Division of Geological & Geophysical Surveys

MISCELLANEOUS PUBLICATION 127

Alaska Coalbed and Shallow Gas Resources
May 2001 Workshop Proceedings

edited by

C.E. Barker, J.G. Clough, and T.A. Dallegge

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August 2003

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STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
Division of Geological & Geophysical Surveys
794 University Avenue, Suite 200
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PTTC West Coast Resource Center

"Dinner Workshop"

TECHNOLOGY CONNECTIONS
PETROLEUM TECHNOLOGY TRANSFER COUNCIL

ALASKA COALBED AND SHALLOW GAS RESOURCES
CONFERENCE
April 30 to May 4, 2001

Organized By:

West Coast PTTC
Alaska Department of Natural Resources
U.S. Geological Survey
Bureau of Land Management - Alaska

Dinner Sponsored by:
Evergreen Resources, Inc.

Co-Sponsored by:
B. J. Services
Bristol Bay Native Corporation
Cook Inlet Region, Inc.
University of Southern California

PTTC gratefully acknowledges that its primary funding comes through the US Department of Energy's (DOE) Office of Fossil Energy through the National Petroleum Technology Office (NPTO) and Strategic Center for Natural Gas (SCNG) within the National Energy Technology Lab (NETL).

May 3, 2001 – Anchorage, Alaska

West Coast Resource Center

Dinner Workshop

"Alaska Coalbed and Shallow Gas Resources"

A West Coast PTTC - Alaska DNR – USGS – BLM-Alaska Workshop

Thursday, May 3, 2001
Anchorage Marriott Downtown
Anchorage, Alaska

Co-Sponsored by: U.S. Department of Energy (DOE), University of Southern California (USC), University of Alaska Fairbanks, Evergreen Resources, Inc., Bristol Bay Native Corporation, BJ Services, Cook Inlet Region, Inc.

6:00pm	***Registration***	
	Moderator	***Charlie Byrer,*** *NETL*
6:30	***Technology Transfer Needs of Independent Producers***	***Don Duttlinger,*** *PTTC*
	A Key Element in America's Energy Future: Maintaining a Reliable Supply of Natural Gas	***Charlie Byrer,*** *NETL*
	Alaska's Needs for Coalbed Methane and Shallow Gas Resources	***Marty Rutherford,*** *Deputy Commissioner,* DNR
	Impact of Gas Pipeline on North Slope and Interior Basins Exploration/Gas Leasing	***Mark D. Myers,*** *Director, Div. of Oil and Gas*
9:30pm	ADJOURN	

The Petroleum Technology Transfer Council (PTTC) was formed in 1994 by the U.S. oil and natural gas exploration and production (E&P) industry to identify and transfer upstream technologies to domestic producers. PTTC's technology programs help producers reduce costs, improve operating efficiency, increase ultimate recovery, enhance environmental compliance, and add new oil and gas reserves.
PTTC is a national not-for-profit organization with regionally focused programs that meet the technology needs of its primary customers - independent oil and natural gas producers. Independents face technology decisions every day, such as whether to address an opportunity or problem with technology, what solution to use, whether it is cost effective, and how to use it.
PTTC serves as the independent producer's **"Bridge to Solutions"** by fulfilling three roles:

- First, it helps identify and clarify producers' problems and makes them aware of technology opportunities.
- Second, it educates producers about technology options.
- Third, it connects producers to these solutions.

Thus, by providing problem identification, education, and connections, PTTC achieves its mission:

TECHNOLOGY CONNECTIONS
PETROLEUM TECHNOLOGY TRANSFER COUNCIL

"PTTC benefits the nation by helping U.S. independent oil and natural gas producers make timely, informed technology decisions."

Dinner Sponsored by Evergreen Resources, Inc.

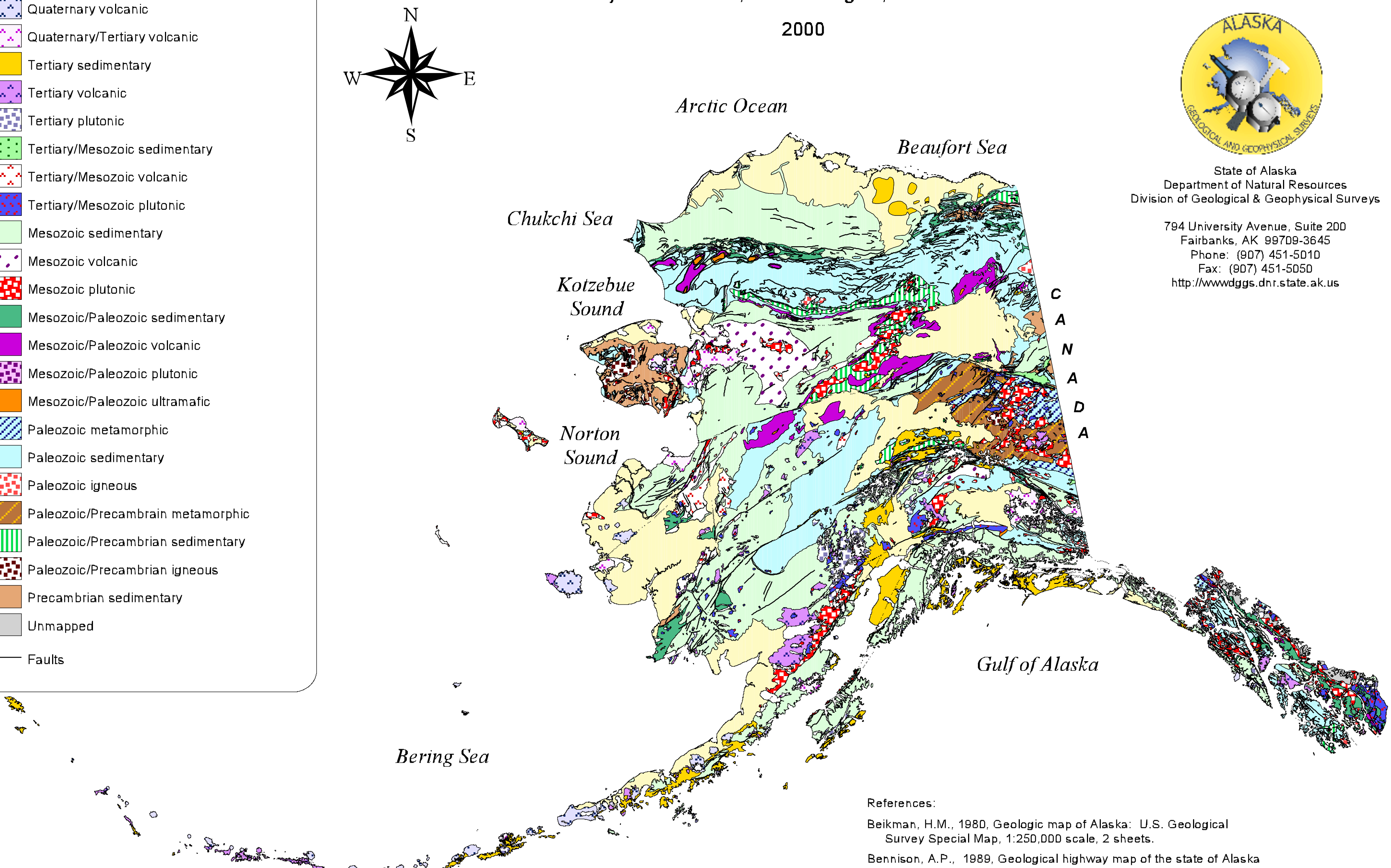
Generalized Geologic Map of Alaska

By M.B. Werdon, D.J. Szumigala, and G. Davidson

2000

Geologic Units

- Ice/Water
- Quaternary sedimentary
- Quaternary volcanic
- Quaternary/Tertiary volcanic
- Tertiary sedimentary
- Tertiary volcanic
- Tertiary plutonic
- Tertiary/Mesozoic sedimentary
- Tertiary/Mesozoic volcanic
- Tertiary/Mesozoic plutonic
- Mesozoic sedimentary
- Mesozoic volcanic
- Mesozoic plutonic
- Mesozoic/Paleozoic sedimentary
- Mesozoic/Paleozoic volcanic
- Mesozoic/Paleozoic plutonic
- Mesozoic/Paleozoic ultramafic
- Paleozoic metamorphic
- Paleozoic sedimentary
- Paleozoic igneous
- Paleozoic/Precambrain metamorphic
- Paleozoic/Precambrian sedimentary
- Paleozoic/Precambrian igneous
- Precambrian sedimentary
- Unmapped
- Faults



State of Alaska
Department of Natural Resources
Division of Geological & Geophysical Surveys

794 University Avenue, Suite 200
Fairbanks, AK 99709-3645
Phone: (907) 451-5010
Fax: (907) 451-5050
http://wwwdggs.dnr.state.ak.us

300 0 300 Miles

500 0 500 Kilometers

References:

Beikman, H.M., 1980, Geologic map of Alaska: U.S. Geological Survey Special Map, 1:250,000 scale, 2 sheets.

Bennison, A.P., 1989, Geological highway map of the state of Alaska and the state of Hawaii: American Association of Petroleum Geologists, 1:3,500,000, 1 sheet.

Plafker, George, Gilpin, L.M., and Lahr, J.C., 1994, Neotectonic map of Alaska: in Plafker, G., and Berg, H.C., eds., The Geology of Alaska, Geology of North America, v. G-1: Geological Society of America, plate 12, scale 1:2,500,000.

Moderator

Charlie Byrer
Natural Energy
Technology Laboratory

Technology Transfer Needs of Independent Producers

Speaker

Don Duttlinger
Petroleum Technology
Transfer Council

Speaker Biography

DON DUTTLINGER
EXECUTIVE DIRECTOR
PETROLEUM TECHNOLOGY TRANSFER CENTER (PTTC)

Don Duttlinger became PTTC's executive director in July 2000. Since1992, he has been president of Intechtra Services Inc., a Houston-based firm that helps US companies establish operations in West Africa and increase production in existing operations. Prior to joining PTTC, Duttlinger served as onshore operations training manager for Mobil Oil/Baker Energy in West Africa. Before that, he worked for Schlumberger Technical Services in South East Asia. He has been on the Board of the Indonesian-American Business Association since 1994, and also served as its executive vice president. Duttlinger earned an MBA degree focusing on International Business from Louisiana State University in 1991, and a BS degree in Construction Management Engineering from Purdue University in 1981. He has been a licensed professional engineer in Texas since 1992.

Petroleum Technology Transfer Council

Presented To: Alaska Coalbed and Shallow Gas Resources Conference

Anchorage, Alaska May 3, 2001

Technology Transfer Needs of Independent Producers

Outline

- What is PTTC?
- Who is PTTC?
- What has PTTC been doing?
- PTTC's vision for the future?

What Is PTTC

- PTTC Started as an Information Clearinghouse
- PTTC Is Producer Driven
- PTTC Is People

About PTTC

PTTC Mission

"PTTC benefits the nation by helping U.S. Independent oil and gas producers make timely, informed technology decisions."

Who Is PTTC

- Board of Directors
- Producer Advisory Groups
- Regional Lead Organizations
- Headquarters Staff

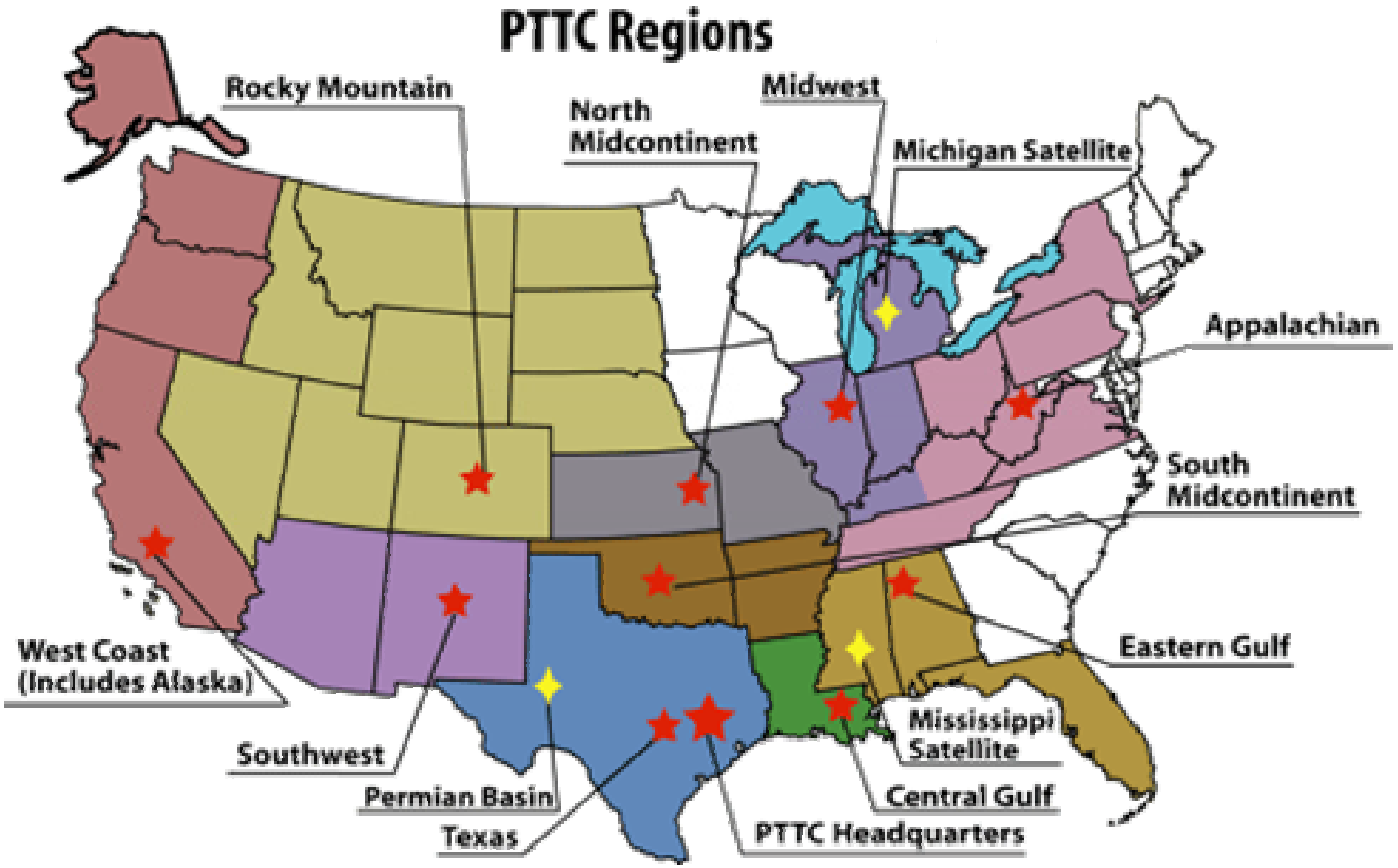
PAG Members

Arrowhead Exploration, Summit Energy, Marathon Oil, Paramount Petroleum, Pruet Oil, Nordan Oil & Gas, Spooner Petroleum, Kelton Oil, Belden & Blake, Oxford Oil, Jarvis Drilling, MEPCO Inc, Howard Energy, Miller Oil, Colt Energy, Russell Petroleum, Gore Oil, Vess Oil, Keen Oil, OneOk Resources, Trans Pacific Oil, Texaco, Sensor Oil and Gas, Comanche Energy, Devon Energy, Bays Exploration, Midwest Energy Corp, Apache Corp, Enron Oil and Gas, Chevron USA, Russell Petroleum, Seneca Resources Corp, Ocean Energy, Tidelands Oil Production, Schlumberger Technical Services, BJ Services, WZI Inc, Baker Hughes, Baroid Drilling Fluids, Baker Petrolite

Petroleum Technology Transfer Council

Timely, informed technology decisions...

