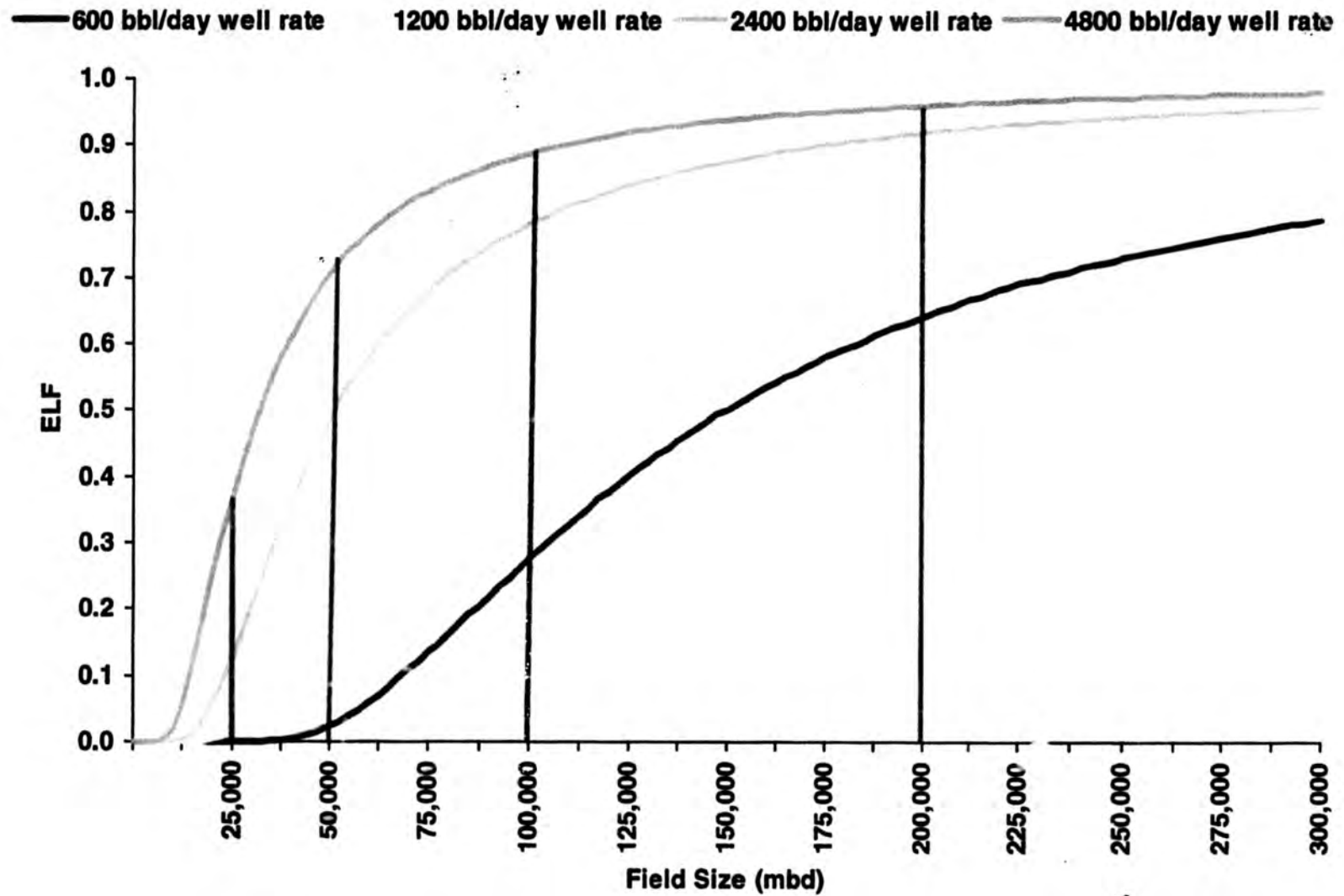


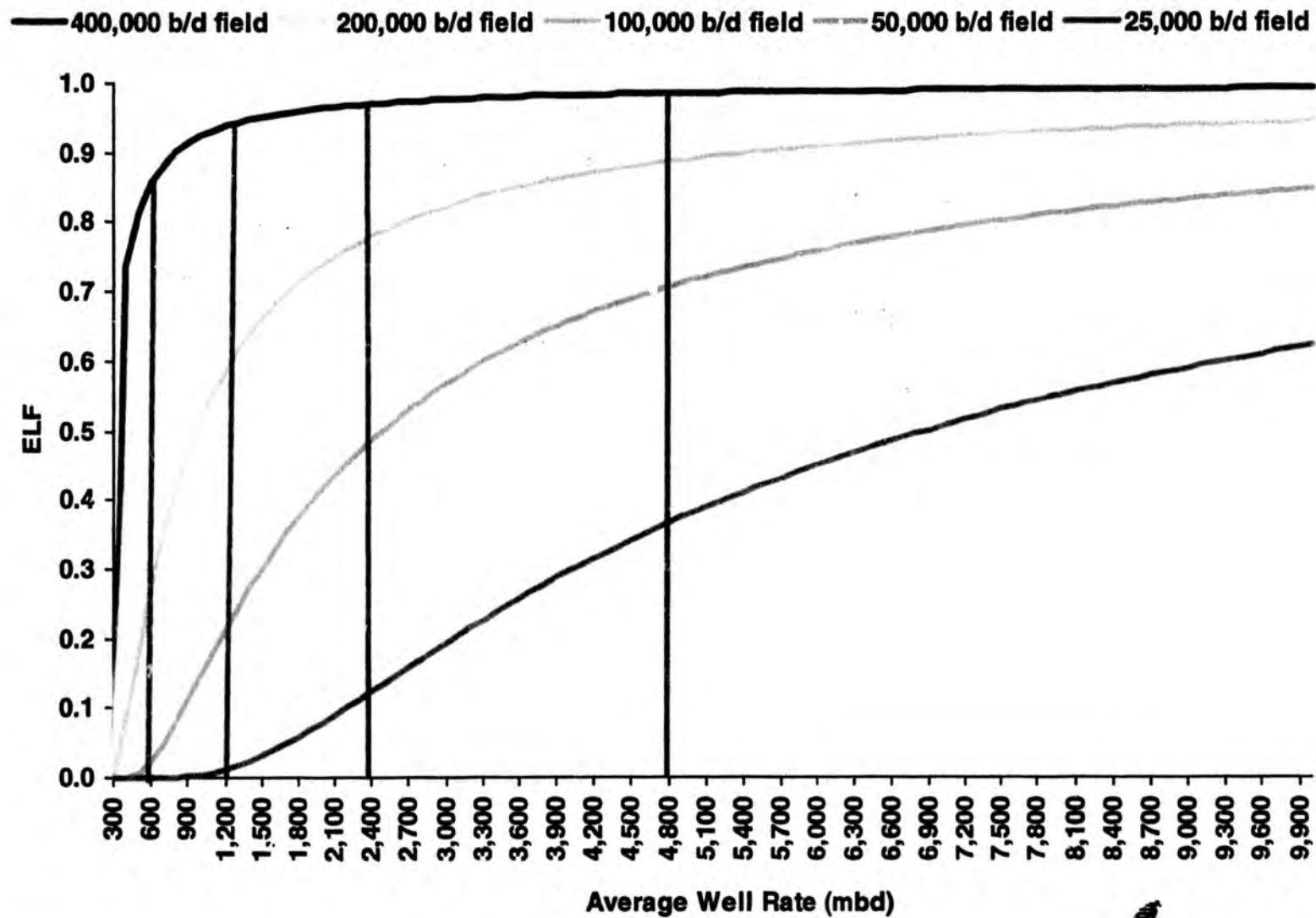
ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

3118 SCOMM 144: HOUSE SPECIAL COMMITTEE ON OIL & GAS 2005-2006

ELF for Four Well Rates and by Field Size



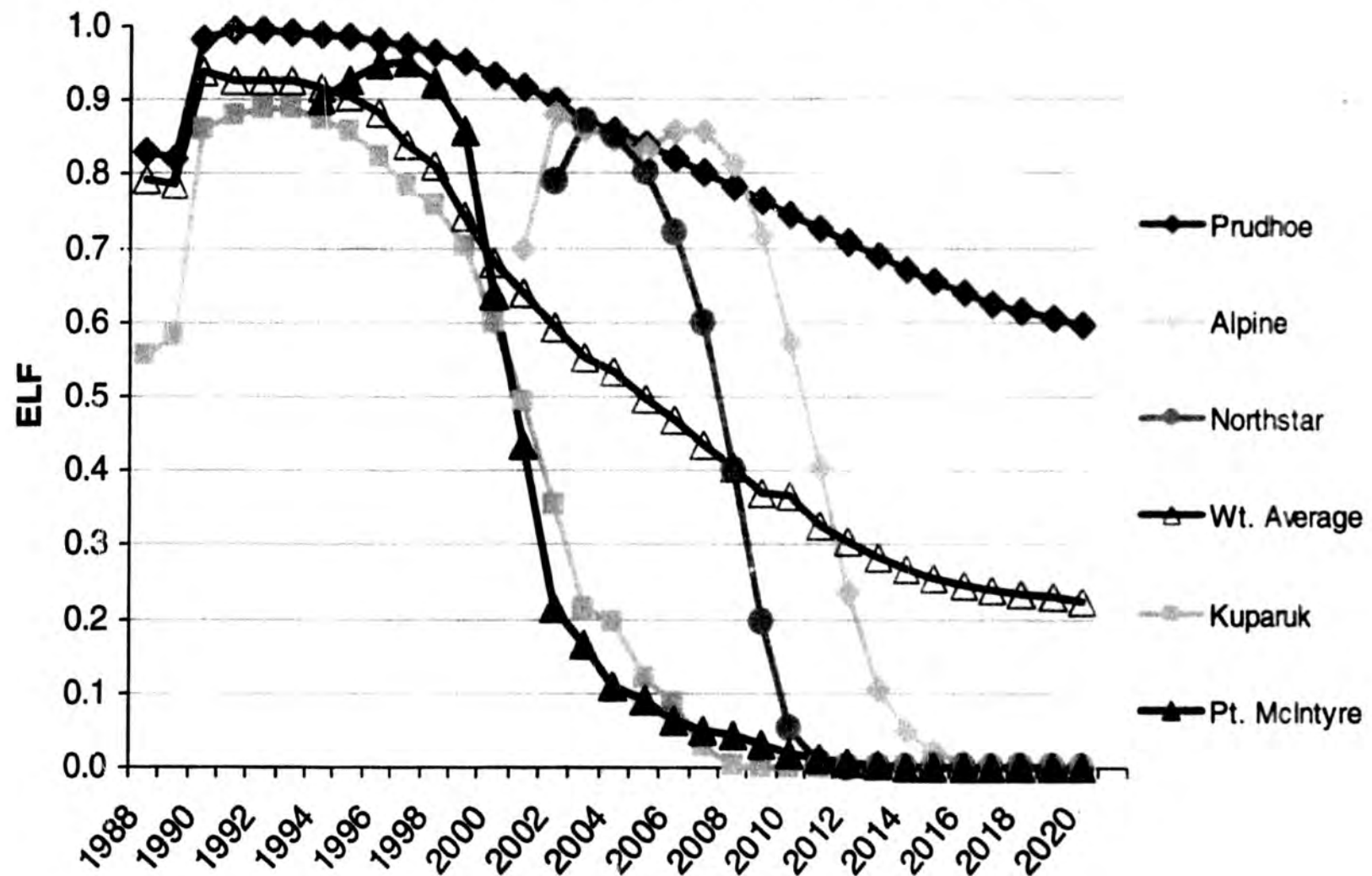
ELF for Five Field Sizes and by Well Rate



Economic Limit Factor FY 2004 Summary Data

NORTH SLOPE					
Region/ Property	Daily Production (bbl/day)	Oil Wells	ELF	Production per Well (bbl/day)	Taxable Daily Production (bbl/day)
Alpine	99,006	35	0.843008	2,828.7	83,462.9
Aurora	10,754	11	0	977.6	0.0
Borealis	31,744	23	0.083892	1,380.2	2,663.1
Eider	562	1	0	562.0	0.0
Endicott	27,914	54	0.000306	516.9	8.5
~~X~~ Kuparuk	155,233	450	0.179808	345.0	27,912.2
~~X~~ Lisburne	10,371	31	0	334.5	0.0
Meltwater	5,241	10	0	524.1	0.0
Midnight Sun	4,501	2	0	2,250.5	0.0
Milne-Kuparuk	30,414	85	0	357.8	0.0
Milne-Schrader Bluff	20,270	52	0	389.8	0.0
Niakuk	12,185	16	0	761.6	0.0
Northstar	65,854	13	0.846758	5,065.7	55,762.4
Orion	2,535	10	0	253.5	0.0
Prudhoe Bay	377,717	770	0.854717	490.5	322,841.0
Polaris	2,619	10	0	261.9	0.0
Point McIntyre	37,965	38	0.108383	999.1	4,114.8
Tabasco	3,713	8	0	464.1	0.0
Tam	31,407	25	0.059667	1,256.3	1,874.0
West Sak	8,926	35	0	255.0	0.0

Oil ELF Select Oil Fields, FY 1988 – FY 2020



Source: Alaska Department of Revenue, Spring 2004 Revenue Sources Book

WOOD MACKENZIE

GLOBAL OIL AND GAS — RISKS AND REWARDS 2004

Alaska's Profitability – Full Cycle, Post Government Take

Rate of Return (IRR – Nominal)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	15/49	14/52	14/53
Alaska's IRR	18.09%	23.57%	29.11%
Global Average IRR	15.20%	18.94%	23.07%

Net Present Value (NPV @10% in \$/Bbl of Oil Equivalent)

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	17/58	11/58	8/58
Alaska's NPV	\$0.90	\$2.14	\$4.43
Global Average NPV	\$0.65	\$1.33	\$2.35

Value Creation Ratio

	Low Price (\$16)	Base Price (\$22)	High Price (\$35)
Alaska's Ranking	22/66	22/66	19/66
Alaska's VCR	1.98	3.33	5.82
Global Ave. VCR	1.90	2.84	4.26

Field Development--What Drives Exploration and Development Decisions?

Presentation to the House of Representatives
Special Committee on Oil and Gas
February 3, 2005

Bill Van Dyke
Division of Oil and Gas
Department of Natural Resources

Good
A knowledge -
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2

Introduction

In its simplest form, oil and gas exploration and development decisions are driven by expected profits. The expected profits need to be commensurate with the necessary investments and the associated risks or the projects are not sanctioned.

Oil and gas companies, just like Walmart and Alaska Airlines, are accountable to their shareholders. They are for-profit corporations.

What is different for oil and gas companies is that the business model has to account for the likelihood of many failures and few successes, especially in the exploration phase. It also has to account for widely fluctuating commodity prices over long time periods. This business model is very different from McDonalds or General Motors.

Oil and Gas Life Cycle

Exploration

- Pre Lease
- Lease acquisition
- Drilling

Delineation/Appraisal

Development

Production

Continue to repeat cycle of exploration/appraisal/development/production as opportunities allow

- Deeper or shallower prospects
- Adjoining and nearby prospects
- Infill drilling
- Enhanced oil recovery

Option to suspend or terminate activity at any stage of the process, and likewise, resume it at a later point in time. This is not unique to Alaska.

- Unexplored leases expire
- Unsuccessful exploration (Mukluk)
- Withdrawn development permits (Point Thomson)
- Shut in fields (Badami)

Continually evaluate opportunities, business practices and performance at each stage using analytical tools (cash flow models) that incorporate risk and reward.

Accounting for Risk

The Process

Identify the risks
Eliminate the risks where possible
Reduce/mitigate the risks where possible
Manage the remaining risks

Example Oil and Gas Risks:

Geology--traps, reservoirs seals, rock porosity and permeability
Fluid type--water v. oil v. gas
Size of accumulation--how full is the trap?
Oil Quality--viscosity, sulfur content, gasoline content
Flow rate from each well--function of viscosity, rock properties, wellbore geometry
Development cost--cost overruns, delays
Operating cost--corrosion, labor cost, regulatory compliance
Transportation cost to market--tariffs and fees
Tax and Royalty structure--government take
Market Price of oil and gas--short term, long term

*good things
to recognize*

During the exploration phase, all the above factors are modeled using assumptions and analogs. As projects move to development and production, the focus shifts to the later half the list. Multiple scenarios are evaluated.

Need to constantly evaluate and optimize the operations:

- Risks and conditions change--good/bad/just different
 - Field conditions--such as labor costs, government take
 - Reservoir conditions--flow rates decline
 - Market conditions--prices, transportation costs
- Adjust operations as needed to maximize net present value.
 - Consolidate operations, automate operations, implement new technology

Again, projects that fall below the established economic thresholds get suspended or terminated if the long term metrics don't look good. Likewise, projects move forward as conditions become more favorable.

- Milne Point EOR
- North Slope gas line

What Separates the Winners From the Losers?

There is no simple single answer. But profitability is a good first lens.

Metrics used to measure profitability

- Rate of return
- Net present value
- Profitability index
- Payout

Factors to consider:

- Size of accumulation-- ultimate recoverable oil and gas
- Flow rate per well
- Location relative to existing infrastructure

Today there are several very large undeveloped oil fields on the North Slope. So size alone isn't the only measure.

Kuvlum, Hammerhead, Umiat

Today there is at least one very large undeveloped satellite pool on the North Slope. So proximity to existing infrastructure isn't the only measure.

Ugnu

Today there are world class gas accumulations on the North Slope so size, location and flow rate together don't guarantee a successful project.

Prudhoe Bay and Point Thomson

The offshore examples cited above are most likely uneconomic to develop today using today's technology and today's expected oil and gas market prices even at a zero tax and zero royalty rate. There always will be a continuum of "sub-economic" to "economic" projects on the North Slope regardless of commodity prices and exploration/development costs.

Projects can move back and forth on this continuum as conditions change.

The Future of Exploration and Development on the North Slope

There is no single or simple analog or model that describes all future exploration and development opportunities on the North Slope. The prospects and their associated economic potential are diverse and not viewed the same by all oil and gas companies.

For Exploration

Opportunities for multiple fields and pools--oil and gas

Some stand alone, some satellites. Some near infrastructure, some remote.

Brooks Range Foothills, remote NPRA (Kokoda)

Satellites outboard of the Kuparuk River Unit

Additional satellites inside producing units

For Development

Opportunities for multiple fields and pools--oil and gas

Some stand alone and some satellites. Some near infrastructure, some remote

Point Thomson

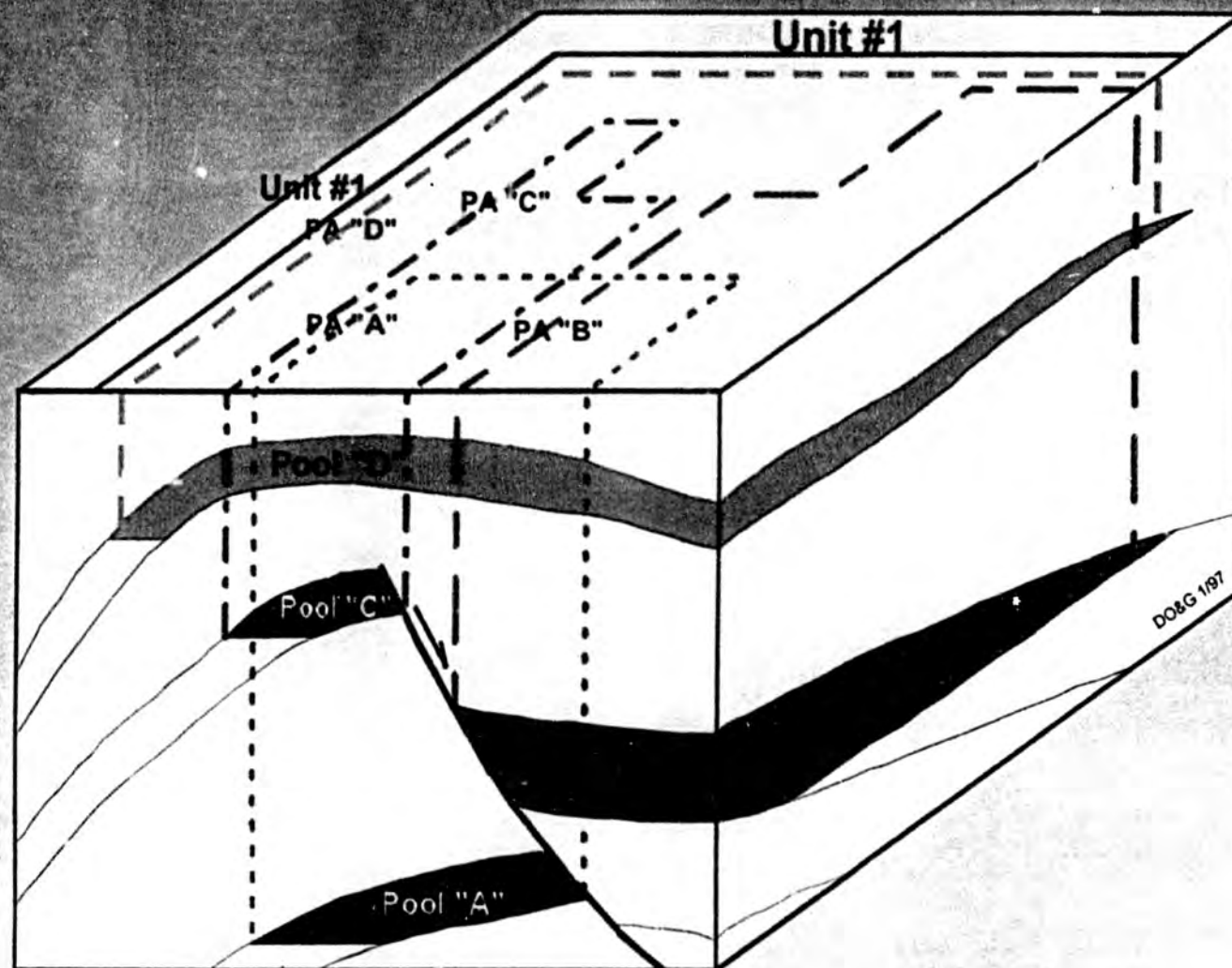
Close-in NPRA, remote NPRA

Oooguruk Unit, Nikaitchuk Unit, Tuvaaq Unit

Alpine satellites

Satellites inside producing units

Hypothetical Unit with 4 Pools & Four Participating Areas (PAs)



①

SOUND WAVES
ARE REFLECTED
DIFFERENTLY
BY EACH
MATERIAL

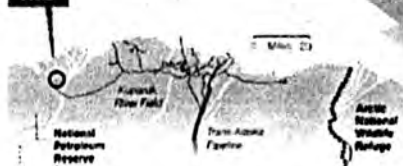


LOOKING FOR OIL
Images generated by supercomputers allow geologists to locate small pockets of oil or gas.

