assess the spatial association of coals relative to inferred gas hydrate resource presence and reservoir sand units. Some wells with the greatest amount of coal (e.g. NW Eileen and MPK-pad areas) also exhibited the greatest amount of gas resource in the lower units (e.g. Staines tongue) overlying the coal-rich sections (L_30-29 and L_27-T/Ugnu). Preliminary results indicate that the location of coals may be indicative of a depositional low associated with the downthrown position relative to a nearby fault that repeatedly reactivates. This would also make these areas good candidates for sealing and trapping of gas over time. These results were presented in Quarterly Report #9, July 2005.

5.6.1.3 Phase 1 Volumetric Study (Subtasks 1.1.1A.2; 1.1.2.3)

Well log-based net pay mapping of interpreted gas hydrate and associated free-gas resources has been completed for all litho-stratigraphic intervals within the limits of the MPU. A draft report is on file (documented in Section 5.6.1.4 of Quarterly Report #9, July 2005) with a detailed final report still in-progress that addresses the procedures and outcomes of this comparative log-based and preliminary seismic attribute approach. The idea of taking on a comparative approach using several methods and data sets provides a range of resource estimates ranging from most likely through upsides. Reservoir net "sand" cutoff determinations involve studies of gamma-ray (GR) log analysis, normalizations requiring bulk shifting of log curves, editing of outlier GR data, contouring of GR mean values to determine areas affected by GR normalization, and manual quality-control. Gas hydrate and free-gas pay isopachs and volumetric tables are on file for each interval.

The UA team is also evaluating gas hydrate and free gas polygons using the USGS interpretations as shown in Figure 5 (this USGS data was also used in the regional development scenario modeling documented in Section 5.10). The UA analysis incorporates seismic attribute analyses, a new structural-stratigraphic model that links the structural architecture through time with basin formation and sand occurrence, changes in depositional facies, reservoir sand quality, and reservoir sand thickness.

Sand body facies identification and dimensions were reviewed in light of gas hydrate and associated free gas interpretations derived from log analyses and of automated fluid classifications-identifications (expert system and artificial neural network based).

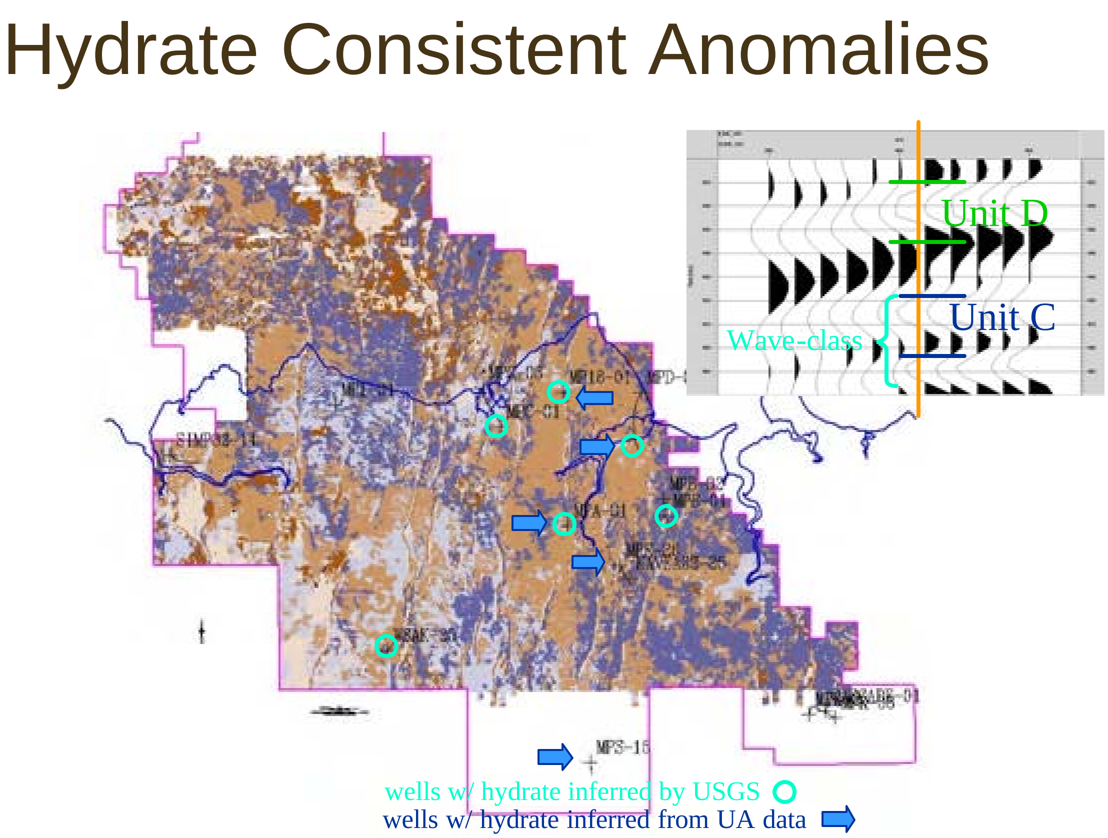


Figure 3: Seismic interpretation of waveform anomalies within the MPU 3D dataset are consistent with petrophysical interpretation of well data within gas hydrate-bearing sediments of the Sagavanirktok formation.

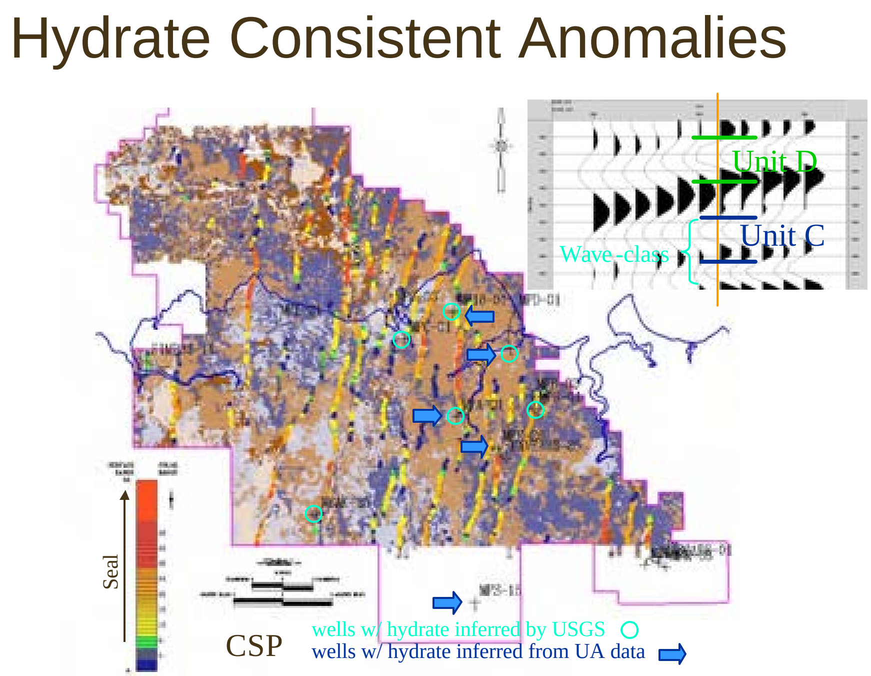


Figure 4: Fault throw and seal interpretations from the MPU 3D seismic dataset help define a potential relation between faulting and gas hydrate occurrence.

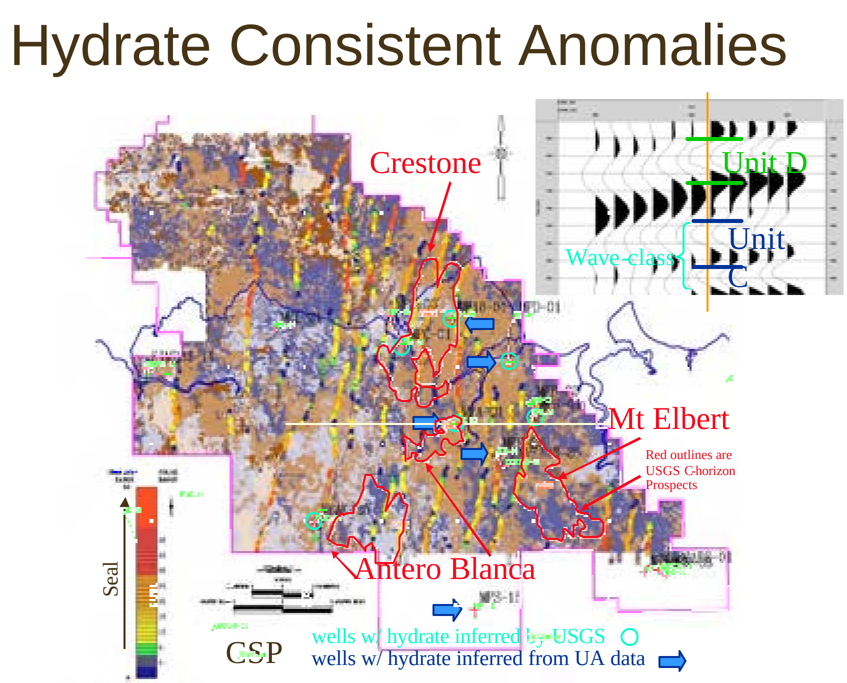


Figure 5: "Hydrate C" prospect outlines (equivalent to UA L_35-34 lithosequence) overlain on fault map interpretation from MPU 3D seismic dataset. The Mt Elbert prospect is evident in the southeastern portion of the map and is not penetrated by a well.

5.6.1.4 Phase 1 Structure and Seismic Studies (Subtasks 1.1.2.7, 1.1.3.1, 1.1.3.1, 1.1.3.2)

Lack of reservoir continuity can result from complex faulting whose sealing properties are variable laterally and vertically. Studies of fault complexity, fault distribution, fault throw, fault displacement timing, and fault seal capacity were completed across the MPU area and integrated with log-based and seismic attribute studies of gas hydrate occurrence (figures 6-8).

Fault maps were completed at all levels within the available MPU 3D seismic data set; fault throw and timing of dip-slip displacement per stratigraphic interval along all major fault traces have been mapped (Figure 7); 3D mapping of fault seal capacity along faults incorporates the amount of dip-slip and mapped shale content of the faulted interval. Fault compartmentalization is verified and mapped. Studies of the role of fault compartmentalization on facies distribution and quality, and distribution of gas hydrate and free-gas emplacement continue (Figure 9). Findings from MPU work as presented at the Hedberg Conference in 2004 (documented in the July 25, 2005 report) will guide on-going and final completion of this work.

Structural interpretations are available at all horizons and will be reviewed in light of fault reactivations (Hennes et al., 2004) and structural inversion of the KRU and MPU areas (Casavant, 2001, 2004)

Seismic waveform attribute analysis has been completed in Phase 1 studies to delineate potential seismic attribute changes and distribution related to lithology, reservoir quality (e.g. porosity), and fluid saturations. Definitive distinctions have been noted; however, definitive distinctions between the above requires further study to eliminate potential ambiguity. Confirmation of time-depth conversions and verification with geologic models will be necessary.

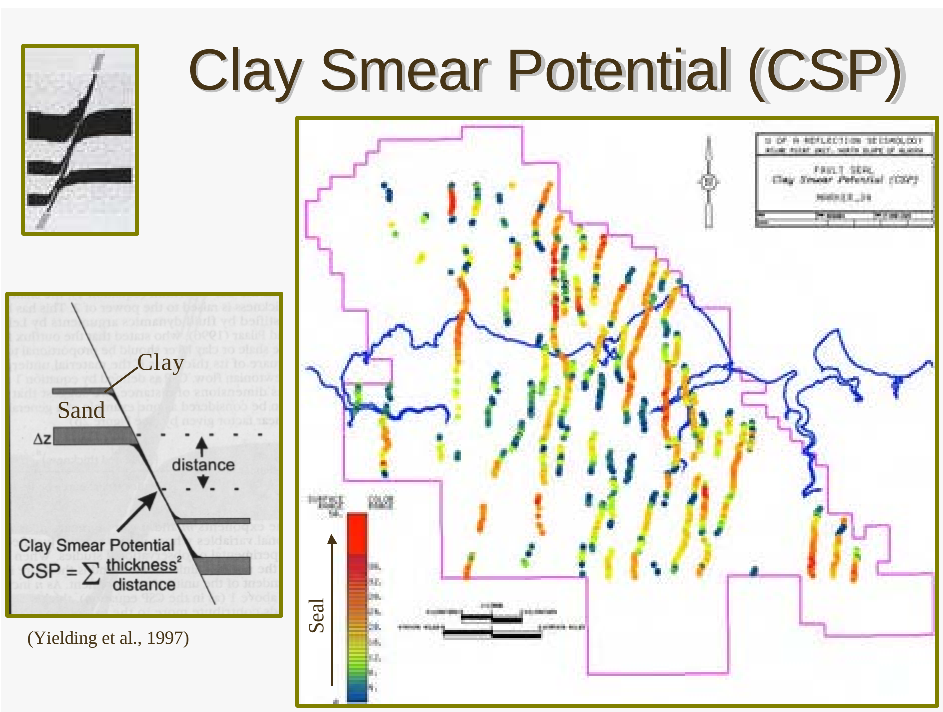


Figure 6: Fault interpretation of the MPU 3D seismic dataset enabled interpretation of "clay-smear potential", which may correlate to gas hydrate traps within the area-of-interest.

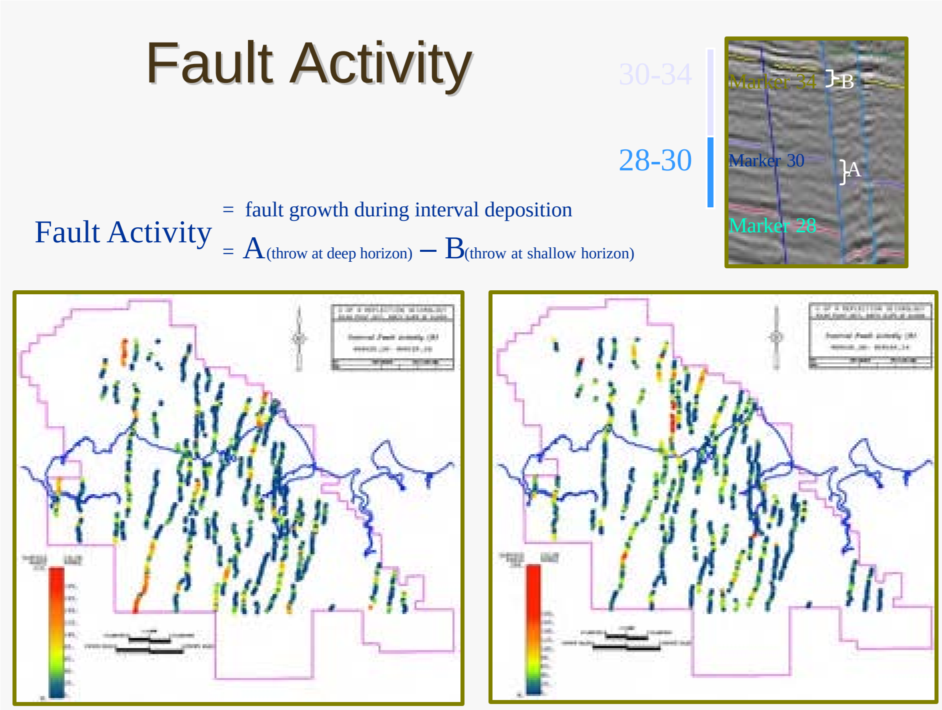


Figure 7: Pre- and syn-depositional faulting is interpreted from the MPU 3D seismic dataset and may influence gas hydrate trapping and thickness of gas hydrate-bearing sediments.

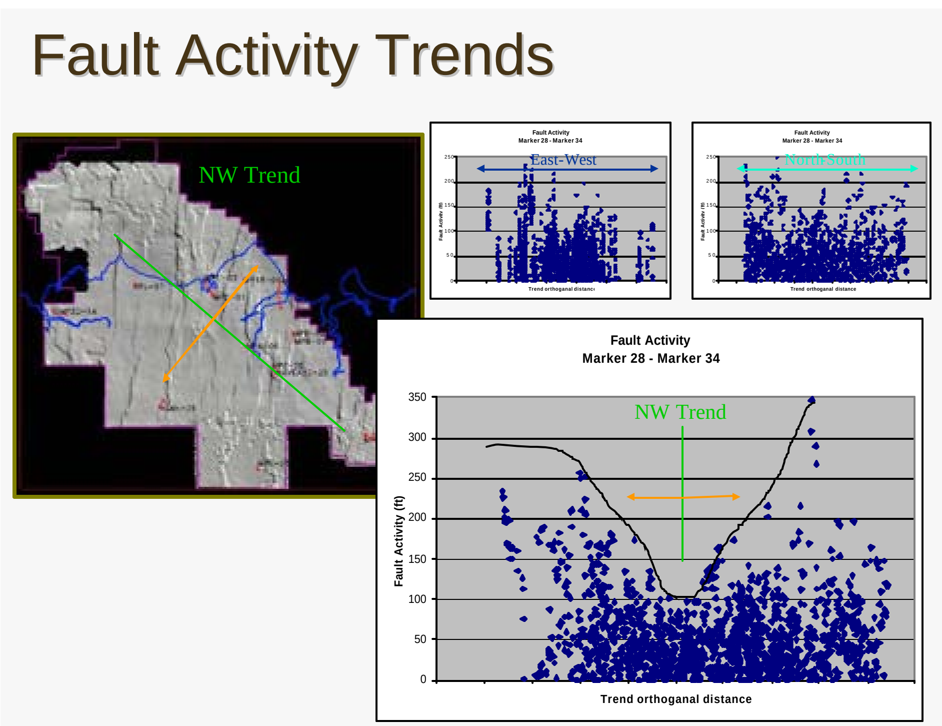


Figure 8: Fault trends interpreted from the MPU 3D seismic dataset may correlate to gas hydrate occurrence.

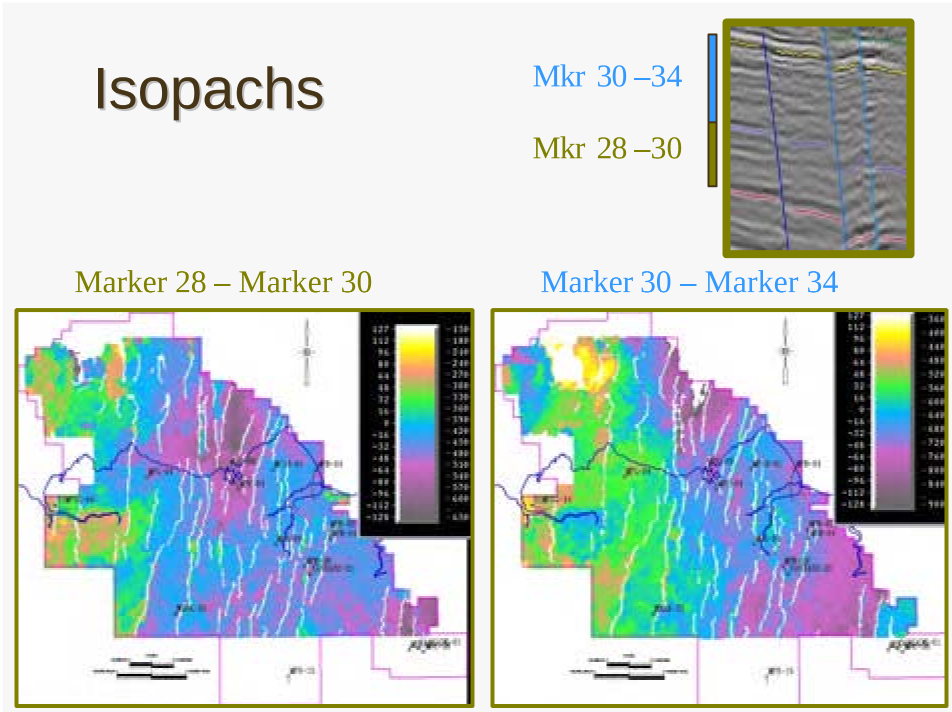


Figure 9: Isopach mapping between chronostratigraphic markers may reveal a linkage between faulting, sediment deposition, and gas hydrate occurrence.

The morphology and distribution of MPU faults and variations in sand deposition across the MPU area supports the presence transtensional deformation and basin formation that both pre-dated and influenced deposition of the Sagavanirktok and likely affected subsequent hydrocarbon emplacement.

5.6.1.4.1 Fault Relation to Interpreted MPU Gas Hydrate Accumulations

A preliminary study of potential spatial linkage between gas hydrate and associated free-gas occurrence in relation to fault proximity, fault morphology, and orientation was completed (figures 10-11). It was thought that such a study might prove insightful to help determine first-order attributes that would in turn help understand reservoir charge, seal, and fluid distribution. All statistical results and resource locations were linked to the appropriate UA seismic interval fault map. Preliminary results of this study indicated the following:

(1) Fault Proximity

- Wells that were closest to a fault are interpreted to have a greater chance of gas and gas hydrate occurrence (Figure 10). The closer a well is to a fault, the greater the amount of gas hydrate resource interpreted within that well.
- There appeared to be no correlation between the density of faults around a well and the occurrence or amount of gas hydrate resource. More work is needed along this line of study since time-depth relationships between the seismic and well logs require further validation.

(2) Fault Morphological Characteristics

- A positive correlation may exist between gas and gas hydrate accumulations versus crudely expressed fault complexity (Figure 11). In general the more fault splays that existed close to a well, the higher the chance of occurrence of interpreted gas hydrate and free-gas.

- This interpretation may relate to the presence of increased fracturing and increased permeability associated with greater displacement and deformation as well as preferred depositional settings (e.g. structural lows) produced by the faulting.

(3) Fault Orientation

- Sediments near faults with an azimuth > 10 degrees appear to be more gas hydrate-prone than those that have an average azimuth of less than 10.
- There may also be a relation of fault orientation to fluid-conductive faults and gas migration conduits.

Cartoon showing radius of spatial analysis

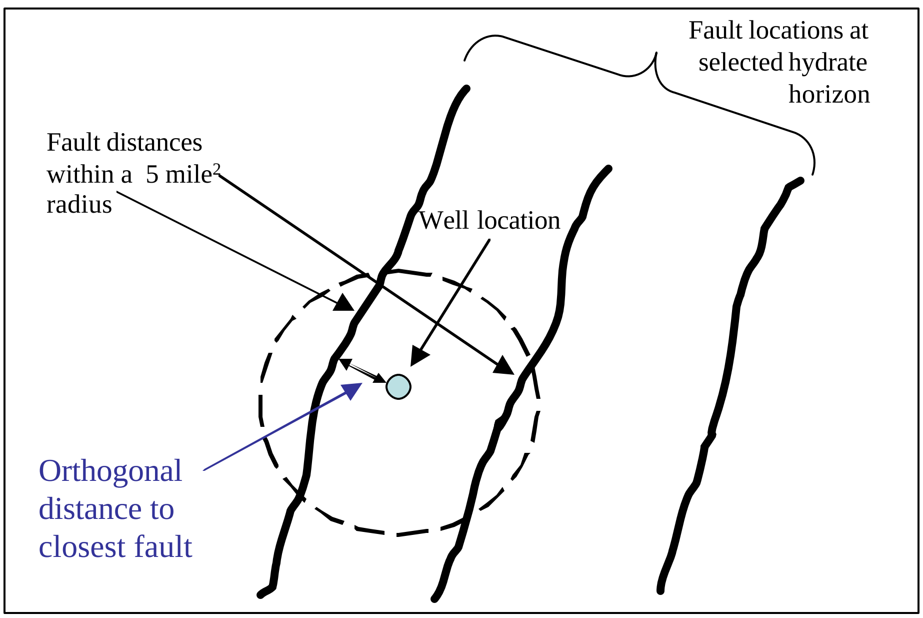


Figure 10: Spatial analysis of faulting relative to well location to help determine whether or not gas hydrate-bearing sediments are more common proximal to certain faults.

A larger area of seismic coverage and more well control may be required, however, for this type of analysis to be statistically robust. Plans are to expand the analysis outside of Milne Point to include the whole of the AOI if additional seismic data or fault map data become available. Linkage to paleodeposition and facies distribution have yet to be analyzed.

Density of major fault surfaces

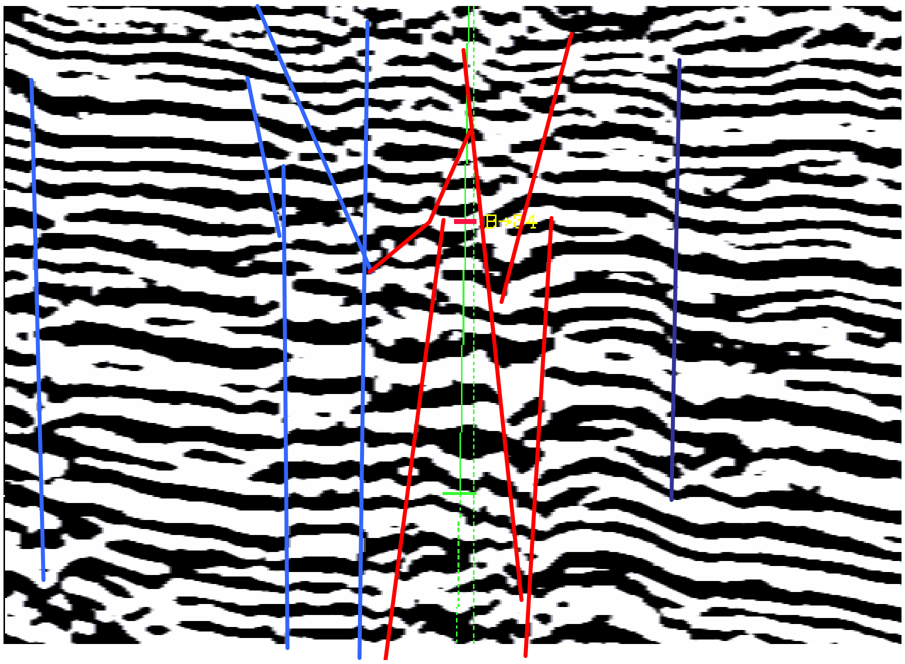


Figure 11: Fault density and complexity may correlate to gas hydrate occurrence.

5.6.1.5 Phase 1 Gas Hydrate Prospect Assessment (Subtasks 1.1.2.5, 1.1.2.6, 1.1.2.7)

Review of the UA 2004 Hedberg abstracts and presentations as summarized in Quarterly Report #9 (July 2005) reveals the integrative and multi-faceted nature of this endeavor. Normalization of key logs for net pay assessment and a preliminary comparative volumetric analyses were completed for both gas hydrate and associated free-gas occurrences within the MPU. Resource evaluation has incorporated geologic cross-section and map data at all geologic levels, as well as associated net pay volume maps, automated pay predictors, and an early volumetrics study derived from preliminary seismic attribute analyses. Both a new automated log-based expert system, and an independent but preliminary artificial neural network framework have been developed for identifying and mapping specific rock facies and fluid types (ice, gas hydrate, free-gas, oil, water, coal gas). The results have been encouraging and are being used to help guide log-based and seismic-based prospect studies.

Lithostratigraphic correlations have guided seismic time-depth (T/D) conversions based on seismic synthetics derived from available sonic logs, Vertical Seismic Profile (VSP), and seismic checkshot data within the MPU area. T/D relationships, derived for the MPU shallow seismic data set, appear close to matching seismic mapping horizons currently used within BP. Given that T-D conversions still appear to be somewhat different between the UA and USGS MPU seismic data sets, a future review and recalibration of the T-D conversions will be needed in order for UA to adequate link to or provide a definitive review and independent ranking of the prospect leads generated in the seismic prospect evaluation exercise of Task 5.0.

5.6.2 Phase 2 Reservoir Characterization Studies – March 2005 Status – (Subtasks 2.1.1, 2.1.2, 2.1.3)

The Phase 2 reservoir characterization will see the continuation, refinement and integration of Phase 1 characterization products and the extrapolation of findings and linkages (integrated seismic and log-data) into the KRU and PBU areas where seismic is currently unavailable. Continued work on the recognition and mapping of facies and fluid types from the seismic data is planned using combining standard seismic attribute analysis and neural network classifications. AOI-wide petrophysical-based analysis or gas hydrate and associated free-gas is anticipated to be completed for prospect analysis and well site selections. Emphasis will be placed on visualization of the geologic models that were started in Phase 1 and anticipated to be completed in Phase 2.

5.6.2.1 Phase 2 Stratigraphic Framework Summary

- A second, more detailed AOI regional correlation exercise is nearly completed, is linked and adapted to prior MPU stratigraphic framework, and will result in revised and finalized well log-based interpretations of lithostratigraphic and sequence stratigraphic picks and frameworks across KRU and PBU.
- AOI cross section generation and interpretation will be completed by mid-March 2005. New surface picks to be re-entered into UA database by end March 2005.
- Previous gross interval units, used for MPU correlation work, have now been further subdivided into subunits comprised of parasequence and parasequence sets in order to achieve more detailed analysis of facies architecture and their linkage to hydrocarbon occurrence, which was first noted in the Phase 1 MPU analysis.
- Revised and detailed set of stratigraphic maps, structure maps cross-sections and unit statistics should be available for review/presentation in late-April 2005.
- These layers and associated heterogeneities related to facies dimensions/reservoir properties should serve as the framework surfaces in future 3D reservoir and production modeling grids and volumetric estimates in both MPU and rest of AOI.
- Model intervals or unit boundaries are defined by either correlative sequence boundaries, intraformational unconformities (SB), and/or maximum flooding surfaces (MFS).
- Outcomes from the MPU analysis have demonstrated structural control on interpreted gas hydrate/free-gas occurrence within the MPU.
    - This structural trapping control interpretation corroborates the Phase 1, Task 5.0 seismic and gas hydrate prospect studies within the MPU and may also indicate that free gas was originally trapped within structural traps before later conversion into gas hydrate with onset of permafrost conditions, lowering of the geothermal gradient, and combination with available pore waters.
- The Phase 1 work also reinforced the importance of completing as much stratigraphic analysis as possible as allowed by data availability. It appears that subtle structural-stratigraphic controls on reservoir heterogeneity and resource distribution in the MPU are much more pronounced throughout the KRU-PBU area.
- Stratigraphic analysis of shallow Sagavanirktok formation sediments within KRU and PBU has continued since January 2005. In addition to building the sequence stratigraphic framework, the focus has shifted to understanding facies associations and distributions that link most often to the occurrence of gas hydrate, free gas and oil as inferred from UA

log analysis, expert system and artificial neural net algorithms that were first developed and tested in MPU during Phase 1 studies.

- Several of the more significant Sequence Boundaries have been recognized and defined within MPU seismic data. Final confirmation of log-seismic horizon linkage awaits outcome of UA request for additional BP data and finalization of UA Time-Depth conversion review.
- Changes in sedimentary base level drops link to changes in mean sea level as well as syndepositional fault reactivation (e.g. regional tilting/normal faulting associated with mid-Tertiary Brookian orogeny and fault reactivation resulting in structural inversion).
- Miscellaneous structural-stratigraphic research is completed. Gas hydrate and free gas resource occurrence is linked to timing of structural movements, persistence and reactivation of deeper-seated structures, and sedimentation histories (e.g. high-growth expanded versus condensed sections), aided by distinguishing faulted sections from unconformities, confirmation of sequence boundaries, interpreted subtle stratigraphic traps, prediction of erosional surfaces, interpreted impermeable paleosol development on structural crest of folds, and confirmation of sequence stratigraphic framework. Preliminary analysis is completed using coal burial history diagrams, palinspastic reconstructions, delta depth-depth plots and Time-Depth (seismic fault throw-depth) plots
- The majority of gas hydrate/free gas resource throughout the AOI appears to be condensed sections related to mostly upper and lower delta plain distributary channel and composite point bar facies as indicated in earlier quarterly reports and data presented at the 2004 Hedberg conference.
- The upper and lower delta plain distributary channel and composite point bar facies are relatively thinner, unconformity-bounded sequences marked by significant vertical and lateral variation, but which on the whole can be correlated across the AOI. They are characterized mostly by single as well as stacked distributary channel sandstone units that have incised into one another and by lower delta plain and transitional proximal delta front units that are commonly interpreted as distributary mouth bar deposits. These channel-prone sequences also contain the greatest number of coal-bearing strata and are often capped by coal-bearing units.
- The spatial association of coal with gas hydrate-bearing units within the MPU and the potential that CMB could be interpreted as a contributing local gas source for gas hydrate occurrence as was suggested at the 2004 Hedberg conference. Any definitive linkage between coals and gas hydrate resources appears to be only of a depositional nature at this time (i.e. association of interbedded coals with gas hydrate-bearing sand facies). A growing number of recent studies are beginning to suggest, however, that misinterpretations of thermal histories and oil-generating potential may be the result of the vitrinite reflectance suppression and contamination due to cavings and mudcake. Thus, related gas formation and charge from low-grade coals within shallower, immature basins can actually be feasible to consider.
- Facies architecture is interpreted within shallow sediments within the MPU by integrating both seismic and log data. This is the subject of a student MS thesis that is underway and is scheduled for completion in late summer 05. Preliminary outputs from Scott Geauner's seismic architectural analysis look promising.

- After the UA Time-Depth relationship is reconfirmed or adjusted, artificial neural network algorithms can be developed and trained in aiding the seismic facies and gas hydrate/free gas/oil classification schemes.
- Results of these seismic-driven analyses combined with well data-based interpretation of gas hydrate and associated free gas resource-prone facies will be used to revise/refine previous UA estimates of gas hydrate distribution and volumetrics derived from both well log data and early UA seismic attribute analyses. Results will also be compared to resource volume estimates derived from Phase 1, Task 5.0 MPU seismic prospects.
- 3D visual renderings of these facies and fluid interpretations will be attempted.
- A detailed log-based study of facies architecture and mapping (vertical-horizontal connectivity, reservoir dimensions) and fine-tuning of reservoir properties (porosity) across the KRU-PBU is the focus of MS thesis work (J. Manuel) scheduled to commence in early Fall 2005 and completed in early Spring 2006. Estimations of facies dimensions, distribution, etc. will be guided by published data and results from the MPU seismic data.
- Sand Net/Gross ratios within these sequences are relatively high and their lateral correlations and log patterns suggest that many of the gas hydrate-bearing reservoir-prone units are linked to the deposition of composite point bar parasequences and in some locales, well-developed and stacked crevasse splay sandstones.
- Where such sand units are well-developed and thicken, mapping shows that they occur within up to three channel meander belts that trend from west-east and southwest-northeast across the AOI. These belts are separated by adjacent fine-grained floodplain deposits that include interbedded coals and stacked crevasse sand units. The tops of many of these sequences are defined by relatively persistent coal units and paleosols, some which had been misidentified as gas hydrate or gas bearing units in previous studies. One of the better-developed and wider meander belts is typified in the KRU. Current activities include characterization vertical connectivity of individual sand bodies within fault-bounded compartments; mudstone barriers present between some sand bodies can affect sand and fluid connectivity.

5.6.2.2 Comparison of Phase 2, Task 6.0 Studies to Phase 1, Task 5.0 MPU Prospects

As of March 2005, the UA fluid prediction studies, stratigraphic-structural analyses, and preliminary seismic attribute studies all suggest that the models presented at the September 2004 Hedberg conference remain viable for interpretation of gas hydrate-bearing reservoirs within the MPU. Post-conference analyses across the KRU and PBU show structural-stratigraphic linkage between fluvial source regions, confirming the role of channel pathways and depocenters that are interpreted to accumulate reservoir-quality gas hydrate-bearing sands within structural traps. This was first interpreted with Phase 1 isopach and structural mapping at several levels within and below the gas hydrate-bearing Sagavanirktok formation. A review of the 2004 Hedberg presentations (also documented in the Quarterly Report #9, July 2005) reveals the limits of a deeper inverted basin and resulting change in depositional dip that is associated with prospective gas hydrate resources in the region. This section provides a qualitative ranking based on UA studies within the MPU of several potential gas hydrate-bearing prospect areas recommended for future data collection and resource testing.

The UA studies conclude that most gas hydrate-bearing reservoirs within the MPU occur within a general area in the eastern MPU where thick and coarser marine and non-marine sands were deposited downdip of the eastern flank of the Colville high and along strike where inflections and a lessening of dip are interpreted.

One such site was previously reported at the 2004 Hedberg conference and related to structural-stratigraphic elements associated with transtensional deformation that resulted in the formation of a small pull-apart basin within the eastern portion of the MPU (Casavant et al., 2004). This area is characterized by a persistent increase in sand deposition and gross unit thickness of stacked sequences as noted in isopach maps and cross-sections and by the presence of minor structural inversion and the downdip flattening of horizons along the eastern flank of the Colville high. Within this general structural-stratigraphic framework, gas hydrate resources in the MPU appear be localized within updip traps, defined in part by variations in sealing capacity along north-northeast-trending faults (Hennes et al., 2004), as well as by the location of older, deeper transtensional fault systems that are well expressed immediately below the Sagavanirktok formation.

The deeper Northwest-trending fault fabric, which is manifested as a monoclinal or hingeline in the shallower Sagavanirktok, is a subset of the larger and wider Northwest Eileen fault complex. The latter fault complex is interpreted to relate to the Late Jurassic to Early Cretaceous rifting of the Alaska Arctic terrane. Interpretations reveal that the nature of this fault system at depths below 4000' BMSL is partly transtensional in character. The latter may well provide key linkages for sourcing and updip leakage of gas resources from the underlying Early Tertiary to Cretaceous Ugnu, West Sak and Kuparuk sandstone reservoirs as suggested by previous studies.

Table 1 summarizes zone fluid and depositional environment interpretations for several wells within the MPU. The general interpreted western limit of gas hydrate prospectivity may impact the Mt Elbert gas hydrate prospect interpretation (Task 5.0) within the MPU and is best shown by net sand maps. That limit is represented by a line roughly connecting the MPC-pad to the WestSak-25 well area. At this point the margin of the prospective area bends to the southeast approximately 1 mile south of the MPS-15 well. The interpreted easternmost margin of gas hydrate prospectivity is less well defined, but could be crudely described by a line drawn roughly from the MPD-01 well south into the MPE-26 pad area. The approximate limits of the most prospective area for gas hydrate occurrence within the MPU appears to be related to a depositional basin or structural flat within the MPU that includes an area that extends south and southwest of the MPB-pad and includes the MPA-pad area. Interpretation of seismic and stratigraphic data indicates that the structurally flat character of this depositionally low area may be due also in part to the partial structural inversion of a former basin with the greatest amount of inversion occurring along the former basin axis.

The westward limits of the prospective area have yet to be well defined, and include potential gas hydrate accumulations localized by both structural and stratigraphic trapping in the vicinity of the MPU J-, G-, I- and H-pad areas. Recent shallow data acquisition within the MPI-16 well, confirmed earlier models for the potential updip stratigraphic as well as structural trapping of gas hydrate resource to the west and northwest of the NWE2-01, MPA-01, MPS-15, and MPE-26 well areas. The UA lithostratigraphic zones involved include L_31, 33, 34a, and 35a. The upper sands of zones 34a and 35a include the USGS C and D gas hydrate-bearing intervals, respectively. The structural and stratigraphic location of the MPS-15 well places it in an approximate axial position within this structural-stratigraphic basin mentioned above. The western margin of the basin is defined by an increase in dip along the eastern flank of the Colville high and is characterized by one or two North-Northeast-trending upthrown fault blocks bordered by en echelon faulting. The easternmost block contains the West Sak-25 well (herein referred to as WS25 block), while the westernmost block is bordered by a fault west of WS25 and another east of the West Sak-17 well. At this time we currently consider the WS25 block and the complex fault zone that marks its eastern flanks just east of WS25 to be of high risk, and as such, have it as the westernmost limit of the prospect area. Although previous Task 5.0 analysis does extend correlative gas hydrate-prone units into the updip WS25 fault block, any prospective gas hydrate-bearing zones would likely lie within or near the lower portion of the ice-bearing permafrost (IBPF). Consequently this makes it difficult from a geophysical standpoint to distinguish gas hydrate-bearing zones from ice-bearing intra-permafrost sands.

Although the lithostratigraphic and sequence stratigraphic correlations show that the gas hydrate-prone units are common to wells MPS-15, MPI-16 and MPA-01, independent log-based fluid-prediction analysis, extrapolation of the base IBPF from the NW Eileen wells, and current structural characterization do not provide definitive support for the WS25 interpretation. We note that the footwall position and close proximity of the WS25 well to a major north-northeast-trending fault that has undergone repeated reactivation suggests that the fault zone has a high potential for being a sealing fault near WS25. There is the potential that gas may not have migrated beyond this fault zone near WS25, but could have migrated up dip to the north before resuming migration to the west. Preliminary waveform classifications indicate the gas hydrate-like classification interpreted in the vicinity of the WS-25 well also exists north within the block; however, this interpretation might be invalid considering that early UA seismic attribute analysis and waveform classification had designated the WS-25 as a training well for gas hydrate-bearing reservoirs per early USGS published interpretation of gas hydrate within that well. The recent analysis based on structural and stratigraphic mapping suggests caution in extrapolating gas hydrate-bearing sediments from MPA-pad southwest to the WS25. This area should be considered higher risk; however, confirmation of gas hydrate existence in the WS25 block by additional drilling and shallow data acquisition is recommended. Data to evaluate would include drilling and fluid shows as well as, resistivity and density/neutron/sonic porosity logs.

The northwest hingeline or monocline apex of Hennes et al (2004) is interpreted to be the shallow expression of a Northwest-trending wrench fault at depth. The hingeline continues just north of the MPA-01 well area and defines what is interpreted to be the northern limit of the gas hydrate-prospective area. Analyses of potential gas hydrate-bearing reservoirs within the MPU B-, C-, and D-pad areas differs from Task 5.0 Phase 1 studies in that much of the gas hydrate-bearing log signatures interpreted in these areas are interpreted to be better attributed to the presence of low-permeability fluvial units associated with the development of intraformational unconformities and associated interpreted paleosols. Study is underway to determine from seismic response as to whether or not these dense zones serve to trap and seal gas hydrate-bearing reservoirs just northeast and downdip of these pad areas (and associated with the north-dipping flank of a northwest-trending monocline). In that sense, a cluster of northwest-trending prospect polygons located north of these pads as interpreted in Task 5.0 seismic-based studies may be either (1) interpreting actual potential gas hydrate accumulations or (2) misidentifying the high-velocity responses of these cement-prone units as gas hydrate-bearing reservoir sands.

Net sand and Net-Gross ratio maps show a depositional or erosional southern limit of the prospective area interpreted to extend to the south from MPU. The MPE-26 and MPS-15 wells occur along the eastern margins of this prospective polygon area. Log and seismic-based gas hydrate-bearing prospect leads within the MPA-pad area are located within the northeast quadrant of what is interpreted as a north-northeast trending elliptical polygon that is structurally controlled by north-northeast-trending faults on its eastern and western flanks and underlying northwest-trending fault zones on its northern and southern flanks. The UA structural-stratigraphic model, artificial neural net (ANN), and expert system (ES) fluid analyses, coupled with the supervised seismic waveform classification scheme independently converge on the gas hydrate prospectivity presented for this region.

5.6.2.3 Phase 1 and 2 Seismic Attribute Analysis and Time-Depth Conversion

Hagbo et al (2003) and Hennes et al (2004) provided early assessments of gas hydrate-prone areas across the MPU based on a variety of seismic attribute analyses. These linkages between resource and seismic attributes are directly related to the soundness of the time-depth conversion developed and applied to the 3D data set. The preliminary attribute work was largely linked to gas hydrate occurrences as they were inferred in certain wells reported in Phase 1.0, Task 5.0 studies. The Phase 1 and 2, Task 6.0 studies were supplemented by an independent log-based geologic and several automated fluid prediction studies. Although a number of seismic attributes have been successful mapped and analyzed regarding the identification of gas hydrate-bearing reservoirs within the MPU, the Task 6.0 confidence in definitively distinguishing between the presence and quality of thin-bedded gas hydrate-bearing reservoir sands and seismic attribute heterogeneity related to non-resource structure-stratigraphic elements remains inconclusive at this time. For example, an earlier polarity switch interpretation from Task 5.0 studies assigned to the presence of a hydrate-free gas contact was alternatively interpreted by Task 6.0 studies to be an unconformity within this stratigraphically-complex system.

Interpretations based on cross-section analysis, structural mapping, and net sand and net/gross sand maps indicated that a number of geologic elements can affect the magnitude and variation of seismic amplitude response within the MPU area. Examples include rapid facies changes, abrupt changes in reservoir thickness/presence associated with stratigraphic pinchouts and/or truncation of sand-rich units, zones of complex structural disruption (commonly interpreted to be associated with deeper faulting), downward propagation of surface noise within the 3D dataset, variation in the relative thickness and occurrence of coal-bearing units, and even the presence of interpreted paleosols(?) or relatively dense, resistive zones seemingly associated with interpreted intraformational unconformities or sequence boundaries, etc. Thus, accurate time-depth conversion is critical to correctly characterizing the distribution and quality of gas hydrate and free-gas occurrence within the MPU.

The issue of observed mismatch in time-depth conversions between UA-interpreted Task 6.0 and USGS-interpreted Task 5.0 log-defined seismic horizons dating back to February 2004 suggests that caution should be taken in stating definitive interpretations of seismic attributes. In an effort to finalize resolution of the issue, the UA team began reviewing the results of the time-depth (T-D) conversion in 2004 through 2005.

Following the September 2004 Hedberg conference, the USGS-based team reviewed log ties between the UA and USGS datasets. UA review of several USGS-interpreted seismic lines truncated down to 950 ms is still unable to account for the 100 ms discrepancy seen between the two datasets. We believe this may not just be a function of differences in time-depth conversion, UA's derived from checkshot surveys and synthetics while the USGS's ties taken from pseudo-synthetics derived from shallow and deep resistivity logs. It is noteworthy that only one checkshot survey was common to both the USGS and UA T-D analysis. We are currently in the process of re-evaluating our checkshot analysis and T-D conversion and hope to arrive at a resolution this Spring semester 2005, if we can receive additional deep velocity and/or additional seismic data around specific boreholes. Until our linkages to well log data can be re-verified, we recommend that the UA seismic attribute analysis as well as the USGS analysis be considered preliminary at best.

Previous discussions with BP geophysicists indicate that seismic-log marker horizons that resulted from the UA T-D conversion appeared to match closely with horizons used and tracked by BP personnel. Given that the UA conversion was limited in its scope by having only seismic velocity data down to only 950 ms, we recognize the importance of seeking and integrating deeper velocity data in our effort to validate and, if necessary, reconstruct our T-D conversion. Acquisition of additional deep velocity data would allow the UA to complete a final review of seismic-well log ties and better relate our research findings (e.g. stratigraphic studies, seismic analysis, artificial neural net, etc.) and prospect analyses with the USGS seismic prospects. Until our T-D conversion is validated, our ability to assess prospective areas for future operations and data collection, and modeling of GH occurrence will rely primarily on log-based geologic modeling and mapping.

5.6.2.4 Phase 2 (2005) Geologic Setting Studies

Cross sections and geologic mapping within the MPU show that gas hydrate (GH) and free-gas (FG) resources are contained mostly within distal deltaic and nearshore marine sand units. Gamma-Ray (GR) – Resistivity deep (Rd) log pattern interpretations indicate that the higher quality gas hydrate-bearing reservoirs within the MPU are contained mostly within thin sand-rich distributary channel and in some cases the upper portions of relatively thicker distributary mouth bar parasequences. Some resistive "hydrocarbon" zones thought to be prospective appear to be related to thin point bar units that log responses suggest could in fact be paleosol horizons.

Stratigraphic analysis of interpreted gas hydrate-bearing reservoirs to the south within the KRU and NW Eileen area of western PBU indicates that the majority of GH and FG zones are stratigraphically lower than those within the MPU and are constrained to mostly stacked fluvial and delta plain deposits related to incised valley deposits that have cut into distributary mouth bar units during low-stand deposition. Distributary mouth bar units are the subsidiary reservoir facies as indicated in Table 1.

Shallow seismic mapping within most of the MPU reveals that numerous north-northeast-trending, mostly down-to-the-east normal faults compartmentalize interpreted nearshore marine and fluvio-deltaic reservoir sands within the shallow Sagavanirktok formation. In some locales these faults appear to extend to surface, offsetting the coarser, gravel-rich units of the upper Sagavanirktok and overlying Gubik formations.

Seismic interpretation within the MPU reveals the presence and influence of at least two northwest-southeast-trending basement fault zones that underlie the shallow strata of the Sagavanirktok and Gubik formations and have slightly deformed (minor lateral translation, little or no dip slip) and influenced deposition of these formations. Although these fault zones are not directly imaged because they exist just below the extent of the shallow seismic data truncated at 950ms, their presence is expressed by an inflection in the regional dip of the shallow strata. Detailed 3D analyses of this seismic data shows that where north-northeast-trending normal faults intersect the underlying northwest-trending faults, the amount of dip slip on the north-northeast faults either decreases or terminates; there is commonly an associated inflection and/or termination in fault trend in map view and in some locations, fault polarity switches. These faults define major structural blocks are interpreted to represent the northern continuation of a northwest-trending basement trend commonly referred to as the Northwest Eileen (NWE) Trend. Related fault-bounded highs are interpreted to continue to the southeast and may control deeper hydrocarbon production within the western third of the giant Prudhoe Bay field.

The basement faults that core these structures represent only a subset of the complexly faulted north-dipping eastern flank of the Colville High. Consisting of a mostly down-to-the-northeast horst-graben architecture, variable displacement along these faults may be linked to a late Jurassic to early Cretaceous-age rifting of the Alaska Arctic Terrane (AAT) and subsequent Cenozoic reactivation associated with shortening of the Brooks Range and consolidation, differential uplift and minor translation of basement blocks that characterize the northern margin (Barrow Arch) of the rifted terrane (Casavant, 2001). The apex of east-west Barrow Arch can be tracked within the adjacent Kuparuk River Unit to the west and again is picked up the PBU area to the east and northeast. A left-stepping offset or northeast bend in the axis of this regional basement uplift occurs along an approximate line that may equate to the eastern margins of the MPU and KRU field areas.

Within the MPU, stratigraphic pinchouts occur at subtle structural inflections that overly the margins of Northwest Eileen fault blocks. Where shallower north-northeast-trending faults with greater displacement intersect underlying northwest-trending fault zones, structural trap doors may exist. In these 3-way closures, hanging wall traps of GH and associated FG are interpreted in updip positions. These gas and gas hydrate-bearing reservoir sands within these hanging wall traps are thicker as a result of syndeposition or fault-related sand preservation (isolated from erosional scouring and truncation associated with the formation of numerous intraformational unconformities that defined sequences within the Sagavanirktok). However, their role in updip trapping of GH remains inferred. Net sand and net-gross maps indicate potential areas exist such as the area around or east of the MPE-pad and east of the MPS-15 well. This interpretation may corroborate the Phase 1, Task 5.0 studies of the Mt Elbert prospect area.

Table 1: The following pages present a summary of UA Task 6.0 MPU well data interpretation and preliminary seismic attribute analysis (NOTE: See legend following table; blue color indicates well lies within/adjacent to a UA prospective site; relation to Phase 1, Task 5.0 prospect polygons are noted where applicable).

Well	USGS Zone E USGS Marker 15a UA Zone L_35a-35	USGS Zone D USGS Marker 15 UA Zone L_35-34	USGS Zone C USGS Marker ~14 UA Zone L_34-33	USGS Zone B USGS Marker 13 UA Zone L_33-31	USGS Zone A or Staines Tongue USGS Marker 12-13 UA Zone L_31-29	FREE GAS Undifferentiated Zone Intervals
3K-06	PF, MB	PF, MB	PF, MB/F	PF, MB	NLS, L_31-30 Rd inc, but not Vel, Rhob-Neut approach each over (x-over) in channel-like sands	
BEECHYPT-01	NLS	NLS (wet)	NLS	NLS	NLS	
CASCADE-01	NA, no MG	Fair LS, MG, SW of Mt Princeton prospect, SA,WF, DMB	LS, fair MG, good ES/ANN for FG, CH	LS, good MG, no logs through upper 1/3 interval, zone faulted?, CH, PB	Similar to MPK-38	
EUGNU-01	PF, neg. ES/ANN	PF, V poor, neg. ES, ANN coals	Faulted out, neg. ANN	NLS, Rd inc, Vel poor, faulted section	NLS, 1/2 of L_30 to L_31 appears faulted out	
KAVEARAK-32	PF?, no Rhob/Vel logs, NLS, small Rd inc. and correl to MPE-26, PAL? PB, no Rhob/Vel logs, no logs for ES/ANN	NLS, DMB, v poor Rd inc., no Rhob/Vel logs, no ES/ANN, SA,WF	Good 10'+ Rd inc, DMB, no Rhob/Vel logs, no logs for ES or ANN, SA,WF, far W of Mt Elbert prospect	NA, log gap, thin Rd zones correl to MPE-26	NLS, small Rd w/coals	
KRUGNU	PF	PF	PF, neg. ES except 2 thin bits ~1940, 1960	NLS, ES saw water zone, but Rd is too high, ANN neg. for FG	NLS, some thick coals	
MP18-01	NA, SA,WF	NA, MG, SA does not appear unique to horizon or prospect location,	NA, within Crestone prospect, SA does not appear unique to horizon or prospect location	NA	NA	Y within Mt. Shavano prospect
MPA-01	PF?, PB, NLS, v poor Rd, Vel, inc., no MG, potential PAL that is correlative thru B, E & K-pads, etc., CH/PB, SA,WF	Mod-good LS, DMB, good ANN, ES, good MG starts, increase in N/G; "East basin" model, increase in net sands on east flank of Kuparuk structure; updip of gas charged sands to SE, SA,WF	LS, MG, ES, ANN (1-5' coals), CH, PB within prospect, SA appears more robust relative to locations outside prospect, N-G mapping and "East basin" model predict mod-good GH to the SW & S SA,WF	NLS, no Rd/Vel inc, FG indicated on USGS x-sect?	NLS, oil?, low Rd & Vel., poor-fair MG, neg. ES, neg, ANN, correlates to section showing oil and low Vp indicate on USGS x-sect for WSAK25	

PB-01	LS, PB, mod Rd, V, no RHOB log, correl well w/MPB-02, PAL, SA,WF	poor LS, DMB, thin Rd/Vel inc, no Neut & Rhob logs, potential PAL, SA,WF	NLS, CH/PB, thin Rd & Vel, assoc w/ shale, SA,WF	NLS, up half faulted out, looks wet	NLS	
MPB-02	NLS? mod Rd & Vel increase, however, RHOB also inc.= potential PAL?, PB, SA,WF	LS? DMB, thin zone of Rd inc, ES show w/coals, neg. ANN, SA,WF	NLS, CH/PB, SA,WF	NLS	NLS	
MPC-01	PF, NLS, SA,WF	Good MG, DMB, far west of Snuffles prospect, SA does not appear unique to horizon or prospect location, SA,WF	NLS, DCH, within Crestone prospect, well located W of SA anomaly, SA appear unique to horizon and prospect location	NLS	NLS	Y within polygon W of Mt Shavano prospect
MPC-03	NA, SA,WF	NA,	NA, within Crestone prospect, SA does not appear unique to horizon	NLS	NLS	Y within prospect W of Mt Shavano prospect
MPD-01	LS, PB, poor Rd, Vel. inc, close to BIBPF), neg. ES or ANN; potential PAL, SA,WF	Thin LS, DCH, signif, Vel, inc. Rhob NA, PAL?, SA,WF	NLS	NLS	NLS	Y within Little Bear prospect (Staines)
MPE-26	NLS, poor ANN, neg. ES, mod Rd & Vel inc. and RHOB inc.= PAL?, noted same zone in NWE ST-2, but Rhob decreasing in NEW, SA,WF	NLS, DCH/DMB, W of Mt. Bierstadt & Mt Elbert prospects, SA,WF	v poor LS, DCH/DMB, v thin Rd inc., neg ES/ANN, far W of Mt Elbert prospect, SA,WF	NLS, v poor Rd, thin zones of Rhob/neu cross-over, good ES, neg. ANN, minor FG reported on USGS x-sect	NLS, neg. ES/ANN	
MPI-16	NA, GR only	NA, GR only	NA, GR only, possible updip play to NWE2-01 and MPS-15,depends on BIBPF, maybe better than Rd inc in NWE2-01 which is south and updip to MPS-15	NA, GR only, possible updip play to MPS-15 & NWE2-01, maybe better Rd inc than in NWE2-01 which is south and updip to MPS-15	Inc. in Rd observed in several thin zones, look like crevasse splays sands	

MPK-25	NA	NA	NA	LS, GF, ~80' gross, 50' net	LS, FG, better than K-38	SAUA
MPK-38	NLS, PB, v. poor Rd inc., but w/ RHOB inc.= PAL stack?	Good LS, DCH, GH?, only Rd, thin zone of Rhob/Neut x-over below GH, but neg. Rd inc (FG), correl to Cascade MG show, neg. Vel, good ES GH, good ANN (GH & FG, SW of Princeton	LS, DCH, fair MG correl to Cascade, SA,WF	LS, DCH, FG, >40-50 ohm, 55' gross, 35' net, good ES/ANN FG	LS, CH/CV/PB, FG, neg. ES/ANN despite Rd inc, thin ANN coals	SAUA
MPL-01	PF, NA	PF	PF or near BIBPF	NA	NLS	
MPS-15	PF or interval pinched out, large washout	good LS, good ES/ANN, SA,WF NA	v thin LS, good ANN FG, neg. ES, coal? SA,,WF NA	NLS, no Rhob , neg. ES, ANN	NLS, coals, thick sds, neg. ES/ANN,	Prospective play updip to the west of this well
PRUDHOE-01	NA, no MG, ES/ANN unknown	NA, probable LS, good MG, unknown ES/ANN equiv shows in NWE2-01, NEW-2, BeechSt-01 FG, K071112 MG, poss. Chev. 18111	NA, thus no ES/ANN, excellent MG, probable GH	MG, no logs over up. 2/3 of interval,	thin prominent MG zones, 3 v thin sds w/ Rhob/Neut x-over, thin ES/ANN zones	
SIMPSON-01	PF, NA	PF, NA	PF, NA	NA	NA L_33-30, NLS L_30-29	
WS-17	PF	PF	PF	PF	NLS, Rd inc w/coals	
WS-25	PF, NLS, DCH/DMB, MG w/coals @2400', SA,WF	PF, DCH/DMB, slight MG, neg. ES/ANN, SA,WF	LS f(BIBPF), correl. to NWE-2 well suggests zone just within PF, CH, well located W of prospect, SA of polygon does not appear unique within sequence given UA T-D conv., SA,WF	NLS, CH/DMB, poor Rd, MG, neg. ES/ANN	NLS, CH/PB, CV, DCH, DMB, thin Rd inc w/coals, MG inc. only w/ coals, oil & low Vp noted on USGS x-sect, neg. ES/ANN	

Table 1 Legend:

ANN = GH inferred by artificial neural network
BIBPF = base of ice-bearing permafrost
ES = GH show inferred by expert system predictor
FG = associated free gas (interpreted)
GH = gas hydrate (interpreted)
LS = GH show inferred by wireline log responses (e.g. favorable Rd, sonic, Rhob, & GR responses)
MG = mud gas present (total background gas)
NA = no logs available through interval
Neut = neutron log response
NLS = no GH/FG show based on log curve responses (e.g. insufficient Rd, sonic, & porosity log responses)
PF = interval lies within permafrost, making log interpretation ambiguous with IBPF log response
Rd = resistivity log responses
Rhob = bulk density log response
SA = total amplitude response observed on UA seismic line(s) in/adjacent to USGS polygon (UA Time-Depth conversion)
Vel = sonic, delta time log
WF = in/near area identified in UA waveform classification as "gas hydrate consistent anomaly" (scheme derived from Phase 1, Task 5.0 gas hydrate picks of variable quality, analysis done only for gas hydrate zones E, D, & C within MPU)
Y = well lies within or near Phase 1, Task 5.0 free gas prospect polygon

FACIES of reservoir unit containing resource (log pattern-based)

Fluvio-deltaic Facies
CH = channel
PB = point bar sand
L = channel levee
CV = crevasse sand
PAL = paleosol, cemented zone

Deltaic-Marine Facies
DMB = distributary mouth bar
DCH = distributary channel
RW = reworked marine sand

Based on wireline data, stratigraphic maps, and fault architectures, many of the UA-defined prospective GH sites within the MPU seem to be located above or just downdip of the hingeline(s) where dips have lessened. At the shallow levels in which the GH occurrence is inferred, these underlying fault zones are expressed only as hingelines. The MPA-01 and MPS-15 well areas, which both contain relatively thick sand reservoirs, also both lie atop or near two different Northwest-trending hingelines.

Linkages between gross isopachs and net/gross sand maps and the distribution of GH as defined by well log analysis and fluid prediction algorithms (e.g. UA expert system and artificial neural network) reinforce the basic premise that GH-bearing reservoirs will most likely be limited to intervals of adequate "sand" quality and thickness in updip structural-stratigraphic traps as interpreted by Phase 1 Task 5.0 and Task 6.0 studies. Our Task 6.0 studies show that increases in the accumulated thicknesses of stacked nearshore and fluvio-deltaic sands are noted where decreases in structural dip occur down the flank (half-graben settings). Isopach maps and structural analyses within the MPU reveal the influence of two underlying northwest-trending normal fault zones characterized by down-to-north displacement (Werner, 1987; Hennes et al., 2004; Casavant et al., 2004). Fault morphologies suggest a complex fault zone marked by transtensional or oblique-normal displacement (Casavant, 2001; Casavant et al., 2004).

Wells associated with candidate areas for GH occurrence and associated wireline and seismic leads are abbreviated in the table below. Based on our current time-depth relationships, preliminary fluid predictors, and structural and stratigraphic mapping, we concur that a reasonable potential for GH occurrence within the "C" interval (L_35-34) exists in an area south and southwest of line connecting the MPD-01 and WS-25 wells. Net/Gross sand ratio maps indicate a structurally-controlled fairway (paleo-shoreline or trend of sand preservation) that reflects the influence of the Northwest-trending and North-Northeast-trending fault sets. The most prospective sites include an area due south of the MPU B-pad.

5.6.2.5 Phase 2 Paleosol Horizon Alternative Interpretation

Well log-based stratigraphic interpretation within the MPU reveals the presence of potential single and stacked paleosol units that may be alternatively interpreted as potential gas hydrate-bearing reservoir zones in previous studies. A lack of available core data and cuttings for analysis keeps this alternate paleosol interpretation speculative. The interpreted paleosols appear as one and/or several relatively thin resistive zones that are characterized by low GR readings and are immediately overlain by above-normal velocity and bulk density responses. Thicknesses of individual resistive units (possibly ankerite or calcite cemented beds) range from 1-4 meters. These units can be interleaved with shale zones comprising what is commonly referred to as a paleosol stack, which commonly produce intermittent, but relatively strong impedance contrasts along sequence boundaries in seismic data.. These vary in thickness within the MPU and appear to reach thickness of 5 meters or more (e.g. ~ 1930'MD in MPB-02). The paleosol interpretation might explain the notable lack of increase in background or "total" gas seen on mud logs across these previously interpreted "gas hydrate-bearing" zones within the MPU. Similar intervals have been correlated and noted in many other wells in the KRU and PBU areas and are the subject of on-going research. Reviews of any available core and/or sample descriptions, drilling exponents, and porosity log litho-identification and MSFL analysis would prove most useful in validating this preliminary interpretation. Although this data had been requested early in the project, little is available for study. We continue to assess this issue and its integration into MPU log- and seismic-based prospect analysis, reservoir characterization, and future modeling during Phases 2 and 3a.

Table 2 lists the MPU wells that are thought to contain potential paleosol intervals based on well log interpretation. Paleosol horizons are based on petrophysical calculations where relevant logs available and correlative horizons where logs for complete petrophysical analysis are not available.

Table 2: Interpreted Possible Paleosol Intervals within MPU Wells.

Well	**USGS-zone**	**UA-zone**	**Comment**
MPB-02	E	L_35a - 35	
MPE-26	E	L_35a – 35	
MPA-01	E	L_35a – 35	Possible thicker paleosol stack interbeds
MPK-38	E	L_35a - 35	Possible thicker paleosol stack interbeds
MPB-02	C	L_34 – 33	2 meter interval may correlate to 3-4 meter interval interpreted above GH in NWEileen-02
MPB-01	E	L_35a - 35	Logs for complete petrophysical analysis not available
Kavea32-25	E	L_35a - 35	Logs for complete petrophysical analysis not available
MPD-01	E	L_35a - 35	Logs for complete petrophysical analysis not available
MPA-01	E	L_35a - 35	Logs for complete petrophysical analysis not available
MPK-25	E	L_35a - 35	Logs for complete petrophysical analysis not available
Cascade-01	E	L_35a - 35	Logs for complete petrophysical analysis not available
WSak-25	E	L_35a - 35	Logs for complete petrophysical analysis not available
MPB-01	D		Logs for complete petrophysical analysis not available
MPB-01	C	L_34 – 33	Logs for complete petrophysical analysis not available

UA chronostratigraphic or sequence stratigraphic analysis shows that these interpreted paleosol units are commonly linked to the upper beds of incised channel deposits or upper units of point bar parasequences that overlie intraformational unconformities. This spatial relationship and their regional correlability also makes these units ideal indicators for detailed sequence boundary interpretation. The latter are critical to accurate chronostratigraphic correlations that ultimately lead to more accurate characterization of reservoir connectivity, potential production modeling, refinement of volumetric assessments, and paleodepositional reconstructions. Phase 2 studies are planned to assess the relations between potential paleosol horizons within the MPU area and the adjacent Eileen trend area (within KRU and PBU) and their potential linkage to underlying northwest-trending fault zones and, in some locations, syndepositional north-northeast-trending faulting. Both are expressed as reactivated structural areas that could well have been associated with subaerial exposure, erosion and subsequent formation of paleosol units that currently occur within the GH stability zone within the MPU area. Their role in the constraining of GH and FG occurrences are not fully understood. Plans exist to incorporate this facies into the UA fluid expert system and in the near future into the artificial neural network (ANN) algorithms that will be also used interrogate the 3D seismic dataset. This data will also be taken into account in an upcoming review of the earlier seismic attribute analyses completed at the UA after our second time-depth conversion (if needed) is validated.

5.6.2.6 Phase 2 Interpretation of PBU L-pad and V-pad Area

In March 2005, a request was made for University of Arizona input into the regional development scenario modeling studies conducted under Task 10 and documented separately in Section 5.10.1. The response was preliminary and compiled over a 2-day period, but is included here to document the interpretation status and discussion. Benefits of this exercise were anticipated to assist the development scenario modeling by adding some stratigraphic trend lines to help determine where to start "development" in certain potential sweet spots. This was a high-level exercise, so detailed interpretation was not incorporated at this stage of studies.

5.6.2.6.1 Preliminary Stratigraphic Interpretation

The current interpretation indicates that the PBU L-pad area is more prospective than the V-pad area. Interpretation of Sagavanirktok channel complex trends are not currently well understood, but in general may trend from west-southwest to northeast. The next mapping phase should better constrain this interpretation. Wells that are currently interpreted to represent depositional axes of eight individual channel complexes include: 1. WS25 to MPE-26, 2. KRU1H-06 to MPS-15, 3. KRU1D-05 to WS-24, 4. NWE1-01, 5. WT-01, 6. WS-06, 7. WETW, and 8. KUPST-01.

Good channel development and associated potential gas hydrate-bearing reservoir sands should be expected in and around both PBU L and V pads at various stratigraphic levels. The recommendation is to place a west-southwest-northeast trend in modeling of gas hydrate resource in the area of both pads. This trend of the gas hydrate (GH) and free-gas (FG) resource is a function of not only general trend of reservoir facies (primarily channel deposits incising high-stand distributary channel-mouth bar units), but also the trend and limits of the Base of Ice-bearing Permafrost (BIBPF) located just to the northwest whose trend varies with depth (and structure) and ranges from north-south to southwest-northeast depending on stratigraphic horizon. The role of fault containment can only be inferred at this time given the data we currently possess. However, we are currently in the process of compiling a detailed AOI composite fault map derived from published data of faults at different stratigraphic levels across the general PBU and KRU areas. The fault compilation map will be used to refine prospect assessments and structural controls in the Phase 2 and 3 studies.

The characterized "sweet spot" stratigraphic units both updip and downdip of the L-pad and V-pad areas. Sweet spot is actually a misnomer for there can be several within a single sequence as well as being vertically stacked. Their position varies slightly from layer to layer and appears to be a function of channel position/dimension (width/thickness) and the structural position (updip trapping related to either an inferred fault or stratigraphic pinchout).