Regionally-Focused

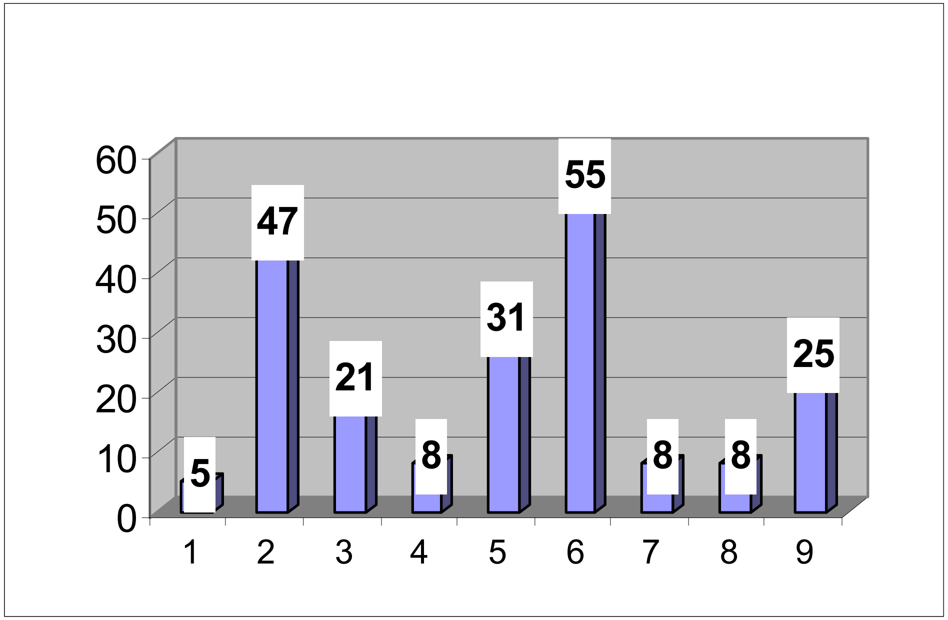


What Has PTTC Been Doing

- Problem Identification
- Awareness/Education
- Connections

Beneficial Technologies

1. Internet/E-Commerce
2. Seismic/Geophysical
3. Horizontal/Directional Drilling
4. Under Balanced Drilling
5. Logging/Formation Evaluation
6. Fracturing/Stimulation
7. Reservoir Management/4-D
8. Production Automation
9. Enhanced Recovery



Core Services—Awareness/Education

- **Unique, Concise Format Recognized and Valued by Industry**
  - From the Operator's Perspective
  - Not Only New Developments
  - Bottom-line Tech. and Econ. Results
  - Learning From Experts and Each Other
- **Not One Answer, but Solution Options**

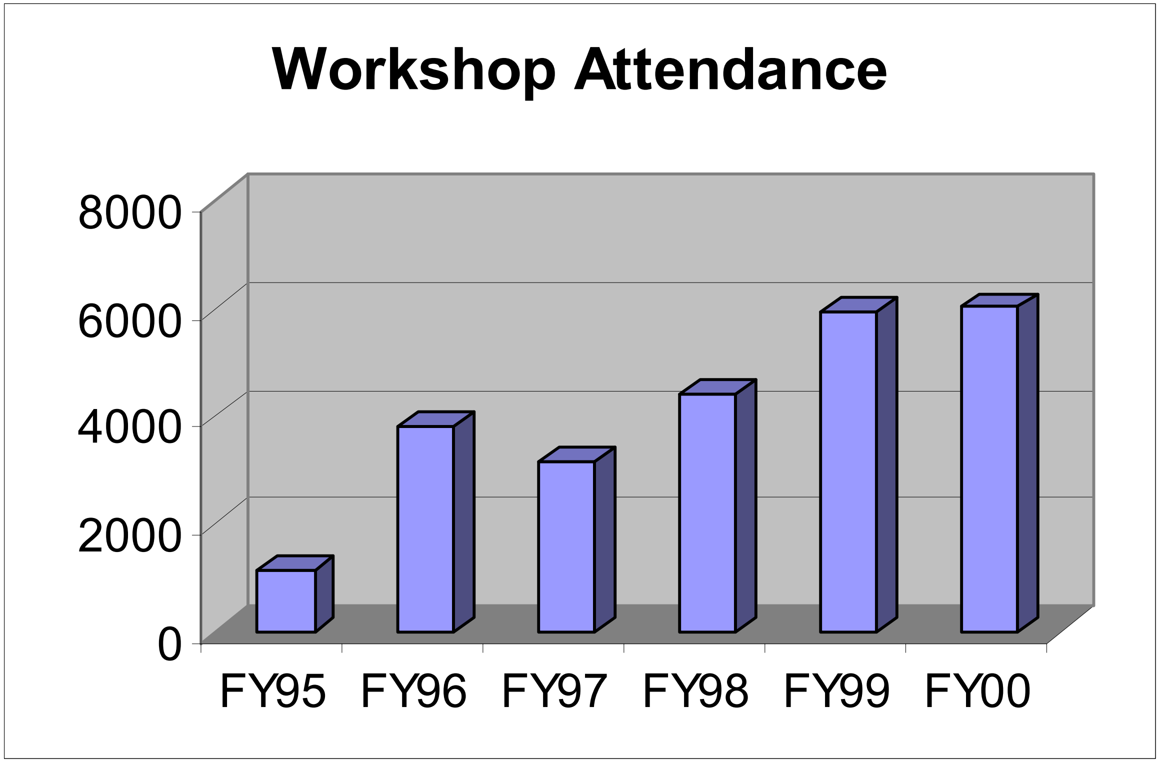
Core Services—Connections

- Low Cost Workshops Providing Real World Solutions to Specific Needs
- Regional Resource Centers/referrals
- Technical Reports, Databases, and Newsletters
- Network of 11 Websites

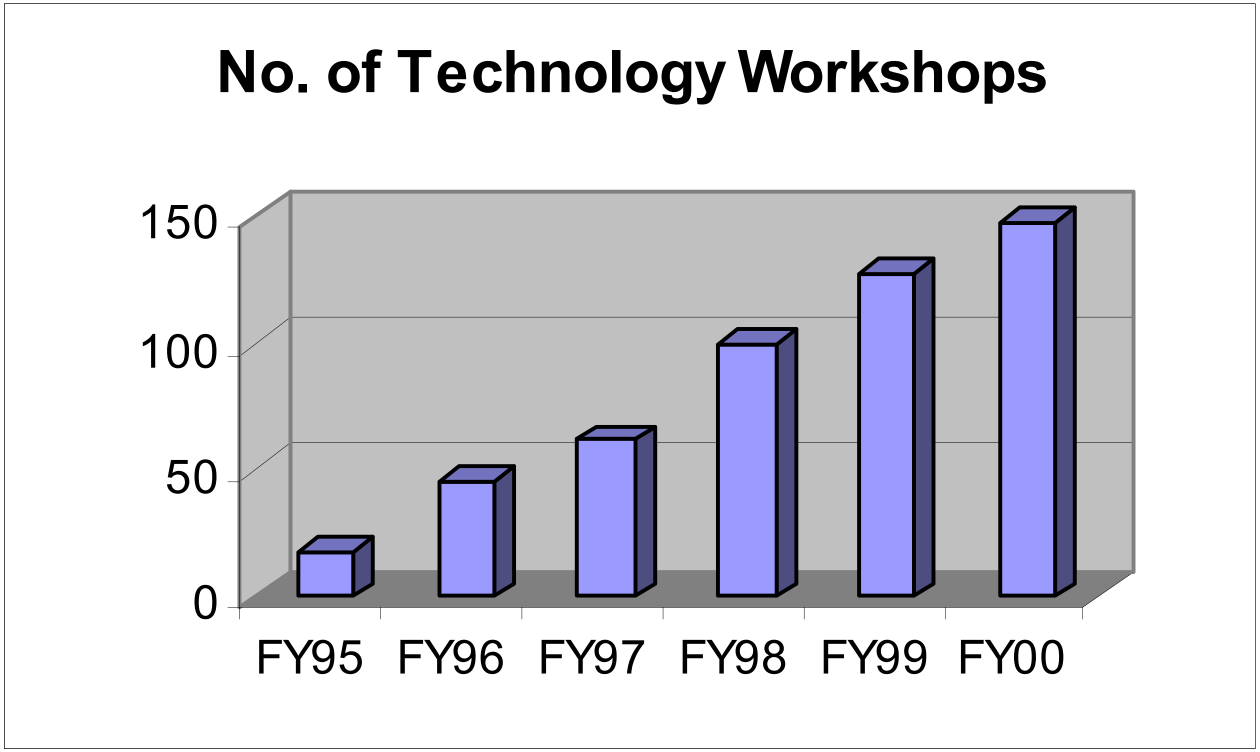
Core Services—Workshops

- **Participants in Conference**
  - Evergreen Resources Inc.
  - Alaska Department of Natural Resources
  - U.S. Geological Survey
  - Bureau of Land Management
  - B.J. Services
  - Cook Inlet Region, Inc.
  - West Coast PTTC/USC

Core Services—Education



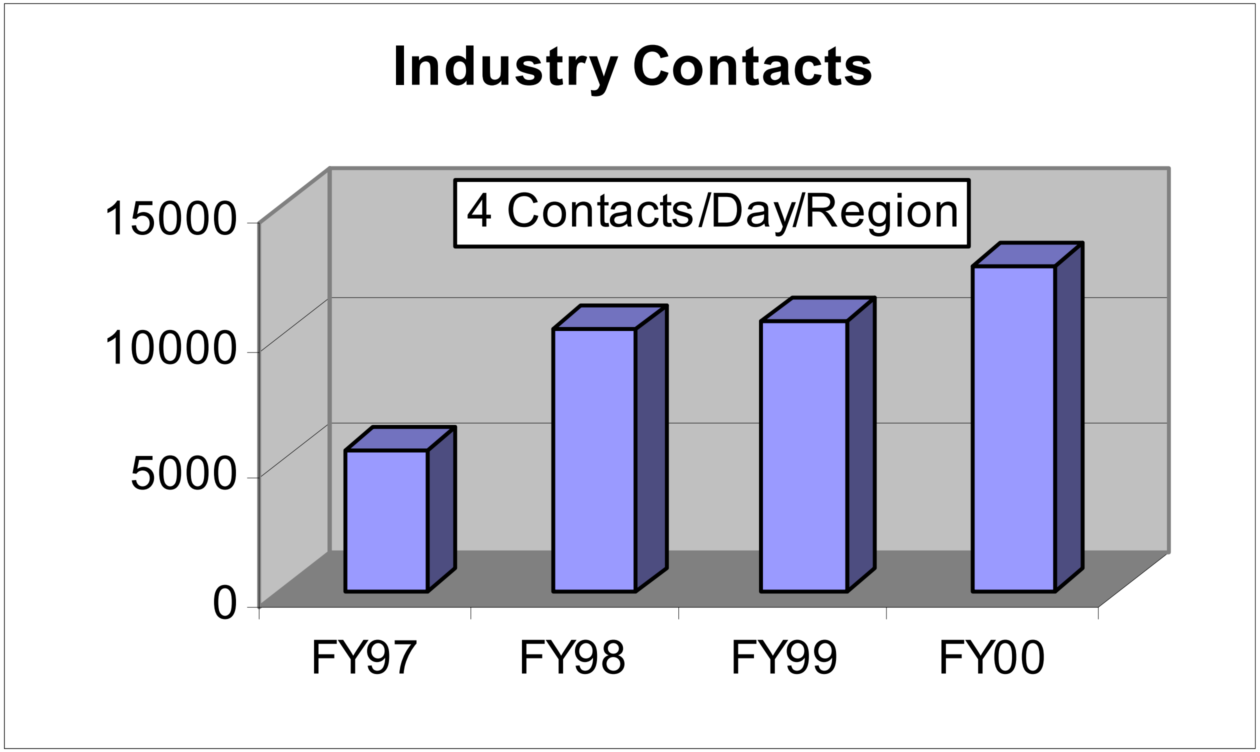
Core Services—Education



Petroleum Technology Transfer Council

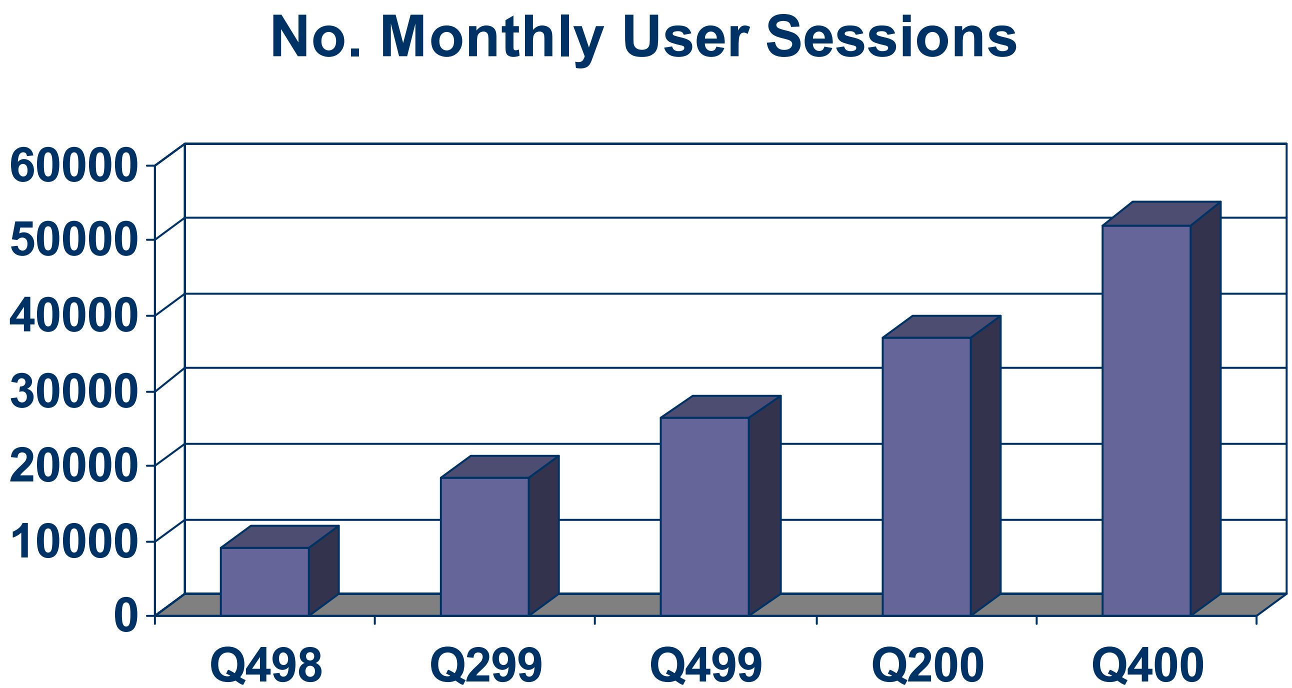
Timely, informed technology decisions...