DRILLING TECHNOLOGY

Old drills were limited to a single vertical well, but newer wells can drill horizontally or spread in different directions to tap small pockets of oil.

Alpine Field



TRANSPORTING THE OIL

A 14-inch pipeline connects the Alpine field to the Trans-Alaska Pipeline about 60 miles west of the Arctic National Wildlife Refuge, a site proposed for new drilling.

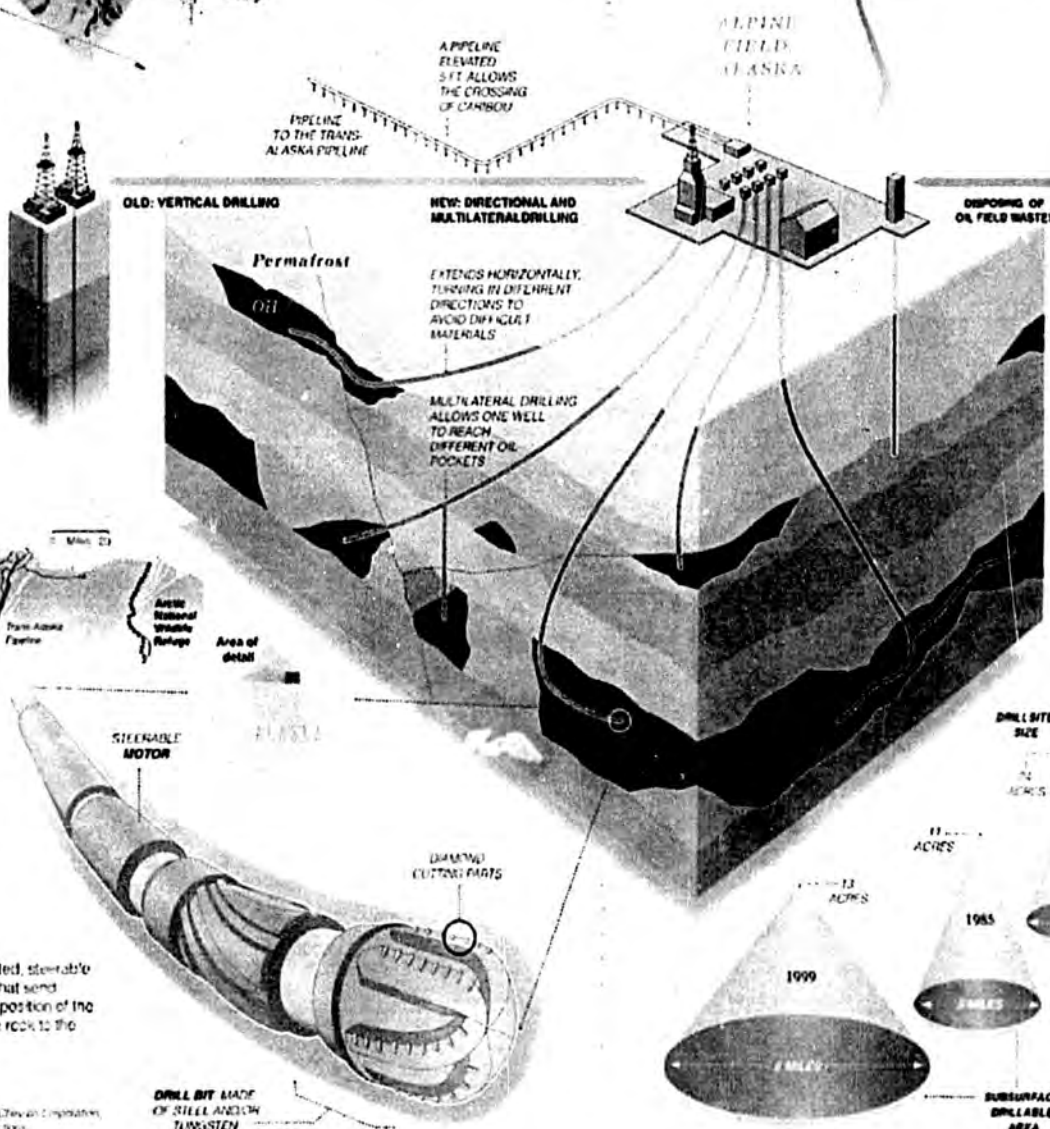
CUTTING PARTS

Today's drills are sophisticated, steerable machines with instruments that send information about the exact position of the drill bit and properties of the rock to the drilling team.

Sources: Phillips Petroleum Company; Chevron Corporation; BP America; McGraw-Hill; Arctic Circle, Connecticut.

Using the Latest Drilling Technology ...

Oil drilling sites like those in the Alpine field on Alaska's North Slope are using cutting-edge technology in hopes of reducing environmental damage.



... To Reduce Environmental Damage

Recent advances are lessening the industry's impact on the fragile Arctic ecosystem.



BP/Amoco

GETTING THERE

To minimize the project's impact on the environment, temporary ice roads are used in the winter, leaving few traces after they thaw.

MUD/ROCK
PASTE
CRUSHED
AND INJECTED



DISPOSING OF WASTES

Mud and debris from drilling used to be placed in big reserve pits. Today, rock cuttings are crushed, mixed with the mud, and sent deep into the earth where they originated. This minimizes the size of well paths.



CROSSING A RIVER

Although traditional pipelines are built above ground, the pipeline to the Trans-Alaska Pipeline plunges beneath the Colville River, preserving the surface and the river best environment.

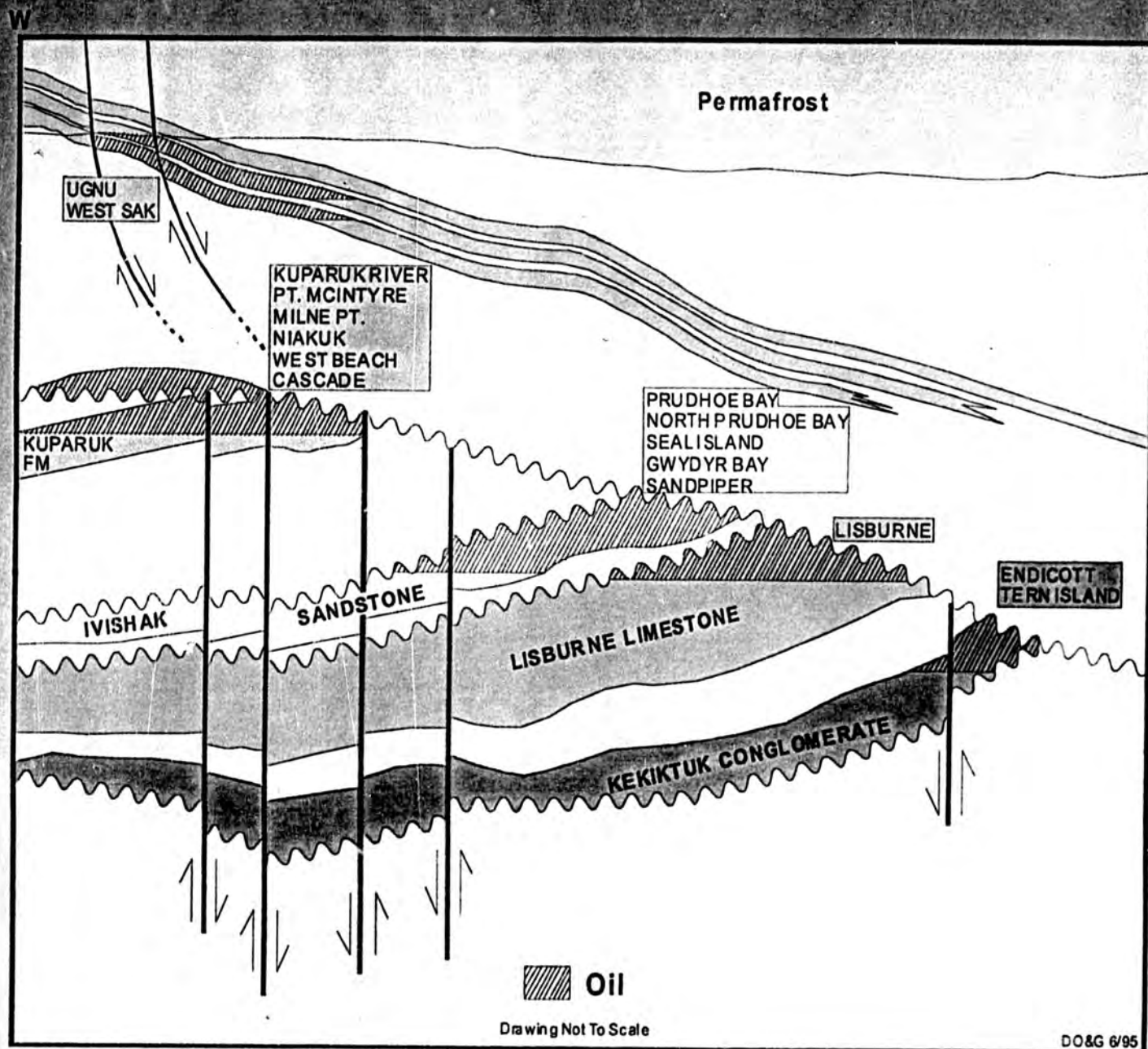
OCCUPYING LESS OF THE TUNDRA

The new drilling technology allows for smaller surface production pads and larger areas explored in the earth.

From Wikipedia/The New York Times

Central North Slope

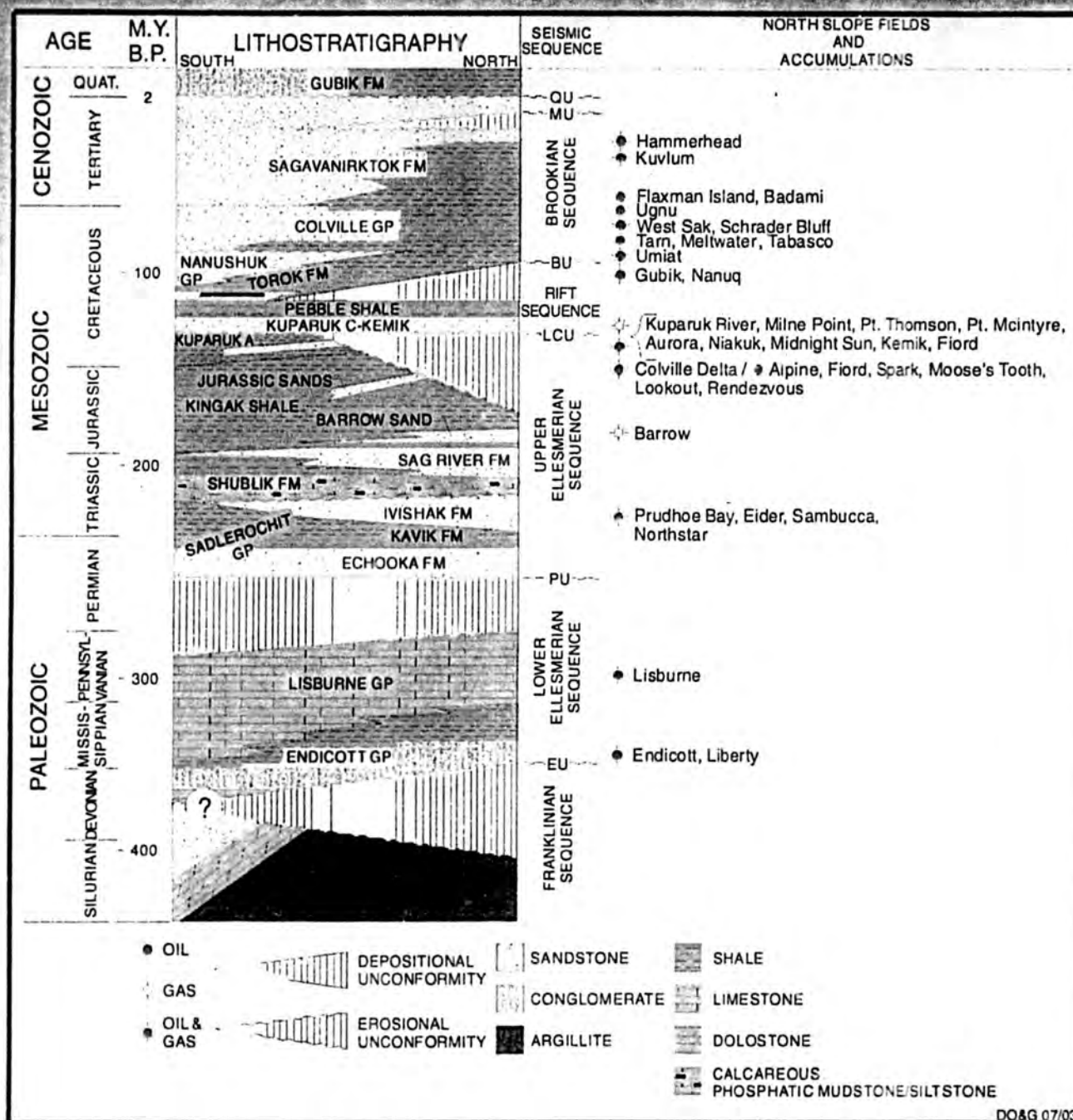
Generalized Geological Cross-Section



<http://www.dog.dnr.state.ak.us/oil/>

3

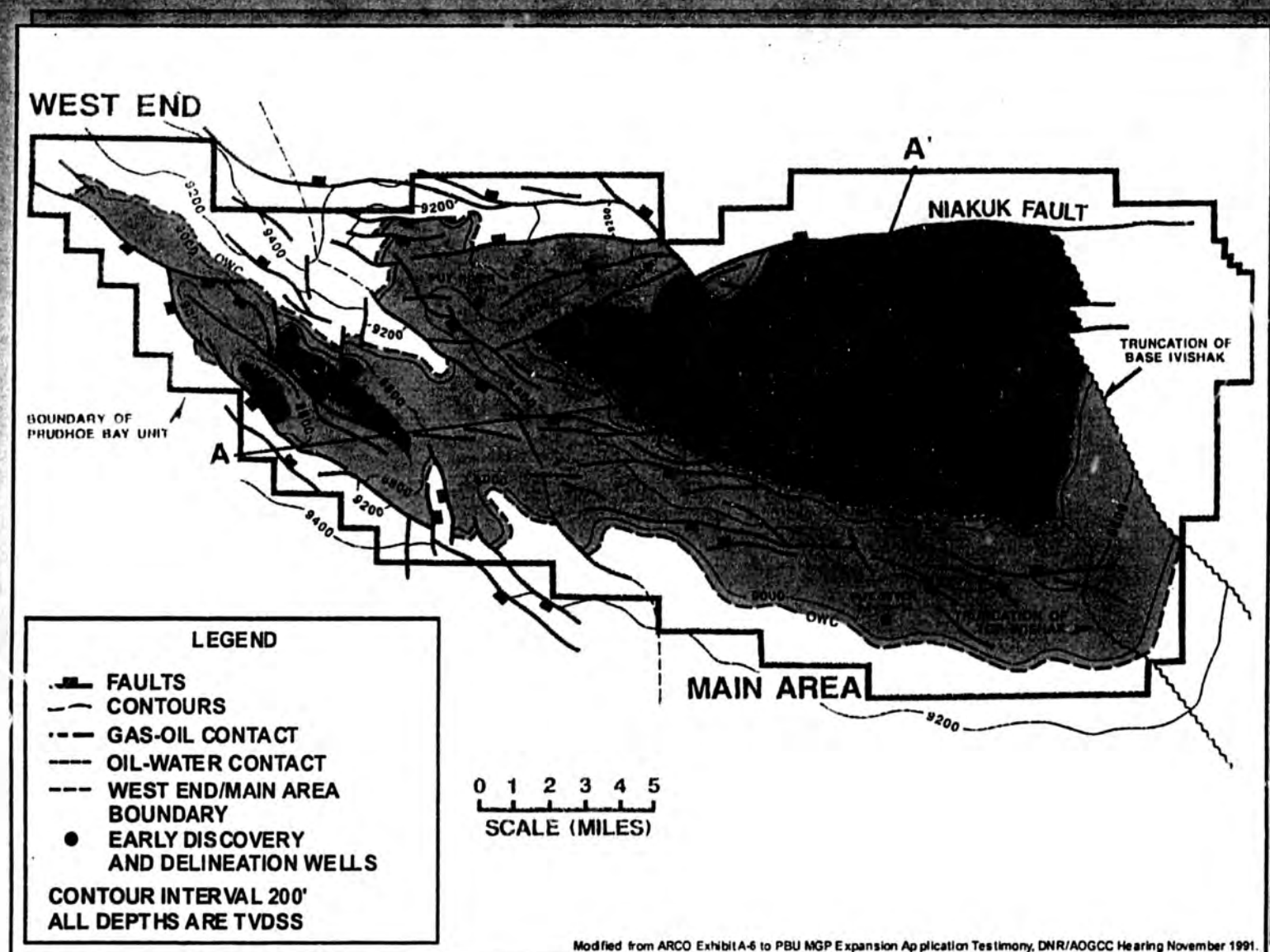
Generalized North Slope stratigraphic column displaying oil and gas reservoirs and associated accumulations



4

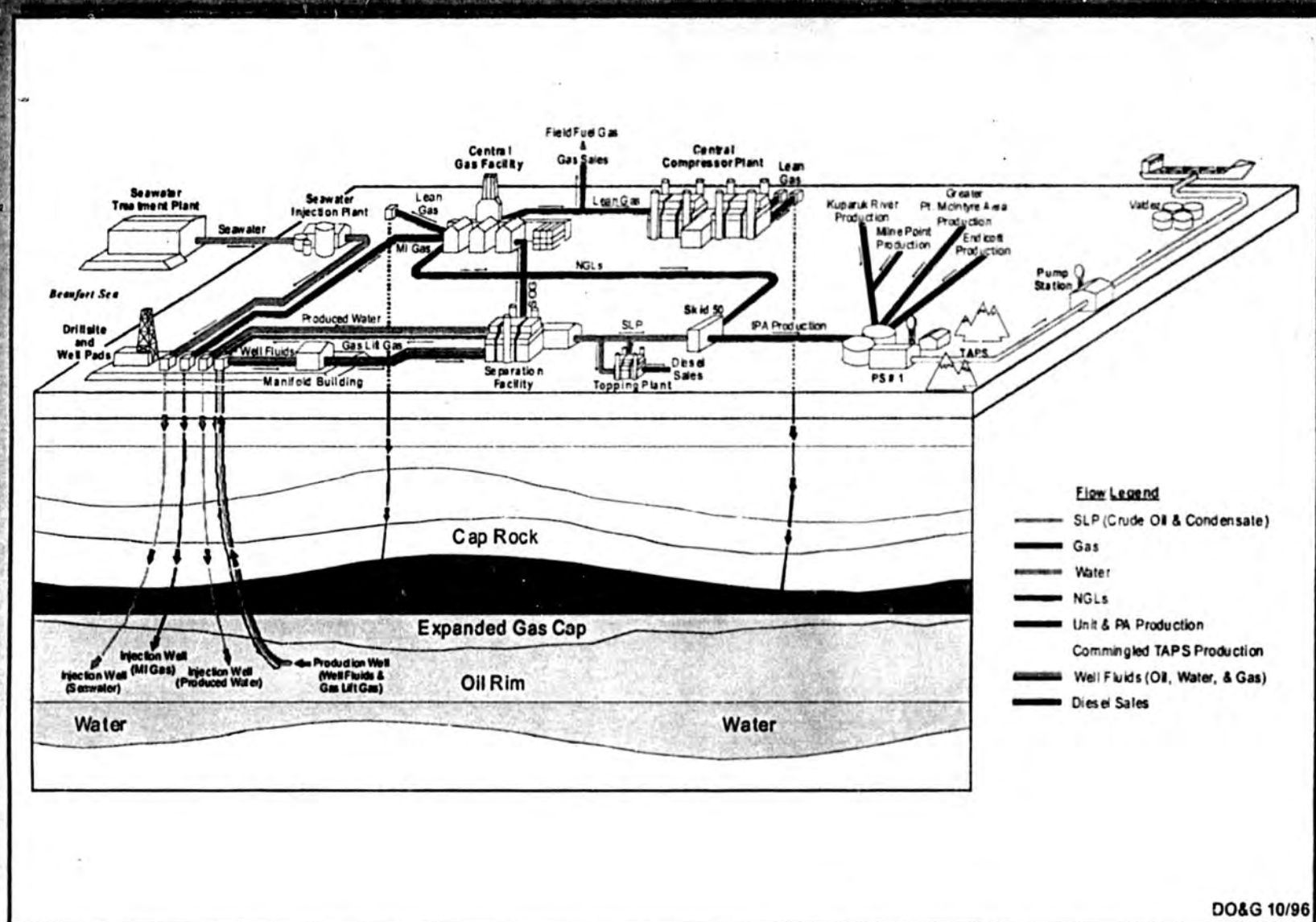
Prudhoe Bay Field

Top Ivishak Structure Map



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Prudhoe Bay Production and TAPS Schematic