Currently, individual channels or channel meander belts have not yet been mapped at the various levels, although this is planned in future studies. They have been noted and generally discussed more often throughout a detailed correlation exercise that has taken place over the past 2 months across the KRU-PBU areas. This updated stratigraphic framework is being used to guide detailed stratigraphic and facies studies during this semester and next. A new set of fieldwide picks for all the wells is anticipated to be completed during Phase 2 studies to capture the detailed log-based characterization across the AOI scheduled for summer and fall 2005. Completion of the tighter vertical stratigraphic framework would allow more precise mapping of variations in individual parasequences and parasequence sets and would be an improvement over the earlier and gross correlations completed in the preliminary regional correlation and mapping studies within the MPU that was provided to guide Phase 1 seismic attribute analysis and time-depth conversion studies. This more detailed framework would be used to re-evaluate the MPU seismic cube as it relates to (1) finalizing Time-Depth validation between the USGS and UA and (2) assisting with Phase 2 attribute mapping and associated neural network studies.

5.6.2.6.2 Upper Sagavanirktok Stratigraphy

The upper prospective intervals in the L-pad area include the UA litho- & sequence-stratigraphic units 35a-35, 35-34a, and 34a-34. These resource prone units are typed in the nearby NW Eileen State 2 well. The 35a-35 includes the poorly developed USGS zone E gas hydrate-bearing unit, which is commonly interpreted as a relatively thin point bar sequence (pb) above an unconformity that cuts into both distributary mouth bar (dmb) units as well as laterally equivalent fluvial channel (fch) and composite point bar (cpb). In higher areas such as the B- and D-pad areas within the MPU, the resistive character of the unit appears to be in some locales associated with a cemented and less permeable strata (paleosol?) that can be tracked for some distance (e.g. BeechyPt, etc.) rather than a gas hydrate. In some locales, the earlier USGS correlations have the E hydrate pick crossing UA-defined stratigraphic intervals (e.g. zone E crosses down to the 35-34a zone in the nearby 33-29E well and unit 35-34a elsewhere is typically equivalent to the USGS Zone D hydrate-bearing unit.

In the L-pad area, however, the zone E gas hydrate-bearing unit looks reasonable and can be expected to pinchout updip to the northwest between the 33-29E and the NWEileen St 2 wells and downdip some unknown distance to the northeast. To the southeast, the unit structurally rises again and is present in the KUPST-01 according to the Expert System/Artificial Neural Network (ES/ANN) fluid predictors and log analysis. This agrees well with the net sand map trends and the slight increase in total background gas seen on mud logs for this zone.

The zone D gas hydrate-bearing unit lies within the upper sand units of the UA litho unit 35-34a. We anticipate gas hydrate resource in this zone to extend northwest updip to a location beyond 33-29E to a point as far out as NWE2-01. This of course depends on interpretation of the BIBPF (base ice-bearing permafrost). If the BIBPF pick is placed below the upper sand as interpreted by UA ES fluid/facies model (K. Glass), then the gas hydrate resource limit would extend to just beyond the 33-29a well. If the BIBPF is interpreted to be shallower (as direct correlation from the NW Eileen St 2 well over to WS-25 might indicate), and therefore, above zone D, then gas hydrate resource potential in this interval could possibly extend out to the NWE2-01 well and beyond into the next depositional trough to the northwest ("East basin"), which contains the sand-rich zones penetrated by the MPS-15 well (2004 Hedberg Casavant et al. & Poulton papers). To the northwest and updip is MPI-16. GammaRay (GR) logs indicate that zone D sands are still well-developed in this area. This zone is prospective if a shallower BIBPF is picked in the MPS-15 well. To the southeast, the zone D gas hydrate-bearing unit is interpreted to extend to the CHEV18112 well, but terminate before the WETW well, which exhibits no increase in resistivity response over background. Prospectivity of zone D in the WETW, if any, is attributed to only several thin zones of moderate gas increase in the mud logs. To the west, the limits of gas hydrate-bearing zone D are interpreted to extend nearly to or just beyond the WS-24 well, again depending on the depth of the BIBPF.

Most promising for gas hydrate-bearing reservoirs in the L-pad is unit 34a-34 (upper well-developed sand(s) contain the USGS C-hydrate zone). This unit is characterized by well-developed channel units (fch) that like the other zones incise to various degrees mixed dmb and fluvial units in the upper part of the underlying 34-33a unit. Palinspastic reconstructions in some locales indicate that some of the better developed dmb, dch, and fch occur together in the same area because of the persistence of paleo-depositional lows that apparently created significant accommodation space for depocenters. Whether these depocenters are derived from structure or incision, is not always easily to interpret. The northwestern limits of the 34a-34 hydrate-bearing sands are interpreted to be just north/northwest of NWE2-01 well.

The upper sands of unit 33-34 in NWE2-02, which is updip of well 33-29E, contain several stacked cpb sequences below the zone C-hydrate that appear to contain prospective gas hydrate-bearing sands. These reservoir sands exhibit a similar response, gain, and separation of deep to shallow resistivity logs as seen in the NW Eileen St 2 well area. No porosity logs were available to UA over this interval to further assess this lead. These same units appear wet in the MPS-15 which is to the northwest and downdip and many of them shale out farther north in the updip MPI-16 well. However, the uppermost sand in this unit remains well-developed and could contain hydrates, depending on where the BIBPF is interpreted. Except for GR, there are no logs available over this interval. The sands in the MPS-15 and MPI-16 appear to be a separate southwest-northeast channel complex whose trend is not well constrained, but approximates the Eileen trend interpretation to the south.

5.6.2.6.3 Lower Sagavanirktok Stratigraphy

Lithostratigraphic unit L_33-31 may contain some gas hydrate-bearing reservoir sands based on UA analysis and fluid predictors. This unit is just above the upper Staines(?) and includes USGS zone B gas hydrate-bearing unit (where picked). Unit L_33-31 may represent a west-southwest-trending channel complex, informally referred herein as the "Eileen complex". In the NWE2-01 well, a gas prospect may be present updip as interpreted from the mudlog gas show in the nearby 33-29E well to the south. The deep resistivity reading is beginning to increase in the NWE2-01 well in this interval (no sonic, porosity logs). The 33-29E well logged mudlog gas increases within the L_33-31 interval, but the deep resistivity appears to indicate primarily water-saturated sands. The WS-24 well log interpretation reveals thinner stacked cpb sands, a good response for gas hydrate-bearing sands incised into shales, not dmb as in the downdip NWE1-01 well.

South of the "Eileen complex", another west-southwest trending channel complex, informally referred herein as the “WETW complex” and present within the CHEV181112 well. This well and the area just updip exhibits excellent free-gas response in a regionally-persistent and well-developed uppermost sand of unit L_33-31. The interpretation indicates that a northwest-trending fluvial channel (fch) incises into a well-developed and thick dch/dmb parasequence unit bordered by marine shales. This zone is correlative to gas-bearing sands in MPK-pad-Cascade-01 area. The WETS well is downdip to CHEV181112, but still exhibits same free gas responses in channel sand. The WKUPSt-01 and NWE1-01 wells also show channel sand developed in this interval and within lithostratigraphic unit L_30-29 (USGS zone A).

Lithostratigraphic unit L_30-29 sands are well developed in the NW Eileen St #2 well area. Updip of the NWE1-01 well, the L_30-29 sands are also well developed with a significant deep resistivity response to interpreted gas within several stacked fch-coal-crevasse splay(cv) facies. This response may increase updip in NW Eileen St 2 area in a potential fault trap. The L_30-29 sands are also present in the WETW and CHEV181112 wells and still exhibit some interpreted free gas responses within this channel sand.

5.6.2.7 Future Phase 2 Work Planned in 2005

Future Phase 2 studies planned in 2005 include:

- Mature PBU L- and V-pad interpretation through AOI mapping and MPU seismic studies
- Compare MPU seismic facies architecture interpretation to well data interpretation
- Expand Artificial Neural Network studies to include seismic interrogation and modeling
- Compile regional fault maps across Eileen trend AOI from published data
- Extend paleosol interpretation from MPU into the KRU/PBU Eileen trend

5.6.3 Phase 2 Reservoir Characterization Studies – July 2005 Status Report

The information in this section is compiled from a quarterly report encompassing the period from January 3, 2005 through June 30, 2005 submitted by UA on July 5, 2005. The report is slightly modified to ensure clarity and help relate to other project tasks. Some comments are added in *parenthetical italics (PI Note:…)* by the project Principle Investigator and primary report author, Robert Hunter, to help relate Task 6.0 studies to completed or in-progress work accomplished in Task 5.0 and associated U.S. Geological Survey and other studies. Potential conflicting Task 6.0 versus Task 5.0 interpretations remain valuable to assess gas hydrate prospect potential within the study area.

5.6.3.1 Task 5.0 MPU Prospect Comparison Studies

UA studies of Task 5.0 MPU gas hydrate prospects were undertaken from January 21, 2005 through March 15, 2005. The results of these studies are also summarized in Table 1 and in Section 5.6.2.2.

a. Submitted UA prospect summary table and report (3/9/05) summarizing UA well log & seismic review and technical comments related to all USGS seismic prospects within MPU (see also Section 5.6.2.2 and Table 1)
b. Transmitted UA marker data (tops) for Kavearak 32-25 well and other key prospect wells (5/16/05) for analysis/planning related to development scenario modeling (Task 10) and stratigraphic prediction within the Mt. Elbert prospect
c. Completed UA review (4/05-5/05) of prospectivity in Mt. Elbert (E-pad) and Mt. Antero (J-I pad) areas for input into development scenario modeling (Task 10)
    i. Submitted Bob Casavant summary with embedded structure maps, gross, net sand and net-gross isopachs, and well log cross sections to Scott Wilson for assistance in modeling; this also included a teleconference meeting (4/28) between Bob C., Scott Wilson (Ryder Scott), and B. Hunter (BP)
    ii. Recommended well log acquisition and coring and formation testing of resource in the Mt. Antero area before Mt. Elbert prospect activities are initiated in order to prove presence or absence of resource north of the Northwest Eileen well area. *(PI Note: Task 5.0 geophysical*

interpretation and studies suggest that the Mt. Elbert prospect is a much thicker and reasonably highly-saturated gas hydrate accumulation as documented in Quarterly Report #9 submitted July 25, 2005 and in the Topical Report submitted June 30, 2005).

iii. Predicted presence of reservoir rock in both Mt Antero and Mt Elbert (Task 5.0) prospect locations. UA log-based geologic model favors Mt. Antero area (southwest of MPA-pad and east of WSak 17 and WSak 25. re: Casavant et al, 2004, Hedberg). Mt. Antero is defined by more well control, is on structural and stratigraphic trend with gas hydrate-bearing reservoirs in/around NW Eileen State pad, within a highly faulted area with known reactivation, and updip & uphole from excellent Ugnu source beds. *(PI Note: Task 5.0 interpretations agree with statement that Mt. Antero prospect is better delineated by well control than Mt. Elbert prospect).* Our analyses show that USGS Mt Elbert play concept is also a sound play and is based on proposed gas hydrate formation resulting from the updip migration of free-gas development seen on logs in the downdip MPU K-pad area. The prospect is, however, within in an unproven fault block that exhibits less faulting (lack of structural continuity to deeper sources), and is outside the MPU "eastern basin" (Casavant, Hedberg, 2004). *(PI Note: Task 5.0 studies suggest there is little link structurally between deeper structures and overlying gas hydrate-bearing reservoirs; the pull-apart basin interpretation is not believed to impact deposition of Mikkelsen Tongue sands within potential gas hydrate-bearing USGS Zone C, D, or E).* Log-based isopachs of reservoir sand and resource suggest uncertainty just east of the MPU E-pad area. Discussed issues with project team and linked to UA's risk assessment. Seismic analysis of the prospect revealed that adequate gross thickness of the L34-L33 units existed, however, the amplitude and attribute anomalies associated with the Mt. Elbert did not seem unique to the prospect polygon and were noted elsewhere throughout the MPU. *(PI Note: Task 5.0 studies directly conflict with this interpretation; it appears from statements in Section 5.6.3.2c, Geophysical activities, that UA decided to not use the USGS-reprocessed seismic volume in Task 6.0 studies).* Thus, it was recommended by that gas hydrate-related seismic attributes should be risked accordingly. Operational or facility access factors were not taken into account in the UA assessment.

5.6.3.2 Geophysical Studies

a. Seismic Modeling to Better Quantify Gas Hydrate Response

i. The aim of this modeling project is to use sonic and density logs to determine the normal-incidence seismic response of gas hydrate-bearing reservoirs and compare it to the response free gas-bearing sand reservoirs, water-bearing reservoir sands, and permafrost. This new modeling effort is directed at concerns about the ability of various data sets to resolve gas hydrate- and gas-bearing units within the Milne Point Unit. The 2D modeling should give a more quantitative idea of the minimum thickness of sand that can be detected for different pore-filling materials, and provide a comparison of the responses for different fills.

ii. Density and sonic values are being taken from sand zones that have a known pore fill and substituted for a single sand in one well log. Everything except for the sand of interest remains constant. This ensures that other zones that may vary between wells do not influence the response. New models are being built to show variation of the seismic response with differences in sand thickness and pore fill. The seismic wavelets used in the modeling have spectral characteristics determined from the Milne Point 3D data sets and later tests may include extracted wavelets.

iii. AVO (Amplitude Versus Offset) modeling would be a better approach to investigate seismic response, however the UA only has post-stack seismic data for Milne Point to compare to the modeling. Normal-incidence modeling will provide an estimate of the detection limits of the sands and, depending upon agreement with the seismic data, may indicate that AVO modeling should be a future step.

b. Finalization/validation of time-depth conversion (1/15-6/30/05)

i. UA re-review of check shot surveys concluded. Most are deemed adequate.

ii. As a result of discussions held at the 2004 Hedberg Conference between B. Hunter, USGS, and the UA, the UA once again requested some additional deep seismic data from MPU for Phase 2 studies in order to investigate and rectify (if needed) an apparent 100ms+ difference in time-depth conversions that exists between the UA and USGS data sets. The time-depth discrepancy has been an outstanding issue and recognized technical handicap since the very early stages of Phase 1 research. It is critical to performing seismic interpretations, integrating log-based and seismic attribute analysis, and performing accurate resource and prospect evaluations. The UA request to incorporate deeper seismic data into the analysis was denied.

iii. In acknowledgment of concerns regarding release of deeper seismic data, UA then requested only a very limited amount of deep data in the form of 10 traces on each side of the of 13 key wells with the sole objective of using it to improve and/or confirm its earlier time-depth (T-D) conversions. Another idea proposed was to simply export a zig-zag 2D line that connected key wells on the UA list for deep structural data in a fashion that could not be used for deep structural interpretation. UA further requested to receive formats for any of the data released (for both the traces around the wells and the USGS processed data) to be in both SegY format and Landmark formats. UA recently began performing wavelet extraction and well tying on a more user-friendly PC-based system. The data and data format request were denied.

iv. UA then asked to get a better handle on the processing flow used in the "processed" seismic that UA had received. UA requested only a brief description of the processing flow and replacement velocity(ies) used in

MPU data set—knowing that the processing details of a survey are critical to establishing sound interpretation. No brief was provided to the UA seismic processing group as of July 2005 *(PI Note: The original processing report for Milne Point 3D Seismic Survey (by Kelman Seismic Processing, dated April 22, 1998) was transmitted to UA on March 2, 2005, signed by UA on March 10, 2005).* Even if the UA did chose, instead, to use the USGS processed data *(PI Note: USGS reprocessed data also transmitted to UA on March 2, 2005, signed by UA on March 10, 2005)*, all previous UA work (including multiple MS theses) had been done with the original processing, so the UA still needed to understand how that data had been processed. Written and oral requests for improvement in technical collaboration between all parties have been consistently issued by the UA. The advisory roles defined in Task 2.0 have not fully materialized at this time. *(PI Note: The UA was provided with the significant data and expertise at the start of Phase 1 studies, including 3D seismic volume truncated to 950ms, area-of-interest well data, and all USGS historical files and notes; updates to this information have continued to be provided).*

v. It was decided by the UA research team to move forward with their well log ties rather than spending any more time trying to resolve the discrepancy with the USGS seismic data. *(PI Note: This discrepancy is recognized; the UA is working with depth-shifted seismic volume, but it is unclear if this shift is accounted for in their well log ties). To our knowledge throughout Phase 1, the UA time-depth conversion were similar to those reported for conversions used within BPXA).*

c. BP coordinated release to UA of the reprocessed USGS 3D MPU seismic data down to 950 ms in early March with the hope that the so-called "higher frequency" data might prove beneficial to the UA seismic attribute analysis. The release and comparison were warranted and appreciated. UA geophysicists (RJ, LP) reviewed the USGS data and it was concluded that the data was in fact not higher frequency, but that reprocessing had actually resulted in lower resolution and less noise, the original data having been processed with a smoothing function. *(PI Note: This statement is incorrect according to USGS records and associated Task 5.0 studies which show that the USGS-reprocessing resulted in an improvement in frequency content nearly double that of the original processed cube).* Although the data looks "better behaved" than the processed BP data that was released to us and then reprocessed here at the UA, a comparison to the UA data currently used revealed the latest USGS data would not make an appreciable difference in the UA seismic attribute analyses done previously or in progress, nor would it help resolve the more problematic 100ms T-D discrepancy noted between the USGS and UA data sets in earlier activities of Phase 1.

5.6.3.3 AOI Gas Hydrate Alternative Coal-Gas Source Study

a. Identification and re-assessment of coal occurrence and continuity

i. Identification of coal-bearing units has helped in identifying the tops and bottoms of the fluvial-dominated flow units in the lower Sagavanirtok formation (e.g. coal seam(s) capping L-27, 28, 29 and sometimes L_30 lithostratigraphic parasequences). Sand units become sandier(?) and thinner upwards. Coal frequency and thickness also increase upward. In the vicinity of the MPU, preliminary studies showed that coal seam abundance was highest between L_31-L29. Although coal seams are most abundant in the overlying L_31-29 sequences, they are also less continuous due to increased incision due to channelization, presence of intraformational unconformities, and associated with thinning and reduction in sequence thicknesses associated with a fluvial (and estuarine) dominated low-stand systems tract (Figure 12). Figure 12 illustrates the correlation and apparent regional extent of relatively thin coal-bearing units that define the tops of highly-interbedded fluvial-dominated lithostratigraphic parasequences (e.g. L_30 through L_26) in an interval that encompasses most of Sagwon member (Noonan, 1987) in the lower third of the Sagavanirktok formation. The stratigraphic datum for the section is the coal-bearing unit capping the L_27 sequence. Interwell distances the Figure 12 cross section are 6.6, 6.4, and 8.5 km, respectively. Coal continuity can only be speculated, but units that exhibit any significant lateral extent across the AOI such as the L-27 coal are usually greater than 2-3 m in thickness with thicker units often composed of 2 or more individual seams. The coals are usually underlain by a thicker shale-rich package, interpreted from well log character to consist of underclays, soil horizons, abandoned channel fill, and interbedded thin crevasse splay sands and limited-extend abandoned channel sands, but of good reservoir

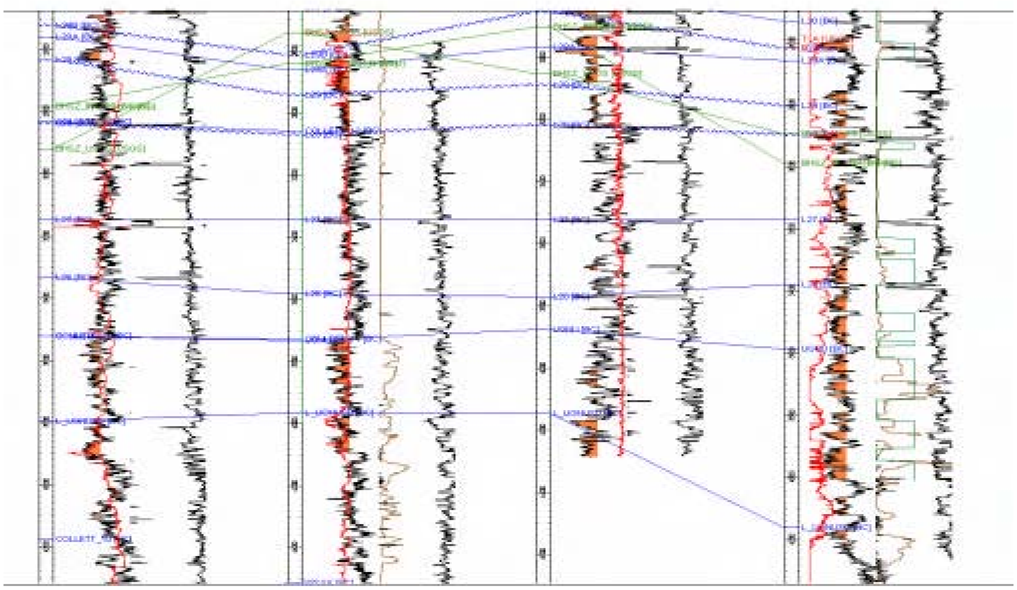


Figure 12: North-South stratigraphic cross section (wells MPL-01, MPA-01, MPS-15, WSAK-24, respectively) showing GR (black), caliper (red) and density (black) curves.

quality. No core material or drill cuttings have been made available to the UA for this study, therefore paleodepositional reconstructions are considered preliminary at this time. The shale unit overlies a fining-upward to blocky coarse-grained parasequence and parasequence set whose gamma ray and resistivity log patterns suggest interbedded point bar, abandoned channel sand deposits, and associated interbedded fine-grained shale drape and levee units. Significant horizontal and vertical heterogeneity exist within these units, which can reach thickness exceeding 200 feet. The apparent lateral extent of the coal-bearing unit (21.5 km) and log character of underlying units suggest periods of tectonic quiescence and subsidence following uplift and erosion as marked by the highly variable transitional facies probably composed of coarser grained fluvial and interbedded finer-grained estuarine deposits.

ii. An investigation into spatial and stratigraphic associations between coal distribution, thickness, and the location of deep oil-gas reservoirs in relation to distribution of shallower gas hydrate resources was started in Phase 1 in the MPU (Figure 13) and was being extended through the AOI in Phase 2. The primary goal was to identify potential source areas that may link directly to uphole/updip gas hydrate formation (e.g. Coalbed Methane (CBM), if any, derived from downhole and/or downdip Tertiary coals, underlying reservoirs, etc.). This description will guide future sampling and isotopic studies that could be readily done at the UA.

iii. Despite previous verbal and written comments to the contrary, the potential contribution of deeper CBM in the formation of shallower gas hydrate is poorly understood. A preliminary spatial analysis of coal occurrence and the distribution of shallow gas hydrate-bearing reservoir sands within the MPU completed in Phase 1 was intriguing enough to warrant further investigation in Phase 2 and 3 (Casavant et al, 2004, Hedberg Conference). Whether there exists a direct linkage to gas hydrate sourcing or whether the coal distribution is simply related to similar tectonic-depositional processes/settings that also happen to control gas hydrate distribution is the crux of the investigation. Statistical and map analysis (e.g. Gandler & Casavant, 2004; Casavant et al, 2004; and UA Phase 2 work) reveals that gas hydrate and downhole coal accumulation seem to be associated with intensely faulted blocks that have experienced reactivation. *(PI Note: Task 5.0 and associated USGS studies indicate that coals are limited to the Staines Tongue stratigraphic interval, which is below all significant gas hydrate-bearing reservoir sands within the predominantly marine Mikkelsen Tongue stratigraphic interval. These studies and associated geochemical source studies suggest that while coalbed methane may provide a local source for some gas, there is a significant (at least 50%) source contribution from mature deeper thermogenic sources, likely related to gas migration from deeper hydrocarbon accumulations through conductive faults into shallower traps. It is possible, however, that nearly 50% of the gas could be sourced from in-situ microbial action from the Staines Tongue interval coal-gas. However, Task 5.0 geophysical studies identified gas hydrate and associated free gas prospects within the Staines Tongue interval reservoir sands. The MPS-15 and MPI-16 wells-of-opportunity penetrated and acquired shallow data within these zones. This data (presented in Section*

5.5 of Quarterly Report #9, July 25, 2005) indicated that these reservoir sands contained low (<5-10%) saturations of gas, which would likely indicate a leaky seal and/or low charge. A low charge may be consistent with a local coalbed methane source and indicative of the limited source potential of these coals).

b. The log-based expert system coal predictor developed by Glass and Casavant (Poulton, Casavant, Glass, 2004) was reviewed and upgraded during Phase 2 studies. The expert system algorithm was extended to all wells within the AOI to assess the hypothesis and explore linkages to upcoming facies mapping, paleodepositional reconstruction maps (Justin Manuel) and to assessments of reservoir continuity effected by facies dimensions, types, and fault offsets and estimated sealing capacities (Hennes et al., 2004). The analysis is complete but date entry, final mapping and documentation remain outstanding at this time.
   i. Knowledge about the quality and distribution of coal-bearing units may be quite useful in fine-tuning the seismic time-depth relationship within the Sagavanirktok formation. *(PI Note: coals are not used as time-lines in chronostratigraphic or sequence stratigraphic studies).*

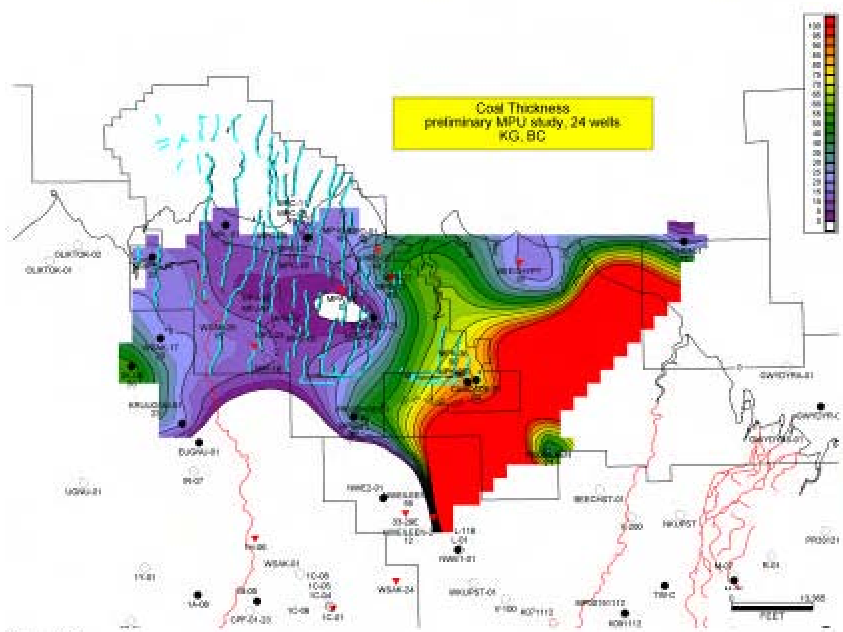


Figure 13: Preliminary and outdated map of total coal thickness for 24 wells in the MPU area.

   ii. Also interesting are isopachs of coal per individual lithosequence. A preliminary investigation of spatial linkages to updip hydrate occurrence, structural setting, facies distributions, and resource volumetrics was begun in Phase 1. Phase 1 findings are awaiting full documentation and integrations with the results of the Phase 2 and Phase 3 studies that encompasses the whole of the AOI.
   iii. Stratigraphic and upcoming facies analysis at the UA will incorporate the coal study (e.g. lateral and vertical distribution of coal related to areas of subsidence/depositional lows/ floodplains adjacent to channel complexes, quality/type/thickness of uphole sands) and presence/absence of hydrate

resource. (PI Note: Task 5.0 and associated USGS studies indicate that no coals exist within the Mikkelsen Tongue zones E, D, and C prospective gas hydrate bearing units. Coals are within the lower Sagavanirktok or Staines Tongue stratigraphic interval).

c. The coal study would help distinguish CBM from other potential conventional sources of downdip/downhole gas that link to the sourcing of shallow gas hydrate. A quick-look analysis done in May 2005 along these lines, has already provided important insights in assessing and risking gas hydrate exploration plays across the AOI where seismic data is not currently available to UA.

5.6.3.4 Gas Hydrate Stability Study

A robust re-analysis of the gas hydrate stability field, based on the UA log-based expert system and published USGS temperature data and based on preliminary findings from Phase 1 study results was undertaken by Glass and Casavant. *(PI Note: During this time period, the USGS also provided all their permafrost and base gas hydrate stability zone data to UA).* To produce an initial estimate of the depth to the base of the ice-bearing permafrost (BIBPF), temperature measurements were obtained for thirteen wells from the USGS website. The thirteen wells chosen for the estimate are WSAK-1, WSAK-11, WSAK-14, WSAK-16, WSAK-17, MPC-01, MPD-01, PBA, PBB, PBG, PBH, PBM, and NHIGHLANDST. Temperature profiles were constructed for the wells. Linear regression constants were derived from the temperature profiles within the ice stability field (ISF) and below the ISF. The BIBPF was determined from the measured depth at which the two linear equations intersect, and is interpreted to be the base of the ice-bearing permafrost. T_{IBPF} was the temperature at which the intersection occurs. *(PI Note: UA may not have compared this methodology to published and provided USGS results; as discussed below, however, the UA method does apparently account for the change in geothermal gradient from within to below the BIBPF).*

The estimates of the BIBPF in eight wells that existed in the UA data base were contoured, and this contour map became the original predicted estimates for wells in which no temperature data were available. To refine the BIBPF estimates in each well, electrical resistivity and compressional wave velocity profiles were used to further refine the estimate of the BIBPF. The depth to the BIBPF was chosen as the depth at which the compressional wave velocity and electrical resistivity profiles could not support an interpretation of ice, or where the character of the permafrost velocity and resistivity values, as characterized by the near-surface region, changes.

A similar procedure was chosen to estimate the depth to the base of the gas hydrate stability field (BGHSF). In this case the depth and temperature limits for gas hydrate stability were taken from the laboratory testing of Westervelt (2004) and modeling by Collett (1993). Wells used for this analysis are the same as used for estimating the BIBPF. Results for the thirteen control wells (those having measured temperature profiles) were compiled and each well within the AOI was assigned a sub-permafrost geothermal gradient and surface-temperature intercept based on the nearest control well. The regression equation surface-temperature intercept was then adjusted to fit the BIBPF in each well to be estimated. An estimate of the BGHSZ for each well was made by projecting the new regression equation downward from the BIBPF to its intersection with the published models for temperature/pressure limits for gas hydrate stability.

UA's modeling of the base of the ice-bearing permafrost (BIBPF) and base of the gas hydrate stability zone (BGHSZ) was compared to the USGS data. The preliminary analysis was completed just prior to the close of Phase 2a contract (6/30/05). Our preliminary findings have important implications *(PI Note: these important implications have not yet been fully documented)* to upcoming well tests, planning, reservoir and production modeling efforts, and future site selection. We have completed a preliminary investigation that has provided a much clearer understanding of linkages between the gas hydrate stability field and the tectono-stratigraphic framework of the AOI. Finalization of maps and documentation will commence in Phase 2-3a studies.

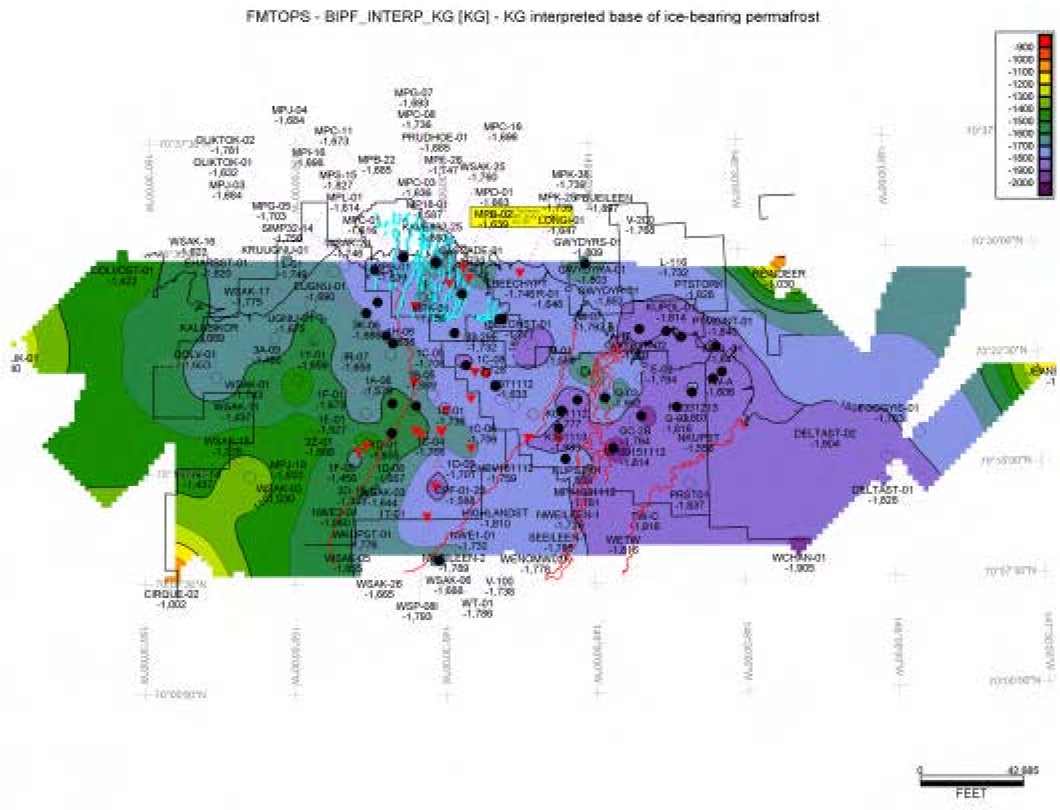


Figure 14: Preliminary PETRA-gridded structure (fluid) map showing depth to the base of the ice-bearing permafrost (BIBPF).

The Figure 14 map is more robust than previously published data and includes BIBPF derived from the UA log-based expert system and incorporates all available published temperature log data. Yellow to purple colors represent shallow to deepening depths, respectively. In a few wells where the predicted BIBPF fell within a thick shale or siltstone interval, manual adjustment of the pick was based on the depth of the BIBPF in nearby wells. The above interpretation incorporates the small number of wells (13) where downhole temperature data was acquired. The preliminary characterization proposes linkages between deep and shallow structure and associated stratigraphic control on the BIBPF (e.g. Collett et al, 1989; Casavant, 2001). Reactivation of basement-surface fault structures and related facies changes within the ice-bearing permafrost interval may be linked to abrupt variations in depth and orientation of some well-constrained contours observed in several maps. Noted is a spatial coincidence between abrupt changes the morphology of the gas hydrate stability field and some major fault segments that bound the northwest-trending Eileen fault block and with the distribution of mapped reservoir facies. North-northeast offset and rapid changes in trends from the predominant northwest gradient relates to deep-to-shallow north-northeast-trending faults that studies indicate were reactivated during and since Sagavanirktok time. Linkages to the distribution of certain facies types both within and below the gas hydrate stability field were being investigated. Documentation of methodology and interpreted tectono-stratigraphic linkages is planned during Phase 2 and 3 studies.

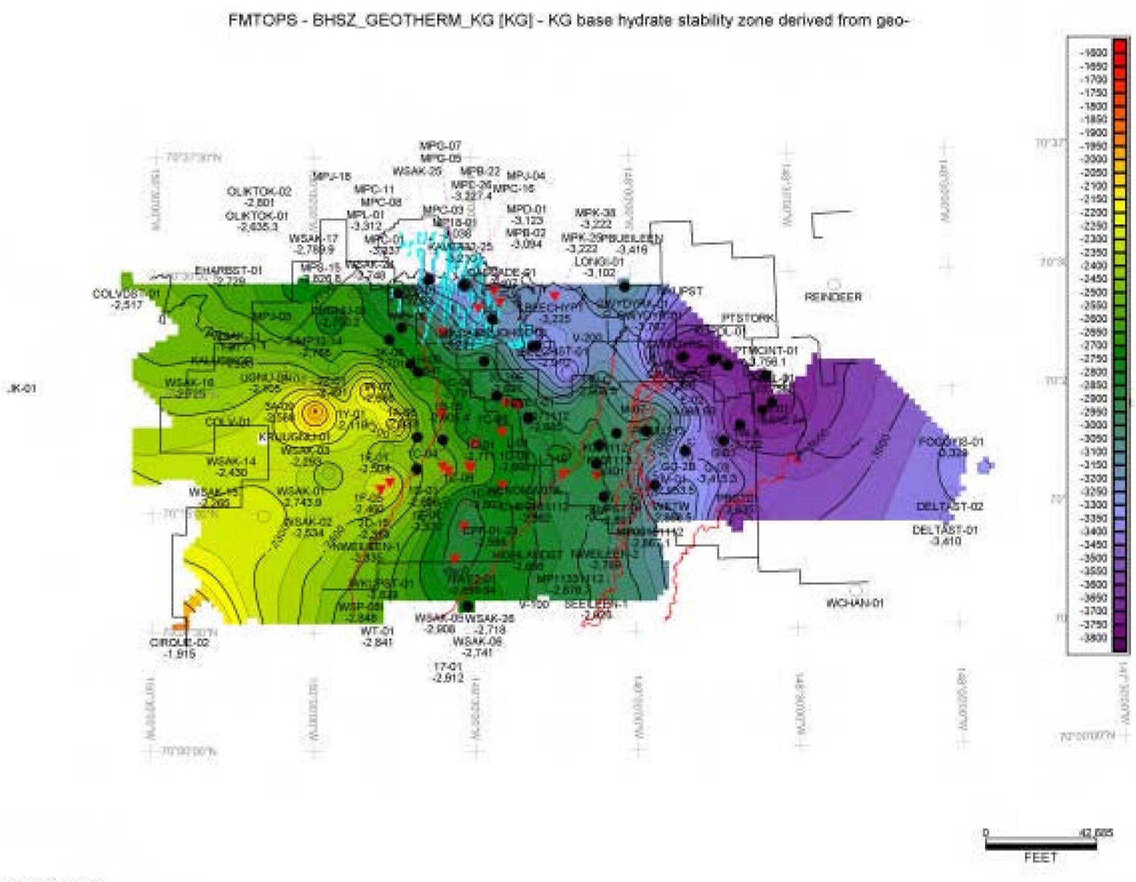


Figure 15: Preliminary UA fluid map on the base of the base of the gas hydrate stability zone (BGHSZ).

Yellow to purple colors in Figure 15 represent a general shallow to deepening of this P-T related fluid horizon from west to east. Note the position of the MPU in relation to gradients and orientation. The methodology of how this surface was derived, linkages to the geology and distribution of gas hydrate resource, and strategies for exploration are planned to be fully documented during Phase 2-3 studies. Figure 16 illustrates a fluid map of the BGHSZ from USGS-published data. Figure 17 shows the thickness of that portion of the gas hydrate stability zone between the interpreted BIBPF and BGHSZ fluid structures shown in figures 14 and 15, respectively. Documentation of methodology and implications of the maps shown in figures 15-17 regarding characterization of gas hydrate resources are planned in Phase 2-3 studies.

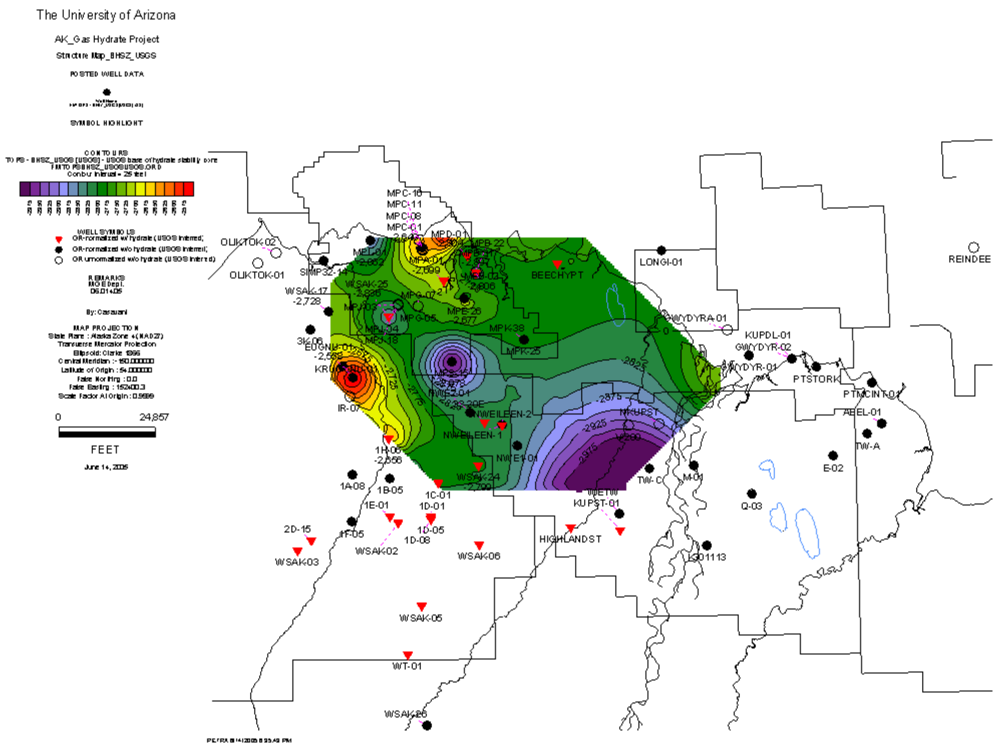


Figure 16: Structural contour of base of gas hydrate stability zone (BGHSZ_USGS using available data published by the USGS across the AOI (area of interest).

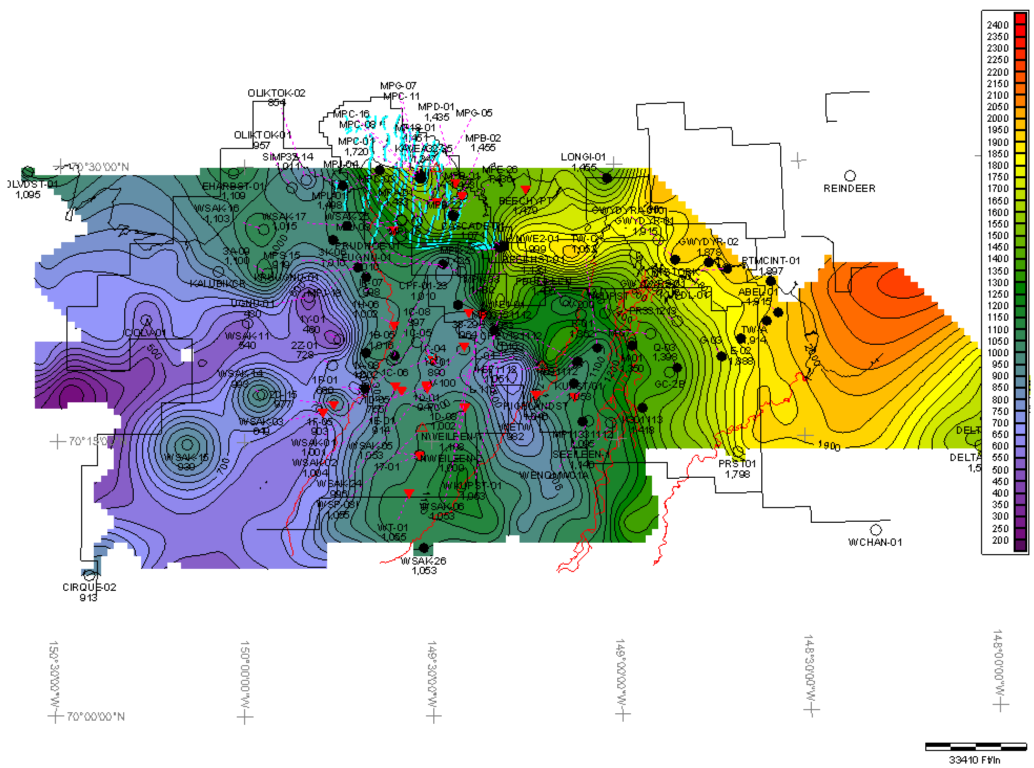


Figure 17: Isopach map of the UA's BIBPF to BGHSZ showing variations in thickness of the gas hydrate stability field.

5.6.3.5 Relation of Structural Control to Gas Hydrate Occurrence

The relation of deep structural control to shallow gas hydrate occurrence (although previously implied in published reports) was begun across the AOI in Phase 2 UA studies.

a. Structural and isopach maps of the deeper units within the AOI have proven useful in understanding deep-shallow structural-stratigraphic linkages in the absence of seismic data in the KRU and PBU areas and deep seismic data in the MPU. This facet of research was first investigated in the MPU (Casavant et al, 2004; Hennes et al, 2004) during Phase 1 studies and was extended to the KRU and PBU areas in Phase 2 (the latter phase also included the incorporation of an additional 40 wells to the data base, some of which lie outside the AOI). Numerous deep marker picks/correlations were made down to below the Highly Radioactive Zone (HRZ) marker (e.g. Kuparuk River formation and Lower Cretaceous Unconformity (LCU).
b. Although preliminary and differing somewhat from the tops known to be used in industry, the map and cross-section products have been useful in fine-tuning shallower correlations and identifying/predicting subtle changes in structure and facies within the shallower Early Tertiary-Late Cretaceous) Ugnu and West Sak formations and overlying Tertiary Sagavanirktok sediments as a result of the basement fault reactivation as discussed in Casavant (2001). *(PI Note: Definite linkage of deep structure to overlying depositional systems may not be as clear as stated here. Some published deeper fault maps would probably be more beneficial to this portion of the research than isopachs of deeper formations).*
    i. Cross-sections (not shown here) have demonstrated the linkage between deep fault structures and flexures to subtle changes in dip, fault offset, and stratigraphic changes within the shallow Sagavanirktok formation. The structure map in Figure 18 reveals a major and complex northeast-southwest-trending basement fault zone to the south of the MPU. This and other structural fabrics are manifested in a variety of other mapped data (stratigraphy, fluid contacts, etc). *(PI Note: It remains important to note that this interpretation is based on fault compilation maps and log-based studies only (no seismic data incorporated into the analyses). The potential linkage of deep structures to overlying depositional systems remains speculative).* Comparison of maps like that shown in Figure 18 with shallower maps of facies and fluid boundaries indicates deep structural control on shallow resource distribution and may warrant continued investigation. Completion and documentation of this work is planned for Phases 2 and 3.
c. Well-log-based tectono-stratigraphic analysis of AOI continued. Precursory studies in the latter part of Phase 1 and during Phase 2 revealed complex linkages between gross formation thickness, net-gross characteristics of stratigraphic sequences, and connectivity of flow units within the Sagavanirktok formation to the location and quality of published gas hydrate or free-gas. This issue was discussed in previous Phase 1 UA progress reports, in initial MPU volumetric analyses, and in presentations at the 2004 Hedberg conference. The UA team continued these studies in efforts to re-address this concern, primarily in support

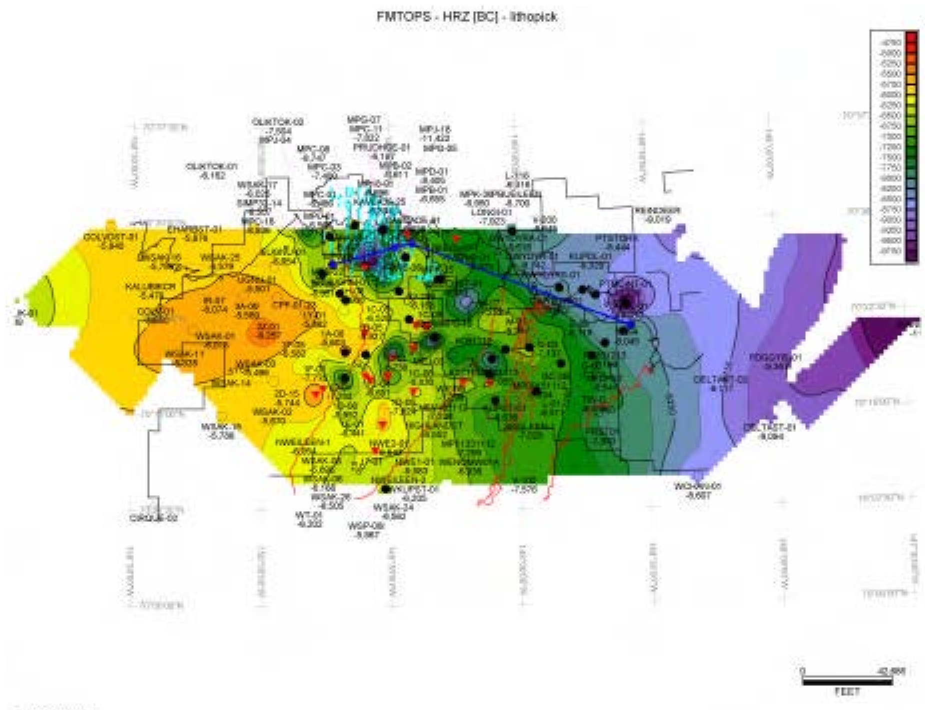


Figure 18: Preliminary structure map of a regional marker bed within the (depths of 5000 to 9000+ ft TVDSS).

of production forecasting and reservoir modeling activities. Future analysis will incorporate the location/depth of *UA* interpreted gas hydrate and free gas occurrences compiled across the entire AOI and not just the MPU as was done for Phase 1. Up to this point only published gas hydrate occurrences across the AOI have been used in the UA analysis. *(PI Note: UA has clearly completed independent gas hydrate occurrence assessment from log analyses and correlation studies).*

5.6.3.6 Log Normalization Update

a. The UA well log data base has grown from 96 well to 130 wells since the early stages of Phase 1. Given the attention on the regional characterization of the AOI in the latter part of Phase 1 and in Phase 2, and the higher number of wells involved it was determined that GR normalization would be reviewed. GR normalization is a useful approach to establish and apply statistically valid GR shift where needed in order to nullify man-made variations in tool response that are linked to a geologic units whose composition varies little to none (Geauner et al, 2004). GR normalization played a key role in our earlier net-sand and net-gross calculations in our Phase 1 reservoir mapping and resource assessment work. A second normalization based on new and old wells was completed in late May 2005 and both results compared. The median shift of the population did not appreciably change, however, outlier wells in the normal distribution increased in the magnitude of required GR shift.
b. A determination of a new sand-shale cutoff for each individual well within only the Sagavanirktok interval was also started in order to remedy some erroneous

bulk GR shifts that were associated with problem logs in the earlier GR normalization. We had not used these wells in our Phase 1 work, but now want to include them (after adjusted) into our Phase 2 and 3 analyses. We have noted that cutoffs and bulk shifting of log curves can only be applied to similar geologic packages and not to the entire curve. In certain wells, the GR logs sometimes abruptly shift across regional unconformities and where log runs either terminated or were sutured to another GR run. Sand-shale cutoffs are critical to our upcoming volumetric analysis of the *whole* of the AOI (Phases 2 and 3). This work should be completed during Phase 2-3 studies.

5.6.3.7 Seismic Time Slicing and Reservoir Analyses

Seismic time-slicing and reservoir seismology analysis/mapping was initiated during Phase 2 studies.

a. Scott Geauner (Casavant, MS student) is researching scaling issues for phase and amplitude attributes in preparation for reservoir seismology study initiated in Phase 2. Channel-like sand units have been observed in Phase 1-2 well log analysis and correlation studies; in some areas, these channel-like units appear to be spatially associated with interpreted gas hydrate and free-gas accumulations. Such linkage still remains speculative at this time, but worthy of investigation given their high reservoir quality, linkage to gas hydrate resources, and wide-spread distribution within some zones.
b. Reservoir seismology and seismic geomorphology research is anticipated to continue during Phase 2 studies within stratigraphic sequences that can be linked to and validated by log-based studies. The MPU seismic geomorphic analysis will be integrated into the regional log-based facies characterization and mapping done by J. Manual (introduced below).
c. During Phase 2 studies, Scott had begun his research into attribute clustering for depositional facies identification (primarily channel), use of Principle Component Analysis and other statistical and processing methods and had produced pilot or test slices from the shallow MPU time cube. *(PI Note: This most likely refers to the UA MPU seismic volume, not the USGS-reprocessed seismic volume).* These slices exhibited significant variation in amplitude and interesting elemental forms (real or artifact) that require further study and validation against log-based geologic maps (control set). *(PI Note: It should be noted here that the log-scale resolution is much finer scale than the seismic dataset resolution. It should also be recognized that many of the log correlations between the wells within the AOI are made over a distance of miles, which may call into question the ability to determine lateral continuity of facies discerned within an individual well log within only a log-based study. An alternative method would be to conduct a geostatistical approach using geobodies calculated from facies interpretation of sands within a single well log and distributed accordingly within the study AOI. A related question is whether or not the frequency of the well-log-based data is sufficient to determine or interpret the lateral continuity of certain facies.)* The foundation of this thesis will rest on both the integration of many activities discussed above and on the accurate identification of channel-facies before further seismic characterization can proceed. Scott's study will integrate the distribution

and quality of gas hydrate resources as interpreted by the UA Phase 1 work within the MPU area and compare/contrast these findings with facies typing, estimated continuity, and volumetric calculations derived from Phase 1 work and from Justin Manuel's Phase 2 and 3 thesis work.

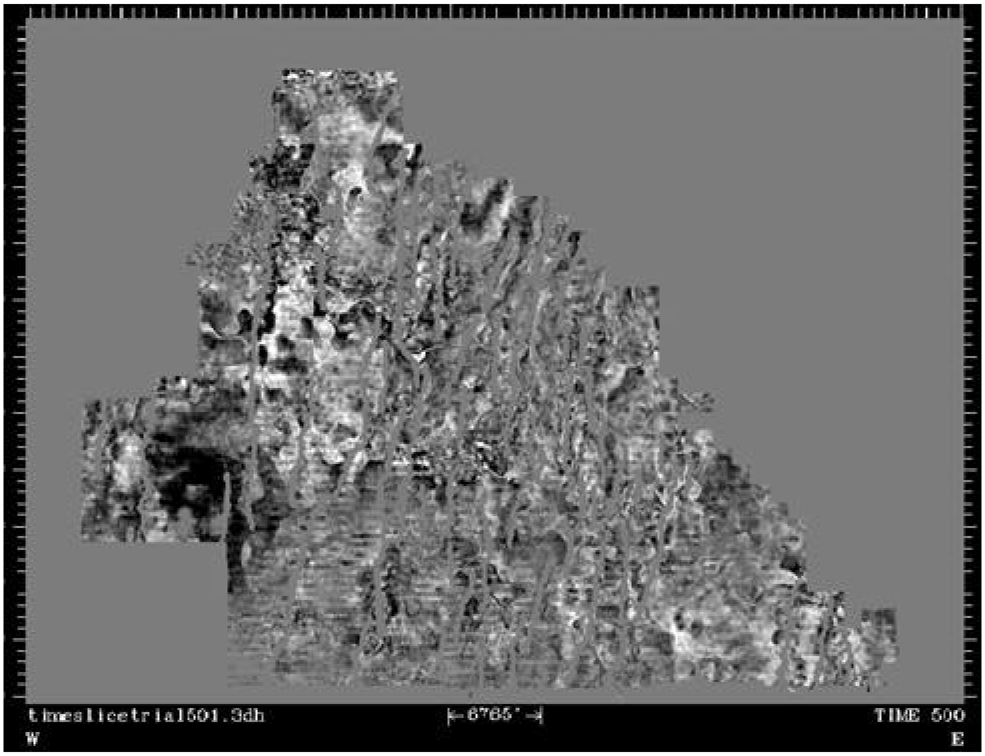


Figure 19: Time-slice of an interval within the 3D MPU dataset

This image shown in Figure 19 is a time-slice within an interval of the 3D MPU seismic volume. Absolutely no geological interpretations should be made from this very preliminary image showing a time-slice flattened on what the current time-depth analysis indicates is the USGS Zone E horizon as picked and autotracked across Milne Point Hennes (2004). 10ms time-slices were constructed, sliced through a stratigraphic sequence capped on top by the Zone E horizon, and confined on the bottom by UA marker or sequence pick S_34 (also picked and tracked by earlier by Hennes, 2004). It is anticipated that the slices will help identify and distinguish variability within the sequence with respect to key depositional facies, which in turn may relate to hydrocarbon potential and reservoir characterization across the MPU and AOI. Further review indicates that horizon repicking will be necessary in some areas of the MPU since some of the attributes on this very precursory image are associated with horizon mispicks related to the autotracking. New additional horizons and thinner-scale sequences observed will also be correlated and mapped based on the identification of unconformities in wells and seismic, which had been noted and reported, but not mapped, in Phase 1 studies.

5.6.3.8 Facies, Paleodepositional Reconstruction, and Volumetric Studies

Well log-based facies analysis, paleodepositional reconstruction, and AOI volumetric studies were initiated in Phase 2.

a. Conceptual studies in this subject were completed in Phase 1 and work was anticipated to be completed in Phase 2.
b. Facies variations across the AOI can be linked to a variety of reservoir poro-perm characteristics, dimensions (volume) and connectivity (important to drilling and production engineering strategies), and economic forecasting.
c. J. Manual (Casavant, MS student) continues to train in recognizing and mapping discrete facies packages for paleodepositional mapping and AOI volumetric analysis, given that gas hydrate resources occur within a variety of facies types. Modern and ancient sand body dimensions as well as deterministic mapping of the AOI data will be integrated into definitions/predictions of sand body type dimension, extent and connectivity.
d. The above will be used to high-grade MPU AOI volumetrics and provide preliminary and comparative assessment to the USGS volumes across the AOI. This work will be integrated with other facies work and integrated into recovery and reservoir engineering models upon its completion in Phase 3 (2006).

5.6.3.9 Sequence Boundary and Flow Unit Assessment

In conjunction with the facies determination, Phase 2 studies are planned to develop a reproducible and accurate “unconformity flag” for improved sequence identification and fluid flow unit assessment that is based on both log signature and seismic criteria, where available.

5.6.3.10 Stratigraphic Studies of Staines Tongue and Zone C

Ken Mallon (KM) initiated stratigraphic studies of 2 main potentially gas hydrate-bearing sand intervals, the Staines Sand and the Zone C horizon, in order to explore and document stratigraphic heterogeneities that might impact gas hydrate reservoir morphology and volumes. *(PI Note: The Staines interval reservoir sands were reported on in Task 5.0, Quarterly Report #9, and shown to be of low-gas and gas hydrate saturation as interpreted from the wells-of-opportunity MPS-15 and MPI-16. The low saturation calculations are interpreted to be due to leaky prospect seals and/or poor gas charge (see related discussion in Section 5.6.3.3 with regard to coalbed methane).*

a. Tested various display designs in Petra and/or Landmark to determine benefits in exhibiting the stratigraphic complexities of the C Horizon and the Staines sand. Decided to use Petra due to its ease of use and data transfer.
b. Overlaid net to gross maps for the C and the Staines with well log curve displays to illustrate sand characteristics and facies changes, and those relationships to Net/gross anomalies.
c. Displayed Gamma Ray curves and expert system fluid predictor curves for the intervals. ANN curves will be incorporated in the future.
d. Imported and overlaid seismic fault maps from Milne Point on the sand maps and log curve displays, providing further opportunities to delineate potential gas hydrate-bearing reservoirs.

5.6.3.11 Artificial Neural Network (ANN) and Expert System (ES) Studies

a. ANN analysis of all wells in Milne Point and several wells in eastern Kuparuk River Unit have been completed. A computer code has been developed to extract salient features from normalized gamma logs and other logs for use in depositional facies classification and an initial ANN is trained to identify some major depositional facies (e.g. sand, coals, shales). Additional "expert" or deterministic tweaking of this preliminary ANN is required. It is hoped to develop an ANN that will be able to identify individual sand body types for future work.
b. Results of the log-based fluid prediction in the ANN and ES schemes has been completed for every well containing shallow data within the MPU and checked against geologic evidence and quick-look analysis to determine the credibility of the predictions. We have confidence that the automated systems correctly predict the presence or absence of gas hydrate, where sufficient well log data are available.
c. ES facies and fluid predictions have been completed now for most of the wells within the AOI. Predicted outcomes include facies such as coals, soil horizons or cemented intervals (potential sequence boundaries), and fluid types such as gas, gas hydrate, oil, free gas, and water.
d. Work on the Landmark-MATLAB interface will commence to enable extracting seismic data from Landmark and performing the ANN classification of seismic facies and fluid types. Once we have our ANN and expert system facies and fluid predictors imported into Landmark we should be able to attach a more credible geological interpretation to the classified seismic facies and fluid types. We will be creating maps of depositional environments to correlate with the seismic data, cross sections, structure analysis, and do a re-analysis of the USGS prospect polygons. This work and summary of results is scheduled for the latter half of Phase 2 or Phase 3.

5.6.3.12 Regional Fault Map Studies

The locations of major regional faults across the AOI have been compiled from pre-existing studies and published data. At this time only shallow faults within the MPU, which were derived from the UA MPU seismic interpretation (Hennes et al., 2004) are being displayed and considered in analysis on UA map products. Older maps of deeper fault sets (E. Cretaceous faults in the KRU, Paleozoic faults in the PBU) derived from published studies, were being digitized and would have been geospatially registered and displayed alongside the shallower MPU faults. This information has and will continue to support our geologic characterization of gas hydrate resource distribution within the AOI.

5.6.4 Phase 2 Reservoir Characterization Studies – October 2005 through end-January 2006 Status Report

5.6.4.1 Educational Component of the UA Gas Hydrate Research Program Studies

A mid-2004 a small preliminary spatial statistical study of fault locations, morphology and interpreted gas hydrate occurrence across the MPU was undertaken by Gandler and Casavant. This work comprised a significant component of a senior geological engineering undergraduate study by Greg Gandler in the Department of Mining and Geological Engineering. Greg's study represented just one of several examples of student projects (roughly 12) undertaken at the UA as a result of the industry-government-university collaboration and data afforded by the gas hydrate research. As a result of the project studies, students have had significant exposure to a "typical" challenging and multi-disciplinary industry project as well as the various professions this represents. As a result of this exposure and experience with the project, Greg and several of his close colleagues chose to continue their education in natural resource development in graduate school. Greg was selected to attend the Petroleum Engineering graduate program at the University of Texas, Austin and will have acquired a M.S. degree in petroleum engineering. To date, the UA gas hydrate research program has provided partial or full support for 5 undergraduate studies or research assistantships within the Department of Mining and Geological Engineering and contributed directly or indirectly to the completion of 6 graduate theses from the Departments of Mining and Geological Engineering and Geosciences. One hundred percent of UA students who elected to participate in the gas hydrate research program received employment offers early in their programs and elected to start careers in natural resource development. Roughly 80% percent of the UA graduating gas hydrate studies students have taken on or will begin careers in the petroleum industry, while the remaining 20% have elected employment in geohydrology and environmental science, respectively. This outcome does not include a number of "non-gas hydrate" students who elected to change majors and/or consider career choices in the energy industry as a result of their association with the student and/or faculty research participants.

As is apparent from the above small and large student projects, such as the example mentioned above, support of this research program provides both undergraduate and graduate students a unique and applicable education experience at various levels of difficulty and comprehensiveness that are all too often not available in many university programs (even though some may proclaim so). Since 2001, the DOE-BP funded UA gas hydrate program research has provided numerous high-quality opportunities for learning, teaching and expanding fundamental knowledge and skill sets needed to tackle the complex 3D and 4D reservoir engineering and petroleum geology projects that underpin our nation's security and prosperity. Furthermore, the availability of industry data and support allow all project participants to immediately and directly apply and test their knowledge and skills in an integrative project where information and research outcomes may affect actual business decisions related energy exploration and development in the past student's professional lifetime.

The UA gas hydrate research program has allowed earth science and earth engineering students (both undergraduate and graduate) to become familiar with a number of state-of-the-art interactive seismic and subsurface geologic workstation systems in common use in the industry today. Students have received exposure to and have had to integrate a number of other common industry surficial and subsurface geological and geophysical software in their studies (including petrophysical, mathematical, statistical, graphics, and image processing). They have acquired fundamental skills and knowledge in petrophysics, wellsite geology, and drilling engineering, and have learned how to perform interdisciplinary research that involved the collection, integration, analysis, and mapping of a variety of subsurface and surface geologic and engineering data. They have developed a basic proficiency in three- and four-dimensional conceptualization and interpretation and have also completed professional quality presentations on the geology, engineering and thermodynamic and rock-fluid phenomena that relate to the characterization of gas hydrate resource occurrence on the ANS. It is difficult to exaggerate the positive benefits that programs such as these have on the training and development and of our future workforce in the energy industry. In addition to and irrespective of any or all technical outcomes from university research programs such the UA gas hydrate program, the educational component and environment that such integrative and supported programs provide cannot be understated and over-appreciated for that matter. The capacity of these collaborative and fully supported programs to lay basic groundwork for educating tomorrows' workforce regarding natural resource management and sustainability and the ability of such programs to provide a balanced technical and political environment to explore and learn about the energy industry is simply unsurpassed.

Programs, like the DOE-BP funded UA gas hydrate research, are in effect a very productive and profitable investment by industry and government. As a result of such programs and support they afford our universities, natural resource departments across our nation can attract and support students and faculty in a manner they could not do otherwise. This is critical in that faculty who have considerable technical and intimate hands-on experience in the business of the industry, can be supported and join the academic ranks to lead and collaborate in the comprehensive and challenging process of educating and preparing the future industry workforce. Industry and government supported programs such as this are critical to replenishing a creative and capable, but aging workforce within the energy industry. Also, being hosted within a large and renowned research university in a non-oil state, programs like the UA gas hydrate research also provide much needed social perspective and talent to students and faculty who specialize in other technical and non-technical fields and vocations (e.g. environmental science, civil service, political science, business, etc.), which at a variety of scales can and often do wield far-reaching and more productive outcomes for the industry The more educated our nation's workforce and voting population become regarding natural resource exploration, management, and sustainability, the greater the business and societal contributions of the energy industry will become.

5.6.4.2 Regional (AOI) Structural Analysis and MPU Seismic Sequence Stratigraphy and Facies Characterization

The Phase 2 fault and Phase 3 structural characterization across the MPU via 3D seismic data (Hennes and Hagbo MS theses) continued through late 2005. The earlier seismic-based fault and structural characterization of the MPU was extended throughout the entire AOI during late Phase 2 and early Phase 3, using well log information and available published fault maps (e.g. Collett. Carmen Hardwick, Casavant). Since the November 2004 Hedberg gas hydrate conference, an additional 78 well logs were added to the UA well log data base and all available published fault and structural maps across the AOI were incorporated into the studies. One component of the UA research has focused on improving our understanding of fault morphologies and occurrence at the shallow Sagavanirktok formation level, their spatial relationship and connectivity with deformation at deeper levels across the AOI (e.g. within the KRU at the Ugnu-WSak (4000 feet BMSL) and Kuparuk River (6000 feet BMSL) and the western half of the PBU at the Sadlerochit (9000 feet BMSL)), and their linkage to reservoir facies types, distributions, and quality as these may relate to gas hydrate and free-gas resource distribution and volumes. Although preparatory groundwork and a preliminary tectonostratigraphic framework were presented at the 2004

Hedberg conference by the UA research team, sufficient data and linkages revealed in the presentations indicated an unequivocal, but complex interaction between structural and stratigraphic controls associated with basement fault reactivation, syndepositional faulting and known and inferred gas hydrate/free gas occurrences. Examples of the shallow gas hydrate accumulation and trapping at the intersections of conjugate north-northeast- and northwest-trending basement fabrics was also superbly illustrated by Task 5.0 seismic based prospects presented at the conference such as the Mt. Elbert prospect.

Results of that preliminary Gandler study mentioned above were presented in a poster format at the 2004 Hedberg conference (Gandler, G.L., R.R. Casavant, R.A. Johnson, C.E. Glass, and T.S. Collett, 2004, Preliminary Spatial Analysis of Faulting and Gas Hydrates-Free Gas Occurrence, Milne Point Unit, Arctic Alaska). The work signaled implications for exploration of gas hydrate resources outside of the MPU area where fault mapping via available 2D seismic and well logs might be adequate. One of the more significant outcomes of the study suggested a that moderate relationship existed between fault density per unit area and morphology of a fault zone with (a) occurrence of gas hydrate-bearing units as interpreted at that time from earlier USGS fluid assessments and (b) distribution of net reservoir sand as mapped by the UA team across the MPU. It was hypothesized that the correlation may relate to those complex and basement-related fault zones (FZs) that have (1) a higher probability of reactivation, (2) controlled the distribution of shallower coarser-grained fluvial-deltaic deposits within the Sagavanirktok formation, and (3) have intersected at depth multiple oil reservoir rocks (sources) that now have direct linkage with the overlying Sagavanirktok reservoir rocks via fault conduits. As Collett (2004) had pointed out, such FZs probably are good avenues for periodic and/or continuous leakage of light gas components from the deeper hydrocarbon sources. Recent spatial analysis and mapping by Casavant on the WSak-Ugnu reservoirs in the KRU support this hypothesis and this documentation is in progress.

As a result of that earlier Gandler study, the UA team expanded the scope of its structural investigation across the entire AOI. Detailed findings from the earlier MPU 3D seismic data have been extrapolated south and west into KRU and southeast into PBU areas and integrated with published regional fault patterns in those units. This regional data will help investigate structural linkages to general facies distribution across the AOI and specific reservoir sand unit dimensions in the MPU as identified from well logs and 3D seismic data, respectively. Current MS research, facilitated by S. Geauner involves the identification and mapping of seismic facies within the MPU. This study is coeval with a regional chronostratigraphic study that is addressing facies types and their distribution across the entire AOI (J. Manuel thesis).