Core Services—Connections



Petroleum Technology Transfer Council
Timely, informed technology decisions...

Core Services—Connections



Web Group

- Improve Consistency (Image, Ease of Use)
- Enhance Capabilities (Consolidate, Leverage Resources, Expand Capabilities)
- File Management
- Keep up With Technological Advances

Petroleum Technology Transfer Council

Timely, informed technology decisions...

Regionally-Focused

- **Newsletters**
  - Regional newsletters or columns in publications of producer groups
  - Technical content, calendar, news
- **Websites**
  - Over 57,000 user sessions/mo.
  - Traffic grows with added content

Tailored Outreach Approaches

- **Mentors**
  - Known and Respected Locally (one of you), Tech Transfer at a Practical Level
  - Proven Technologies That Can Be Implemented Now
  - Stimulating Action, Connecting Groups
- **Satellite Centers (Michigan, Mississippi)**
- **Troubleshooters**

Mentor Achievements

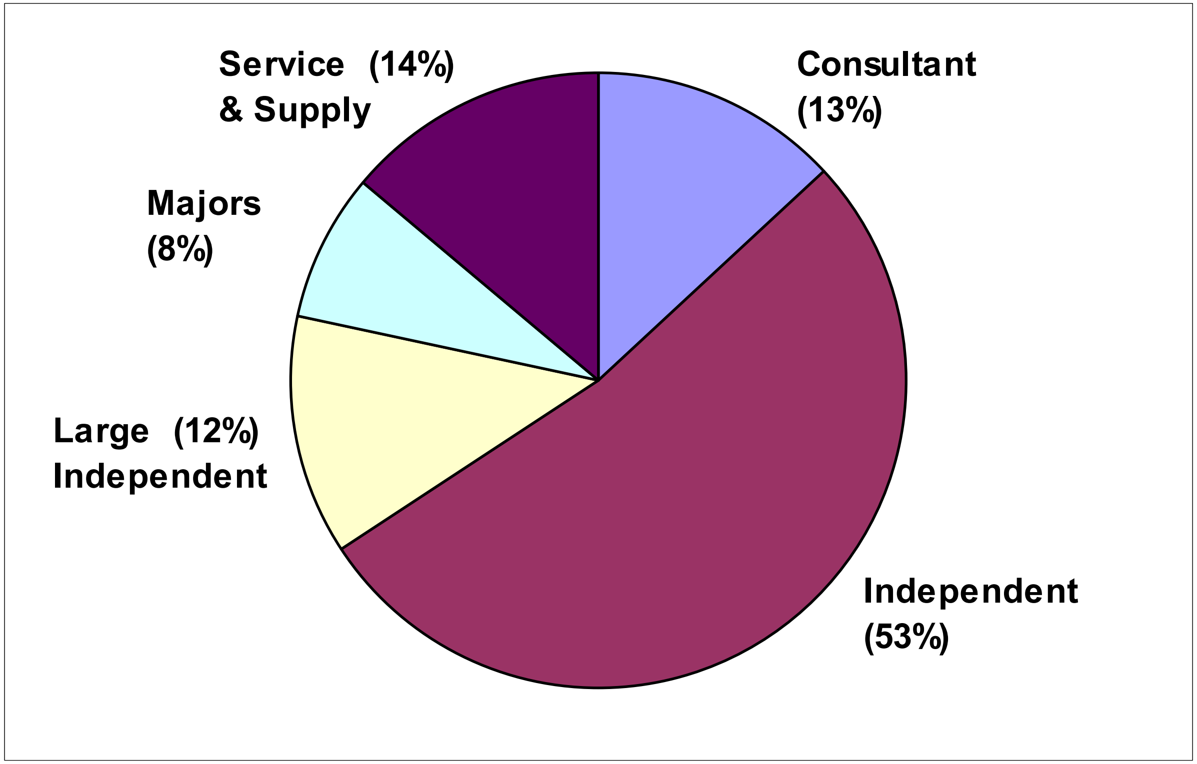
- Applied Technology Workshops
- Technology Demos at O&G Facilities
- Permian Basin Website
- Develop Case Studies
- Promote PTTC Locally and Regionally
- Supporter of CO_2 Conference
- Work with Professional Societies and Trade Groups

National Outreach & Tech Transfer

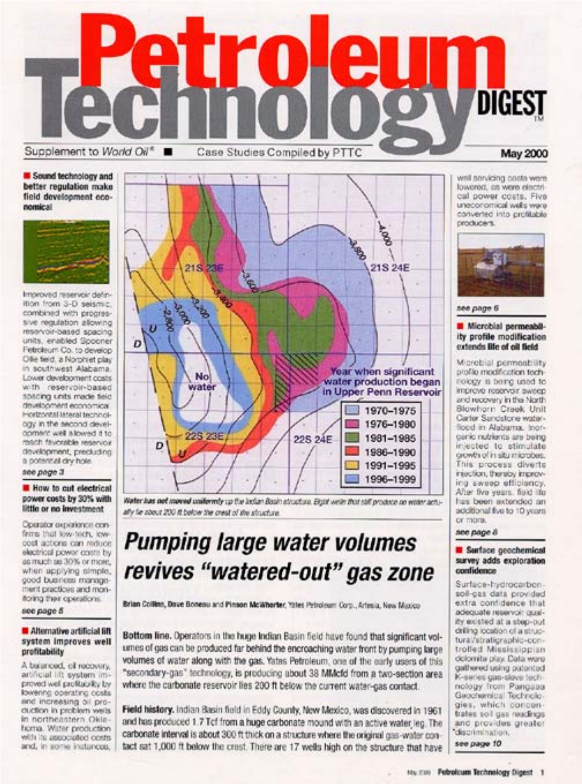
- PTTC Network News
- Petroleum Technology Digest
- Solutions From the Field
- National Website
- Exhibit and Present @ Major Events

Petroleum Technology Transfer Council
Timely, informed technology decisions...

Distribution Of PTTC Network News



Petroleum Technology Digest



Petroleum Technology DIGEST™

Supplement to *World Oil*® ■ Case Studies Compiled by PTTC May 2000

■ **Sound technology and better regulation make field development economical**

Improved reservoir definition from 3-D seismic, combined with progressive regulation allowing reservoir-based spacing units, enabled Spooner Petroleum Co. to develop Olle field, a Norphlet play in southwest Alabama. Lower development costs with reservoir-based spacing units made field development economical. Horizontal lateral technology in the second development well allowed it to reach favorable reservoir development, precluding a potential dry hole.

see page 3

■ **How to cut electrical power costs by 30% with little or no investment**

Operator experience confirms that low-tech, low-cost actions can reduce electrical power costs by as much as 30% or more, when applying simple, good business management practices and monitoring their operations.

see page 5

■ **Alternative artificial lift system improves well profitability**

A balanced, oil recovery, artificial lift system improved well profitability by lowering operating costs and increasing oil production in problem wells in northeastern Oklahoma. Water production with its associated costs and, in some instances, well servicing costs were lowered, as were electrical power costs. Five uneconomical wells were converted into profitable producers.

see page 6

■ **Microbial permeability profile modification extends life of oil field**

Microbial permeability profile modification technology is being used to improve reservoir sweep and recovery in the North Blowhorn Creek Unit Carter Sandstone waterflood in Alabama. Inorganic nutrients are being injected to stimulate growth of in situ microbes. This process diverts injection, thereby improving sweep efficiency. After five years, field life has been extended an additional five to 10 years or more.

see page 8

■ **Surface geochemical survey adds exploration confidence**

Surface-hydrocarbon-soil-gas data provided extra confidence that adequate reservoir quality existed at a step-out drilling location of a structural/stratigraphic-controlled Mississippian dolomite play. Data were gathered using patented K-series gas-sieve technology from Pangaea Geochemical Technologies, which concentrates soil gas readings and provides greater discrimination.

see page 10

Water has not moved uniformly up the Indian Basin structure. Eight wells that still produce no water actually lie about 200 ft below the crest of the structure.

Pumping large water volumes revives "watered-out" gas zone

Brian Collins, Dave Boneau and **Pinson McWhorter**, Yates Petroleum Corp., Artesia, New Mexico

Bottom line. Operators in the huge Indian Basin field have found that significant volumes of gas can be produced far behind the encroaching water front by pumping large volumes of water along with the gas. Yates Petroleum, one of the early users of this "secondary-gas" technology, is producing about 38 MMcfd from a two-section area where the carbonate reservoir lies 200 ft below the current water-gas contact.

Field history. Indian Basin field in Eddy County, New Mexico, was discovered in 1961 and has produced 1.7 Tcf from a huge carbonate mound with an active water leg. The carbonate interval is about 300 ft thick on a structure where the original gas-water contact sat 1,000 ft below the crest. There are 17 wells high on the structure that have

May 2000 Petroleum Technology Digest 1

Measuring Success

- **Workshop Activity Level Rising**
- **Repeat Attendance Growing**
- **Website Traffic Increasing**
- **Challenges**
  - Operator Reluctance to Share Successes
  - PTTC Resource Constraints

Vision For The Future

- Develop Close Alliances
- Leverage and Strengthen the Websites
- Expand Outreach
- Improve Efficiency and Further Partnerships

Expanded Outreach

- Focused Effort on Expanding Mentor Program Into More Regions
- More Funding to Sustain and Expand Regional Programs
- PUMP Award Recent Success


The Future

A Key Element in America's Energy Future: Maintaining a Reliable Supply of Natural Gas

Speaker

Charlie Byrer
Natural Energy
Technology Laboratory

A Key Element in America's Energy Future: Maintaining a Reliable Supply of Natural Gas

Alaska Coalbed and Shallow Gas Resources Workshop

April 30 - May 4, 2001

Charles W. Byrer
National Energy Technology Laboratory

Natural Gas Prices Expected to Remain Strong

Henry Hub Gas Price

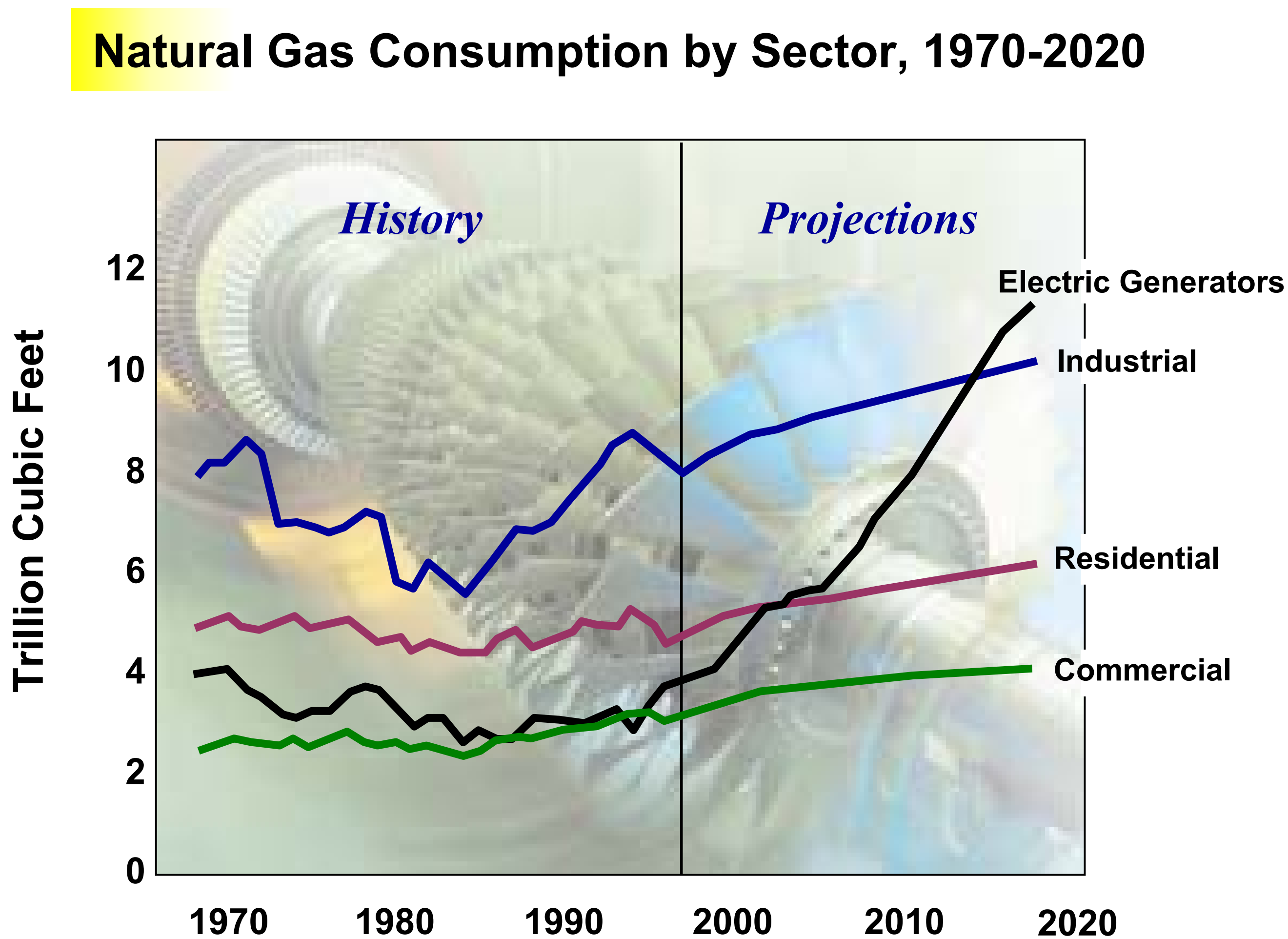
Source: Cambridge Energy Research Associates