DO&G 10/96

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OIL AND GAS



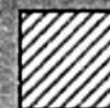
modified from:

Lease Ownership Without Common Equity

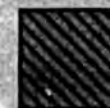
		ADL 300102	ADL 300101
ADL 300105	ADL 300104	ADL 300103	ADL 300301
ADL 300204	ADL 300203	ADL 300305	ADL 300304
ADL 300205	ADL 300206	ADL 300201	ADL 300202



BP 100%



CHEVRON 100%



BP 50%
CHEVRON 50%



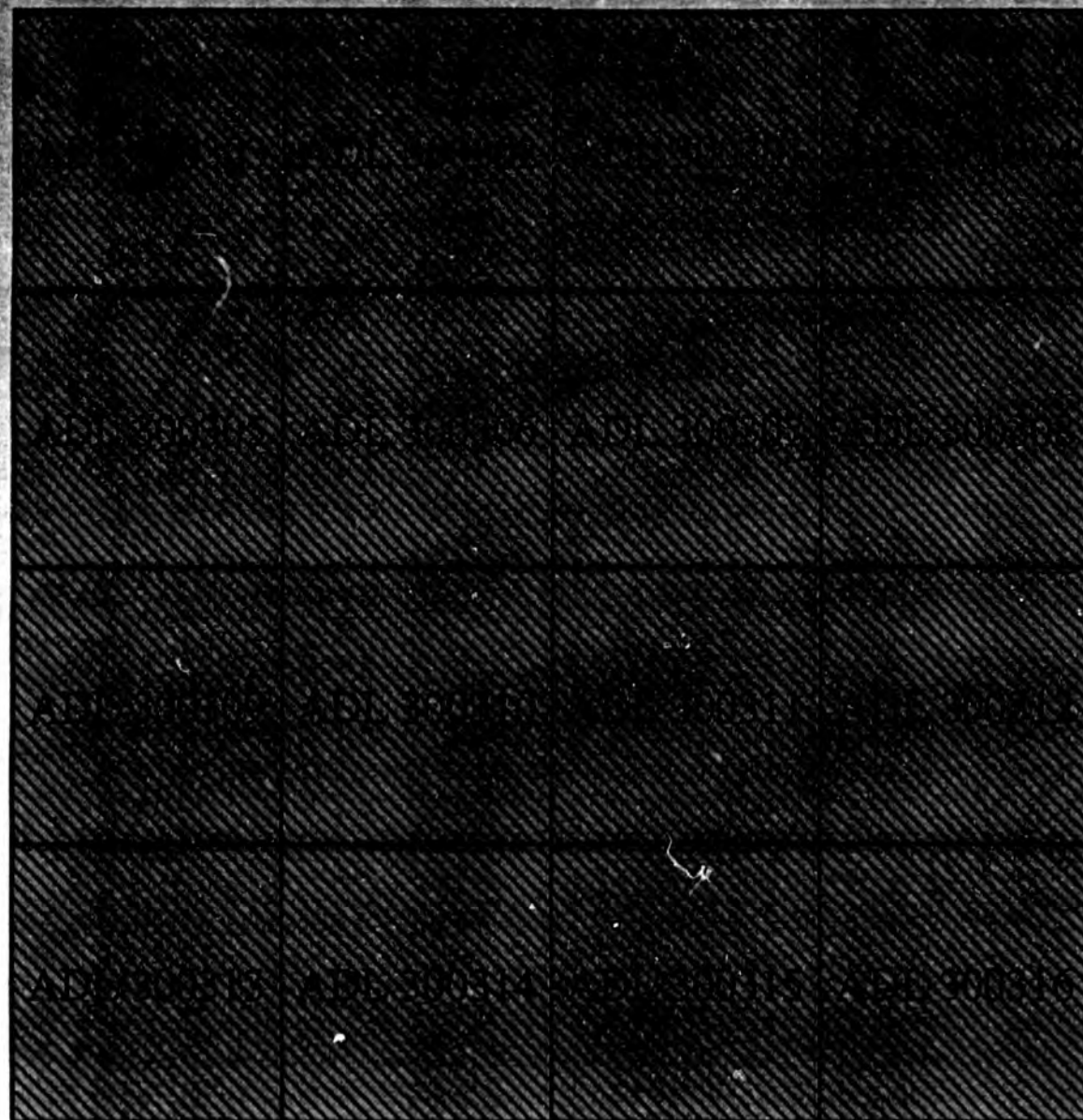
UNOCAL 100%



WINTHER 100%

(8)

Lease Ownership With Common Equity



BP 35%



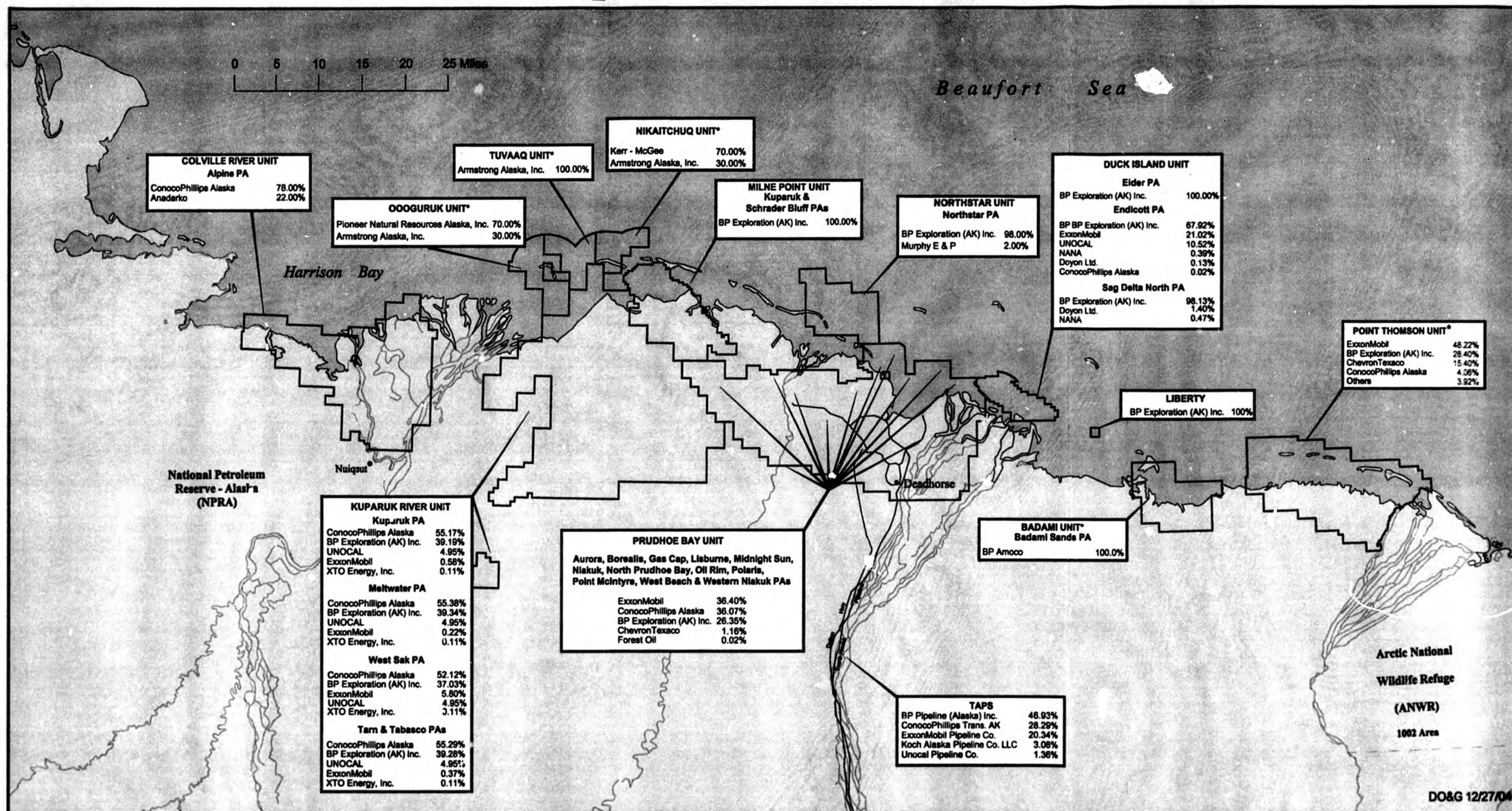
CHEVRON 35%

WINTHER 5%

UNOCAL 25%

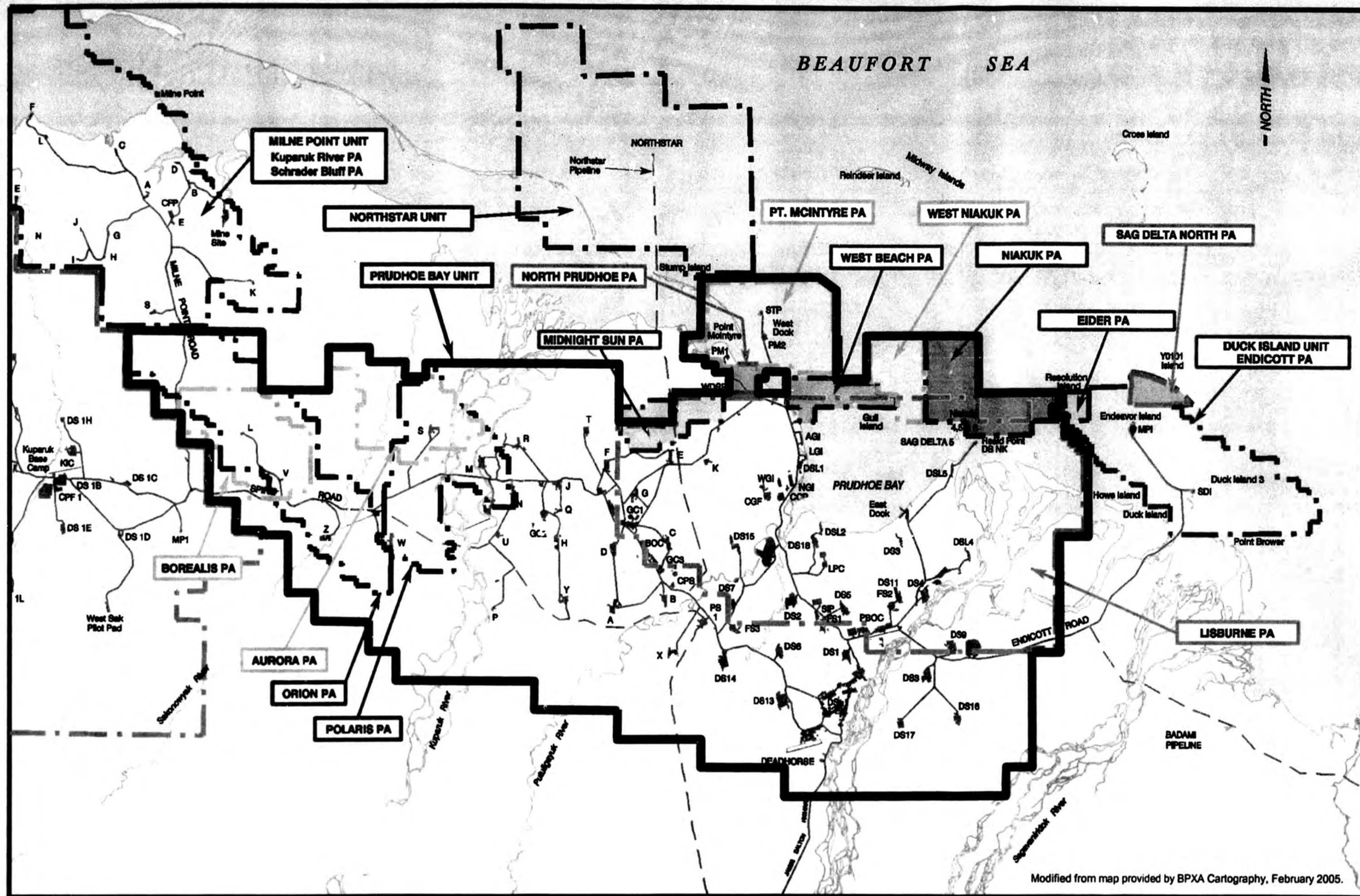
9

North Slope Oilfield and Pool Ownership



*When there is no production or PA, percentages are based upon working interest ownership on an acreage basis.

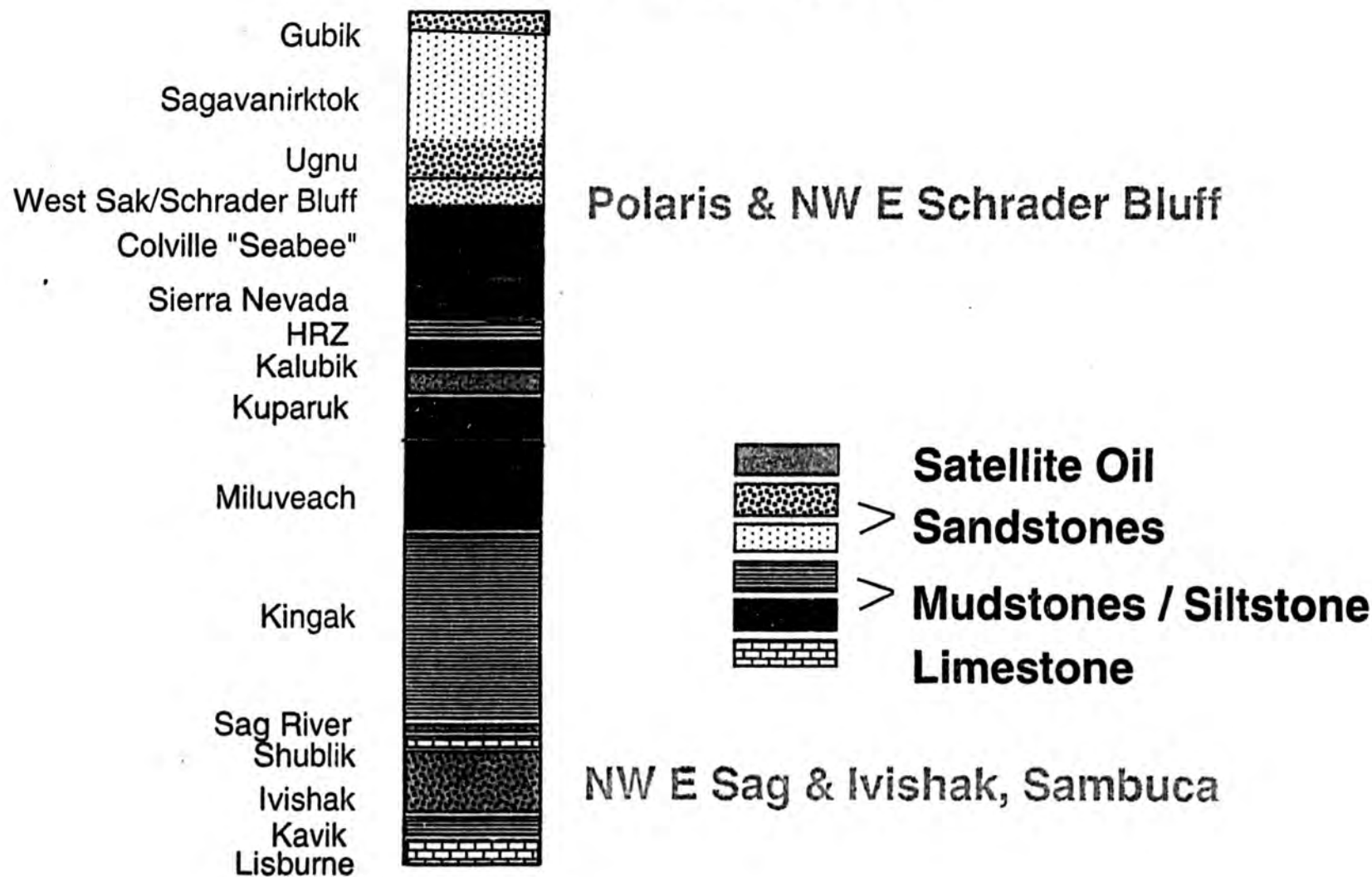
10



Modified from map provided by BPXA Cartography, February 2005.