Scott's MPU 3D seismic fault review and seismic facies characterization builds upon work that was started by Hennes et al (2004) and Casavant et al. (2004). It involves the identification of seismic sequences within the Sagavanirktok formation, which were not identified or broken out in "topset play" and slope channels of the "turbidite play" intervals in the thick Brookian sequence (e.g. Houseknecht and Schenk, U.S.G.S. ANWR 102 Open File Report 98-34). Confirmation of the finer UA seismic sequence stratigraphic framework and interpreted systems tracts is also being integrated and constrained by a regional sequence stratigraphic framework for the whole AOI that is based on well log control (Manuel and Casavant). The goal of Scott's detailed seismic facies study and our regional chronostratigraphic analysis is to see if we can better characterize local and regional structural-stratigraphic controls on gas hydrate occurrence, which published studies to date have mostly described in general terms (e.g. Collett et al, 1988). Several components of this work are the focus of a robust MS research project by Scott Geauner (MGE). Scott's thesis: "Fault analysis, seismic facies modeling and volumetric reassessment of gas hydrates in the Milne Point Unit, North Slope, Alaska," is scheduled for completion in May, 2006.

While some of the findings from Scott's detailed fault characterization validate preliminary linkages stated in the Gandler-Casavant 2004 study, other findings are new. For example his more extensive analyses validate some characteristics common among the larger north-northeast-trending faults. These faults are more often than not complex multi-splay fault zones (FZs) containing mostly synthetic and few antithetic splays. Previous USGS, UA, and industry studies have mostly depicted these zones as single fault features on published maps and have addressed mostly the larger fault displacement only (e.g. Hennes, 2004; Hagbo, 2004). But as Gandler et al (2004) and Casavant et al (2004) pointed out, the multiple splay zones may characterize zones of repeated fault block reactivation and it is highly probable that these link to sand deposition and updip fluid migration in numerous ways. The FZs described by Scott vary in width along an individual zone and relative to other zones. Changes in width are often associated with much of the north-northeast displacement being partitioned across and taken up by low dip-displacement, but possibly more lateral displacements along north-northwest-trending FZs. We hypothesize that the low dip-offset of the north-northwest-trending FZs have caused these FZs to be under-characterized when it comes to their role in fluid migration, entrapment and facies changes.

The north-northeast-trending FZs are characterized by intense faulting, are laterally extensive, and often exhibit the greatest amount of throw if one adds total displacements across a single FZ. As Casavant et al (2004) demonstrated at the 2004 Hedberg conference regarding sand thickness in the MPU, these zones are interpreted to bound a transtensional basin. Scott's more recent characterization has mapped in detail the locations of all the multiple normal fault splays that characterize the basin-bounding FZs. Within the limits of the MPU a few extensive and prominent north-northeast-trending FZs do exhibit what appears to be a single, fault plane (e.g. several high-angle west-dipping north-northeast-trending faults that bound two half-grabens west of the WSak 17 and WSAK 25 wells, respectively. For a majority of north-northeast-trending FZs, however, 3D seismic data show that predominantly west-dipping displacement is partitioned across anywhere from three to six fault splays. All of the fault splays are interpreted to be high-angle and do not converge within the shallow seismic data set available to us (above 950 ms). Their downward projection does suggest convergence with depth with what has been interpreted a master basin-bounding sidewall fault associated with a deeper-seated pull-apart basin (Casavant et al., 2004). If this hypothesis is validated, the latter mostly likely formed above a reactivated basement-seat wrench zone (possibly related to a paleo-transform or near-margin transcurrent FZ that was reactivated during earlier Paleozoic and later Mesozoic rift events that shaped the current morphology of the Alaska Arctic Terrane (Casavant, 2001).

Given that the total displacement on a fault system is the sum of throws across the multiple splays of that system, Scott will be re-investigating fault displacements associated with these FZs in an effort confirm or re-establish total displacement. Locations of many interpreted gas hydrate and free-gas occurrences along major FZs across the AOI suggest that reservoir sand juxtaposition may play an important role in gas hydrate entrapment or that these resources are simply retained within these zones having migrated up along fault planes (Collett et al., 1988). Our reinvestigation of fault throws may prove very important if we are to accurately assess reservoir sand continuity across individual splays within a FZ to establish whether the trapping of gas hydrate occurred at the fault. These descriptions in prospective areas should be accounted for in future reservoir engineering models and integrated with interpretation of seismic data wherever possible. This work will be compared to and linked with earlier studies on resource trapping and distribution (e.g. Hennes et al, 2004; Hennes thesis), which addressed the potential role of clay smearing along fault planes as a mechanism (and predictor) for gas hydrate and free-gas resource trapping against faults in up-dip positions (Figure 6).

Major components of Scott's detailed MPU fault characterization and mapping unequivocally validated many of the preliminary observations shown at the 2004 Hedberg conference (Casavant et al, 2004) and validated during Phase 2 studies. These include: (1) deformation along many of the largest and more complex (multi-splay) north-northeast-trending fault zones (FZs) and intermittent northwest-trending FZs that extend from the basement to the surface and in some locations appear to control the geomorphology of some rivers and coastline trends within the MPU. This was demonstrated along the Barrow arch and in KRU-PBU areas in Casavant, 2001); (2) a minor, but recognizable transtensional component along the north-northeast-trending basin bounding FZs as validated by fault oversteps or transfer zones as illustrated at the Hedberg conference by Casavant et al (2004); (3) basement fault reactivation occurrence along both north-northeast- and northwest-trending FZs within the MPU; and (4) the northwest-trending "hingeline" swath of Hennes et al (2004) as one of several discontinuous zones of northwest-trending FZs (Casavant et al, 2004). These FZs exhibit only minor normal displacements at the Tertiary-level. This may reflect the presence of a larger translational or strike-slip component that is more difficult to reconcile on vertical seismic lines.

Recent stratigraphic analysis and paleodepositional mapping across the entire AOI by Manuel and Casavant (in progress) confirm several phases of Tertiary reactivation along several of the major northwest- and north-northeast-trending FZs as documented by Casavant (2001), and discussed again by Casavant and others (2004 and Hennes and others (2004) at the Hedberg conference. The nature of structural-stratigraphic linkages with regard to control on facies distributions, paleodepositional environments, gas hydrate occurrence, and reservoir volumes are being finalized in UA regional studies and will be documented in several papers and thesis (J.Manuel) due for review in mid-2006.

5.6.4.3 Gas Hydrate Stability Study and Expert System Fluid and Facies Predictor

Structural and fluid analysis in Phase 1 2004 and Phase 2 2005 studies by Glass and Casavant also reveal the association of relatively thick coarse-grained low-stand tract fluvial deposits that have been identified within AOI. The fault systems that controlled the location of what appears to be incised channel systems may have a pronounced influence on where one picks the depth of the base of the ice-bearing permafrost in such areas, and thus, the gas hydrate stability window required for resource accumulations to be interpreted or explored. Several papers by Glass and Casavant that are in preparation at this time (listed below) document Phase 2 and 3 UA studies pertaining to regional "quick-look" fluid predictions. Preliminary isopachs of the gas hydrate stability interval argue strongly for structural-stratigraphic control on the gas hydrate stability field. Expected completion of these drafts (in progress) for subsequent review and submission for peer-reviewed publication is also planned during summer 2006. Three planned publications include:

1. Estimating the Base of the Ice-bearing Permafrost Using Simulated Well Bore Temperature Logs, North Slope of Alaska

2. Use of Thermal Conductivity Modeling to Distinguish Gas Hydrate from Ice-bearing Sediments within the Ice-bearing Permafrost on the Central North Slope, Alaska

3. Expert system for estimating pore fluid concentrations below permafrost using petrophysical well logs on the Alaskan North Slope

Work on the artificial neural network research (ANN) has progressed minimally since late 2004 to mid-2005. The principal investigator, anticipates possible reactivation of the ANN research during the summer 2006 when sufficient time for research can be dedicated. ANN training and prediction of facies and fluid types using only well log data resulted in modest success in Phase 1 and 2. Results of that work were presented at the 2004 Hedberg conference (poster by Poulton, Casavant, and Glass). The next phase of the proposed ANN research is now scheduled for summer 2006 and providing that funds still remain during the no-cost extension period, it will focus on trying to identify and train ANN markers associated with the presence of gas hydrate-bearing reservoir rocks within the MPU seismic data. Given that much of the geologic characterization will be completed and available to the ANN algorithms, there is anticipation of ANN being able to discern gas hydrate-bearing sands from lithologic facies changes. Although this seems plausible based on similar studies performed elsewhere, results are quite difficult to predict at this early stage of the research.

5.6.4.4 Regional Composite Fault Map

During the summer and fall of 2005, a regional composite fault map of the AOI from various stratigraphic levels was compiled and sutured from a variety of published sources by Casavant and MGE undergraduate student, Gywn Smith. Vertical and lateral extrapolation of regional north-northeast- and northwest-trending FZs from formations within the PBU (Ivishak formation level) and KRU (Kuparuk River formation level) into the MPU has been completed and is being integrated in our study of variations in the gas hydrate stability field and mapping of reservoir sands and facies within Sagavanirktok parasequences in which gas hydrates and free-gas are known or interpreted to occur.

5.6.4.5 Regional Sequence Stratigraphic Characterization and Paleodepositional Reconstruction

During the last half of 2005, a sequence stratigraphic framework that was developed and applied within the MPU after initial proposal and presentation at the 2004 Hedberg conference (Geauner and Manuel, 2004; Casavant et al., 2004) was extended throughout the whole of the Eileen trend AOI. As Wagoner and others (1990) succinctly state, sequence stratigraphic analysis “involves the recognition and correlation of a hierarchy of stratal units including beds, bedsets, parasequences and parasequence sets and sequences bounded by chronostratigraphically significant surface of erosion, non-deposition, or their correlative surfaces”. The UA framework shows that the Sagavanirktok formation topset play can be subdivided into several regionally correlable sequences.

A clearer understanding of the role of intraformational unconformities on the distribution of stratigraphic units, especially in the western half of the AOI has been achieved. A former model, which invoked most of the lithostratigraphic units climbing up-dip from east to west into the permafrost region does not adequately characterize the heterogeneity observed from detailed well log correlations and seismic attribute analysis. UA analysis (in progress) will show multiple intraformational erosional surfaces (2-3 sequences) removing gas hydrate-bearing sequences from east to west and more adequately account for the absence and/or preservation of stratigraphic units, facies types, and gas hydrate-bearing reservoir sands along the flanks and nose of a section of the Colville High known as the southeast-plunging Kuparuk anticline. The chronostratigraphic analysis is tied to both a regional structural characterization across the AOI and to a detailed seismic-based structural study within the MPU. Some of this work is the topic of a MS Thesis by Justin Manuel entitled “A chronostratigraphic framework of the Sagavanirktok formation, North Slope Alaska: Incorporating facies characterization, reservoir continuity and dimensions in relation to gas hydrate and associated free-gas resources.”

Major fluvial, transitional and nearshore marine facies belts and their general lateral and vertical distributions have been mapped for several of the major gas hydrate-bearing intervals across the AOI. The structural influence of both north-northeast- and northwest-trending fault systems on the development and extent of ancient fluvio-deltaic systems within the high-stand system tracts and locations of incised channel deposits within low-stand systems tracts is now much better understood (Figure 20). This integrative structural-stratigraphic study is anticipated to help distinguish control types and combinations that have the greatest or most frequent effect on gas hydrate and free-gas distributions and entrapment. The final UA analysis on fluid distributions is anticipated to be completed by the summer 2006 and a final look at volumetrics over several prospective drilling areas is planned to be reviewed again.

The upper gas hydrate bearing units in the Northwest Eileen-02 well belong to two separate sequences defined by unconformities and different depositional sequences. The map illustrated in Figure 20 shows a thinning over two (and possibly three) underlying northwest-trending “hingelines” across the AOI which coincide with the location of structural flats (dip changes) along the eastern flank of the underlying southeast-plunging mid-Tertiary Kuparuk high. These are interpreted to be faulted zones at the Sagavanirktok level. To the east of the easternmost hinge, facies are dominated by nearshore marine, whereas to the west, facies are dominated by a mixture of highly-variable transitional and fluvial facies. Slices above and below the stratigraphic interval shown on this map (Figure 20) show the migration of the facies and locations of interpreted persistent incised valley channel sand deposits (not shown well here) that fed these systems and incised into the underlying deltaic and marine facies. Manually contoured maps better highlight many of these features. Sand body types and dimensions are being analyzed for future modeling and volumetric purposes. North-northeast structural influences on the paleodeposition can also be seen in this example “time” slice such as south of KRUUGNU-01 and a channel in the MPA-01 location.

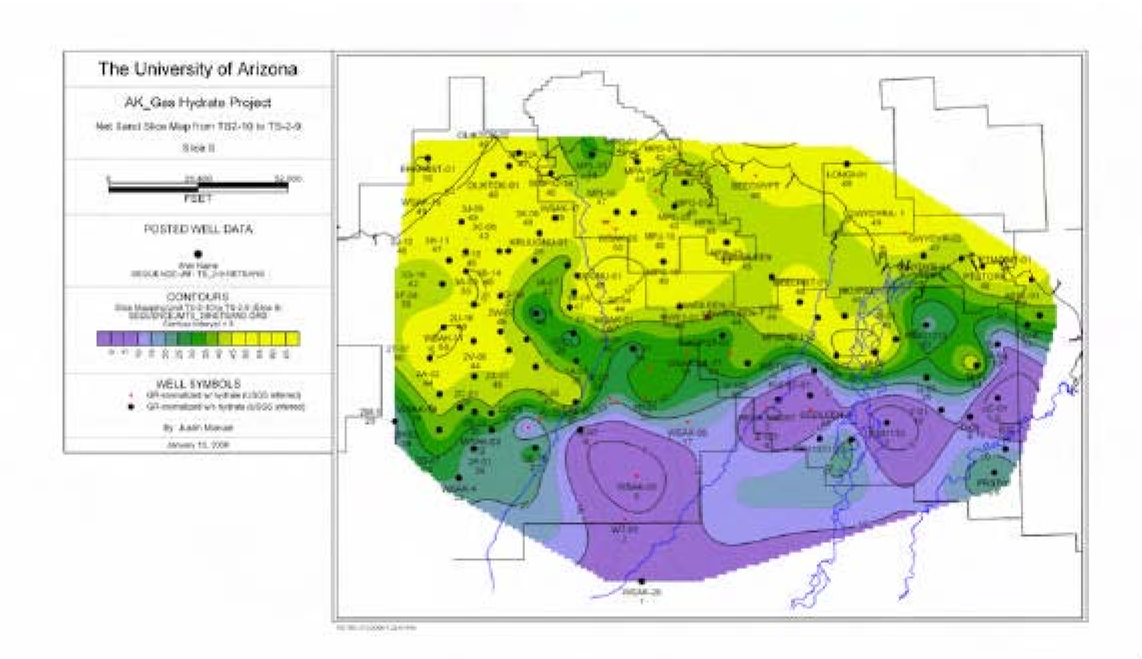


Figure 20: 5-foot contoured net sand slice map (all wells QCd) in the uppermost part of the thickest gas hydrate-bearing parasequence within the Northwest Eileen-02 well (Zone C). *(PI Note: Note that the L-106 and V-107 log data are not yet included in this analysis.)*

5.6.5 Phase 1-2 Accomplishments and Phase 3 Study Recommendations – March 2006 Status Report

5.6.5.1 Subtask 6.3.1, Petrophysical Studies of Gas Hydrate-Free Gas Occurrence

5.6.5.1.1 Estimate Net Sand and Pay Volumes in Zones C and B

Net sand and net pay volumes are estimated through interpretations of wireline log, available core, and drill-stem test data (NWEileen-02). Net sand and net pay volumes are essential to estimating the maximum likelihood of gas hydrate and free gas accumulations as a resource and to compiling a realistic 3-dimensional reservoir model for the North Slope Eileen gas hydrate trend. UA Phase 1-2 activities progressed from the assessment of net reservoir quality and distribution within the MPU to throughout the entire Eileen trend Area-of-Interest (AOI). The results will help evaluate and select sites of opportunity for additional shallow data acquisition and potential future well testing in MPU, western PBU, and/or possibly KRU. Detailed assessment involving structural and sequence stratigraphic synthesis is being conducted during the no cost extension only for the better developed gas hydrate and free-gas bearing reservoir Units C and B (UA parasequences 34 and 33, respectively).

5.6.5.1.2 Visually Verify Expert System (ES) Estimates of Gas Hydrate, Free Gas, Petroleum and Water Occurrences in Zones C and B across the AOI

The Expert System (ES) was employed to provide quick, preliminary estimates of pore-filling fluid phases and saturations (gas, water, gas hydrate, oil) within each of the more than 140 wells in the AOI database (Glass and Casavant, 2006a)[1]. An ES was chosen for this task for the following reasons: 1. Experienced petrophysicists have difficulty evaluating more than two to three data sets at a time. Correct estimates of free gas and gas hydrate occurrences within a well require a simultaneous evaluation of a minimum of six independent wireline logs (sonic, resistivity, density, gamma ray, caliper, and neutron porosity), mudlogs and other tests, and gas hydrate stability constraints (base of permafrost and depth to the base of the gas hydrate stability field) at each measurement location (usually 0.5 foot increments) within the upper 3,500 feet of the well. That corresponds to over 42,000 independent evaluations for each well in the database. Confronted with such a task, petrophysicists can commonly concentrate on datasets with which they are most familiar and can subconsciously exclude potentially important information in other datasets from the decision process. 2. ES estimates represent precise and objective log- and statistical-based mathematical calculations. The discernment of the presence of free gas, gas hydrate, water, and oil-bearing reservoirs using these wireline log datasets is also a complex pattern recognition task requiring an experienced petrophysicist to evaluate and supplement computer calculations, provide quality control, and produce geologically reasonable results. The free gas, gas hydrate, oil, and water saturation calculations of the ES are therefore carefully verified by an experienced petrophysicist prior to being included within the resource assessment. The ES is especially helpful in flagging transition areas and trends where gas hydrate, free-gas, and petroleum concentrations are variably saturated and gradually increasing. These areas are easy for an analyst to miss, especially where well control is sparse or well data is incomplete. 3. Thorough quantitative and 3-dimensional analysis of particular log-curve elements also involve recognition and quantification of facies (coal, sand, shale), regions of reservoir interfingering or pinchout, and 3-D spatial assessment of drilling elements, such as borehole washouts. In some locations, borehole washouts are additional indicators of syn- and post-drilling gas hydrate dissociation and can be integrated with the stratigraphic interpretation, structural mapping, and pay assessments.

5.6.5.1.3 Estimate Net Sand and Pay Volumes in Sagavanirktok Zones A, D, E (Eileen trend) and Ugnu-WSak (Tarn Trend)

5.6.5.1.3.1 Eileen Trend

Free gas- and gas hydrate-bearing Sagavanirktok formation reservoirs also exist both above and below zones C and B gas hydrate-bearing reservoirs within the Eileen trend. Only preliminary estimates of net sand have been made to-date for most of these additional reservoir units. To estimate the total potential free gas and gas hydrate resource within the AOI, these additional reservoir units would need the same level of analysis devoted in prior studies to zones C and B.

5.6.5.1.3.2 Tarn Trend (potential future work).

This trend is southwest and west of the primary current AOI. Regional analysis corroborates previous USGS studies that indicate significant gas hydrate resources also occur within the Tarn trend. Although not currently a priority study within the primary AOI, this trend could be evaluated at a later time in the context of the regional sequence stratigraphic framework, which is critical to identifying and predicting gas hydrate prospects and to understanding the up dip connectivity of gas hydrate-bearing reservoir units as they become truncated and/or sealed by intraformational unconformities (presently undefined) that mark higher-order sequence boundaries within the Ugnu and upper West Sak formations. Prior to undertaking this potential future analysis, all wireline, drilling and mudlog data for all wells within the Tarn trend would need to be obtained.

5.6.5.2 Subtask 6.3.2, Thermal Conductivity Modeling

5.6.5.2.1 Permafrost, Gas Hydrate Stability Zone, and Transitions, Eileen trend

In addition to the petroleum system components, a necessary condition for the occurrence of gas hydrate is a pressure/temperature zone within which gas hydrate is stable. Thermal conductivity modeling guides the evaluation of gas hydrate and associated free gas resources (Glass and Casavant, 2006b)[2]. This evaluation also enables estimating the 0°C (base of the permafrost) contour, the –1°C (upper limit of the base of the ice rich permafrost) contour, and corresponding depths to the base of the gas hydrate stability zone. Combined with regional sequence stratigraphic analysis, identification of intraformational unconformities, net sand mapping, and structural mapping, the thermal conductivity modeling helps estimate updip and downdip limits of gas hydrate and free gas resources across the AOI. It has also allowed mapping of intervals or corridors marked by variable phase transitions which are locally dependent on sand/shale content, pressure, and salinity anomalies.

5.6.5.2.2 Intrapermafrost Gas Hydrate

For the first time we have been able to identify and distinguish gas hydrate within the ice-rich permafrost of the North Slope (Glass and Casavant, 2006c)[3]. The approach can be described simply as follows, “If a material conducts sound and electric current like ice, but conducts heat like water, it must be gas hydrate.” The technique is demonstrated for the only two wells we have in our database having the necessary thermal and wireline logs. Both wells show intrapermafrost gas hydrate up dip from known gas hydrate occurrences in NWEILEEN-2. Intrapermafrost gas hydrate, if it can be identified, may significantly increase the known gas hydrate resources on the North Slope. However, accessing the potential intra-permafrost gas hydrate resource would add the complexity of an ice phase to the resource extraction process. Future well data acquisition is recommended to help verify intrapermafrost gas hydrate occurrence including thermal logs, wireline logs, mudlogs, and cores.

Later studies, if approved, could test the intrapermafrost gas hydrate detection technique by fully logging several new wells of opportunity being drilled for deeper targets in the Milne Point, Kuparuk River, and/or Prudhoe Bay areas. Well log measurements should include resistivity, acoustic Vp-Vs, bulk density, neutron density porosity, NMR, electromagnetic, image logs and drilling mud gas and temperature logging both within and below the permafrost in areas where the likelihood of gas hydrate occurrence is high (e.g. twinning the NW Eileen wells, the PBU L- and V-pad areas). As was stated in the August 2005 Alaska DNR_USGS Alaska Gas Hydrate workshop (AKDNR report, 2005), both conventional wireline logging and LWD (logging while drilling) should be completed to fully assess the distribution of potential gas hydrate resources both within and below the permafrost interval on the North Slope of Alaska. It is recognized, however, that potential production of intrapermafrost gas hydrate would be more problematic.

5.6.5.3 Subtask 6.3.3, Saturation Estimate, Gas Hydrate and Free Gas-bearing Reservoirs

5.6.5.3.1 Gas Hydrate and Free Gas Volumetric Estimates, Eileen Trend Zones C and B

This is a high-priority task. The volumetric estimates are based on petrophysical interpretations that incorporate detailed structural and sequence stratigraphy analyses, and verified ES estimates of pore fluid saturations. Maximum value estimates include an interpretation of possible intrapermafrost gas hydrate, gas hydrate below the permafrost but above the lowest depth to the base of the hydrate stability zone (depth projected from the 0°C contour), and free gas both within and below the gas hydrate stability field. Minimum value estimates include an interpretation of gas hydrate below the base of the permafrost (0°C contour) and above the maximum depth to the base of the gas hydrate stability zone (depth projected from the 0°C contour). Expected value estimates include petrophysical interpretation of the likelihood of gas hydrate existing within the zone defined by the -1°C contour and the base of the gas hydrate stability zone (depth projected from the -1°C contour). Free gas typically occurs only below the gas hydrate stability zone, but can also occur within the gas hydrate stability zone within stratigraphically-isolated units or where sufficient formation water is not available.

5.6.5.3.2 Develop ES Using Mallik Training Site

The ES has been developed within a Microsoft EXCEL environment and trained on interpreted pore fluid saturations from the JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate research well, Mackenzie Delta, Northwest Territories, Canada. Please refer to Section 5.6.5.1.2 for a discussion of the rationale behind the use of the ES. However, it is recognized that differences in formation properties, salinities, and other reservoir parameters may prevent this site from being a valid comparison for these statistical, predictive Alaska North Slope reservoir estimates.

5.6.5.3.3 Test ES Using NW Eileen State 2 Site

The accuracy of the ES is demonstrated using the Arco-Exxon NW Eileen State 2 well (UWI = 500292011700). This well was chosen for demonstration because it is the only well to date on the Alaskan North Slope in which gas hydrate-bearing sandstones were directly sampled (cored) and confirmed. Please refer to 5.6.5.1.2 for a discussion of the rationale behind the use of the ES. *(PI NOTE: Even though they were not cored wells, the PBU L-106 and V-107 wells with more modern suites of logs would be better to use for this ES training. These wells should at least be used/added within the ES.)*

5.6.5.3.4 Verify ES Using Human Interpretation in Zones C and B

Refer to Section 5.6.5.1.2 for a discussion of the rationale behind the use of the ES.

5.6.5.3.5 Gas Hydrate and Free Gas Volumetric Estimates, Eileen Trend Zones A, B, D and Tarn Trend Ugnu

Refer to Sections 5.6.5.1.2, 5.6.5.1.3, and 5.6.5.3.1 for discussion.

5.6.5.3.6 Refine ES Using More Sophisticated Shape Detection

At the present time the ES is confined to searching for distinctive absolute log values or variations in log values from background values (using low-pass filters to define background behavior). It is possible that better discrimination is possible using more sophisticated shape recognition techniques. For example, at the present time the ES demands that the gamma ray log display counts below 55 prior to assigning a pore fluid as gas hydrate, ice, free gas, or petroleum. *All logs within the AOI will be verified as normalized to account for vintage, acquisition settings changes, and cased versus open-hole.* Gas hydrate certainly occurs preferentially in sand, but we have also observed that gas hydrate most often occurs within fluvial point bar and channel sand deposits, and less frequently in marine mouth bar sand deposits. One such approach to improving

ES efficacy would include the automatic (or interpretive) detection of fluvial point bar and channel signatures based on their diagnostic shape on the gamma ray log.

5.6.5.4 Subtask 6.3.4, Artificial Neural Network (ANN) to Assess Reservoir Properties

5.6.5.4.1 Prepare and Refine ANN for Application to MPU 3D Seismic Cube

Early attempts at ANN training and modeling using wireline log data as an aid to objectively identify and map sand, shale and coal facies as well as gas hydrate and free gas intervals were met with less than optimal success. As a result, we were unable to complete the ANN program and achieve final verification and quantification of this approach relative to standard petrophysical interpretations and the ES model results. Petrophysical verification of the preliminary ANN results (Phase 2) indicated that ANN results were inadequate when compared with results from standard petrophysical interpretation and ES modeling.

Given the Phase 2 and 3 findings achieved via the structural and stratigraphic characterizations related to Subtasks 6.3.1, 6.3.3 and 6.3.6 and acquisition of additional research personnel, continuation of the ANN training and investigation of the MPU 3D seismic data may be possible. This work would need to be refined and validated first if it were to be of practical use. If validated within the MPU dataset, its application to KRU and PBU 3D seismic data set could become most promising. Priority of this work in subsequent UA activities, although downgraded in priority at this time, could be elevated accordingly if verification of its ability to resolve facies and hydrate-bearing rocks from the seismic signal is achieved (if within tuning ability), and if additional seismic data sets are made available in the KRU and/or PBU.

5.6.5.5 Subtask 6.3.5, Regional Sequence Stratigraphic Framework

5.6.5.5.1 Extend Lower Sagavanirktok Stratigraphic Framework throughout AOI

Phase 2, Task 5.0 studies of the Staines Tongue unit indicate that there may be significant saturation risk with charge or seal issues as demonstrated by the data acquired within this interval in the MPS-15i and MPI-16 wells-of-opportunity. Former Task 6.0 studies of this complex formation have addressed reservoir continuity within a lithostratigraphic framework. Though lithostratigraphic analyses are useful for quick-look regional synthesis, sequence stratigraphic analyses are required for understanding true reservoir continuity, achieving meaningful linkages between stratigraphic and structural controls on gas hydrate occurrence, and resolving and predicting stratigraphic trapping and reservoir continuity.

5.6.5.5.2 Analyze Sequence Stratigraphy of Zones C and B with Emphasis on Structural and Stratigraphic Controls on Gas Hydrate and Free Gas Occurrence

Although the sequence stratigraphic approach has been applied across the lower half of the Sagavanirktok (below the mid-Eocene unconformity), detailed analysis of reservoir distribution, dimensions, connectivity and gas hydrate/free gas emplacement have been addressed primarily for those parasequences that have the highest potential for containing sizeable gas hydrate and free-gas resources within the NW Eileen trend area (western PBU, southern MPU, eastern KRU). As stated in Section 5.6.4.5, major fluvial, transitional and nearshore marine facies belts and their general lateral and vertical distributions have been mapped for several of the major gas hydrate-bearing intervals across the AOI.[4] The structural influence of both north-northeast- and northwest-trending fault systems on the development and extent of ancient fluvio-deltaic systems within the high-stand systems tracts and locations of possible incised channel deposits within low-stand systems tracts is now much better understood. The sequence stratigraphic analysis is tied to both a regional structural characterization across the AOI and to detailed seismic-based structural study in the MPU.

Importantly, early results suggests that this integrative structural-stratigraphic study will help distinguish types and combinations of controls that have the greatest effect on gas hydrate and free-gas distribution, saturation, and quality. A final analysis on fluid distributions and volumetrics is being provided over several prospective drilling areas throughout the AOI that can be incorporated into future well planning and data acquisition activities.

5.6.5.5.3 Analyze Seismic Stratigraphy of Zones D, C, B and Refine MPU Structure

Previous seismic studies have tended to generalize the distribution of facies types and their linkages to gas hydrate and free gas resource occurrences. Seismic interpretation is linked to well control and provides exceptional detail of an area that is a subset of the regional synthesis described in Sections 5.6.4.5 and 5.6.5.5.2. The identification of seismic sequences and seismic attribute responses to different sand facies designations (well log-based) is a major objective of this project task.

Seismic slices may reveal in higher-resolution significant vertical and lateral variation in the distribution and quality of reservoir facies.[5] This is important for accurate estimates of reservoir continuity that affect production models. Higher resolution mapping of both faults and seismic facies should provide better information regarding dimensions and connectivity of reservoir facies, and predicting which fault systems contribute to gas and gas hydrate sourcing, charging, and trapping.[6] Risk assessments can then be refined at a number of scales and for a variety of geologic elements (fault types, facies type, reservoir sand thickness, etc.).

5.6.5.5.4 Analyze Sequence Stratigraphy of Zones A, D, E (Eileen Trend), and Ugnu, WSak (Tarn Trend)

5.6.5.5.4.1 Eileen Trend

As discussed in Section 5.6.5.5.1, published studies and UA Phase 2 work in the MPU show that free gas and gas hydrate-bearing reservoirs occur both above and below C and B gas hydrate-bearing reservoirs and within the Tarn trend. Although preliminary estimates of net sand have been made for most of these units across the AOI, we have not been able to devote the detailed attention to these units during the no-cost extension period that we have for zones C and B. To fully evaluate the free gas and gas hydrate resource within the AOI, these units need the same degree of attention as zones C and B.

5.6.5.5.4.2 Tarn Trend (potential future work)

The Tarn/Cirque trend is southwest and west of current Eileen Trend AOI. Our regional analysis agrees with previous USGS studies that indicate significant gas hydrate-bearing reservoirs and resources occur within that trend, and we are well prepared to evaluate them in the context of the regional sequence stratigraphic framework first tested and defined in the MPU and extended throughout the AOI for zones C and B. We have found this framework critical to identifying and predicting gas hydrate prospects and to understanding the updip connectivity of gas hydrate-bearing reservoirs where truncation and sealing by intraformational unconformities occur increasingly to the west. Wireline log, drilling and mudlog data for all wells within that trend would need to be obtained for this potential future work.

5.6.5.6 Subtask 6.3.6, Integrate Regional Structural and Stratigraphic Controls on Gas Migration and Gas Hydrate Accumulation

5.6.5.6.1 Synthesize Fault Maps across AOI

A series of published fault locations were compiled and integrated into a regional fault map to help guide regional stratigraphic and structural analysis related to gas hydrate occurrence and prediction across the AOI. This work is the extension of a regional synthesis that investigated subsurface resource distributions to geomorphic expressions of the reactivation of long-lived subsurface structures[6].

5.6.5.6.2 Reinterpret AOI Structure Map at Sagavanirktok Level

Wireline log-based computer mapping shows regional structure across the AOI at the Sagavanirktok level as a low-gradient, relatively simple surface that dips to the east-northeast. Detailed 3-D seismic structural mapping within both MPU and analysis of published structure maps in the KRU and western PBU, however, clearly show that structure across the AOI is much more complex and variable. After integrating a number of structure maps and fault data (subtask 6.3.6) from various stratigraphic levels in the KRU, MPU and PBU, this study would provide a more rigorous interpretation of the AOI structure during mid-Tertiary time and link to stratigraphic variations and location of reservoir sands both within and beneath the permafrost.

Early results from this task indicate that some of the sand-rich fairways or depocenters at the mid-Tertiary level link to deeper structural-stratigraphic controls that influenced older paleodepositional systems in a generally similar manner. Some of the interpreted gas hydrate occurrences across the AOI appear to be located within or near these structural anomalies, which are best illustrated in hand-contoured map interpretations. Locations of the anomalies appear to be most often at the intersection of interpreted reactivated northwest- and north-northeast-trending fault systems. They are characterized by the truncation of stratigraphic units on upthrown blocks and by differential compaction associated with thicker and/or preserved coarse-grained units on downthrown block. *(PI-NOTE: If true, this interpretation could definitely adversely impact the Mt. Elbert Prospect interpretation (the primary Task 8.0 Drilling Candidate). This alternate interpretation should be thoroughly investigated within the AOI and extending into MPU with integration of 3D seismic interpretation).*

5.6.5.6.3 Integrate Regional Structural-Sequence Stratigraphic Analysis for Characterization of Gas Hydrate-bearing Zones C and B

The integration of ES and manually-interpreted gas hydrate and free gas occurrences in the C and B intervals and structural and stratigraphic mapping was extended beyond the MPU into the rest of the AOI during late Phase 2. This work proceeded as the sequence stratigraphic framework was refined and modified through regional correlation studies. The pace and completeness of this work was linked to the acquisition of additional well log data and progression of our fluid analysis studies (Subtasks 6.3.1 and 6.3.2) and structural mapping activities (Subtasks 6.3.5 and 6.3.6). Documentation of the entire 6.3.6 subtask would require additional funding beyond the no-cost extension period (end-2006).

5.6.5.6.4 Conduct a Regional Structural Analysis of Eileen Trend Units A, D, E and Tarn Trend Ugnu-WSak

See Section 5.6.5.5.4 for discussion and relevance.

5.6.5.6.5 Pull-apart Basin Relation to Gas Hydrate and Free Gas Occurrence

Based on 3D seismic fault mapping in Phase 1, a north-northeast trending pull-apart basin, located in the eastern half of the MPU, was interpreted in Phase 2 studies. Subsequent research has revealed that this basin influenced the majority of sand deposition and constrained the distribution of gas hydrate-bearing sands within the MPU. *(PI-NOTE: This is a major statement and should be given high-priority to verify this alternate interpretation; verification of this alternate interpretation could significantly impact the current Mt. Elbert prospect Drilling Candidate interpretation. This alternate interpretation should be thoroughly investigated within the AOI and extending into the MPU with integration of 3D seismic interpretation.)* Fault analysis and reinterpretations of mid-Tertiary structure southward into the KRU suggest a continuation of the same or similarly-sized basin feature along the eastern margin of the KRU. Structural features such as this can control sand deposition and are important for reservoir modeling purposes.

5.6.5.6.6 Link Geomorphologic Indices to Subsurface Structures Associated with Inferred Sub- and Intra-permafrost Hydrate Distributions

Sequence stratigraphic analyses, seismic fault mapping in the MPU and local tectonic geomorphologic indices indicate that some fault zones have been repeatedly reactivated and extend upward from the basement through the permafrost to surface, and that mid-Tertiary deformation is still active in parts of the AOI[4,5,6]. The UA is well poised to complete this investigation between geomorphic linkages and subsurface structures that are conducive to gas migration and sub and intra-permafrost gas hydrate formation. Our studies show that certain fault zones are complexly faulted and probably represent leaky fault systems that periodically charged shallow reservoir sands with gas that leaked from deeper oil bearing reservoirs. Outcomes of this research would help define prospective gas hydrate “fairways” in regions where 3D seismic data and/or available diagnostic well log data are scarce. Extension of this study outside the AOI would require additional diagnostic wireline, drilling, mudlog and temperature survey data.

5.6.5.6.7 Evaluate Correlation, if Any, of Shallow Gas Hydrate Occurrence With Deeper Coal Occurrence

5.6.5.6.7.1 Spatial Correlation Between Coals and Gas Hydrate

A spatial and quantitative study of coal bearing units within the Sagavanirktok formation was completed in the MPU during the early part of Phase 2 studies. Preliminary findings, presented at the 2004 AAPG Hydrate Hedberg conference[7], indicated the thickest net coal was present along the flanks of a sand-rich basin (subtask 6.3.6). It is unknown whether the presence/absence of coal was due to non-deposition or due to scouring by incised channel units that represent important updip or shelf elements in our sequence stratigraphic reconstruction of the Sagavanirktok. We did not have time in early Phase 2 to link coal distribution with overlying reservoir facies or to the location of gas hydrate resources interpreted by manual or ES analyses. Studies of coals in deeper formations on the North Slope, however, indicate that coals can contribute a considerable coal gas or coalbed methane (CBM) component to sourcing overlying or updip reservoirs. Completion of this study could provide data and interesting linkages that could be integrated into future studies of gas hydrate and CBM across the AOI and elsewhere.

Coal beds and interbedded coal-bearing units have been quantified in our ES model. Model results have been successfully validated and tested with manual interpretations and published coal studies in the Ugnu and West Sak Formations.

5.6.5.7 References to March 2006 Status Report

1 Glass, C. E. and R. R. Casavant, 2006a, *Expert system for estimating gas hydrate concentrations using petrophysical wireline logs on the Alaskan North Slope,* in final preparation and informal review prior to AAPG submission.

2 Glass, C. E. and R. R. Casavant, 2006b, *Simulating Well Bore Temperature Using Gamma Ray Logs,* in final preparation and informal review prior to Journal submission.

3 Glass, C. E. and R. R. Casavant, 2006c, *Using Thermal Conductivity Modeling to Distinguish Gas Hydrate-bearing Sediments from Ice-bearing Sediments within the Permafrost on the Central North Slope, Alaska,* in final preparation and informal review prior to journal submission.

4 Manuel, J., 2006, *A chronostratigraphic framework of the Sagavanirktok Formation, North Slope Alaska: Incorporating facies characterization, reservoir continuity and dimensions in relation to gas hydrate and associated free-gas resources,* MGE Masters Thesis, University of Arizona. Anticipate preparation of study for internal review and journal submission.

5 Geauner, S., 2006, *Fault analysis, seismic facies modeling and volumetric reassessment of gas hydrates in the Milne Point Unit, North Slope, Alaska,* MGE Masters Thesis, University of Arizona. Anticipate later adaptation of study for internal review and journal submission.

6 Casavant, R.R., 2001, *Morphotectonic Investigation of the Arctic Alaska Terrane: Implications to Basement Architecture, Basin Evolution, Neotectonics and Natural Resource Management*, Ph.D thesis, University of Arizona.

7 Casavant, R.R., A.M. Hennes, R.A. Johnson, & T.S. Collett, 2004, *Structural analysis of a proposed pull-apart basin: Implications for gas hydrate and associated free-gas emplacement, Milne Point Unit*, Arctic Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geohazards, Vancouver, BC, CAN, 5 pp.

5.7 TASK 7, Phase 2: Drilling, Completion, and Production Lab Studies

<u>University of Alaska Fairbanks (UAF)</u>
UAF Principle Investigator: Shirish Patil
UAF Co-Principle Investigator: Abhijit Dandekar
UAF Research Professional: Narender R Nanchary
UAF Graduate Students: *Jason Westervelt, Stephen Howe,* Namit Jaiswal, Prasad Kerkar, Hemant Phale
UAF Undergraduate Student Assistant: Phillip Tsunemori

5.7.1 Educational Component of the UAF Gas Hydrate Research Program Studies

5.7.1.1 Phase Behavior, Reservoir Engineering, Formation Damage Assessment, and Reservoir Model Studies

Significant progress has been made and objectives met for almost all the Phase 1 study sub-tasks. However, there are still several beneficial studies that can be accomplished in Phase 3 studies. The following subsections briefly summarize the University of Alaska Fairbanks (UAF) research accomplishments and experimental capabilities. This research will help transition into Phase 3 studies and enable UAF to continue to play a key role in Alaska gas hydrate research. Key accomplishments of these studies were reported in detail in Quarterly Reports 1-9.

5.7.1.2 Experimental Capabilities at Petroleum Development Laboratory

As a part of the collaborative project with DOE NETL and BPXA, UAF has been able to utilize a state-of-the-art gas hydrate research laboratory (Figure 21). Using these facilities, UAF has been able to make key contributions in the areas of phase behavior, relative permeability measurements, and formation damage assessment to address potential productivity issues.

Figure 21: UAF Lab Equipment

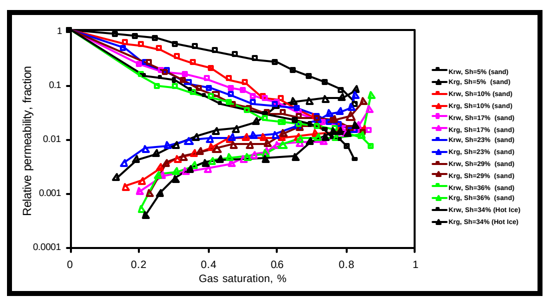


Figure 22: Relative Permeability Plots

5.7.1.3 Relative Permeability and Reservoir Modeling Study Accomplishments

The gas-water relative permeability data for gas hydrate systems is essential when either considering the depressurization methods or inhibitor injection methods for dissociation and recovery of gas from gas hydrate formations. Such types of data are virtually non-existent in the literature. UAF has indigenously designed and developed a displacement apparatus capable of forming gas hydrate and conducting relative permeability experiments. UAF has successfully measured the gas-water relative permeability functions, in the presence of gas hydrate saturations ranging from 5-36%, for unconsolidated Oklahoma sand and for Anadarko Hot Ice #1 core samples. The key gas-water relative permeability results are shown in Figure 22 (and prior reports). Results indicate a reduction in relative permeabilities as gas hydrate saturation increases.

UAF has adapted a commercial simulator, CMG STARS, to model gas hydrate dissociation caused by depressurization of an adjacent free gas accumulation in an ANS gas hydrate accumulation. Even though CMG is a commercially available simulator and capable of handling thermal oil recovery processes, UAF developed a novel approach to modify the simulator by formulating kinetic and thermodynamic models to describe the gas hydrate decomposition. Results are very encouraging and demonstrate the potential of the depressurization production method by dissociation of gas hydrates adjacent to free gas. UAF modeling indicates that as free gas is produced at rates of up to 25 MMscfd/d per well, the free gas-bearing zone depressurizes and the adjacent gas hydrate accumulation begins to release significant additional gas (Figures 23 and 24).

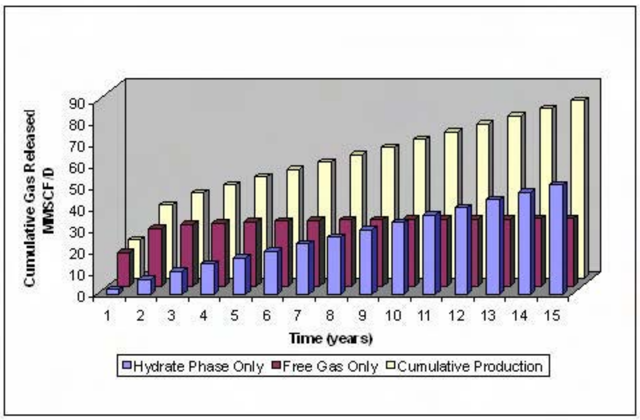


Figure 23: Gas Hydrate Production Modeling

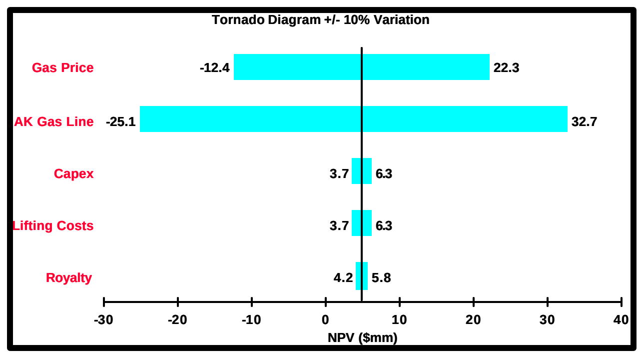


Figure 24: Gas Hydrate Economic Variables

The potential of gas production from formations containing gas hydrate is analyzed using the results of the sensitivity study. This study provided a useful tool to predict the potential and economic viability of a recovery process. The modified CMG STARS is user friendly and easy to initialize unlike other commercial simulators. It has been adapted to handle temperatures below 0°C. A variety of operating conditions and constraints may be specified for each of the multiple and/or horizontal wells. The modified simulator also works well for gas hydrate accumulations in different geologic media and for different production mechanisms.

5.7.1.4 Continuation into Phase 3 Research

The gas-water relative permeability data for gas hydrate systems, obtained in the Phase 1 studies is primarily for reconstituted sediment samples. However, we are still lacking the realistic gas-water relative permeability data for gas hydrate systems for actual field samples. Obtaining such data will be feasible only by acquiring sediment samples from objective field areas. Actual field samples are critical inputs to the reservoir simulation work, as gas-water relative permeability data provides direct input to reservoir and fluid flow modeling. Additionally, issues related to the kinetic reaction parameters and ice formation reactions also need to be resolved before we are in a position to compare our results with the existing simulators such as the EOSHYDR TOUGH2. We also need to determine if formation of ice may inhibit or contribute to gas dissociation from gas hydrate during production. We need to compare the order of magnitude of heat released while forming ice to that of becoming resistant to gas flow. Similarly, there is also a need to investigate the phase behavior characteristics of gas hydrate systems in actual field samples, as the studies carried out so far were mostly on synthetic samples. This is also an important aspect of reservoir simulation as this directly relates to the production of 'additional' gas from gas hydrate dissociation.

In order to address evaluation of drilling fluid and assessing formation damage under borehole conditions, a set up has been designed and built, where a specially designed dynamic filtration core holder used to study permeability impairment under dynamic flow conditions. The refrigerated circulator maintains drilling flow temperature around 5^{o}C and 1500 psi of overburden pressure is applied on the Berea sandstone sample with water and Isco 500DX pump. The drilling mud is circulated across the face of a core with the Drilling Fluid Recirculation Unit and the dynamic filtration rate is measured. Permeability changes measured in this manner will help study the depth of invasion of both the mud filtrate and the mud solids and the resulting permeability impairment. After mud circulation, reverse injection of methane gas can be performed. Return permeabilities would also be measured. Despite a strict time frame and patience required for the experiment, we are optimistic about the availability of actual drilling fluid samples from Baroid to make this analysis truly representative.

Depending upon the mud rheology i.e. flow index factor, the flow rate required to maintain particular shear rate can be calculated based on the width across the core face and core holder gap. The cumulative filtrate collected in gas-liquid separator placed on weighing balance on the formation side of the core over extended period of time for 200 psi overbalance pressure drop will be specific to the in-situ drilling fluid and shear rate employed on the sample. The decrease in return permeability from the formation to wellbore side of the sample may help direct formation damage studies due to drilling fluid invasion. This is an important contribution to the overall project objectives.

In Phase 3, UAF will play key role in analyzing core samples acquired from field work by measuring rock and fluid properties, helping design appropriate mud systems, assessing formation damage and core studies, while continuing the work on production modeling and economic studies.

5.7.2 Phase 2 Subtask 7.1: Design Integrated Mud System for Effective Drilling, Completion, and Production Operations

Objectives for subtask 7.1 include: 1. design fully integrated mud system for permafrost and gas hydrate bearing reservoirs, 2. determine mud contamination and formation damage risk, and 3. evaluate mud chiller system. These studies are discussed further in Section 5.11, Task 8.0.

5.7.3 Subtask 7.2, Phase 2: Assess Formation Damage Prevention

This section is compiled from a pre-publication (in-review) entitled "Assessment of Formation Damage from Drilling Fluids Dynamic Filtration in Gas Hydrate Reservoirs of the North Slope of Alaska" by P. B. Kerkar, S. L. Patil, A. Y. Dandekar, G. A. Chukwu, S. Khatniar and R. B. Hunter.

5.7.3.1 Abstract

Drilling with warm drilling fluids through gas hydrate can be hazardous and lead to dissociation of gas from gas hydrate. A significant decrease in potential productivity near the well-bore could occur due to the invasion of fine solids from drilling or completion fluids, forming external and internal filter cake under dynamic conditions. An experimental setup for the evaluation of formation damage at in-situ conditions was designed to assess completion fluids suitability and formation damage. At the confining pressure of 1500 psi, chilled drilling fluids at 41-50^{o}F are circulated across the Berea sandstone core for 10 hours in a dynamic filtration core holder. KCl/polymer water-based Mackenzie Delta base mud, flocculated mud, flocculated mud with starch based filtration control material and dispersed mud are tested at 30, 40, 80 sec^{-1} and 100/200 psi overbalance with absolute permeability measurement both before and after the drilling fluid circulation. The drilling fluid type, its flow rate, and shear rate, effective particle size, additive concentration, and the amount of static and dynamic overbalance were characterized to establish their influence on drilling mud leak-off volume and the post mud circulation permeability.

5.7.3.2 Introduction

Well productivity can be significantly affected by near-wellbore formation damage caused by drilling or completing with poorly-compatible fluids within the reservoir sections. Historically, the use of perforated completions allowed for penetration of the producing formation beyond the damaged area, but the recent trend towards highly deviated, horizontal, and multi-lateral non-perforated wells has resulted in an increased emphasis on formation damage control. This, in turn, has increased the importance of evaluating drilling fluids and completion techniques used from a reservoir damage perspective. Moreover, for gas hydrate-bearing reservoirs, this need for establishing the suitability of a drilling fluid containing hydrate inhibitors and promoters is emphasized. During the last ten years, there has been a very significant increase in the number of highly deviated and horizontal wells drilled through hydrocarbon reservoirs. The driver for the increased numbers of deviated wells, horizontal wells, and multilateral wells, some with open hole completions using advanced drilling technology has been to more cost-effectively develop resources. Open hole completions undoubtedly allow production from a greater percentage of the wellbore surface but this increase will only be realized in practice if the damage caused by the drilling and completion fluids can be minimized. The objective of this study is to evaluate formation damage due to water-based drilling fluid incompatibility with gas hydrate-bearing reservoirs. The permeability impairment data obtained through this analysis for the near wellbore formation would help to predict the production data, near wellbore skin and recovery factor. The filtrate loss amount to the formation for various mud compositions can be calculated over the entire wellbore length.

5.7.3.3 Experimental Set-up

Typical formation damage analysis involves the flow of drilling fluid resembling wellbore annulus with initial and post circulation permeability measurement. The experimental set-up is designed for formation damage testing of core samples, at in-situ conditions of pressure and temperature in arctic permafrost regions. Besides these objectives and previous analysis from literature, the conditions to form gas hydrate inside the core sample, static / dynamic filtration with oil / water-based drilling fluid, followed by gas hydrate dissociation modeling are envisioned to design an experimental system which can include reservoir gas, initial oil or condensate saturation, secondary water flooding, formation damage testing with leak-off through the core, and before-and-after permeability measurement, in both forward and reverse (backflow for damage clean up) directions. Brine, oil, condensate, water or oil based drilling mud, gels or other fluids can be injected into and through the core sample. The permeability measurements can be done with both gases and liquids. Two Isco 500DX metering pumps are used; one for pumping liquid through the core and another for maintaining overburden pressure and replenishing the mud in the circulation loop.

Despite of the procurement of core equipment from manufacturers, for instance, dynamic filtration core holder (DFCH; Figure 25), drilling fluid recirculation system, floating piston accumulator, back pressure regulators from Temco Inc., flow meters from Omega, differential pressure transducers and multi-channel demodulator from Validyne, weighing balances from A and D Weighing, and refrigerated recirculation unit from Julabo, the whole design and setup is unique in its own way since each of these units are customized and/or modified from their off-the-shelf specifications to meet specific needs for future gas hydrate formation and dissociation studies in arctic conditions and measuring the associated formation damage by drilling fluids. An integral part of the system shown in Figure 26 is the RPS-2500 drilling fluid recirculation system and SmartRPS software provided by Temco Inc. The customized computer data-acquisition-and-control system hardware provides on-screen display of all measured values (pressure, temperature, volumes, etc.), automatic logging of test data and means to control some of the operational parameters such as drilling fluid flow rate.

The special DFCH (Figure 25) supplied by Temco Inc. has been used to allow drilling and completion fluids (or gels, etc.) to be injected at the face of the core (simulating flow through the borehole, across the rock face) and through the core (simulating flow in both directions between the formation and the borehole.) Test conditions can be up to 1500 psi flowing pressure and 2000 psi overburden (confining) pressure, at 350^{o}F (177^{o}C). The inlet pressure into the core sample (that is, the pressure at the flow-through face) is measured with a pressure transducer. Likewise, the differential pressure across the core (across face and the drilling fluid) and overburden pressure are measured with two differential pressure transducers.

Leak-off fluids produced through the core sample are collected in a separator, rested on a weighing balance. The fluids, which flow by the face of the core, without leaking through it, can be measured by subtracting the cumulative leak-off volume from the cumulative volume pumped by the recirculation pump. The system is also designed for the measurement of liquid permeability.

Several design features such as the use of two single stage gas regulators in series to have an effect of constant downstream pressure double stage regulator for methane source, or the arrangement of valves to facilitate the measurement of the dual directional permeability with same reservoir fluid source and same back pressure regulator settings, or the minimum dead volume without compromising over the tubing size for thick drilling fluid for extended analysis make the system more adaptable for arctic conditions.

5.7.3.4 Experimental Conditions and Procedure

5.7.3.4.1 Representative core samples – Berea sandstone

Analysis of cores recovered from Blake Ridge (Ginsburg et al., 2000) and the Cascadian margin (Shipboard Scientific Party, 2002) revealed that gas hydrate saturations were highest in coarse grained, reservoir quality sediments. Core samples from a well in the Canadian Arctic, subjected to extensive analysis (Winters et al., 1999), also revealed that gas hydrate resided primarily in the coarsest sand and gravel intervals. Much less gas hydrate was found in fine-grained mudstones. Similar trends were noted in borehole cores from the Nankai Trough (Matsumoto, 2002a). It appears to be well established that hydrophilic porous media such as sands and sandstones remain liquid-water-wet in the presence of water ice. It can be argued that the growth habits of ice and gas hydrate may be similar because many of their physical properties are similar (Dvorkin et al., 2000). Alaska onshore gas hydrate in Prudhoe Bay-Kuparuk-Milne Point unit areas are interpreted within a series of sandstone and gravel layers interbedded with multiple thick siltstone units (Kamath and Patil; 1994). Over 50 exploratory and production well-logs have interpreted gas hydrate occurrence in six laterally continuous sandstone and conglomerate units. The gas hydrate is geographically restricted to the area overlying the western part of Prudhoe Bay oil field (Collett; 1993 and 1998). The widely used standard porous rock for experimental work in the petroleum industry (Murlidharan et al.; 2002) is the Berea sandstone. Yousif et al. (1991) have also successfully formed methane hydrate in Berea sandstone to study depressurization phenomena. Moreover, Marshall et al. (1997) have recommended standard materials such as Berea sandstone, synthetic disks or reservoir core, if available, while defining the standard methodology for formation damage testing. Keeping these caveats in mind and looking at the availability, Berea sandstone with average porosity 17.88% and absolute permeability 105-145 md is a reasonable choice as a representative sample to study formation damage phenomena.

5.7.3.4.2 Overburden pressure and temperature conditions

Geothermal gradients calculated from a series of high-resolution temperature surveys conducted in 11 closely spaced Prudhoe Bay Unit wells (Collett et al.; 1988) range from 1.55 to 1.90^{o}C/100 m in the ice-bearing permafrost sequence, and from 2.55 to 3.17^{o}C/100 m below the base of the ice-bearing horizons. Hence, there is a local variation in the geothermal gradient as great as 0.62^{o}C/100 m in a region that is characterized by generally uniform rock types and constant external temperatures.

Most gas hydrate stability studies assume that the subsurface pore-pressure gradient is hydrostatic (9.795 kPa/m or 0.433 psi/ft). A pore-pressure gradient greater than hydrostatic will result in a thicker gas hydrate stability field. Pore-pressure gradients calculated from shut-in pressure recorded during shallow (approximately 1312 to 6561 ft) drill-stem testing in wells from the Alaska North Slope range from 9.3 to 11.2 kPa/m, with an average gradient of 9.7 kPa/m (0.43 psi/ft), which is nearly hydrostatic. Collett (1993) evaluated pore-pressure, acoustic transit time and gamma-ray logs from 22 wells. Within the near-surface (0-1500m or 0-4921 ft) sedimentary rocks of the Alaska North Slope, however, no significant pore-pressure discontinuities were observed. Hence, the gas-hydrate overburden pressure determination in this study assumes a hydrostatic pore-pressure gradient (9.795 kPa/m or 0.433 psi/ft). A well log based characterization study by Collett (1998) in the Prudhoe Bay-Kuparuk area has revealed the presence of stable hydrates between 210 and 950 m (690 and 3120 ft). For this analysis, the depth of 1055 m (3464 ft) combined with the hydrostatic pressure gradient of 0.433 psi/ft yields an overburden pressure of 1500 psi.

5.7.3.4.3 Drilling fluids temperature conditions

One of the techniques to avoid consequences during drilling of gas hydrate, such as well circulation through plugging of choke and kill lines or plugging of BOP, is reducing the temperature of drilling fluid. If gas hydrate is present, mud should be cooled and balanced to offset gas cut versus borehole erosion, the circulation rate should be increased to remove the gas, the penetration rate should be decreased and mud gas samples should be tested to confirm the presence of gas hydrate.

The JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate research well in the Mackenzie Delta, Northwest Territories, Canada drilled to a depth of 1150 m (Dallimore et al.; 1999). Drilling and coring of the permafrost section (0-670 m) proved to be challenging, with significant borehole erosion in some zones and limited core recovery. Mud temperatures during drilling of the main hole beneath the permafrost casing (670-1150 m) were maintained near 35.6^{o}F (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 gas hydrate-bearing zones. In this analysis, we circulated the coolant in the jacket around the DFCH as well as around the drilling fluid recirculation unit to maintain drilling fluid temperature at around 41-50^{o}F (5-10^{o}C). Temperature surveys by the USGS indicate that the temperature of the permafrost above the gas hydrate-bearing zones at the Mallik site is up to 10^{o}C warmer than the Alaska North Slope permafrost intervals. Therefore, to avoid excessive hole erosion caused by salts in a freeze-suppressed mud system, it is recommended to run casing over the permafrost-bearing interval before penetrating the gas hydrate-bearing interval with the chilled drilling fluid.

5.7.3.4.4 Drilling fluids static and dynamic filtration pressure conditions

The pressure drop of 100 and 200 psi across the formation and wellbore side has been recommended by Marshall et al. (1997) as a standard practice for formation damage testing. Hence 100 and 200 psi, overbalance conditions are maintained and filtrate on the formation side of the core was collected in a fluid measuring system.

5.7.3.4.5 Experimental procedure

A water saturated Berea sandstone core of maximum diameter of 1.5-inch and length of 2-inch was installed in DFCH-1.5. The desired temperature was set in 1-setpoint mode with the circulation of the Thermal H5S fluid from Julabo refrigerated circulator (FP50-MC). The overburden pressure of 1500 psi was applied in the steps of 500 psi and sufficient time was allowed for core to align itself in the overburden pressure before measuring the absolute permeability. The drilling fluid recirculation system, its by-pass loop, and mud face and the floating piston accumulator were filled with the chilled drilling fluid. The static and dynamic filtration was carried out at overbalance pressure with continuous leak-off measurement followed by damaged permeability measurement from wellbore to reservoir side and return permeability from reservoir to wellbore side of the core sample. The detailed procedure for each operation can be found in Kerkar (2005).

5.7.3.5 Results and Discussions

5.7.3.5.1 Drilling fluids rheology

The choice of drilling fluids was based on the formulation used in drilling the JAPEX/JNOC/GSC Mallik 2L-38 gas hydrate research well in the Mackenzie Delta, Northwest Territories, Canada. Quickgel, finely ground, premium grade, high yielding Wyoming sodium bentonite and barite in water-based drilling fluid, would act as the viscosifier. Sodium sulfite (Na_2SO_3) is a moderately strong reducing agent yielding sodium sulfate on oxidation. It also removes oxygen to help prevent corrosion. Potassium chloride, which is used as a shale inhibitor in the second mud formulation, will allow analysis of the flocculated dispersed colloidal system such as clay. The analysis with Dextrid LT, modified potato starch, would provide filtration control properties of the flocculated mud with minimum viscosity. Since Ferrochrome Lignosulfonate, Q-Broxin, can be used in all dispersed water-based systems and it functions well in dispersed fresh water fluids or saturated salt water based fluids, its analysis would test its role as a thinner or filtration control agent. The relationship between shear stress and shear rate can be established using a Fann-VG viscometer. Traditionally, water based drilling fluids are known to follow a power law model. The rheology of the drilling fluid samples selected for this analysis is given in Table 3.

5.7.3.5.2 Drilling fluid flow conditions

The linear velocity and the flow rate required to obtain the desired shear rate across the core face are calculated using the equation (1) and shown in Table 1. The core holder used in the present analysis, has a specific, constant flow-through gap at the core face and width of flow through area. Hence, knowing the power law index of drilling fluid, the flow rates were determined for intended shear rate values of 30, 40, and 80 sec^{-1} for this analysis.

*nwGapQw*12...302+=? (1)

where,

Q = Recirculation pump flow rate, ml/min

?$_w$ = Shear rate across core face, sec^{-1}

Gap = Flow-through core holder gap (at core face), cm

W = Width of flow-through area of core holder (at core face), cm

N = Power law index

5.7.3.5.3 Mackenzie Delta Base Mud – Effect of shear rate

The deposition of mud particles on the sand face to initiate the formation of a mud cake is controlled by the hydrodynamic forces acting on particles in the mud. The fluid loss into the formation is the driving force pushing the particle towards the core face. The shear stress exerted by the mud on the core is the force tending to entrain the particle in the flow loop. When the fluid loss to the formation is small (low overbalance pressure, low permeability) the hydrodynamic force tending to push the mud colloids onto the formation is insufficient and all the mud solids are entrained.

Figure 27 is a plot of cumulative filtrate volume versus cumulative time at different shear rates or annular velocities for Mackenzie Delta base mud (BM) on Berea sandstone. It is clearly seen that at early times, the filtration rate is high. As the mudcake builds up, filtration rate decreases until an equilibrium filtration rate has been attained. During mudcake build-up under dynamic filtration conditions, the force preventing particle deposition on the surface is proportional to the shear rate. Therefore, at higher shear rates, the mudcake formed is thin and the filtration rate is high. Because no mudcake is present during the spurt loss period, the shear rate does not affect spurt loss, which can be seen in Figure 27. Figure 28 indicates the permeability impairment at various shear rates of base mud. At higher shear rates solid particles near the core face experience the higher entraining force into the flow loop and hence the return permeability is more than that obtained at lower shear rates.

5.7.3.5.4 Mackenzie Delta Base Mud – Effect of overbalance

Figures 29 and 30 illustrate the effect of overbalance pressure on the dynamic filtration and permeability damage respectively at the same shear rate. The overbalance pressure of 200 psi led to higher dynamic fluid leak-off and significant damage to the core, resulting in 20% return permeability of the initial permeability. However, attainment of only minimal gas hydrate saturation may have increased ability to transmit a pressure-pulse within the sample, given that the remaining pore space would contain a mobile fluid phase.

5.7.3.5.5 Static and dynamic filtration with base mud

Figure 31 compares the filtration results for BM at the same overbalance pressure. The dynamic filtration rate declines continuously with time until equilibrium is reached, whereas static filtration rate was found to be constant. Less fluid leak-off resulted commensurate with the increased mudcake thickness, which occurs in the absence of erosion.

5.7.3.5.6 Flocculated mud dynamic filtration – Effect of Shear rate

Figures 32 and 33 illustrate the effect of particle size on the dynamic filtration rate and the corresponding formation damage (permeability), respectively. It is anticipated that the particle size in the NaCl (flocculent) containing mud is larger than that in deflocculated mud. The complete Brownian motion for all dispersed particles would be extremely rare and undesirable in a drilling fluid. As the degree of flocculation of the mud increases, so does the degree of flocculation of the filter-cake solids. Figure 32 shows the effect of shear rate on the dynamic filtration, giving increased fluid leak-off due a to a more permeable filter-cake, on the order of 700 to 900 ml, unlike the 150 to 250 ml in the case of base mud.

The permeability reduction within the sample penetrated by flocculated mud is small and the return permeabilities are on the order of 66, 83 and 95% of original permeability for 30, 40 and 80 sec^{-1} shear rates, respectively, as shown in Figure 33. These are much higher than those observed in the case of base mud. This indicates that the mud particles in case of flocculated mud do not invade to a greater depth, giving higher return permeability.

5.7.3.5.7 Flocculated mud – Effect of overbalance

Figure 34 indicates a difference of 700 ml in the dynamic fluid leak of both muds at 80 sec^{-1} shear rate and 100 psi overbalance. This difference increases about 1000 ml at 200 psi overbalance pressure and 40 sec^{-1} shear rate, as shown in Figure 35. Moreover, as the overbalance pressure conditions become high, the damage becomes more severe, giving return permeability of 65% at 200 psi as shown in Figure 36.

There are two mechanisms that cause permeability impairment in these fresh water muds; (a) fresh water filtrate causes fines release and migration and (b) clay particle invasion. In the case of flocculated mud, near the core face, both clay invasion and fines migration may play a role. But since the fines release is significantly reduced by the high salinity filtrate, this mechanism is expected to be insignificant at a higher core depth in a flocculated mud system. Comparison of Figures 27, 28, 32, 33 reveals that the higher dynamic filtration rate does not always imply higher damage. The filtrate volume of the BM-NaCl mud is twice as large as that of the base mud, but the permeability reduction is less and the return permeability is higher for BM-NaCl mud. As explained above, higher salinity filtrates inhibit fines release and migration and therefore cause significantly less damage. The comprehensive summary of the experiments with base mud and that with NaCl is presented in tables 4 and 5.

5.7.3.5.8 Mackenzie Delta drilling fluid – Effect of shear rate

Dextrid is used as a filtration control additive in water-based drilling fluids. In this analysis, 50 gm of a commercial Dextrid was added to the base mud with 50 gm potassium chloride. The results in Figure 37 clearly show that spurt loss was significantly reduced. The increase in shear rate has opposite effect on cumulative leak off. This indicates that the Dextrid mudcake reduces the permeability at the wellbore to formation interface and that the mudcake, which can resist the shear rate applied by the flowing the mud stream, is thinner and with higher strength. The lower mudcake permeability can also be inferred from the damaged permeability values in Figure 38. With Dextrid, there is adequate supply of bridging material in the form of barites and mudcake filtration is controlling the filtration process. The effect of controlling particulate deposition and mudcake properties has a greater influence on fluid loss than shear thinning effects upon filtrate viscosity. The return permeability at higher shear rate is of the order of 80-90%.

5.7.3.5.9 Mackenzie Delta drilling fluid – Effect of overbalance

The effect of overbalance pressure at 200 psi is found to cause more cumulative leak-off (Figure 39) and severe damage (Figure 38), entraining more solids into the core sample. The static filtration rate at 100 psi overbalance is found to be negligible as compared to that in the dynamic case (Figure 40). The experimental conditions and summary of the results with Mackenzie mud are given in Table 6.

5.7.3.5.10 Dispersed mud dynamic filtration – Effect of shear rate

Q-Broxin (chrome lignosulfonate) lowers the filtration against flocculated mud primarily through deflocculation, but can act as a colloidal bridging and plugging agent if it is present in sufficient quantity. Filter cakes from highly deflocculated muds are known to show reduced compressibility, owing to the close packing of solids, which lowers filtration rates as shown in Figure 41 but often decreases mudcake lubricity. For Q-Broxin added mud, the permeability impairment (Figure 42) is more severe than that in the flocculated mud system, especially at higher shear rates. Since the mud particles are dispersed and therefore smaller, it is to be expected that the probability of capturing the smaller particles is lower than that of the bigger particles. Since smaller particles penetrate deeper before being captured, they cause permanent damage. It is important to note that there is no mudcake on the core after 10 hours of mud circulation for Q-Broxin mud. Comparison of this severe permeability damage with a flocculated mud system reveals that the higher dynamic filtration rate does not always imply higher damage. The filtrate volume of flocculated drilling mud was higher, but the permeability reduction was less and the return permeability was higher. As discussed earlier, this may pertain to the fact that higher salinity filtrates inhibit fines release and migration, and therefore cause significantly less damage.