U. S. Market Outlook

- **Over the next 20 years, natural gas consumption is expected to grow from 22 trillion cubic feet (Tcf) to almost 35 Tcf**
- **Consumption will increase in every sector**
- **Increased demand for electricity generation will be the largest driver**
  - Consumption is expected to triple to more than 11 Tcf
- **Much of this increase will need to be domestic supply**

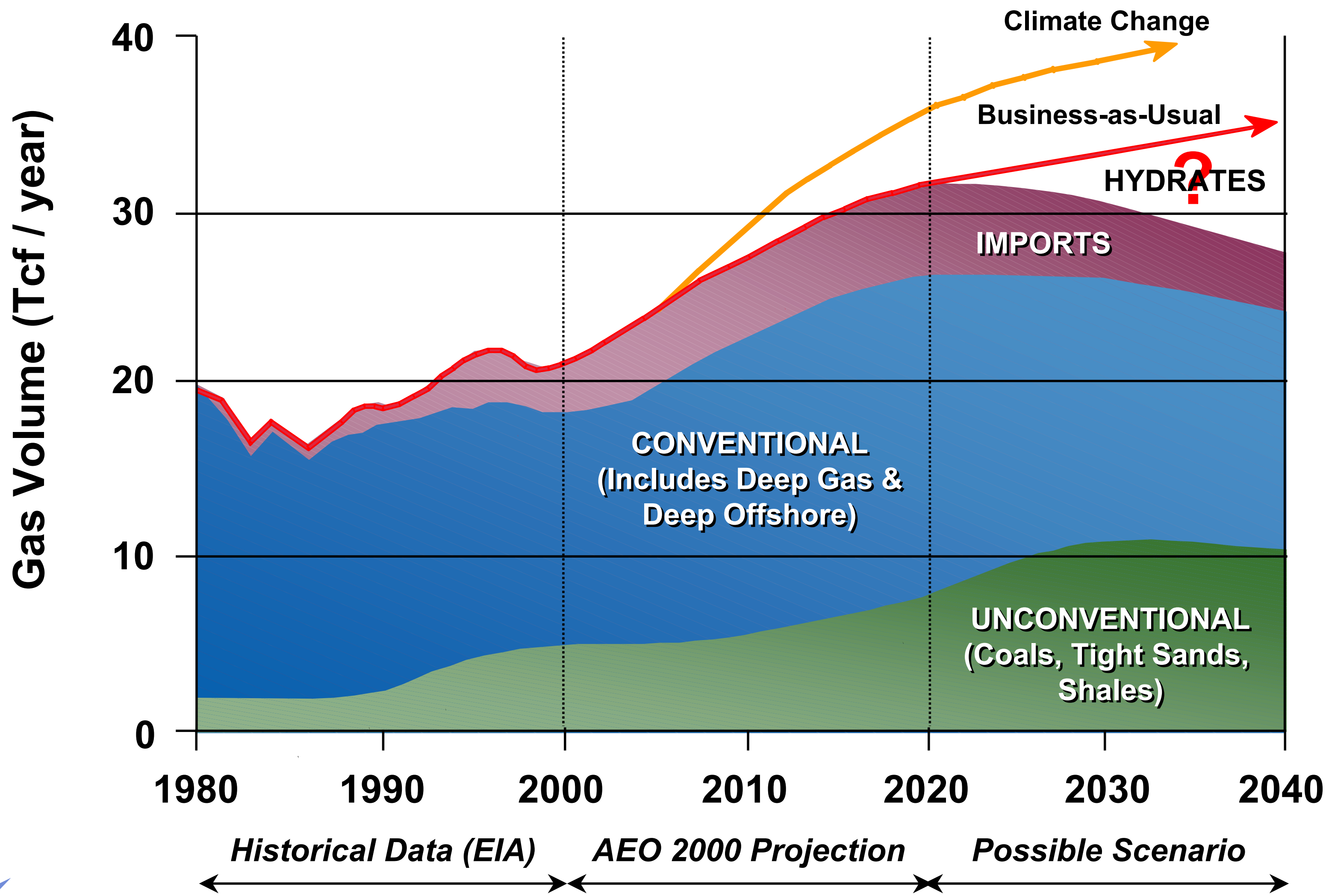
NETL

Natural Gas Use is Projected to Increase Most Dramatically for Electricity Generation



Source: www.eia.doe.gov/neic/speeches/aeo2001

Enough Affordable Natural Gas to Meet Demand?



Sources: NETL, Boswell

Potential Gas Committee Natural Gas Resource Estimates
(as of December 31, 2000)

	2000 Tcf	1998 Tcf	Change: Δ
Traditional Resources			
Probable Resources (Current Fields)	207.0	216.0	-4.27%
Possible Resources (New Fields)	332.2	293.0	+13.4%
Speculative Resources (Frontier)	397.8	385.7	+3.1%
Subtotal Traditional	**935.8**	**896.1**	**+4.4%**
Coalbed Methane			
Probable Resources (Current Fields)	16.3	14.4	**+13.2%**
Possible Resources (New Fields)	54.3	43.5	**+24.8%**
Speculative Resources (Frontier)	84.6	83.6	**+1.2%**
Subtotal Coalbed Methane	**155.2**	**141.4**	**+9.7%**
Proved Reserves (DOE Estimates)	**167.4**	**167.0**	
Grand Total	**1258.4**	**1204.5**	**+4.5%**

NETL

Lessons From the Past

- **Concerns over the future of natural gas supplies existed in the late 1970s and early 1980s**
  - Three new sources of gas supply were brought to market through R&D and technology
- **Increased volumes of unconventional gas**
  - Since 1980, unconventional gas has added nearly 3,000 Bcf per year (8 Bcfd) of new supply

	1978 Bcf	**1999 Bcf**
Tight Gas	1,560	2,890
CBM	-	1,250
Gas Shales	70	370
Total	**1,630**	**4,510**

NETL

Lessons From the Past

- **Deepwater Gulf of Mexico**
  – Development of the Gulf of Mexico slope has added 1,120 Bcf per year (3 Bcfd) of new gas supply

1980	1999 Bcf
-	1,120

- **Reserve growth from existing fields**
  – The great bulk of natural gas reserve additions have been from reserve growth rather than new discoveries

	1999 Bcf
Reserve Growth	19,685
New Discoveries	3,887

Strategic Center for Natural Gas

Vision:

By 2020, U.S. public is enjoying benefits from an increase in gas use:

- Affordable supply
- Reliable delivery
- Environmental protection

Mission:

Be the focal point for an integrated gas program:

- Spearhead annual DOE-wide gas RD&D planning and program assessment
- Provide science and technology advances through NETL's on-site programs
- Shape, fund, and manage extramural RD&D
- Conduct studies to support policy development

NETL

Five RD&D Activity Clusters

Strategic Center for Natural Gas
Borehole to Burner Tip

Electric Power Using Coal
Mining to Light Switch

Energy Policy Support
A Key Issue in Use of Fossil Energy

Environmental Quality / Defense Programs
Supporting the DOE Complex

Oil Supply

Fuels

Supply and Delivery of Clean Fuels for Transportation/Other End Use Sectors

Drilling, Completion & Stimulation Objectives

- **Faster**
  - New bit technology and slim hole
- **Deeper**
  - High temperature and pressure
  - Develop smarter drilling systems
  - Increase penetration rates in hard rock
- **Cheaper**
  - Reduce cost of drilling in shale, low-perm, and deep water
  - Develop cheaper horizontal and multilateral wells
- **Smarter**
  - Continuing improvement: MWD and LWD technologies
- **Cleaner**
  - Develop cost effective, environmentally friendly drilling technologies to increase access to federal lands using a small footprint

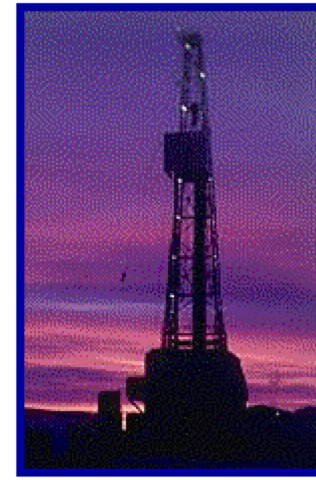
NETL

Gas Exploration & Production Program Goals

- **Near-Term: Recover more from developed fields**
  - Locate by-passed zones in conventional reservoirs
  - Enhance stripper well production
- **Mid-Term: Exploit low-permeability formations (including coalbed methane)**
  - Reduce drilling cost
  - Improve success rates in finding gas
  - Increase recovery efficiency
- **Long-Term: Encourage E&P of frontier resources**
  - Deep (>16,000 feet) gas
  - Methane Hydrates
  - Offshore gas

NETL

Latest Success Story



- **Project Specifics**
  - Union Pacific Resources (UPR) Company
  - Rock Island #4 Well drilled in Wyoming
  - Deep horizontal well (15,000 TVD w/1,700 ft horizontal)
  - Greater Green River Basin (Tight Sand)
- **Results**
  - Production exceeded expectations (2.1 bcf in six months)
  - Based on well's success, six more wells being drilled
  - Potentially huge reserves; gas bearing play covers 900 square miles
- **Project Demonstrates**
  - Successful partnership between industry and Government
  - Successful crosscutting of key program elements
    - Deep gas; low perm; horizontal well; deep horizontal coring

Stripper Well Program
FY 2001 Activity

- **New Initiative: Stripper Well Consortium**
  - Includes both oil and gas
  - Cofunded by NPTO and SCNG at $1 million/year
  - NYSERDA providing $100K/year
- **Consortium Benefits**
  - Industry plays key role in prioritizing research
  - Networking and partnering opportunities
  - Minimal investment by member leverages Federal R&D funds
  - Partnership between industry, academia, and government
- **Project Details**
  - Consortium started January 2001
  - Operated by Penn State University

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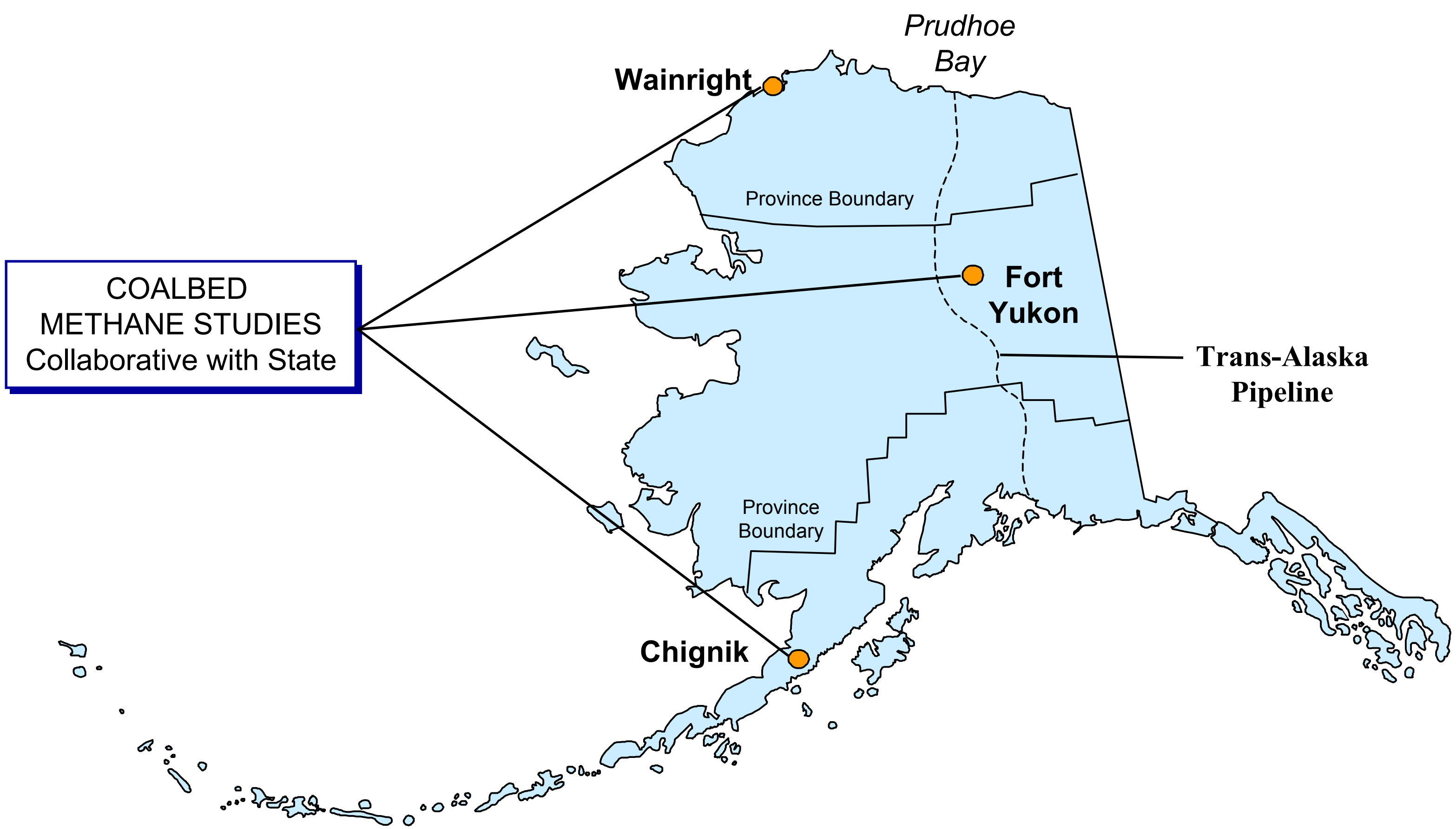
Gas Hydrates
Turning a Problem into a Potential Resource