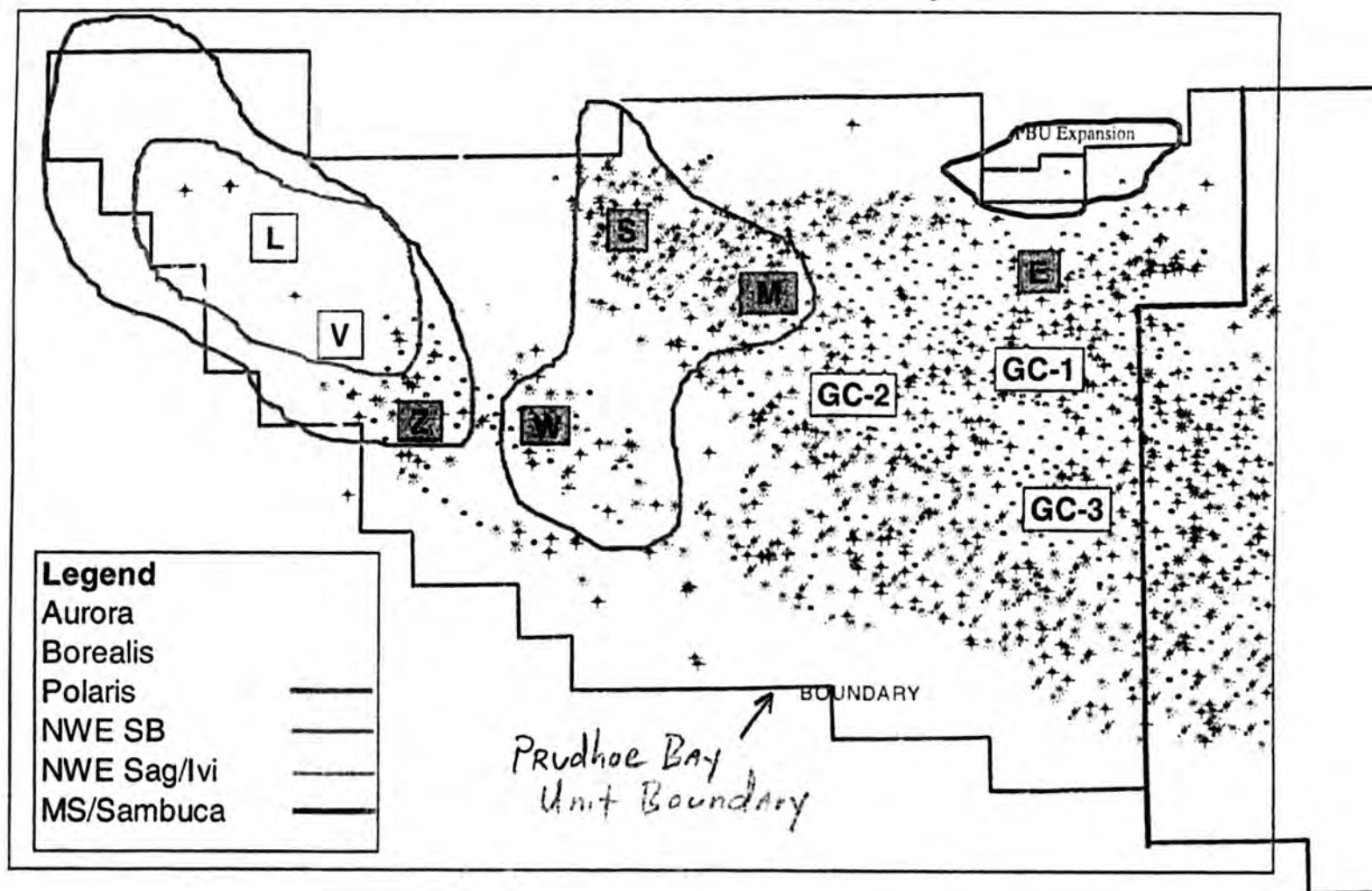
Prudhoe Satellites Update

Stratigraphy

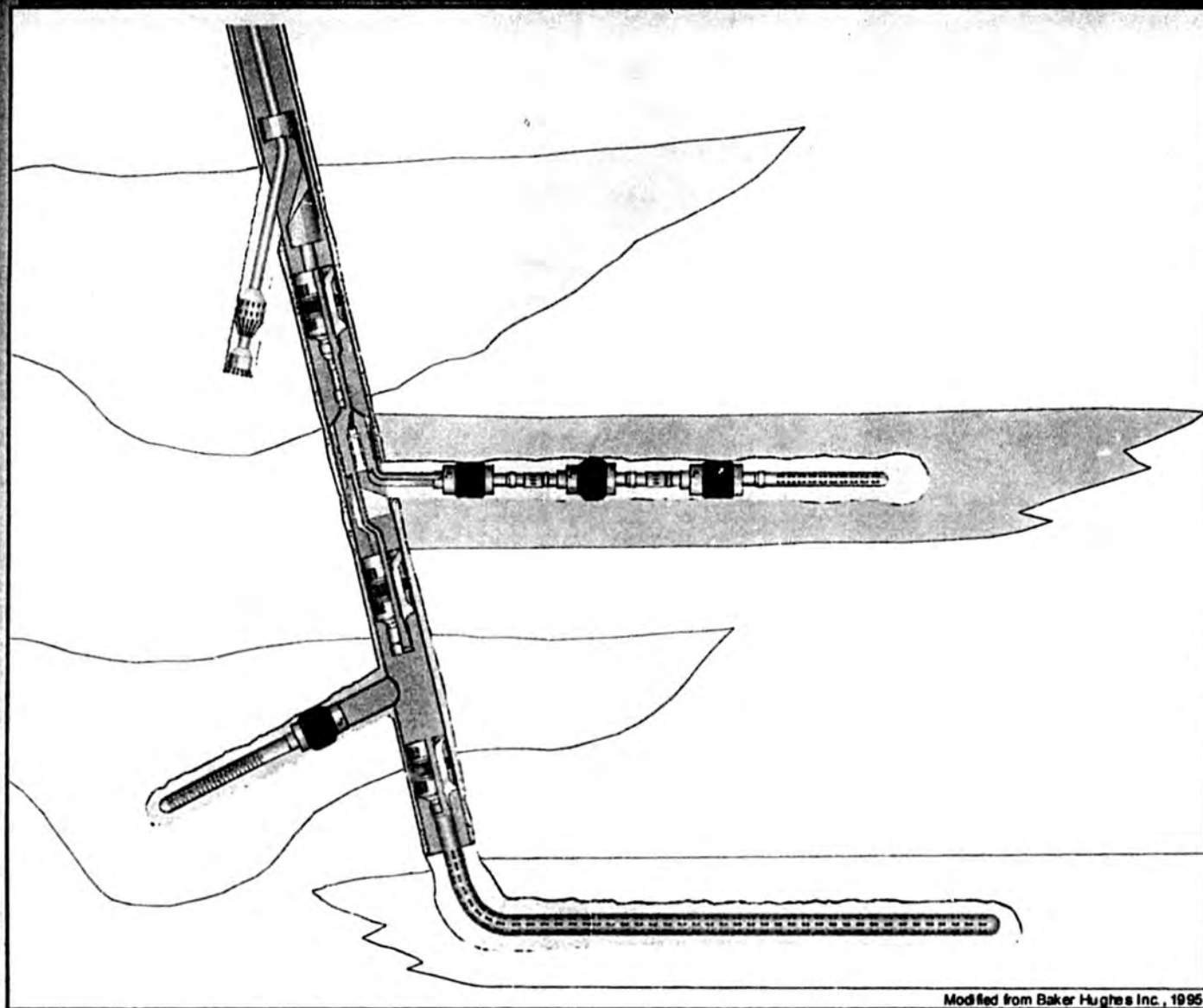


Prudhoe Satellites Update

Satellite Development Map



Multilateral Wellbore Completions

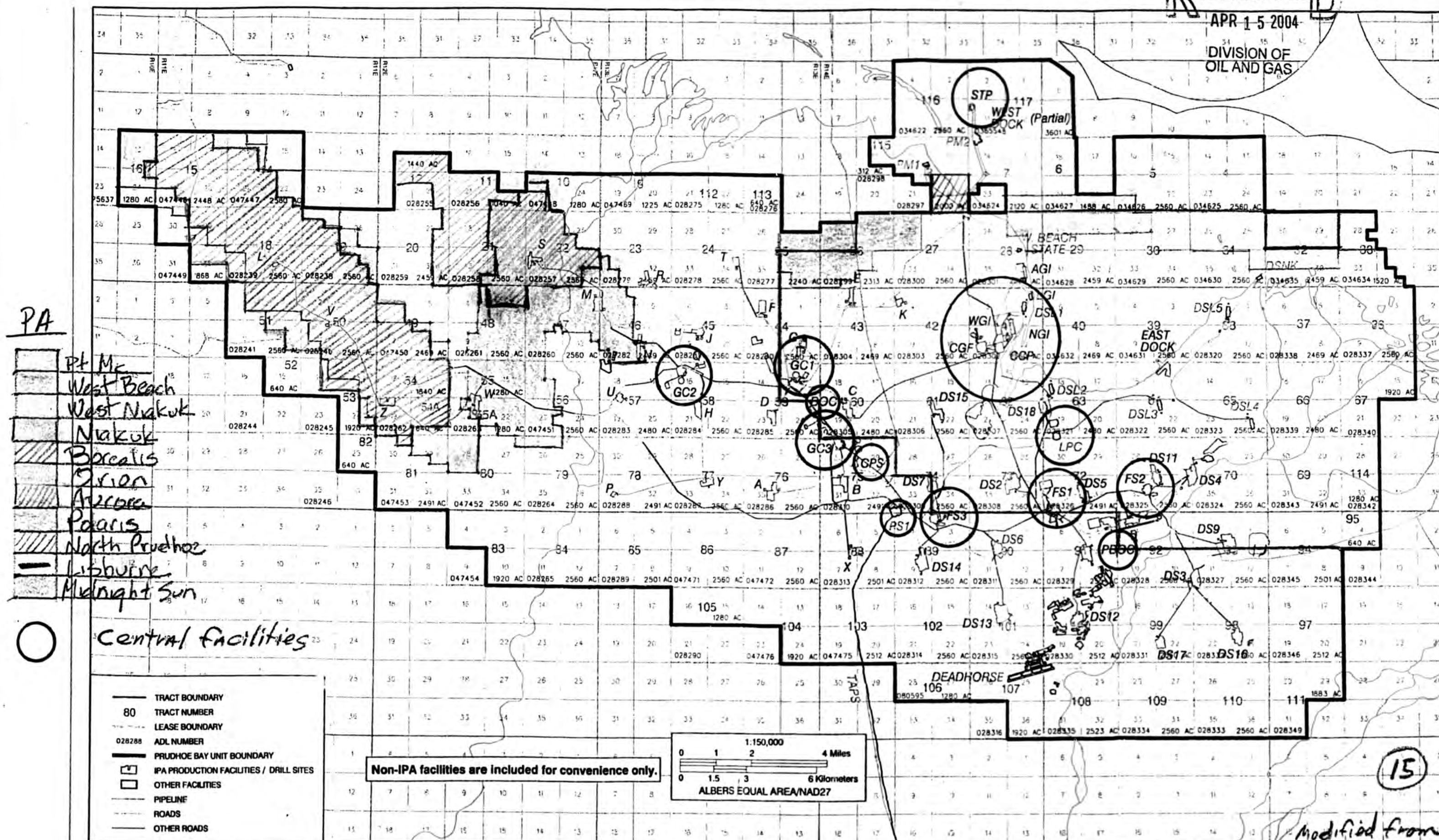


Modified from Baker Hughes Inc., 1995

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APR 15 2004

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OIL AND GAS



Modified from
BPXA Cartography/3-17-04/m14360.doc

SCOMM

1444:4

ALASKA STATE LEGISLATURE

SENATOR
Gene Therriault
119 N. Cushman Suite 101
Fairbanks, Alaska 99701
(907) 488-0857
FAX (907) 488-4271



While in Juneau
State Capitol
Juneau, Alaska
99801-1182
(907) 465-4797
FAX (907) 465-3884

Senate
Senate District F

Senate Joint Resolution 5

"Urging the United States Congress
Congress to reauthorize the Methane Hydrate
Research and Development Act."

SPONSOR: Senator Gene Therriault

SPONSOR STATEMENT:

For many years—even decades—Alaskans have been waiting for a natural gas pipeline project to deliver our tremendous resource on the North Slope to market. The benefits of such a project will include access for in-state uses, jobs for Alaskans, and cash to the state treasury. However, if we want to maximize the benefits to Alaskans, we need to make sure that our focus doesn't narrow too tightly to exclude the very real possibilities that await us.

Current discussions and negotiations for an Alaska Natural Gas Pipeline envision a 4.5 billion cubic feet per day (bcfd) project based on proven commercial reserves of 35 trillion cubic feet (tcf). These reserves will provide a supply to the pipeline for 16-20 years. However, according to Department of Natural Resources projections, project life increases from about two decades to more than 3 ½ decades when the available reserves increase from the 30-35 tcf of known conventional gas associated with current oil fields to 60 tcf due to the discovery of new conventional reserves or commercialization of hydrates in place beneath existing infrastructure.

Gas hydrates are naturally occurring ice-like substances composed of water and gas, in which a solid water-lattice accommodates gas molecules in a cage-like structure. Gas hydrates are widespread in permafrost regions and beneath the sea in sediment of outer continental margins. While methane, propane, and other gases can be included in the hydrate structure, methane hydrates appear to be the most common in nature.

The amount of methane sequestered in gas hydrates is enormous, but estimates of the amounts are highly speculative. In 1995, the USGS conducted the first systematic assessment of the in-place natural gas hydrate resources of the United States. That assessment estimated that the permafrost-associated gas hydrates on the Alaska North Slope may contain as much as 590 trillion cubic feet of in-place gas. Of this total, 40-100 tcf are in-place in reservoirs beneath the current infrastructure of the central North Slope.

The most recent (2001) estimate by the Minerals Management Service (MMS) puts the off-shore estimate at more than 32,000 trillion cubic feet in the Beaufort and Chukchi Seas.

A growing body of evidence suggests that production of natural gas, stored as gas hydrates, may be technically feasible. However, numerous technical challenges must be resolved before this potential resource can be considered an economically producible reserve. To that end, Congress passed H.R. 1573 the Methane Hydrate Research and Development Act of 2000 to determine whether or not gas hydrates could become a significant source of natural gas in the future. That Act expires—along with federal funding—later this year.

Senate Joint Resolution 5 calls on Congress to re-authorize the Methane Hydrate Research and Development Act along with appropriations totaling \$70 million over 5 years. The relevance of the potential additional reserves present in the form of gas hydrates is important to the pipeline project currently under discussion and negotiation. The sizing of the pipeline, access points into the pipeline, financing costs, and ultimately tariff rates could all be positively impacted by a determination of the commercial viability of gas hydrates.

Alaska State Legislature

SENATOR
GENE THERRIAULT

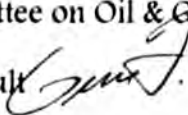
Mailing Address:
119 N. Cushman, Suite 101
Fairbanks, Alaska 99701
(907) 488-0857
Fax: (907) 488-4271

While in session
State Capitol
Juneau, Alaska
99801-1182
(907) 465-4797
Fax: (907) 465-3884
SENATE DISTRICT F

Senate

MEMORANDUM

TO: Representative Vic Kohring, Chair
House Special Committee on Oil & Gas

FROM: Senator Gene Therriault 

DATE: February 14, 2005

SUBJECT: Scheduling of SJR 5

I respectfully request that Senate Joint Resolution 5 be scheduled for a hearing in the House Special Committee on Oil and Gas on Tuesday, February 15. It is my understanding that notice was provided for a House version of the resolution, pending introduction and referral to your committee, and that SJR 5 can be heard at that time. SJR 5 passed the Senate without objection, 18-0, last week and has been transmitted to the House and referred to your committee.

Senate Joint Resolution 5 calls on Congress to re-authorize the Methane Hydrate Research and Development Act along with appropriations totaling \$70 million over 5 years. The potential additional reserves present in the form of gas hydrates are relevant to the pipeline project currently under discussion and negotiation.

Included in this packet is a memo provided by the U.S. Geological Survey on the progress-to-date on gas hydrate research on the North Slope.

At the time this resolution was introduced the U.S. Senate had not yet confirmed Samuel Bodkin as Secretary of Energy. I would appreciate it if you would entertain an amendment to update the individuals the resolution is to be sent to.

Please contact me if you have any additional questions.



Alaska State Legislature

Senate Majority Web: www.akrepublicans.org

Sponsor: Senator Gene Therriault
Current Version: SJR 5
Contact: Joe Balash, 465-4797

Fact Sheet for: Senate Joint Resolution 5

Short Title: REAUTHORIZE METHANE HYDRATE RESEARCH ACT

Summary:

- Requests the U.S. Congress to reauthorize the Methane Hydrate Research and Development Act to fund research and field testing under that Act.
- Requests reauthorization for five years, with appropriations of at least \$70 million over that time frame.

Benefits:

- Funds research, mapping and computer simulation to determine the actual volume of gas hydrates that could be produced, and eventually lead to commercialization of Alaska's natural gas hydrates—40 to 100 trillion cubic feet of which are in place in the central portion of the North Slope in close proximity or underlying existing producing fields.
- Furthers research currently under way in the MacKenzie River delta and on Alaska's North Slope.
- Could help meet the burgeoning national demand for natural gas, predicted to increase from 59 billion cubic feet per day to 84 billion cubic feet per day by 2025.
- Could help extend the life of the proposed Alaska natural gas line, remove potential reserve risk, and provide an important supply of gas for the Lower 48.
- Could help attract project financing and potentially lower the tariff, which could in turn increase exploration and early expansion of the proposed natural gas pipeline.

Background:

- Gas hydrate is a substance composed of methane molecules trapped in cages of water molecules. Hydrates are abundant in low temperature and high pressure environments, most notably in the permafrost zones of Alaska and deep waters of the Gulf of Mexico. Gas hydrates in Alaska could total 32,000 trillions of cubic feet, and when freed, yield 164 to 180 times their volume in free gas. As of yet, however, it is not known how to harvest their energy.

FISCAL NOTE

STATE OF ALASKA
2005 LEGISLATIVE SESSION

Fiscal Note Number: 1
 Bill Version: SJR 5
 (S) Publish Date: 2/9/05

Revision Date/Time (Note if correction): _____ Dept. Affected: Natural Resources
 Title Reauthorize Methane Hydrate Research Act RDU Resource Development
 Component Oil and Gas Development
 Sponsor Sen. Theriault
 Requester Senate Resources Component No. 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

OPERATING EXPENDITURES	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011
Personal Services						
Travel						
Contractual						
Supplies						
Equipment						
Land & Structures						
Grants & Claims						
Miscellaneous						
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0

CAPITAL EXPENDITURES						
-----------------------------	--	--	--	--	--	--

CHANGE IN REVENUES ()						
-------------------------------	--	--	--	--	--	--

FUND SOURCE (Thousands of Dollars)

1002 Federal Receipts						
1003 GF Match						
1004 GF						
1005 GF/Program Receipts						
1037 GF/Mental Health						
Other (Specify Type--Do not abbreviate)						
TOTAL	0.0	0.0	0.0	0.0	0.0	0.0

Estimate of any current year (FY2005) cost: 0.0

Mark this box (X) if funding for this bill is included in the Governor's FY 2006 budget proposal: ☐

POSITIONS

Full-time						
Part-time						
Temporary						

ANALYSIS: (Attach a separate page if necessary)

No fiscal impact anticipated with passage of this resolution.

Prepared by: Mark D. Myers, Director Phone 269-8800
 Division Oil and Gas Date/Time 2/4/2005
 Approved by: Tom Irwin, Commissioner Date 2/4/2005
 Agency Natural Resources

To: The Honorable Pete V. Domenici, Chairman
Senate Committee on Energy & Natural Resources

From: Dr. Mark D. Myers, Director, Alaska Division of Oil and Gas
Senator Gene Therriault, Chair,
Alaska Legislature, Legislative Budget and Audit Committee
Representative Ralph Samuels, Vice Chair,
Alaska Legislature, Legislative Budget and Audit Committee

Subject: State of Alaska Briefing Document on Proposal to Reauthorize
Methane Hydrate Research and Development Act of 2000,
Public Law 103-193, 114 Stat. 234

Date: January 24, 2005

Executive Summary

Currently, 59 bcfd of natural gas is consumed daily in the United States. The Energy Information Administration estimates that domestic demand for natural gas will increase to 77 bcfd by 2015, and to 84 bcfd by 2025. If the Alaska natural gas pipeline currently envisioned is built, the 35 tcf of known Alaska reserves could satisfy 4.5 bcfd of the total domestic demand for a period of two decades. Alaska's vast gas resources are estimated to also include 250 tcf of undiscovered conventional resources, 590 tcf of onshore (100 tcf within or near existing North Slope infrastructure), and more than 32,000 tcf of offshore gas hydrates, which could supply a much greater percentage of domestic demand for generations to come, particularly if two conditions are met: 1) gas hydrates can be commercialized; and 2) the rules for access to and expansion of an Alaska natural gas pipeline encourage competition in the exploration for and development of Alaska natural gas. The latter condition is currently the subject of rule-making by the Federal Energy Regulatory Commission. However, the former—commercialization of gas hydrates—is at risk absent Congressional action in 2005. Congressional action is needed to reauthorize Pub. L. 106-193, 114 Stat. 234 (2000), the Methane Hydrate Research and Development Act, and to fund research and field testing under that Act. It is proposed that the Act be reauthorized for a period of five years, with appropriations of no less than \$10 million/year in years 1-3 and \$20 million/year in years 4-5.

The large quantity of hydrates that underlie the existing Kuparuk River, Milne Point, and Prudhoe Bay Fields could in itself remove all potential reserve risk from year 20-35 and beyond for an Alaska natural gas pipeline producing at 4.5 bcfd. Reducing reserve risk will have a positive effect on project financing and potentially result in a lower tariff, which in turn could lead to increased exploration and early expansion of the pipeline.

Introduction

Sharply rising U.S. consumption of natural gas coupled with increasing worldwide gas demand intensify the need to find additional sources of natural gas. An increasingly global LNG market is developing based on these growing international energy demands, and upon the enormous natural gas reserves in the Middle East and other areas of the world. Reliance on these supplies worsens the U.S. trade deficit, places the U.S. natural gas market increasingly in direct

competition with other regional natural gas markets (many of which are mushrooming), exacerbates public environmental and security concerns with proposed tanker traffic and plant sitings, and increases U.S. reliance on foreign sources for energy supplies.

Undeveloped Alaska natural gas resources, both conventional and unconventional, are capable of delivering a vitally important share of U.S. gas needs. The recent rise in energy costs to what many consider to be a new long-term level has led to negotiations for building an Alaska North Slope (ANS) natural gas pipeline to ship these domestic supplies to distribution hubs serving the lower 48 states. The currently envisioned pipeline would deliver 35 tcf of proven Alaskan gas reserves from existing oil fields at a rate of 4.5 bcf/d for more than two decades, supplying about 6% of the 77 bcf/d of U.S. demand forecast by the EIA for 2015.

Furthermore, numerous assessments recognize that the total North Slope gas resource far exceeds just these proven reserves. Mean estimates by USGS, MMS, and the State of Alaska place at least 242 tcf of undiscovered, technically recoverable conventional gas under federal onshore and offshore areas (Table 1, AK Division of Oil and Gas, 2005) plus 590 tcf in-place of gas hydrates onshore in permafrost areas, and more than 32,000 tcf in-place of gas hydrates offshore in the Beaufort Sea (Sherwood and Craig, 2001 after Collett, 1995). Alaska's total gas hydrate endowment, including the surrounding federal waters, is estimated at over 169,000 tcf of in-place gas hydrate (Sherwood and Craig, 2001 after Collett, 1995). USGS assessments estimate 40 to 100 tcf of gas in-place in shallow permafrost-associated gas hydrate reservoirs in the infrastructure-served central ANS onshore area alone (Figure 1). The Alaska North Slope is one of the most promising places in North America to determine the resource potential of gas hydrates because of existing infrastructure, which will prove vital in supporting the emerging technologies required (Johnson, 2003).

Given that all reasonable estimates of the total ANS gas resource are much larger than the 35 tcf basis for the currently envisioned Alaska to Lower 48 gas pipeline, including the vast potential in the form of methane hydrates, it is essential that the federal government take steps to ensure that two conditions be fulfilled: 1) current progress in gas hydrate research and development must continue at full momentum to determine as quickly as possible whether these resources are commercially viable, and 2) the rules for access to and expansion of an Alaska North Slope gas pipeline must encourage industry competition to develop much needed additional gas, both from potential gas hydrate reservoirs and from revitalized exploration for conventional gas reserves. The Federal Energy Regulatory Commission is aware of the second condition, and is actively working to establish rules that will safeguard its ability to require capacity expansion as new reserves become available.

The economic return and risk associated with building the ANS gas pipeline depends largely on its useful lifespan, a function of both available reserves and pipeline capacity. Table 2 summarizes the relationship between project lifespan and reserves for two capacity scenarios, the 4.5 bcf/d base case and a 5.6 bcf/d expansion case, respectively. In the base case, project life increases from about 2 decades to more than 3 1/2 decades when the available reserves increase from the 30-35 tcf of known conventional gas associated with current oil fields to 60 tcf due to the discovery of new conventional reserves or commercialization of hydrates in place beneath existing infrastructure.

The remainder of this proposal addresses meeting the former condition – federal funding in support of gas hydrate resource commercialization.

Call for Legislative Action

The Methane Hydrate Research and Development Act of 2000 (Public Law 103-193, 114 Stat. 234) was created to determine whether or not gas hydrates could become a significant source of natural gas in the future. Because this Act expires at the end of the 2005 fiscal year, immediate congressional action is needed to replace it. Governor Murkowski's proposal urges new legislation to cover the five year period 2006-2010, with total appropriations of no less than \$70 million. Beginning with annual funding of \$10 million to continue and expand ongoing research in 2006-2008, appropriations would increase to \$20 million annually in 2009-2010 as the emphasis shifts from laboratory research and computer simulations to field testing and development pilot projects.