5.7.3.5.11 Dispersed mud – Effect of overbalance and static filtration

Figure 43 and 44 show the effect of overbalance pressure and static filtration on cumulative leak-off of dispersed mud respectively. The permeability impairment with respect to higher overbalance pressure conditions is shown in Figure 42. The permeability damage at higher overbalance pressure is much more severe. The cumulative leak off at static conditions is higher than that observed at a moderate shear rate of 30 sec^{-1}. The summary of the experimental conditions and results with dispersed mud is given in Table 7.

5.7.3.6 Conclusions

Using the experimental apparatus for formation damage testing, with leak-off through a core at in-situ conditions of pressure and temperature, KCl/polymer water-based drilling fluids at overbalance pressure were analyzed for static and dynamic filtration and return/damaged permeability through Berea sandstone. At the confining pressure of 1500 psi, chilled drilling fluids at 41-50^oF are circulated across the core for 10 hours in a dynamic filtration core holder. The Mackenzie Delta base mud, flocculated mud, flocculated mud with starch based filtration control material and dispersed mud are tested at 30, 40, 80 sec^{-1} and 100/200 psi overbalance to draw the following conclusions on the effect of individual components, their amounts in drilling fluids, particle size, and filtrate amount on permeability impairment.

1. Annular fluid velocity or shear rate or flow rate has a pronounced effect on dynamic fluid loss. Mackenzie Delta base mud and flocculated and deflocculated drilling fluid systems exhibit increasing cumulative leak-off with shear rate. However, the addition of a filtration control agent gives the reverse trend.

2. The extent of overbalance was found to be a very important parameter, with greater overbalance causing more fluid leak-off and more damage. The damage at the highest investigated overbalance pressures of 200 psi was severe. Hence, the critical overbalance drilling pressure, below which no filter cake will be formed on formations with permeability on the order of 103 md, may not be as high as 200 psi. However, according to previous investigations, for low permeability formations (K<1md), maintaining the drilling at unreasonably high overbalance pressure just above critical pressure (thus ensuring mudcake formation) can be difficult unless the annular velocity is low.

3. The dynamic filtration mud leak-off amount is found to be much more than that in static filtration, with all drilling fluid formulations and same overbalance pressure conditions. Dynamic filtration conditions, even at moderate shear rate (30 sec^{-1}) always give higher spurt loss and filtration rates than static conditions. This underlines the importance of this research at representative borehole conditions.

4. Formation damage due to fines release and migration controlled by high salinity filtrate can be significant as far as cumulative leak-off amount is concerned. The flocculated drilling fluid with salt results in more cumulative leak-off. This emphasizes the necessity of salt concentration higher than the critical salt concentration required to prevent the fines release and migration. However the return permeability values are found to be high, indicating the higher cumulative leak-off does not necessarily mean higher damage, especially when it is compared with that of a deflocculated mud system.

5. The permeability impairment is strongly dependent on the state of dispersion of mud. The deflocculated mud with lignosulfonate causes more damage, by invading deeper with smaller particles. The flocculated mud gives poor quality filter cake, with more filtrate loss into the formation. The drilling fluid formulation giving a low permeability, high strength external mudcake would be ideal to minimize formation damage.

6. The presence of 50 gms of filtration control agent, Dextrid (starch based material), in a liter of water reduces the spurt loss and subsequent filtration rates significantly. The return permeability is found to be 94% after mud circulation at 80 sec^{-1} shear rate.

5.7.3.7 Tables and Figures

The following section displays tables 3-7 and figures 25-44 referenced in Section 5.7.3.

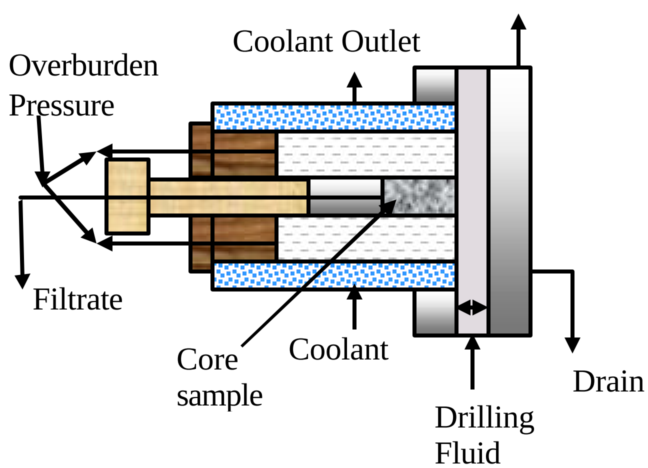


Figure 25: Dynamic Filtration Core Holder (DFCH-1.5)

Table 3: Water-Based Drilling Fluids Compositions, Rheology and Flow Rates for Desired Shear Rates

Compositions	Power Law Index, n	Consistency Factor; k $lbf.sec^n/100\ ft^2$	Plastic Viscosity; PV cp	Apparent Viscosity; cp	Yield Point; Yp lb/100 ft^2	Density; ?mud ppg	Shear Rate sec^{-1}	Flow Rate gpm	Linear Velocity ft/min
BM: 1 liter water + 0.3 gm Na_2SO_3 + 0.3 gm Barite + 0.5 gm KOH + 3 gm Quickgel	0.6777	0.03653	1.5	2.25	1	8.3	30	0.3503	10.8794
							40	0.4671	14.3859
							80	0.9342	28.7718
BM + 50 gm KCl	0.5142	0.1417	1.5	3	2	8.5	30	0.3087	9.5069
							40	0.4116	12.6759
							80	0.8231	25.3518
BM + 50 gm + 15 gm Dextrid	0.7365	0.04555	3	4.125	1.5	8.6	30	0.3626	11.1683
							40	0.4835	14.8911
							80	0.9671	29.7822
BM + 50 gm + 50 gm Q-Broxin	0.7365	0.03037	3	2.75	1.5	8.6	30	0.3626	11.1683
							40	0.4835	14.8911
							80	0.9671	29.7822

Table 4: Summary of the Experimental Parameters and Results with Base Mud

Mud Composition	Shear rate	Flow rate	Velocity	Core diameter	Core length	Core c/s area	Overbalance Pressure	Damaged k/ko	Return k/ko	Filtrate	Projected invasion	Volume circulated
	sec^{-1}	gpm	ft/min	inch	inch	$inch^2$	psi			ml	ft	liter
BM	30	0.3503	10.7896	1.469	2.028	1.694	100	0.2826	0.5761	139.1018	2.2325	795.6421
	40	0.4671	14.3861	1.469	2.024	1.694	100	0.1347	0.7959	218.9143	3.5135	1060.8561
	80	0.9343	28.7722	1.465	2.028	1.685	100	0.2212	0.8138	255.4	4.1211	2121.7122
	40	0.4671	14.3861	1.461	1.937	1.676	200	0.0856	0.2126	305.5679	4.9572	1060.8561

Table 5: Summary of the Experimental Parameters and Results with Base Mud with NaCl

Mud Composition	Shear rate	Flow rate	Velocity	Core diameter	Core length	Core c/s area	Overbalance Pressure	Damaged k/ko	Return k/ko	Filtrate	Projected invasion	Volume circulated
	sec^{-1}	gpm	ft/min	inch	inch	$inch^2$	psi			ml	ft	liter
BM + 50 gm KCl	30	0.3087	9.5068	1.457	2.067	1.667	100	0.1461	0.4597	701.411	11.4406	701.0490
	40	0.4116	12.6757	1.465	2.067	1.685	100	0.2668	0.8358	904.9449	14.6021	934.7320
	80	0.8232	25.3515	1.449	1.937	1.649	100	0.5198	0.9532	953.028	15.7141	1869.4640
	40	0.4116	12.6757	1.457	2.028	1.667	200	0.0946	0.6859	1358.288	22.1548	934.7320

Table 6: Summary of the Experimental Parameters and Results with Mackenzie Delta Mud

Mud Composition	Shear rate	Flow rate	Velocity	Core diameter	Core length	Core c/s area	Overbalance Pressure	Damaged k/ko	Return k/ko	Filtrate	Projected invasion	Volume circulated
	sec^{-1}	gpm	ft/min	inch	inch	$inch^2$	psi			ml	ft	liter
BM + 50 gm KCl+15 gm Dextrid	30	0.362659	11.1687	1.437	2.051	1.622	100	0.1837	0.7448	151.4157	2.5378	823.6020
	40	0.483546	14.8916	1.398	2.004	1.535	100	0.0825	0.8154	139.9715	2.4801	1098.1360
	80	0.967092	29.7833	1.457	1.996	1.6672	100	0.0765	0.9422	132.9289	2.1682	2196.2721
	40	0.483546	14.8916	1.398	1.976	1.535	200	0.0425	0.6700	221.8416	3.9307	1098.1360

Table 7: Summary of the Experimental Parameters and Results with Deflocculated Mud

Mud Composition	Shear rate	Flow rate	Velocity	Core diameter	Core length	Core c/s area	Overbalance Pressure	Damaged k/ko	Return k/ko	Filtrate	Projected invasion	Volume circulated
	sec^{-1}	gpm	ft/min	inch	inch	$inch^2$	psi			ml	ft	liter
BM + 50 gm KCl+ 50 gm Q-Broxin	30	0.362659	11.1687	1.457	2.016	1.667	100	0.23077	0.39615	149.65	2.4409	823.6020
	40	0.483546	14.8916	1.398	2.028	1.535	100	0.24895	0.83000	239.448	4.2426	1098.1360
	80	0.967092	29.7833	1.437	2.016	1.622	100	0.47999	0.87995	430.478	7.2151	2196.2721
	40	0.483546	14.8916	1.429	2.024	1.605	200	0.04889	0.30174	662.88	11.2331	1098.1360

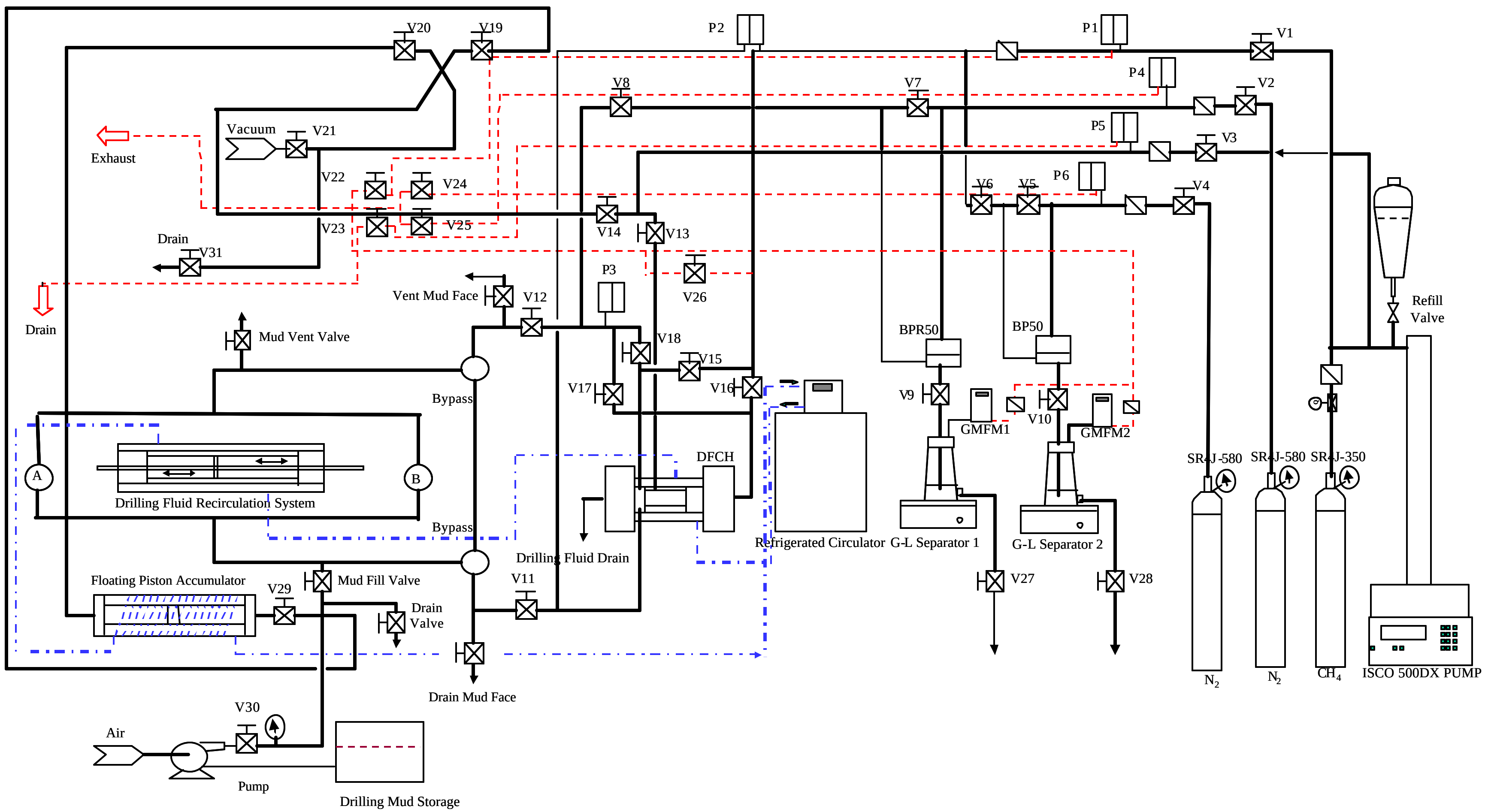


Figure 26: Flow Diagram of Formation Damage Assessment System with Drilling Fluid Dynamic Filtration

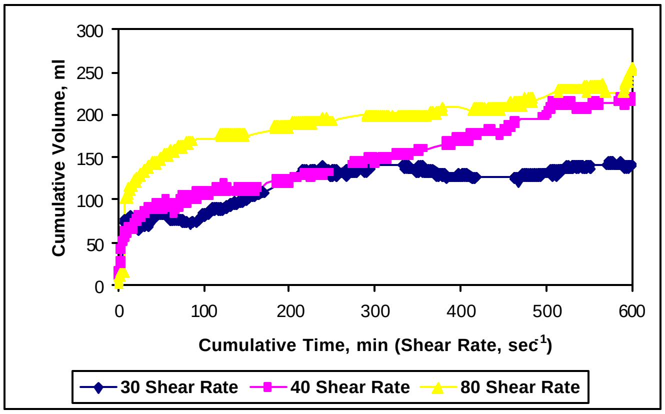


Figure 27: Effect of Shear Rate on the Dynamic Filtration of Base Mud at 100 psi Overbalance

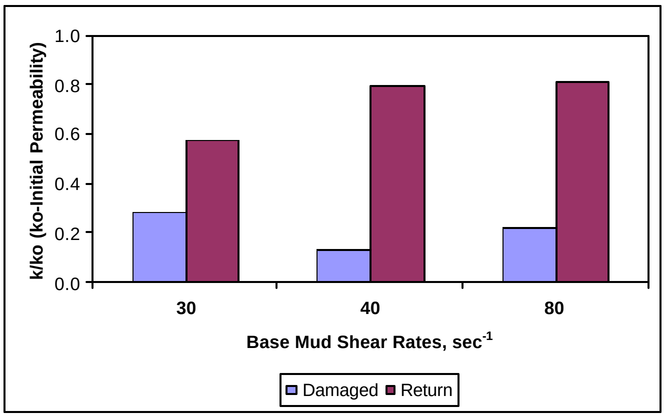


Figure 28: Effect of Shear Rate on Permeability Impairment with Base Mud at 100 psi Overbalance

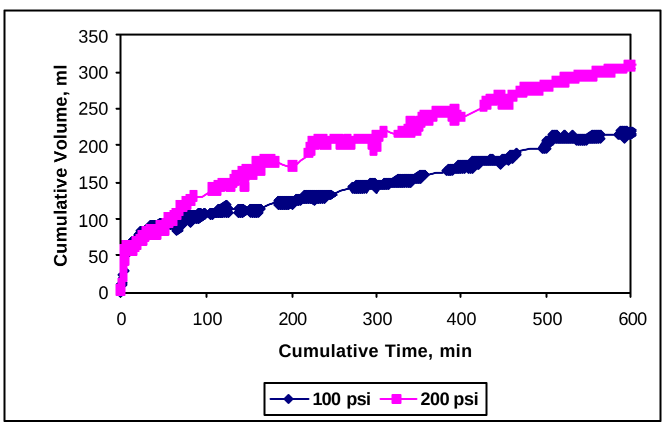


Figure 29: Effect of Overbalance Pressure on Dynamic Filtration of Base Mud at 40 sec^{-1} Shear Rate

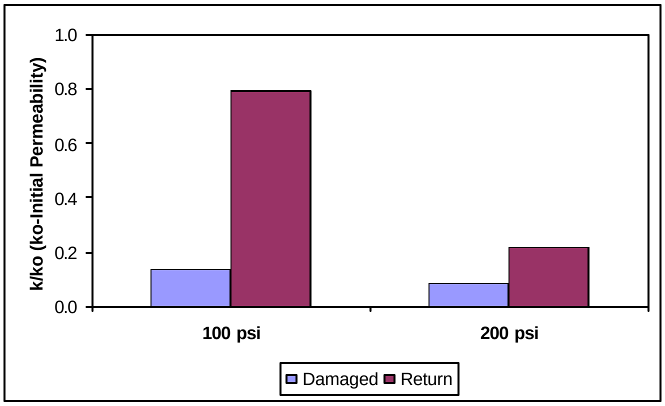


Figure 30: Effect of Overbalance Pressure on Permeability Impairment with Base Mud at 40 sec^{-1} Shear Rate

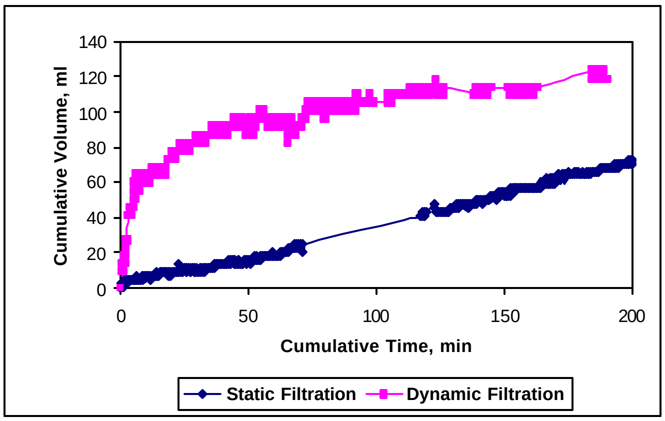


Figure 31: Comparison of Static and Dynamic Filtration (40 sec^{-1}) of BM at 100 psi Overbalance

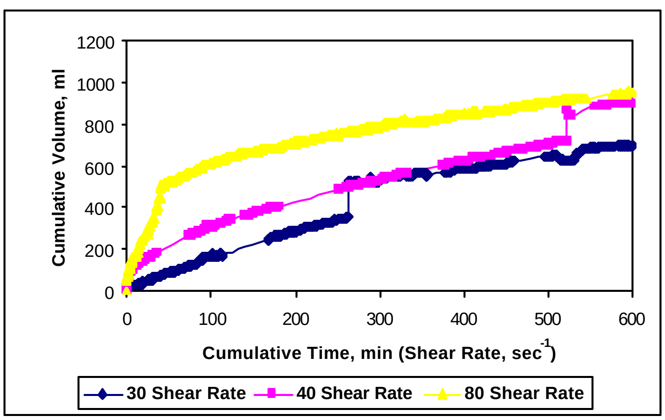


Figure 32: Effect of Shear Rate on the Dynamic Filtration of Flocculated Mud at 100 psi Overbalance

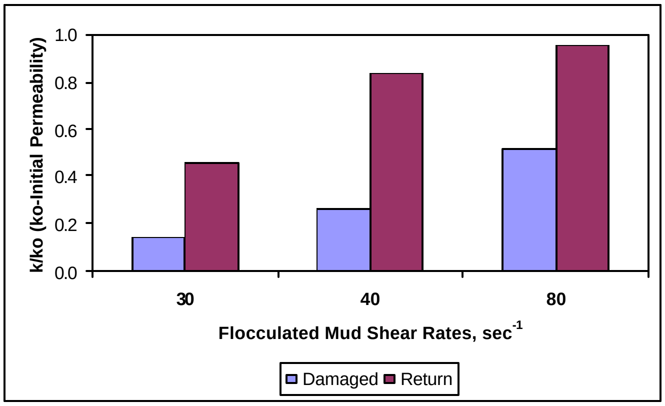


Figure 33: Effect of Shear Rate on Permeability Impairment with Flocculated Mud at 100 psi Overbalance

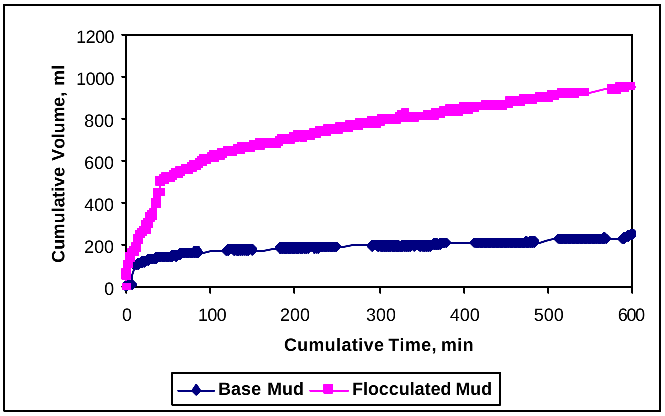


Figure 34: Effect of Flocculent on the Dynamic Filtration at 100 psi Overbalance and 80 sec^{-1} Shear Rate

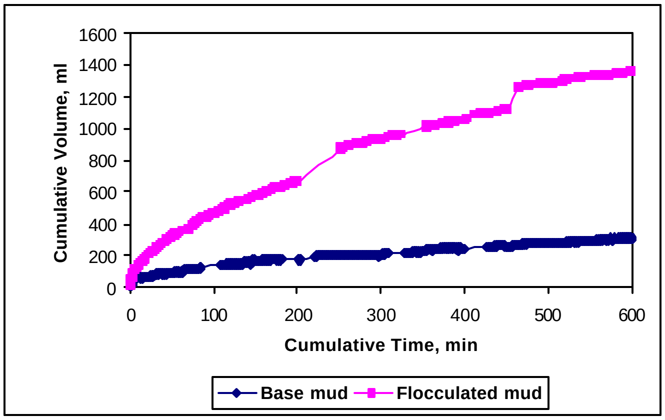


Figure 35: Effect of Flocculent on the Dynamic Filtration at 200 psi Overbalance and 40 sec^{-1} Shear Rate

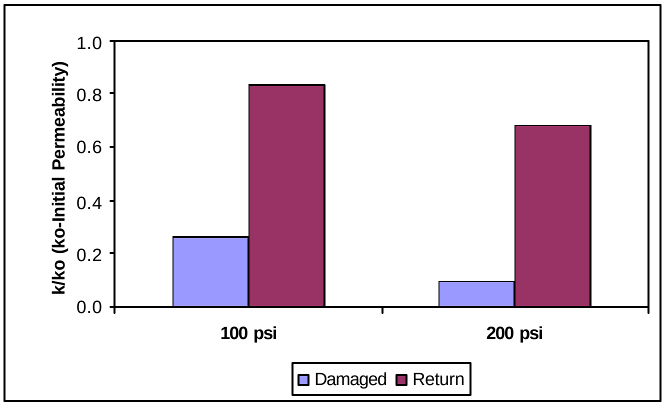


Figure 36: Effect of Overbalance Pressure on Permeability Impairment with Flocculated Mud at 40 sec^{-1} Shear Rate

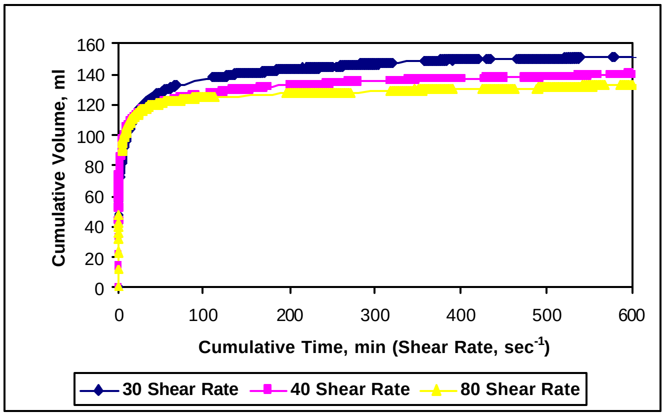


Figure 37: Effect of Shear Rate on Dynamic Filtration of Mackenzie Mud at 100 psi Overbalance

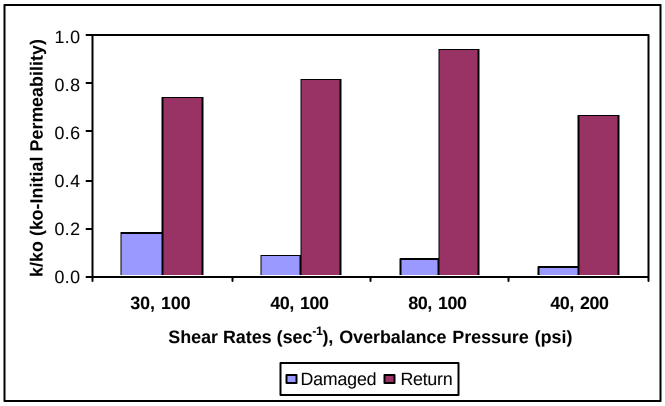


Figure 38: Effect of Shear Rate and Overbalance on Permeability Impairment of Mackenzie Mud

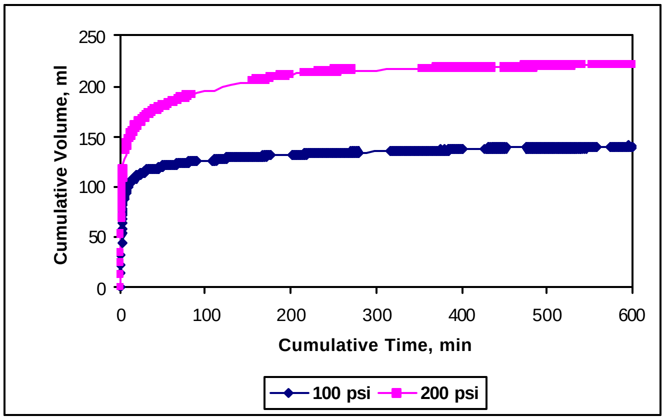


Figure 39: Effect of Overbalance on Dynamic Filtration of Mackenzie Mud at 40 sec^{-1} Shear Rate

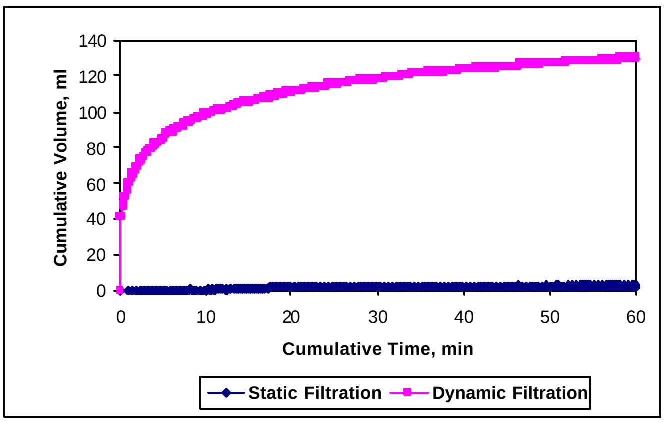


Figure 40: Comparison of Static and Dynamic (30 sec^{-1}) Filtration of Mackenzie Mud at 100 psi Overbalance

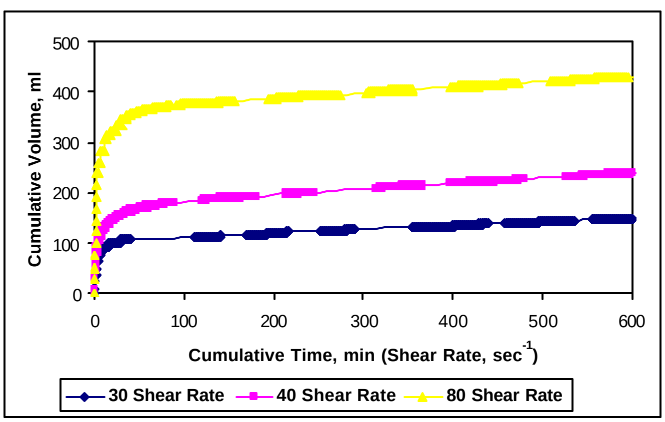


Figure 41: Effect of Shear Rate on Dynamic Filtration of Dispersed Mud

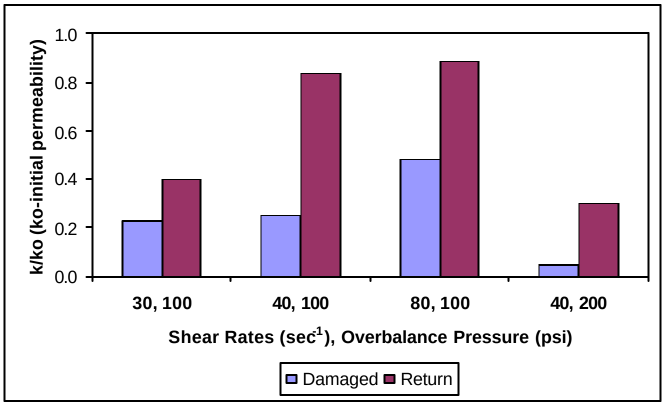


Figure 42: Effect of Shear Rate and Overbalance on Permeability Impairment with Dispersed Mud

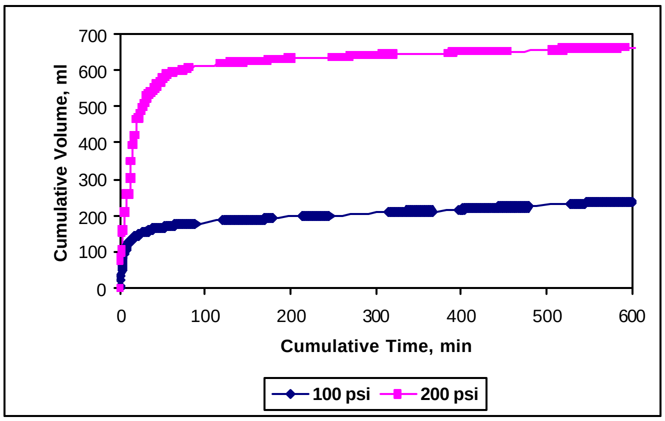


Figure 43: Effect of Overbalance Pressure on Dynamic Filtration (40 sec^{-1}) of Dispersed Mud

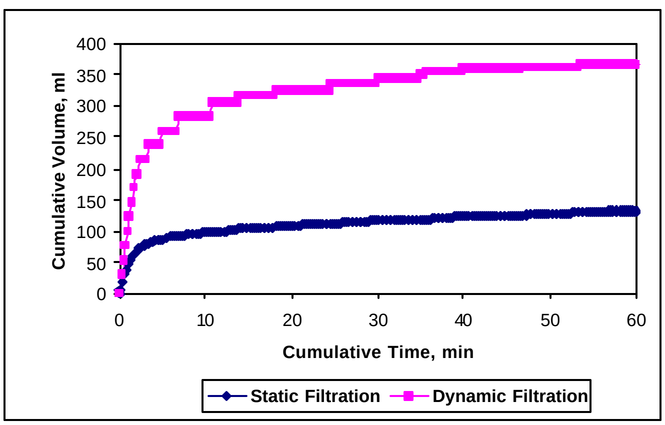


Figure 44: Comparison of Static and Dynamic (80 sec^{-1}) Filtration with Dispersed Mud at 100 psi Overbalance

5.7.4 Petrophysical and Other Physical Properties of Gas Hydrate Core Samples

No core samples were acquired during the reporting period.

5.8 Phase 2 Task 8.0: Design Completion and Production Testing for Gas Hydrate Well

This task was modified by mutual agreement between BP and DOE during the reporting period. The modified task carried forward into Phase 3a Task 8.0 well operations is entitled: **Plan and Implement Drilling of Stratigraphic Test Well** as reported below in Section 5.11. Accomplishments toward Task 8 during Phase 2 are documented in this section and culminated with the January 11, 2006 approval for drilling the stratigraphic test well.

- Initiated long-lead well permit discussions to allow potential future well operations
- Developed long-lead materials and rig plans to allow possible future well operations
  - Data acquisition to include wireline core, full open-hole logging, MDT
  - Met with Corion for wireline core technical discussion and applicability
  - Met with OMNI Lab for core processing and analyses
  - Met with CoreMonger Lab for core processing and storage discussions
  - Evaluated core storage options with ASRC Energy Services (AES) and others
  - Evaluated mud-chilling options and providers and selected DrillCool, Inc.
  - Evaluated and planned open-hole logging program and met with Schlumberger
- Prepared Continuation Application, Budget, Decision Support Package, and “Authority to Negotiate” documents to support Phase 3a stratigraphic test approval (January 11, 2006)
  - Met with BP Gas and MPU management for discussions and decisions
  - Developed stratigraphic test plans with BP MPU technical and drilling staff
  - Completed “Authority to Negotiate” document and worked through approvals
  - Obtained Stratigraphic Test well operations approval January 11, 2006
- Provided operational integrity and HSE requirements for stratigraphic test operations
  - Provided justification for rig operations and safety requirements
  - Assured clarified processes and procedures conformed to BP standards
  - Proposed turnkey operation with newly consigned rig, Doyon Arctic Fox
  - Selected BP-led operation with Doyon Arctic Fox rig and ASRC Energy Services
- Prepared initial procedures, plans, and cost estimates for stratigraphic test well operations

5.9 TASK 9, Phase 2: Develop Field Operations and Data Acquisition Plans for Well(s) of Opportunity and/or Dedicated Test Well(s)

This task was modified by mutual agreement between BP and DOE during the reporting period. The modified task was carried forward into Phase 3a well operations within Task 8 as documented in contract Amendment 11 and reported below in Section 5.11.

5.10 TASK 10, Phase 2: Reservoir Modeling and Project Commercial Evaluation and Continuation of Progression into Phase 3

- Planned and coordinated Phase 2 reservoir modeling and regional resource assessments
  - Provided input to DOE NETL-coordinated reservoir model comparison studies
  - Coordinated and Implemented regional Eileen trend fieldwide potential development scenario studies
    - Input Sagavanirktok zone polygons from USGS studies
    - Developed statistical approach and sequential development scenario

  - Reviewed preliminary study results and implemented improvements
  - Ranked potential future development areas
  - Documented study results as discussed below
- Completed reservoir simulation studies using CGM STARS and coupled with regional potential field development scenario studies
  - Resulted in BP-DOE decision to proceed into Phase 3a stratigraphic test well operations (Mt Elbert-01 well).

5.10.1 Regional Screening Study of Large Scale Gas Hydrate Production on Alaska's North Slope, RyderScott Company (Scott Wilson)

5.10.1.1 Summary

Using the current understanding of the gas hydrate resource potential within current facility infrastructure on the North Slope of Alaska and production characteristics as defined by testing at the Mallik research well and reservoir modeling, a set of scenarios was developed to define ranges of potential gas production volumes and associated costs. The reference case outlines results as predicted from available information from the Mallik production experiments, University of Alaska Fairbanks (UAF) and Ryder Scott Company simulations using CMG's STARS and ProCast, USGS geologic characterization and mapping studies, and coordination by BP through ASRC Energy Services.

Reference case forecasts predict from 2.5 TCF of gas may be produced in 20 years, and nearly 10 TCF ultimate recovery after 100 years (note that a typical industry forecast does not exceed 50 years). Downside cases envision simple "pilot" well operations to acquire additional reservoir data (Phase 3a and 3b studies) leading to a conclusion of technical or economic infeasibility. Upside cases identify future potential if both dissociation and thermal stimulation yield positive results, while an extreme upside case captures the full potential of an unconstrained possible future development with highly productive, widely spaced wells. With the explicit goal of identifying the magnitude of the potential "prize" to be obtained by continuing down the research and development path, this work shows that continued research is justified based on the stakes and potentially lost value further data is not acquired to help determine whether or not these resources might one day be considered to be technically producible reserves.

5.10.1.2 Introduction

In an effort to quantify the resource potential of the gas hydrate-bearing formations on the Alaska North Slope, a project was undertaken to forecast and schedule gas production from gas hydrate using methods typically employed in conventional large natural gas development projects. Hydrate gas is defined here as methane gas evolved during the dissociation of naturally occurring natural gas hydrate within shallow reservoir sands on the North Slope of Alaska. These resources have been previously mapped, studied, and quantified at about 44 TCF gas in-place (Collett, 1993) and are being further characterized by University of Arizona studies (Task 6) of this project. However, until recently, there has not been a concerted effort to determine the amount of the resource that might be recovered by means of conventional petroleum technologies and to quantify the ranges of potential outcomes that could be narrowed by use of specific recommended field testing and data acquisition.

This section of this report documents the work done to describe a systematic development plan, consistent with current industry practice, to potentially make the gas hydrate resource an accessible, significant part of the ANS gas resource portfolio. This section of this report does not estimate reserves in the sense of financial reporting standards but, is only a preliminary step in understanding the potential magnitude of the resource, and what milestones would need to be met before that resource might become a legitimate reserve as defined by the SPE/WPC (See Definitions).

5.10.1.3 Development Planning Process

5.10.1.3.1 Areal Extent

The development planning effort started with areal estimates of gas hydrate occurrence as presented by Collett[1] (1993) and shown in figure 45-47. Figure 45 and the individual zone maps (Figure 46) were modified to incorporate an understanding of the temperature and pressure equilibrium data in conjunction with the regional structure maps. This effectively moved the

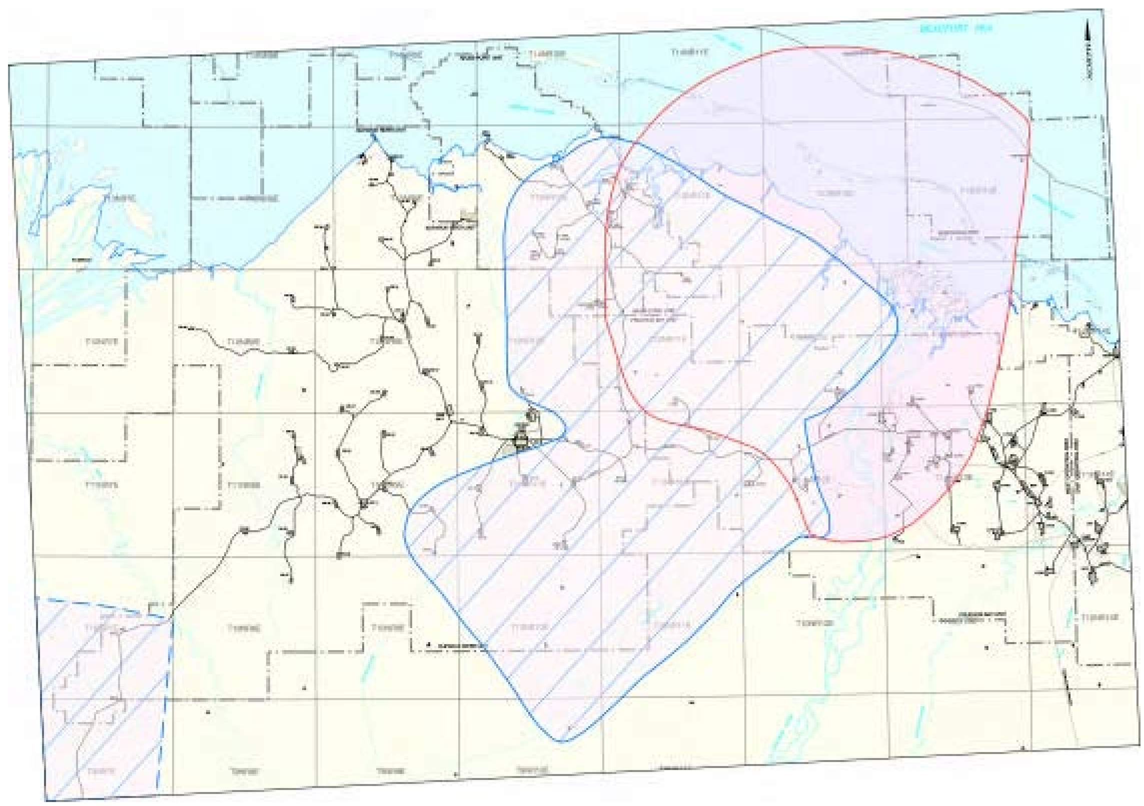


Figure 45: Alaska North Slope facilities and Gas Hydrate Extent (Collett, 1993[1])

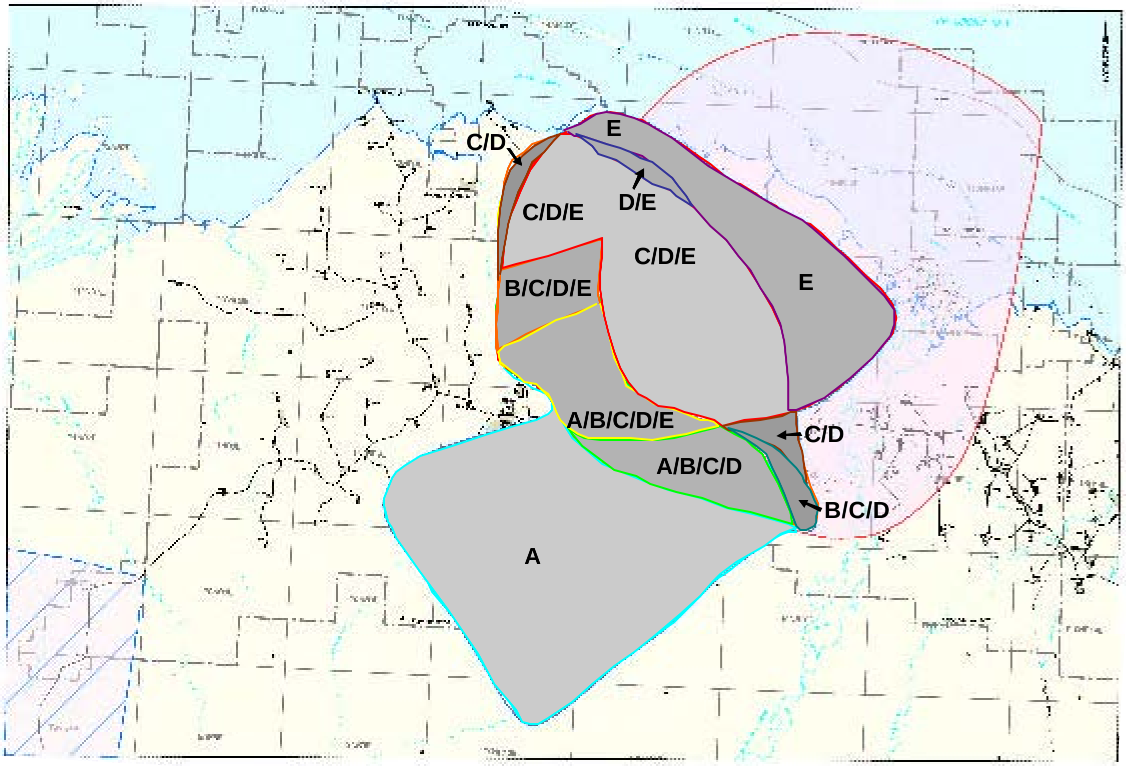


Figure 46: USGS gas hydrate-bearing zones within the Eileen trend Area-of-Interest

interpreted free-gas / gas-hydrate interface farther to the northeast. Using uniform average reservoir properties, these changes increased the calculated original hydrate gas in place (OHGIP) by 5 TCF to approximately 49 TCF. Scaling these values back based on recent more detailed work indicate a more likely risked OHGIP of 33.9 TCF as shown Table 8.

Table 8:
Eileen Trend Hydrate Gas In Place Estimates

Zone Name	GIP	Risk Factor	Risked GIP
A	17.9	0.35	6.3
B	8.9	1.00	8.9
C	10.8	0.82	8.9
D	6.1	1.00	6.1
E	6.1	0.60	3.7
Total	49.8	0.68	33.9

Although quoted extensively as a potential in-place resource, both in-place and potential recoverable volumes remain difficult to quantify. Since there is little commercial history of gas production from gas hydrate, bypassed opportunities to collect wireline and core measurements across the zones of interest make occurrence and continuity difficult to predict, even in densely drilled areas like the Alaska North Slope.

5.10.1.3.2 Vertical Extent

This areal extent was broken down by structural components to define the depositional vertical character of the gas hydrate accumulations known as sub-zones A through F as shown in the Figure 48 cross section. Although other classification systems have been used, this one matches the level of detail and areal scope that is required for this regional study. Additional discussion of variance between the volumes described within these zones and those defined for specific areas as described by descriptive work done by the University of Arizona (Casavant, 2004[2]). That (Task 6.0) work shows somewhat smaller in-place volumes and significantly less homogeneity. For purposes of this work, however, the differences fell within the range of variance in the production forecasts.

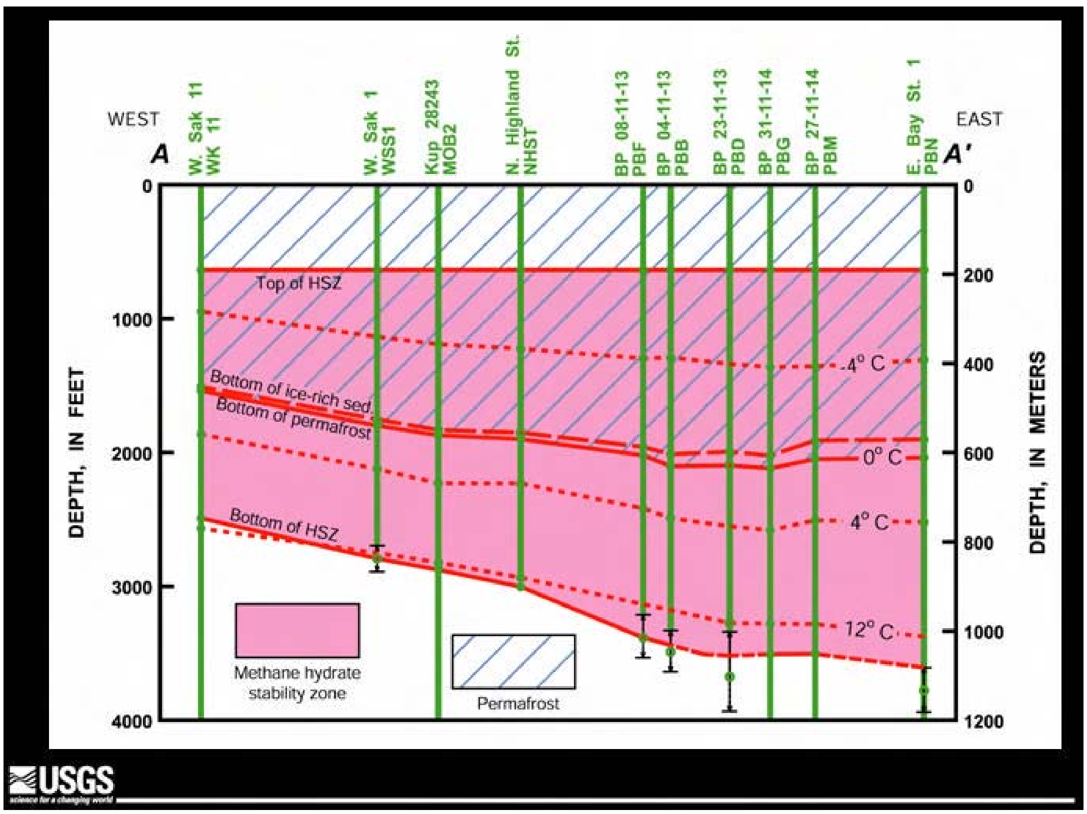


Figure 47: Gas Hydrate Stability zones and selected wells (Collett, 1993)

These maps were composited to identify those areas with multiple target horizons and were compared to more recent measurements of the base of the Ice-Bearing Permafrost layer (BIBPF) and the base of the Gas Hydrate Stability zone. These updated surfaces were used to map each zone and catalog potential well locations. As is common in large-scale staged developments, those areas with the greatest potential and fewest obstacles were targeted for the earliest development. This methodology focused attention on the Prudhoe Bay L and V pads in the C, D and A zones as areas with multiple thick gas hydrate bearing horizons within existing infrastructure. The cross-section in Figure 48 shows that zones are not always continuous across the area. The work presented from Task 6.0 in this report corroborates that the gas hydrate-bearing zones of interest may be even more laterally discontinuous.

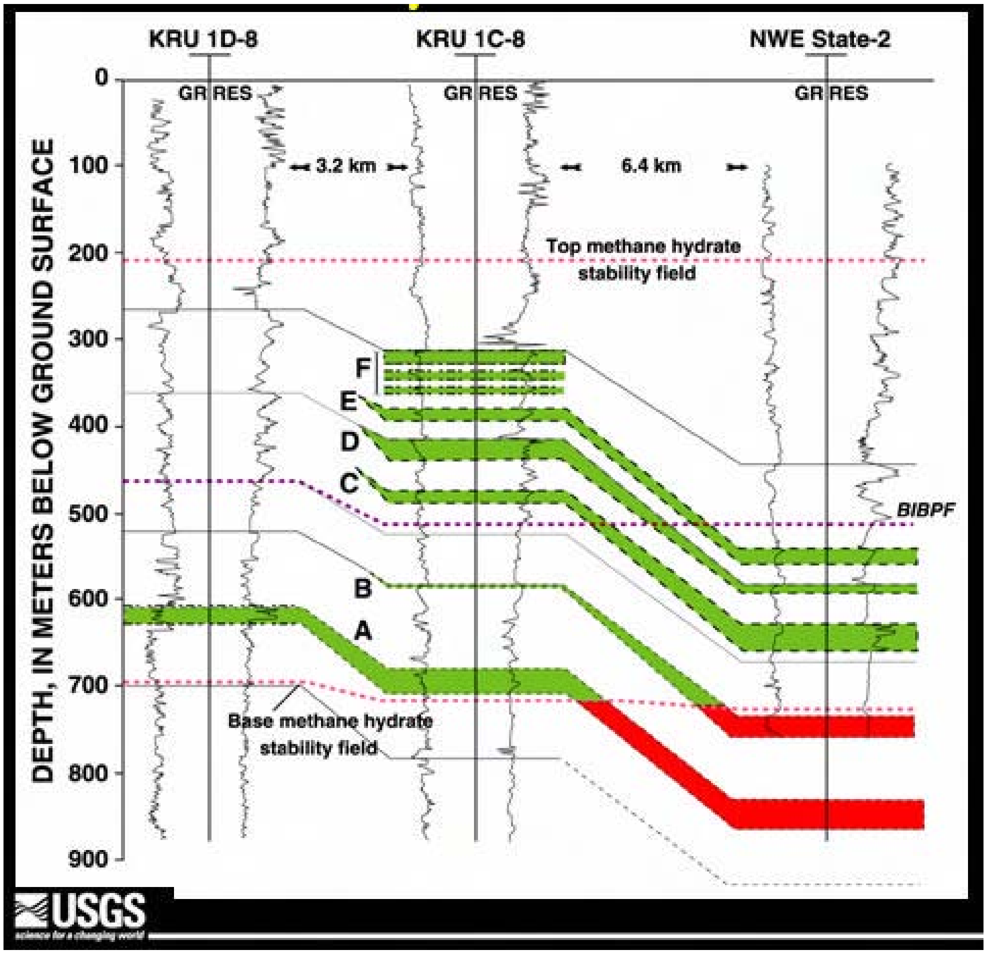


Figure 48: Gas Hydrate Zone Designations (Collett, 1993)

5.10.1.3.3 Type Well Development

Type wells were built based on the CMG STARS ™ modeling work presented first at the Vancouver AAPG Hedberg Conference (Wilson et al, September 12-16, 2004[3]). These single well forecasts are based on small scale chemical / thermal models implemented within a simulation grid to reflect large scale production forecasts for various reservoir and well configurations. Several studies were done to develop type wells for a variety of producing conditions, reservoir and fluid properties, and thermodynamic conditions.

5.10.1.3.4 Permeability/Producibility Studies

Using the MDT results from the Mallik 5L-38 gas hydrate production research well (S.H. Hancock, 2004[4]), relative permeabilities within the type-well grids were set such that gas hydrate saturated formations would have an initial net relative permeability to water and gas on the order of 0.02 md. This value falls within the range of the in-situ measured permeabilities at Mallik and can be considered the best current estimate of the initial permeability of gas hydrate-bearing, high permeability shallow sand reservoirs. A very aggressive exponential growth relative permeability curve had to be used to transition from gas hydrate filled pores with dissociation induced by depressurization to water and gas filled pores which show permeability on the order of 300 md.

The magnitude of the change required to transition from 0.02 md to 300 md was not one normally seen in classic simulation studies using only liquid gas and rock phases, but is easily conceivable when considering the dynamics of a dissociating solid phase and its affect on clearing pore throats. At this microscopic scale, this is only a first estimate of the potential relationships between relative permeability to water and gas as a function of gas hydrate saturation. However, these values agree in principle with older studies of the same subject that found that some finite permeability existed even after what was thought to be complete pore closure due to ice and gas hydrate formation (Sturgeon-Berg, 1996[5]). It is recommended that similar studies be developed for gas hydrate-bearing porous media. The relative permeability plots in Figure 49 show the Water relative permeability curve used. A similar curve was generated for the gas relative permeability.

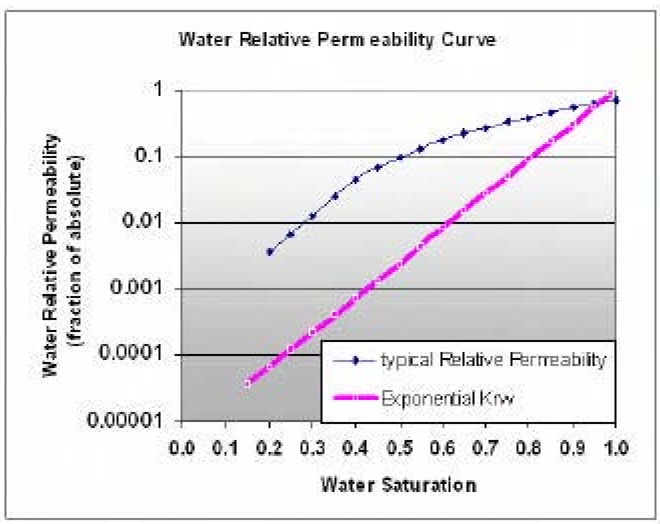


Figure 49: Water relative permeability curves used to match Mallik MDT results

5.10.1.3.5 Well Layout

Simple trial runs with a vertical well model and the Mallik-derived relative permeability curves quickly showed that commercial rates were not possible with a vertical configuration and simple pressure depletion. A horizontal well model was built to increase formation exposure and potential rates. The grid was modified to contain smaller cells near the horizontal wellbore so that gridding related issues could be minimized while maintaining reasonable run-times. Figure 50 shows an x-y view of a 2100 ft (600 Meter) horizontal well in a 640 acre drainage area. The pressure has been pulled down to highlight the anisotropic drainage patterns with blue being the lowest pressure and red being the highest.

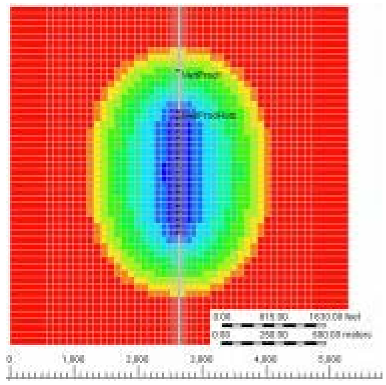


Figure 50: Map view of horizontal well in 640 acre drainage area.

In the vertical direction (z), a second layer was included to provide ambient heat-flux. Recommended heat flux constants from Mallik results were doubled to simulate transfer from both top and bottom surfaces. Although other descriptions could have been used, this system is finding success in producing difficult reservoirs like the West-Sak field in Alaska and in the thin coal zones near Poteau, Oklahoma. Although the type well only incorporated a single horizontal

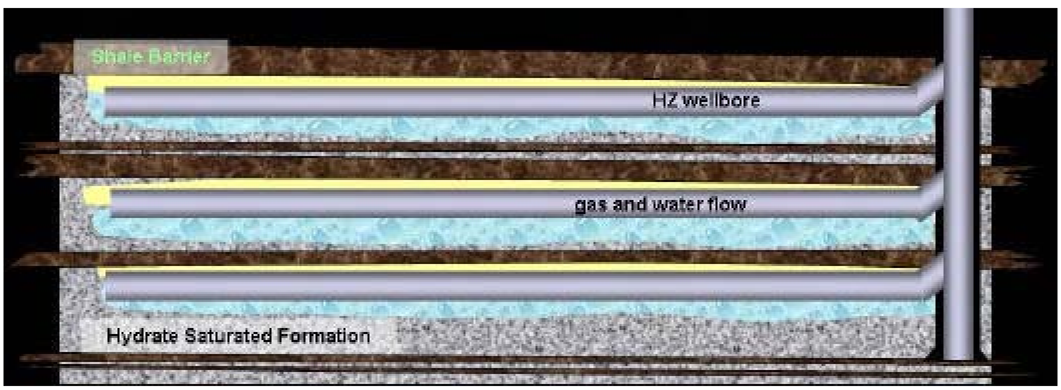


Figure 51: Example Multi-lateral well in several distinct Gas Hydrate zones.

well path, multiple horizontal completions could be drilled to drain isolated layers. These multi-laterals would look like the example shown in Figure 51.

These type wells within a regional development would be essentially additive at the expected rates. Forecasting can be handled by incorporating multiple type-well events at the same location, but with shared pad and surface casing costs. Technical forecasts using this simplification should be sufficiently rigorous since the only expected effect of a multilateral compared to two isolated laterals would be that the two legs may interfere on a long term temperature recharge. With high water production expected from all cases, lift cost and method may actually decrease as measured in $/mscf due to economies of scale.

5.10.1.3.6 Underlying Gas Pressure Dissociation

A large fraction of past reservoir modeling efforts have concentrated on the pressure dissociation of a gas hydrate body by offset depletion of an underlying gas body (Howe[6], Hong[7], McGuire[8]). If placed optimally in the reservoir, water production can be minimized by allowing water to under-run the producing wells. This option is, under all circumstances, the most economical to implement since it shares synergies with conventional gas production development strategies.

However, for purposes of a full life-cycle staged testing plan, this option is not the optimal early stage target for several reasons. Although it is the least technology intensive, dissociation by associated gas-zone pressure depletion requires the longest lead time to evolve gas from gas hydrate. It also provides the least definitive information concerning the hydrate-derived gas production process, since there are several anecdotal examples where this process may already be occurring, although it cannot be proven definitively or used in the extension of the technology to other applications (Makogon[9]). Additionally, within the majority of the study area, accumulations of free gas do not exist regionally adjacent to the gas hydrate accumulations; this can be further complicated by stratigraphic and structural compartmentalization as documented in tasks 5 and 6. Recent interpretation of the base of the gas hydrate stability zone has pushed this regional contact farther to the north and east than shown in figures 45 and 46. For these reasons, this method was not used in this planning exercise until the late stage development when it is assumed that sufficient technology development has delineated the gas hydrate resource and gas market demand would require use of all remaining gas sources.

5.10.1.3.7 Low-Saturation Gas Hydrate-bearing Reservoir Sand Completions

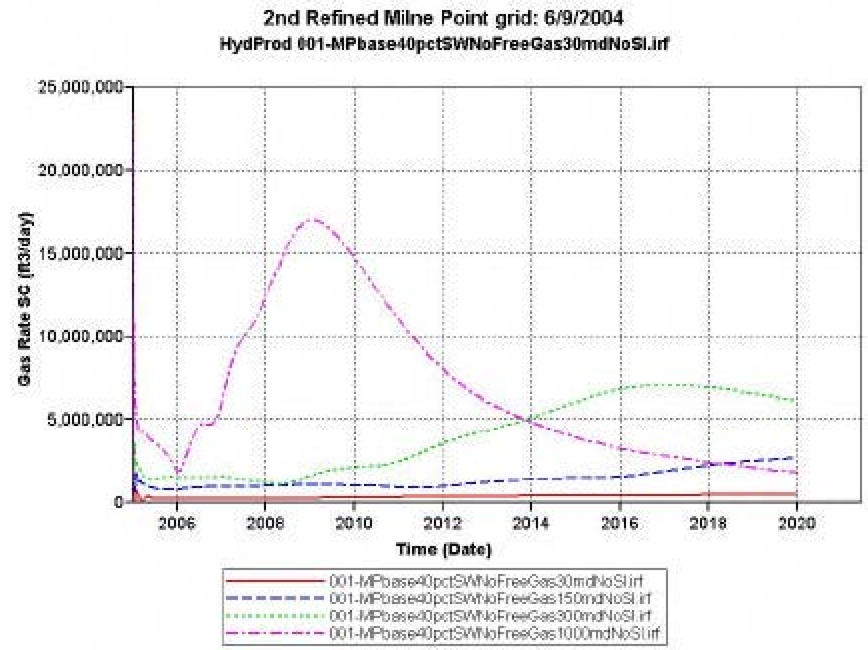
Since a majority of the gas hydrate is not interpreted to be in direct connection with a free gas accumulation, it is imperative to estimate the stakes and potential of a gas hydrate-only development where wells would be drilled directly into a gas hydrate accumulation and produced as dedicated gas dissociated from gas hydrate-bearing reservoir producers. Based on current modeling, this well type would require long horizontal sections to gain sufficient reservoir exposure to initiate and sustain gas dissociation from gas hydrate. In addition, significant quantities of fresh water would likely be produced with the dissociated gas and this water would have to be used or properly disposed. Some scenarios envision dissociated water remaining in the reservoir while gas is stripped off the top of the dissociated zone. This is possible under some circumstances and can be viewed as an upside production option.

5.10.1.3.8 High-Saturation Gas Hydrate-bearing Reservoir Sand Completions

There has been a great deal of discussion over the in-situ free-water saturation of North Slope gas hydrate-bearing reservoir sands. Based on the results from the Mallik well test experiments and MDT testing, which showed small but positive permeability, and well log interpretations which are inconclusive in estimating actual saturation of both gas hydrate and free water, a case can be made where gas hydrate exists in a matrix of pressure conductive free water and rock. Although this sounds detrimental to production practices, it provides a means of propagating a low pressure front farther into the formation than the equivalent higher gas hydrate saturation case. This led to the counter-intuitive premise that the best gas hydrate producers would be those wells with moderate gas hydrate saturations, while those with the highest gas hydrate saturation may become secondary or complementary targets due to less ability to propagate a pressure front to induce gas hydrate dissociation.

As shown in Figure 52 and first presented at the AAPG Hedberg conference in September, 2004, this characteristic was confirmed in modeling efforts which compared gas hydrate production responses for several different water saturations.

High Water Saturation case for 30, 150, 300, and 1000 md



Low water Saturation Case for 150, 300, and 1000 md

(30 md case had no production)

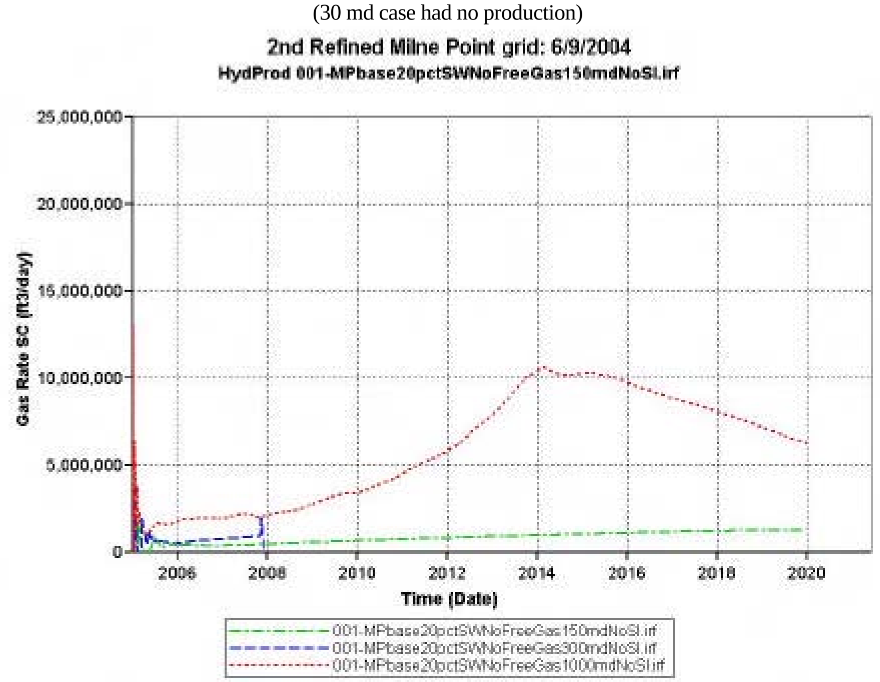


Figure 52: Different Gas Rate Forecasts based on initial water saturation (Wilson, 2004[3])

5.10.1.3.9 Type Well Details

Table 9 outlines the salient features of each type well and the associated gas development options. Type wells were tested at various native permeabilities, initial water saturations, and relative permeabilities. These parameters were found to be the greatest drivers of the production response at the anticipated development spacing of between 640 and 160 acres/well.

Table 9: Type well descriptions and major differences

Type Well Names	Estimated Ultimate Recovery @ 40 years	Peak Rate	Years to Peak Rate	Production Character
Mallik Relative Permeability				
Low Water Saturation Hydrate Producer Mallik rel-perm	5% @ 640 acre spacing	1 mmscfpd	100+ years	Long slow incline, low gas, water production rates
High Water Saturation Hydrate Producer Mallik rel-perm	15%@ 640 acre spacing	2 mmscfpd	65 years	Moderate incline, low gas, water production rates
Infill wells High Water Saturation Hydrate Producer Mallik rel-perm	60%@ 160 acre spacing	1 mmscfpd	NA	Flat production, interference and decline after 20 years, low gas, water production rates
Pilot Wells : Mallik rel-perm				
Pilot Test Well: High Water Saturation Hydrate Producer	20%@ 40 acre spacing	4 mmscfpd	1 year	Moderate incline, moderate gas, water production rates
Pilot Test Well: Low Water Saturation Hydrate Producer	20%@ 40 acre spacing	2 mmscfpd	1 year	Moderate incline, low gas, water production rates
Extended Pilot Area 9 Spot Test Well: Low Water Saturation Hydrate Producer	NA (unconstrained drainage)	2 mmscfpd	40 years	Moderate incline, low gas, water production rates
Upside Case: Classic rel-perm				
Low Water Saturation Hydrate Producer **Classic rel-perm**	40% @ 640 acre spacing	12 MMscfpd	10 years	Moderate incline, high gas, water production rates
High Water Saturation Hydrate Producer **Classic rel-perm**	60% @ 640 acre spacing	22 MMscfpd	3 years	Rapid incline, high gas, water production rates
Large Scale Systems				
Associated Gas under Hydrate	70%	25 MMscfpd	- NA -	Simple Decline, No water Production

The term “Mallik rel-perm” is used to describe the effective permeability to gas and water measured in the Mallik well tests. “Classic rel-perm” is used to describe a typical gas-water relative permeability relationship for rocks with absolute permeability in the range of 300 md. Selected sample type well production forecasts are shown graphically in figures 53 – 54.

Reference Case forecasts for selected type wells are presented in Figure 53.