- **A huge worldwide resource**
  - Oceans: 30,000 to 49,100,000 Tcf
  - Continents: 5,000 to 12,000,000 Tcf
  - Conventional resource: 3,000 Tcf
- **A huge US resource**
  - If 1% recoverable: 3,200 Tcf
  - Conventional resource: 1,301 Tcf
- **Program elements**
  - Resource characterization
  - Safety & seafloor stability
  - Global climate change
  - Production

Hydrate Authorization Bill Passed May 2000

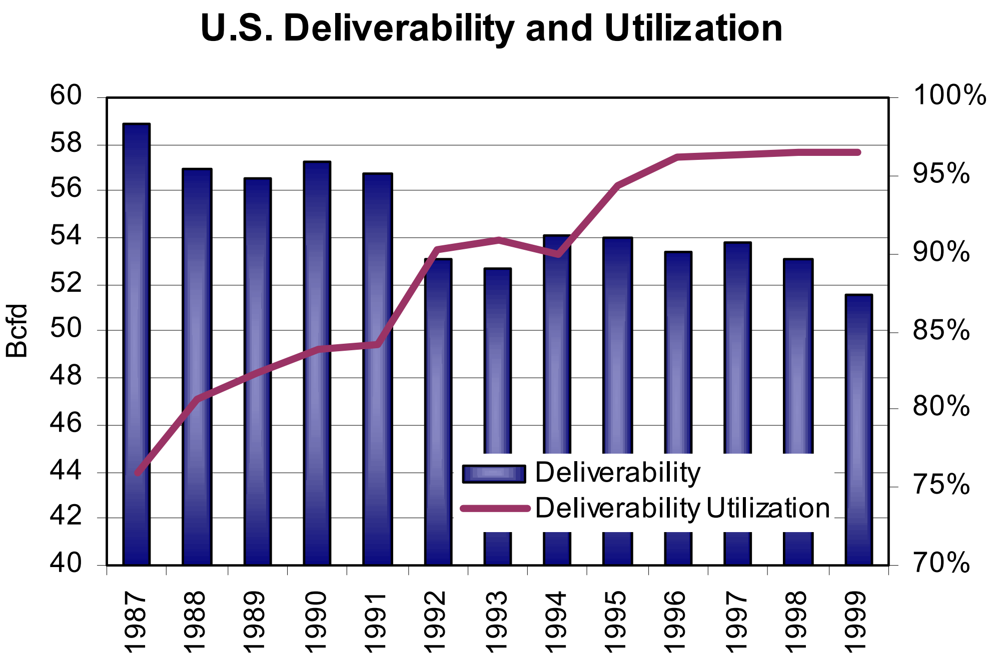
- Requires government to coordinate
  - Energy, Interior, Defense, Commerce, NSF
- Mandates advisory panel from industry, academia, government

Coalbed Methane Studies in Alaska

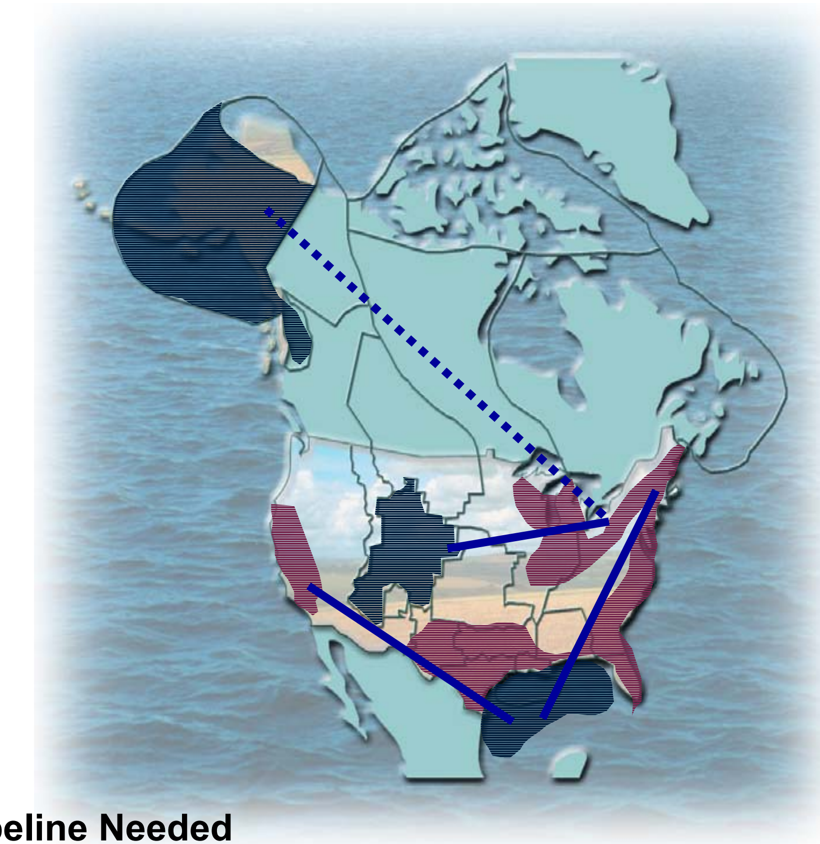


Reference: USGS

Natural Gas Deliverability “Maxed Out”



Source: EIA, NGSA, & WEFA, Inc.



New Pipeline Needed

Upgraded Pipeline Needed

High Demand Region

Potential Major Supply Region

Source: EIA Natural Gas Report

http://www.energy.psu.edu/swc

- Overview
- SWC Membership
- Funded Projects
- Become a Member
- Upcoming Meetings
- Submitting Proposals
- Contacts

Welcome

to the Stripper Well Consortium (SWC)

The SWC is an industry-driven consortium that is focused on the development, demonstration, and deployment of new technologies needed to improve the production performance of natural gas and petroleum stripper wells.

SWC is comprised of natural gas and petroleum producers, service companies, industry consultants, universities, and industrial trade organizations. The Strategic Center for Natural Gas, the National Petroleum Technology Office, and the New York State Energy Research and Development Authority provide base funding and guidance to the consortium. By pooling financial and human resources, the SWC membership can economically develop technologies that will extend the life and production of the nation's stripper wells.

Program Sponsors

NETL

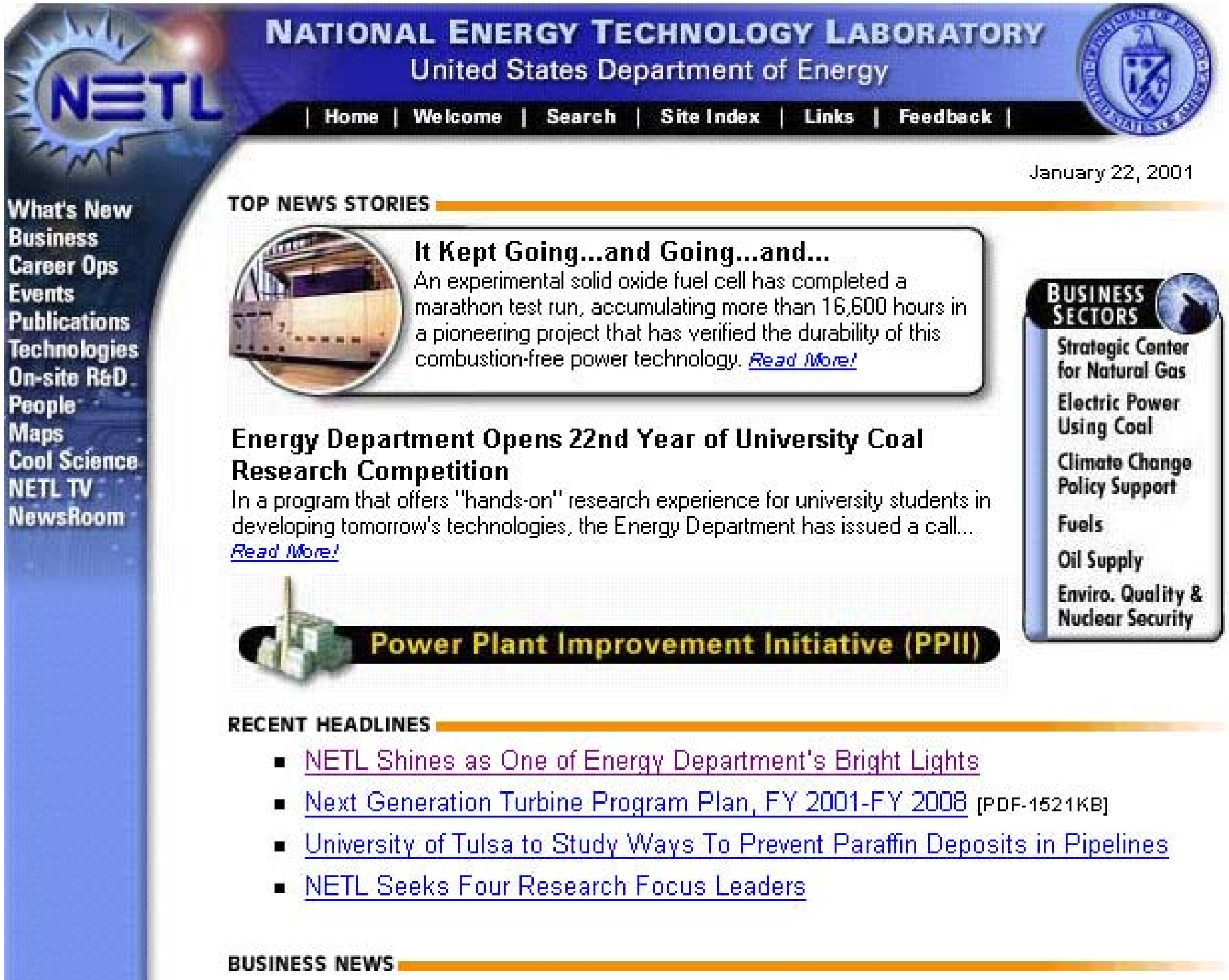
Strategic Center for Natural Gas

National Petroleum Technology Office

NETL

Visit Our Website

www.netl.doe.gov



Alaska's Need for Coalbed Methane and Shallow Gas Resources

Speaker

Marty Rutherford
Alaska Department of
Natural Resources

NOTES:

Impact of Gas Pipeline on North Slope and Interior Basins Exploration/Gas Leasing

Speaker

Mark D. Myers
Alaska Division of Oil & Gas
Director

Alaska's Conventional and Coalbed Methane Gas Potential

Mark D. Myers
Division of Oil and Gas
May 2001

Alaska Department of Natural Resources

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

The State Revenue Pie

Petroleum Revenue Sources, (FY 2000):

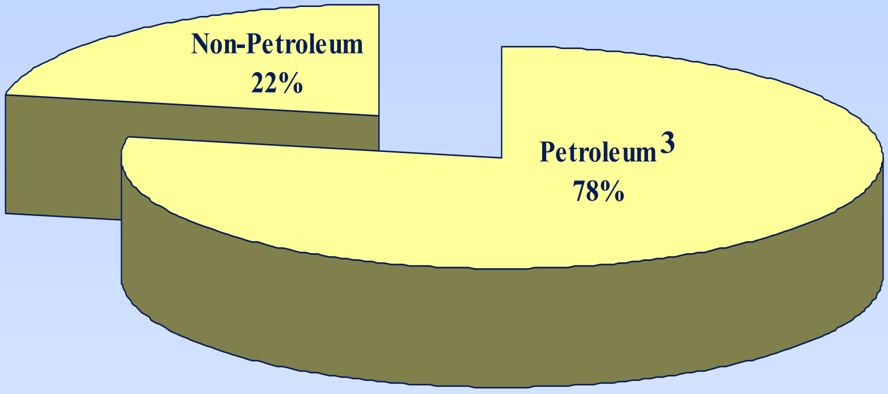
Royalties, Bonuses & Rents[1,2]:
$731.9 Million

Royalties to Permanent Fund & School Fund[4]:
$306.5 Million

Settlements to CBRF[4]:
$448.3 Million
(Includes Royalties & Taxes)

Taxes:
$910.4 Million[2]
(Oil & Gas Property Tax + Income Tax + Severance Tax)

FY 2000 Unrestricted Revenue



1 Includes Federally shared rentals

2 Source: pg. 25, DOR Fall 2000 Revenue Sources Book

3 Source: pg. 26, DOR Fall 2000 Revenue Sources Book

4 Source: pg. 23, DOR Fall 2000 Revenue Sources Book

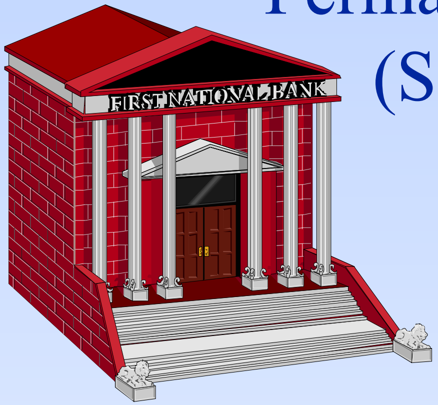
dhz 01/01

Where Our Petroleum Royalty Money Goes…

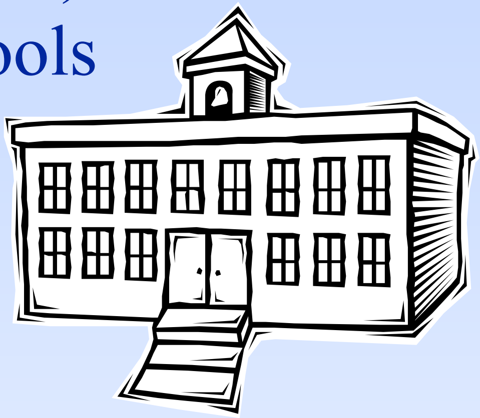
*Year 2000 to date

(70%)*
General Fund
(Spending)

(29.5%)*
Permanent Fund
(Savings)