As stated in the proposal, the goals of the reauthorization and appropriations are threefold: 1) determine conclusively whether major gas hydrate accumulations can become a commercially producible resource, 2) grow the body of publicly available data, knowledge, and technology relevant to detailed resource assessment, exploration, and production of gas hydrates, and 3) fund a field testing program at a level adequate to remove commercial hurdles that would impede or prevent private industry from pursuing gas hydrate pilot projects. Specific steps will enable achieving each of these objectives and a careful review of the previous legislation may be required to ensure language in the reauthorization that is consistent with this legislative intent.

Conceptual Steps and Justification

The suggestions that follow are not intended to replace careful planning by those managing gas hydrate research and development programs and should not be used in constructing legislative language without broad support of those program managers. At this point, we recommend using language in the reauthorization that will ensure clear legislative intent without specifying detailed procedures for reaching these goals. In the broadest sense, activities fall into two categories: 1) developing improved assessments of both the total resource potential associated with gas hydrates and the volume of hydrate-related gas likely to become commercial over time given that pipeline capacity exists to ship it to market, and 2) developing gas hydrate production technologies, including field tests to prove up and compare alternative techniques. Both goals should be pursued beginning in year 1 with expanded desktop research and maintaining current research programs, leading to a greater emphasis on testing operations in years 4 and 5. Participation in "wells of opportunity" (i.e., industry wells targeting deeper horizons providing opportunity for data acquisition during penetration of shallow gas hydrate-bearing horizons) during years 1 through 4 merits federal funding to share or offset the costs of reservoir evaluation.

Continue technical and commercial assessments of onshore North Slope sub-permafrost gas hydrates and their associated free gas resources

Ongoing office, laboratory, and field research projects will feed directly into activities under a renewed gas hydrates act. The most successful research is likely to come from collaborative interdisciplinary teams of geologists, geophysicists, reservoir engineers, petroleum engineers, and commercial analysts representing a cross section of federal and state resource management agencies, industry, consultants, and universities. As stated in the proposal, the Alaska Department of Natural Resources, Division of Oil and Gas is also discussing with the Alaska State Legislature obtaining funding for an additional geologist dedicated to gas hydrate issues. This would facilitate the pairing of state and federal expertise and data sets, allowing for faster and more accurate collaborative resource assessments. In order for this structure to be effective, early administrative attention will be required from the participating organizations to establish the ground rules and data confidentiality requirements. Some of these ground rules and requirements which must be agreed upon early are likely to include issues such as the extent of data sharing, assessment methodologies, conditions for using proprietary data in making public resource interpretations, and specific data types and interpretive results that can be released to the public and/or shared with participating industry to support the conclusions.

Once these resource evaluation and development planning teams are in place, they should be authorized to integrate and expand upon current regional-level assessments of in-place permafrost-related gas hydrate and associated free gas resources. Some of these current assessments include the collaborative efforts underway involving the BLM, USGS, and State of Alaska. Future assessments funded by this legislation should expand upon this coordination, using consistent methodologies across federal and state lands of North Alaska. Assessment provinces should include the known hydrates in and near existing infrastructure on state lands of the central North Slope Colville-to-Canning corridor as well as more remote areas. The first remote provinces to be assessed should include state-lands foothills, the NPRA in the west, and the ANWR 1002 area in the east.

The proliferation of 3D seismic data across large areas of the North Slope over the last decade provides these research teams the opportunity to create much more reliable assessments than has ever been possible before. Access to these privately-acquired seismic surveys is restricted, but includes the state or federal agency that manages the lands in question. By assigning appropriate technical personnel in accordance with their agency's data access privileges, the research teams should be able to obtain, use, and integrate all available 3D seismic data coverage to develop a comprehensive portfolio of specific gas hydrate and associated free gas prospects. In some cases, it may be appropriate to license new or existing seismic surveys for assessment work, or even purchase the rights to release certain seismic data to the public. The portfolio should quantify the geologic risk profile and probabilistic distribution of in-place resource for each prospect using a standard petroleum systems approach. This work has been pioneered with tremendous success in the Milne Point Unit through the BPXA – DOE cooperative research study (e.g., Inks and others, 2004), where it is the basis for highly detailed gas hydrate resource estimates and production profile modeling.

Dedicated logging and/or coring of gas hydrate and sub-hydrate free gas intervals in several key wells per year should be considered beginning in year 1. The additional data obtained will

improve assessments of hydrate resource beneath existing infrastructure. Office and laboratory studies should continue into years 4 and 5, when they will begin to benefit from incorporation of the results of more field-based production testing. Subsequent iterations of reservoir performance models will thus be better calibrated and will more reliably forecast production rates and ultimate recovery of untested gas hydrate reservoirs. Better production forecasting will mean better ability to convert assessments of in-place resource to estimates of technically and economically recoverable gas reserves. Ultimately, the research will develop regional depletion plans and realistic potential development programs using reserves and rate profiles to assess regional development economics. The work will extrapolate reservoir models into regionally verified resource potential, construct production rate profiles within a range of expectations, and calculate potential regional gas reserves.

A final step in the office-based research process will be to develop commercial filters to apply to in-place or technically recoverable assessment figures to screen out resources located in accumulations too small to develop profitably. Estimates of the magnitude of reserves that may eventually be shipped would be far more useful than the technically recoverable reserves figures so often cited in resource assessments.

Design and conduct field production tests and pilot development of North Slope hydrates to assess viability of producing free gas and associated methane hydrate by depressurization of the free gas leg

The dearth of factual production data is one of the most critical gaps in commercializing much needed gas hydrate resources. Many in private industry acknowledge the enormous scale of the in-place resource, but without proven production potential, are unwilling to risk large-scale investments in testing and developing these reservoirs. Given the gas supply shortage facing the nation and the likelihood that construction of a gas pipeline will begin in the near future, the national interest is best served by funding public projects to close the gap in collaboration with, but without relying exclusively upon industry.

Beginning in year 1, and working in parallel with the assessment teams, engineers and geologists will be tasked with designing testing operations to begin during year 2 and continuing with the increased funding in subsequent years. Research to date has identified gas hydrate accumulations within the footprint of existing North Slope infrastructure that include a gas hydrate cap in communication with an underlying free gas column (Figures 2 and 3) as viable candidates for initial production testing. Accumulations of this description have been termed Type 1 hydrates (Moridis and Collett, 2003). Conventional completion and production of the free gas column eventually lowers reservoir pressure below the stability limit of the overlying gas hydrate zone, causing it to dissociate and release additional free gas across a broad regional contact. Because hydrates store 164 to 180 times as much methane as the same volume of free gas, their dissociation contributes large volumes of producible gas. The Messoyakha gas field in the West Siberian Basin is often cited as a producing example of a permafrost-associated gas hydrate accumulation, due to the difference between expected and actual declines in both reservoir pressure and production rate.

Feasibility studies carried out under a cooperative project between BP Exploration (Alaska) and the DOE (Howe and others, 2004) have adapted commercially available reservoir simulation

software to model schematic and actual hydrate-bearing reservoirs, with more detailed versions in progress (Figure 3).

The following discussion provides an overview of the current understanding in some of the more significant modeling. Cases 1-3 of Figure 4 depict simulated production profiles of a Type 1 gas hydrate representing 15 years of production from the same 300 mD permeability reservoir, but with variations in the type and number of producing wells. The initial plateau flow rates of these three cases are operationally constrained at levels ranging from 25 to 50 million cubic feet per day (mmcf/d) per well. A 50 mmcf/d plateau rate can be maintained significantly longer using a single horizontal producer than with two vertical producers constrained to 25 mmcf/d each. After 15 years, the simulated total flow rates are nearly the same at about 18 mmcf/d, regardless of whether one, two, or three producers are involved. Additional models indicate that after the steep decline that initially follows the plateau, the very slow decline rate of later years is due to steady supply of free gas from hydrate dissociation (Figure 5). This modeling is highly encouraging, but requires validation by field testing.

Details of design activities would be determined by the actual team, but a logical workflow would presumably begin with selection of candidate prospects for field testing within areas supported by existing North Slope infrastructure. Potential locations are already available in the Milne Point Unit where collaborative studies have integrated well data and 3D seismic data to quantify both Type 1 and Type 2 (hydrate only) prospects.

Numerous questions will be addressed at the outset of the design phase, including whether to drill a dedicated research well or share one intended for deeper production. Decisions will be required regarding optimal borehole angle, the duration of test production, and facility limitations. Depending on the type of wellbore selected for the testing and pilot program, drilling or work-over and completion operations will be necessary to expose the production zone in the free gas leg. This stage, including formation evaluation, should be complete within the first month, followed by an initial well testing phase that may last several weeks or months.

At this point, it is recommended that the well be placed on long-term production test for meaningful comparison to modeled production profiles. Depending on free gas volumetrics, the difference between original reservoir pressure and the hydrate stability limit, and operational constraints on the test producer's plateau flow rate, a pilot production plan lasting more than two years may be required to monitor the effects of depressurization and consequent hydrate dissociation. Because long term production testing may yield substantial quantities of methane, it will be advantageous to plan for local use of the gas. Possibilities include fuel for testing operations or field utilities, or reinjection for pressure maintenance of other reservoirs.

Design and conduct field production tests and pilot development of North Slope hydrates to assess viability of producing directly from hydrates without free gas depressurization

A second test should be designed to assess the viability of producing directly from hydrates that have no free gas leg available for conventional completion and depressurization. A major share of potential ANS gas hydrate resources appear to be trapped within these hydrate-only areas. Potentially, such a test could be conducted in the hydrate cap of a Type 1 reservoir, in Type 2 hydrates, which are accompanied by an underlying zone of movable water in the reservoir, or in

Type 3 hydrates, which fill the entire formation (Moridis and Collett, 2003). The project team will face many of the same decisions as for the free gas/hydrate dissociation test, including site selection, type of wellbore, and duration.

The critical difference between this and a free gas production test is that steps must be taken to prevent further cooling of the reservoir around the producer that would lead to reformation of the hydrates and shut off the flow of gas. The three ways of dissociating the hydrate structure to release gas are by lowering pressure, increasing temperature, or altering reservoir chemistry. However, dissociation is an endothermic (heat consuming) reaction that lowers the temperature of the surrounding formation. So, while it may be possible initially to liberate some free gas simply by lowering reservoir pressure adjacent to the well bore, it can freeze solid again unless heat and/or chemical inhibitors are added to the formation. The optimum test for producing directly from hydrates would provide the capability of experimenting with and comparing various thermal and chemical stimulation technologies. Several processes have been proposed that warrant consideration in the design phase:

- thermal stimulation with steam huff and puff
- thermal stimulation by closed-system circulation of warm water from the surface (either artificially heated on-site or still-warm formation water separated out of production stream from deeper reservoir)
- thermal stimulation by closed-system circulation of hot waters brought directly to the reservoir from a deeper aquifer zone in the same well
- thermal stimulation by in-situ catalytic combustion, electromagnetic, or microwave sources
- inhibitor injection (e.g., methanol)
- Carbon dioxide replacement of methane in hydrate structure (McGrail and others, 2004). If this process becomes viable, it may provide synergistic carbon sequestration benefits, in addition to liberating methane.

It will be up to the test design team to identify and select the most promising of these methods for direct field comparison.

Hypothetical R&D Activity and Expenditure Timeline

Table 3 represents a broad framework for executing the suggestions outlined above. This legislative proposal is submitted in recognition of the need for funding rapid and material advances toward unlocking the potential of our gas hydrate resources. Details of research and development tasks and the proposed expenditure timeline are subject to revision by project teams.

Recommendation

An urgent need exists for the reauthorization of federal legislation appropriating funds to support gas hydrate research and development. In the face of escalating demand and uncertain supply from overseas imports, it is critical that the United States increase domestic supply and diversify its sources of natural gas to include the development of unconventional resources. Known gas

hydrates overlying the already-developed oil fields of Alaska's North Slope afford a unique opportunity to meet both objectives provided they can be produced and brought to market economically. The need to better understand hydrate commerciality is all the more pressing given the inter-relationship to planning for the construction, operation, and regulation of an Alaska gas pipeline. The steps suggested here are offered as a conceptual basis for more detailed planning that will be needed to realize the intended goals of the proposed legislation.

(Figures 1-5, Tables 1-3, and References following on separate pages)

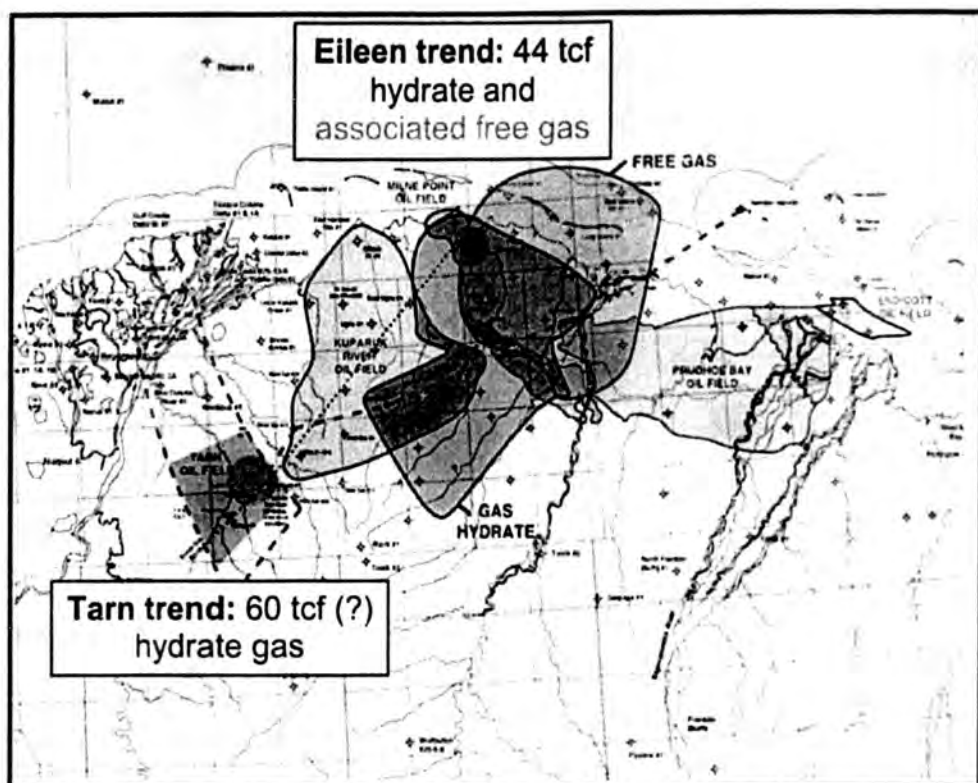


Figure 1. Known gas hydrate accumulations (blue) and hydrate-associated free gas accumulations (orange) in the vicinity of the major North Slope oil fields (green). The USGS estimates up to 100 tcf in place of hydrate in the Eileen and Tarn trends combined. From T.S. Collett, 10/01 and Hunter and Collett, (2004).

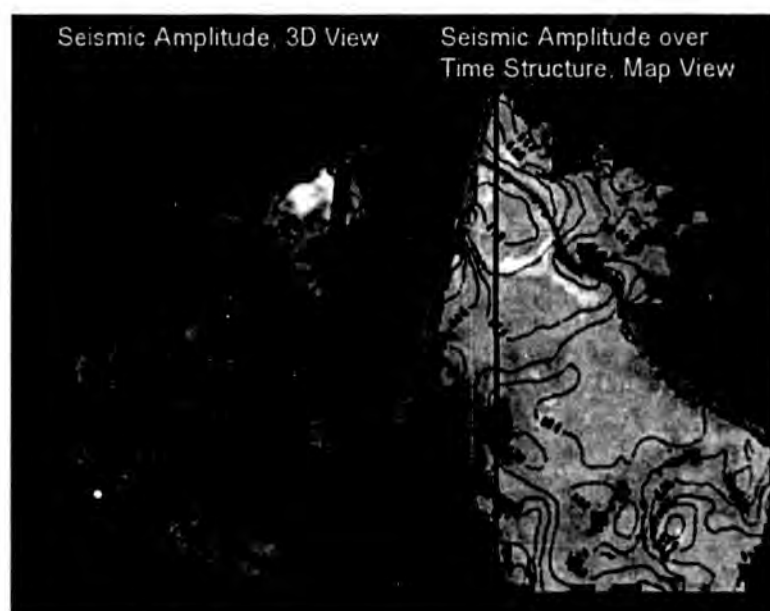


Figure 2. Seismic amplitude of a gas hydrate prospect within the Milne Point Unit in 3-dimensional view (left) and in map view with time structure (right). Warmer shades in shallowest corner of the fault-bounded reservoir compartment are interpreted to be gas hydrates, consistent with the estimated depth of the hydrate stability zone. From Hunter (2004).

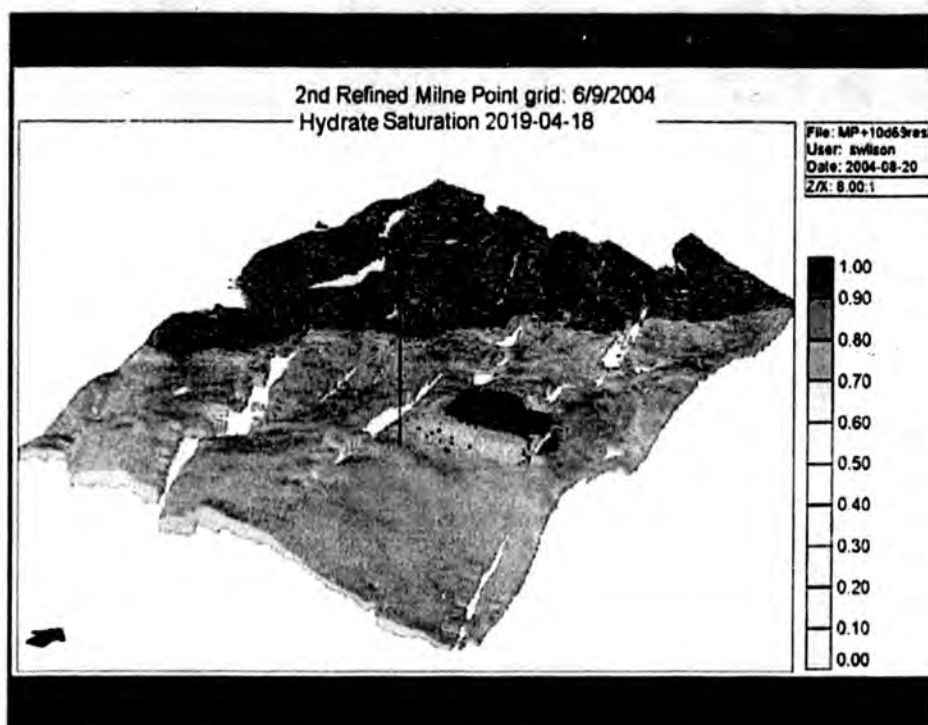


Figure 3. Milne Point Unit reservoir model showing gas hydrate cap (orange) overlying free gas (green) and a single vertical producing well. From Howe and others (2004).