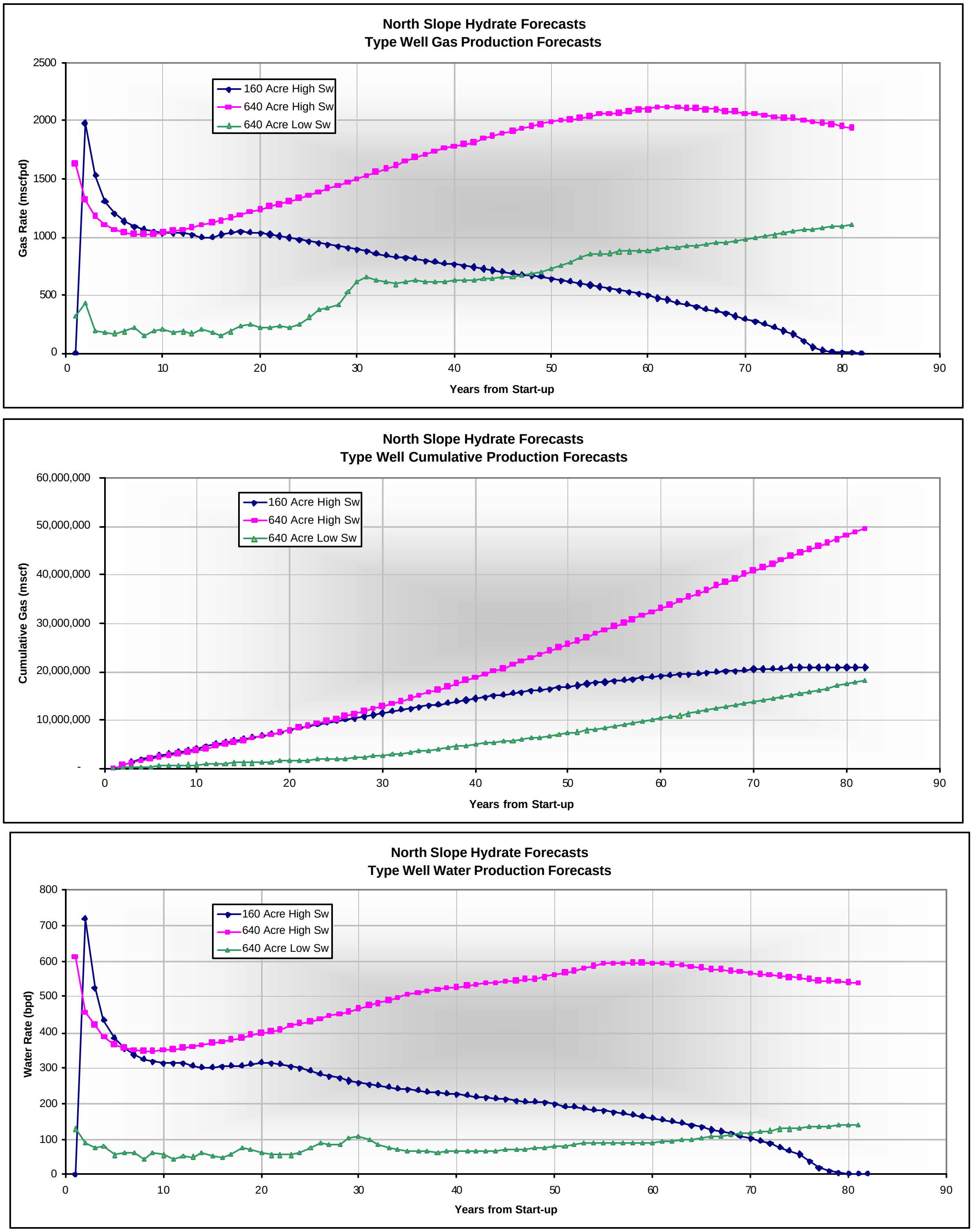


Figure 53: Reference case gas and water forecasts for selected type wells

Upside type well production forecasts for selected type wells are presented in Figure 54.

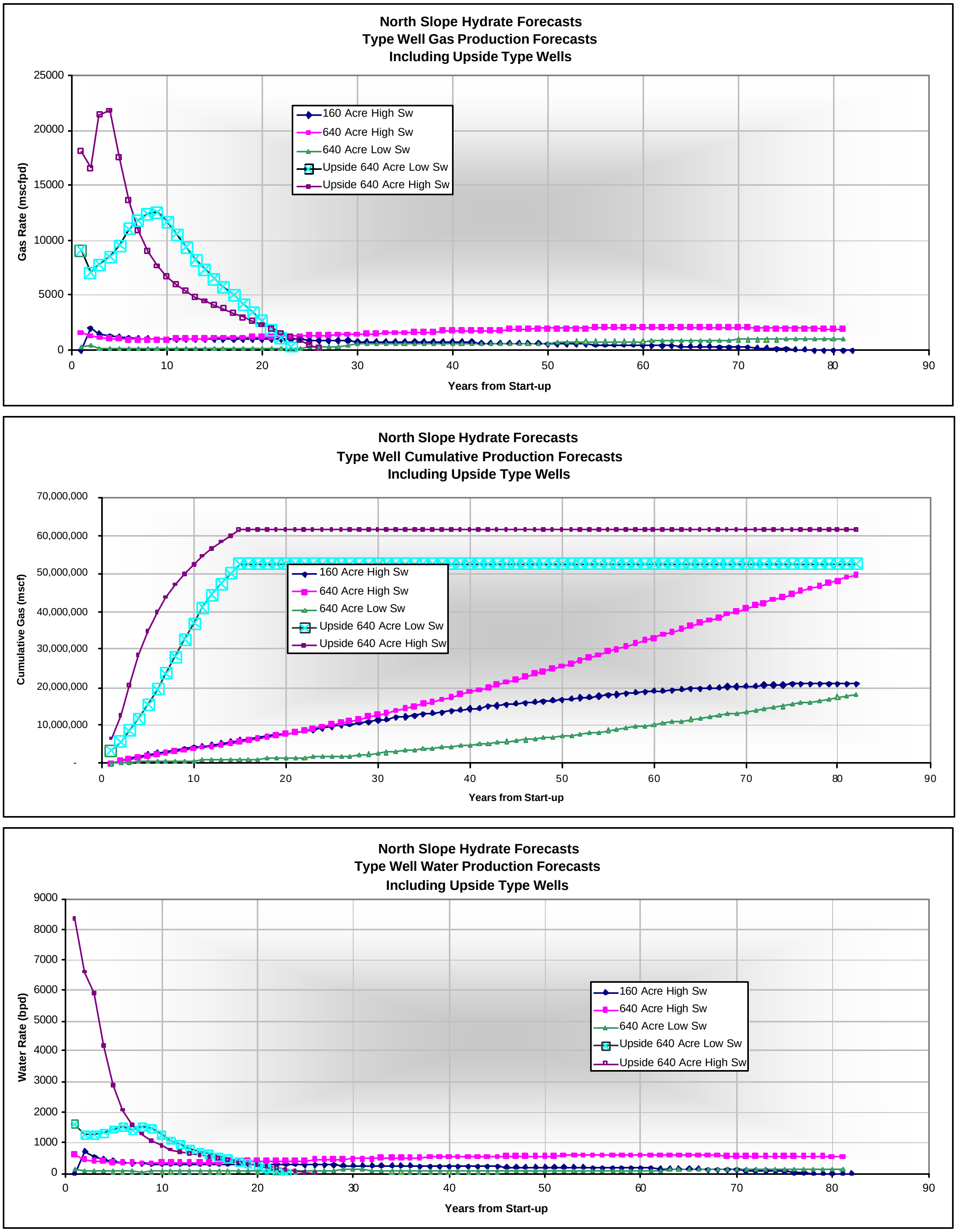


Figure 54: Upside Case gas and water forecasts for selected type wells in upside case

5.10.1.3.10 Development Timing

Development phasing is predicted to follow historical patterns where initial positive results are built upon with ever expanding implementation until development reaches the point of diminishing return and is scaled back. For purposes of this work these various stages are:

- Stage 1: Single well pilot testing
- Stage 2: Multi-well pilot testing and performance calibration
- Stage 3: Limited initial development
- Stage 4: Full scale development
- Stage 5: Resource harvesting and optimization
- Stage 6: Resource management and infrastructure optimization
- Stage 7: Re-development and technology enabling advances

Each of these successive stages builds upon the prior and relies on poorer and more technically challenging resources.

5.10.1.3.10.1 Stage 1: Single Well Pilot Testing

At recommended candidate prospect location(s), one or more wells are drilled and data is acquired to help mitigate uncertainties. The well or a subsequent well is completed, extensively tested, and monitored to identify production and reservoir description parameters (Figure 55). Preferably, this well is managed as a long term test and is studied under a variety of conditions and possible production scenarios. If unsuccessful, the well would ultimately be abandoned and further testing may be recommended under a new scenario or cancelled. If successful, these results could be used to optimize testing plans for Stage 2.

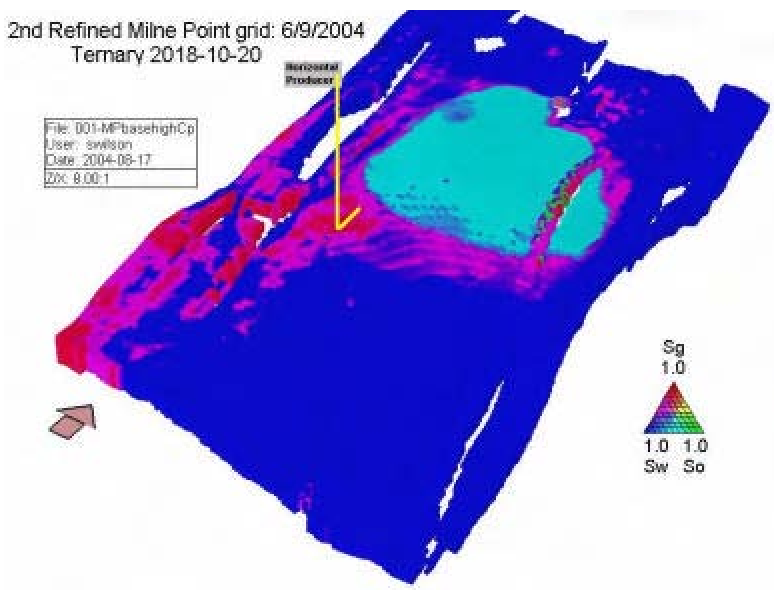


Figure 55: Stage 1 Single Well Pilot Testing

The first "pilot" well could be a fairly simple single well test with a vertical section or even backside completion in a current or new prospect location. Figure 56 shows an example well specifically targeting a small isolated gas hydrate accumulation. Constraining the data collection to a well defined area would likely help minimize ambiguity and accelerate full-life-cycle data collection.

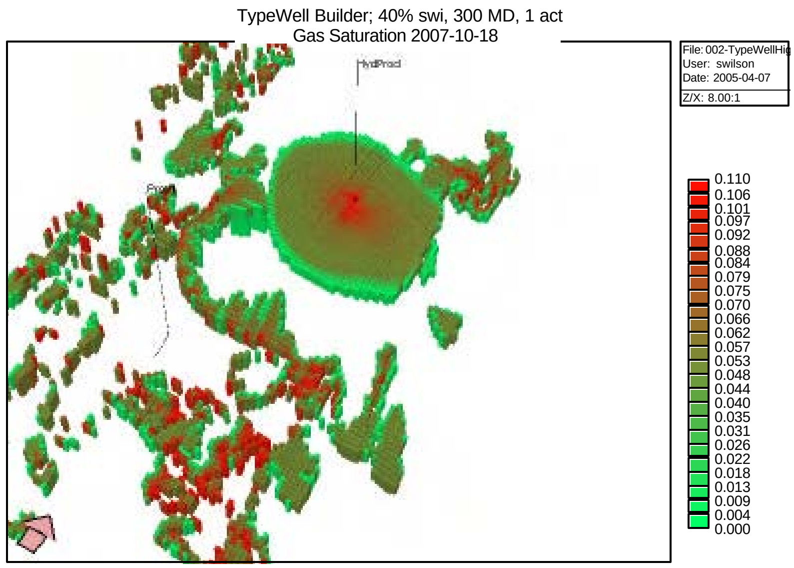


Figure 56: Stage 1a with Further delineation with second pilot well

5.10.1.3.10.2 Stage 2: Multi-well Pilot testing and performance calibration

Several wells would be drilled to confirm and define variances of the "pilot" well(s). These results would be more indicative of a larger scale development and many not target as high of potential areas, so that upside and downside risk can be better quantified. A multi-well program in a small area could be used to gather data representative of long term potential of wider spaced Stage 3 wells. Stage 2 could proceed when and where a local gas source would be of use.

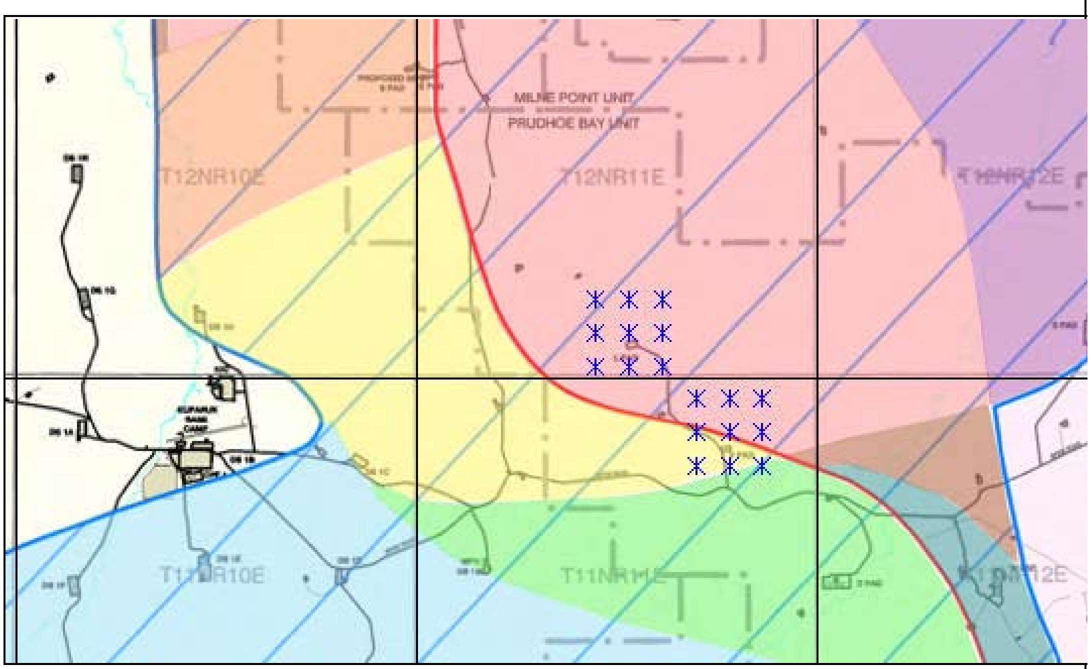


Figure 57: Stage 2 Multi-Well Pilot Testing

5.10.1.3.10.3 Stage 3: Limited Initial Development

Stage 3 would be the first stage with an intention of reaching commercial rates and economies of scale. A high potential area of the field would be used in conjunction with the areas within existing infrastructure as illustrated schematically in Figure 58. Outlying areas with good reservoir properties would probably be tested in Stage 3 in order to fully evaluate larger scale development commitments during Stage 4.

Stage 3 would be analogous to the West Sak 1J viscous oil development but with additional step-out testing. It would require a major capital commitment but would likely begin to be self-funding after a few years. This would be the first time that significant gas volumes would be booked as proved reserves based on the performance of the pilot tests, the evidence of extensive geologic continuity of resource, and, by this time, a gas market or at least demonstrated local need for gas (for example, gas for steam generation to assist viscous oil development).

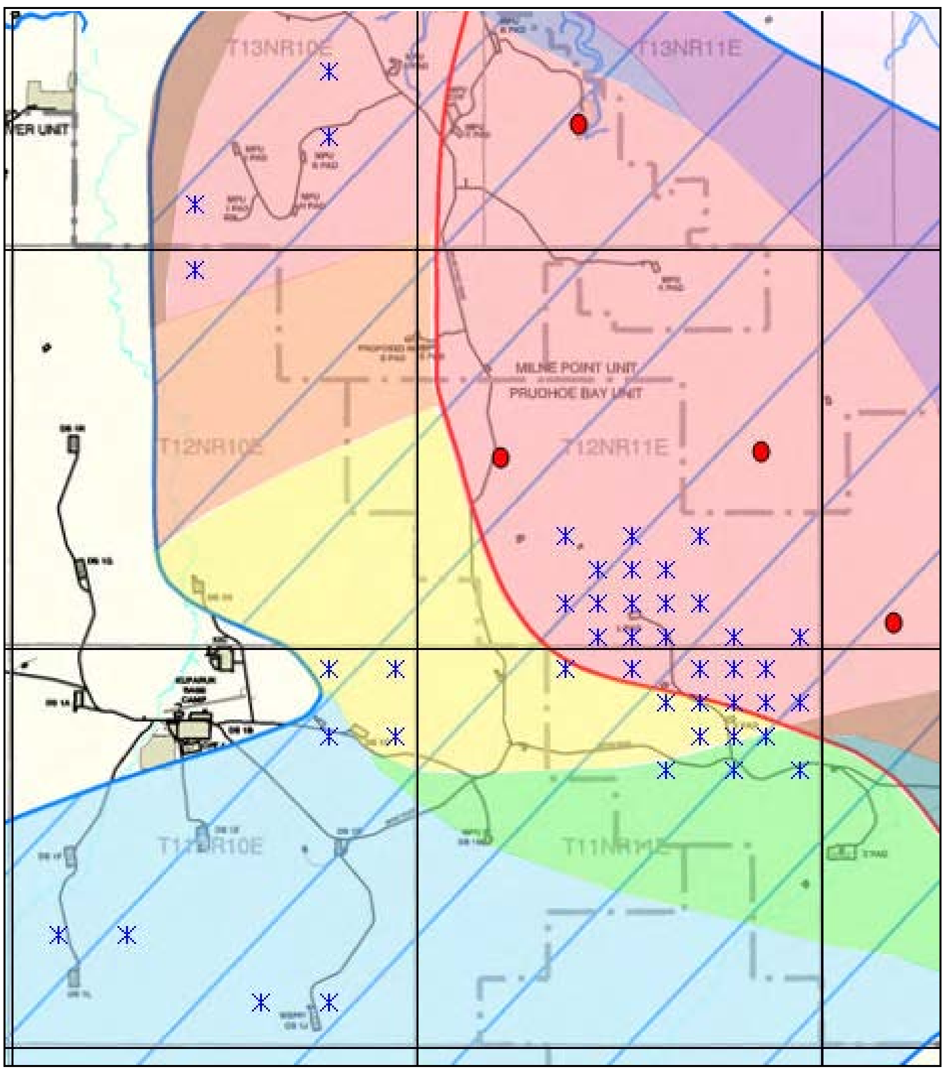


Figure 58: Stage 3 Limited Initial Development

5.10.1.3.10.4 Stage 4: Full scale development

Full Scale development would begin when the entire structure is mapped and widely spaced 640 acre wells could be drilled to fully delineate the resource. These could be drilled initially off existing gravel pads and infrastructure. Infill wells could be drilled as needed for rate acceleration and to improve ultimate recovery. Figure 59 has small cross-hairs on all potential locations that might meet the requirements stated in this schematic model. The circles beneath selected locations indicate the net pay in the A sand below that location. During Stage 4, infrastructure specific to gas hydrate development would need to be included in capital budgeting. In theory, facilities surplussed / under-utilized following significant oil decline could be re-used.

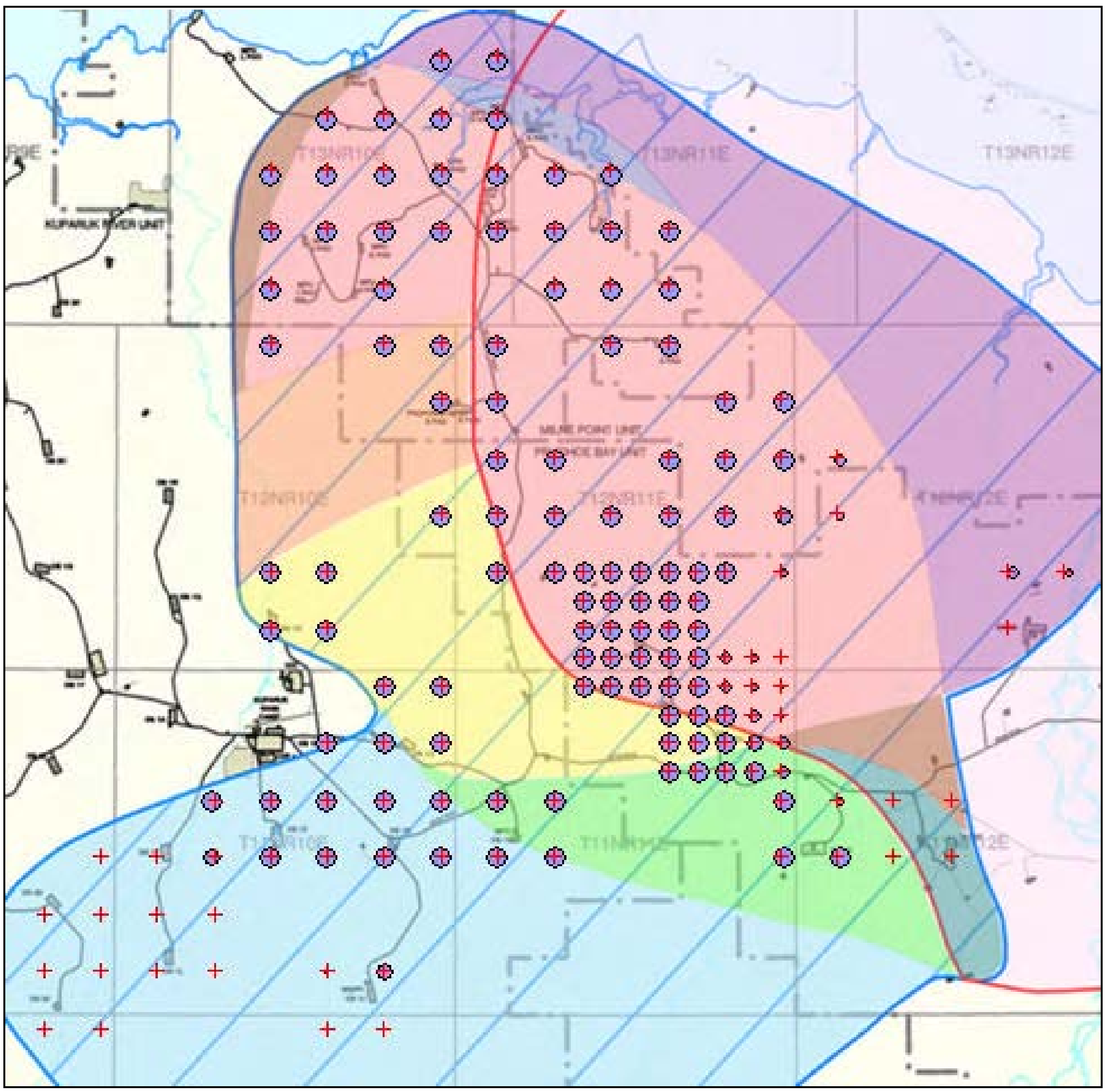
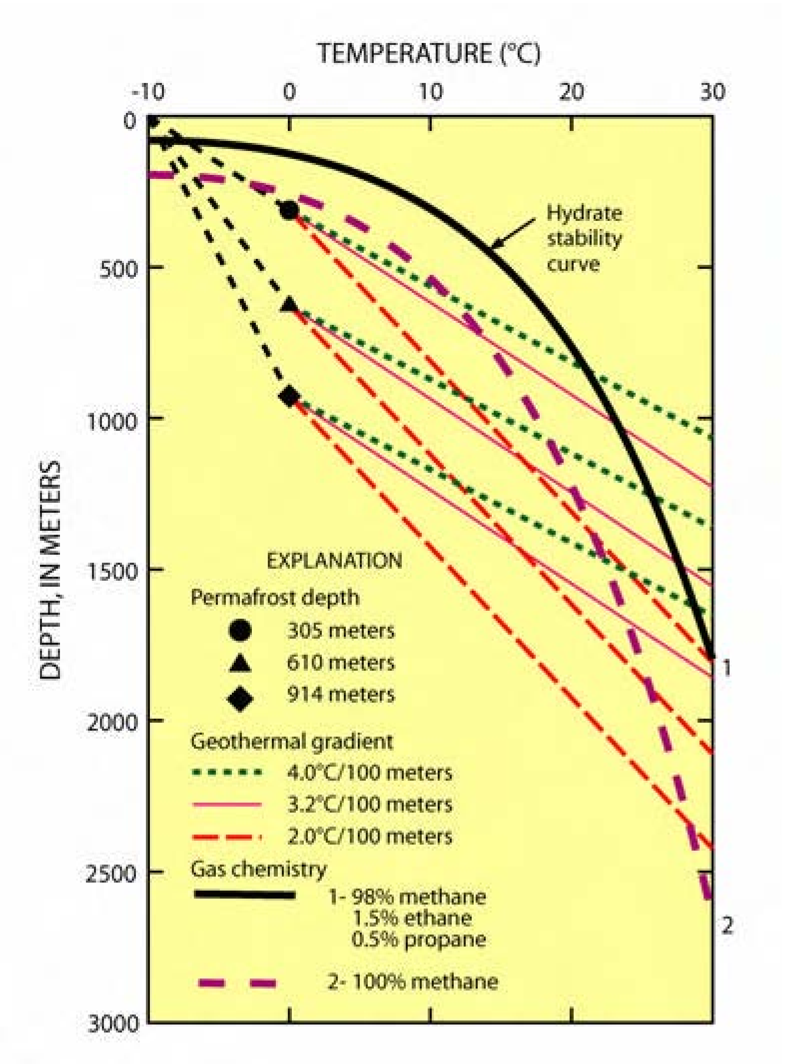


Figure 59: Stage 4 Full Scale Development

In the southwest corner of the mapped area (Figure 59), several wells are highlighted as "thermal stimulation candidates" where the gas hydrate within zone A is likely too shallow to fall within the "target" depths and are not scheduled as pressure depletion producers. The target depths at any surface location are those that fall below the Base Ice Bearing Permafrost (BIBPF) but above the Base Gas Hydrate Stability Zone (BGHSZ). In theory, these gas hydrate-bearing reservoirs could be dissociated by pressure reduction alone if ambient temperatures could be maintained. Dissociating gas hydrate above the BIBPF would likely also require thermal or chemical means. Figure 60 from the USGS shows this relationship in simplified form for conditions common on the North Slope of Alaska.



After Collett, USGS

Figure 60: Gas Hydrate Stability curve for common ANS conditions

5.10.1.3.10.5 Stage 5: Resource Harvesting and Optimization

Well penetrations would be infilled to the tightest spacing (160-80 acres) to fully develop the resource. Additional work would concentrate on improving existing wells, identifying missed opportunities and minimizing costs through optimization. Additional major capital expenditures for facility/pad extensions are evaluated on a case by case basis. The small red circles on Figure 61 are new drill sites that may be required to effectively drain the resource. The wells to the far southwest are above the BIBPF depth but are assumed to be productive due to technology advances or innovative uses of existing infrastructure.

As one example of an enabling technology advance, work is underway within the MPU to use hot water produced from deep water-bearing Ivishak sands as onsite hot water injection. This will increase injectivity in shallower zones compared to the central injection water system that arrives at the wellhead colder and loads the gathering and distribution pipelines.

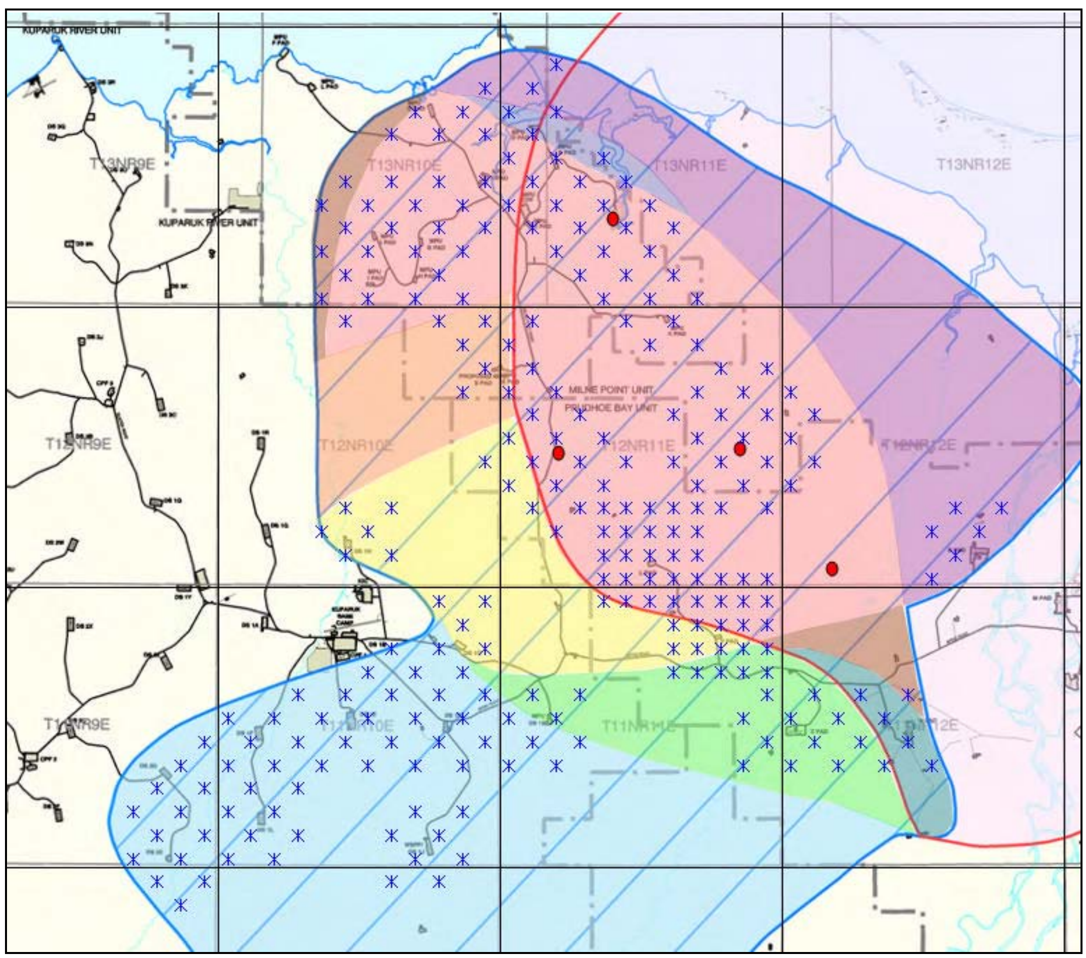


Figure 61: Stage 5 Resource Harvest and Optimization

5.10.1.3.10.6 Stage 6: Resource Management and Infrastructure Optimization

Well penetrations within current infrastructure areas would be completed with new widely spaced locations drilled in high potential new areas as determined from penetrations to date (Figure 62). Extensive use of multi-lateral completions would develop the remaining smaller accumulations. Barring additional discoveries or technology improvements, the resource would be on decline until redevelopment.

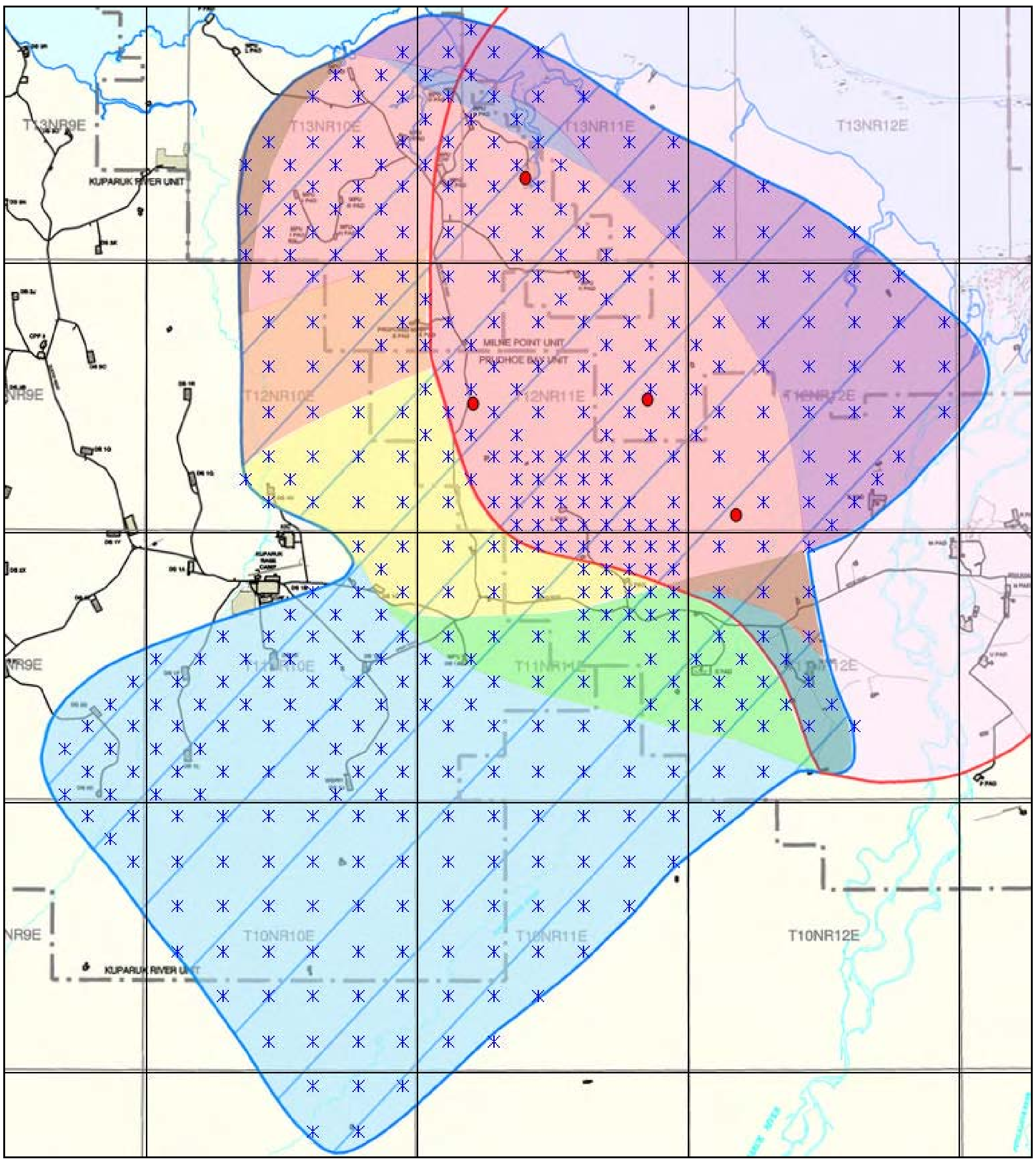


Figure 62: Stage 6 Resource Management and expansion

5.10.1.3.10.7 Stage 7: Redevelopment and technology enabling advances

Continued improvements in drilling and production technology may enable development of 160 acre locations, perhaps through Stage 6 wellbores (Figure 63). These wells would not be as productive as prior wells but would continue to increase recovery factors incrementally as modeled. Although this 160 acre well density looks unrealistic when placed near the current North Slope infrastructure, extensive 20 and even 10 acre developments in tight gas basins and steam-drive heavy oil reservoirs serve as precedents that, given economic incentives, a more dense well spacing could potentially move forward.

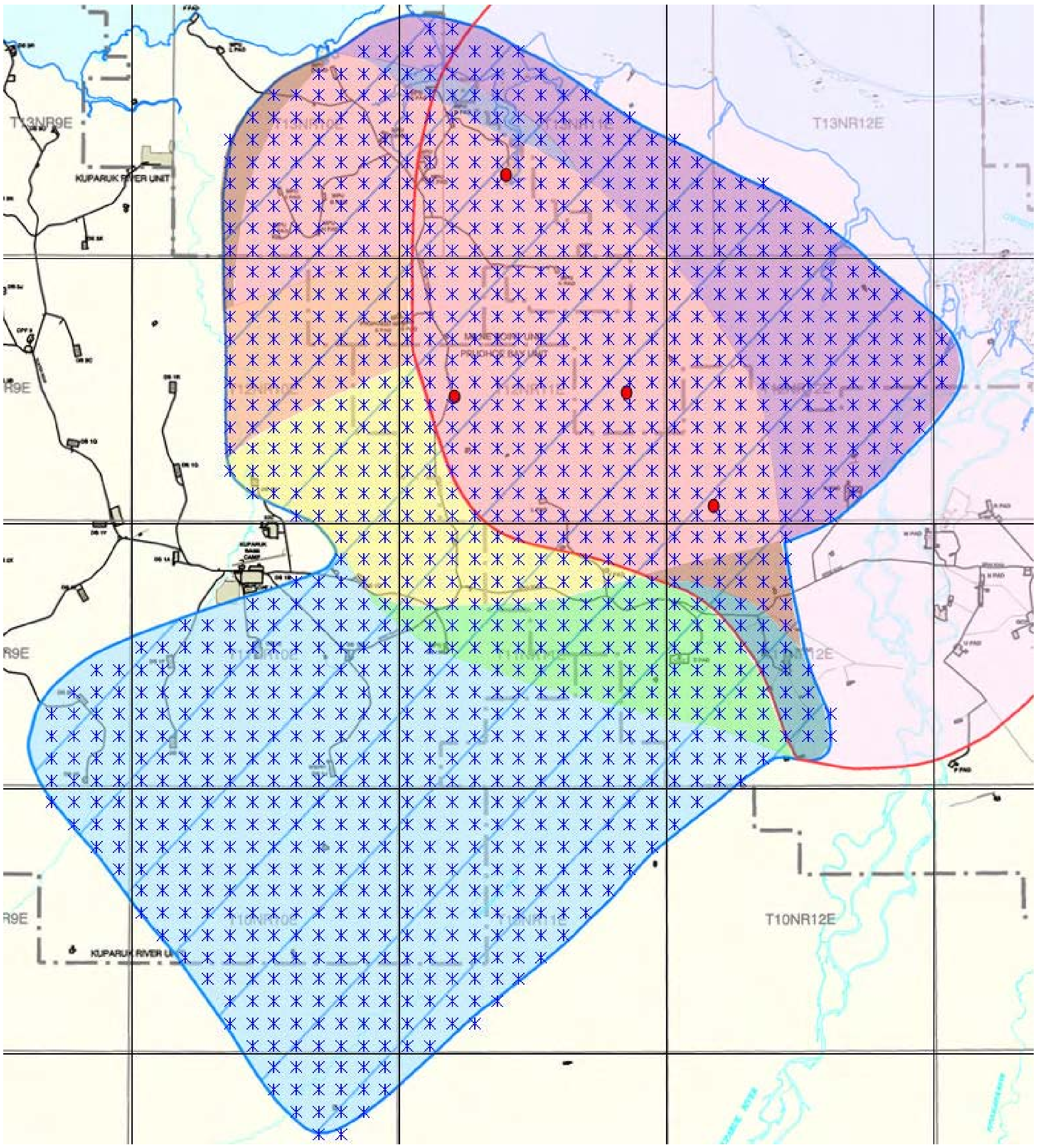


Figure 63: Stage 7 Re-Development and technology enabling advances

5.10.1.4 Fieldwide Production Forecasts

Figures 64-66 outline production trends that are predicted in this schematic regional development scenario modeling using the type wells and development timing outlined in this report. Development timing is also schematic for purposes of this modeling exercise (tables 10-12). These forecasts are broken into four cases:

- A **Downside Case** indicating disappointing "pilot" test well(s) results, confirmed by additional testing and ultimate project economic failure, but a technical success in evaluation the resource potential.
- A **Reference Case** where encouraging pilot results would transition into large scale pilots and ultimately field-wide 160 acre development through all pressure dissociation targets.
- An U**pside Case** where good pilot results would move into 160 field-wide development and heat or chemical assisted production.
- An **Extreme Upside Case** where outstanding pilot response would prove up a very attractive resource and development would move forward at a fast pace to the point of overselling. This case has a precedent in the lower48 Coal Bed Methane (CBM) Resource development starting in the early 1980's. This case also benefits from reduced well counts based on better drainage from each well.

5.10.1.4.1 Downside case description

The downside case is equivalent to exploration well dry hole investments. Minimal capital is spent to gain knowledge. Although drilled wells may be abandoned, investment is kept to a minimum and data collection and interpretation is given highest priority. In this case the pilot results are disappointing and the experiment may continue to subsequent pilots, but may also be abandoned. No sales gas is generated, so a production forecast is not relevant. The direct cost of this case would be on the order of $2-20MM and could be shared with many interested parties.

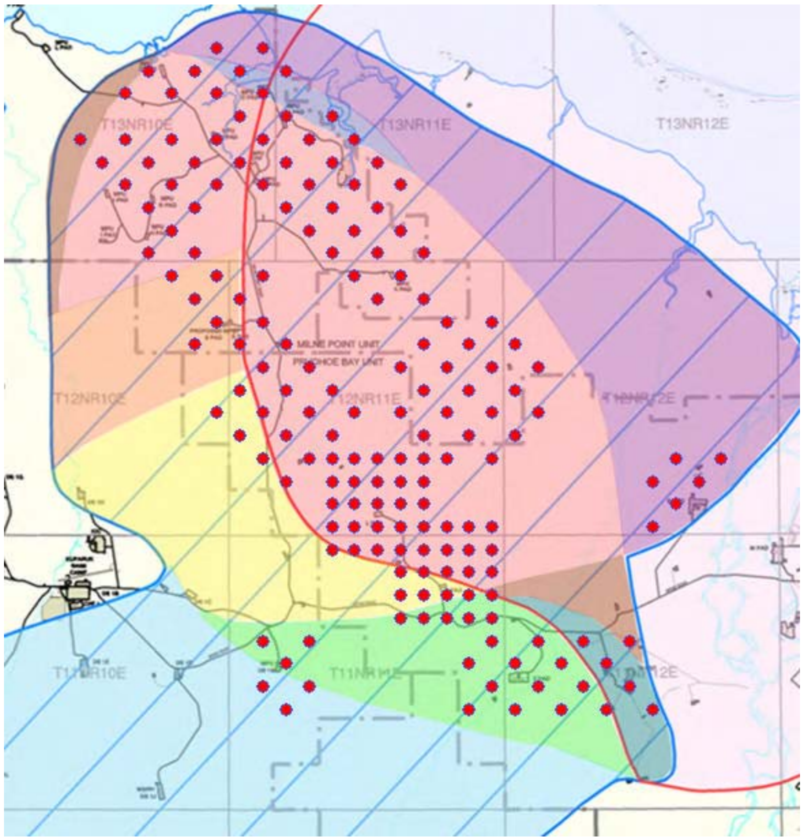
5.10.1.4.2 Reference case description

The reference case would start with positive but not remarkable pilot test results. After a 2 year evaluation and planning effort, a pilot expansion would be implemented. Development would continue at a pace consistent with North Slope operations. Table 10 outlines the Reference case.

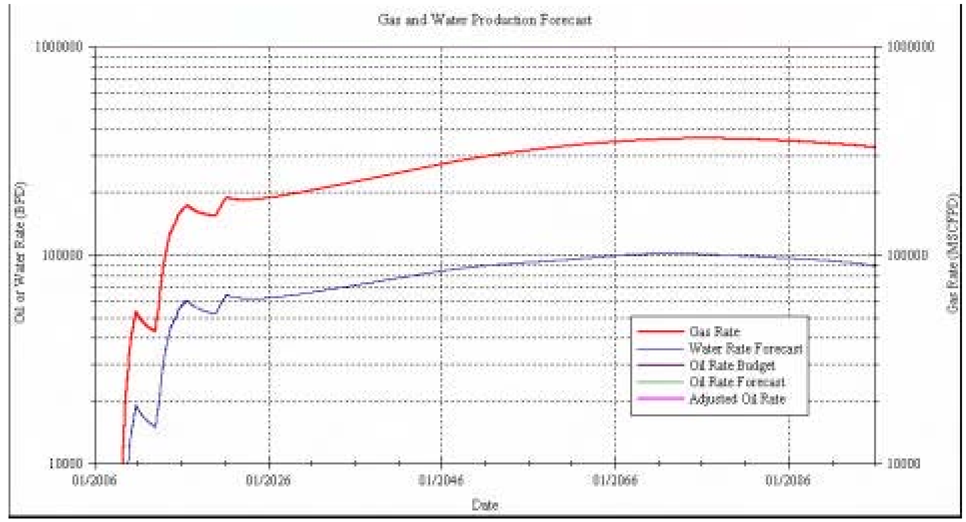
Table 10: Reference Case Details

Type Well and/or Current focus description	Start Date	Rig name	Well Count	Well Type
Pilot	1/2006	Pilot Well Rig	1	Pilot
Multi-Well Pilot	1/2009 12/2009	Pilot Rig2 Pilot Rig3	20 18	highsw
640 Acre Development wells Pilot Thermal wells	1/2013 2/2013 1/2014	Hydrate Rig1 Hydrate Rig2 Hydrate Rig3	20 20 16	Highsw
Full 640 Acre Development within infrastructure	6/2014 1/2015 6/2015	Hydrate Rig4 Hydrate Rig5 Hydrate Rig6	14 14 25	Highsw
Late Life infills and new pad 640's	1/2020	Hydrate Rig7	25	Highsw
Total	Complete in 2023	5 rig peak	173	Highsw

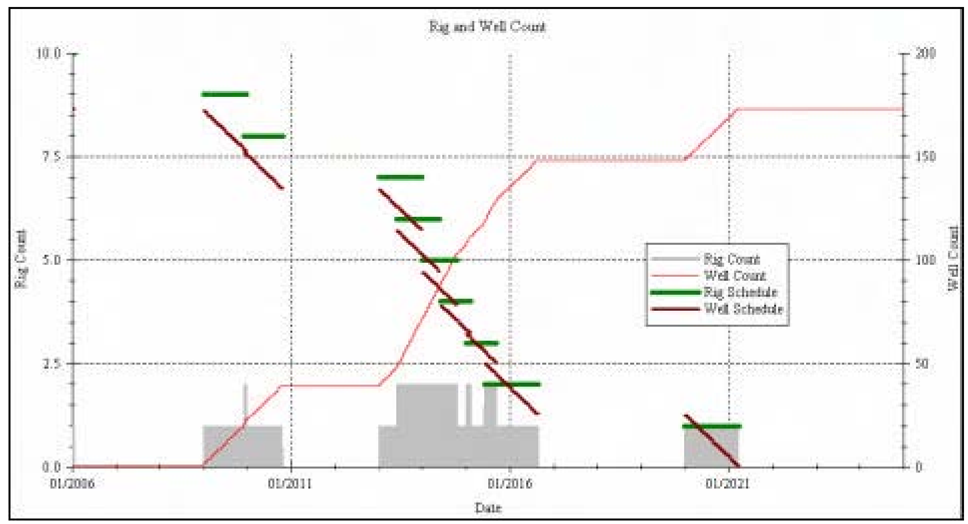
Figure 64 shows a map with schematic well locations, production forecasts and development timing assumptions for the Reference Case.



Approximate well locations for reference case



Reference case production forecast



Reference case drilling schedule and assumptions

Figure 64: Reference Case Well Locations, Production Profile and Drilling progression.

5.10.1.4.3 Upside case description

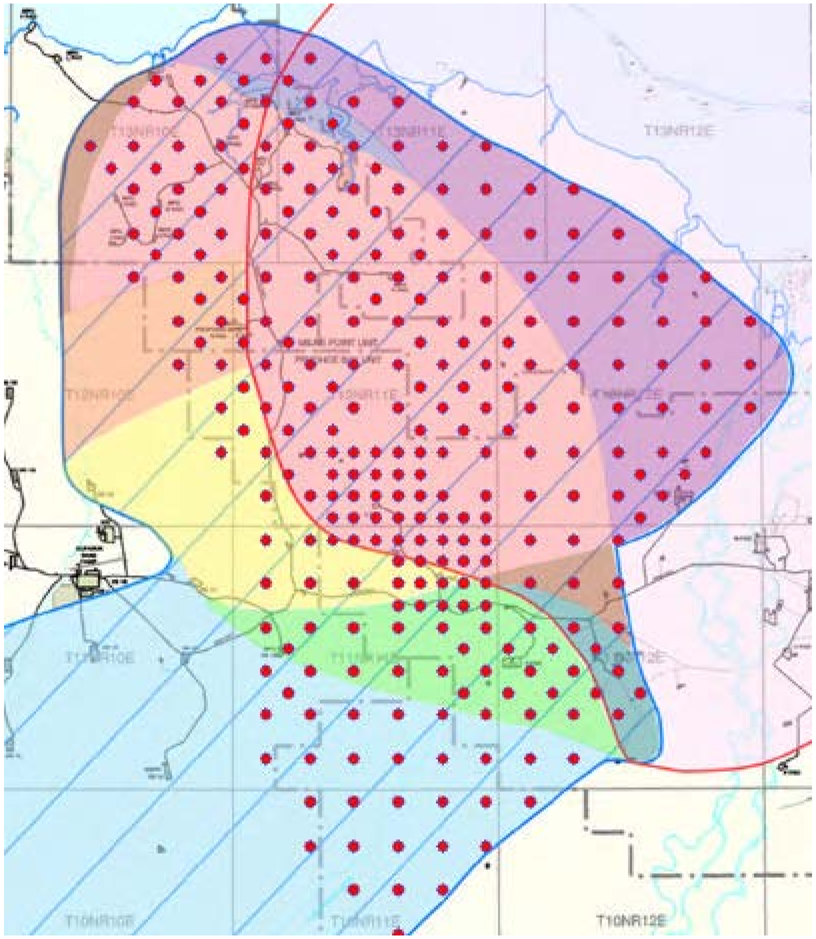
The upside case would occur if the pilot results are better than expectations and development is determined to be significantly “economic”. Development could move forward at a “reasonable” pace. Greater density wells would be drilled in the “target” area and thermal methods could be developed in conjunction with pressure dissociation wells. This case is similar to the reference case but would be developed more rapidly and with greater front-end capital loading due to the lower risk profile investments. Infill wells to 160 acres would carry a large fraction of the reserve load and would increase peak rates and well counts. This case carries the highest overall recovery at 100 years due to the increased drilling density.

Table 11 and the production plot in Figure 65 summarize this upside case.

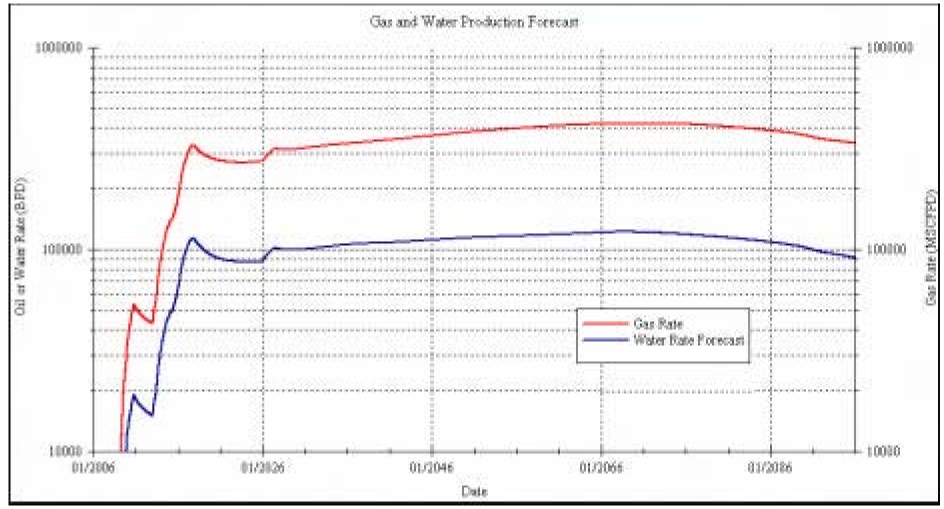
Table 11: Upside Case description

Type Well and/or Current focus description	Start Date	Rig name	Well Count	Well Type
Pilot	1/2006	Pilot Well Rig	1	Pilot
Multi-Well Pilot	1/2009 3/2009	Pilot Rig2 Pilot Rig3	20 18	Highsw Highsw
640 Acre Development wells Pilot Thermal wells	1/2013 2/2013 1/2014	Hydrate Rig1 Hydrate Rig2 Hydrate Rig3	20 20 16	Highsw Highsw Highsw
Full 640 Acre Development	6/2014 1/2015 6/2015	Hydrate Rig4 Hydrate Rig5 Hydrate Rig6	14 14 25	Highsw Highsw Highsw
160 Acre Infill Wells	9/2015 12/2015 3/2016	Hydrate Rig7 Hydrate Rig8 Hydrate Rig9	36 36 36	160 Highsw 160 Highsw 160 Highsw
Late Life	1/2026	Hydrate Rig10	28	Highsw
Total	Complete in 2027	4 rig peak	284	

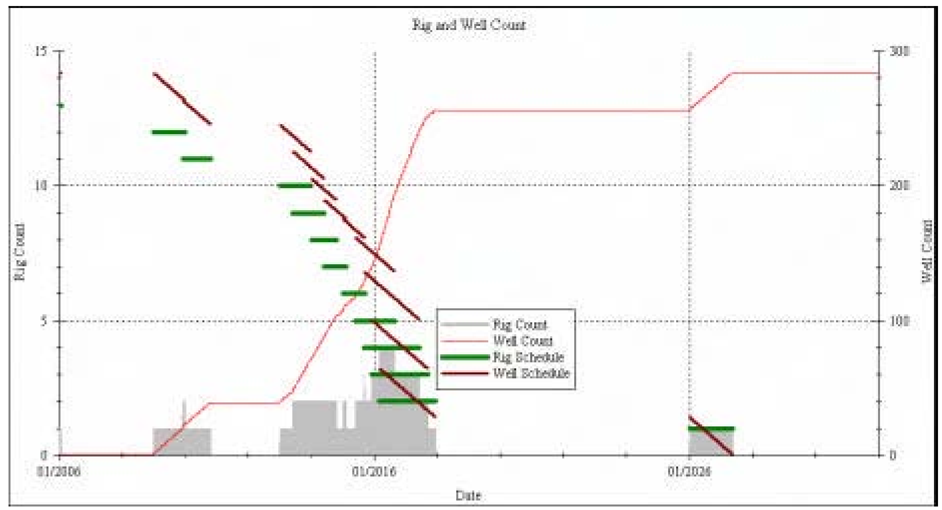
Figure 65 shows a map with schematic well locations, production forecasts and development timing assumptions for the upside case.



Approximate well locations for upside case



Upside production forecast



Upside drilling schedule and assumptions

Figure 65: Upside Case Well Locations, Production Profile and Drilling progression.

5.10.1.4.4 Extreme Upside Case description

It is typical that statistical predictions of expected outcomes can under-predict the range of possible outcomes. In order to capture the most positive potential development scenario, an extreme upside case was developed to capture the entire resource with highly productive wells that follow the San Juan Basin CBM development pattern. What began there as a government incentivized science experiment moved, slowly at first, but then rapidly toward a classic resource development rush where values were bid up past economic realities and a price collapse in the basin ensued. The same thing happened in the Powder River Basin (PRB) in 2002 where insufficient pipeline capacity led to inability to transport all the gas that was coming on line from PRB coal gas producers. In that case, obtaining permits became the limiting factor in developing the resource.

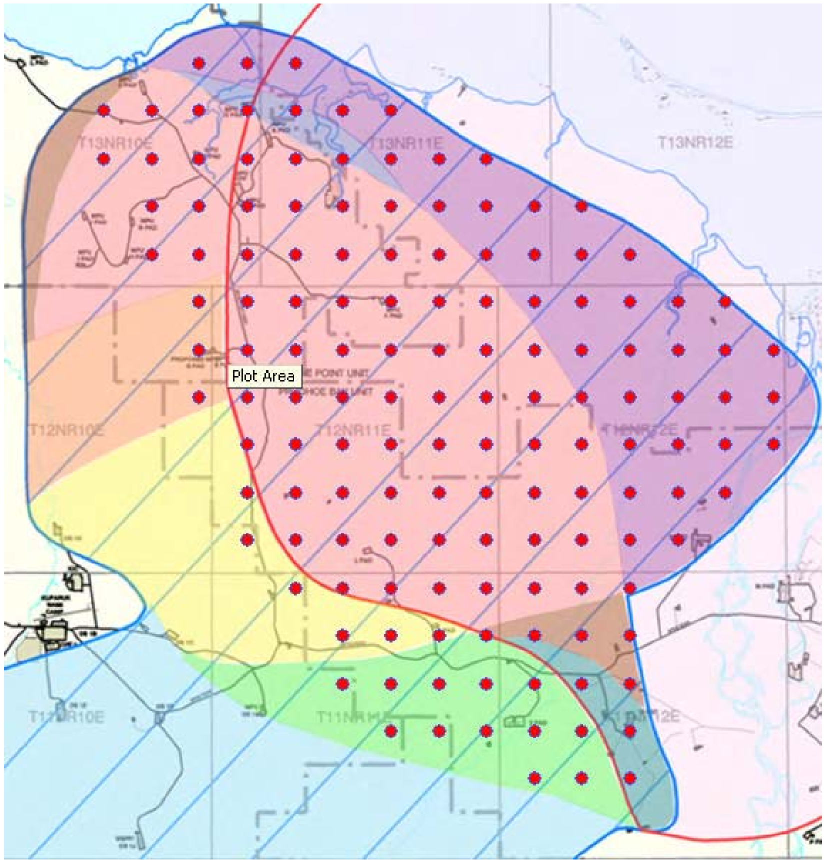
For the highly improbable extreme upside case, a very positive response would develop to pressure dissociation and development would progress at a rapid pace. Some thermal stimulation testing might be attempted in the areas not well suited for dissociation, where the native formation temperature is near or below the water freezing point and the dissociation reaction cannot be maintained without outside heat input. These wells are modeled to perform essentially the same as the reference case dissociation wells and create a long, but low rate production profile. The rate for these wells cannot be seen until 2035 when the primary dissociation reserves are depleted. Total recovery for this case at 100 years is lower than the upside case because of the wider well spacing and accelerated recovery which might decrease the motivation to infill partly depleted areas.

Table 12 outlines this extreme upside case and Table 13 summarizes the development scenarios.

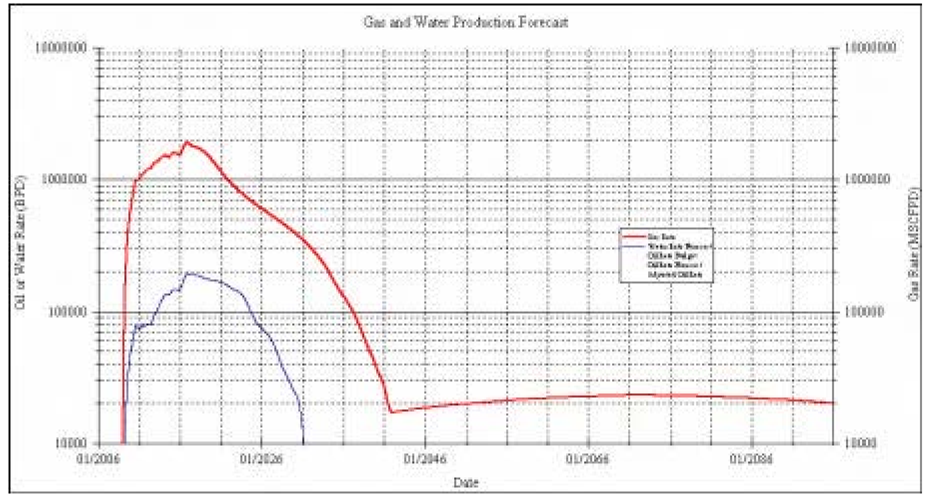
Table 12: Extreme Upside case description

Type Well and/or Current focus description	Start Date	Rig name	Well Count	Well Type
Pilot	1/2006	Pilot Well Rig	1	Pilot
Multi-Well Pilot	1/2009 3/2009	Pilot Rig2 Pilot Rig3	18 18	Upside Upside
640 Acre Development wells Pilot Thermal wells	1/2010 2/2010 1/2011	Hydrate Rig1 Hydrate Rig2 Hydrate Rig3	10 10 10	Upside Upside HighSw
Full 640 Acre Development	6/2012 1/2013 6/2013 9/2014 12/2015 3/2016 6/2016	Hydrate Rig4 Hydrate Rig5 Hydrate Rig6 Hydrate Rig7 Hydrate Rig8 Hydrate Rig9 Hydrate Rig10	10 10 15 10 10 10 10	Upside Upside Upside Upside Upside Upside Upside
total	Complete in 2016	2 Rig Peak	142	

Figure 66 shows a map with approximate well locations, production forecasts and development timing assumptions for the extreme upside case.



Approximate well locations for extreme upside case



Extreme Upside Production Forecast

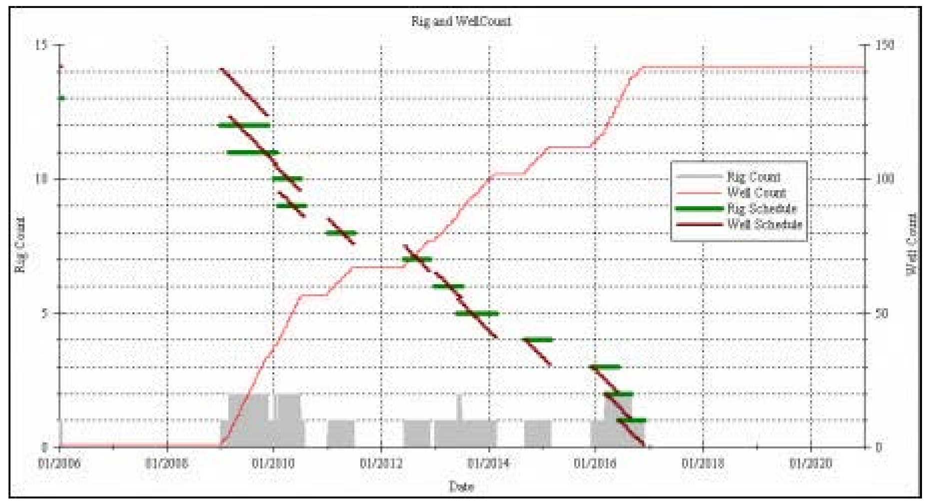


Figure 66: Extreme Upside Case Well Locations, Production Profile and Drilling progression.

Table 13 Development Scenario Summary		
Case name	**Description**	**Well Count**
Downside case	Pilot Fails, Additional testing negative	1-5
Reference Case	160 Acre development in “target” Area	165
Upside Case	Some 160 Acre development in “target” Area & thermal methods in up-structure area	283
Extreme Upside	640 acre development in all areas, low well count due to decreased in-fill needs.	141

5.10.1.5 Forecast Results

Results from the various potential schematic development scenarios show a wide range of outcomes. ***It is crucial to note that none of these forecasts would qualify for Proved, Probable, or even Possible reserve categories using the SPE/WPC definitions since there has yet to be a fully documented case of economic gas production from gas hydrate.***

Each of these categories, by definition, would require a positive ***economic*** prediction, supported by historical analogies, prudent engineering judgment and rigorous geological description of the available resource. In this case, the initial work on describing the geologic resource has been input from a general regional characterization exercise and continues on many fronts (Tasks 5.0 and 6.0), while developing a historical analogy, from which mathematical models can be based, is the obvious next step.

Table 14 outlines those forecasts and the range of possible outcomes.

Table 14: Ranges of Forecast Results			
Case name	**description**	**Well Count**	**G_p @ BCF**
Downside case	Pilot fails, additional testing negative	1-5	0
Reference Case	640 Acre development in “target” Area	172	2.5 TCF @ 40 years 9.6 TCF @ 100 years.
Upside Case	Some 160 Acre development in “target” Area & thermal methods in up-structure area	283	3.6 TCF @ 40 years 11.8 TCF @ 100 years.
Extreme Upside	640 acre development in all areas, low well count due to decreased in-fill needs.	141	8.8 TCF @ 40 years 9.3 TCF @ 100 years.

5.10.1.6 Summary and Conclusions

Significant time and resources have been spent over the past 25 years in studying and quantifying gas hydrate occurrence. In the past 15 years, the technology of gas hydrate plugging mitigation in pipelines has been of great interest due to increased use of sub-sea multiphase flowlines. Although significant natural gas hydrate deposits have been identified, quantification of potential recoverable gas from these deposits is impractical due to lack of empirical or even anecdotal evidence. This screening study was undertaken to set ranges on the 33 TCF in-place potential resources within the Eileen gas hydrate trend that might someday be recoverable given various potential future production scenarios. These ranges are from the downside case of effectively zero Estimated Ultimate Recovery (EUR) to 12 TCF EUR under the dense spacing upside case. The extreme upside case has lower recoveries due to wider well spacing.

5.10.1.7 Acknowledgements

Sincere appreciation is owed to Bob Hunter of ASRC Energy Services for coordinating and leading this effort. His thoughtful reviews, technical input, and helpful advice added significantly to the rigor of the evaluation. Tim Collett of the United States Geologic Survey provided baseline volumetric maps of the relevant area and guidance concerning adjustments to in-place volumes as a result of more recent work. BP provided access to personnel and data to further the goals of quantifying and this potential resource. None of this would have been possible without the collaborative BP-DOE Alaska gas hydrate research project.

5.10.1.8 Disclaimer

5.10.1.9 Regional Development Scenario Study References

Collett, Timothy S.: "Natural Gas Hydrates of the Prudhoe Bay and Kuparuk River Area, North Slope, Alaska," AAPG Bulletin, Vol. 77, No. 5, May, 1993, p 793-812.

S. J. Howe, N. R. Nanchary, S. L. Patil, D. O. Ogbe, and G. A. Chukwu, R. B. Hunter, S. J. Wilson. "Economic Analysis and Feasibility Study of Gas Production from Alaska North Slope Gas Hydrate Resources," AAPG Hedberg Conference, September, 2004.

S.H. Hancock, T.S. Collett, S.R. Dallimore, T. Satoh, T. Inoue, E. Huenges, J. Henninges, and B. Weatherill: "Overview of thermal-stimulation production-test results for the JAPEX/JNOC/GSC et al. Mallik 5L-38 gas hydrate production research well" 2004.

Richard Sturgeon-Berg, "Permeability Reduction Effects Due to Methane and Natural Gas Flow through Wet Porous Media," Colorado School of Mines, MS thesis T- 4920, 9/30/96.

Stephen John Howe, "PRODUCTION MODELING AND ECONOMIC EVALUATION OF A METHANE HYDRATE PILOT PRODUCTION PROGRAM ON THE NORTH SLOPE OFALASKA," University of Alaska, Fairbanks MS Thesis, May, 2004.

Hong H., Pooladi-Darvish, M., and Bishnoi, P. R.:Analytical Modeling of Gas Production from Hydrates in Porous Media," *Journal of Canadian Petroleum Technology (JCPT)* November 2003, Vol. 42 (11) p. 45-56.

5.10.1.10 Regional Development Scenario Studies Planning Tools

5.10.1.10.1 Mapping and Well Layout Tools

Well Layouts were generated using the internal plotting functions within Excel coupled with Visual Basic utilities which can generate ASP X and Y Coordinates from Township-Range legal descriptions: "T10NR12E section 12 NE/4 of NE/4". A full suite of approximately 1500, 80 acre well locations was generated and categorized in each of the criteria shown in Table 15.

Table 15: Well location categorization

Category	Source of data
SEQNUM	Generated
LEASE	Generated
TWP	Input
RGE	Input
M_SECT	Input
QTRQTR	Input
x	Calculated from TRSQTR
y	Calculated from TRSQTR
WellType	Input
StartYear	Input
StartMo	Input
A existence	Modified from USGS (Collett, 1993) Mapping
B existence	Modified from USGS (Collett, 1993) Mapping
C existence	Modified from USGS (Collett, 1993) Mapping
D existence	Modified from USGS (Collett, 1993) Mapping
EF existence	Modified from USGS (Collett, 1993) Mapping
PadName	Based on BP Base Map within 2 miles
UNIT	Based on BP Base Map
Xpos	Calculated from TRSQTR
Ypos	Calculated from TRSQTR
Code	Binary code indicating occurrence of each zone
ASPX	Calculated from Xpos
ASPY	Calculated from Ypos
A sand Top	Interpolated from USGS (Agena) Well Picks contoured into a
B sand Top	Interpolated from USGS (Agena) Well Picks contoured into a
C Sand Top	Interpolated from USGS (Agena) Well Picks contoured into a
D Sand Top	Interpolated from USGS (Agena) Well Picks contoured into a
E Sand Top	Interpolated from USGS (Agena) Well Picks contoured into a
IBPFDepth	Interpolated from USGS (Agena) Well Picks contoured into a
HSZDepth	Interpolated from USGS (Agena) Well Picks contoured into a
Net A sand in Target	Calculated from union of formation top, thickness, BIBPF,
Net B sand in Target	Calculated from union of formation top, thickness, BIBPF,
Net C sand in Target	Calculated from union of formation top, thickness, BIBPF,
Net D sand in Unstable zone	Calculated from union of formation top, thickness, BIBPF,
Net E sand in Unstable zone	Calculated from union of formation top, thickness, BIBPF,
InCompositArea	Modified from USGS (Collett, 1993) Mapping
Stage	Input based on most likely scenario for well planning
AsandVol	Calculated
BsandVol	Calculated
CsandVol	Calculated
DsandVol	Calculated
EsandVol	Calculated

Given the ability to select and highlight individuals based on a complex set of criteria enabled fairly complex well scheduling to be implemented in a short period of time. This scheduling mechanism was used to develop well counts and timing that fed into a development planning tool "Forecast" which is capable of scheduling rate-table based type wells into a drilling schedule to additively forecast field-wide production scenarios. The May 12, 2005 version of this spreadsheet is included in the project report CD. The spreadsheet has Tabs and 4 macro modules that contain functions that automate repetitive tasks as shown in Table 16.