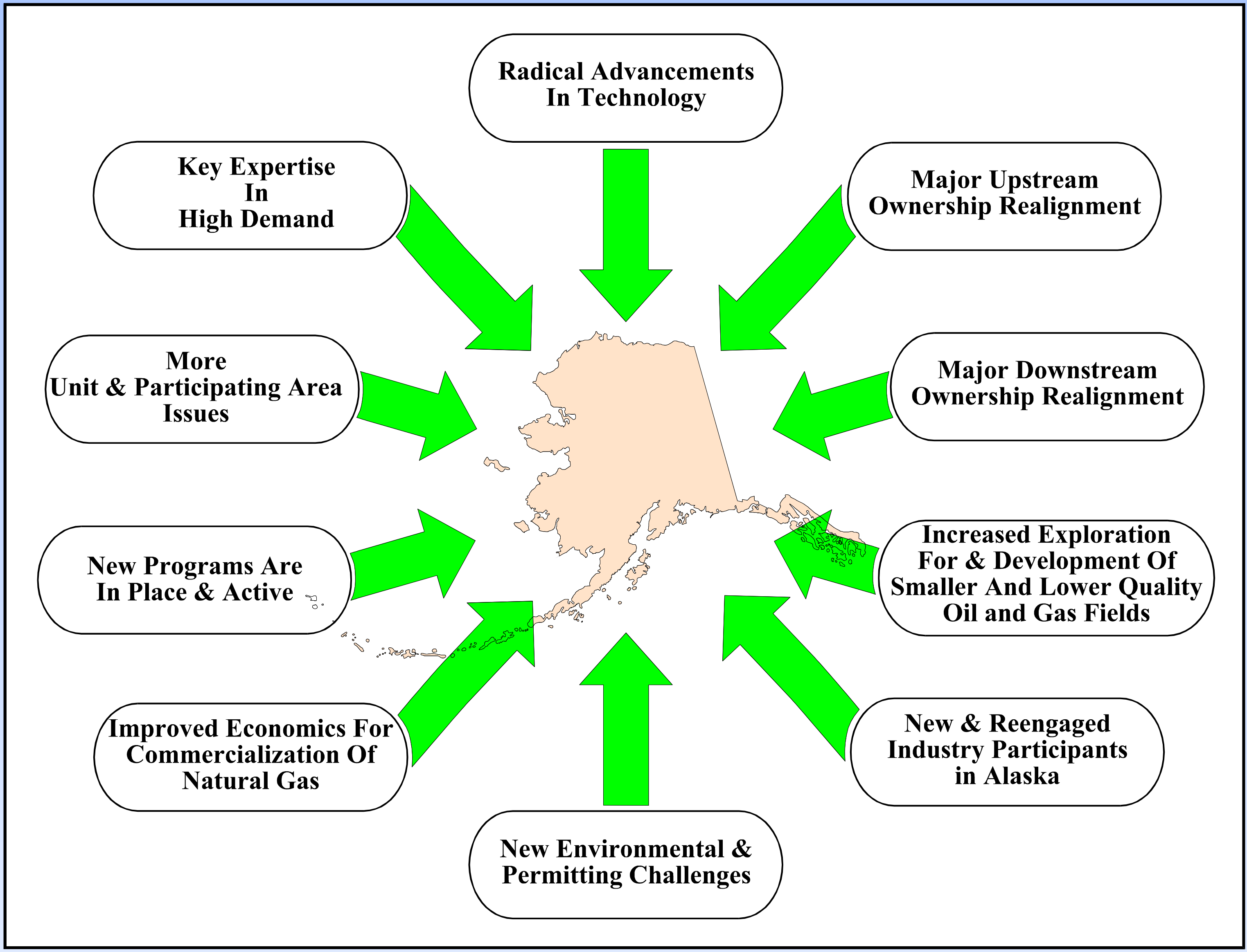
(0.5%)*
Schools



**Production for new leases allocated
50% Permanent Fund
49.5% General Fund
0.5% Schools

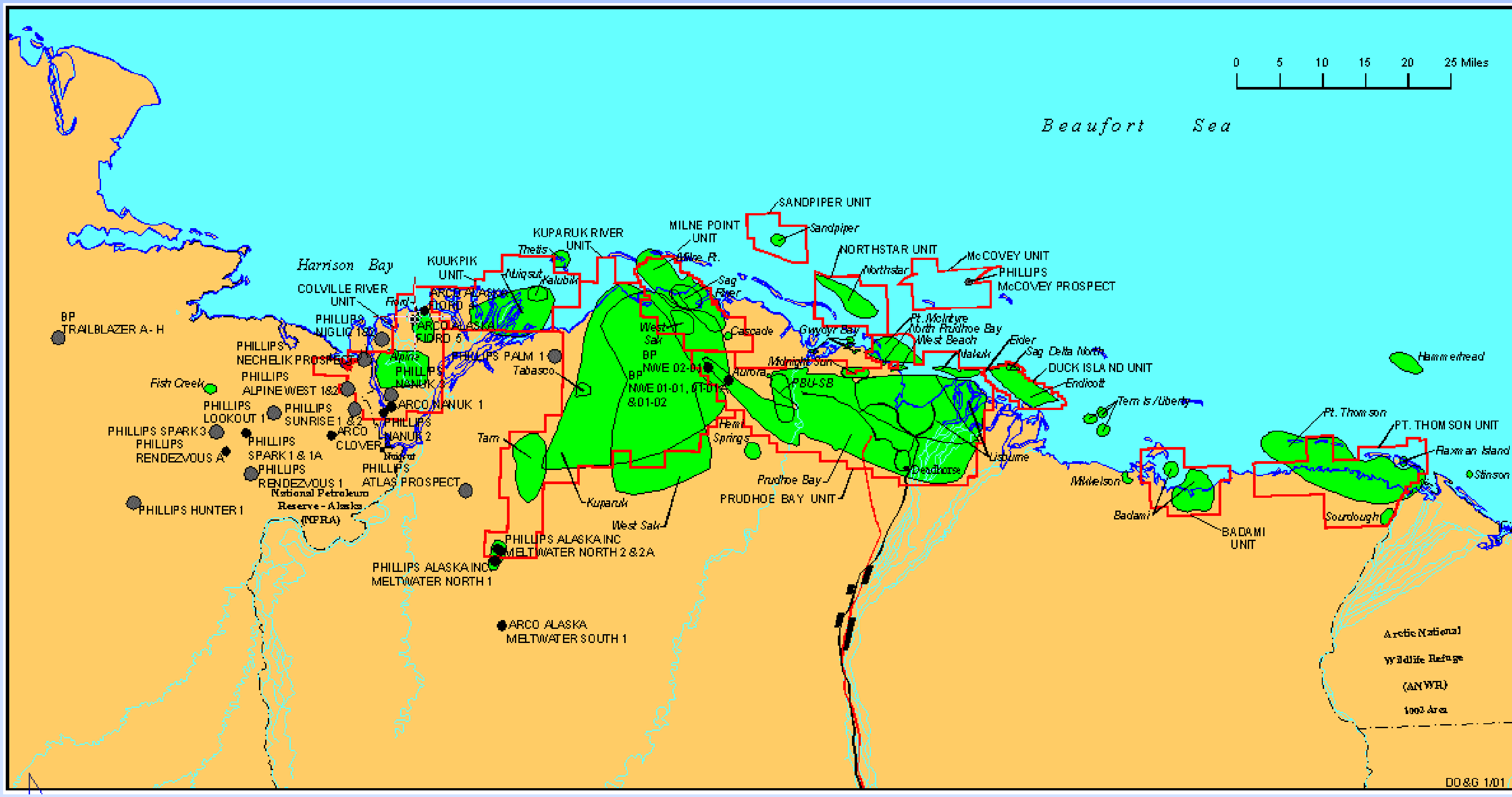
dhz 01/01

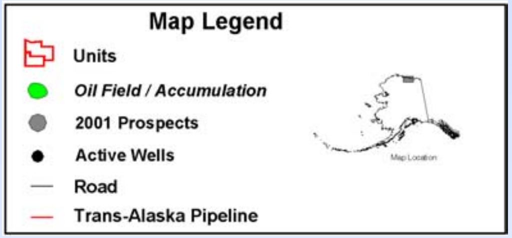
Recent Dynamic Changes in Alaska's Oil and Gas Business