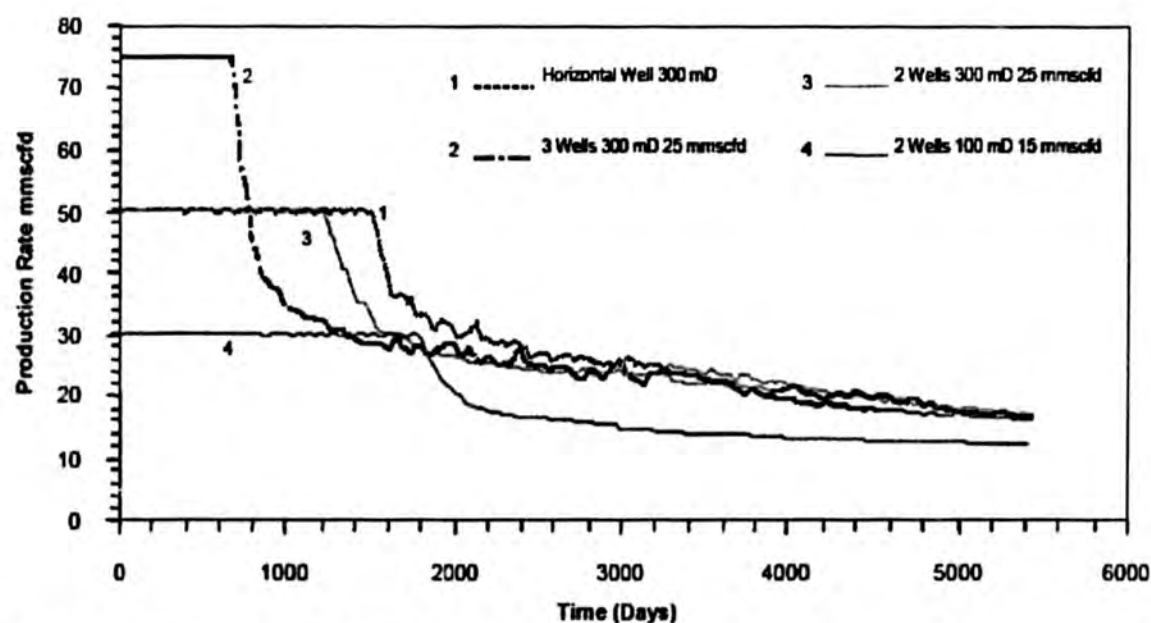


Figure 4. Gas production profile from a schematic reservoir. Cases 1, 2, and 3 compare offtake profile from the same reservoir using one horizontal, three vertical, and two vertical wells, respectively. Note extended plateau for one horizontal compared to two vertical wells, and that total flow in all scenarios is virtually the same after 15 years. Case 4 represents a lower permeability reservoir. Originally from Howe and others (2004) cited by Hunter (2004)

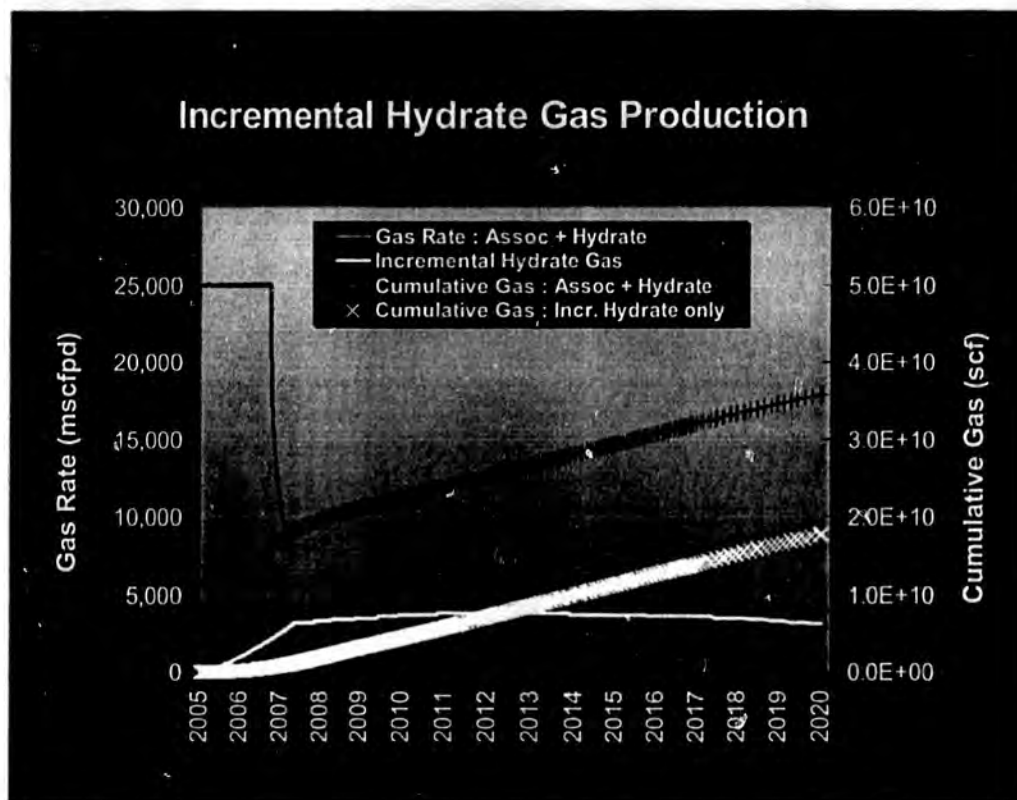


Figure 5. Graph showing modeled contribution of hydrates to total production for the reservoir model in Figure 3 (not the schematic reservoir represented in Figure 4). Production of original free gas constitutes all of the initial production; reservoir depressurization results in dissociation of overlying hydrates into free gas. In this particular simulation, dissociated hydrate gas accounts for nearly all production beyond the fifth year, and continues at a nearly constant rate for the next decade.

Table 1. Mean value, total natural gas reserve and resource base for Alaska assessment areas.

**All Values Trillions of Cubic Feet (TCF)
Alaska Division of Oil and Gas (01/12/05)**

BASIN	KNOWN RESERVES	RISKED UNDISCOVERED CONVENTIONALLY RECOVERABLE RESOURCE	RISKED UNDISCOVERED CONVENTIONALLY RECOVERABLE DEEP GAS RESOURCE ²	GAS HYDRATES IN PLACE RESOURCE ⁶	COALBED METHANE IN PLACE RESOURCE	BASIN TOTAL
NORTH ALASKA (onshore)	35.000 ¹	141.700 ⁸	17.700 ²	590.000 ⁵	800.000 ⁷	1,566.700
NORTH ALASKA (Beaufort shelf) ²	0.000	32.070	N/A	32,325.000 ³	N/A	32,357.070
NORTH ALASKA (Chukchi shelf) ²	0.000	60.110	N/A	50.000 ³	N/A	110.110
CENTRAL ALASKA ⁴	0.000	2.760	N/A	N/A	N/A	2.760
YUKON FLATS ⁹	0.000	5.460	N/A	N/A	N/A	5.460
KANDIK ⁵	0.000	0.116	N/A		N/A	0.116
NENANA/TANANA	0.000	N/A	N/A	N/A	N/A	N/A
COPPER RIVER	0.000	N/A	N/A	N/A	N/A	N/A
TOTAL BY GAS TYPE	35.000¹	242.216	17.700²	32,965.000	800.000⁷	34,042.216

After Craig, J., and Sherwood, K., Prospects for development of Alaska natural gas: a review as of January 2001, Minerals Management Service, Alaska Region. tbl. 9, p. 76.

Modified to include only North and Central Alaska basins and updated to include new information as footnoted.

N/A = Not Assessed

¹ Current estimate of known "stranded" recoverable North Slope conventional gas reserves in Prudhoe Bay, Point Thomson and smaller fields.

² Subcategory of and included in "Undiscovered Technically Recoverable Conventional Reserves". Represents Basin Deep or Basin Centered component > 15,000' depth.

³ Craig and Sherwood arbitrarily split offshore hydrate resource estimates between Beaufort and Chukchi Sea shelves. Total North Alaska offshore gas hydrate potential remains 32,375 tcf.

⁴ 1995 National Assessment of United States Oil and Gas Resources, U.S. Geological Survey, Open File Report, Digital Data Series-30, pub. 1995. For all central Alaska basins except the Kandik Basin. Other basins not evaluated individually.

^{4.5} Geological Survey of Canada estimated mean undiscovered gas in place ~ 0.489 - 0.800 TCF. Alaska component estimated as 0.116 Tcf.

⁶ Collett, personal communication, 11/26/04.

⁷ Barker, C.E., Clough, J.G., Roberts, S.B., and Fisk, R., Coalbed methane in Northern Alaska: potential resources for rural use and added supply for the proposed trans-Alaska gas pipeline; AAPG-SPERM Joint Technical Conference, Anchorage, AK, May 2002.

⁸ Includes nonassociated and associated gas. State and Native lands are estimated to be approximately 60 TCF and are included in this total.

⁹ Oil and Gas Assessment of Yukon Flats, East-Central Alaska, 2004, USGS Fact Sheet 2004-3121, December 2004.

Table 2. Useful life of an Alaskan gas pipeline given variations in reserves and capacity.

Reserves, TCF		Project Life (Years)	
		Pipeline Capacity BCF/Day	
		(4.5)	(5.6)
Known Resources 	33	20.1	16.1
	36	21.9	17.6
	40	24.4	19.6
	60	36.5	29.4
	100	61.5	48.9
Undiscovered Resources	150	91.3	73.4

Table 3. Methane Hydrate Research, Development and Field Operations -- Authorization Budget

	2006	2007	2008	2009	2010	Total Spending
North Slope Studies						
Seismic data processing and/or acquisition	4.00	2.00	-	-	-	6.00
Regional resource assessments	0.50	0.75	1.00	1.00	0.50	3.75
Prospect definition studies	1.00	1.00	1.00	0.75	0.50	4.25
Data Acquisition (wells of opportunity)						
Logs (3 ea, 2006 - 2009)	0.36	0.36	0.36	0.36	-	1.44
Core (1, for thermal studies)		0.50	0.50	-	-	1.00
Thermal stimulation research	0.50	0.50	0.50	1.00	1.00	3.50
Carbon dioxide replacement research	0.50	0.50	0.50	0.50	0.50	2.50
Test designs/site selection/planning/permitting/LL items	0.50	0.75	0.75	0.25	-	2.25
	7.36	6.36	4.61	3.86	2.50	24.69
North Slope Field Operations						
Test production of NS Hydrates from underlying free gas zone	-	3.00	4.56	4.56	2.00	14.12
Test direct production of NS Hydrates	-	-	-	6.38	5.48	11.86
	-	3.00	4.56	10.94	7.48	25.98
Total North Slope Spending	7.36	9.36	9.17	14.80	9.98	50.67
Gulf Coast and Other L-48 Studies	2.64	0.64	0.83	5.21	10.02	19.34
Total Spending	10.00	10.00	10.00	20.00	20.00	70.00

Average daily fully-loaded rig cost: \$35,000/day 45 days, RU, D&C, rig test = \$1.575 million
 Production testing costs: \$12,500/day 15,000 /day for direct production test (includes thermal costs)
 Incremental shallow logging costs: \$120,000/well

Test production of NS Hydrates from underlying free gas zone: - operations start mid-2007, w/ 45 days of rig work, prior to long-term production testing
 Test direct production of NS Hydrates: - operations start early-2009, w/ 45 days of rig work, prior to long-term production testing

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United States Department of the Interior
U.S. Geological Survey

MEMORANDUM

January 3, 2005

**TO: Bonnie Robson, Consultant to Legislative Budget & Audit, Alaska State
Legislature**
FR: Timothy S. Collett, U.S. Geological Survey
**CC: Brenda Pierce (USGS); Robert Fisk (BLM); Robert Hunter (BPXA); Jim
Clough (DGGS)**
SU: Alaska North Slope Gas Hydrate Energy Research Issues.

I want to first take this opportunity to thank you for your email inquiry that dealt with gas hydrate research opportunities on the Alaska North Slope (ANS). There are two major gas hydrate projects with an ANS focus. The first is a "basin-wide" gas hydrate energy assessment project being managed by the BLM, USGS, and the DGGS. The second project is a joint industry-government effort, lead by BPXA and DOE to determine the energy resource potential and producibility of several known gas hydrate accumulations in the area of the Prudhoe Bay and Kuparuk River oil fields. In response to your request, I have compiled the following report that contains short summary overviews of both the BLM-USGS-DGGS and BPXA-DOE ANS gas hydrate energy assessment projects. I have also included a short technical review of our historical work on gas hydrates in northern Alaska. This report begins with several recommendations that address your questions about the status of the ongoing gas hydrate research efforts in Alaska and what additional work could be considered to assess the energy resource potential of gas hydrates on the ANS. Thank you again for this opportunity, please contact us if you have any other questions.

RECOMMENDATIONS:

1. The BPXA-DOE gas hydrate project is approaching a critical decision point in their ANS gas hydrate energy assessment efforts. By March of 2005, BPXA-DOE will make the decision to evolve from a mostly office exercise to an active field testing phase. It appears that both BPXA and DOE will make the decision to move ahead with a more aggressive field program, but this decision is still pending. This project could benefit from additional financial support. Letters of support to both BPXA and DOE management would also help clarify the potential importance of gas hydrate energy resource development from a State of Alaska perspective.

2. Activities under the Methane Hydrate Research and Development Act of 2000 are "shall cease to be effective after the end of fiscal year 2005". However, since most of the gas hydrate field production studies under the BPXA-DOE project are scheduled to start near the end of 2005 and run through 2007, it is obvious the Methane Hydrate Research and Development Act of 2000 will need to be renewed. Early indications are that there is broad support to move ahead with new government led gas hydrate research, but the future of the DOE led gas hydrate efforts beyond FY-2005 is unclear.

3. The ANS "basin-wide" gas hydrate assessment being lead by the BLM-USGS-DGGS is moving ahead on schedule with the results of the ANS gas hydrate energy assessment study to be released near the end of FY-2007. The BLM has financially supported most of the direct cost of this project since its start in FY-2003, with the USGS providing in-kind support in the form of research staff salaries. Under the stated goals and timelines, this project is adequately funded. However, both the project goals and scope associated with this effort could be modified with input from other State or Federal interest groups.

4. As summarized later in this report, the BPXA-DOE ANS gas hydrate project is designed to assess the commercial viability of gas hydrates and associated free gas resources in the Prudhoe Bay, Kuparuk River, and Milne Point field areas on the ANS. As noted above, this project has also reached a critical milestone and the future of this effort is unclear. An argument can be made that the State of Alaska and other Federal interest groups in Alaska (including BLM and the USGS) should be more involved in technical aspects of assessing the production response and characteristics of the known and inferred gas hydrate accumulations on State and Federal lands in northern Alaska. Instead of leaving the development of the technology required to produce gas from Alaskan gas hydrate accumulations to the BPXA-DOE project, it might be wise to expand this effort to include a stronger State of Alaska and Federal research component. With the inclusion of State and Federal land and resource management agencies it is likely that we will develop a more complete understanding of the energy resource potential of gas hydrates across the entire ANS.

WHAT ARE GAS HYDRATES?

Gas hydrates are naturally occurring ice-like substances composed of water and gas, in which a solid water-lattice accommodates gas molecules in a cage-like structure. Gas hydrates are widespread in permafrost regions and beneath the sea in sediment of outer continental margins. While methane, propane, and other gases can be included in the hydrate structure, methane hydrates appear to be the most common in nature. The amount of methane sequestered in gas hydrates is probably enormous, but estimates of the amounts are highly speculative. In 1995, the USGS conducted the first systematic assessment of the in-place natural gas hydrate resources of the United States. That study suggested that the amount of gas in the Nation's hydrate accumulations greatly exceeds the volume of known conventional domestic gas resources. The 1995 USGS assessment also estimated that the permafrost-associated gas hydrates on the Alaska North Slope may contain as much as 590 trillion cubic feet of in-place gas. The production history of the

Russian Messoyakha gas hydrate field, in the West Siberian Basin, demonstrates that gas hydrates are an immediate source of natural gas that can be produced by conventional methods. Gas hydrates also represent a significant drilling and production hazard. Russian, Canadian, and American researchers have described numerous problems associated with gas hydrates, including well blowouts and casing failures.

HISTORY OF GAS HYDRATE EXPLORATION IN ALASKA:

The Eileen and Tarn Gas Hydrate Accumulations. Two large gas hydrate accumulations have been identified near the Prudhoe Bay Oil Field. The volume of gas estimated within the known gas hydrates of the Prudhoe Bay-Kuparuk River infrastructure area alone may exceed 100 trillion cubic feet of in-place gas. However, it is important to note that none of the completed gas hydrate energy assessments have predicted how much gas could actually be produced from the known gas hydrate accumulations in northern Alaska.

The occurrence of gas hydrates on the North Slope of Alaska was confirmed in 1972 with data from the Northwest Eileen State-2 well located in the Prudhoe Bay Oil Field. Most of the gas hydrates near the Eileen discovery well, occur in a series of laterally continuous sandstone reservoirs; and are geographically restricted to the area overlying the western part of the Prudhoe Bay Oil Field and the eastern part of the Kuparuk River Oil Field. Three-dimensional seismic surveys in the Prudhoe Bay Oil Field indicate the presence of free-gas accumulations trapped stratigraphically downdip below several of the gas hydrate units. The volume of gas within the gas hydrates of the Prudhoe Bay-Kuparuk River area is estimated to be about 37 to 44 trillion cubic feet.

Recently, data from wells along the western margin of the Kuparuk River Field have revealed a large gas hydrate accumulation overlying the Tarn Oil Field. The Cirque-1 well, located about four miles southwest of the Tarn Oil Field, blewout in 1992 after drilling through what appears to be a free-gas interval possibly trapped below the gas hydrate stability zone. The gas-hydrate-bearing stratigraphic interval in the Tarn area appears to be the up-dip equivalent of the West Sak sands which are estimated to contain more than 20 billion barrels of in-place viscous oil and is the focus of recent development activity. Preliminary analyses of other recently completed wells along the western margin of the Kuparuk River Oil Field suggest that the "Tarn Gas Hydrate Accumulation" may be larger than the "Eileen Gas Hydrate Accumulation".

Gas Hydrate Production. The production potential of the Eileen or Tarn gas hydrate accumulations has not been adequately tested; but it is the present focus of a DOE-BPXA led industry R&D gas hydrate research program (i.e., BPXA-DOE Gas Hydrate Resource Characterization Project). Although unverified by field testing, production models of gas hydrate-bearing reservoirs within prospects interpreted from seismic and well data in the Milne Point area suggest that sustained production rates of several million cubic feet of gas per day can be achieved. In December 2003, the Canadian Mallik 2002 Gas Hydrate Production Research Well Program partners (including the USGS and the DOE) publicly released the results of the first modern, fully integrated field study and constrained

production test of a natural gas hydrate accumulation. The Mallik 2002 gas hydrate production testing and modeling effort has, for the first time, enabled rational assessment of the production response of a gas hydrate accumulation. Project-supported gas hydrate production simulations have shown that under certain geologic conditions gas can be produced from gas hydrates at rates exceeding several million cubic feet of gas per day.

A growing body of evidence suggests that a huge volume of natural gas is stored as gas hydrates in northern Alaska and that production of natural gas from gas hydrates may be technically feasible. However, numerous technical challenges must be resolved before this potential resource can be considered an economically producible reserve.

BLM-USGS-DGGS PROJECT REVIEW:

Evaluation of Alaska North Slope Gas Hydrate Energy Resources: A Cooperative Energy Resource Assessment Project

Bureau of Land Management (DOI-BLM)

United States Geological Survey (DOI-USGS)

State of Alaska Division of Geological and Geophysical Surveys (DNR-DGGS)

Gas hydrates may become an important global source of clean burning natural gas. For BLM, and the State of Alaska, gas hydrates are potentially a large untapped onshore energy resource on the North Slope of Alaska. To develop a complete regional understanding of this potential energy resource, BLM, USGS and the State of Alaska have entered into an Assistance Agreement to assess gas hydrate energy resource potential in northern Alaska. This agreement combines the resource assessment responsibilities of the USGS and the DGGS with the surface management and permitting responsibilities of the BLM. As interest in gas hydrates continue to grow, information generated from this agreement will help guide these agencies to promote responsible development of this potential arctic energy resource.

The primary objective of this project is to assess the recoverable resource potential of onshore natural gas hydrate and associated free-gas accumulations on the North Slope of Alaska. This project will assess the regional gas hydrate resource potential on both State of Alaska and Federal managed lands in northern Alaska. This project will actively collaborate with the BPXA-DOE methane hydrate research project, which is presently evaluating the energy resource potential of the known gas hydrate accumulations in and around the Prudhoe Bay and Kuparuk River oil fields.

The BLM-USGS-DGGS Alaska gas hydrate assessment project is divided into three concurrent phases over five years. Phase-I will study the known gas hydrate accumulations within and near existing development infrastructure of the Eileen and Tam trends. Phase-II will identify and characterize undiscovered gas hydrate accumulations in NPRA, ANWR, and the other relatively sparsely drilled areas between the Canning and Colville Rivers. Phase-III will develop a comprehensive assessment of the recoverable

resource potential of gas hydrates and associated free-gas accumulations in northern Alaska.

Phase-I will focus on mapping and characterizing the reservoir properties of the Eileen and Tarn gas hydrate accumulations in close association with the BP-DOE project. We may also conduct field operations to assess various gas hydrate production concepts. Test well operations could be conducted in cooperation with the ongoing BP-DOE or other joint industry research programs.

Phase-II will develop an understanding of the regional gas hydrate petroleum system with a goal to discover significant gas hydrate and associated free gas accumulations within NPRA, ANWR, and Alaska State lands between the Canning and Colville Rivers. The gas hydrate assessment techniques developed in Phase-I of this effort will be used in Phase-2 to assess available seismic and downhole well log data for the presence of gas hydrate.

Phase-III will develop a systematic geologic appraisal of the volume of gas that could be economically produced from the gas hydrates and associated free-gas accumulations on the North Slope of Alaska. The information and field test data from the first two phases of this study will be used to generate and calibrate reservoir simulations, which will be used to model various gas hydrate production scenarios. The field calibrated production simulations will be used to assess the volume of recoverable resources. This project may also include the assessment of the potential gas hydrate resources in the Canadian Mackenzie Delta.

BLM Gas Hydrate Project Manager:

Robert Fisk

Bureau of Land Management (DOI-BLM)

Anchorage, Alaska

Phone: 907-271-4407

Email: bob_fisk@ak.blm.gov

USGS Gas Hydrate Project Manager:

Timothy S. Collett

United States Geological Survey (DOI-USGS)

Denver, CO

Phone: 303-236-5731

Email: tcollett@usgs.gov

DGGS Gas Hydrate Project Manager:

James G. Clough

State of Alaska Division of Geological and Geophysical Surveys (DNR-DGGS)

Phone: 907-451-5030

Email: jim@dnr.state.ak.us

BPXA-DOE PROJECT REVIEW:

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

BP Exploration (Alaska), Inc. (BPXA)

U.S. Department of Energy (DOE)

Under the Methane Hydrate Research and Development Act of 2000, the U.S. Department of Energy (DOE) funds laboratory and field research on both Arctic and marine gas hydrates (a copy of the 2000 Methane Hydrate R&D Act has been attached to this briefing document). Among the current Arctic studies, BP Exploration (Alaska), Inc. and the DOE have undertaken a project to characterize, quantify, and determine the commercial viability of gas hydrates and associated free gas resources in the Prudhoe Bay, Kuparuk River, and Milne Point field areas on the Alaska North Slope. Ultimately, this project could determine if gas hydrates can become a part of the Alaska North Slope gas-resource portfolio.