Table 16: Worksheet Tabs and Macros driving the spreadsheet to forecast development scenarios

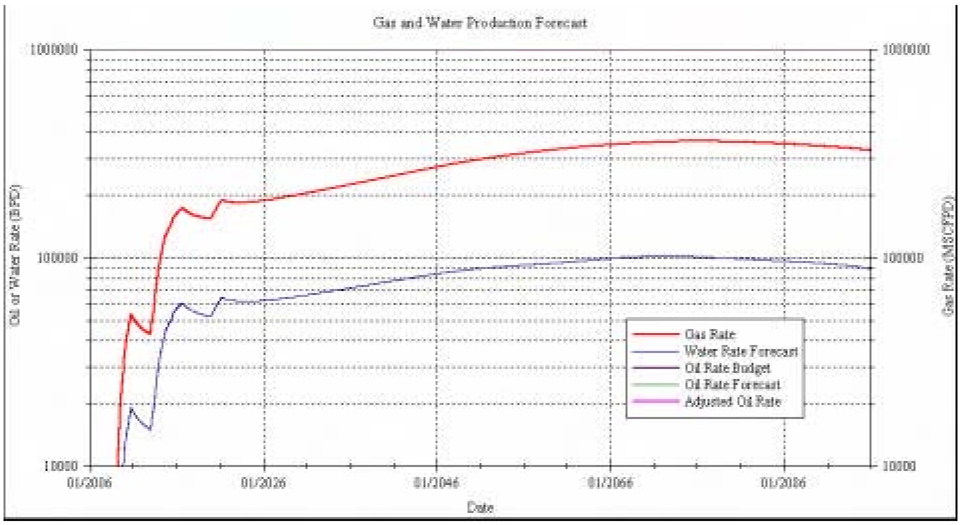
Map	Bitmap of field and clear well locator map. This is the figure that can be used to identify well locations in relation to surface features.
Hydrate Wells	Detailed well listing giving all relevant parameters. Only the top line has live calculations for grid interpolations and net thickness.
Gas Only Wells	Well locations originally thought to be below the BGHSZ. Subsequent mapping showed them as gas hydrate-bearing.
Townrange Corners	Traces of the edges of selected geographical features. Available mostly to tie-in x-y locator routines.
Data_Well_Depths	Eileen Gas Hydrate Zones – modified from Collett (1993)
Data_Well_Depths for Surfer	Eileen Gas Hydrate Zones – modified from Collett (1993); formatted with single line column headers.
A Sand Grid Depths	Open grid of A sand depths from contoured raw data. This is the page where 3D locations are interpolated from for each well location.
C Sand Grid Depths	Open grid of C sand depths from contoured raw data. This is the page where 3D locations are interpolated from for each well location.
E Sand Grid Depths	Open grid of E sand depths from contoured raw data. This is the page where 3D locations are interpolated from for each well location.
Ice and HydDepths data+	Depths to Base Ice and Base Gas Hydrate Stability Zones for selected wells as Provided by USGS (Agena) 2005.
IBPF Grid Depths	Open grid of Ice Bearing Permafrost depths from contoured raw data. This is the page where 3D locations are interpolated from for each well location.
HYDSTAB Grid Depths	Open grid of Gas Hydrate Stability zone depths from contoured raw data. This is the page where 3D locations are interpolated from for each well location.
Zone Net and Gross H, Props	Various general parameters describing zonal properties from Collett, USGS

5.10.1.10.2 Field development Planning Rollups

Forecast was used to roll up complex production type wells. This program is written in C++ and generates daily forecasts by layering type-well forecasts over a summation array as each well is drilled and completed. The following algorithm is used to generate the field-wide forecasts:

1) Determine earliest drilling date and initialize summary arrays
2) Read first rig parameters and load type well as of completion date
    a. For each completion, add daily type well rate to summary arrays for 100 years
3) Read next rig
4) Repeat step 2a for each rig and well

Although this process sounds fairly simple, the algorithms involve millions of summations for each case, so the raw summation arrays are then used to generate cumulative curves from which any time resolution can be derived. This program is available to project participants at www.ryderscott.com\download2\setupforecast.exe. Figure 67 shows a sample of the resulting production forecast and well scheduling display.



Reference case production forecast

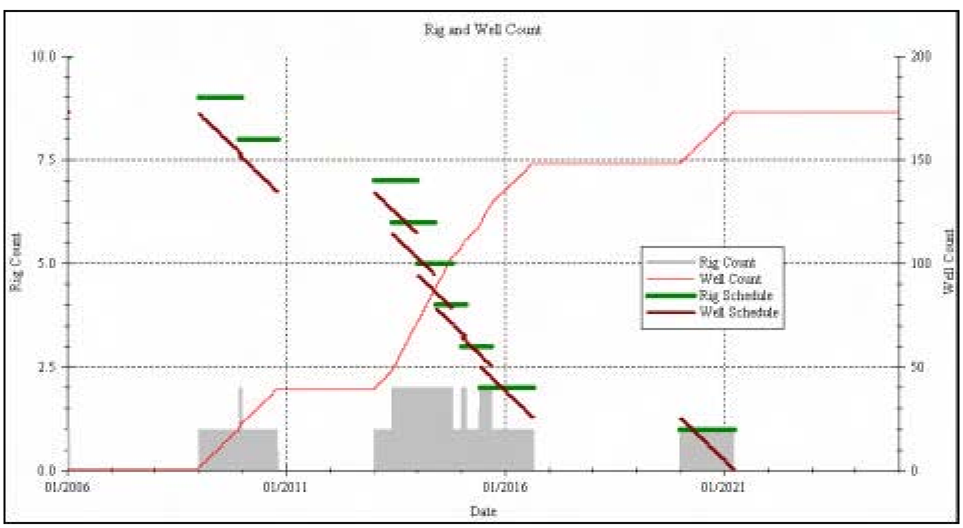


Figure 67: Reference case drilling schedule and assumptions

5.10.2 CMG STARS Reservoir Modeling Discussion and Perspective

The below discussion is adapted from January 3, 2005 correspondence with Scott Wilson, Ryder Scott Company, to document some additional perspective of earlier reservoir modeling efforts during the Phase 1 studies. The commentary also recommends additional experimental work using the lab apparatus developed at the University of Alaska Fairbanks to conduct relative permeability and other studies at higher gas hydrate saturations within porous media.

The first attempt to use CMG STARS as a gas hydrate reservoir simulator may date back to the Shell work in the early 1990's or perhaps to Hong and Pooladi-Darvish at the University of Calgary. Steven Howe, in his MS thesis at UAF, accomplished studies using a slanted strip model, which laid the foundation for groundwork for further work by Scott Wilson at Ryder Scott by creating a running framework, identifying its deficiencies, and presenting complete and honest results, including shortcomings.

Scott Wilson resolved the major shortcomings of early UAF modeling by applying significant industry experience level simulation and extending that work to what was presented at the 2004 Hedberg conference. Scott also added an initial ice phase to the framework to close the gap between STARS mathematical capabilities and those of the other models (EOSHYDR, Masuda). CMG staff may see an opportunity for a new market and may work to clear the remaining limitations in their code (i.e. "modified CMG STARS is user friendly and easy to initialize unlike other commercial simulators. It can handle the temperatures much below 0°C. ") It remains much easier to provide inputs to and obtain outputs from the industry-standard STARS model than the current alternatives. However, there remains concern that the STARS model may not handle the very near-wellbore high-pressure drawdown area, resulting in poor modeling of near-wellbore formation of ice or reformation of gas hydrate at the wellbore if cooling associated with pressure drawdown during production allows temperatures to fall below 0^{o}C (ice) or self-limits gas dissociation within the gas hydrate temperature stability field (gas hydrate).

Throughout this process, all gas hydrate reservoir simulators have used the 3-phase relative permeability data inherited from prior work: Steven (UAF) from Pooladi-Darvish (University of Calgary), Scott Wilson from UAF, etc. When input variables are uncertain, the strategy was to assume reasonable values were assigned to the given variables by preceding studies, then to double-check simulator outcomes for reasonableness. In the UAF case, Steven initialized the entire grid with 10% gas saturation in order to create a mobile gas phase. Scott Wilson shifted this arbitrary value down to 1% by distorting the gas relative permeability at low gas saturations to enable pressure transmission within the model. The resulting data indicates a very pessimistic gas flow regime where at only 5% gas hydrate saturation, water relative permeability is 0.5 while gas relative permeability is only 0.02. The trend toward reduced relative permeability with increased gas hydrate saturation is intuitive, but the magnitude is dramatic. Experimental values generated by relative permeability studies at UAF on the Hot Ice samples, have a similar kw/kg ratio for the 34% gas hydrate saturation case, which is interesting, but may be coincidental.

Directionally, this work is provocative if one extrapolates this data to >70% gas hydrate saturations. Scott Wilson recommends further studies with gas hydrate-bearing porous media to compare to the Sturgeon-Berg work at Colorado School of Mines (MS thesis (T-4920) by Richard Sturgeon-Berg, 'Permeability Reduction Effects Due to Methane and Natural Gas Flow

Through Wet Porous Media," dated 9/30/96, CSM). Richard found positive and measurable permeability even after total freezing of a water saturated core, which is different than one would assume based on the plot in the pdf file. These results could be intuitively extrapolated to indicate that, even in a fully-saturated gas hydrate-bearing reservoir sand, sufficient relative permeability could exist to at least transmit a pressure pulse and at most to enable production of in-situ, mobile phase pore waters to induce dissociation of gas hydrate by production of the mobile water phase.

New work at UAF could close the gap between these relatively low hydrate saturations tested experimentally during the Phase 1 UAF experiments and the total ice/gas hydrate saturation used by Sturgeon-Berg at CSM. UAF has also provided assistance in doing the theoretical derivation of reaction constants used with CMG STARS. It remains to be seen if this work can ultimately be fed directly into large scale simulators. Sadly, relative permeability is one of the first places a modeler turns when in need of a history match parameter, and henceforth, the measured data can be rendered useless.

Some of the comments in the file might be mis-used if taken out of context. For example, the statement "UAF modeling indicates that as gas is produced at rates of up to 25 mmscfd/d per well, the free gas zone depressurizes and the adjacent gas hydrate accumulation begins to release significant additional gas" must be read very carefully to realize that the 25 mmscfpd is the free-gas zone rate, whereas the gas hydrate zone is modeled as producing only about 3-4 mmscfpd but over many years.

5.10.3 UAF Mt. Elbert Prospect Modeling Interim Planning

UAF constructed a reservoir model within the characterized Mt Elbert gas hydrate prospect. These studies were accomplished by Hemant Phale in collaboration with Scott Wilson and entitled “Simulation Study on Injection of CO2-microemulsion for Methane Recovery from Gas Hydrate Reservoirs”. The complete results of this study will be presented in a later report following thesis finalization. A brief review of preparatory work is presented in this section.

5.10.3.1 Abstract

Gas hydrates are crystalline substances composed of water and gas, mainly methane, in which a solid water lattice accommodates gas molecules in a cage like structure. Large methane-gas hydrate reservoirs have been found on the North Slope of Alaska that may be exploited as a future energy source. The total volume of natural gas-in-place within these gas hydrate reservoirs is estimated to be about 37 to 44 TCF. Depressurization, thermal stimulation, or a combination of these methods is being evaluated for commercial production of natural gas from hydrate-bearing geologic formations. An alternative method of gas hydrate production using CO_2 is being investigated. This concept has several attractive features: 1) CO_2 is thermodynamically favored in gas hydrate, 2) the heat of formation of CO_2 hydrate is 20% greater than the heat of dissociation of CH_4 hydrate, 3) refilling pore space with CO_2 hydrate is expected to maintain mechanical stability of the hydrate-bearing formations during production, and 4) the process is climate friendly, removing CO_2 from the atmosphere while simultaneously producing clean-burning natural gas. This study focuses on the simulation study of methane recovery with simultaneous CO_2 sequestration from a reservoir located at Mt. Elbert site which is a part of Milne Point Unit (MPU) on North Slope of Alaska using a simulator STOMP-HYD (Subsurface

Transport over Multiple Phases, Hydrate Operational Mode). Series of simulations will be carried out to verify different production scenarios; including the effect of pressure and temperature of injected CO_2-microemulsion on methane hydrate dissociation rate, effect of different porosity and permeability values of the formation, variation in location of injection well for CO_2, effect of CO_2 injection rate and the effect of concentration of injected CO_2-microemulsion. From this study, a set of optimum parameters for methane gas production with simultaneous CO_2 sequestration will be presented.

5.10.3.2 Problem Statement

Gas-hydrates are crystalline substances composed of water and gas, mainly methane, in which a solid lattice accommodates gas molecules in a cage like structure. These sources have been regarded as a potential unconventional source of natural gas because of their enormous gas storage capacity. Significant quantities of naturally occurring gas-hydrates have been detected on the North Slope of Alaska. On the North Slope of Alaska, the methane-hydrate stability zone extends beneath most of the coastal plain province (Figure 1) and has thickness greater than 1000 meters in the Prudhoe Bay area.

The occurrence of natural gas-hydrate on the North Slope of Alaska was confirmed in 1972 (Collett, 1993) when ARCO and Exxon successfully recovered a core containing gas hydrate. This core was obtained from a depth of 664 to 667 meters in the Northwest Eileen State-2 well (Figure 77), located in the Prudhoe Bay oil field. The occurrence of gas hydrate in the cored and tested interval of the Northwest Eileen State-2 well was evident on the mud and open-hole well logs by the release of unusually large concentrations of methane during drilling and an increase in acoustic transit-time velocity and electrical resistivity.

In the Prudhoe Bay-Kuparuk River area, all of the well-log inferred gas-hydrate occurs below the regional Eocene unconformity and within the 450 to 700 meter thick nonmarine to marine sequence overlaying the Ugnu sandstones. Most of the North Slope gas-hydrate occurs within six laterally continuous lower Tertiary sandstones and conglomerates and are geographically restricted to the area overlaying the eastern part of the Kuparuk River oil field and the western part of the Prudhoe Bay oil field.

This simulation study uses the simulator STOMP-HYD (Subsurface Transport over Multiple Phases, Hydrate Operational Mode) which is being developed by Dr. Mark White at Pacific Northwest National Laboratory (PNNL), Richland, Washington. The researchers at PNNL have investigated the possibility of CO_2-microemulsion injection for methane recovery from the gas hydrate-bearing reservoir sands. The current study focuses on the simulation study of CO_2-microemusion injection for methane recovery from gas hydrate reservoir located at Mt. Elbert prospect site within the MPU. Two potential gas hydrate-bearing reservoir zones have been identified at this location which are zone C and zone D. The zone D has been identified as the upper layer of formation whereas the zone C is the lower layer of the formation at Mt. Elbert site.

5.10.3.3 Data Required

The following initial data was needed in order to get a true picture of the reservoir description:

Hydrologic Property Distribution Data:

1) Porosity distribution maps for the formations within the reservoir
2) Permeability distribution maps for the formations within the reservoir
3) Gas hydrate saturation map for the formations within the reservoir

Formation Property Data:

1) Saturation-Capillary Pressure-Permeability relationship
2) Thermal Conductivity
3) Grain Density
4) Bulk Density
5) Rock Compressibility

Fault Information:

Also the information regarding the faults present within the formation was also needed.

5.10.3.4 Data Received

The following data was received from the correspondence with investigators of the BP-DOE Alaska gas hydrate research team, including Dr. Tim Collett, Mr. Robert Hunter, and Mr. Scott Wilson. All the collected information is summarized below:

Hydrologic Property Distribution Data:

1) Porosity:

Unit	Porosity Low	Porosity Best	Porosity High	Source
C	34	38	40	NWEIL2
D	36	37	38	NWEIL2

2) Permeability:

Unit	Permeability, md
C	300 (Uniform in I, J & K directions)
D	300 (Uniform in I, J & K directions)

3) Gas Hydrate Saturation:

The input data files for gas hydrate saturation for zone C and D were received. The contour maps of gas hydrate saturation for these two zones were then generated using the software Surfer. The contour maps of gas hydrate saturations for zone C and D are shown below. The values of gas hydrate saturation are given in percentages.

1. **Zone C:**

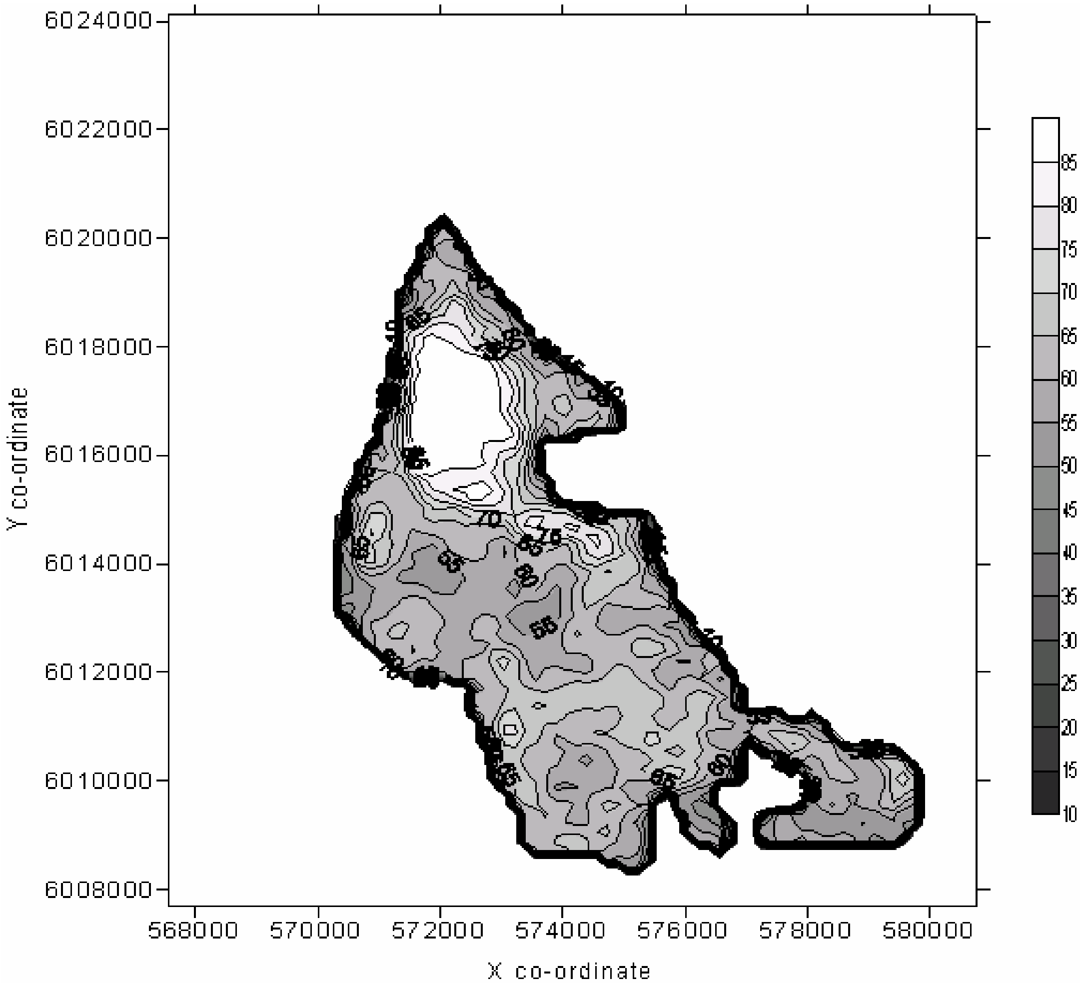


Figure 68: Contour map of hydrate saturation for zone C

Data file used for generating this contour map: **mtelbertCsaturation_rectangle.asc**

2. Zone D:

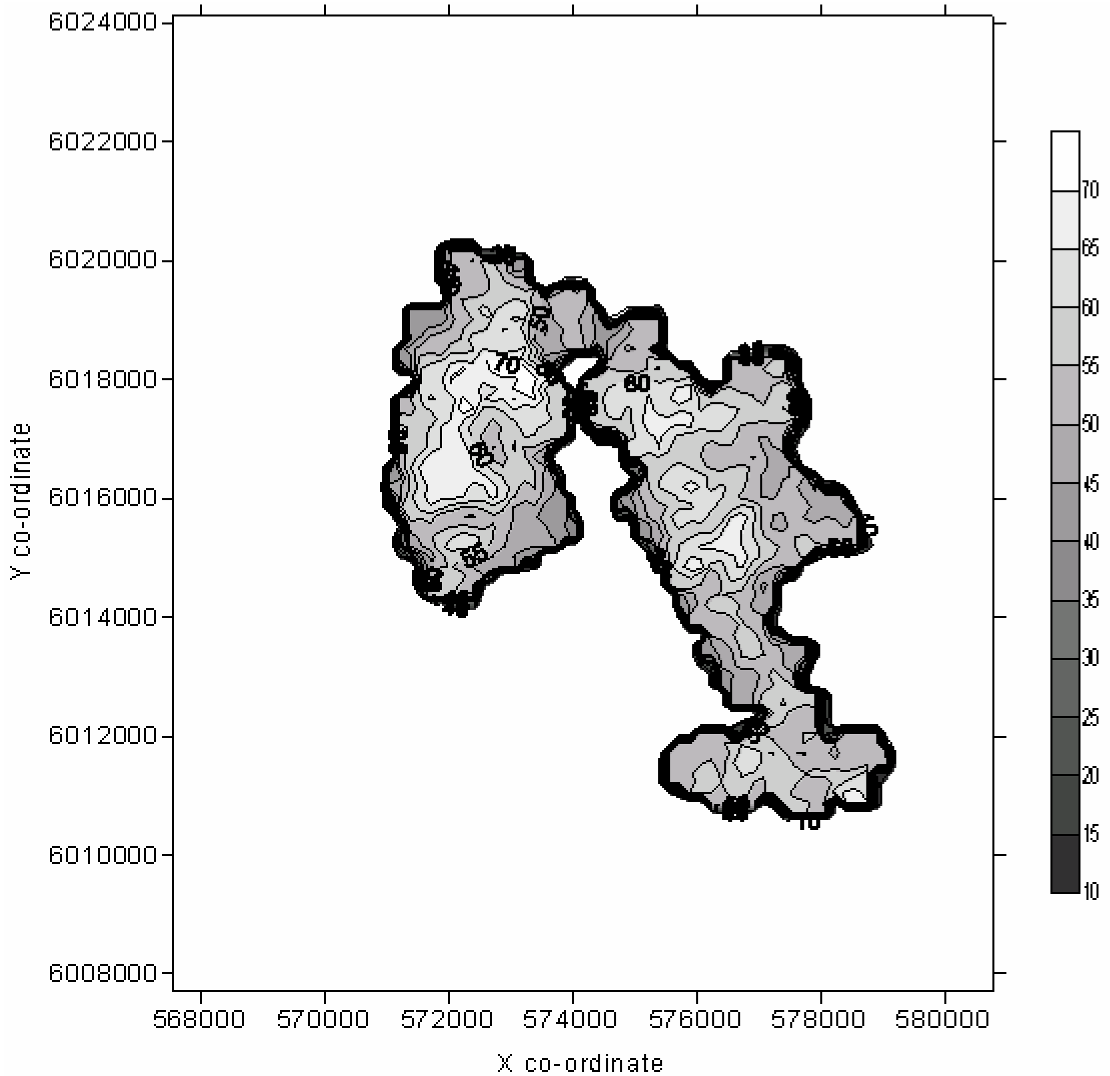


Figure 69: Contour map of hydrate saturation for zone D

Data file used for generating above contour map: **mtelbertDsaturation_rectangle.asc**

Mr. Robert Hunter has also suggested investigation using uniform gas hydrate saturation (S_h) of 60% with 20% of mobile water saturation and 20% irreducible water saturation (Sw_{irr}).

4) Thickness:

The input data files for formation thickness of zone C and zone D were received and using that data & with the help of software Surfer, the contour maps of thickness for these two zones were generated. The contour maps are shown below:

1. Zone C:

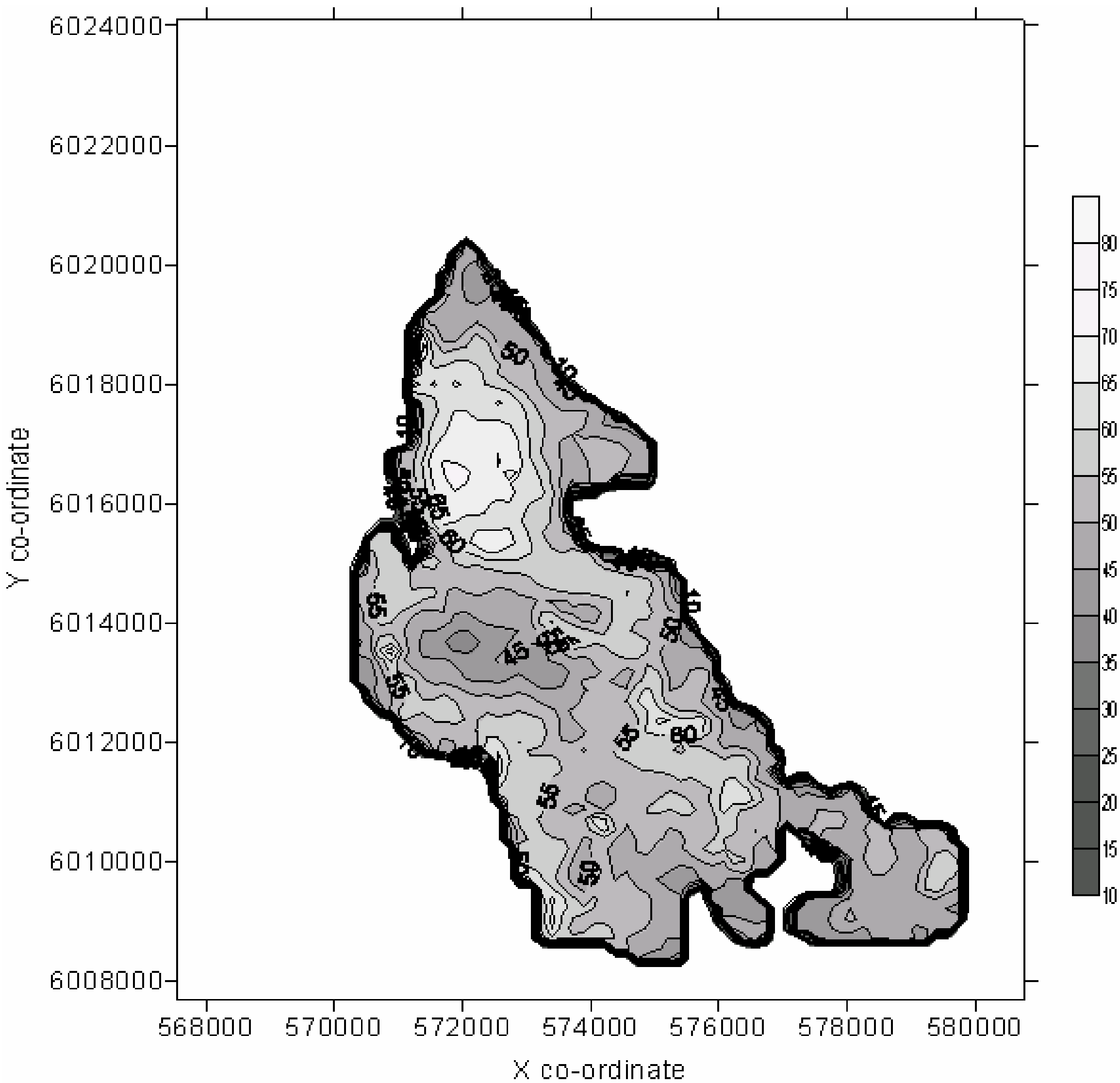


Figure 70: Contour map of thickness for zone C

Data file used for generating above contour map: **mtelbertCthickness_rectangle.asc**

2. Zone D:

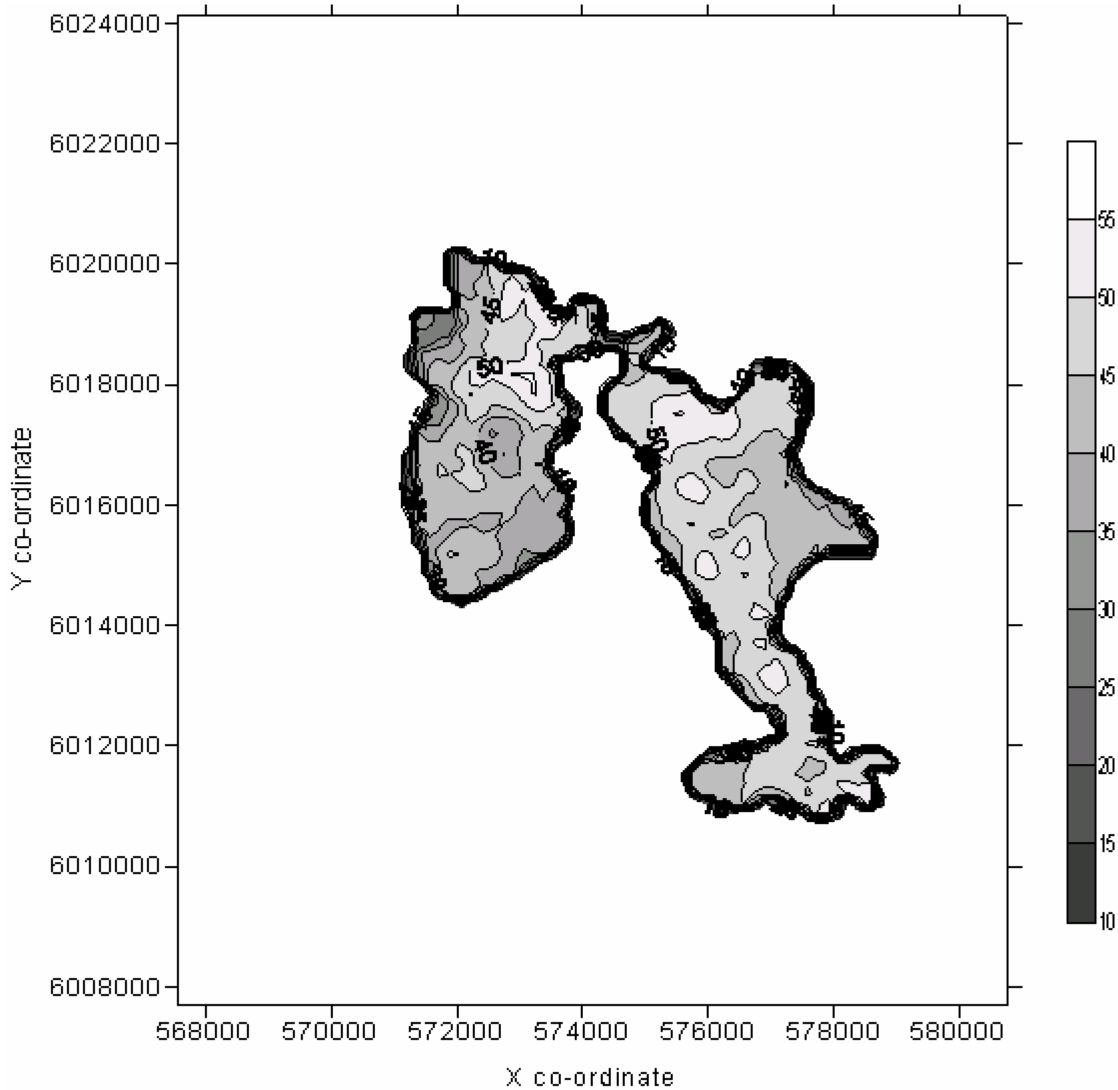


Figure 71: Contour map of thickness for zone D

Data file used for generating above contour map: **mtelbertDthickness_rectangle.asc**

5) <u>Depth of formation</u>:

The input data files for depth of formation of zone C and zone D were received. With the help of the software Surfer and the data received, the contour maps of formation depth for these two zones were generated. The contour maps are shown below:

1. Zone C:

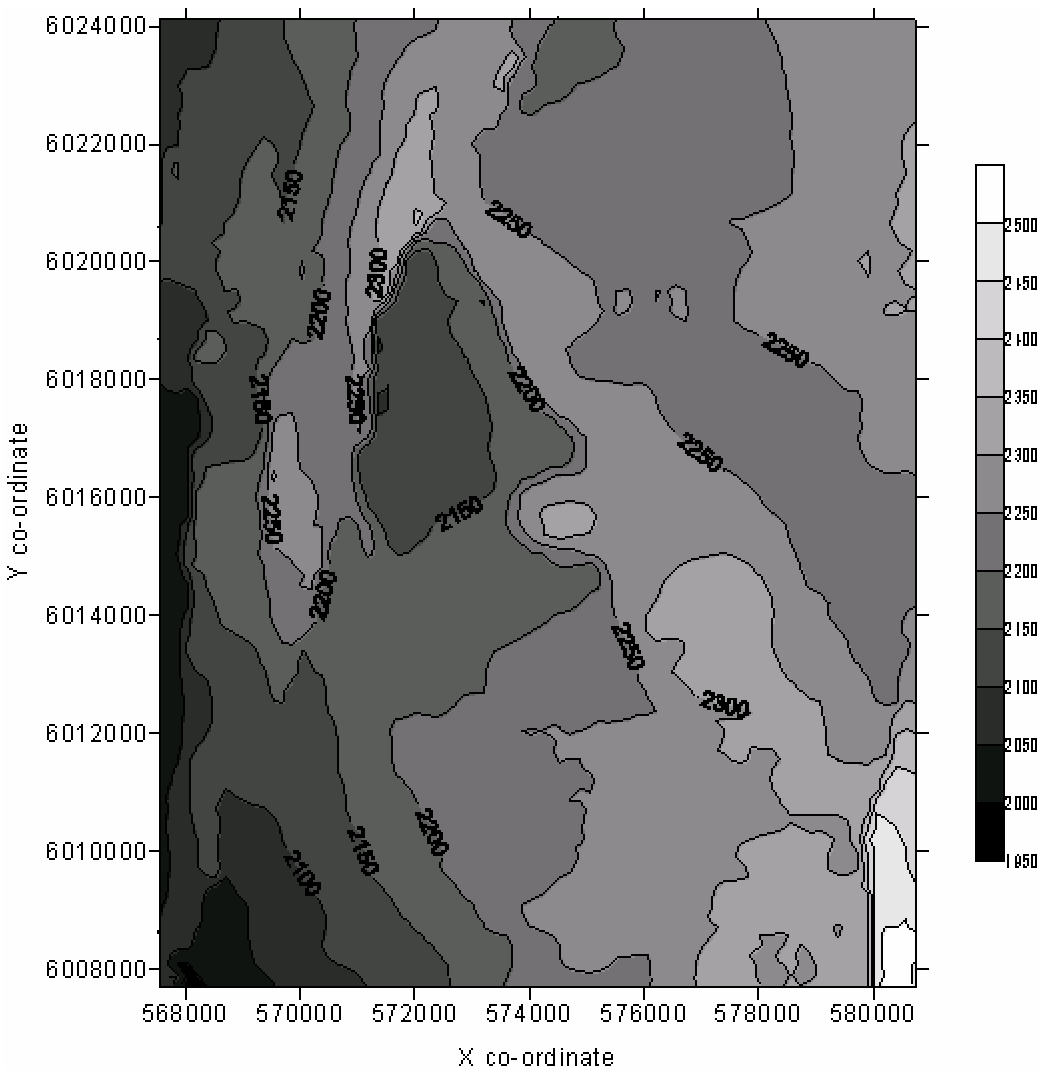


Figure 72: Contour map of depth for zone C

Data file used for generating above contour map: **mtelbertCdepth_rectangle.asc**

2. Zone D:

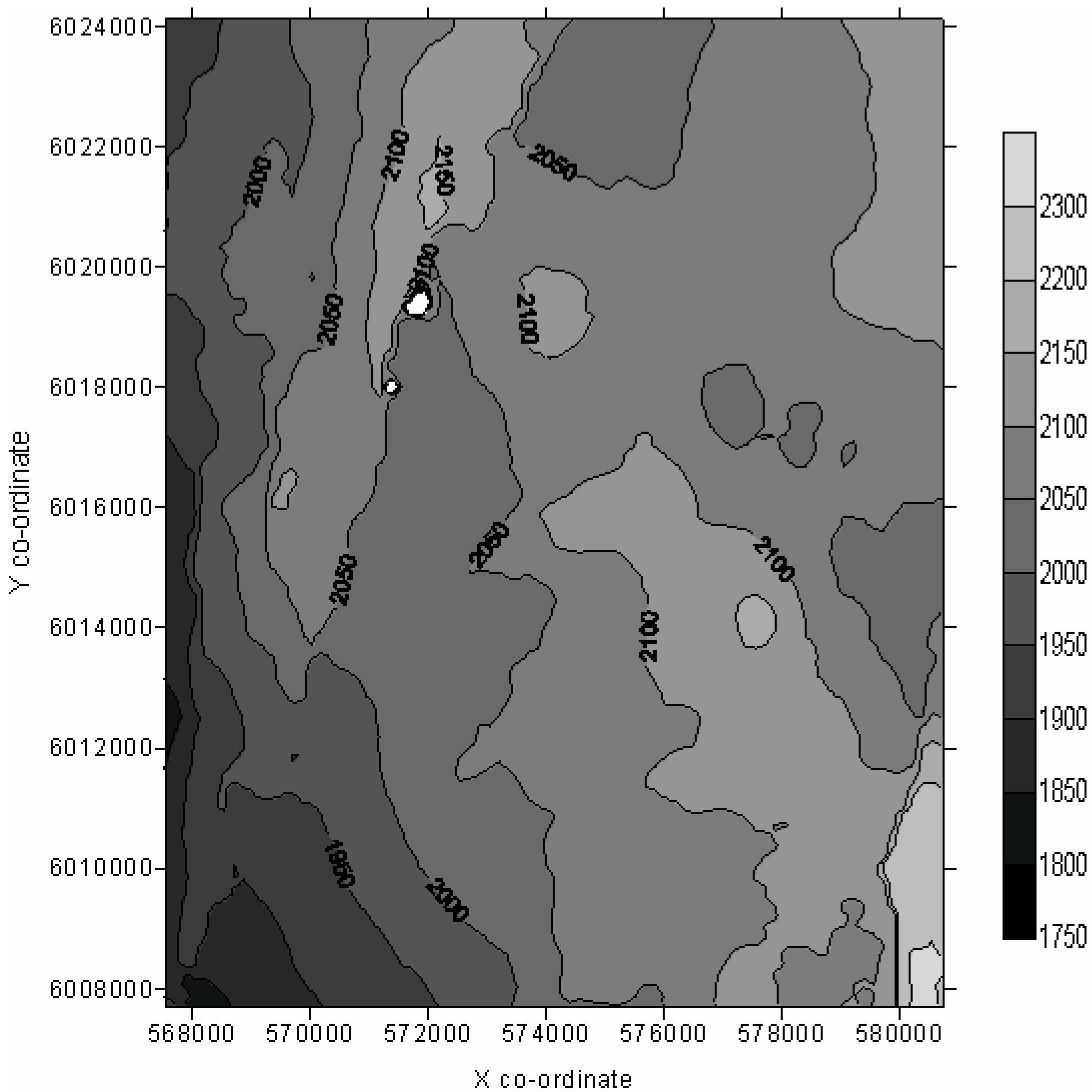


Figure 73: Contour map of depth for zone D

Data file used for generating above contour map: **mtelbertDdepth_rectangle.asc**

From figures 72 and 73, it is clear that zone D is upper layer whereas zone C is the lower layer of the gas hydrate-bearing reservoirs at the Mt. Elbert prospect site.

Formation Property Data:

1) Thermal Conductivity:

1. Zone D:

Thermal Conductivity of Rock: 2.743E+05
Thermal Conductivity of Water: 5.35E+04
Thermal Conductivity of Oil: 1.653E+06
Thermal Conductivity of Gas: 7400

2. Zone C:

Thermal Conductivity of Rock: 5.4E+5
Thermal Conductivity of Water: 5.35E+04
Thermal Conductivity of Oil: 1.653E+06
Thermal Conductivity of Gas: 7400

2) Grain Density:

Dr. Tim Collett has suggested using a value of 2.65 g/cc for grain density of the formation.

3) Bulk Density:

Calculate the bulk density from the assumed value of porosity, grain density and water density. (Dr. Tim Collett)

4) Rock Compressibility:

1. Zone D:

Rock Compressibility: 2.347E+06 /psi

2. Zone C:

Rock Compressibility: 1.0E+14 /psi

Fault Information:

The input data file for CMG simulator containing the fault information was received, but it was not clear how to use that information in the current study other than as boundaries to the 3-way structural trap of the Mt Elbert prospect.

5.10.3.5 Work Plan

1. Based on the contour maps for zone C and D, it appears that both of these zones have different shape and size. This needs to be taken into consideration while generating the grid system for the simulation. According to the input data file received (002-expKg-TypeWell160AcSpacingHighSwNoFreeGas300md.dat), it seems like Mr. Scott Wilson is using a rectangular grid system of 50 x 50 x 2. So if needed, the same approach will be used for defining the grid system. The gas hydrate saturation, depth of formation and formation thickness data is available for both of these zones in the form of a 32200 x 32200 matrix. Therefore, it is required to convert that same data for a matrix of 50 x 50 for each zone.

2. After gathering all the required information, the next step is to define the grid system of 50 x 50 x 2 over each contour map for zones C and D in order to extract all the information for the entire reservoir that needs to be defined in the simulation.

3. The information regarding the faults present at Mt. Elbert site is available in the form of an input file, but the way it has to be used is not known yet.

4. Mr. Scott Wilson has suggested using constant values of porosity and permeability; therefore there will not be any variation in the value of these two properties for a given single case.

However, since we have generated contour maps for gas hydrate saturation, thickness and formation depth for individual zones, this data will be used for the simulation input. Some geostatistical tools (e.g. WinGSlib) will be used to calculate the variation in the property over the entire filed and the correlations obtained from these geostatistical tools will be used for the simulation input.

5. Bulk density of the formation needs to be calculated from the knowledge of grain density, porosity and water density.

6. The following different production scenarios will be tested during this simulation study, so as to analyze their effect on the potential production of natural gas from the gas hydrate-bearing reservoir sands:

a) Variation in the porosity values

b) Variation in the permeability values

c) Variation in the temperature and pressure of injected CO_2-microemulsion

d) Variation in the injection rates of CO_2-microemulsion

e) Variation in the CO_2-microemulsion concentration

f) Variation in the location for injection and production wells

5.11 TASK 8.0, Phase 3a: Plan and Implement Drilling of Stratigraphic Test Well

5.11.1 Task 8, Phase 3a, Executive Summary

- Completed NEPA Environmental Questionnaire with inputs from BP HSE and Drilling
    - Prepared list of questions and requirements and compiled BP HSE/Drilling input
    - Compiled inputs from newly consigned/constructed Arctic Fox rig
    - Defined stratigraphic test operation plans as Categorical Exclusion within MPU
- Planned Stratigraphic Test Well and held regular weekly meetings with BP/DOE/team
    - Developed and implemented task schedules for well permits, materials, plans
    - Identified critical tasks and path for well permits, materials, contracts, rig, and ice pad/road; modified task schedules as needed
    - Evaluated task risks and developed risk mitigations
    - Developed contacts and contracts with appropriate subcontractors for well permitting (ASRC Energy Services (Lynx)), operations (ASRC Energy), wireline coring (Corion), core processing (OMNI and Core Mongers), wireline and MDT evaluation program (Schlumberger), and other
    - Prepared and checked surface ice pad/road and bottom hole location (BHL)
        - Discovered and corrected BHL discrepancy
    - Developed agenda, convened, and moderated weekly well planning meetings for Mt Elbert prospect location beginning mid-January 2006
        - Setup planning meetings, agendas, and timelines to accomplish 2006 well
        - Provided task status updates and coordinated well operations and data acquisition plans
        - Developed statement of risks document, addressed concerns, and developed plans to mitigate risks

- Selected ice road route to ensure safe access within existing infrastructure, roads, pads, pipelines, and power lines
  - Evaluated ice pad access from MPU E- and B-pads
  - Selected B-pad access route to minimize traffic and infrastructure disturbance
- Developed detailed wireline and MDT evaluation program with team
- Initiated cementing program with Schlumberger, MPU provider
  - Evaluated alternate Ceramicrete technology, and selected conventional cementing program due to no current Ceramicrete field tests
  - Met with ASRC Energy Services, Argonne National Lab, BJ Services, and UAF to discuss status of Ceramicrete cement testing (2/1/06)
- Initiated mud program, evaluated alternative technologies, and incorporated DrillCool, Inc. mudchilling system
- Planned core program and procedures with Corion
  - Planned compatibility of Corion and Doyon Arctic Fox rig equipment
    - Helped ensure 5” RAMS available for hookup to Corion tubulars
- Initiated planning of core handling and processing program with OMNI
- Initiated and reviewed detailed plan of operations for well permits
  - Discussed and reviewed well plans and permits with appropriate industry and State of Alaska representatives
  - Developed and reviewed figures for drilling permit
- Initiated and reviewed drilling and data acquisition time and cost plans
  - (3/14/06) Determined inability to drill well due to third party rig delays and approaching end-of-tundra travel and ice seasonal drilling
  - Notified DOE and subcontractors of decision to defer drilling of well
- Developed, reviewed, and submitted program drilling, data acquisition, and data evaluation budget
  - Identified areas for potential cost savings for desktop and field operations
  - Calculated potential cost savings and evaluated budget options
  - Provided backup documentation for materials, contractors, and budget

- Initiated review of potential alternative, gravel pad options for future stratigraphic and/or potential future Phase 3b production test
  - Prepared and reviewed draft proposal for evaluation
  - Evaluated potential gas handling options for possible future production test well (test not currently approved by DOE or BP) at alternative gravel pad site
    - Evaluating potential synergy with Alchem Field Services, Inc – DOE project which developed skid-mounted gas-to-liquid facility
      - Multiple units may be constructed in commercial venture with Waste Management, Inc. and be available for lease by early 2007
      - Units apparently have capability to convert 0.5-2.0 MMCF/d methane into approximately 25-100 BPD #1 low-sulfur diesel fuel
      - Unit construction/operating costs may be up to $3MM; however, leased unit may alternatively be available as demonstration plant

5.11.2 Planning and Implementing Drilling of Stratigraphic Test Well

5.11.2.1 Task Definition

The planning and execution of a stratigraphic test well within the MPU Mt. Elbert prospect has been adopted as an integral project objective. This objective is defined as Task 8.0 within Amendment 11 of the BP-DOE Cooperative Agreement:

“Task 8.0 - Plan and Implement Drilling of Stratigraphic Test Well:

Recipient will implement appropriate data acquisition consisting of a drilling and evaluation program based on a single vertical stratigraphic test well with appropriate logging, coring and MDT testing of the previously documented "Mt. Elbert" or comparable prospect within the Milne Point Unit. The field activity will be designed to determine the validity of pre-drill seismically-based predictions of gas hydrate occurrence and reservoir quality and to collect other data as necessary to enable a decision whether or not to conduct future dedicated gas hydrate reservoir production testing on the Alaska North Slope. Recipient will maximize synergies with existing and planned ANS developments. Recipient will either plug and abandon the well before moving off or suspend the well with or without instrumentation for future use as an observation well”

5.11.2.2 Plan of Operations

5.11.2.2.1 Introduction

In 1Q06, BP Exploration (Alaska) Inc. (BPXA) prepared a Plan of Operations (Appendix B1) to support permit applications to drill the Mt. Elbert-01 stratigraphic test well in the northern portion of the Eileen gas hydrate trend within the Milne Point Unit (MPU). The surface owner at this location is the State of Alaska and BPXA has valid rights to drill and operate at this site under lease number ADL 255231 within the MPU. BPXA would retain a working interest in the prospect after the well is drilled. Synergies with existing and planned ANS developments have been maximized by the utilization of existing BPXA drilling engineering and operations staff to plan and manage the drilling concurrent with ongoing drilling operations within the MPU and adjacent fields. Operations support infrastructure to be utilized is in place in the form of the MPU production complex and existing drilling rig service and support contracts. All required environmental permits have been obtained under both existing and operation specific permitting criteria and the final permit to drill has been obtained from the Alaska Oil and Gas Conservation Commission.

5.11.2.2.2 Drilling Operation Schedule

The initial Plan of Operation called for the Mt. Elbert #1 well to have been drilled in March and April of 2006 from an ice pad with ice road access. Regulatory and operational criteria dictated that drilling and plugging be completed by April 30 and site clearance operations be completed by May 15, the end of the seasonal cross tundra travel period. By the end of February 2006 all well design, permit applications, equipment specification and location surveying had been accomplished. Contracts for services were in place and mobilization plans were complete. The drilling rig selected for the project was the Doyon Drilling rig Arctic Fox (Figure 74), which was at the time under contract to another operator. A BPXA rig contract was prepared contingent upon timely completion of the previously contracted wells. In the final week of February and the first week of March 2006 it became increasingly obvious that there was significant delay in the rig availability due to drilling operations difficulties for previously contracted third-party wells. Support equipment mobilization and ice construction were temporarily suspended. By mid March, it was confirmed that the rig would not be released to BPXA in time to meet the planned operational schedule. On March 16, 2006 the BPXA / DOE project management team reached the decision to defer the program until the 2007 winter drilling season.

Figure 74: Doyon Arctic Fox on ANS operations, 2005-2006 Winter Exploration Season

BPXA has re-evaluated the rig selection for this project. At this time BPXA would plan to utilize Doyon Drilling Rig #14 which is currently under contract to BPXA. It is anticipated that the rig would be available to begin drilling the Mt. Elbert #1 well by early 2007.

5.11.2.3 Drilling and Evaluation Program Design

5.11.2.3.1 Well Design Process

As operator of the Milne Point Unit, BPXA has collected considerable area-specific engineering and operational data relating to drilling mechanics, formation characteristics and reservoir fluids. This data was evaluated and utilized in the engineering design of the Mt. Elbert #1 well. It was determined that the well objectives can be met by an up-to 4000 foot vertical hole following what have become standard MPU engineering criteria for wells of this depth. The well design was collated into a Drilling Plan Summary. This summary contains information on all technical aspects of the drilling plan and is the data packet submitted to the Alaska Oil and Gas Conservation Commission (AOGCC) in support of an application for Permit to Drill (AOGCC Form 10-401). On March 6, 2006 the AOGCC issued Permit No: 206-033 (Appendix B2) granting approval and stipulations to the Drilling Plan Summary.

5.11.2.3.1.1 Generalized Drilling and Abandonment Procedure

The drilling procedure sequence does not vary significantly from standard MPU practice. Minor variations for utilizing a Kelly rig and incorporation of the mud cooler and wireline retrievable coring equipment were adopted. The general procedure consists of constructing the location and mobilizing the rig. Surface hole of 12 ¼ inches would be drilled to 1950 feet and 9 5/8 inch casing would be set and cemented. Next the interpreted gas hydrate-bearing interval from 1950 feet to up to 2600 feet would be cored with a 7 7/8 x 3 inch core bit. The hole would then be opened to 8 1/2 inches and drilled out to up to 4000 feet total depth. Well evaluation logging with electric line tools would be conducted in the open hole and multiple wireline formation tests would be run using the Modular Formation Dynamics Tester (MDT) tool on drill pipe. The well abandonment would be conducted in conformance with AOGCC requirements and BPXA standard practice. Sections of the open hole would be plugged with balanced cement plugs and cement would be lapped into the casing shoe. The casing would be plugged near the surface and the casing and wellhead would be cut off below tundra level. The location would be cleared and cleaned to ADEC specification and inspected after the ice pad melts. A Time versus Depth plot for this well plan is presented as Appendix B3.

5.11.2.3.1.2 Well Plan Engineering Detail

Discussion of engineering and operational details of the well plan is presented. Specific design data can be found in the Drilling Plan Summary which is part of Appendix B2 and other referenced attachments.

5.11.2.3.1.2.1 Drill site location

The Mt. Elbert-01 location is 1,242 feet from-north-line (FNL) and 4,183 feet from-east-line (FEL) of Section 30, T13N, R11E UM onshore on State of Alaska lands approximately one half mile east of MPU E-Pad, North Slope Borough (NSB) Resource Development District in the Prudhoe Bay area of Alaska (Figure 75).

5.11.2.3.1.2.2 Ice Road and Pad

The ice road and pad would be constructed on frozen tundra to mitigate potential impacts to wetlands. Water and ice aggregate for ice road and pad construction and maintenance, rig operations, camp and maintenance use would be obtained from permitted sources within the area. Ice construction methods of spraying and flooding would be employed. The ice road to the ice pad would be a spur from MPU B-Pad to the drill site location (Figure 75). Ice road sections would be of sufficient thickness (6 to12 inches) and width (50 feet) to provide adequate surface protection and allow safe transport of personnel, equipment, and supplies to the drill site. Ice pad dimensions would be 400 feet by 400 feet and occupy an area of approximately 3.7 acres. Pad thickness would be a minimum of 6 inches or as required for pad leveling and bearing capacity. A working surface of timbers and matting boards would be placed on the ice pad to support the rig structure, and an impermeable plastic membrane would be placed in the well cellar area. Maintenance activities for the ice pad and water source ice roads include plowing, and resurfacing and re-grading with water as needed. The ice structures would thaw during breakup. Security markers and remnant debris would be collected for disposal prior to summer compliance inspection.

5.11.2.3.1.2.3 Major Equipment Considerations

5.11.2.3.1.2.3.1 Rig selection

Rig mobilization to the Alaska North Slope is extremely expensive and time consuming. Rig selection was consequently limited to rigs already present in the area. The selection criteria were further narrowed to specify rigs not obligated under existing contracts or involved in pre-established drilling schedules. As the well design is simple and shallow by local standards, rig capabilities were not a significant criterion. It was found that the Doyon Drilling rig Arctic Fox was the only unit that appeared to be available for the project as planned.

5.11.2.3.1.2.3.2 Thermal Modeling and Mud Chiller

The most atypical design criterion for this well is the requirement to minimize the disruption of the thermal regime through the gas hydrate stability zone. This element is critical to the entire evaluation program and especially to the recovery of relatively undisturbed cores from the interpreted gas hydrate-bearing interval. Previous drilling results utilizing chilled mud were reviewed and thermal flux computer models were run. It was concluded that the target temperature for mud going down hole was 2º C. An analysis of the market availability of qualified rental mud chillers resulted in the selection of Drill Cool Systems Inc. to install and supply a modular mud cooling system like the one used during operations of the 2002 Mallik gas hydrate program (Figure 76).

5.11.2.3.1.2.3.3 Coring Technology

The well evaluation program calls for continuous coring through the primary zones of interest within the gas hydrate-bearing intervals and recovery of the cores in a relatively undisturbed state. Wireline retrievable coring technology including the ability to run drilling bit inserts was required. REED Hycalog Coring Services (Corion) was selected as the vendor for this service. Corion expertise and equipment contributed to the approximately 95-100% gas hydrate-bearing core recovery during the 2002 Mallik gas hydrate program. Detailed equipment specifications and operational procedures were developed for inclusion in the well plan.

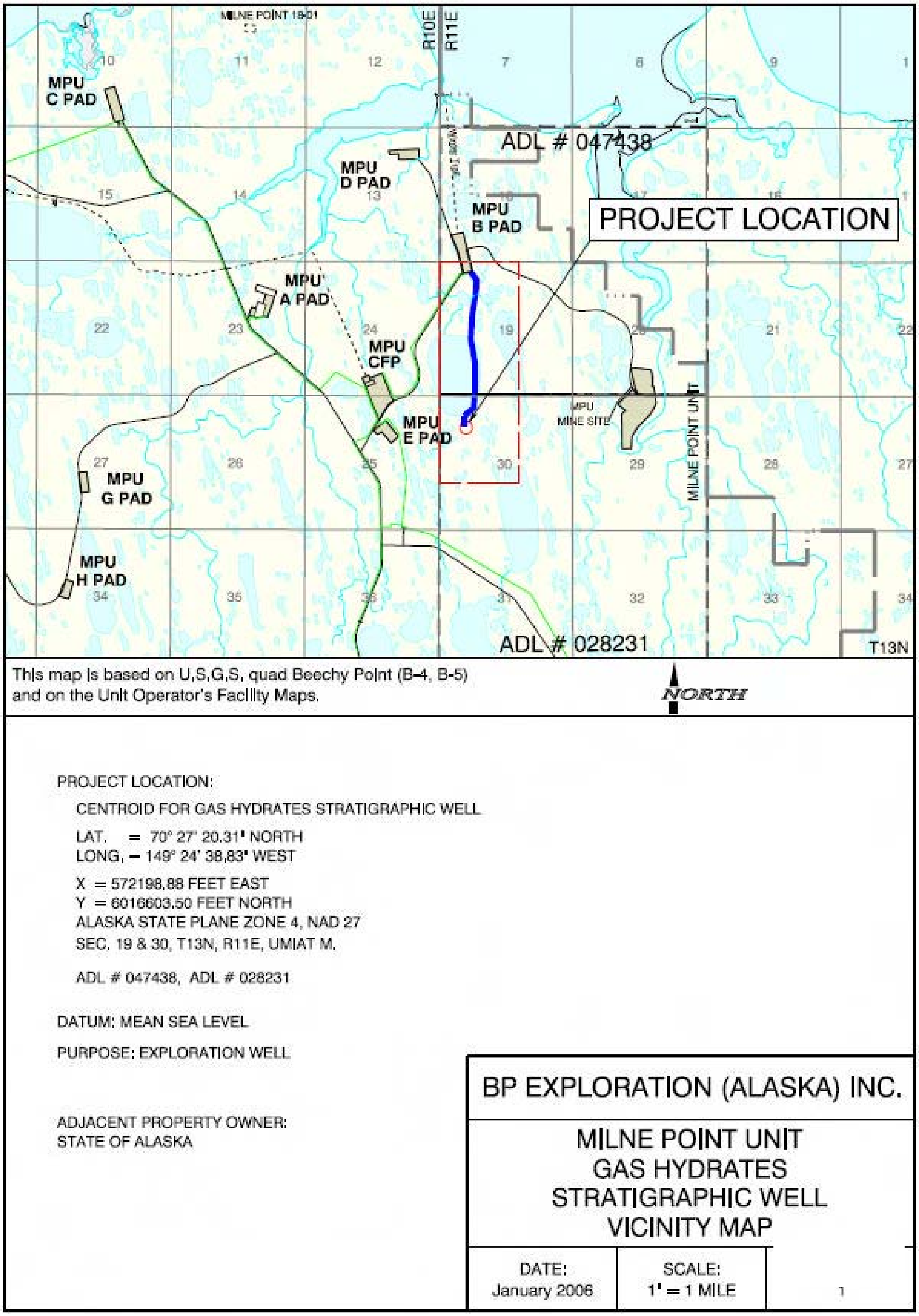


Figure 75: Mt Elbert-01 Stratigraphic Test Well Location within MPU.

Figure 76: Mud-Chilling Unit (red building), Courtesy Mallik Research Project, 2002

5.11.2.3.1.2.4 Pore Pressure and Fracture Gradient

Pore pressure and fracture gradient were evaluated through analysis of offset well data. Prospect-specific seismic data was reviewed for any indications of pressure anomalies. No unusual indications were noted other than those associated with the interpreted presence of gas hydrate-bearing intervals. The pressure gradient appears typical for the area at 0.433 psi per foot and the fracture gradient is expected to equal 1.0 psi per foot.

5.11.2.3.1.2.5 Mud Program

The well would be drilled in two sections. The surface hole to 1950 feet would be drilled with a simple fresh water gel mud system. In order to meet the temperature requirements, the final hole section to up to 4000 feet would be drilled with a potassium chloride –polymer Low-Solids Non-Dispersed (LSND) system with 8% KCl. This concentration would allow mud temperature depression down to -3.87 º C.

5.11.2.3.1.2.6 Casing Program

In order to utilize casing inventory already on hand and to accommodate the coring and MDT logging tool assemblies required for the evaluation program, a standard MPU casing design was selected. Twenty inch conductor would be set at 80 feet subsurface. Nine and five eights inch casing would be set at 1950 feet, just above the interpreted gas hydrate-bearing coring interval. A 7 inch contingency liner would be available if hole conditions require it. Table 17 illustrates the planned casing program.

Casing Program:

Hole Size	Csg Diam	Wt/ Ft	Grade	Conn	Burst	Collapse	Length	Top MD/ TVDrkb	Bottom MD/ TVDrkb
30"	20"	92	H-40	Weld	1530	520	80 ft	20	100 ft
12¼"	9⅝"	40	L-80	BTC	5750	3090	1932 ft	18	1950 ft
8½"	7" contingency liner	26	L-80	BTC	7240	5410	2150 ft	1850 ft	4,000 ft

Table 17: Mt Elbert-01 Casing Program

5.11.2.3.1.2.7 Cement Program

The standard surface casing cement utilized in the MPU is formulated to be mixed with 70 º F water. This would enable the slurry to set at the sub freezing temperatures in the permafrost region. The setting process is an exothermic reaction and a significant amount of heat is released. Laboratory tests to determine the affects of lowering the mix temperature were conducted. It was noted that no significant reduction could be made without adversely affecting the setting time and compressive strength build rate of the slurry. It was decided that the ArcticSet cement, which was available from the contracted service company, should be used in its normal fashion. If unacceptably high temperatures were to occur in the well after cementing, chilled mud would be circulated prior to further drilling into the interpreted gas hydrate-bearing interval. Table 18 illustrates the planned cement program.

Cement Program:

Casing Size	9⅝", 40ppf, L-80, BTC	
Type:	Surface Casing to 1950'.	
Basis for Calculation	80' shoe jts, 150% in permafrost (12-1/4" hole), and cement to surface. Shoe Depth: 1950' MD. 1450' Arctiset Lite @ 10.7 ppg and 500' ArcticSet @ 15.8 ppg	
Cement Volume:	Spacer	5 bbl of water, 10 bbl CW 100 and 40 bbl Mud Push
	Lead (BOC @ 1450 ft)	270 sxs (212.5 bbls), ArcticSet Lite @ 10.7 ppg. Yield 4.43 ft3/sx, mix fluid 20.667 gps.
	Tail (TOC @ 1450 ft)	446 sxs (79.50 bbls), ArcticSet @ 15.8 ppg. Yield 1.05 ft3/sx, mix fluid 4.10 gps.
	Temp	2 °C @ 1950 ft MD.

Casing Size	7" 26ppf, L-80, BTC Contingency Liner	
Type:	Production Liner from 4000' TD to 1800' (150' liner lap)	
Basis for Calculation	80' shoe joints, 30 % excess in open hole. 500' ArcticSet Lite @ 10.7 ppg and 1700' Class G at 15.8 ppg.	
Cement Volume:	Spacer	5 bbl of water, 10 bbl CW 100 and 30 bbl Mud Push
	Lead (BOC @ 2300 ft)	20 sxs (15.8 bbls), ArcticSet Lite @ 10.7 ppg. Yield 4.43 ft3/sx, mix fluid 20.667 gps.
	Tail (TOC @ 2300 ft)	256 sxs (53.0 bbl) Class G @ 15.8 ppg. Yeild 1.16 ft3/sx, mix fluid 4.97 gps.
	Temp	24 ° C @ 4000 ft MD.

Table 18: Mt Elbert-01 Cement Program

An alternative cementing program was considered using the experimental "Ceramicrete" cement under development as discussed in Section 2.3. However, this cement has not yet completed yard testing, a necessary precursor to field testing. If future field testing of this cement were to occur, it is recommended it be first attempted on a well conductor, second (if conductor successful) on a well surface casing, and third (if surface casing successful), on a later well production casing. Advantages of this experimental cement may include minimizing formation and/or annular space damage while maintaining gas hydrate temperature stability during completion operations.

5.11.2.3.1.2.8 Drilling Mechanics and Bit Program

The Arctic Fox rig is a mechanical drive unit with a kelly rather than a top drive. It was planned to utilize standard rotary bottom hole assembly design and a 12 ¼ inch milled-tooth tricone bit in the surface hole to 1950 feet. The intermediate interval would be rotary-cored with a 7 7/8 inch core bit to 2600 feet and then opened to 8 1/2 inches and drilled to total depth of up to 4000 feet with rotary equipment and a milled-tooth roller bit. Drilling mechanics and mud hydraulics were based on standard practice.

5.11.2.3.1.2.9 Well Control

The maximum anticipated bottom hole pressure and maximum surface pressure are calculated to be 1740 psi and 1340 psi respectively. A standard 3000 psi Blow-out Preventor (BOP) stack would be utilized and all well control procedures consistent with AOGCC regulations and BPXA standard practice would be utilized. A formation integrity test would be performed after drilling out the surface casing shoe. Chilled mud, proper hole cleaning and controlled drilling rates would be used to control gas breakout from drilled gas hydrate-bearing reservoirs. A wireline BOP, circulating sub and packoff would be utilized when retrieving cores.

5.11.2.3.1.2.10 Drilling Hazards and Contingencies

The drilling and coring of highly-saturated gas hydrate-bearing intervals likely presents the most severe hazard in this well. Gas hydrate is interpreted to be present from the base of the permafrost to approximately 2850 feet Measured Depth (MD) in the vertical well. Mud system design specifies an 8 % KCl LSND system which would have a thermal crystallization temperature of - 3.78ºC. Operating temperature of mud being pumped down hole would be maintained at 2.0ºC. Circulating temperature, mud chemistry and drilling mechanics would be optimized to minimize gas hydrate dissociation while maintaining primary well control. All circulating system components would be monitored and actively protected from freeze up, both while circulating and during static periods. Cores would be allowed to pressure stabilize below the wellhead and flow checks would be conducted prior to continuing the retrieval and opening the wireline riser to lay down cores. The core would be laid down, removed from the floor, sectioned, and containerized at sub-freezing temperatures. All core storage and any onsite geoscience or analytical studies would be conducted in a refrigerated, containerized unit remote from the wellbore.

The possibilities of stuck pipe, pack off or lost circulation exist throughout the well. BPXA and industry standard drilling practices have evolved for mitigating these risks. Proper drilling mechanics and operational techniques, mud chemistry and adequate hole cleaning would be exercised to combat these risks.

Hydrocarbons in the form of methane hydrate are expected from the base of the permafrost through the base of the gas hydrate stability zone at ± 2850 feet. Neither liquid hydrocarbons nor free gas hydrocarbons are anticipated in any drilled section. There are no faults or hydrogen-sulfide-bearing intervals interpreted for the well location and there are no anti-collision issues with existing wellbores.

5.11.2.3.2 Evaluation Program and Data Acquisition

Much remains unknown regarding gas hydrate-bearing reservoir sand petrophysical properties and lateral continuity based on sedimentary characteristics and depositional environment. Although the gas hydrate stability zone has been safely and successfully penetrated by hundreds of wells within the AOI, the primary targets of these wells are deeper, oil-bearing reservoirs and very few of these wells have specifically acquired complete data sets within the gas hydrate-bearing intervals of interest to this study. Furthermore, since ANS oil reservoir development occurs from centralized gravel pads which access these reservoirs through directional drilling, the data collected within shallow sands (500-2,500 feet below surface) is typically centered within a few hundred feet of the gravel pads since most wells do not begin to build angle until near or below the base of ice bearing permafrost (approximately 1,800 feet below surface). The last dedicated well to acquire data within the gas hydrate-bearing reservoir sands was the Northwest Eileen-02, drilled in 1972. This well acquired a few feet of conventional core data and tested several zones using Drill Stem Testing (DST) techniques (Figure 77).

The possibility to induce in-situ gas hydrate dissociation through producing connate waters from within an under-saturated gas hydrate-bearing reservoir establishes saturation and permeability as key variables which, when better understood, could help mitigate productivity uncertainty. Approved field operations will enable acquisition of gas hydrate-bearing reservoir data within Phase 3a studies (2006-2007). A key part of this analysis will be targeted acquisition of cores and wireline logs within gas hydrate-bearing reservoir sands and associated sediments. The wireline logging is planned to include Modular Dynamic Testing (MDT). Analysis of these core, log, and MDT data should help reduce the uncertainty regarding gas hydrate-bearing reservoir productivity. The Mt Elbert-01 well is planned to be a vertical penetration from an ice pad located directly above the Mt Elbert gas hydrate prospect within the MPU. The vertical well should facilitate safer and more successful acquisition of core, log, and MDT data.

5.11.2.3.2.1.1 Mud Log and Gas Show Data Acquisition during Drilling Operations

One of the most diagnostic tools indicative of shallow gas hydrate-bearing sands is the mud log with gas detection. Mud logs will be acquired in the surface and production holes to help facilitate identification of gas hydrate-bearing sands within the gas hydrate stability zone.