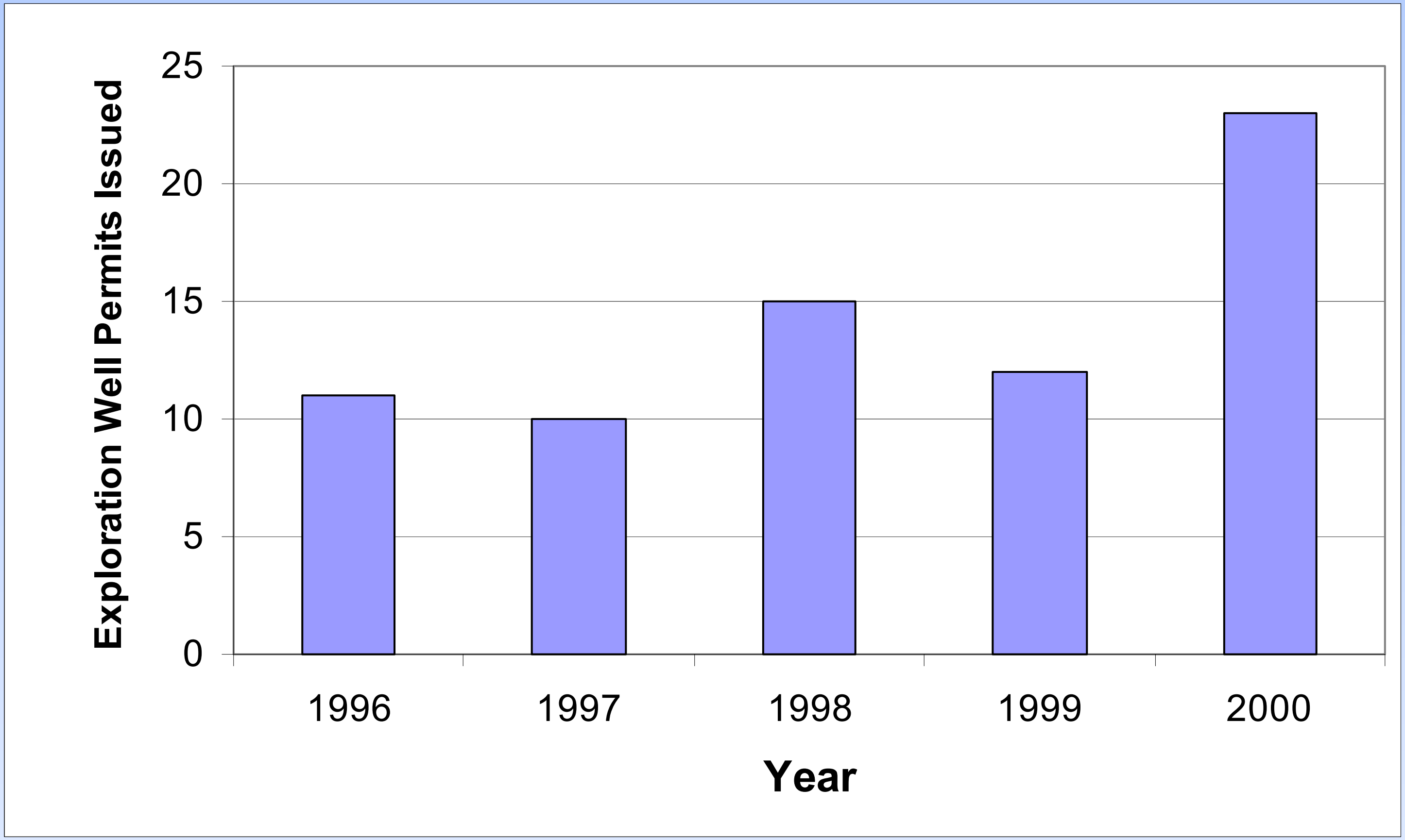
mdm/mep 03/01

Proposed North Slope Activity - 2001

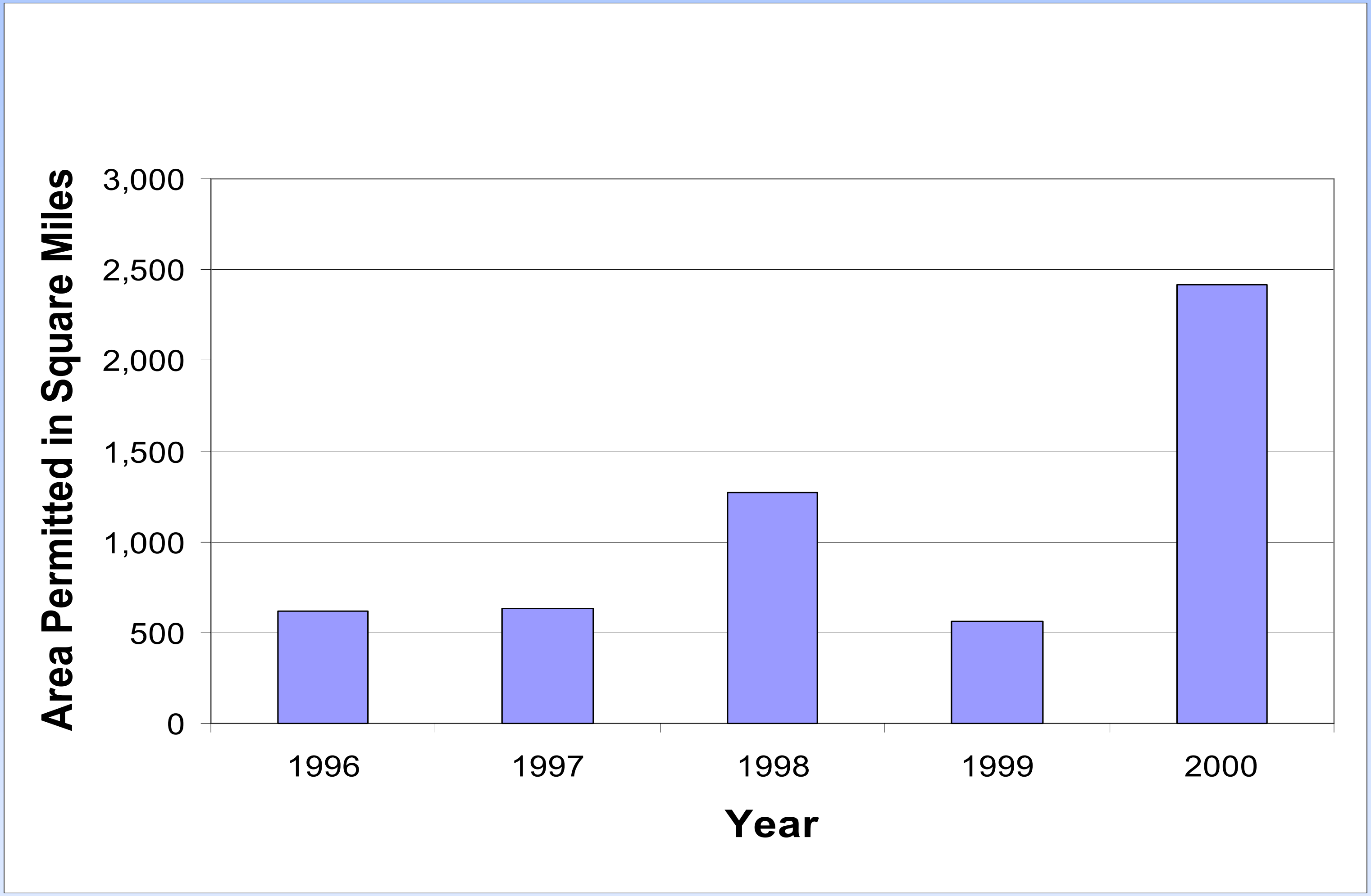




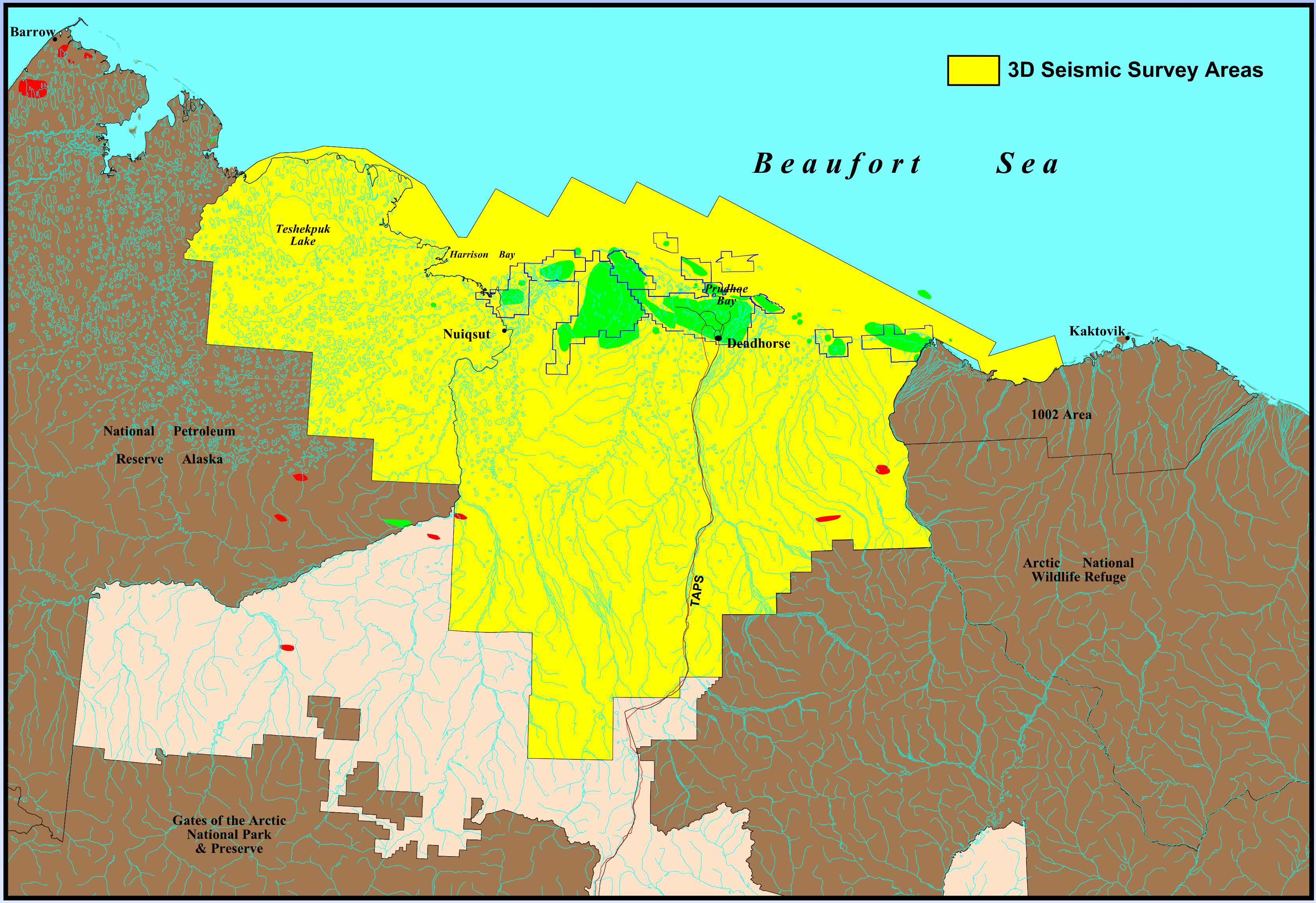
North Slope Exploration Wells Permitted



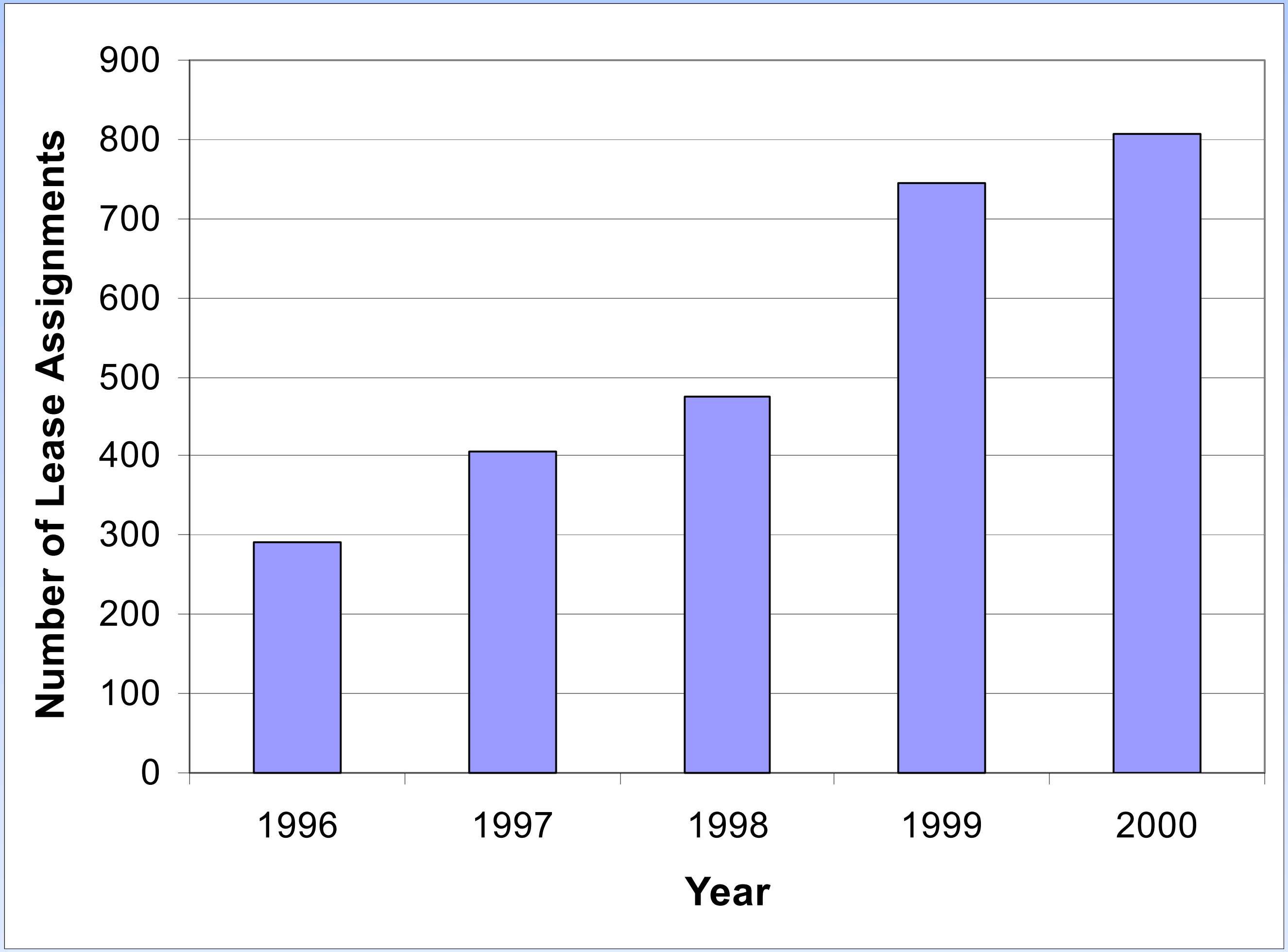
3-D Seismic Survey Miles in Alaska



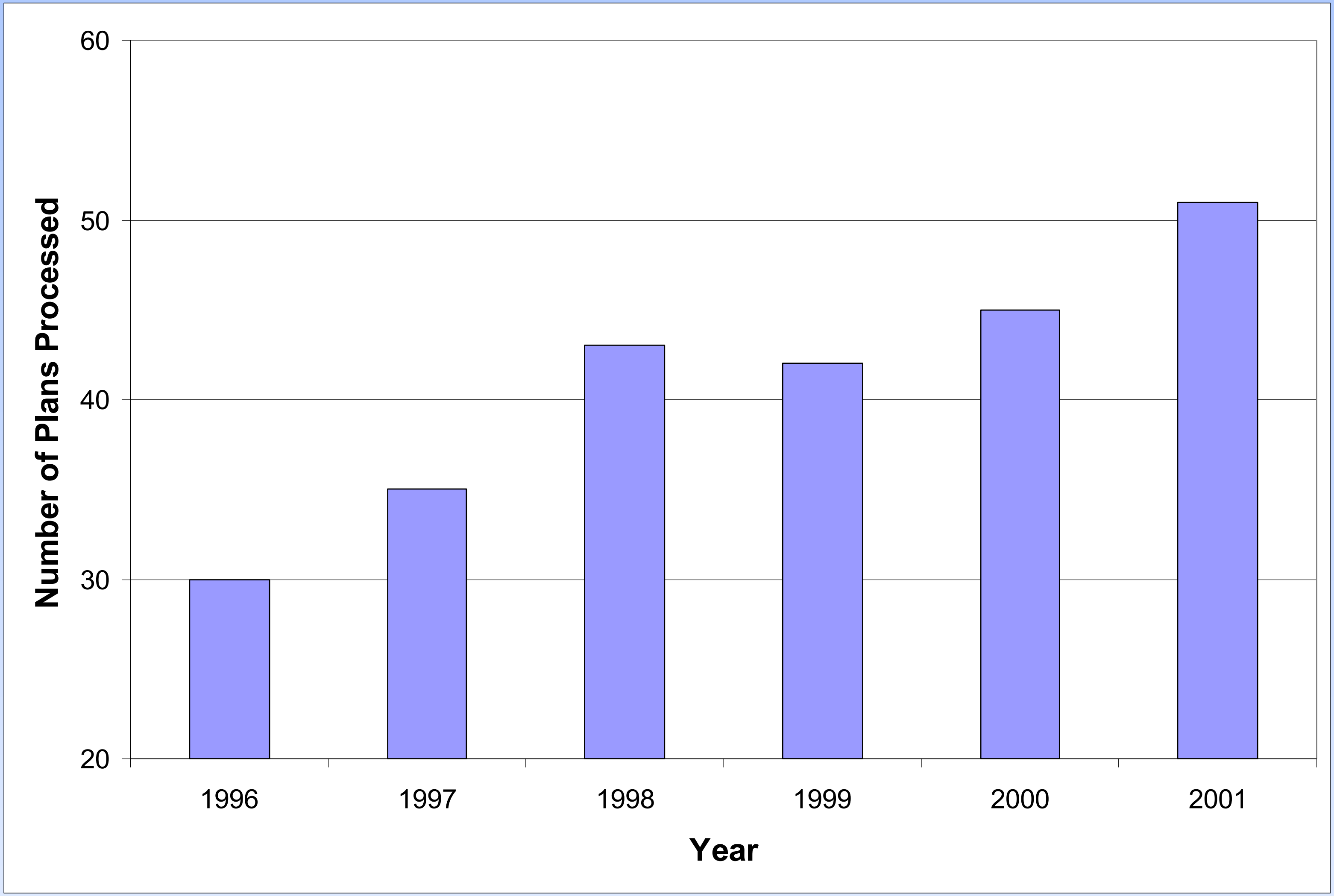
North Slope 3-D Seismic Survey Areas



Lease Assignments in Alaska



Unit Activity
Plans of Development / Exploration



Proved Gas Reserves

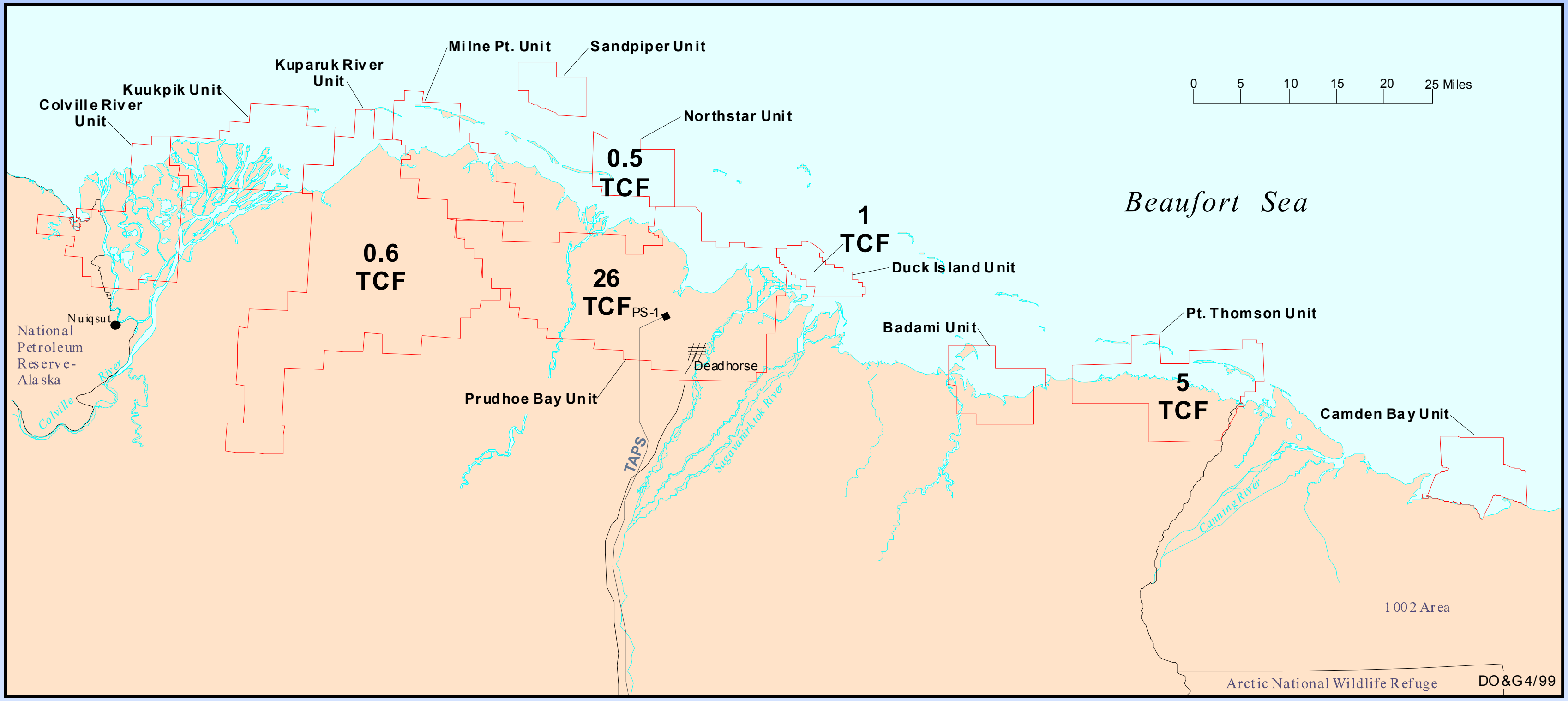
Gas Reserves (BCF)