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

One of the important contributors to this effort is the U.S. Geological Survey, which has led ANS gas hydrate research for three decades. Dr. Timothy Collett of the USGS continues to promote the importance of this area to gas hydrate research and potential development. Shirish Patil of the University of Alaska Fairbanks (UAF) School of Mining and Engineering is leading reservoir and petroleum engineering research and supporting laboratory studies. Dr. Robert Casavant leads the reservoir and fluid characterization efforts at the University of Arizona (T A) with Dr. Roy Johnson and Dr. Mary Poulton.

Gas hydrates are present in many arctic regions and offshore areas around the world. In the U.S., notable deposits of gas hydrate occur in the offshore Atlantic, Gulf of Mexico (GOM), offshore Pacific, offshore Alaska, and also onshore Alaska regions beneath permafrost. Collett (1998) estimates that up to 590 TCF of in-place ANS gas resources may be trapped in clathrate hydrates. Of that total, an estimated 44 to 100 TCF of in-place gas hydrate resources may occur beneath existing ANS production infrastructure within the Eileen and Tarn trends, respectively (Collett, 1993). However, much like conventional oil and gas resources, economic production of gas from potential gas hydrate resources will require a unique combination of factors, including all of the required petroleum system components (e.g., source, trap, seal, charge, reservoir, etc.), adequate industry infrastructure, industry access to acreage, familiar production

technology, and favorable economics. In addition, industry must be able to estimate ultimate recovery potential, production rates, operating costs, and potential profitability within reasonable risk limits. Currently, the most likely areas for a favorable combination of these factors are the ANS and the Gulf of Mexico.

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

Interim results from this project have identified potential shallow gas hydrate prospects within reservoir sands of the Sagavanirktok formation in the Milne Point Unit (MPU) area. Areas where gas hydrate may exist in association with movable free gas or possibly movable water have the most potential for production of hydrate-sourced natural gas, based on a preliminary understanding of the geology and potential production behavior investigated within reservoir model scenarios. However, these potential prospects remain largely unproven and require confirmation, delineation, and further data acquisition to mitigate uncertainties.

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

Interpretations of gas hydrate and associated free-gas resources within the study area correlate with gas hydrates that were originally cored and tested in the 1972 NW Eileen State #2 well and also penetrated by other wells targeting deeper reservoirs within the ANS development area. Geophysical attributes of gas hydrate occurrence are also under investigation. Seismic modeling of shallow (<950 ms) velocity fields suggests both amplitude and waveform variations may help locate gas hydrate-bearing reservoirs. Permafrost can also complicate seismic identification of gas hydrates due to its similar acoustic properties. Identification of gas hydrate prospects within the MPU 3D seismic

volume are based on seismic interpretation and modeling, gas hydrate-similar waveform classes, and fault-seal geometries integrated with well log-derived properties. Fault blocks with significant in-place volumes within identified gas hydrate-bearing reservoirs can be further delineated and/or production tested if the project proceeds into phases 2 and 3.

Understanding the nature of fluid flow and permeability is critical to assessing the productivity of gas hydrates. As part of this project, UAF has developed a new method for measuring gas-water relative permeability for laboratory synthesized gas hydrate within porous media. This work provides input to reservoir modeling and fluid flow. Although laboratory methods may differ from natural methods required to form gas hydrate, the experiment design allows gas hydrate to form in porous media over relatively long periods of time and allows measurement of effective permeability and relative permeability for different saturation values. Although some dissociation of gas hydrate occurs due to differential pressure across the core, the low temperature decreases the rate of gas dissociation. Considerable additional experimental and theoretical work remains to develop an analytical or generalized model to predict relative permeability for gas hydrate reservoir simulation. The experimental data obtained from this work will allow identification of gas hydrate stability zones, determination of flow behavior, and development of techniques for safe production of natural gas from gas hydrates.

The project team has adapted a commercial simulator (CMG-STARs) to model gas hydrate dissociation due to depressurization of an adjacent free gas accumulation in an MPU-area ANS gas hydrate prospect containing an estimated 23 BCF gas in-place. Preliminary results also demonstrate the potential of the depressurization production method by dissociation of gas hydrate adjacent to free gas. Modeling indicates that as gas is produced at rates from 8 to 25 MMscfd per well, the free gas zone depressurizes and the adjacent gas hydrate accumulation begins to release significant additional gas. Preliminary results also demonstrate the potential for depressurization of a partially-saturated gas hydrate-bearing reservoir through production of movable connate waters from a reservoir containing both gas hydrate and movable water at fractional saturations.

Work is proceeding in the areas described above as well as on a number of other tasks. Phase 1 of the project is currently scheduled for completion by November 2004. The Phase 2 progression or project termination decision is scheduled for the next quarter.

BPXA Gas Hydrate Project Manager:

Robert B. Hunter

BP Exploration (Alaska), Inc., Alaska Gas

Alaska Gas Hydrate Project Manager

Phone: 907-339-6377

Email: Robert.Hunter@bp.com

USDOE Gas Hydrate Project Manager:

Ray Boswell

Acting Technology Manager for Methane Hydrates

US DOE/National Energy Technology Lab
Morgantown, WV 26505
Phone: 304-285-4541
Email: ray.boswell@netl.doe.gov

SCOMM

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ALASKA STATE LEGISLATURE

Rep. Vic Kohring
Chair
Rep. Ralph Samuels
Vice Chair
Rep. Lesil McGuire
Rep. Norm Rokeberg
Rep. Nancy Dahlstrom
Rep. Beth Kerrtula
Rep. Berta Gardner



Alaska State Capitol
Juneau, Alaska 99801-1182
Room 24
(907) 465-4899
Fax (907) 465-3818
[Charisse Millett@legis.state.ak.us](mailto:Charisse_Millett@legis.state.ak.us)

HOUSE SPECIAL COMMITTEE ON OIL & GAS

STATE CAPITOL, RESOURCES ROOM # 124

Committee Schedule Announcement
House Special Committee on Oil & Gas
Tuesday, March 1st and Thursday, March 3rd, 2005
Ramona Barnes room #124 5:00pm

Tuesday March 1st, 2005

- + Overview, Alaska Oil and Gas Conservation Commission, Dan Seamount.
- + Governor's appointment of Dan Seamount to Alaska Oil and Gas Conservation Commission.

= Bills previously heard

Thursday March 3rd, 2005

- + Overview, BP – Viscous Oil 101
Mr. Don Dunham, Assets Manger, GKA & Point Thomson
Mr. Chris West, Viscous Oil Technology Team Leader

= Bills previously heard

*First Hearing in First Committee of Referral

+Teleconferenced

=Bills previously heard/scheduled



Official Business

Alaska State Legislature

House of Representatives

Office of the Chief Clerk

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MEMORANDUM

Date: February 16, 2005

To: Representative Kohring, Chair
House Special Committee on Oil and Gas

From: Suzi Lowell *SL*
Chief Clerk

Subject: Governor's Appointment

Speaker Harris referred the following Governor's appointment to the House Special Committee on Oil and Gas and the Resources Committee.

Alaska Oil and Gas Conservation Commission
Mr. Daniel Seamount of Anchorage
Appointed: 1/13/2000 Reappointed: 1/11/2005
Term Expires: 3/1/2011

The resume and committee report are attached for your use.

Attachments as noted

RESUME

APR 1 OIL & GAS CONSERVATION
COMMISSION 1/6

DANIEL TAYLOR SEAMOUNT Jr.

Home Address

23747 Hilltop Dr.
Chugiak, AK 99567
WK. 279-1433

OCCUPATIONAL GOAL: Geologist

WORK EXPERIENCE:

Union Oil Co. of Cal., 2/8/93 to present
P.O. Box 196247, Anchorage, AK 99519-6247

Title: Senior Advising Geologist

Duties: For last year have worked regional exploration and specific prospects in Cook Inlet. Prospect areas have included North Middle Ground Shoal, Sunfish, Redoubt Shoal, coal bed methane, South Cook Inlet, Susitna Basin and west side. Utilized Atlas's WDS well log system and Landmark's Stratworks, Petroworks, and Seisworks packages. For 3 1/2 years prior, was project manager and Team leader of a group which exploited development, exploration, and business opportunities in Cook Inlet and Alaska North Slope. Heavily involved in planning and budgeting wells, forming partnerships, facilities construction & re-mediation, and safety and environmental projects. Made numerous written and oral presentations to management and partners to update them on project progress and presented to state agencies (DNR & AOGCC) to form units, drilling PA's, and Plan of Operations. Provided geological input on well bore disposal of platform effluent. Presently working on plan of operations for Matanuska Valley Coal Bed Methane project. Also worked on Kuparuk and Endicott Fields on North Slope.

Union Oil Co. of Cal., 5/16/88 to 2/8/93
3300 N. Butler, Farmington, NM 87401
P.O. Box 2620, Casper, WY 82602-2620

Titles: District Development Geologist: 8/89 to present
Geologist: 5/88 to 8/89

Duties: Supervised and worked development and exploration geology of UNOCAL operated properties in the San Juan, Paradox, and Piceance Basins. Exploited tight sandstone reservoirs (27 wells), coal seam gas (57 wells), and conventional sandstone and carbonate oil and gas reservoirs. Horizontal, deviated, and vertical well bores were utilized. Additional work included managing geological contractors, progress reporting of drilling programs and field mapping. Also assisted in exploration projects in the Green River & DJ Basins. Presented San Juan Dakota reservoir characterization results to NM State O&G Comm. in approval process of tight gas sands designation. Worked with Utah O&G Comm. in forming Lisbon Field Unit.

Presented to numerous potential partners and was on a team which sold Unocal's alternative fuel tax credit to outside investors.

Marathon Oil Co., 7/13/81 to 5/16/88
P.O. Box 120, Casper, WY 82602

Titles: Staff Geologist: 1986 to 1988
Project Supervisor: 1984 to 1986
Geologist: 1981 to 1984

Duties: Oil and gas prospecting in the D-J Basin (one Paleozoic discovery), the Green River Basin (assisted in two Moxa Arch Frontier and Dakota gas discoveries and one sub-economic oil well), the Las Animas Arch (a number of Morrow Prospects on hold), and the central Kansas uplift (Pennsylvanian basal ss and Lansing- Kansas City Fm.). Work included regional & local mapping of structures, thickness, and facies of Rocky Mountain petroleum reservoirs and presentation of prospects to management. Was expert witness in Nebraska lawsuit between Marathon and KN Energy.

Chevron U.S.A. Inc., 8/18/73 to 1/3/79

2525 N. Chester, Oildale, CA 93308 (10/75 to 1/79)
575 Market St., San Francisco, CA 94105 (8/73 to 10/75)

Titles: **Geologic Assistant: 1975-1979**

Computer Analyst : 1973-1975

Duties: *Utilized geologic and geophysical computer programs. Performed well site work and prospect generation in California onshore and offshore.*

Institute of Geophysics and Planetary Physics, 1/3/79 to 7/13/81

University of Ca, Earth Science Dept. Riverside, CA 92521

Title: **Research Associate (half time while finishing MS)**

Duties: *Assisted research scientists in geothermal, seismic, and earthquake studies. Also, supervised the drilling of heat flow test holes.*

EDUCATION:

M.S. - Geology, 6/81, University of CA, Riverside, CA.

Emphasis on geothermal development and exploration. Thesis titled, " Well Log Study of the Hydrothermally Altered Sediments of Cerro Prieto Geothermal Field, Baja California, Mexico".

B.S. - Geology, 5/73, University of CA, Riverside

INTERESTS

Backpacking

Fishing

Hiking

Hunting

Skiing

Wild Life Viewing

Alaska Oil and Gas Conservation Commission (AOGCC)



AOGCC Program Overview

Presentation to House Oil & Gas
by

Dan Seamount, AOGCC
Commissioner

March 1, 2005



Alpine Oil Field

Alaska Oil and Gas Conservation Commission (AOGCC)



Alpine Oil Field



AOGCC Program Overview

Presentation to House Oil & Gas

By

Dan Seamourd, AOGCC
Commissioner

March 1, 2005

Alaska Oil and Gas Conservation Commission (AOGCC)



Mission

Protect the public interest in oil and gas resources and protect underground supplies of drinking water.

The Alaska Oil and Gas Conservation Act requires conducting all oil and gas drilling, production and measuring operations to prevent physical resource waste, to promote greater ultimate recovery and to afford all owners of oil and gas rights an equal opportunity to recover their fair share of the resource.

Agenda

Introduction

AOGCC

- Oversight
- Clients
- Work Sites
- Organization
- Goals, Services, & Strategies
- Oil & Gas Activity and AOGCC Accountability

Some Major Issues

- Gas Line Oversight
- Offshore Cook Inlet Future

Oversight since 1955

Quasi-judicial State regulatory agency-
Mainly Sub-surface

Prevent physical waste of hydrocarbon resources

- Oversight for underground operations
- Regulate drilling and production for oil & gas

Promote greater ultimate recovery

Protect fresh water

- Manage Class II UIC program
- Ensure compliance of well construction

Protect correlative rights

- Jurisdiction over private and public lands
- Adjudicate disputes between resource owners



Amelia

w/ increased permits

↑ eliminated 4 staff last year

Where Does AOGCC Fit In?

Issues	Oil Company (Regulated Community)	Land Owner (e.g. DNR DOG or Native Corporation)	ADEC (Exercises Police Powers of the State)	AOGCC (Exercises Police Powers of the State)
Ownership of Resource	Lessee of Oil & Gas Lease (Has Right to Drill and Produce)	Landlord & Lessor of Oil & Gas Lease	None Regulatory or Proprietary Mainly Surface & Air	None Regulatory Not Proprietary Mainly Sub-surface
Jurisdiction	Only on Lands Where They Have Right to Drill and Produce	Owns Land Only	State, Federal and Private Lands	State, Federal and Private Lands
Economics	Profit Oriented	Manages Owned Resources for Revenue & Other Values	Regulates to Protect Environment	Regulates to Prevent Waste, Protect Correlative Rights & Promote Greater Recovery
Net SS Interest	Owne Majority of Production	Owne Minority of Production (Royalty Interest)	None, Regulates Only	None, Regulates Only

AOGCC generally regulates sub-surface activities.
AOGCC and other agencies have regulatory authority over most surface activities.

Oversight Strategy

Statewide Regulations (20 AAC 25) and Statute Title 31

Regulatory & Adjudicatory	Inspection
Two Reservoir Engineers	One Engineer & 5 On-site Inspectors
Two Petroleum Engineers	Well Control Equipment
Two Petroleum Geologists	- Drilling and Production
Drilling Permits	Metering
Sundry Permits	Well Integrity Demonstrations
Orders	Visual Equipment Checks
- Conservation, Injection, Aquifer Exemption	Incident Investigations
Compliance Reviews	Other Inspections
Field Studies	

Public Hearings and Open Meetings

Where Does AOGCC Fit In?

Issues	Oil Company (Regulated Community)	Land Owner (e.g. DNR DOG or Native Corporation)	ADEC (Exercises Police Powers of the State)	AOGCC (Exercises Police Powers of the State)
Ownership of Resource	Lessee of Oil & Gas Lease. (Has Right to Drill and Produce)	Landlord & Lessor of Oil & Gas Lease	Role Is Regulatory, Not Proprietary- Mainly Surface & Air	Role Is Regulatory, Not Proprietary- Mainly Sub-surface
Jurisdiction	Only on Lands Where They Have Right to Drill and Produce	Owner's Land Only	State, Federal and Private Lands	State, Federal and Private Lands
Economics	Profit Oriented	Manages Owned Resources for Revenue & Other Values	Regulates to Protect environment	Regulates to Prevent Waste, Protect Correlative Rights, & Promote Greater Recovery
Net \$\$ Interest	Owens Majority of Production	Owens Minority of Production (Royalty Interest)	None- Regulates Only	None- Regulates Only

AOGCC generally regulates sub-surface activities.
ADEC and other agencies have regulatory authority over most surface activities.

Oversight Strategy

Statewide Regulations (20 AAC 25) and Statute Title 31

Regulatory & Adjudicatory

Two Reservoir Engineers,
Two Petroleum Engineers,
Two Petroleum Geologists

Drilling Permits

Sundry Permits

Orders

- Conservation, Injection,
Aquifer Exemption

Compliance Reviews

Field Studies

Inspection

One Engineer & 5 On-site
Inspectors

Well Control Equipment

- Drilling and Production

Metering

Well Integrity Demonstrations

Visual Equipment Checks

Incident Investigations

Other Inspections

Public Hearings and Open Meetings

PRINCIPAL CLIENTS

- Individual Alaskans
- Oil & Gas Industry (regulated Community)
- Alaska Department of Natural Resources
- Alaska Department of Revenue
- Alaska Department of Environmental Conservation
- U.S. Environmental Protection Agency
- U.S. Department of the Interior
 - Minerals Management Service
 - Bureau of Land Management
- U.S. Department of Energy
- Trade Organizations
- Other Interested Parties

OIL AND GAS OPERATORS AND OWNERS NORTH SLOPE

- | | |
|--------------------------------------|--|
| • ConocoPhillips Alaska Inc. |  |
| • BP Exploration (Alaska) Inc. | |
| • Anadarko Petroleum Corp. | |
| • ExxonMobil Alaska Production Inc. | |
| • Pioneer Natural Resources AK Inc. | |
| • Brooks Range Petroleum Corporation | |
| • Arctic Falcon Exploration LLC | |
| • ChevronTexaco | |
| • Local Alaska | |
| • Petro-Canada (Alaska) Inc. | |
| • Burlington Resources Inc. | • ASRC |
| • Shell Oil Company | • Kerr-McGee Oil and Gas Corporation |
| • Encana Oil and Gas (USA) Inc. | • Winstar Petroleum LLC |
| • North Slope Borough | • Ultrastar Exploration LLC |
| • Devon Energy Production Company | • Armstrong Alaska Inc. / Resources LLC |
| | • Alaska Venture Capital Group |
| | • U.S. Department of Energy |
| | • U.S. Department of Interior |
| | • U.S. Navy |
| | • Alaskan Grude Corporation |

OIL AND GAS OPERATORS AND OWNERS COOK INLET/MAT-SU VALLEY

Unocal Alaska
Forest Oil Corp
Marathon Oil Company
Phillips Alaska Inc /ConocoPhillips
XTO Energy Inc
Anadarko
Cook Inlet Region Inc
Aurora Gas LLC
Northstar Energy Group Inc
Pelican Hill Oil & Gas Inc
Alaska Crude Corporation
Prodigy Alaska, LLC
Escopeta Oil Company LLC
Gas-Pro Alaska, LLC
Trading Bay Oil and Gas, LLC
Herbaly Exploration, LLC



Grayling Platform

OTHER AREAS

Pioneer Natural Resources AK Inc
Andex Resources LLC
Cassandra Energy Corporation
Rutter & Wilbanks Corporation
Delphi International

May 11, 2009

Prepared for the House Oil & Gas Committee

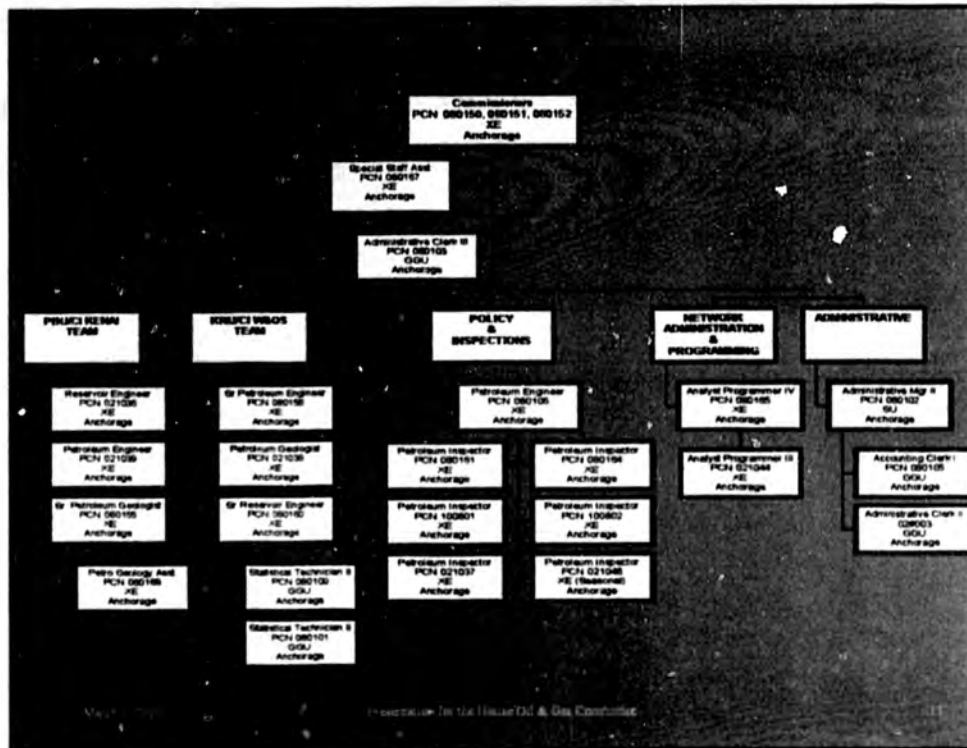
Work Sites



Courtesy of the Anchorage Convention & Visitors Bureau

May 11, 2009

Prepared for the House Oil & Gas Committee



Organization –

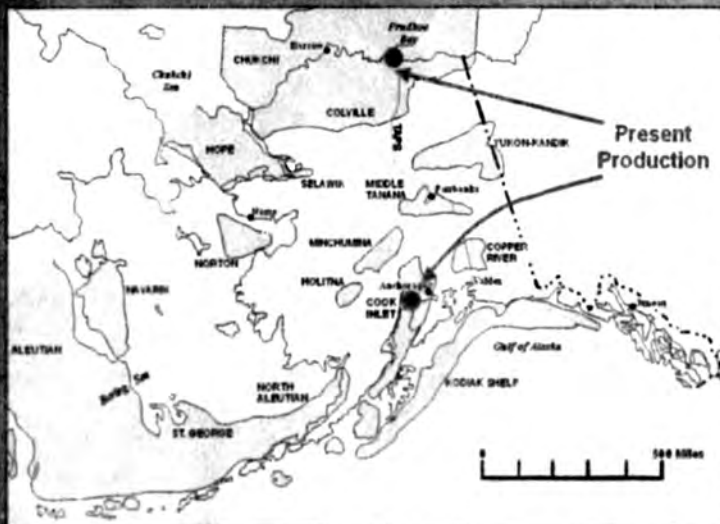
“WEST TEAM”
KRU/CI W & OS Decision



Cook Inlet
Geographic
Delineation of
Decisions Teams



Alaska Oil and Gas Basins



Alaska has huge exploration potential in many lightly explored basins

AOGCC Goals and Strategies

PREVENT PHYSICAL WASTE OF THE RESOURCE

Inspect well drilling and well control equipment to ensure all wells are drilled and operated using best engineering practices and in compliance with approved regulations and procedures - **Inspections**

Ensure minimal gas waste due to unnecessary flaring and venting from producing wells - **Inspections, Reporting**

Quickly adjudicate permits for drilling and sundry well work to ensure that wells are constructed, maintained and operated in compliance with regulations, orders and procedures - **Permitting**

Work with industry and public to ensure that development plans maximize recoverable reserves - **Field Studies**



AOGCC Goals and Strategies (cont.)