5.11.2.3.2.1.2 Log Data Acquisition during Drilling Operations

The base plan for log data acquisition during drilling operations (LDD) will be limited to gamma-ray, resistivity, and directional at the bit to facilitate stratigraphic correlations and associated picking of surface casing near base permafrost and core intervals. The chilled drilling fluids should maintain the stability of the gas hydrate-bearing zones and preserve the integrity of the wellbore, allowing high-quality wireline log and MDT in-situ data acquisition. However, MPU field well operations experience in wells drilled without chilled fluids may favor adding a full suite of logging-during drilling (LDD) tools, including NMR, dipole sonic, and acoustic caliper through the production hole, as a contingency in case hole stability problems occur and since acquisition of log data remains a high-priority objective for this project. The current base plan is to acquire only limited LDD data with full-suite open-hole wireline data acquired after the core is cut and the well drilled to total depth (TD). An alternate contingency LDD program could be implemented in recognition and risk-mitigation for the potential for hole stability problems to develop during the several days required for coring and drilling to TD. Current field experience indicates that attempts to acquire data with the Schlumberger LDD CMR+ tool do not yield the data quality of that acquired with the Halliburton LDD NMR tool. The Schlumberger wireline dipole sonic is much better than the Sperry-Sun LDD BAT sonic for low velocity shear wave data acquisition. Baker Hughes INTEQ has a full waveform LDD sonic; the older APX model did not deliver as high a data quality as was expected in early trials, but the redesigned tool is supposed to work better in this environment. There are also alternative ways to design this program to eliminate all wireline except the MDT, but this is not the primary plan.

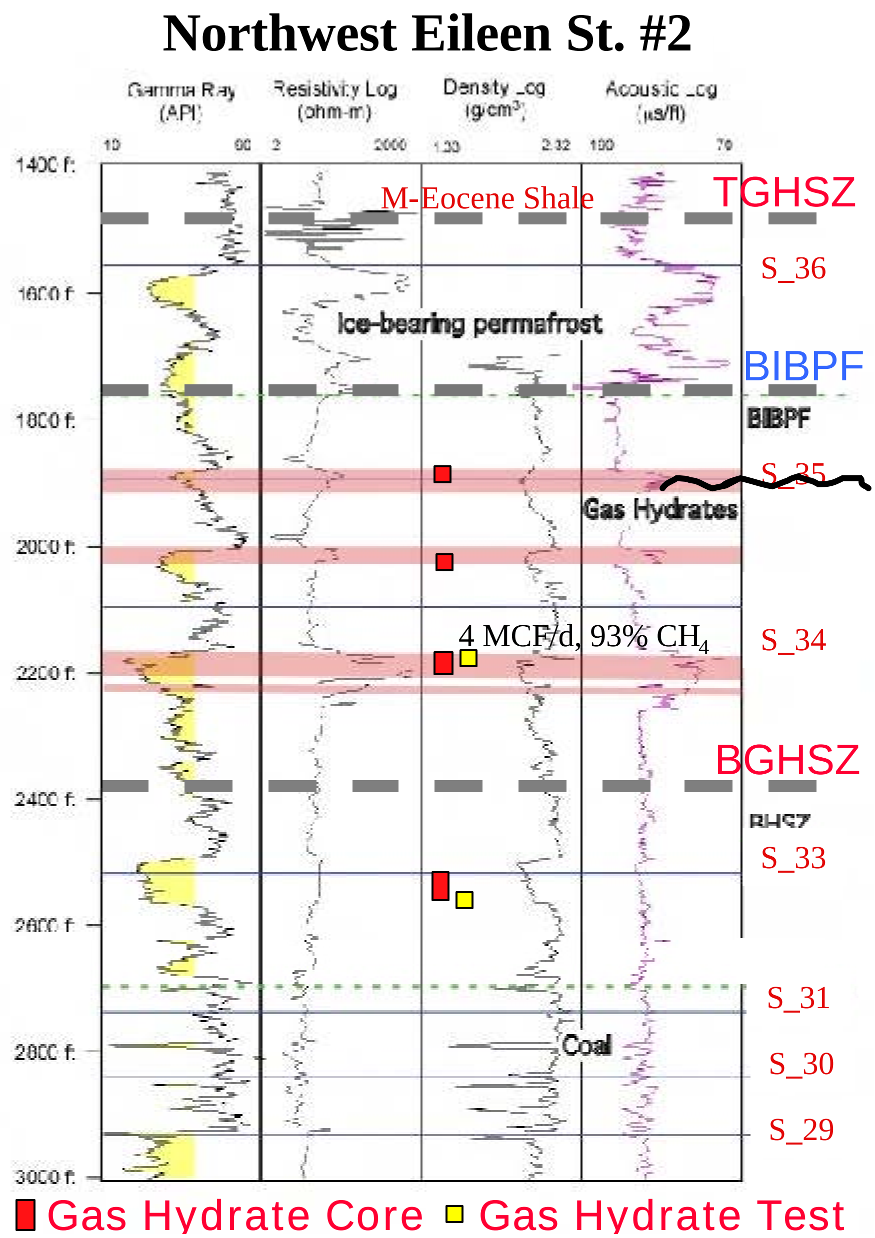


Figure 77: Northwest Eileen State-02 Type Well and data acquired within gas hydrate-bearing zones of interest.

5.11.2.3.2.1.3 Log Data Acquisition during Open-Hole Wireline Operations

Since the well is planned to be near-vertical, wireline logs are planned to acquire high-quality gas hydrate-bearing reservoir petrophysical data, provided that the mud-chilling operations maintain adequate borehole stability and in-situ conditions (preventing borehole washouts and gas hydrate dissociation during drilling, coring, and data acquisition operations). Wireline logs would be run from approximately 1,950 to 4,000 feet (or TD) in the "production" hole below surface casing below BIBPF as shown in Figure 77-78. The MPE-26 type log shown in Figure 78 is directly beneath MPU E-pad within the shallow zones of interest. MPE-26 is approximately 1,500 feet west of the proposed Mt Elbert-01 well location (Figure 79).

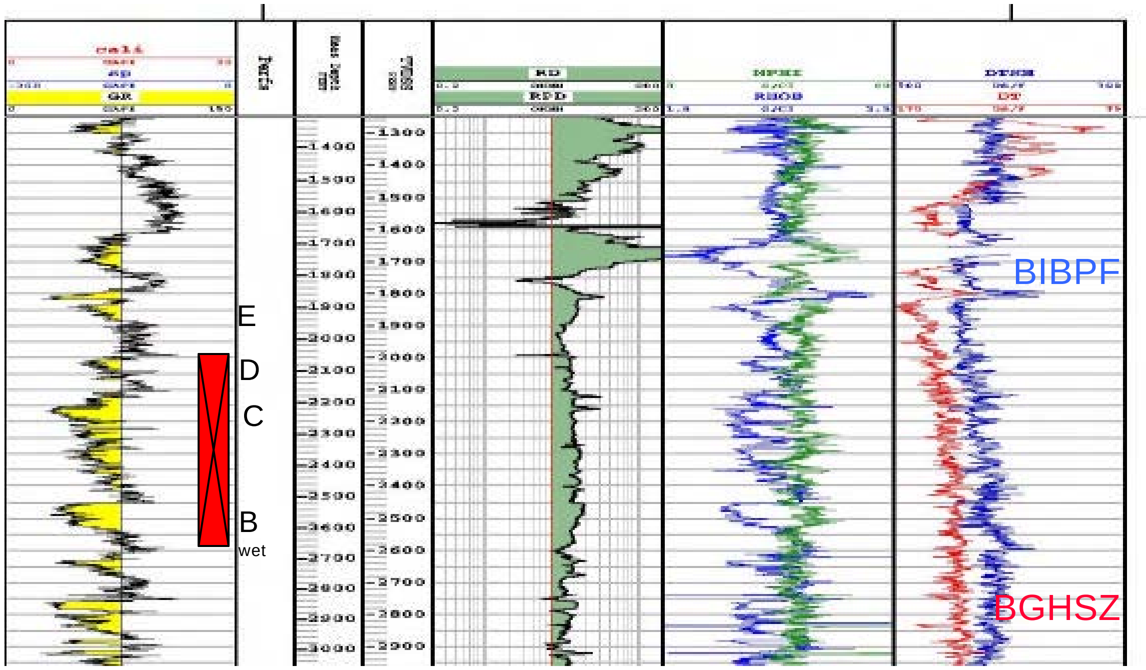


Figure 78: MPE-26 Type Log showing planned intervals of wireline log and core data acquisition between BIBPF and BGHSZ.

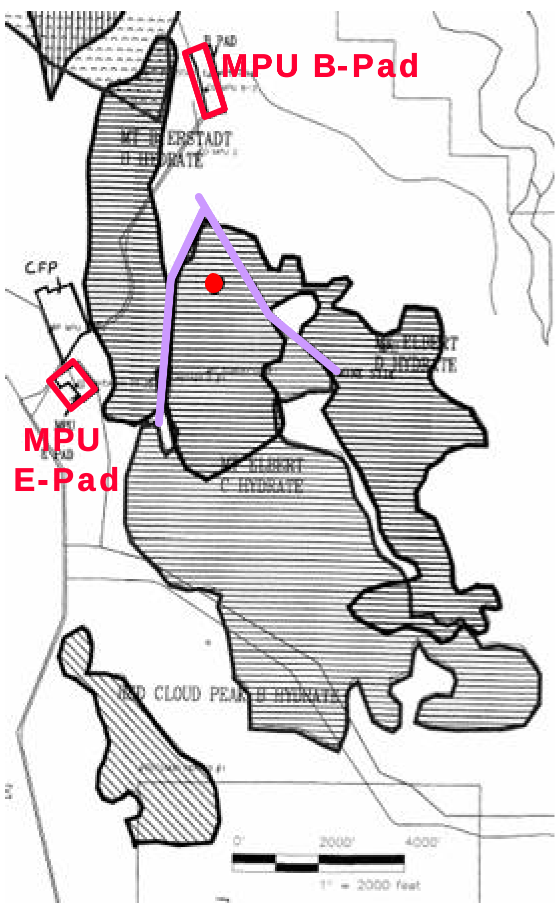


Figure 79: Mt Elbert-01 well location (red circle) within MPU Mt Elbert gas hydrate prospect.

Wireline logs planned would include gamma-ray, resistivity, neutron-density in the "platform-express" along with dipole sonic (with shear wave data), nuclear magnetic resonance (NMR), and formation micro-imager (FMI) to help determine gas hydrate-bearing reservoir properties. Planned data acquisition is summarized in Table 19.

Evaluation Program:

12¼" Surface Hole	
Coring Program:	• None
Mud Logging:	• Surface to casing shoe
Open hole Logs:	• MWD:Directional/Gamma/Resistivity
8½" Intermediate Hole	
Coring Program:	• **Run 1:** Continuous Core, Wireline retrieved from 2000' to 2600'
Mud Logging:	• Casing point to TD.
Open hole Logs:	• **Run-1:** 1850-4000 Platform Express (hydrate) -High Resolution Laterolog Array-SP Log (HRLA) -Compensated Neutron Litho Density Log -Array Induction-SP Log (AIT) -Electromagnetic Propagation Tool Log (EPT) – DiElectric msmt • **Run-2:** 1850-3500 Dipole Shear Imager (hydrate) -Dipole Shear Imager Log -Natural Gamma Ray Spectroscopy Log -Environmental Measurement Sonde Log • **Run-3:** 1850-3500 Formation MicroImager (hydrate) -FMI Borehole Image Log • **Run-4:** 1850-3500 Combinable Magnetic Resonance Tool (hydrate) -Combinable Magnetic Resonance Log -Natural Gamma Ray Spectroscopy Log -Environmental Measurement Sonde Log -CMR Station Log-Elemental Capture Sonde • **Run-5:** XPT (Optional) • **Run-6:** MDT Open Hole; 2 points per sand, two sands expected
Cased Hole Logs:	• **Run-1:** MDT cased hole contingency only

Table 19: Data Acquisition Plan Summary, Mt Elbert-01 Stratigraphic Test

5.11.2.3.2.1.4 Core Acquisition during Drilling Operations

Drilling a near-vertical well and maintaining borehole stability with chilled drilling fluids should help enable acquisition of quality core data within the interpreted gas hydrate-bearing intervals and associated sediments. No studies of ANS gas hydrate-bearing porous media have been made in the past. From 400-600 feet of continuous core is planned within the interpreted reservoir sands and associated sediments within the gas hydrate stability zone (Figure 80). Wireline coring will facilitate quick core acquisition and tripping to help preserve core quality once overburden pressures are removed during core recovery to surface. Analyses of the core will include petrophysical, mineralogical, depositional environment, and select sampling for experimental studies, including phase behavior, relative permeability, formation damage, geomechanical, and other assessments.

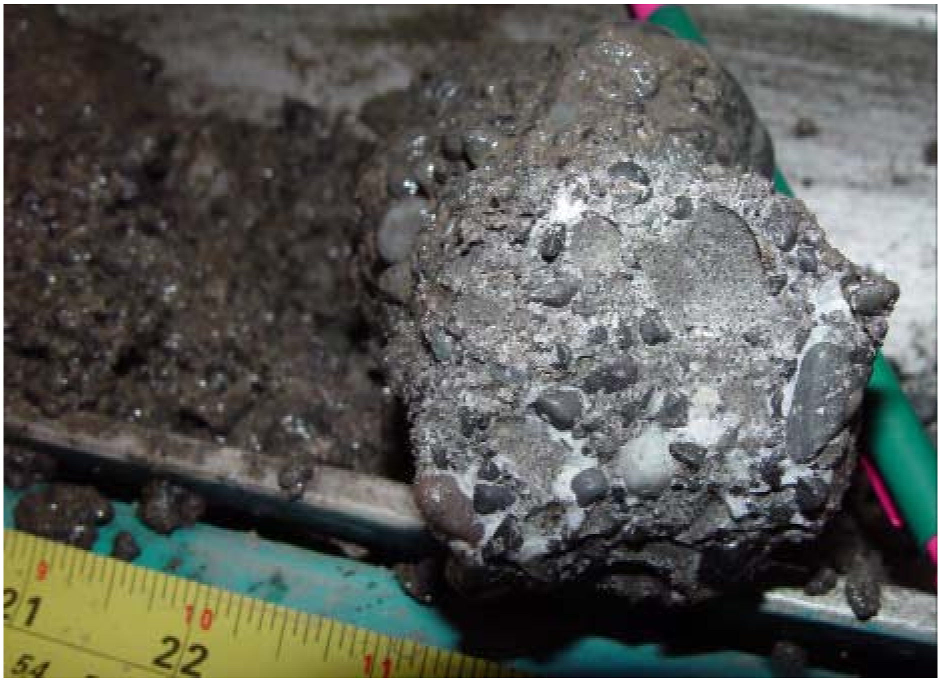


Figure 80: Gas hydrate occurs as a pore-filling phase evident within 3-inch Corion wireline-retrieved cores of reservoir sands at Mallik (Courtesy Mallik 2002 gas hydrate program).

5.11.2.3.2.1.5 Modular Dynamic Testing Data

During the 2002 Mallik gas hydrate program, Modular Dynamic Test (MDT) data provided some valuable insights into the potential productivity of gas hydrate-bearing reservoir sands. These tests revealed for the first time that movable connate waters could be produced through the MDT tool within gas hydrate-saturated reservoir sand intervals. This revelation may importantly indicate an ability of the gas hydrate-saturated reservoir to transmit a pressure pulse with offtake of mobile connate waters. The ANS MDT tests are expected to yield important data regarding gas hydrate-bearing reservoir connate water mobility, permeability, relative permeability, dynamic permeability (during dissociation of gas hydrate), and other data in combination with core and wireline logs. Analysis of this data is anticipated to help promote a better understanding of the potential productivity and potential production methods of these gas hydrate-bearing reservoirs. Three to four separate MDT sites within 2-3 interpreted gas hydrate-bearing reservoir sands are anticipated to be tested for up to 10.5 hours per test. The MDT tool basically allows a limited down-hole production test, which can yield this very important data.

5.11.2.4 Remaining Tasks and Recommendations

Pre-operational drilling engineering, permitting and equipment selection for the Mt. Elbert #1 stratigraphic test well was complete at the time of project deferral in March 2006. The deferral, combined with the change in drilling rig selection, has resulted in several issues which would have to be addressed before operations could commence. These considerations and the required actions are presented below. Timing for implementation of these recommendations varies and is contingent upon confirmation of the approximate date of rig availability.

5.11.2.4.1 Scheduling

The project is presently listed on the BPXA drilling schedule as being drilled by the Doyon Drilling Rig #14 beginning in early 2007. This schedule should be confirmed to the project team as soon as possible and any potential conflicts eliminated or addressed.

5.11.2.4.2 Staffing

The drilling engineers who developed the original operational plan for this project and the specialized service company personnel required for it may have assumed other positions. It is recommended that they or their management be contacted to confirm their availability to rejoin the project team in a timely manner.

5.11.2.4.3 Permitting

All permits must be reviewed for currency. The application for Permit to Drill would need to be modified to reflect a change in drilling rig assignment.

5.11.2.4.4 Major Equipment

The layout of the mud cooling and coring equipment needs to be integrated with the new rig. This work should be accomplished and equipment lists finalized significantly in advance of the equipment being mobilized from California and Canada, respectively.

5.11.2.4.5 Service Company Contracts and Mobilization

All service companies involved with the project should be contacted to ensure current contract status and availability of required equipment and personnel.

5.11.2.4.6 Drilling Engineering

The well plan engineering and operations procedure should be reviewed in light of the change in rig assignment. In particular, the change from a kelly rotary to top drive system would affect both specification of down hole drilling assemblies and specific operational sequences.

5.11.2.4.7 Operational Well Plan

The final Operational Well Plan, which would incorporate all equipment specifications, operational sequences and specialized service procedures, should be completed well in advance of rig mobilization to the location.

6.0 CONCLUSIONS

Phase 1 and 2 conclusions and Phase 3a plans from desk-top studies are presented in this report. The first dedicated gas hydrate coring and production testing well, NW Eileen State-02, was drilled in 1972 within the Eileen gas hydrate trend by Arco and Exxon. Since that time, ANS 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 helped create industry - government alignment necessary to reconsider the resource potential of the potentially large (44 – 100 TCF in-place) unconventional ANS methane hydrate accumulations beneath or near existing production infrastructure. Studies show this in-place resource is compartmentalized both stratigraphically and structurally within the petroleum system.

The BPXA – DOE collaborative research project enables a better understanding of the resource potential of this ANS methane hydrate petroleum system through comprehensive regional shallow reservoir and fluid characterization utilizing well and 3D seismic data, implementation of methane hydrate experiments, and design of techniques to support potential methane hydrate drilling, completion, and production operations.

Following discovery of natural gas hydrate in the 1960-1970's, significant time and resources have been devoted over the past 40 years to study and quantify natural gas hydrate occurrence. However, only in the past decade have there been significant attempts to understand the potential recoverability of methane from hydrate. Although significant in-place natural gas hydrate deposits have been identified and inferred, estimation of actual recoverable gas from these deposits is difficult due to the lack of empirical or even anecdotal evidence.

The potential to induce gas hydrate dissociation 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 (presented in the March 2003 Quarterly report and technical conferences) and corroborated by the results of continued UAF and Ryder Scott reservoir model research as presented in Section 5.9 of the December 2003 Quarterly report and herein.

The possibility to induce in-situ gas hydrate dissociation through producing connate waters from within an under-saturated gas hydrate-bearing reservoir establishes saturation and permeability as key variables which, when better understood, could help mitigate productivity uncertainty. A schematic potential development screening study was undertaken to set ranges on the potential resources that might one day be recovered (if production is technically and economically feasible) given various possible production scenarios of the ANS Eileen gas hydrate trend, which may contain up to 33 TCF gas-in-place. Type-well production rates modeled at 0.4-2 MMSCF/d yield potential future peak field-wide development forecast rates of up to 350-450 MMSCF/d. Individual wells would exhibit a long production character with flat declines, analogous to Coalbed Methane production.

Results from the various scenarios show a wide range of potential development outcomes. None of these forecasts would qualify for Proved, Probable, or even Possible reserve categories using the SPE/WPC definitions since there has yet to be a fully documented case of economic production from hydrate-derived gas. Each of these categories would, by definition, require a positive economic prediction, supported by historical analogies, prudent engineering judgment and rigorous geological characterization of the potential resource before a decision on actual development could proceed.

Approved field operations will enable acquisition of gas hydrate-bearing reservoir data within Phase 3a studies (2006-2007). A key part of this analysis will be acquisition cores and wireline logging of gas hydrate-bearing reservoir sands and associated sediments. The wireline logging is planned to include Modular Dynamic Testing (MDT). Analysis of this core, log, and MDT results may help reduce the uncertainty regarding gas hydrate-bearing reservoir productivity and may lead to Phase 3b gas hydrate production test studies, although these Phase 3b studies are not currently approved.

7.0 PROJECT AND RELATED REFERENCES

7.1 General Project References

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

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

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

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

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

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

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

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

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

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

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

Digert, S. and Hunter, R.B., 2003, Schematic 2 by 3 mile square reservoir block model containing gas hydrate, associated free gas, and water (Figure 2 from December, 2002 Quarterly and Year-End Technical Report, First Quarterly Report: October, 2002 – December, 2002, Cooperative Agreement Award Number DE-FC-01NT41332

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

Howe, Steven J., 2004, Production modeling and economic evaluation of a potential gas hydrate pilot production program on the North Slope of Alaska, MS Thesis, University of Alaska Fairbanks, 141 p.

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

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

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

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

Hunter, R.B., et. al., 2004, Characterization of Alaska North Slope Gas Hydrate Resource Potential, Spring 2004 Fire in the Ice Newsletter, National Energy Technology Laboratory.

Jaiswal, Namit J., 2004, Measurement of gas-water relative permeabilities in hydrate systems, MS Thesis, University of Alaska Fairbanks, 100 p.

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

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

Lee, M.W., 2004, Elastic velocities of partially gas-saturated unconsolidated sediments, Marine and Petroleum Geology 21, p. 641–650.

Lee, M. W., 2005, Well-log analysis to assist the interpretation of 3-D seismic data at the Milne Point, North Slope of Alaska, U. S. Geological Survey Scientific Investigation Report SIR 2005-5048, 18 p.

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

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

Werner, M.R., 1987, Tertiary and Upper Cretaceous heavy-oil sands, Kuparuk River Unit area, Alaska North Slope, in Meyer, R.F., ed., Exploration for heavy crude oil and natural bitumen: American Association of Petroleum Geologists Studies in Geology 25, p. 537-547.

Westervelt, Jason V., 2004, Determination of methane hydrate stability zones in the Prudhoe Bay, Kuparuk River, and Milne Point units on the North Slope of Alaska, MS Thesis, University of Alaska Fairbanks, 85 p.

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

7.2 University of Arizona Research Publications and Presentations

7.2.1 Professional Presentations

a. Casavant, R.R., Hennes, A.M., Johnson, R., and T.S. Collett, 2004, Structural analysis of a proposed pull-apart basin: Implications for gas hydrate and associated free-gas emplacement, Milne Point Unit, Arctic Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 5 pp.
b. Hagbo, C. and R. Johnson, 2003, Delineation of gas hydrates, North Slope, Alaska, 2003 Univ. of Arizona Dept. Geosciences Annual GeoDaze Symposium
c. Hagbo, C., and Johnson, R. A., 2003, Use of seismic attributes in identifying and interpreting onshore gas-hydrate occurrences, North Slope, Alaska, Eos Trans. AGU, 84, Fall Meet.
d. Hennes, A., and R. Johnson, 2004, Structural character and constraints on a shallow, gas-hydrate-bearing reservoir as determined from 3-D seismic data, North Slope, Alaska, 2004 Univ. of Arizona Dept. Geosciences Annual GeoDaze Symposium.

7.2.2 Professional Posters

a. Poulton, M.M., Casavant, R.R., Glass, C.E., and B. Zhao, 2004, Model Testing of Methane Hydrate Formation on the North Slope of Alaska With Artificial Neural Networks, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 2 pp.
b. Geauner, S., Manuel, J., and R.R. Casavant, 2004, Well Log Normalization and Comparative Volumetric Analysis of Gas Hydrate and Free-Gas Resources, Central North Slope, Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 4 pp.
c. Gandler, G.L., Casavant, R.R., Johnson, R.A., Glass, K, and T.S.Collett, 2004, Preliminary Spatial Analysis of Faulting and Gas Hydrates-Free Gas Occurrence, Milne Point Unit, Arctic Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 3 pp.
d. Hennes, M., Johnson, R.A., and R.R. Casavant, 2004, Seismic Characterization of a Shallow Gas-Hydrate-Bearing Reservoir on the North Slope of Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 4 pp.
e. Hennes, A., and R. Johnson, 2004, Pushing the envelope of seismic data resolution: Characterizing a shallow gas-hydrate reservoir on the North Slope of Alaska, 2004 Univ. of Arizona Dept. Geosciences Annual GeoDaze Symposium.
f. Geauner, J.M., Manuel, J., And Casavant, R.R., 2003, Preliminary Subsurface Characterization And Modeling Of Gas Hydrate Resources, North Slope, Alaska, in: Student Abstract Volume, 2003 AAPG-SEG Student Expo, Houston, Texas.

7.2.3 Professional Publications

a. Poulton, M.M., Casavant, R.R., Glass, C.E., and B. Zhao, 2004, Model Testing of Methane Hydrate Formation on the North Slope of Alaska With Artificial Neural Networks, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 2 pp.
b. Geauner, S., Manuel, J., and R.R. Casavant, 2004, Well Log Normalization and Comparative Volumetric Analysis of Gas Hydrate and Free-Gas Resources, Central North Slope, Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 4 pp.
c. Gandler, G.L., Casavant, R.R., Johnson, R.A., Glass, K, And T.S.Collett, 2004, Preliminary Spatial Analysis Of Faulting And Gas Hydrates-Free Gas Occurrence, Milne Point Unit, Arctic Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential And Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 3 pp.
d. Hennes, M., Johnson, R.A., And R.R. Casavant, 2004, Seismic Characterization Of A Shallow Gas-Hydrate-Bearing Reservoirs On The North Slope Of Alaska, AAPG Hedberg Conference, Gas Hydrates: Energy Resource Potential And

Associated Geologic Hazards, September 12-16, 2004, Vancouver, BC, Canada, 4 pp.

e. Johnson, R. A., 2003, Shallow Natural-Gas Hydrates Beneath Permafrost: A Geophysical Challenge To Understand An Unconventional Energy Resource, News From Geosciences, Department Of Geosciences Newsletter, V. 8, No. 2, p. 4-6.
f. Hagbo, C., And Johnson, R. A., 2003, Use Of Seismic Attributes In Identifying And Interpreting Onshore Gas-Hydrate Occurrences, North Slope, Alaska, EOS Trans. AGU, 84, Fall Meet. Suppl., Abstract OS42B-06.
g. Geauner, J.M., Manuel, J., And Casavant, R.R., 2003, Preliminary Subsurface Characterization And Modeling Of Gas Hydrate Resources, North Slope, Alaska; in: Student Abstract Volume, 2003 AAPG-SEG Student Expo, Houston, Texas.
h. Hennes, A., and R. Johnson, 2004, Structural character and constraints on a shallow, gas-hydrate-bearing reservoir as determined from 3-D seismic data, North Slope, Alaska, 2004 Univ. of Arizona Dept. Geosciences Annual GeoDaze Symposium.
i. Hennes, A., and R. Johnson, 2004, Pushing the envelope of seismic data resolution: Characterizing a shallow gas-hydrate reservoir on the North Slope of Alaska, 2004 Univ. of Arizona Dept. Geosciences Annual GeoDaze Symposium.
j. Hagbo, C. and R. Johnson, 2003, Delineation of gas hydrates, North Slope, Alaska, 2003 Univ. of Arizona Dept. Geosciences Annual GeoDaze Symposium.
k. Geauner, J.M., Manuel, J., and Casavant, R.R., 2003, Preliminary subsurface characterization and modeling of gas hydrate resources, North Slope, Alaska; in: Student Abstract Volume, 2003 AAPG-SEG Student Expo, Houston, Texas.
l. Casavant, R. R., 2002, Tectonic geomorphic characterization of a transcurrent fault zone, Western Brooks Range, Alaska (linkage of shallow hydrocarbons with basement deformation), SPE-AAPG: Western Region-Pacific Section Joint Technical Conference Proceedings, Anchorage, Alaska, May 18-23, 2002, p. 68.

7.2.4 Sponsored Thesis Publications

a. Hennes, A.M., 2004, Structural Constraints on Gas-hydrate Formation and Distribution in the Milne Point, North Slope of Alaska, M.S. Thesis (Prepublication Manuscript), Dept. of Geosciences, University of Arizona, Tucson, 76 pp.
b. Hagbo, C.L., 2003, Characterization of Gas-hydrate Occurrences using 3D Seismic Data and Seismic Attributes, Milne Point, North Slope, Alaska, M.S. Thesis, Dept. of Geosciences, University of Alaska, Tucson, 127 pp.
c. Zhoa, Bo, 2003, Classifying Seismic Attributes in the Milne Point Unit, North Slope of Alaska, M.S. Thesis, Dept. of Mining and Geological Engineering, University of Arizona, Tucson, 159 pp.

7.2.5 Artificial Neural Network References

Bishop, C., 1995, Neural Networks for Pattern Recognition: Oxford Press.

Broomhead, D., and Lowe, D., 1988, Multivariable functional interpolation and adaptive networks: Complex Systems, 2, 321-355.

Casavant, R. R., 2001, Morphotectonic Investigation of the Arctic Alaska Terrane: Implications to Basement Architecture, Basin Evolution, Neotectonics and Natural Resource Management: Ph.D thesis, University of Arizona, 457 p.

Casavant, R., Hennes, A., Johnson, R., and Collett, T., 2004, Structural analysis of a proposed pull-apart basin: Implications for gas hydrate and associated free-gas emplacement, Milne Point Unit, Arctic Alaska: AAPG HEDBERG ONFERENCE, "Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards" September 12-16, 2004, Vancouver, BC, Canada.

Collett, T., Bird, K., Kvenvolden, K., and Magoon, L., 1988, Geologic interrelations relative to gas hydrates within the North Slope of Alaska: USGS Open File Report, 88-389.

Darken, C., and Moody, J., 1990, Fast adaptive K-means clustering: Some empirical results: IEEE INNS International Joint Conference on Neural Networks, 233-238.

Gandler, G., Casavant, R., Glass, C., Hennes, A., Hagbo, C., and Johnson, R., 2004, Preliminary Spatial Analysis of Faulting and Gas Hydrate Occurrence Milne Point Unit, Arctic Alaska: AAPG HEDBERG CONFERENCE, "Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards" September 12-16, 2004, Vancouver, BC, Canada.

Geauner, S., Manuel, J., Casavant, R., Glass, C., and Mallon, K., 2004,Well Log Normalization and Comparative Volumetric Analyses of Gas Hydrate and Free-gas Resources, Central North Slope, Alaska: AAPG HEDBERG CONFERENCE, "Gas Hydrates: Energy Resource Potential and Associated Geologic Hazards" September 12-16, 2004, Vancouver, BC, Canada.

Girosi, F. and Poggio, T., 1990, Networks and the best approximation property: Biological Cybernetics, 63, 169-176.

Glass, C. E. 2003, Estimating pore fluid concentrations using acoustic and electrical log attributes, Interim Report, UA Gas Hydrate Project.

Hagbo, C., 2003, Characterization of gas-hydrate occurrences using 3D seismic data and seismic attributes, Milne Point, North Slope, Alaska: MS Thesis, University of Arizona, Tucson, Arizona.

Hashin, Z and S. Shtrikman, 1963, A variational approach to the theory of the elastic behavior of multiphase materials, Journal of the Mechanics and Physics of Solids, Vol. 11, p. 127-140.

Haykin, S., 1994, Neural Networks. A Comprehensive Foundation: Macmillan.

Light,W., 1992, Some aspects of radial basis function approximation, in Singh, S., Ed., Approximation Theory, Spline Functions and Applications: NATO ASI series, 256, Kluwer Academic Publishers, 163-190.

Mavco, G., T. Mukerji and J. Dvorkin, 1988, The rock physics handbook, Cambridge University Press.

Moody, J., and Darken, C., 1989, Fast learning in networks of locally-tuned processing units: Neural Computation, 1, 281-294.

Musavi, M., Ahmed,W., Chan, K., Faris, K., and Hummels, D., 1992, On the training of radial basis function classifiers: Neural Networks, 5, 595-603.

Poggio, T. and Girosi, F., 1989, A theory of networks for approximation and learning: A.I. Memo No. 1140 (C.B.I.P . Paper No. 31), Massachusetts Institute of Technology, Artificial Intelligence Laboratory.

Poulton, M., 2002, Neural networks as an intelligence amplification tool: A review of applications: Geophysics, vol. 67, no. 3, pp. 979-993.

Poulton, M., (Ed.), 2001, Computational Neural Networks for Geophysical Data Processing: Pergamon, Amsterdam, 335p.

Powell, M., 1987, Radial basis functions for multivariable interpolation: A review, in Mason, J. and Cox, M., Eds., Algorithms for Approximation: Clarendon Press.

Zell, A., 1994, Simulation Neuronaler Netze: AddisonWesley.

Zhao, B., 2003, Classifying Seismic Attributes In The Milne Point Unit, North Slope of Alaska: MS Thesis, University of Arizona, Tucson, Arizona.

7.3 Gas Hydrate Phase Behavior and Relative Permeability References

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

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

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

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

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

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

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

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

Mehrad, N., 1989, “Measurement of gas permeability in hydrate saturated unconsolidated cores”, M.S thesis, University of Alaska Fairbanks.

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

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

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

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

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

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

Westervelt, J.V., 2004. "Determination of methane hydrate stability zones in the Prudhoe Bay, Kuparuk River, and Milne Point units on the North Slope of Alaska". MS Thesis, University of Alaska Fairbanks, Fairbanks, AK.

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

Winters, W.J., Dillon, W.P., Pecher, I.A. and Mason, D.H., 2000, “GHASTLI-Determining physical properties of sediment containing natural and laboratory formed gas hydrate” in Natural

Gas Hydrate in Oceanic and Permafrost Environments, edited by M.D. Max, pp 311-322, Kluwer, Dordrecht.

7.4 Drilling Fluid Evaluation and Formation Damage References

7.4.1.1 Formation Damage Prevention References, In-Review Publication

The following references were used in developing Section 5.7.3 of this report.

1. Collett, T.S.: "Well Log Characterization of Sediments in Gas-Hydrate-Bearing Reservoirs", SPE 49298, presented at SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 27-30, 1998.

2. Collett, T.S., Bird, K.J., Magoon, L.B.: "Subsurface Temperatures and Geothermal Gradients on the North Slope of Alaska", SPE 19024, Society of Petroleum Engineers, 1988.

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

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

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

6. Ginsburg, G., Soloviev, V., Matveeva, T., Andreeva, I.: "Sediment Grain Size Control on Gas Hydrate Presence, Sites 994, 995, and 997", Proceedings of the Ocean Drilling Program, Scientific Results, Leg 164, edited by C.K. Paul et al., chap. 24, Ocean Drilling Program, College Station, Texas, 2000.

7. Kamath, V.A., Patil, S.L.: "Description of Alaskan Gas Hydrate Resources and Current Technology", studies by University of Alaska Fairbanks, January 1994.

8. Kerkar, P.B.: "Assessment of Formation Damage from Drilling Fluids Dynamic Filtration in Gas Hydrate Reservoirs of the North Slope of Alaska", M.S. Thesis, University of Alaska Fairbanks, August 2005.

9. Marshall, D.S., Gray, R., Byrne, M.: "Development of a Recommended Practice for Formation Damage Testing", SPE 38154, presented at the SPE European Formation Damage Conference, Hague, Netherlands, June 2-3, 1997.

10. Matsumoto, R., "Comparison of Marine and Permafrost Gas Hydrates: Examples from Nankai Trough and Mackenzie Delta, Proceedings of the Fourth International Conference on Gas Hydrates, Yokohama, 19-23 May 2002a.

11. Murlidharan, V., Putra, E., Schechter, D.S.: "Investigating the Changes in Matrix and Fracture Properties and Fluid Flow under Different Stress-state Conditions", M.S. Thesis, Texas A & M University, 2002.

12. Shipboard Scientific Party: "Leg 204 Preliminary Report, Drilling Gas Hydrates on Hydrate Ridge, Cascadia Continental Margin", ODP Texas A & M University, December 2002, Available from World Wide Web: http://www-odp.tamu.edu/publications/prelim/204_prel/204PREL.PDF.

13. Winters, W.J., Dallimore, S.R., et al.: "Physical properties of sediments from the JAPEX/JNOC/GSC Mallik 2L-38 Gas Hydrate Research Well", in Geological Survey of Canada Bulletin 544: Scientific Results from JAPEX/JNOC/GSC Mallik 2L-38 Gas Hydrate Research Well, Mackenzie Delta, Northwest Territories, Canada, edited by Dallimore, S.R. et al. Geological Survey of Canada, Ottawa, 1999.

14. Yousif, M.H., Abass, H.H., Selim, M.S., Sloan, E.D.: "Experimental and Theoretical Investigation of Methane-Gas-Hydrate Dissociation in Porous Media"; SPE 18320, SPE Reservoir Engineering, February 1991.

7.4.1.2 Formation Damage Prevention References, General

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

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

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

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

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

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

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

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

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

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

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

Crowell, E.C., Bennion, D.B., Thomas, F.B., Bennion, D.W., 1992, “The Design & Use of Laboratory Tests to Reduce Formation Damage in Oil & Gas Reservoirs”; 13th Annual Conference of the Ontario Petroleum Institute.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Marshal, D.S., Gray, R., Byrne, M.; 1997, "Development of a Recommended Practice for Formation Damage Testing"; SPE 38154; Presented at the 1997 SPE European Formation Damage Conference; Netherlands, 2-3 June 1997.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

7.5 Coring Technology References

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

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

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

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

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

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

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

“Methane Hydrates: A US Department of Energy Website”. www.fossil.energy.gov

“Natural Gas Demand”. [www] www.naturalgas.org/business/demand.asp.

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

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

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

7.6 Reservoir and Economic Modeling References

Brown, G., Storer, D., and McAllister, K., 2003, Monitoring Horizontal Producers and Injectors during Cleanup and Production Using Fiber-Optic-Distributed Temperature Measurements, SPE 84379.

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

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

Stephen J Howe, 2004, Production modeling and economic evaluation of a potential gas hydrate pilot production program on the north slope of Alaska”, MS Thesis, University of Alaska Fairbanks, Fairbanks, AK.

Howe, S.J., Nanchary, N.R., Patil S.L., Ogbe D.O., Chukwu G.A., Hunter R.B and Wilson S.J., “Production Modeling and Economic Evaluation of a Potential Gas Hydrate Pilot Production Program on the North Slope of Alaska”, *Manuscript Under Preparation*.

Howe, S.J., Nanchary, N.R., Patil S.L., Ogbe D.O., Chukwu G.A., Hunter R.B and Wilson S.J., "Economic Analysis and Feasibility study of Gas Production from Alaska North Slope Gas Hydrate Resources", Submitted for Presentation at the AAPG Hedberg Conference in Vancouver in September 2004.

Jaiswal N.J presented on "Measurement of Relative Permeabilities for Gas-Hydrate Systems" and received third prize in International Thermal Operations and Heavy-Oil Symposium and SPE Regional Meeting Bakersfield, California, USA.

Jaiswal, N.J., Dandekar, A.Y., Patil, S.L. and Chukwu, G.C., "Measurement of Relative Permeability for Gas-Hydrate System", at 54th Arctic Science Conference, 23rd Sept-2003.

Jaiswal N.J., Westervelt J.V., Patil S.L., Dandekar A.Y., Nanchary, N.R., Tsunemori P and Hunter R.B., "Phase Behavior and Relative Permeability of Gas-Water-Hydrate System", Submitted for Presentation at the AAPG Hedberg Conference in Vancouver in September 2004.

McGuire, P.L., 1982, "Recovery of gas from hydrate deposits using conventional technology," SPE/DOE 10832, *Proc. Unconventional Natural Gas Recovery Symposium Pittsburgh PA*, pp. 373-387, Society of Petroleum Engineers, Richardson Texas.

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

Moridis, G. J., 2002, "Numerical Studies of Gas Production from Methane Hydrates". Paper SPE 75691, presented at the SPE Gas Technology Symposium, Calgary, Alberta, Canada, 30 April – 2 May 2002b.

Moridis, G.J. and Collett, T.S., 2004 in-press, "Gas Production from Class 1 Hydrate Accumulations".

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

Nanchary, N.R., Patil S.L., Dandekar A.Y., "Numerical Simulation of Gas Production from Hydrate Reservoirs by Depressurization", Journal of Petroleum Science & Engineering (Elseveier publication), *Under Review*.

Nanchary, N.R., Patil S.L., Dandekar A.Y and Hunter, R.B., "Numerical Modeling of Gas Hydrate Dissociation in Porous Media", Submitted for Presentation at the AAPG Hedberg Conference in Vancouver in September 2004.

Swinkles, W.J.A.M. and Drenth, R.J.J., 1999, "Thermal Reservoir Stimulation Model of Prediction from Naturally Occurring Gas Hydrate Accumulations", Society of Petroleum Engineers, SPE 56550, 13 p.

Tsunemori, Phillip, 2003, presented "Phase Behavior of Natural Gas from Gas Hydrates" and received first in International Thermal Operations and Heavy-Oil Symposium and SPE Regional Meeting Bakersfield, California, USA.

Tsypkin, G.G. 1992, Appearance of two moving phase transition boundaries in the dissociation of gas hydrates in strata. Dokl. Ross. Akad. Nauk. 323. 52-57 (in Russian).

Yousif, M., H., Abass H., H., Selim, M., S., Sloan E.D., 1991, Experimental and Theoretical Investigation of Methane-Gas-Hydrate Dissociation in Porous Media, SPE Res. Eng. 18320, pages 69-76.

Tsypkin, G.G. 1991, Effect of liquid phase mobility on gas hydrate dissociation in reservoirs. Izvestiya Akad. Nauk SSSR. Mekh. Zhidkosti i Gaza. 4: 105-114 (in Russian).
Westervelt J.V: MS Thesis: "Determination of methane hydrate stability zones in the Prudhoe Bay, Kuparuk River, and Milne Point units on the North Slope of Alaska".

7.7 Short Courses

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

8.0 LIST OF ACRONYMS AND ABBREVIATIONS

Acronym	Denotation
2D	Two Dimensional (seismic or reservoir data)
3D	Three Dimensional (seismic or reservoir data)
AAPG	American Association of Petroleum Geologists
AAT	Alaska Arctic Terrane (plate tectonics)
AETDL	Alaska Energy Technology Development Laboratory
ADEC	Alaska Department of Environmental Conservation
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
BGHSZ	Base of Gas Hydrate Stability Zone
BIBPF	Base of Ice-Bearing Permafrost
BLM	U.S. Bureau of Land Management
BMSL	Base Mean Sea Level
BP	BP or BPXA
BPXA	BP Exploration (Alaska), Inc.
CMR	Combinable Magnetic Resonance log (wireline logging tool – see also NMR)
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)
FG	Free Gas (commonly referenced in association with and below gas hydrate)
GEOS	UA Department of Geology and Geophysics
GH	Gas Hydrate
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
LDD	Generic term referencing Logging During Drilling (also LWD and MWD)
LNG	Liquefied Natural Gas
MGE	UA Department of Mining and Geological Engineering
MPU	Milne Point Unit
MSFL	Micro-spherically focused log (wireline log indication of formation permeability)
NETL	National Energy Technology Laboratory
NMR	Natural Magnetic Resonance (wireline or LDD tool – see also CMR)
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
T-D	Time-Depth (referencing time to depth conversion of seismic data)
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
Vp	Velocity of primary seismic wave component
Vs	Velocity of shear seismic wave component (commonly useful to identify GH) (also component in Di-pole sonic logging tool)
VSP	Vertical Seismic Profile
WOO	Well-of-Opportunity

9.0 APPENDICES

9.1 APPENDIX A: Project Task Schedules and Milestones

9.1.1 U.S. Department of Energy Milestone Log, Phase 1, 2002-2004 (SOW in Amendments 1-8)

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 – 12/06	12/02 and Ongoing	Subcontracts Completed Research Management
Task 2.0	Provide Technical Data and Expertise	MPU: 12/02 PBU: * KRU: *	MPU: 12/02 PBU: * KRU: *	Ongoing, See Technical Progress Report
Task 3.0	Wells of Opportunity Data Acquisition	Ongoing	Ongoing	Ongoing, See Technical Progress Report
Task 4.0	Research Collaboration Link	Ongoing	Ongoing	Ongoing, See Technical Progress Report
Subtask 4.1	Research Continuity	Ongoing	Ongoing	
Task 5.0	Logging and Seismic Technology Advances	Ongoing		Ongoing, See Technical Progress Report
Task 6.0	Reservoir and Fluids Characterization Study	12/06	Ongoing to Phases 2 and 3	Interim Results presented, 2004 Hedberg Conference
Subtask 6.1	Characterization and Visualization	12/06	Ongoing to Phases 2 and 3	Interim Results presented, 2004 Hedberg Conference
Subtask 6.2	Seismic Attributes and Calibration	12/06	Ongoing to Phases 2 and 3	Interim Results presented, 2004 Hedberg Conference
Subtask 6.3	Petrophysics and Artificial Neural Net	12/06	Ongoing to Phases 2 and 3	Interim Results presented, 2004 Hedberg Conference
Task 7.0	Laboratory Studies for Drilling, Completion, Production Support	6/04	6/04	
Subtask 7.1	Characterize Gas Hydrate Equilibrium	6/04	6/04	Results presented, 2004 Hedberg Conference
Subtask 7.2	Measure Gas-Water Relative Permeabilities	6/04	6/04	Results presented, 2004 Hedberg Conference
Task 8.0	Evaluate Drilling Fluids	12/04		
Subtask 8.1	Design Mud System	11/03		
Subtask 8.2	Assess Formation Damage	9/05	Into Phase 2	

Task 9.0	Design Cement Program	12/04		
Task 10.0	Study Coring Technology	2/04	2/04	
Task 11.0	Reservoir Modeling	12/06	Ongoing task	Interim Results presented, 2004 Hedberg Conference
Task 12.0	Select Drilling Location and Candidate	9/05		Topical Report submitted, June 2005
Task 13.0	Project Commerciality & Phase 2 Progression Assessment	9/05	Redesigned 2005 Phase 2	BPXA and DOE decision

* Date dependent upon industry partner agreement for seismic data release

9.1.2 U.S. Department of Energy Milestone Log, Phase 2, 2006 (SOW in Amendment 9)

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	1/05 – 1/06	Ongoing	Subcontracts Completed Research Management
Task 2.0	Provide Technical Data and Expertise	MPU: 12/02 PBU: * KRU: *	MPU: 12/02 PBU: * KRU: *	Ongoing, See Technical Progress Report; Industry Support more feasible?
Task 3.0	Wells of Opportunity Data Acquisition	Ongoing	Ongoing	Ongoing, See Technical Progress Report
Task 4.0	Research Collaboration Link	Ongoing	Ongoing	Ongoing, See Technical Progress Report
Subtask 4.1	Research Continuity	Ongoing	Ongoing	
Task 5.0	Logging and Seismic Technology Development and Advances	Ongoing		Ongoing, See Technical Progress/Topical reports
Task 6.0	Reservoir and Fluids Characterization Study	12/06	Ongoing into Phases 2 and 3	
Subtask 6.1	Structural Characterization	12/06	Ongoing into Phases 2 and 3	
Subtask 6.2	Resource Visualization	12/06	Ongoing into Phases 2 and 3	
Subtask 6.3	Stratigraphic Reservoir Model	12/06	Ongoing into Phases 2 and 3	
Task 7.0	Laboratory Studies for Drilling, Completion, Production Support	12/06		Some Hiatus; Phase 2-3a design, studies, & decision
Subtask 7.1	Design Mud System	12/05		
Subtask 7.2	Assess Formation Damage	1/06		
Subtask 7.3	Measure Petrophysical and Other Physical Properties	9/06	Phase 3a	No Samples Acquired; await Phase 3a acquisition

Task 8.0	Design Completion / Production Test for Gas Hydrate Well	4/06	Mt Elbert-01 strat test only	Design of Phase 3a Strat Test operation Complete
Task 9.0	Field Operations and Data Acquisition Program Planning	4/06	Mt Elbert-01 strat test only	Planning for Potential operations underway
Task 10.0	Reservoir Modeling and Project Commercial Evaluation	1/06		Regional Resource Review & Development Planning
Subtask 10.1	Task 5-6 Reservoir models	Ongoing		
Subtask 10.2	Hydrate Production Feasibility	1/06		
Subtask 10.3	Project Commerciality & Phase 3a Progression Assessment	1/06		January 2006 approval for Phase 3a Stratigraphic Test

* Date dependent upon industry partner agreement for seismic data release

9.1.3 U.S. Department of Energy Milestone Log, Phase 3a, 2006-2007 (SOW in Amendment 11)

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	1/06 – 12/06	Ongoing*	Subcontracts Completed Research Management
Task 2.0	Provide Technical Data and Expertise	MPU: 12/02 PBU: ** KRU: **	MPU: 12/02 PBU: ** KRU: **	Ongoing, See Technical Progress Report; Industry Support more feasible?
Task 3.0	Wells of Opportunity Data Acquisition	Ongoing	As-identified	Ongoing, See Technical Progress Report
Task 4.0	Research Collaboration Link	Ongoing	Ongoing*	Ongoing, See Technical Progress Report
Subtask 4.1	Research Continuity	Ongoing	Ongoing*	
Task 5.0	Logging and Seismic Technology Development and Advances	Ongoing*	As-needed	Ongoing, See Technical Progress/Topical reports
Task 6.0	Reservoir and Fluids Characterization Study	12/06		Evaluating extension into 2007 for defined scope
Subtask 6.1	Structural Characterization	12/06		Current contract to 12/06
Subtask 6.2	Resource Visualization	12/06		
Subtask 6.3	Stratigraphic Reservoir Model	12/06		
Task 7.0	Laboratory Studies for Drilling, Completion, Production Support	12/06		Evaluating extension into 2007 for defined scope
Subtask 7.1	Design Mud System	9/07*		Current contract to 12/06
Subtask 7.2	Assess Formation Damage	9/07*		
Subtask 7.3	Measure Petrophysical and Other Physical Properties	9/07*		

Task 8.0	Implement completion/production Test for gas hydrate well	3/07*		Stratigraphic Test on 2007 Drilling Schedule
Task 9.0	Reservoir Modeling and Project Commercial Evaluation	12/07*	Ongoing	Regional Resource Review & Development Planning
Subtask 9.1	Task 5-6 Reservoir models	12/07*	As-needed	
Subtask 9.2	Project Commerciality & Phase 3b Production Test Decision	12/07*	Early decision possible	Phase 3a Stratigraphic Test to mitigate uncertainties

* Date dependent upon project continuation beyond December 2006 (Amendments 12^{+})
** Date dependent upon industry partner agreement for seismic data release

9.1.4 U.S. Department of Energy Milestone Plans

(DOE F4600.3)

DOE F 4600.3#

U.S. DEPARTMENT OF ENERGY FEDERAL ASSISTANCE MILESTONE PLAN: PHASE 1

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-D	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
Task 11.0	Reservoir Modeling	>>>>------------------------>>>>>>>>>----------------->>>>>>>>>>>>>>>>>>>>>>>!>>>	UAF, RyderScott
Task 12.0	Drilling Candidate Selection	>>>------ ----->>>>>>------->>>>>>>>>>>>---->>>>>>>>>>>>>!	BPXA, UA, USGS, RyderScott
Task 13.0	Commerciality Assessment	>>>>>>------------------------------->>>>>>>>--------------->>>>>>>----->>>>>>>>>>	BPXA, UAF, Ryder Scott

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 12/04.
Explanation of Symbols: (> = Major Task Work); (- = Minor Task Work); (! = Milestones).
Additional significant milestones presented in Quarterly Technical Progress Reports.

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

DOE F 4600.3#

U.S. DEPARTMENT OF ENERGY FEDERAL ASSISTANCE MILESTONE PLAN: PHASE 2-3a (2005-2006)

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 12/31/07 (through Phase 3a)

6. Identification Task Number	7. Planning Category (Work Breakdown Structure Tasks)	8. Program/Project Duration (Currently illustrates Phases 2-3, 2005 - 2006) ← Planning/Analysis → ← DECISION---→ ←Planning--------→← IMPLEMENTATION …delayed to 2007→ J F M A M J J A S O N D J F M A M J J A S O N D	9. Comments (Primary work Performer)
Task 1.0	Contracts and Research Management Planning	>>>>>>>!>>>--->>>>>>!-->>>>>>>>>>>>>>>>>>!---------------------->>---->>-->>>>>>>	BPXA, AES
Task 2.0	Technical Data and Expertise	-->>>>>>----->>>>--!---->>>>>>>>>-------!--->>>>>>>>>-------->>>>>>>>-->>>>>>>>--	BPXA, AES
Task 3.0	Wells of Opportunity - Data	------------->>>>>-!------------>>>>>---!----->>>>>>>>>>>>>>>------------>>>>>>>>	BPXA, AES
Task 4.0	Research Collaboration Link	---------->>>>>>>>>!---------->>>>>>>>>>!>>	BPXA, USGS, AES, UAF,UA
Task 5.0	Logging/Seismic Technology	>>>>>>>>>>>>>>>>>>>>!>>>>>>>>>>>>>>>>>>>>!>>>>>>>>>-------------------------->>	USGS, BPXA
Task 6.0	Characterize Reservoir/Fluid	------->>>>>>>>>>>>>!---------->>>>>>>>>>!>>>>>>>>>>>>>>>>---------->>>>>>>>>>>>>>	UA, USGS
Task 7.0**	Lab Studies: Drilling, Completion, Production	------------>>>>>>>!---------->>>>>>>>>>!>>>>>>>------------------->----->>>>>>>>>	UAF
Task 8.0**	Stratigraphic Test Decision, Design, and Implementation	-->>>>>>>>>>>>!>>>----->>>>>>>>>>>>!>>>>>>>------------------------->>>>>>>>>>>	APA, BPXA, AES, UAF
Task 9.0**	Field Operations Planning and Implementation	---->>>>>>>>>>!>>>------->>>>>>>>>>!>>>>>>>------------------------->>>>>>>>>>>	APA, BPXA, AES, UAF
Task 10.0**	Reservoir Modeling and Commercial Evaluation	----->>>>>>>>>>>>>>>!>>>>>>>>>>>>>>>>>---!--	RS, AES, BPXA, UAF

10. Remarks * Schedule shows Phases 2-3a from 2005 through end-2006. Phase 2 project from 1/05 through 12/05. Phase 3a stratigraphic test initiated 6/05 and included 9/05 Continuation Application culminating in 1/06 decision to Drill. . Explanation of Symbols: >> Major Task Work; -- Minor Task Work; ! Milestone. Significant technical work and milestones presented in Technical Progress and Topical Reports. **Note new (Phase 2-3a) Task numbers.

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

DOE F 4600.3#

U.S. DEPARTMENT OF ENERGY FEDERAL ASSISTANCE MILESTONE PLAN: PHASE 3a and 3b

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 Task Number	7. Planning Category (Work Breakdown Structure Tasks)	8. Program/Project Duration (Currently illustrates Phases 3a-3b, 2007-2008 projection) ←Phase 3a Strat Test→ ←3b DECISION→←3b Planning→←POTENTIAL PHASE 3b IMPLEMENTATION→ J F M A M J J A S O N D J F M A M J J A S O N D	9. Comments (Primary work Performer)
Task 1.0	Contracts and Research Management Planning	!>>>>>>!>>>--->>>>>!-->>>>>>>>>>!>>>>>>>>---------------------------->>!>>>>>>>>	BPXA, AES
Task 2.0	Technical Data and Expertise	!->>>>>>----->>>>--!---->>>>>>>>!----------->>>>>>>>-------->>>>>>>>-->!>>>>>>--	BPXA, AES
Task 3.0	Wells of Opportunity - Data	!------------>>>>>-!------------!>>>>--------->>>>>>>>>>>>>>>----------!>>>>>>>>	BPXA, AES
Task 4.0	Research Collaboration Link	!>>>>>>>>>>>>>>>>>>!---------->>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>!>>>>>>>>	BPXA, USGS, AES, UAF,UA
Task 5.0	Logging/Seismic Technology	!>>>>>>>>>>>>>>>>>>!>>>>>>>>>>>>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>!>>>>>>>>	USGS, BPXA
Task 6.0	Characterize Reservoir/Fluid	!------>>>>>>>>>>>>!---------->>!>>>>>>>>>>>>>>>>>>>>>>>---------->>>>>!>>>>>>>>	UA, USGS
Task 7.0	Lab Studies: Drilling, Completion, Production	!----------->>>>>>>!---------->>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>!>>>>>>>>	UAF
Task 8.0	Implement 2007 Strat Test Evaluate/Design Production Test & Phase 3b progression	! -->>>>>>>>>>>!>>>----->>>>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>!>>>>>>>>	APA, BPXA, AES, UAF
Task 9.0	Reservoir Modeling and Commercial Evaluation	!---->>>>>>>>>>>>>>!>>>>>>>>>>>>!>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>>!>>>>>>>>	RS, AES, BPXA, UAF

10. Remarks * Schedule shows Phases 3a-3b (3b not approved-indicated in red) from 2007 projected through end-2008. Phase 3a stratigraphic test deferred until early 2007 by 3rd party rig delay. Explanation of Symbols: >> Major Task Work; -- Minor Task Work; ! Milestone. Significant technical work and milestones presented in Technical Progress and Topical Reports.

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

9.2 APPENDIX B: Plan and Implement Stratigraphic Test Well

9.2.1 APPENDIX B1: 2005-06 Ice-Season Plan of Operations, MPU Mt Elbert-01

The Milne Point Unit **Draft** Plan of Operations for the Gas Hydrate Stratigraphic Test Project for the **proposed 2006 winter exploration program** are shown in this section.

9.2.1.1 LIST OF FIGURES

9.2.1.2 INTRODUCTION

BP Exploration (Alaska) Inc. (BPXA) and the U.S. Department of Energy (DOE) plan a Gas Hydrate Stratigraphic Test Project in the Milne Point Unit (MPU) of the North Slope of Alaska (see Figure 1) as part of a jointly supported collaborative gas hydrate research project.

BPXA has prepared this Plan of Operations (herein "Plan") to support applications to drill one stratigraphic test well, Mt. Elbert-01, approximately one half mile east of MPU E-Pad (figures 1, 2, and 3). The well will be drilled in the northern portion of the Eileen gas hydrate trend at the Mt. Elbert gas hydrate prospect from an ice pad just south of a large unnamed lake. The surface owner at this location is the State of Alaska and BPXA has valid rights to drill at this site under lease number ADL 255231. BPXA will operate the well based on BPXA's extensive North Slope experience and because BPXA is the Unit Operator. BPXA will retain a working interest in the prospect after the well is drilled.

The following Plan describes all activities necessary to drill this stratigraphic test well, including ice road and pad construction, drilling activities, data acquisition, camp/waste management, plugging and abandonment and site cleanup.

9.2.1.2.1 Project Summary

BPXA is undertaking these operations as part of the BPXA-U.S. Department of Energy (DOE) gas hydrate Cooperative Research project. Operations are planned within the Mt Elbert Prospect within the MPU on the North Slope to help determine if gas hydrate could become an economically recoverable gas resource. If proven capable of production at economically viable rates, methane hydrate gas within existing infrastructure areas could supplement export gas, fuel-gas, and /or lean-gas for reservoir energy pressure support, and/or help sustain long-term production of portions of the geographically-coincident 20-25 billion barrels viscous oil resource.

As shown on the maps (figures 1, 3, and 3), BPXA is currently proposing to build an ice road and ice pad for the drill site to enable acquisition of data within a vertical well. The drill site area is accessible by existing gravel roads with an ice road spur constructed from MPU B-Pad to access the ice pad drill site.

The ice road and pad specifications are shown in Figure 3 and 4 and discussed in Section 8.2.1.4. Limited ancillary facilities are planned. A temporary mobile camp for project personnel will be located on MPU B-Pad. Temporary storage facilities for fuel and drilling waste will be located at MPU CFP. Ice road and pad site preparation is expected to begin mid-February 2006.

Drilling activities are described in Section 8.2.1.5. Drilling of the well is expected to begin in mid to late March 2006. If warranted, a temperature thermocouple sensor may be cemented onto the outer casing for future temperature data readings using smart well completion technology.

BPXA is requesting that permits extend at a minimum through May 15, 2006 as a contingency to complete well drilling and site cleanup, as needed. If permitting approvals or drilling rig are not obtained prior to end of the winter 2005-2006 season, the project may be reinitiated in winter 2006-2007.

General operations, including a preliminary schedule are provided in Section 8.2.1.5; local and community issues and site access are discussed in Section 8.2.1.6; and plugging and abandonment (P&A) and regulatory requirements are outlined in Section 8.2.1.7.

9.2.1.3 DRILL SITE LOCATION

The ice pad is located onshore on State lands approximately one half mile east of MPU E-Pad, in the MPU North Slope Borough (NSB) Resource Development District. The ice road and pad will be constructed on frozen tundra to mitigate potential impacts to wetlands. The exact position of the surface drilling location may shift in response to newly acquired data, stream determinations, or to accommodate configuration constraints of equipment, but will remain within the general drilling area as shown in Figure 2 and 3. The bottom hole depth may slightly vary, depending upon ongoing geological and geophysical evaluations, but is expected to be less than 4,000 feet true vertical depth sub-sea. A legal description of proposed site operations follows.

Drill Site: 967' FWL, 1232' FNL, Section 30, T13N, R11E, Umiat Meridian

Bottom hole: BPXA plans to drill a vertical hole to optimize data acquisition. Specific bottomhole location has been submitted for approval in the Permit to Drill issued by the Alaska Oil and Gas Conservation Commission (AOGCC) and for an exemption of hydrocarbon spill potential to be submitted to the Alaska Department of Environmental Conservation (ADEC).

9.2.1.4 ICE ROAD AND ICE PAD CONSTRUCTION

Water and ice aggregate for ice road and pad construction and maintenance, rig operations, camp and maintenance use will be obtained from permitted sources within the area (Figure 6). Water will be obtained from permitted sources. Withdrawal rates and quantities will be in accordance with permit stipulations.

Ice construction methods of spraying and flooding will be employed. Ice chips may be obtained from permitted sources, including shallow lake ledges that are frozen to the ground, or from lakes frozen to the ground.

Water withdrawal pumping velocities and screening techniques will be in accordance with Alaska Department of Natural Resources/Office of Habitat Management and Permitting requirements, and compliance with these requirements will be included in the contract between the ice road/pad contractor and BPXA.

9.2.1.4.1 Ice Road Construction

The planned ice road to the ice pad will be a spur from MPU B-Pad to the drill site location. Specifications on ice road construction are presented in Figure 4. All new ice road sections will be of sufficient depth (6 to 12 inch) and width (50 feet) to provide adequate surface protection and allow safe transport of personnel, equipment, and supplies to the drill site.

9.2.1.4.2 Ice Pad Construction

Proposed ice pad dimensions will be 400 ft. by 400 ft. and occupy an area of approximately 3.7 acres (Figure 5). The pad will be constructed by applying successive layers of water and ice aggregate over an initial snow base until it reaches the desired thickness (minimum thickness of 6 inches). A working surface of timbers and matting boards will be placed on the ice pad to support the rig structure, and an impermeable plastic membrane will be placed in the well cellar area.

Clean equipment (such as drill pipe) may be stored on the tundra adjacent to the ice pad. There will be no storage of dry or liquid chemicals or fluids on lakes. Only non-hazardous materials will be stored off the pad. Maintenance activities for the ice pad and water source ice roads include plowing, and resurfacing and re-grading with water as needed. The ice structures will thaw during breakup. Security markers and remnant debris will be collected for disposal prior to summer compliance inspection.

9.2.1.5 GENERAL OPERATIONS

BPXA will act as operator of the drilling program and will be responsible for all surface and subsurface activities. General operations at the site are described below.

9.2.1.5.1 Proposed Schedule

Following is a proposed schedule of planned activities:

Permitting	January – March, 2006
Site Surveying & Preparation	February 25 – February 27, 2006
Ice Construction	February 28 – March 9, 2006
Chiller & Rig Mobilization	March 10 – March 21, 2006
Drilling and Data Acquisition	March 22 – April 20, 2006
Rig Down	April 21– April 29, 2006
Site Closure and Cleanup	April 30 – May 15, 2006
Site Inspection	July – August, 2006

9.2.1.5.2 Work Force

Approximately 30 people will be involved in this project onsite. Most labor will be housed in a mobile camp located at MPU B-Pad. As an option for some portions of the program, personnel could be housed in existing Prudhoe Bay or Milne Point area facilities and drive to the site on a daily basis. The MPU CFP will provide food service for the drilling camp personnel and be responsible for food quality and proper storage. All food and food wastes will be stored at MPU CFP to prevent wildlife attraction.

A small support camp facility may remain onsite to support possible data acquisition activities following rig release.

During construction activities, workers will be housed off-site and commute to the ice pad drill site on a daily basis. During drilling, trailers may be provided for critical personnel (e.g., Drilling Supervisors) who monitor the operation 24 hours a day and for support of acquisition of subsurface core sample operations, processing, and analyses.

9.2.1.5.3 Operations Water Supply

Estimated water use requirements for the project are summarized in the table below:

Activity	Total Gallons
Site Preparation and Construction	
Ice Road Spurs to Water Sources, approximately ¼ mile, 40' wide	200,000
Ice Road Spurs to Ice Pad, approximately 1-½ mile, 50' wide	1,100,000
Ice Pad: 400' x 400'	2,000,000
Operations and Maintenance	
Rig drilling use: 20,000 gpd/rig for 20 days	400,000
Mobile camp use: 30 people @100 gpd/person for 45 day	135,000
Ice pad, and ice spur road maintenance (if needed)	100,000
TOTAL PROGRAM	**3,935,000**

Figure 6 also illustrates area water sources. BPXA intends to control water usage to minimize storage, hauling and disposal requirements. Drinking water will be treated and stored in sanitary tanks for human use at MPU Pad facilities. Water used for rig and cuttings wash will be recycled into the drilling mud to the extent practicable.

9.2.1.5.4 Drilling and Data Acquisition Operations

Facility layouts will be similar to previous North Slope winter ice pad programs (see Figure 5). The layout is based on preliminary rig selection for this program, and will be altered as needed. The ice pad will be sized to house the rig, ancillary equipment, data acquisition activities, mud chiller equipment, and the temporary storage area for drill cuttings. When operations are completed, the rig will be transported out of the project area and areas of operation will be inspected and cleaned as necessary.

BPXA plans to contract with Akita/Doyon for the use of the Arctic Fox #1 for this project. Mobilization of the rig to the drill site is expected to occur in mid March 2006. Drilling operations are expected to take between 15 and 20 days but could run longer. Liquid fuel (e.g., diesel) and chemicals (e.g., drill mud additives) necessary to support drilling operations will be stored in lined containment areas and handled in accordance with BPXA's Best Management Practices (BMPs). Well control will be handled according to commonly accepted, safe oilfield practices utilizing a diverter, blowout preventer, and other resources as necessary. Based on offset well control, no oil-bearing zones are anticipated to be penetrated in the operations. Upon final demobilization of the rig, all support equipment will be removed from the temporary ice pad location.

The test is exploratory in nature and any required well work will be accomplished using approved industry techniques and procedures in accordance with sound engineering. Fluids produced from operations would be stored in portable tanks for not more than a few days, and then trucked from the location by approved carrier for use or disposal, as appropriate.

9.2.1.5.5 Fuel Storage

Fuel transportation, storage, and use will be in accordance with North Slope Borough, Alaska Department of Natural Resources (ADNR), and Alaska Department of Environmental Conservation requirements. Fuel storage will be located in the drilling rig (approximate 8,500 gallons in secondary containment), at the MPU CFP and MPU B-Pad facilities, and at water source pumps.

Secondary containment for all drill site fuel storage tanks will be a minimum of 110 percent of the single largest tank or any group of tanks permanently manifolded together. Fuel flow diagrams, fuel transfer procedures, valving details, and safety precautions for the drilling rig are listed in the drilling contractor's Spill Prevention, Control, and Countermeasures (SPCC) Plan.

Fuel will not be stored on lakes or river ice. However, small day tanks (approximately 100 gallons) must be sited at pumps located at water sources and refilled at those locations periodically.

Fuel supplies will be brought to the area by a fuel truck. Fuel trucks will travel to the drill site via existing gravel roads and the site ice road.

9.2.1.5.6 Waste Disposal

Drilling and non-drilling wastes will be managed as described below.

9.2.1.5.6.1 Drilling Wastes

All drilling waste storage will be temporary. There will be no surface disposal of the wastes on site. Drill cuttings will be trucked to the PBU Drill Site 4 (DS-4) Grind and Inject facility or other approved facility. Waste drilling fluids will be trucked for injection to PBU DS-4 or other approved facility. There will be no storage of drilling waste on site; a container truck will be available on the ice pad for placement of wastes prior to transportation to the PBU DS-4 facility for disposal. Any oil-based products in use will be recycled back to the rig or packaged in drums and hauled to Prudhoe Bay for shipment to an approved recycle facility.

9.2.1.5.6.2 Non-drilling wastes

All waste disposal procedures will conform to local, state and federal requirements. The general waste management plan is to temporarily store wastes and periodically haul waste materials back to existing North Slope facilities for proper treatment and disposal.