ADMINISTER ALASKA'S UNDERGROUND INJECTION CONTROL (UIC) & ANNULAR WASTE DISPOSAL PROGRAMS

Protecting Alaska's Underground Sources of Drinking Water is a Primary Responsibility of AOGCC

Provide engineering and geological review of all applications for Enhanced Oil Recovery (EOR) & underground disposal of drilling wastes - **Inspections**

Provide engineering and geological review of all applications to ensure injection wells comply with all regulations - **Permitting**

AOGCC Goals and Strategies (Continued)

PROTECT CORRELATIVE RIGHTS

Provide all owners of oil and gas rights the opportunity to recover their fair share of the resource through well spacing regulations, permit review, and pooling authority. — **Field Studies & Orders**

WHEN NECESSARY, ADJUDICATE DISPUTES BETWEEN OWNERS

Provide a public forum to resolve disputes that are within the Commission's jurisdiction.
— **Adjudicatory Hearings**

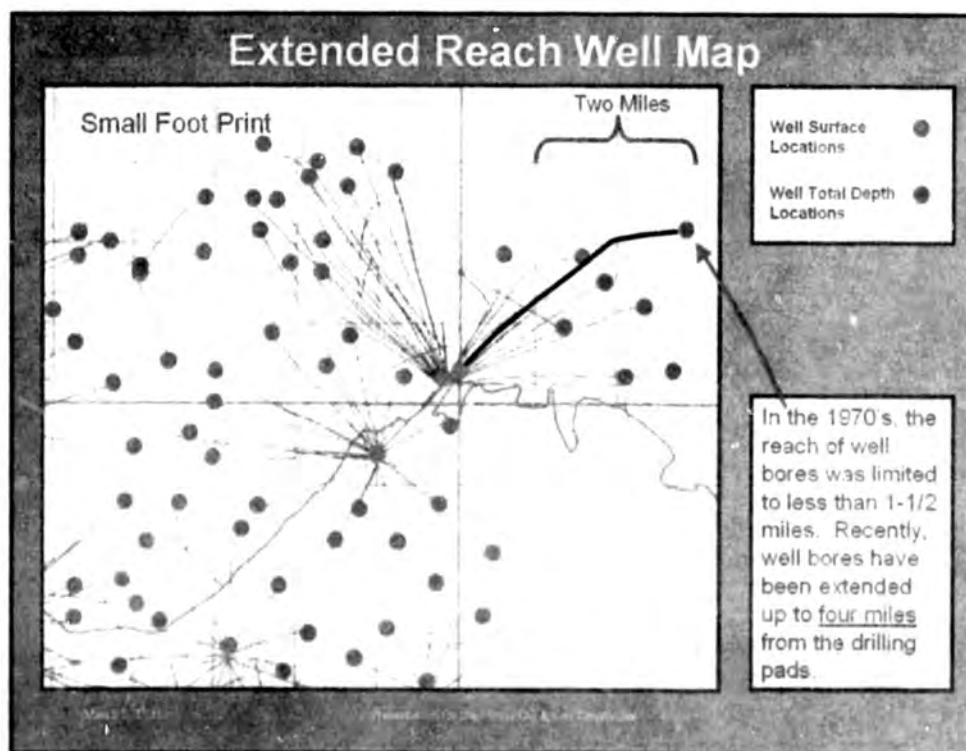
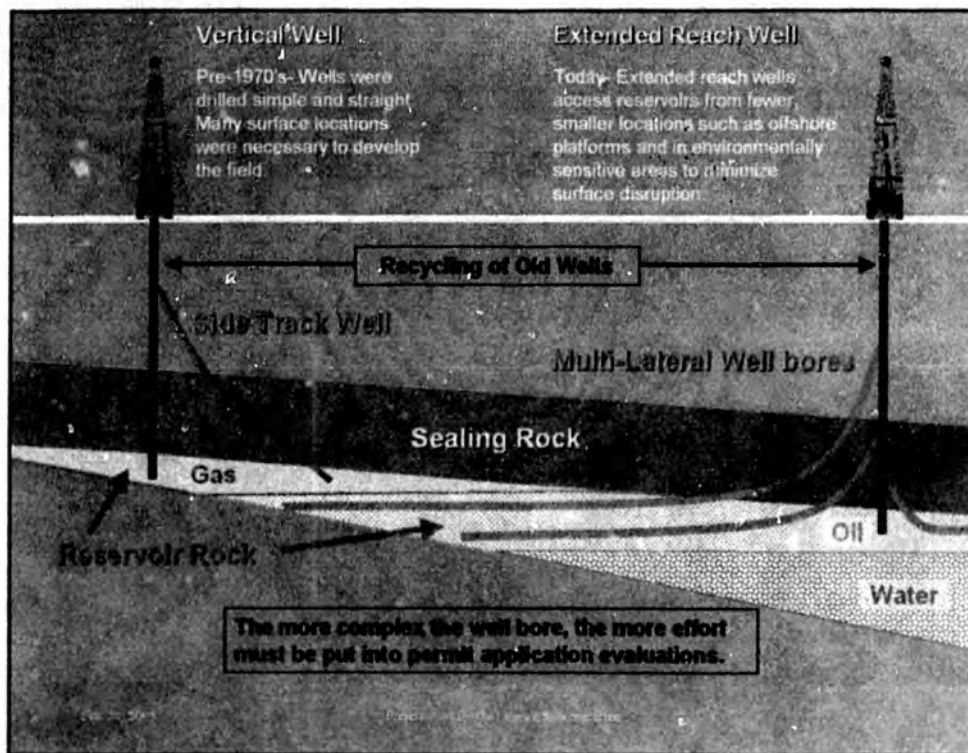


Texas, 1901

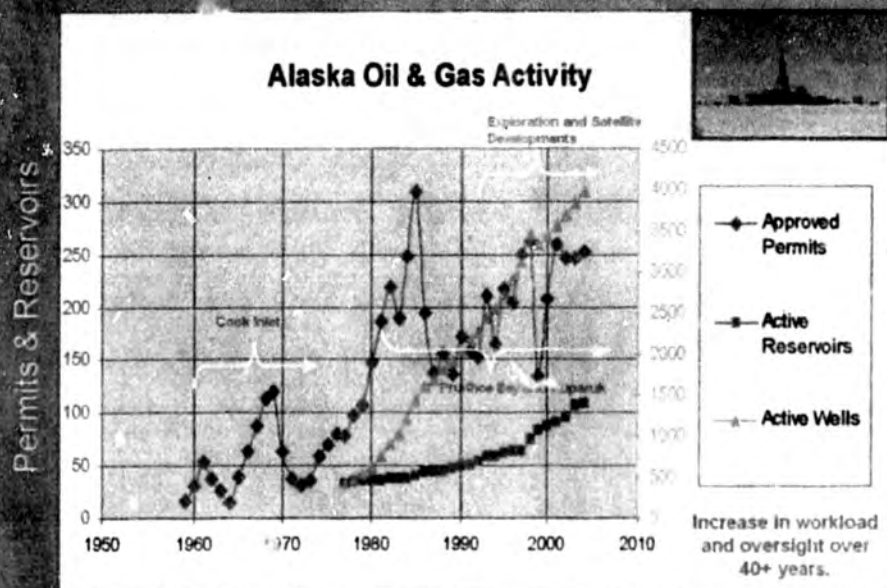
AOGCC PRIMARY SERVICES

Regulate, monitor, and inspect all subsurface activities directly related to oil and gas exploration and production including the design and integrity of wells, well control procedures and equipment, reservoir management plans and proposed underground injection programs.

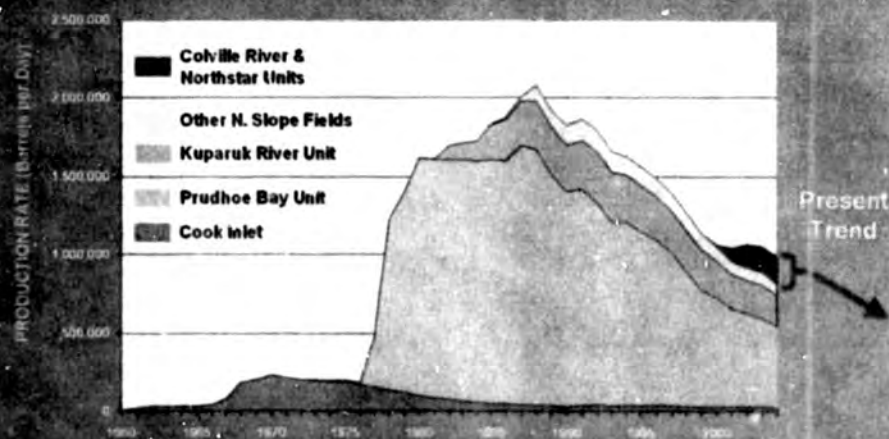
- Hold hearings and open meetings.
- Issue pool rules and other conservation orders.
- Approve and monitor plans for reservoir development and enhanced oil recovery.
- Approve permits for initial drilling, re-drilling, sidetracking, and remedial well operations. This includes the evaluation and approval of proposed designs for drilling fluids, well control, casing, cementing and well completion operations.
- Inspect drill rigs and wells to insure compliance with AOGCC regulations.
- Witness safety valve, mechanical integrity, and blowout preventer tests.
- Witness meter-proving, calibration, and oil quality tests.
- Implement well spacing rules.
- Monitor production rates, injection well patterns, gas/oil/water ratios, and pressure maintenance efforts.
- Monitor and evaluate gas flaring.
- Collect and maintain all statewide oil and gas production records.
- Collect and maintain all well history files and well log records.
- Administer Alaska's Underground Injection Control (UIC) program and the annular waste disposal program.
- Conduct public outreach programs.



Activity

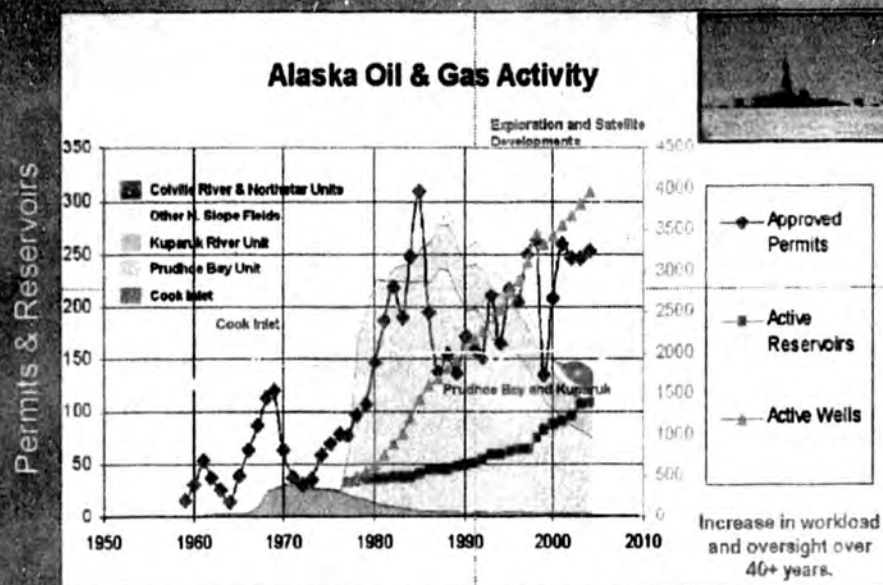


ALASKA'S DAILY OIL & NGL PRODUCTION RATE

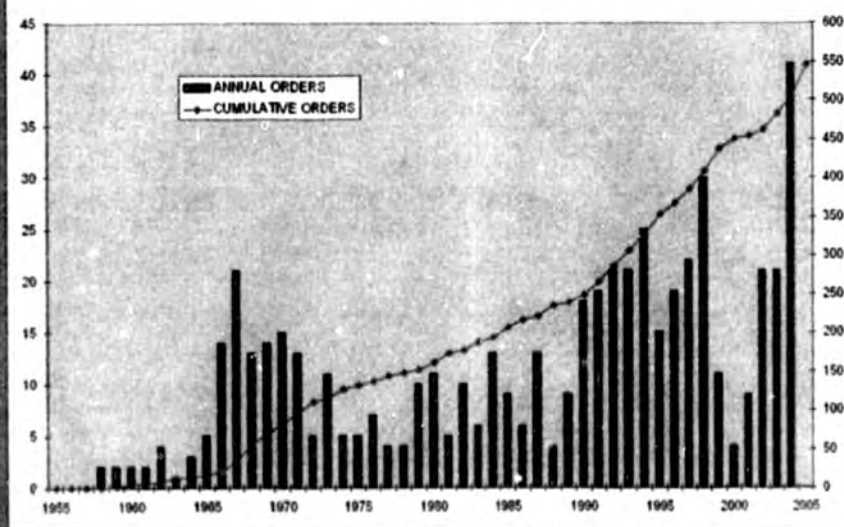


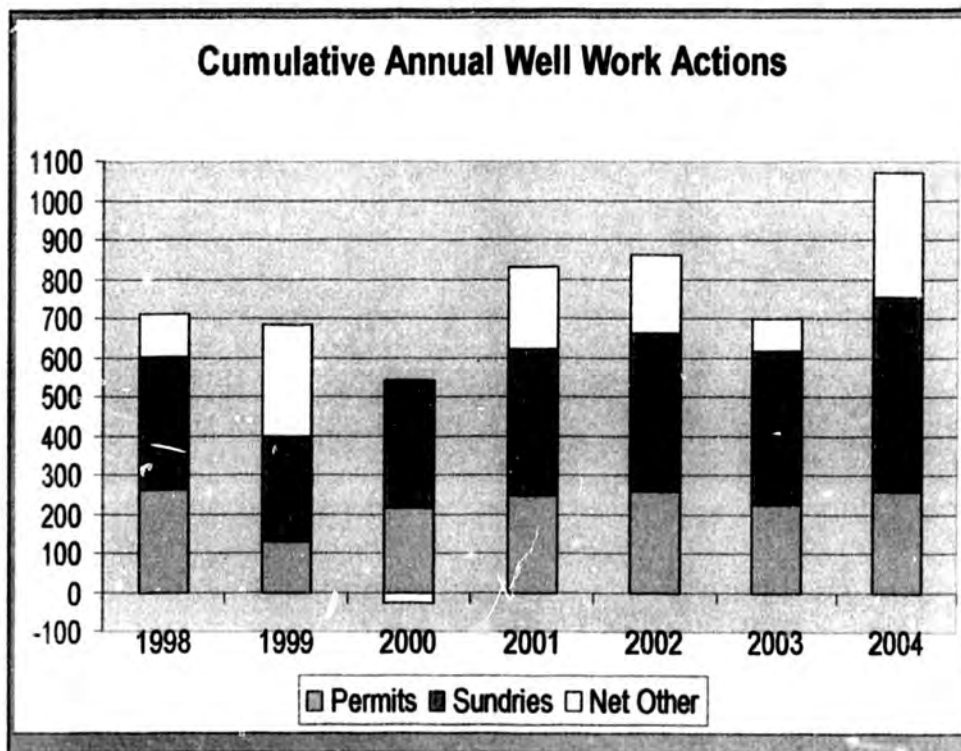
Last year, Alaska's daily oil and NGL production rate dropped by 6%

Activity and Resource Recovery

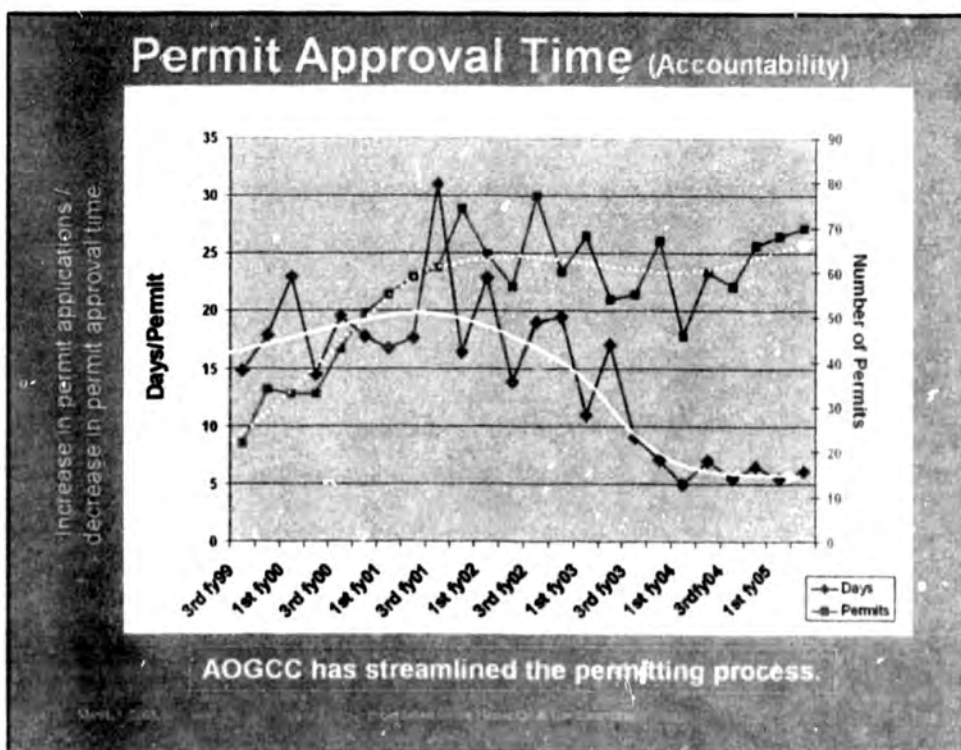


Alaska Oil and Gas Conservation Commission Conservation Order History





All indicators point to a good future for A's economy



Key Challenges and Projects

- Determine the impacts of major gas sales upon ultimate hydrocarbon recovery from Prudhoe and Pt. Thomson reservoirs before gas sales off-take rates can be approved. - **Mitigation of oil losses**
- Facilitate expanded statewide exploration and development including NPRA and exploration licensing areas that are outside the North Slope and Cook Inlet. - **Increased production**
- Evaluate and respond to the need for a revised regulatory scheme to safely oversee new development of coal bed methane and shallow gas resources. - **Responsible development**
- Finalize AOGCC's Internet-based Well and Production Information System available to anyone in the world. - **Help increase investment in Alaska**

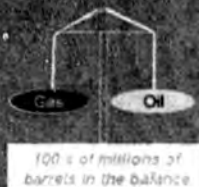
Key Challenges and Projects (continued)

- Maintain an active role to protect Alaska's UIC program. Take over responsibility for Class I injection wells from EPA. - **Faster permit decisions**
- Respond to changing conditions in mature oil fields to make certain operations are conducted in a safe and skillful manner while ensuring that recovery of oil and gas resources is maximized. - **Safer operations and less resource waste**
- Comprehensive review of natural gas production in Alaska and of all gas which is being flared, vented or otherwise not put to beneficial use. - **Less resource waste**
- Continue to evaluate ways to increase the AOGCC's efficiency. - **Reduce costs**

Alaska Oil and Gas Conservation
Commission
(AOGCC)



Reservoir Conservation
Challenges
Related to Gas Sales



Gas Reserves Ranking - AOGCC
Projections of Proven Reserves

Pool	Sales TCF
Prudhoe Oil Pool	22
Point Thomson	8
Lisburne/Pt. McIntyre	2
Other	3
Total	35

Note: Expected range of 28-39 TCF

House Bill 135

&

Senate Bill 98

Sec. 7. GAS PIPELINE. (a) The sum of \$1,200,000 is appropriated from the general fund to the Department of Administration, Alaska Oil and Gas Conservation Commission, for reservoir studies and depletion plan evaluations related to the state gas pipeline and to bringing North Slope natural gas to market.

AOGCC Gas Sales Evaluation – Resources

Budget

- Current 1 consultant on board (\$125/yr for 3-5 yrs)
- \$500M additional available in budget
- If PBU Owners don't provide timely necessary information:
 - Requested \$1.2MM for FY2006
 - Up to \$5 MM for next 3-5 years

If Owner Cooperation is Improved

- Lowered costs and time

In any case

We don't want to be the bottleneck but

We must perform proper technical analysis