Combustible and non-combustible wastes from the drill rig and rig camp will be bagged and trucked to the North Slope Borough waste disposal facility on a regular basis.

Sanitary and domestic wastewater will be trucked to BPXA's Base Operations Center (BOC) waste disposal facility or other approved facilities. However, sanitary and domestic wastewater could be discharged in accordance with NPDES Permit No. AKG-33-0000.

Storm water discharges are covered under NPDES Permit No. AKG-33-0061 and are subject to the permit and SWPPP conditions.

9.2.1.5.7 Air Emissions

BPXA will not require an individual Air Quality Construction Permit from ADEC. Drilling operations will be covered under Air Quality Control Minor Permit No. AQ0977MSS01 or other minor permit. The drilling contractor will operate combustion equipment in accordance with all air quality regulations. If required, BPXA will place bilingual signs on the tundra and the road leading to the drill pad or on the pad, which establish public access safety zone(s). It is expected that no off-pad safety zone will be required for compliance with air quality standards.

9.2.1.5.8 Oil Discharge Prevention and Contingency Plan

The proposed Mt. Elbert-01 well is a stratigraphic test well that will be drilled in non-oil-bearing zones. A statement from the AOGCC has been requested and will be submitted to the ADEC for an Oil Discharge Prevention and Contingency Plan (ODPCP) exemption. If the exemption is not received, the well will be covered by an amendment to the MPU ODPCP and if required, will obtain approval by the Alaska Department of Environmental Conservation (ADEC). Personnel will be briefed on procedures for fuel transfer and storage, oil spill reporting requirements, spill prevention, and the requirements of the ODPCP. The BMPs are contained in the ODPCP.

A discharge of oil or diesel during the winter would result in contamination of snow and ice. Response to such a spill would include the deployment of mechanical and manual means to recover the hydrocarbon release. The ODPCP contains additional information on spill response scenarios.

9.2.1.5.9 Environmental and Safety Training

All BPXA and contractor project personnel will receive Health, Safety, and Environmental and North Slope orientation (NSTC training). Training components may include permit requirements and conditions, cultural awareness, spill prevention and reporting, wildlife interaction, site safety, etc. Additionally, all personnel will participate in a specific training program for polar bear awareness and safety. The polar bear component consists of a video on polar bear safety and a briefing on the Polar Bear Interaction Plan.

9.2.1.5.10 Wildlife

Winter operations should have no detrimental effects on local wildlife. Wildlife that may be expected in the area during winter months include caribou, arctic foxes, snowy owls, over wintering fish if they are present in permitted water sources, and ravens.

As part of the environmental training program, all personnel will be instructed not to disturb or feed wildlife. Operations will be conducted in accordance with the BPXA Polar Bear Interaction Plan, which details site layout, snow management, garbage control, waste management, material storage, lighting, and personnel control. The interaction plan is designed to minimize the potential for human-bear interactions through site and personnel management.

9.2.1.5.11 Communications

A satellite link and cellular phones will be used for communication. A BPXA representative will be on site-at all times during drilling and data acquisition operations. Designated contacts are:

Name	Title	Company	Office (907)	Cell (907)
Mike E. Miller	Drilling Manager	BPXA	(removed for this report)	
Scott A. Digert	MPU Project Manager	BPXA	(removed for this report)	
Robert Hunter	Gas Hydrate Project Lead	ASRC Energy	(removed for this report)	
BPXA 24-hour Security Switchboard		(removed for this report)		
MPU Front Desk		(removed for this report)		

9.2.1.6 LOCAL AND COMMUNITY ISSUES

9.2.1.6.1 Subsistence

BPXA will conduct exploration in a manner that prevents unreasonable conflicts between exploration and subsistence activities. A key measure in BPXA's approach to reducing possible subsistence effects is the overall approach taken to minimize effects on tundra, lakes, and fish, bird, and wildlife populations.

9.2.1.6.2 Site Access

For proprietary and safety reasons, access to the rig or rig facilities will be restricted to authorized persons and regulatory personnel only. Authorized regulatory personnel carrying photo identification may access the pad at any time. They must contact the on-site drilling supervisor if they wish access to rig facilities and they must comply with all applicable safety regulations and policies. All other personnel must obtain authorization from the BPXA Drilling Department at BPXA's Anchorage office, located at 900 East Benson Boulevard. The telephone contact for BPXA's Drilling Superintendent is (907) 564-(removed for this report). BPXA will not deny access or assistance to hunters or travelers in distress

9.2.1.7 WELL ABANDONMENT AND SITE RESTORATION

Upon completion of drilling and data acquisition operations, the well will be plugged and abandoned in compliance with relevant State of Alaska regulations. A thermocouple encased in a stainless steel tube may be cemented onto the outer well casing to provide additional future data measurement of the gas hydrate zone. The thermocouple would remain below grade level and future data readings would need to be accessed by helicopter or approved off road vehicle.

Ice pads will be cleared of equipment and ice surfaces cleaned. All equipment and supplies will be removed and the location will be cleaned of any debris. Ice structures will thaw during breakup.

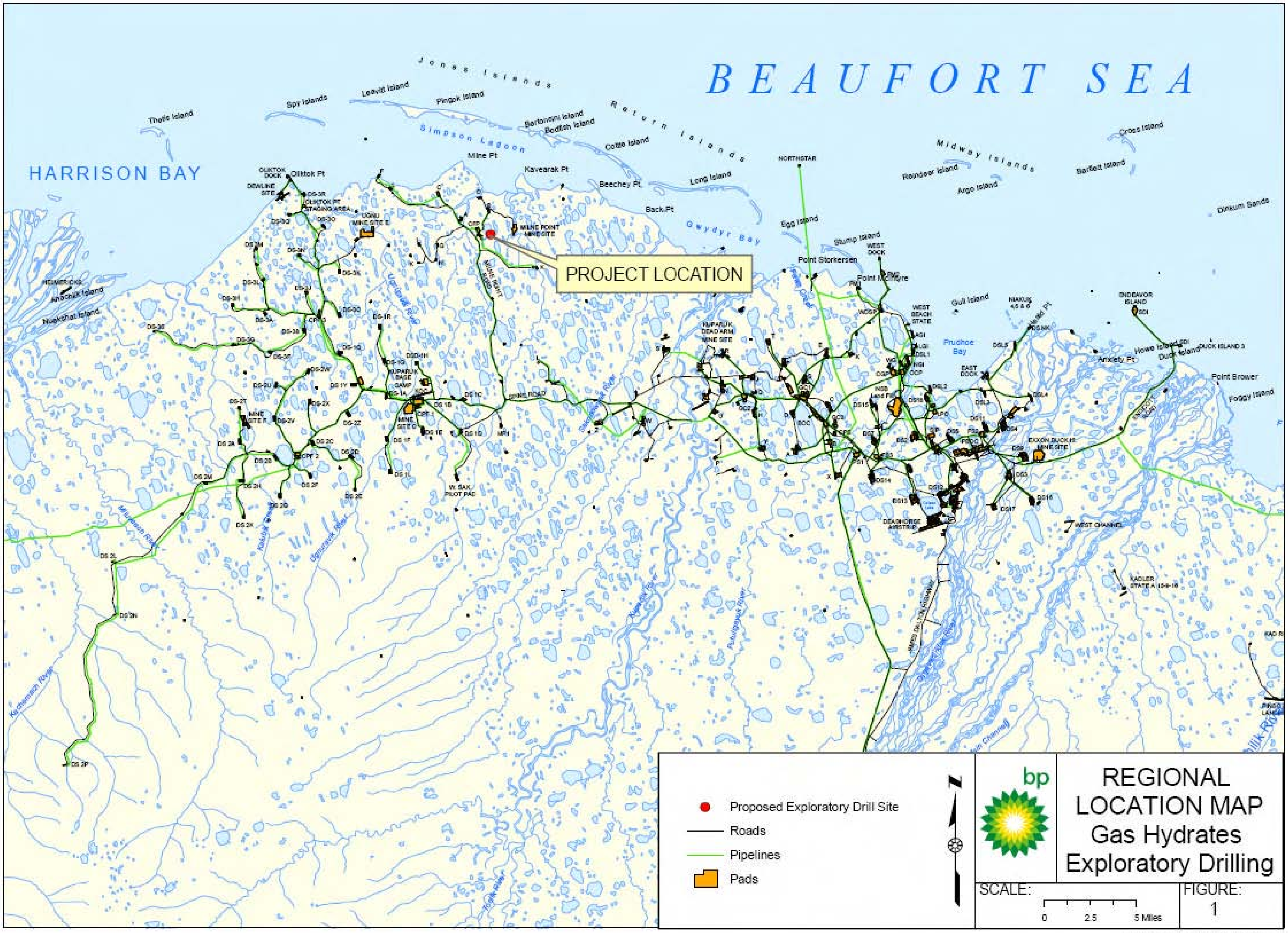
9.2.1.8 REGULATORY REQUIREMENTS

Environmental permits and approvals required (or potentially required) for the proposed drilling project are listed below.

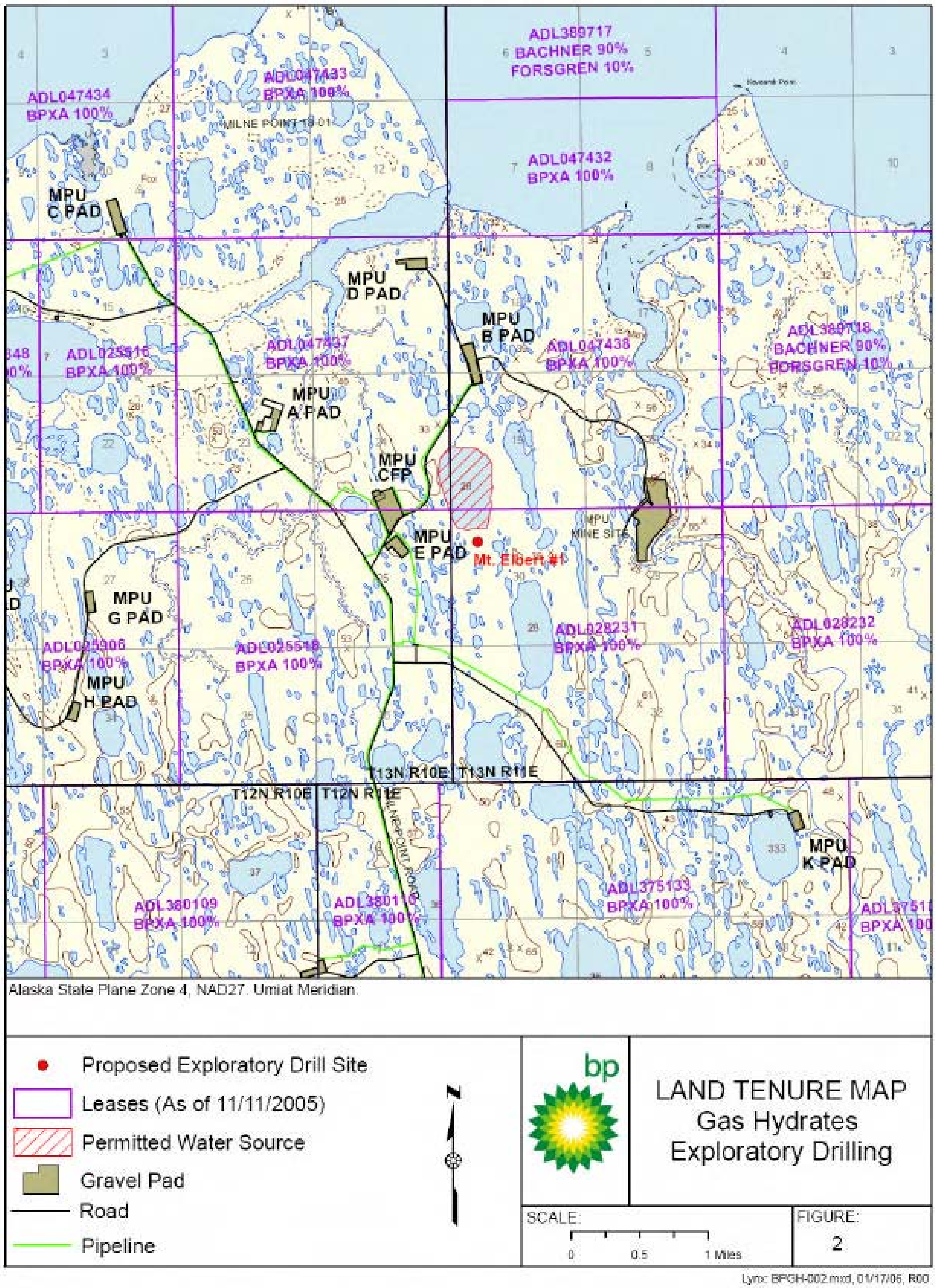
Agency	Authorization
USDOE	NEPA –Categorical Exclusion
ADNR/DOG	Lease Operations Plan Approval
ADNR/DML&W	Temporary Water Use Permit (existing)
ADNR/DML&W	Land Use Permit LAS 25132 (existing)
ADNR/OHMP	Title 41 Fish Habitat Permit
ADNR/OPM&P	Coastal Project Consistency Determination
ADNR/SHPO	Cultural and Archeological Clearance
ADEC/DAQ	Air Quality Control Minor Permit
ADEC/SPAR	Amendment to ODPCP
NSB	Administrative Approval - Ice Road / Pad
NSB	Administrative Approval - Drilling Operations

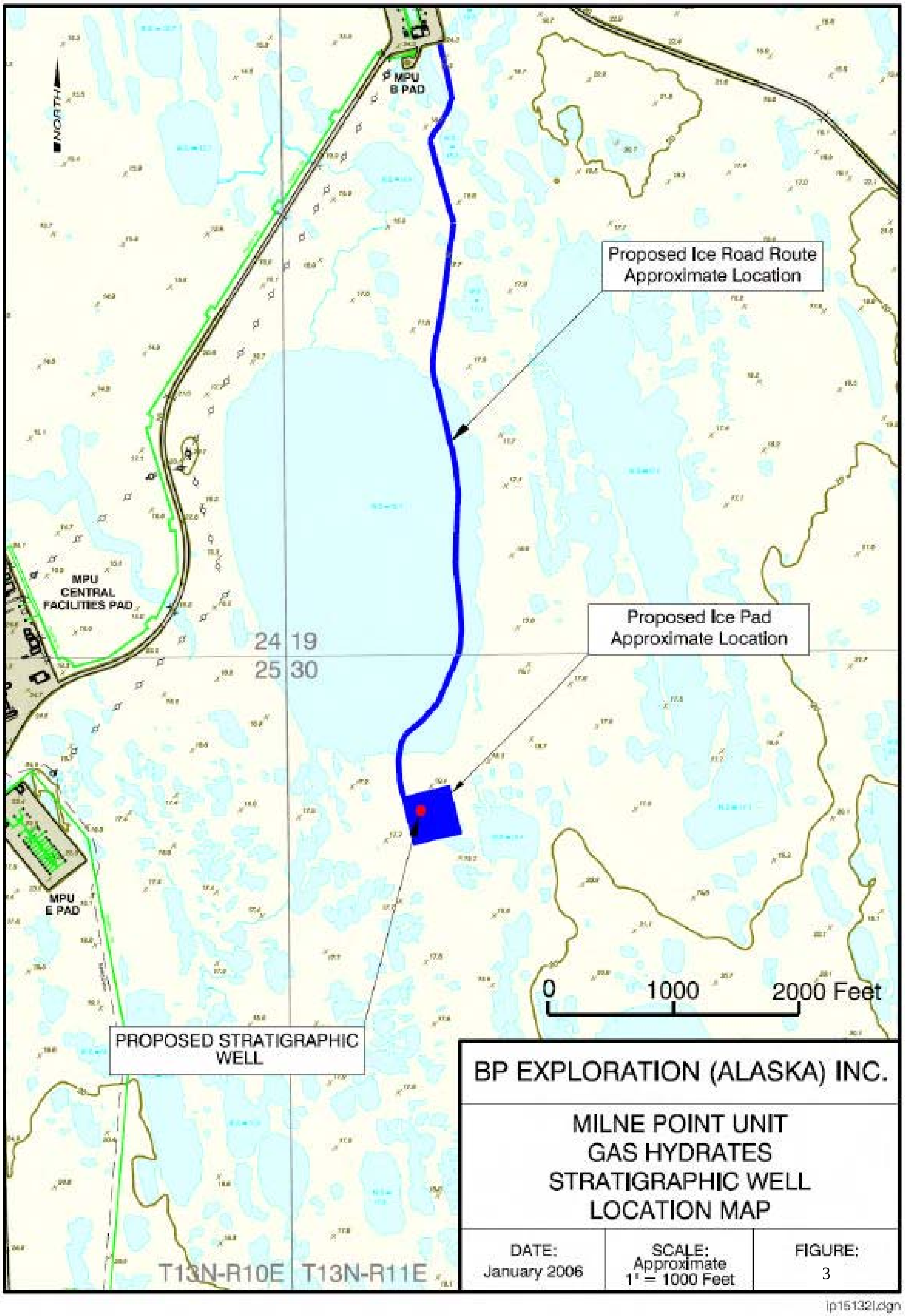
9.2.1.9 FIGURES

The following pages display the figures referenced in the Appendix B1, Draft Plan of 2006 Operations report.

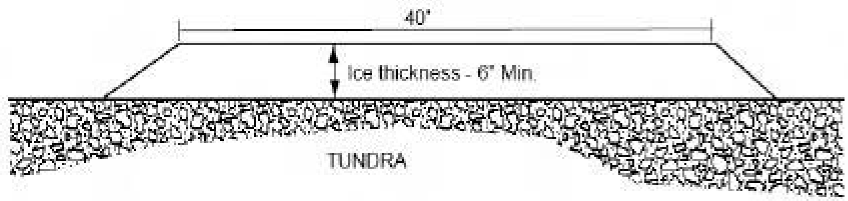


Lynx: Lynx040.mxd, 11/17/04. R00


ADL389717
BACHNER 90%
FORSGREN 10%
ADL047433
BPXA 100%
ADL047434
BPXA 100%
MILNE POINT 18-01
ADL047432
BPXA 100%
MPU
C PAD
MPU
D PAD
MPU
B PAD
ADL025516
BPXA 100%
ADL047437
BPXA 100%
ADL047438
BPXA 100%
ADL389718
BACHNER 90%
FORSGREN 10%
MPU
A PAD
MPU
CFP
MPU
E PAD
Mt. Elbert #1
MPU
MINE SITE
MPU
G PAD
ADL025906
BPXA 100%
ADL025518
BPXA 100%
ADL028231
BPXA 100%
ADL028232
BPXA 100%
MPU
H PAD
T13N R10E
T13N R11E
T12N R10E
T12N R11E
MILNE POINT ROAD
MPU
K PAD
ADL375133
BPXA 100%
ADL380109
BPXA 100%
ADL380110
BPXA 100%
Alaska State Plane Zone 4, NAD27. Umiat Meridian.
Proposed Exploratory Drill Site
Leases (As of 11/11/2005)
Permitted Water Source
Gravel Pad
Road
Pipeline
N
bp
LAND TENURE MAP
Gas Hydrates
Exploratory Drilling
SCALE:
0
0.5
1 Miles
FIGURE:
2
Lynx: BPGH-002.mxd, 01/17/06, R00


NORTH
MPU
B PAD
Proposed Ice Road Route
Approximate Location
MPU
CENTRAL
FACILITIES PAD
Proposed Ice Pad
Approximate Location
24 19
25 30
MPU
E PAD
0 1000 2000 Feet
PROPOSED STRATIGRAPHIC
WELL
BP EXPLORATION (ALASKA) INC.
MILNE POINT UNIT
GAS HYDRATES
STRATIGRAPHIC WELL
LOCATION MAP
DATE:
January 2006
SCALE:
Approximate
1" = 1000 Feet
FIGURE:
3
T13N-R10E T13N-R11E
jp15132l.dgn

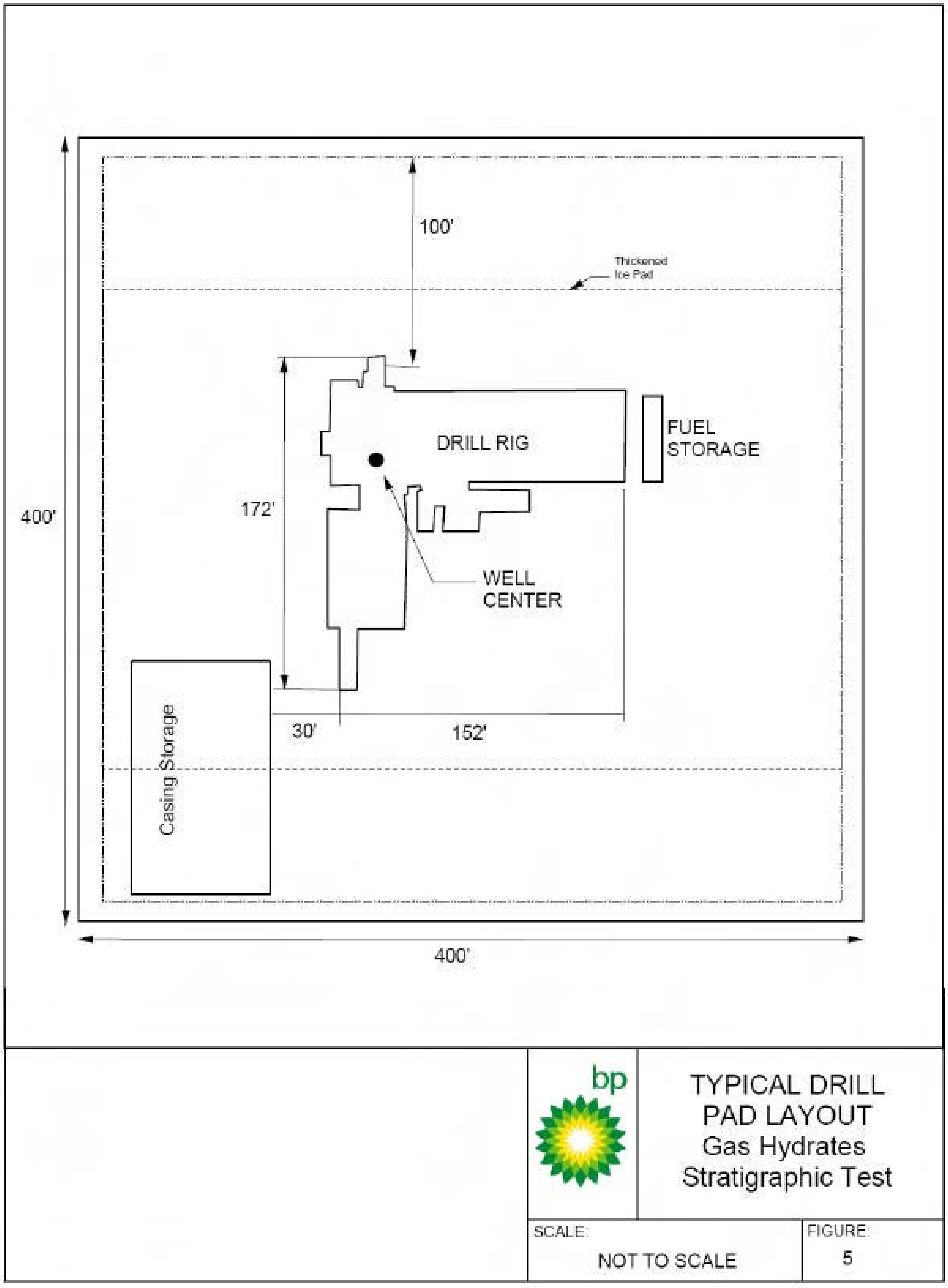
ICE ROAD CROSS-SECTION

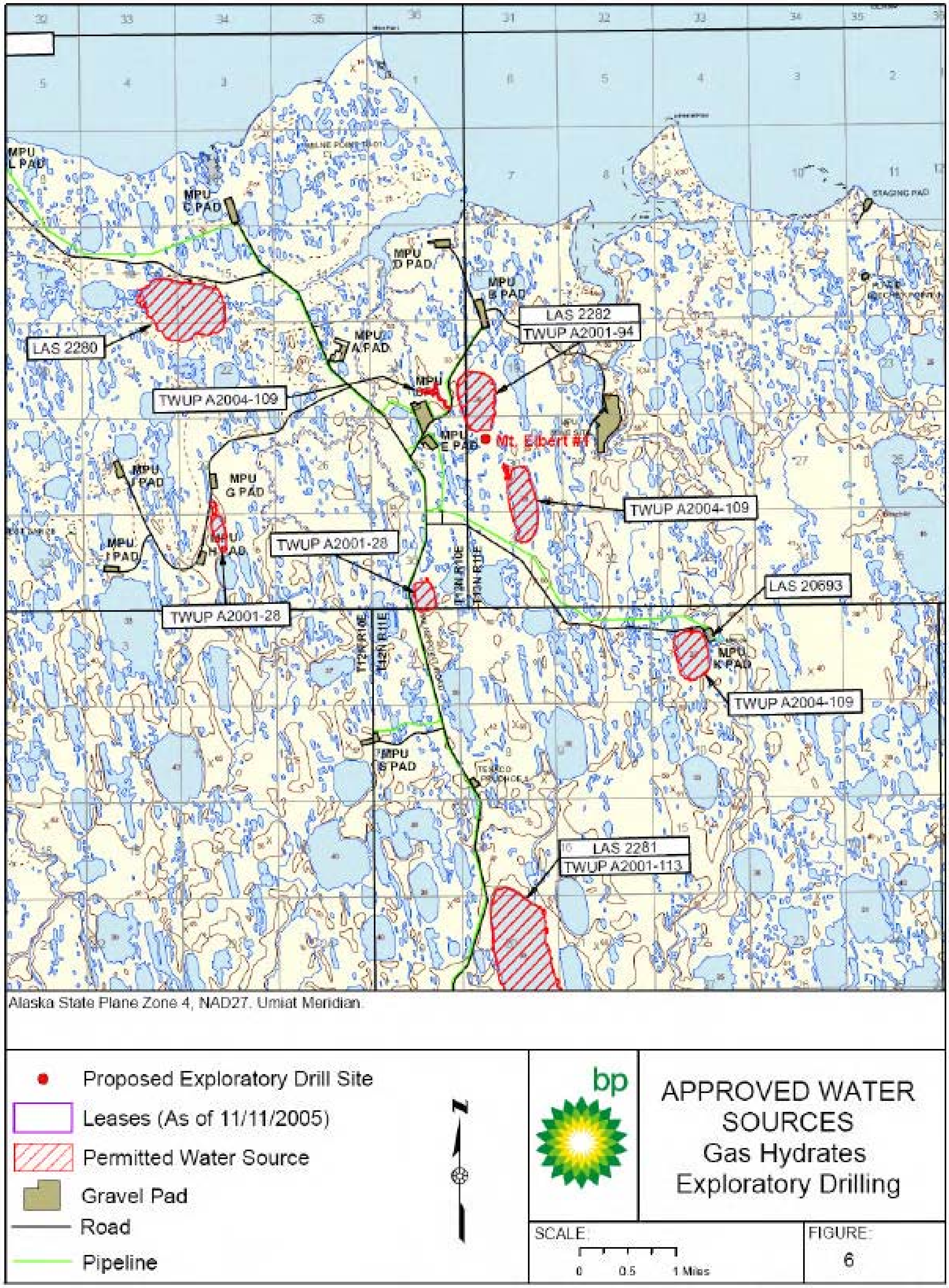


ICE ROAD SPECIFICATIONS
Gas Hydrates
Stratigraphic Test

SCALE:	FIGURE:
NOT TO SCALE	4

Lynx: BPGH-006.mxd, 01/17/06, R00


100'
Thickened Ice Pad
DRILL RIG
FUEL STORAGE
400'
172'
WELL CENTER
Casing Storage
30'
152'
400'
bp
TYPICAL DRILL PAD LAYOUT
Gas Hydrates Stratigraphic Test
SCALE:
NOT TO SCALE
FIGURE:
5
Lynx: BPGH-004.mxd, 01/17/06, R00


MPU L PAD
MPU C PAD
MPU D PAD
MPU B PAD
MPU A PAD
MPU E PAD
MPU F PAD
MPU G PAD
MPU H PAD
MPU I PAD
MPU J PAD
MPU K PAD
MPU S PAD
LAS 2280
LAS 2282
TWUP A2001-94
TWUP A2004-109
Mt. Elbert #1
TWUP A2004-109
TWUP A2001-28
TWUP A2001-28
LAS 20693
TWUP A2004-109
LAS 2281
TWUP A2001-113
T12N R10E
T12N R11E
T13N R10E
T13N R11E
Alaska State Plane Zone 4, NAD27, Umiat Meridian
Proposed Exploratory Drill Site
Leases (As of 11/11/2005)
Permitted Water Source
Gravel Pad
Road
Pipeline
N
bp
APPROVED WATER SOURCES
Gas Hydrates Exploratory Drilling
SCALE:
0
0.5
1 Miles
FIGURE:
6
Lynx: BPGH-002.mxd, 01/17/06, R00

9.2.2 APPENDIX B2: AOGCC-Approved Drilling Permit, MPU Mt Elbert-01

STATE OF ALASKA

FRANK H. MURKOWSKI, GOVERNOR

ALASKA OIL AND GAS CONSERVATION COMMISSION

333 W. 7th AVENUE, SUITE 100
ANCHORAGE, ALASKA 99501-3539
PHONE (907) 279-1433
FAX (907) 276-7542

Dan Kara
Senior Drilling Engineer
BP Exploration (Alaska) Inc.
PO Box 196612
Anchorage, AK 99519-6612

Re: Milne Point Unit, Mt. Elbert-01
BP Exploration (Alaska) Inc.
Permit No: 206-033
Surface Location: 1242' FNL, 4183' FEL, SEC. 30, T13N, R11E, (Planned)
Bottomhole Location: 1242' FNL, 4183' FEL, SEC. 30, T13N, R11E, (Planned)

Dear Mr. Kara:

Enclosed is the approved application for permit to drill the above referenced exploration well.

This permit to drill does not exempt you from obtaining additional permits or approvals required by law from other governmental agencies, and does not authorize conducting drilling operations until all other required permits and approvals have been issued. In addition, the Commission reserves the right to withdraw the permit in the event it was erroneously issued. A weekly status report is required from the time the well is spudded until it is suspended or plugged and abandoned. The report should be a generalized synopsis of the week's activities and is exclusively for the Commission's internal use.

All dry ditch sample sets submitted to the Commission must be in no greater than 30' sample intervals from below the permafrost or from where samples are first caught and 10' sample intervals through target zones.

Operations must be conducted in accordance with AS 31.05 and Title 20, Chapter 25 of the Alaska Administrative Code unless the Commission specifically authorizes a variance. Failure to comply with an applicable provision of AS 31.05, Title 20, Chapter 25 of the Alaska Administrative Code, or a Commission order, or the terms and conditions of this permit may result in the revocation or suspension of the permit. When providing notice for a representative of the Commission to witness any required test, contact the Commission's petroleum field inspector at (907) 659-3607 (pager).

Mt. Elbert-01
206-033

Sincerely,

Cathy P. Foerster

Cathy P. Foerster
Commissioner

DATED this 6th day of March, 2006

cc: Department of Fish & Game, Habitat Section w/o encl.
Department of Environmental Conservation w/o encl.

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION

RECEIVED
FEB 24 2006
Alaska Oil & Gas Cons. Commission

PERMIT TO DRILL

20 AAC 25.005

1a. Type of work: ☒ Drill ☐ Redrill ☐ Re-Entry

1b. Current Well Class: ☒ Exploratory ☐ Service ☐ Development Oil ☐ Stratigraphic Test ☐ Development Gas ☐ Multiple Zone ☐ Single Zone

1c. Specify if well is proposed for: ☐ Coalbed Methane ☒ Gas Hydrates ☐ Shale Gas

2. Operator Name: BP Exploration (Alaska) Inc.

5. Bond: ☒ Blanket ☐ Single Well — Bond No. 6194193

11. Well Name and Number: Mt. Elbert-01

3. Address: P.O. Box 196612, Anchorage, Alaska 99519-6612

6. Proposed Depth: MD 4000 TVD 4000

12. Field / Pool(s): Milne Point Unit

4a. Location of Well (Governmental Section):
Surface: 1242' FNL, 4183' FEL, SEC. 30, T13N, R11E, (Planned)
Top of Productive Horizon: 1242' FNL, 4183' FEL, SEC. 30, T13N, R11E, (Planned)
Total Depth: 1242' FNL, 4183' FEL, SEC. 30, T13N, R11E, (Planned)

7. Property Designation: ADL 028231

8. Land Use Permit:

13. Approximate Spud Date: April 1, 2006

9. Acres in Property: 2560

14. Distance to Nearest Property: 7545'

4b. Location of Well (State Base Plane Coordinates): Surface: x-572199 y-6016604 Zone-ASP4

10. KB Elevation (Height above GL): 24 feet

15. Distance to Nearest Well Within Pool: 734' at 4000' away from MPE-08

16. Deviated Wells: Kickoff Depth: None feet; Maximum Hole Angle: N/A degrees

17. Maximum Anticipated Pressures in psig (see 20 AAC 25.035): Downhole: 1740 Surface: 1340

18. Casing Program:

Hole	Casing	Weight	Grade	Coupling	Length	Top MD	Top TVD	Bottom MD	Bottom TVD	Quantity of Cement, c.f. or sacks (including stage data)
30"	20"	92#	H-40	Weld	80'	20'	20'	100'	100'	260 sx Arctic Set (Approx.)
12-1/4"	9-5/8"	40#	L-80	BTC	1932'	18'	18'	1950'	1950'	270 sx AS Lite, 446 sx Arctic Set
8-1/2"	7"	26#	L-80	BTC	2150'	1850'	1850'	4000'	4000'	20 sx AS Lite, 256 sx Class 'G'

19. PRESENT WELL CONDITION SUMMARY (To be completed for Redrill and Re-entry Operations)

Total Depth MD (ft):	Total Depth TVD (ft):	Plugs (measured):	Effective Depth MD (ft):	Effective Depth TVD (ft):	Junk (measured):

Casing	Length	Size	Cement Volume	MD	TVD
Conductor / Structural					
Surface					
Intermediate					
Production					
Liner					

Perforation Depth MD (ft):

Perforation Depth TVD (ft):

20. Attachments: ☒ Filing Fee, $100 ☒ BOP Sketch ☒ Drilling Program ☐ Time vs Depth Plot ☐ Shallow Hazard Analysis ☐ Property Plat ☐ Diverter Sketch ☐ Seabed Report ☒ Drilling Fluid Program ☒ 20 AAC 25.050 Requirements

21. Verbal Approval: Commission Representative: Date:

22. I hereby certify that the foregoing is true and correct.
Contact Steve Lewis, 252-3457
Printed Name Dan Kara Title Senior Drilling Engineer
Prepared By Name/Number: Sondra Stewman, 564-4750
Signature Phone 564-5667 Date 2/24/06

Commission Use Only

Permit To Drill Number: 206-033
API Number: 50-029-23302-00
Permit Approval Date: 3-6-06
See cover letter for other requirements

Conditions of Approval:
If box is checked, well may not be used to explore for, test, or produce coalbed methane, gas hydrates, or gas contained shales: ☐

403 required for plugging.

Samples Req'd: ☒ Yes ☐ No
Mud Log Req'd: ☒ Yes ☐ No
H_2S Measures: ☐ Yes ☒ No
Directional Survey Req'd: ☐ Yes ☒ No*
* Inclination survey only. 2-28

Other: 3000 psi BOP test. Well may not be drilled deeper than 4000' tvd without express Commission approval

APPROVED BY THE COMMISSION , COMMISSIONER

3-6-06 Date

Form 10-401 Revised 12/2005

DUPLICATE

Submit In Duplicate

bp

ASTI

Well Name: **Mt. Elbert # 1**

Drilling Plan Summary

Type of Well:	Stratigraphic Test
Surface Location: *(As Proposed)*	**1242 ft. FNL** and **4,183 ft. FEL** Section 30, T13N, R11E UM X=572199, Y=6016604 ASP4 Lat = 70.455641846, Lon= -149.410786174 **Note: the section is ~40 short of 5,280 in EW direction.**
Distance to Property line	7545 ft. MPU unit boundary
Distance to nearest well	734' @ 4000 ft. MD from MP E-08

AFE Number:	GS2420H15
Estimated Start Date:	April1, 2006

Rig:	Doyon Arctic Fox
Rig days to complete:	25

MD:	4,000'	**TVD:**	4,000'	**Max Inc:**	N/A	**KOP:**	None	**KBE:**	24'
Well Design:	Stratigraphic Test								
Objective:	Gas Hydrates								

Mud Program:

12¼" Surface Hole (0' –1950): Fresh water spud mud

Density (ppg	PV	YP	pH	API Filtrate	Chlorides (mg/l)
<9.4	10 - 30	25 – 50	9 – 9.5	NC – 10	NC

8½" Intermediate Hole (1,950' – 4,000'): 8% KCl LSND (-3.78° C TCT)

Density (ppg	PV	YP	pH	API Filtrate	Chlorides	MBT
8.9 -9.6	10 – 25	15 -20	7.0 – 8.0	<8	39,950	<25

Waste Disposal: NO ANNULAR INJECTION. Drill Cuttings taken to DS-4 disposal site
Call the Pad 4 waste disposal site prior to truck leaving location so the site can be ready to unload waste. Exempt liquid wastes can be taken to DS-4 or CPAI KRU 1R-18.

Casing Program:

Hole Size	Csg Diam	Wt/ Ft	Grade	Conn	Burst	Collapse	Length	Top MD/ TVDrkb	Bottom MD/ TVDrkb
30"	20"	92	H-40	Weld	1530	520	80 ft	20	100 ft
12¼"	9⅝"	40	L-80	BTC	5750	3090	1932 ft	18	1950 ft
8½"	7" contingency liner	26	L-80	BTC	7240	5410	2150 ft	1850 ft	4,000 ft

Cement Program:

Casing Size	9⅝", 40ppf, L-80, BTC	
Type:	Surface Casing to 1950'.	
Basis for Calculation	80' shoe jts, 150% in permafrost (12-1/4" hole), and cement to surface. Shoe Depth: 1950' MD. 1450' Arctiset Lite @ 10.7 ppg and 500' ArcticSet @ 15.8 ppg	
Cement Volume:	Spacer	5 bbl of water, 10 bbl CW 100 and 40 bbl Mud Push
	Lead (BOC @ 1450 ft)	270 sxs (212.5 bbls), ArcticSet Lite @ 10.7 ppg. Yield 4.43 ft3/sx, mix fluid 20.667 gps.
	Tail (TOC @ 1450 ft)	446 sxs (79.50 bbls), ArcticSet @ 15.8 ppg. Yield 1.05 ft3/sx, mix fluid 4.10 gps.
	Temp	2 °C @ 1950 ft MD.

Casing Size	7" 26ppf, L-80, BTC Contingency Liner	
Type:	Production Liner from 4000' TD to 1800' (150' liner lap)	
Basis for Calculation	80' shoe joints, 30 % excess in open hole. 500' ArcticSet Lite @ 10.7 ppg and 1700' Class G at 15.8 ppg.	
Cement Volume:	Spacer	5 bbl of water, 10 bbl CW 100 and 30 bbl Mud Push
	Lead (BOC @ 2300 ft)	20 sxs (15.8 bbls), ArcticSet Lite @ 10.7 ppg. Yield 4.43 ft3/sx, mix-fluid 20.667 gps.
	Tail (TOC @ 2300 ft)	256 sxs (53.0 bbl) Class G @ 15.8 ppg. Yeild 1.16 ft3/sx, mix fluid 4.97 gps.
	Temp	24 ° C @ 4000 ft MD.

Evaluation Program:

12¼" Surface Hole	
Coring Program:	• None
Mud Logging:	• Surface to casing shoe
Open hole Logs:	• MWD:Directional/Gamma/Resistivity
8½" Intermediate Hole	
Coring Program:	• **Run 1:** Continuous Core, Wireline retrieved from 2000' to 2600'
Mud Logging:	• Casing point to TD.
Open hole Logs:	• **Run-1:** 1850-4000 Platform Express (hydrate) -High Resolution Laterolog Array-SP Log (HRLA) -Compensated Neutron Litho Density Log -Array Induction-SP Log (AIT) -Electromagnetic Propagation Tool Log (EPT) – DiElectric msmt • **Run-2:** 1850-3500 Dipole Shear Imager (hydrate) -Dipole Shear Imager Log -Natural Gamma Ray Spectroscopy Log -Environmental Measurement Sonde Log • **Run-3:** 1850-3500 Formation MicroImager (hydrate) -FMI Borehole Image Log • **Run-4:** 1850-3500 Combinable Magnetic Resonance Tool (hydrate) -Combinable Magnetic Resonance Log -Natural Gamma Ray Spectroscopy Log -Environmental Measurement Sonde Log -CMR Station Log-Elemental Capture Sonde • **Run-5:** XPT (Optional) • **Run-6:** MDT Open Hole; 2 points per sand, two sands expected
Cased Hole Logs:	• **Run-1:** MDT cased hole contingency only

Formation Markers:

Formation Tops	MD (ft)	TVD (ft)	Pore Pressure (psi)	EMW (lb/gal)
Top Mikkelson Tongue	1450	1450	630	8.35
Base Permafrost	1800	1800	782	8.35
"D" Hydrate	2000	2000	868	8.35
"C" Hydrate	2100	2100	912	8.35
Top Staines Tongue	2770	2770	1203	8.35
Base Gas Hydrate Stability Zone	2853	2853	1239	8.35
C12 Seismic Marker	3390	3390	1472	8.35
Top Ugnu	3710	3710	1736	8.35

Recommended Bit Program:

BHA	Hole Size	Depth (MD)	Footage	Bit Type	TFA	GPM
1	12¼"	0 – 1950'	1950'	Baker Hughes MX-1	.84	650
2	8½"	1,800' – 4,000'	2,200'	Baker Hughes MX-1	.71	450

Well Control:

Surface/Intermediate hole:

- Maximum anticipated BHP: 1,740 psi @ 4000' TVD
- Maximum surface pressure: 1,340 psi (Based on full gas column to surface @ 0.1 psi/ft)
- Planned BOP test pressure: 3,000 psi
- Integrity tests: FIT to 11.5 lb/gal 20' below the 9 5/8" shoe.
- Wireline core retrieval: Wireline BOP, circulating sub and packoff to be utilized when retrieving cores.

Drilling Hazards & Contingencies:

Hydrate drilling, coring and handling:

- Hydrates will be present from the base of the permafrost to approximately 2850 ft MD. Mud system design specifies an 8 % KCl Low Solids Non Dispersed system which will have a thermal crystallization temperature of minus 3.78 ° C. Operating temperature of mud being pumped down hole will be maintained at minus 2.0 ° C. Circulating temperature, mud chemistry and drilling mechanics will be optimized to minimize hydrate sublimation while maintaining primary well control.

- All circulating system components will be monitored and actively protected from freeze up both while circulating and during static periods.

- Rig gas detector system will be fully operational and portable gas sensors will be utilized in the affected areas prior to cuttings handling or core processing.
- During coring operations mud properties and temperatures will be maintained to minimize hydrate sublimation.
- Core retrieval will be conducted with wireline utilizing wireline BOP, circulating sub and packoff head.
- Cores will be allowed to pressure stabilize below the wellhead and flow checks will be conducted prior to continuing the retrieval and opening the wireline riser to lay down cores.
- Core will be recovered in 24 ft sections contained in aluminum core sleeves. The sleeves are slotted to prevent pressure entrapment. The core will be lain down, removed from the floor, sectioned and containerized all at sub freezing temperatures.
- All core storage and on site geo-science will be conducted in a refrigerated containerized unit remote from the well bore.

Drilling mechanics, lost circulation and stuck pipe:

- Losses are possible in the entire interval due to tight hole or pack off. NOTE: Elevated mud weights are NOT required for controlling hydrates. Control hydrate gas evolution with mud properties and hole cleaning.
- Sticky clays may be present from the lower permafrost on down to total depth.
- Potential for packing off/stuck pipe, tight hole, and swabbing exists throughout the well and particularly from 2,800' to total depth.

Expected Pressures:

- Pore pressure is expected to be a fresh water gradient (8.35 ppg) from surface to total depth.

Pad Data Sheet:

- Review MPU E and B Pad Data Sheets

Hydrocarbons:

- Hydrocarbons in the form of Methane Hydrates are expected from the base of the permafrost through the base of the hydrate stability zone at ± 2850'.
- No liquid hydrocarbons are anticipated in any well section.
- No free gas hydrocarbons are anticipated in any well section.

Faults:

- No fault intersections are expected in this vertical well.

Hydrogen Sulfide:

- MP is not designated as an H_2S area.

Anti-collision Issues:

- Mt. Elbert #1 poses no collision risk to any MPU wells.
- Mt. Elbert #1 surface location is 7545 ft. from the MPU unit boundary
- Mt. Elbert #1 is 734' @ 4000 ft. MD from MP E-08

DRILLING PROCEDURE:

Pre-Rig Operations:

1. Survey in ice road and pad.
2. Construct ice road and pad.
3. Drill and set and cement 20" conductor casing and well cellar.
4. Drill mouse hole and rat hole.
5. Install FMC landing ring on conductor.
6. N/U Doyon Drilling Diverter System prior to rig move.
7. Hold pre-spud meeting in Anchorage and at MPU Base Camp.
8. Conduct emergency response training with MPU ERT, BP Drilling, and Doyon Rig Crews.

Drilling and Evaluation:

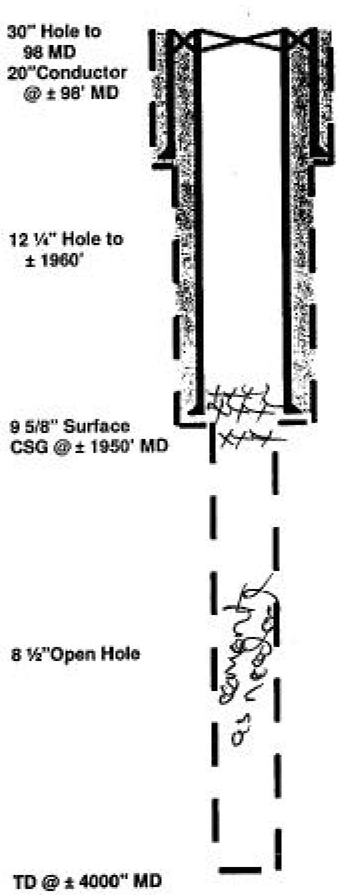
1. Move in and rig up Doyon Arctic Fox Drilling Rig.
2. Install and test Mud Chiller, MWD unit, LWD unit, Wireline unit.
3. Take on water and spud mud.
4. Function Test Diverter System.
5. Make up12¼" Tricone drill bit on packed rotary assembly and spud to ± 300'. POOH
6. Make up BHA #1: 12¼" packed rotary assembly w/ MWD tools. Drill 12¼" surface hole to +/- 1,950'. Maintain mud temperature at -2° C with mud cooler.
7. Circulate and condition for casing.
8. Run 9 5/8" surface casing.
9. Cement 9 5/8" surface casing.
10. ND diverter system, install wellhead and NU/Test BOPE.
11. M/U BHA #2, 7 7/8" core bit with drilling insert on packed rotary coring assembly. RIH to ± 1800' and test casing to 3000 psi.
12. Drill out shoe track, floats, rathole and 20' of new formation.
13. POOH to 1850' and perform FIT to 11.5 PPG EMW.
14. Drill to core point at ± 2000'.
15. Wireline retrieve drilling insert and run core sleeve.
16. Core 7 7/8" open hole section from ± 2000' to ±2600'.
17. POOH and lay down core barrel.
18. P/U 8 ½" bit and MWD on packed rotary assembly.
19. Ream and MWD log to 2600'
20. Drill 8½" intermediate hole section to TD at ±4000'.
21. POOH and Lay down MWD.
22. R/U Wireline loggers.
23. Run open hole e-line logs.
24. P/U 8 ½" cleanout assembly.
25. Make clean out run to ± 3200'
26. POOH and L/D clean out BHA.
27. M/U MDT tools for drill stem conveyed MDT
28. RIH to first MDT point at ± 2600'

29. Perform 4 sequential MDT from 2600" to 2000'.
30. POOH and L/D MDT tools.

Abandonment: 403 necessary for plugging [initials] 3/3-06

1. P/U cementing stinger and RIH to 200' below bottom hydrate interval. (± 2600')
2. Spot 100' viscous mud pill.
3. POOH 100' and set balanced plug from ± 2500' to 2100'
4. POOH to 2000' and clear cementing string
5. WOC 6 hrs and tag plug per AOGCC regulations.
6. Clear cementing string and set balanced plug from 2100' to 1700'
7. POOH to 1600' and clear cement string.
8. WOC 6 hrs and tag plug per AOGCC regulations. Clear cement string and POOH laying down pipe.
9. L/D remaining drill pipe in derrick.
10. RIH with drill pipe and side ported stinger.
11. Spot 100' (5 bbl) of weighted viscous mud pill from 350' to 250'.
12. POOH to 250'.
13. Rig up cement lines and cement to surface.
14. POOH to 25' and flush casing, wellhead and BOP.
15. POOH and L/D stinger.
16. Nipple down BOP and wellhead. Confirm TOC and top up to 5' sub surface if required.
17. Externally cut off 20" conductor and 9 5/8" casing at least 3' below tundra surface.
18. Weld on prefabricated well cap and marker per AOGCC requirements.
19. Move Arctic Fox Drilling Rig off location.
20. Abandon well cellar and conductor section as per AOGCC regulations.
21. Clean up location and ice road. Notify MPU Environmental Dept. for site inspection.

BP Gas Hydrate Stratigraphic Test — Mt. Elbert #1
Proposed Completion with Open Hole



Wellhead Design:
11" 5K FMC Generation V Wellhead on 20" starter spool.

Casing Design and Open Hole

Description	Hole Size	CSG OD	MD = TVD	WL	Grade
Conductor	30.0"	20.0	98'	94#	H-40
Surface	12.250"	9.625	1950'	40#	L-80
Open Hole	8.5"	-	4000'	-	-

Cementing Program

Conductor: Cement to surface.

Surface casing: ArcticSet Lite at 10.7 ppg to 1450' & ArcticSet at 15.8 ppg from 1450' to 1950'

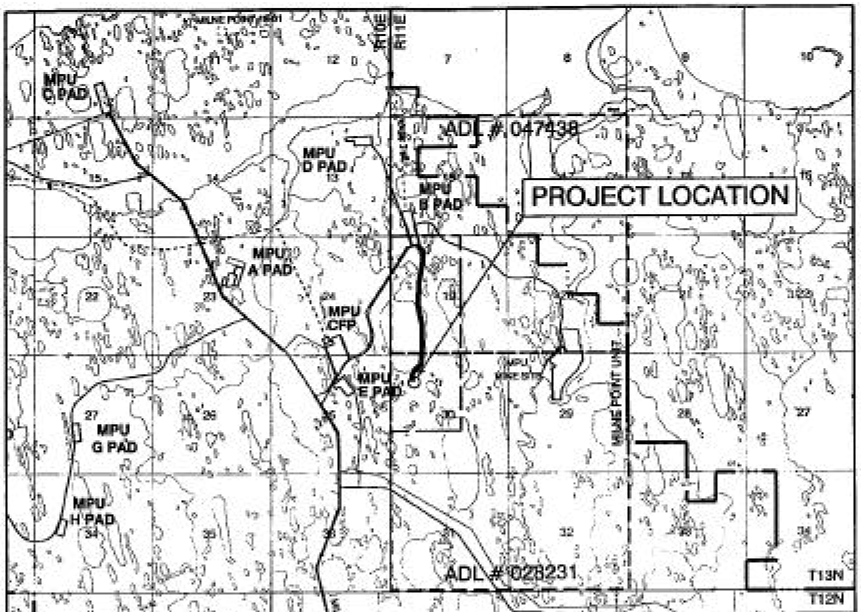
Abandonment Barriers

Open hole plug will be set from 100' below any hydrocarbon interval to 100' above the casing shoe

150' surface plug from 4' below ground level will be set in 9 5/8" casing

February 23, 2006

Stephen K. Lewis/ASRC Energy



This map is based on U.S.G.S. quad Beechy Point (B-4, B-5)
and on the Unit Operator's Facility Maps.

NORTH

PROJECT LOCATION:

CENTROID FOR GAS HYDRATES STRATIGRAPHIC WELL

LAT. = 70° 27' 20.31" NORTH
LONG. = 149° 24' 38.83" WEST

X = 572198.88 FEET EAST
Y = 6016603.50 FEET NORTH
ALASKA STATE PLANE ZONE 4, NAD 27
SEC. 19 & 30, T13N, R11E, UMIAT M.

ADL # 047436, ADL # 028231

DATUM: MEAN SEA LEVEL

PURPOSE: EXPLORATION WELL

ADJACENT PROPERTY OWNER:
STATE OF ALASKA

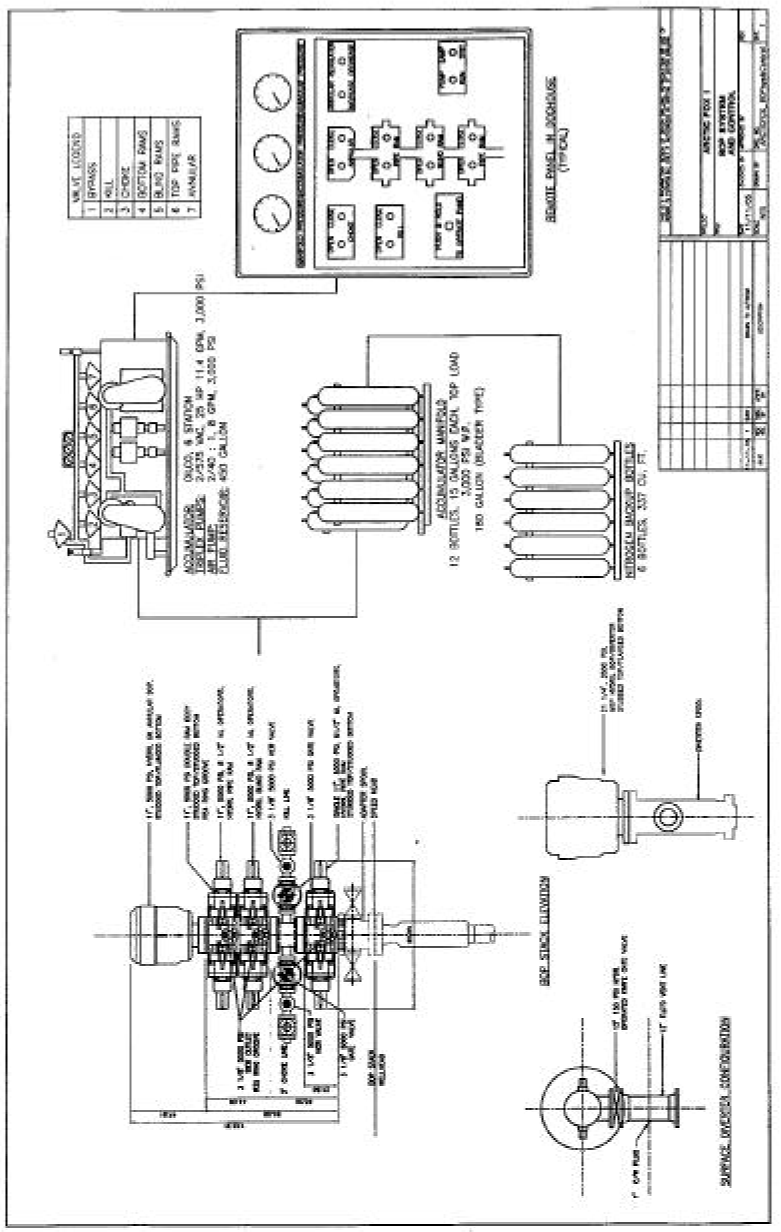
0 1 2 Miles

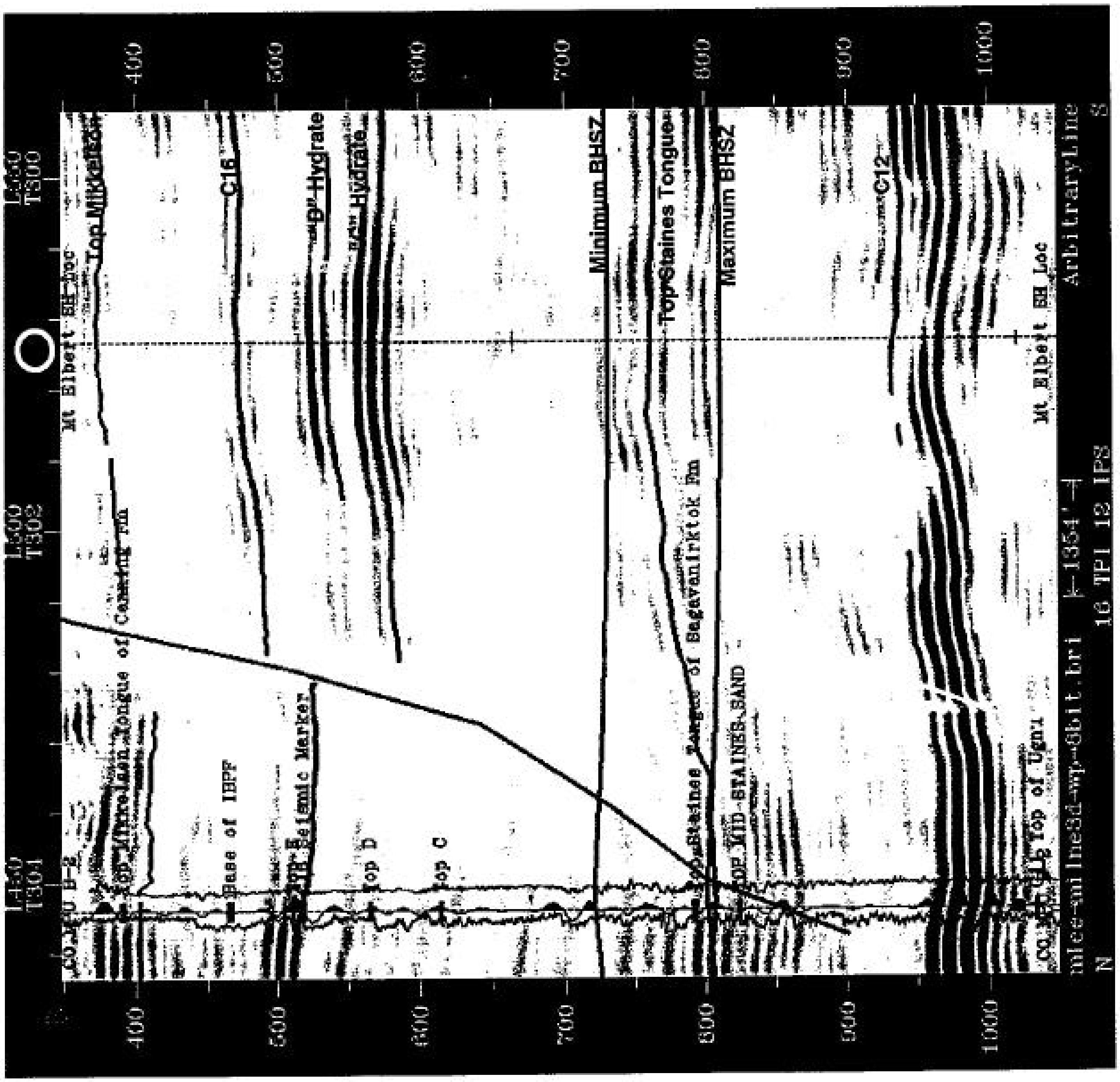
BP EXPLORATION (ALASKA) INC.

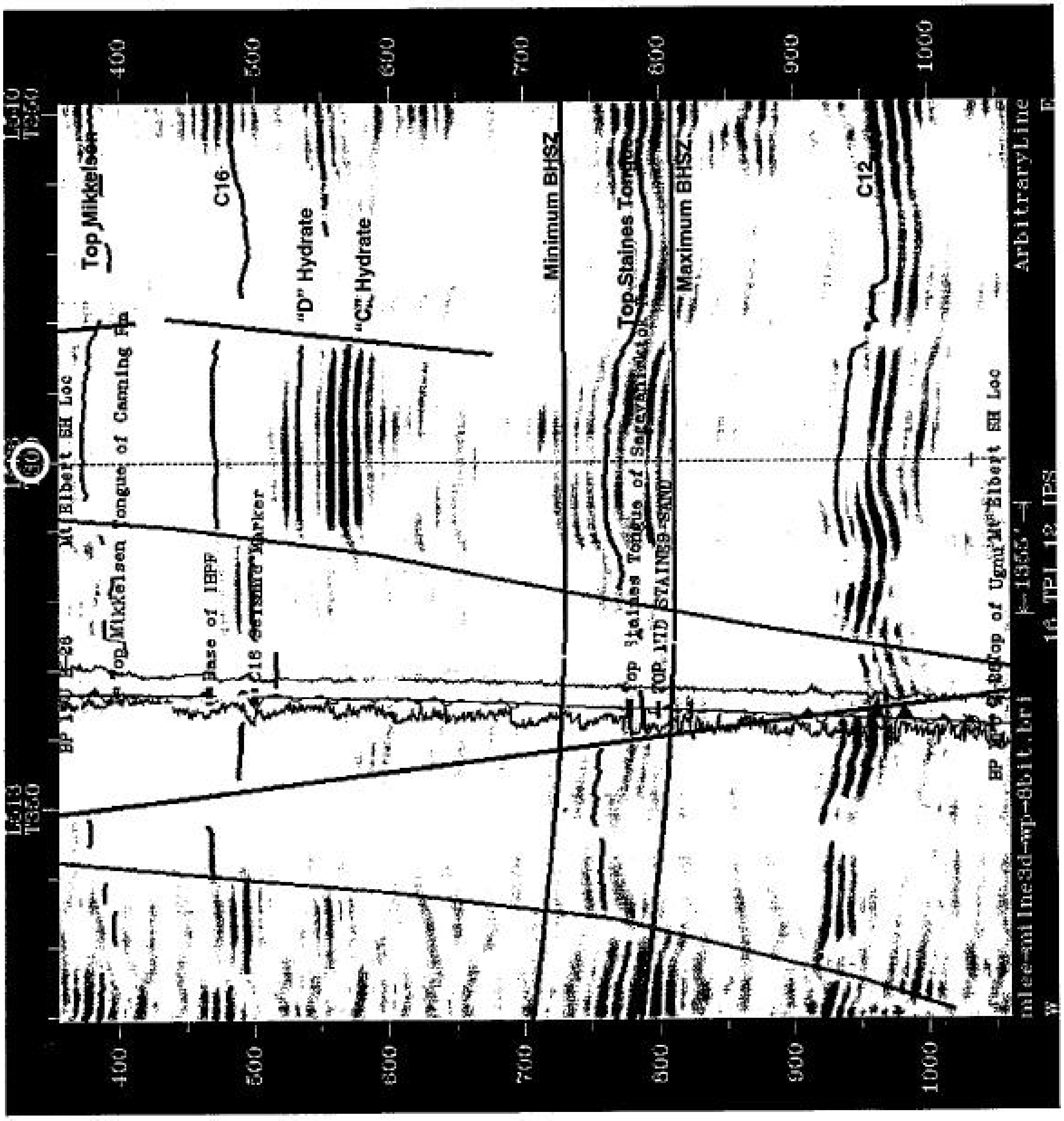
MILNE POINT UNIT
GAS HYDRATES
STRATIGRAPHIC WELL
VICINITY MAP

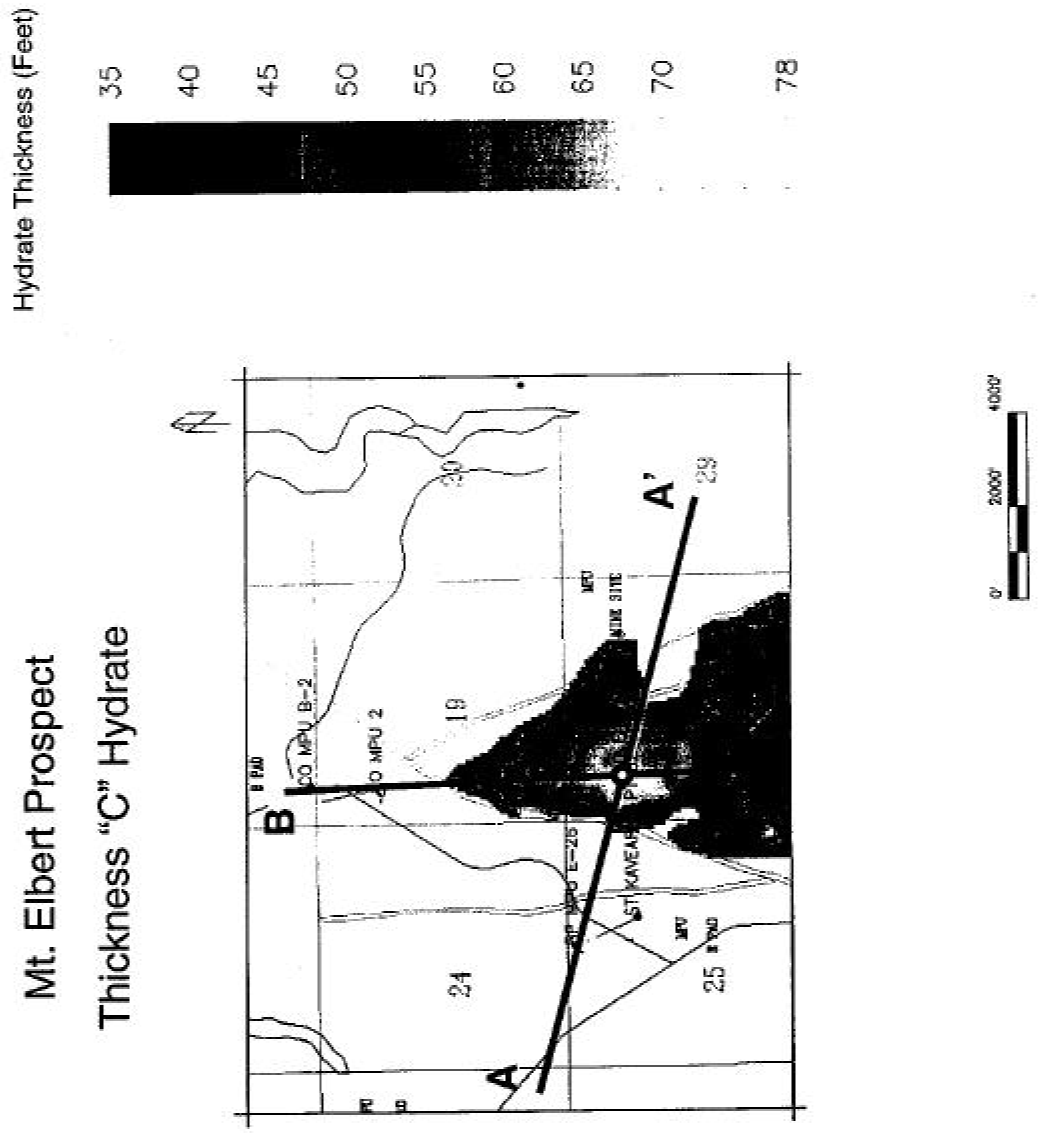
DATE:	SCALE:	FIGURE:
January 2006	Approximate 1" = 1 MILE	1

ip15132V.dgn


VALVE LEGEND
1 BYPASS
2 KILL
3 CHOKE
4 BOTTOM RAMS
5 BLIND RAMS
6 TOP PIPE RAMS
7 ANNULAR
REMOTE PANEL IN DOGHOUSE
(TYPICAL)
ACCUMULATOR MANIFOLD
12 BOTTLES, 15 GALLONS EACH, TOP LOAD
3,000 PSI W.P.
180 GALLON (BLADDER TYPE)
NITROGEN BACKUP BOTTLES
6 BOTTLES, 537 CU. FT.
BOP STACK ELEVATION
SURFACE DIVERTER CONFIGURATION


400
500
600
700
800
900
1000
Top Mikkelsen
C16
Minimum BHSZ
Top Staines Tongue
Maximum BHSZ
C12
Mt Elbert BH Loc
Base of IBPF
Top D
Top C
Arbitrary Line
16 TPI 12 IPS


Top Mikkelsen
C16
"D" Hydrate
"C" Hydrate
Minimum BHSZ
Top Staines Tongue
Maximum BHSZ
C12
ArbitraryLine
Mt Elbert BH Loc
400
500
600
700
800
900
1000


Mt. Elbert Prospect
Thickness "C" Hydrate
Hydrate Thickness (Feet)
35
40
45
50
55
60
65
70
78
B
A
A'
MPU B-2
MPU 2
MINE SITE
B PAD
19
24
25
29
30
0'
2000'
4000'

9.2.3 APPENDIX B3: Mt Elbert-01 Time/Depth Plot

The plot is estimated based on the Doyon Arctic Fox rig. Substitution of Doyon 14 rig would likely reduce this drilling time estimate.