North Slope	
Badami Unit	39
Barrow	34
Colville River Unit	60
Duck Island Unit	843
Kuparuk River Unit	611
Milne Point Unit	14
North Star	450
Prudhoe Bay Unit	23,879
Other Undeveloped	5,000
TOTAL North Slope	**30,930**
Cook Inlet	**2,564**
TOTAL STATE	**33,494**

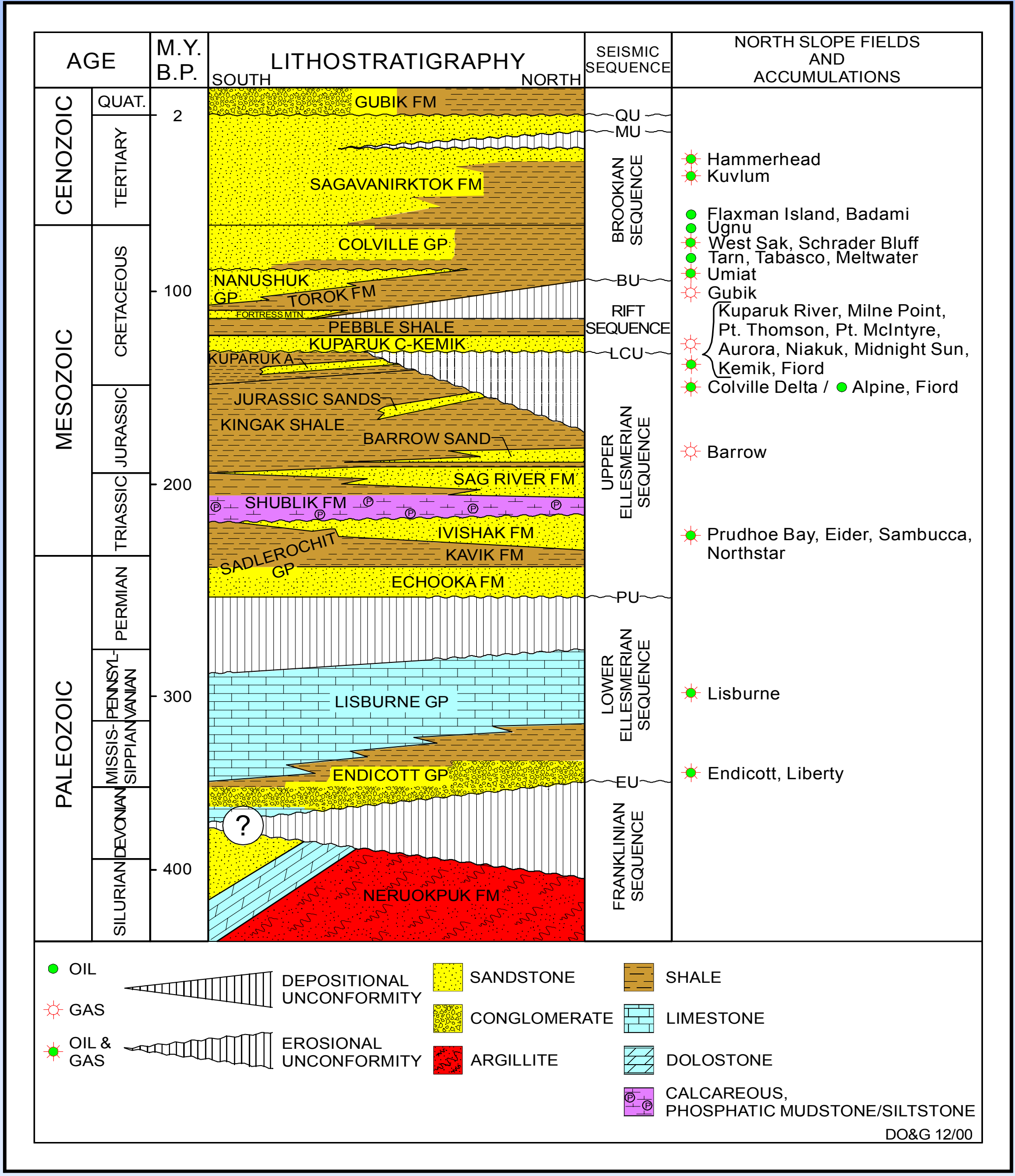
krb/03/01

North Slope Gas Resources

Prudhoe Bay Field is the Primary North Slope Gas Resource



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



Areawide Lease Sales

North Slope

- 3 Sales Held: 1998, 1999 & 2000
- 1.4 Million Acres Leased
- $65 Million in Bonus Bids
- 1.9 Million Acres Under Lease
- 6 Sales Proposed Over Next 5 Years

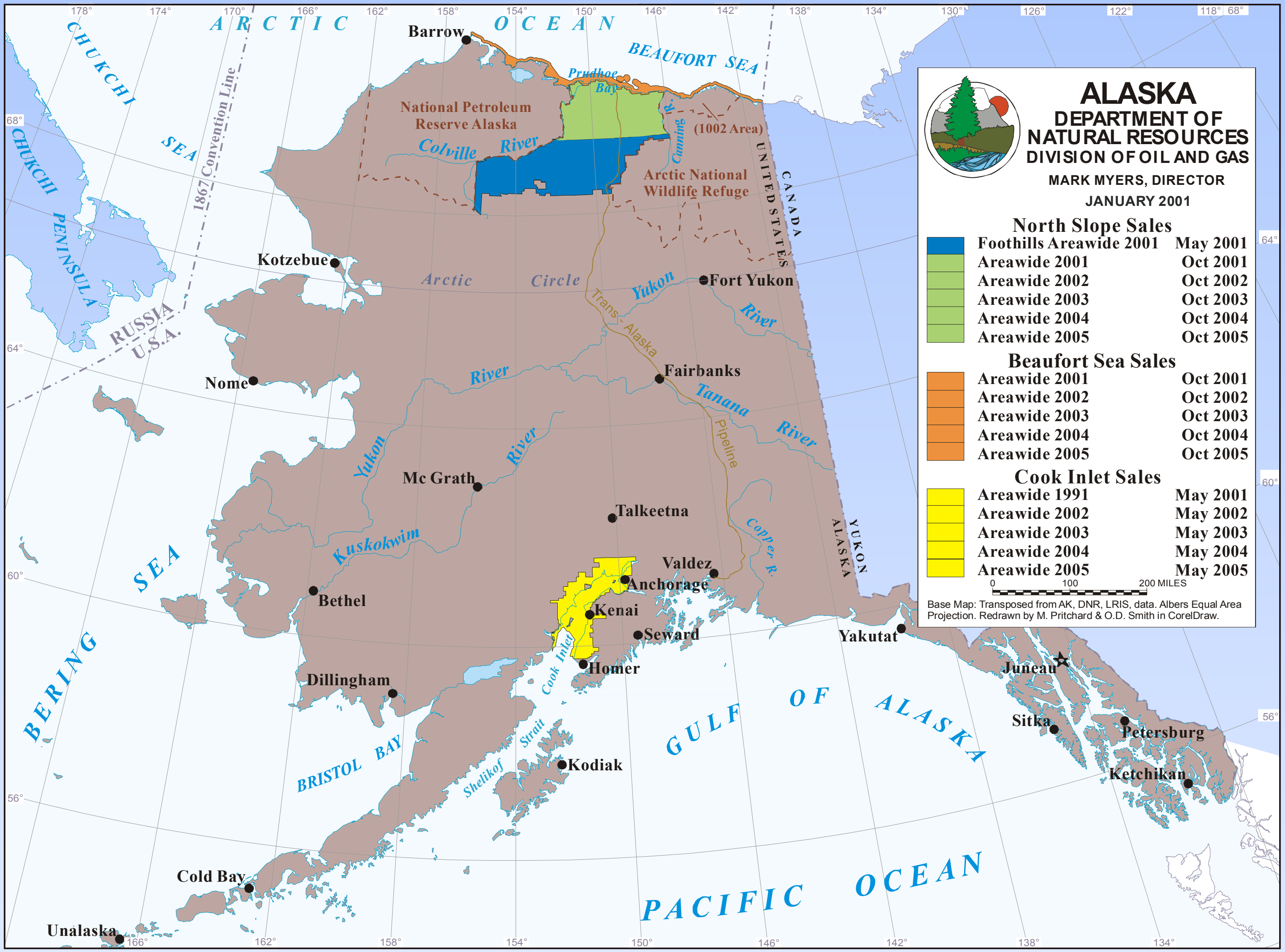
Cook Inlet

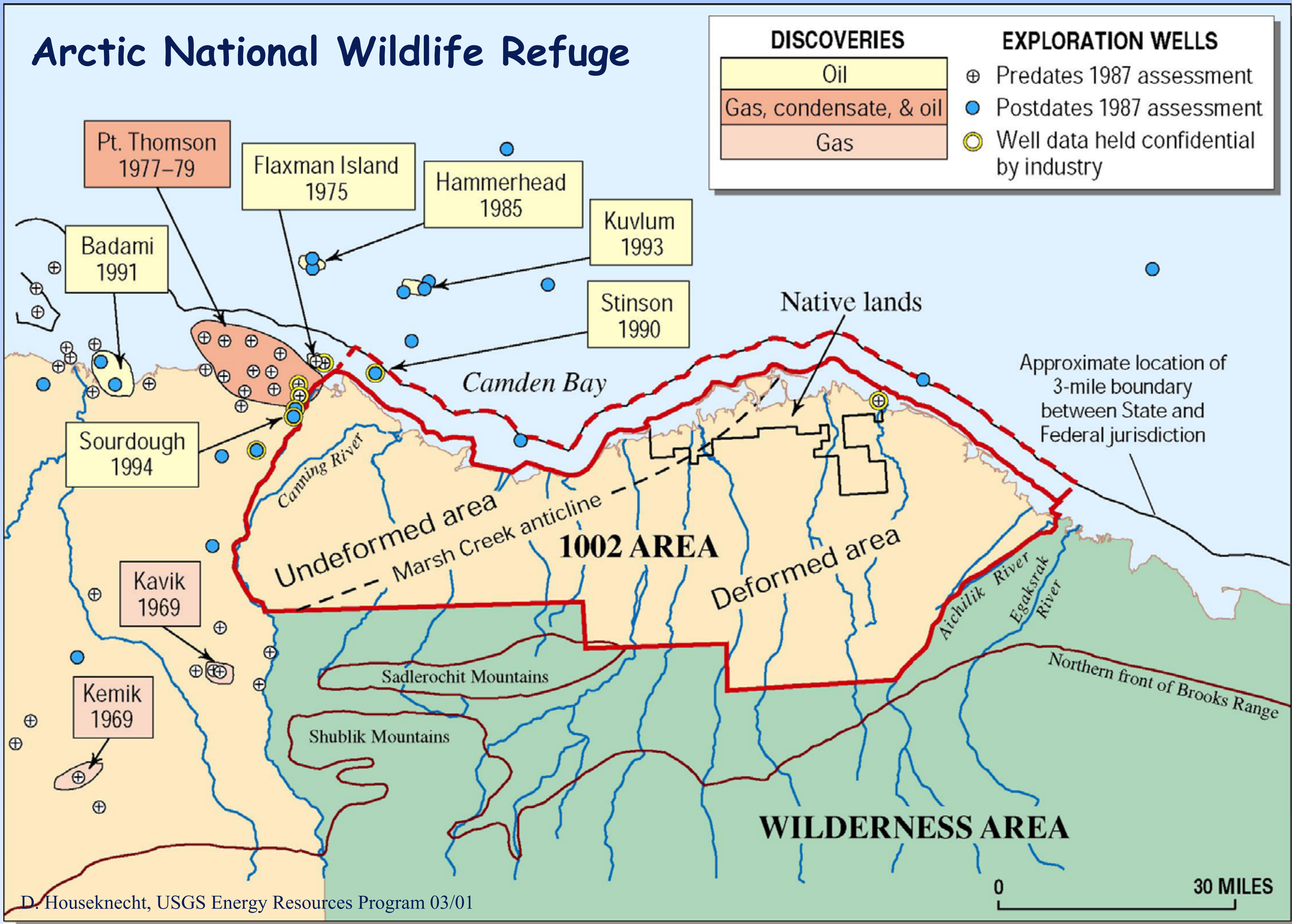
- 2 Sales Held: 1999 & 2000
- 215,000 Acres Leased
- $2.3 Million in Bonus Bids
- 716,000 Acres Under Lease
- 5 Sales Proposed Over Next 5 years

Beaufort Sea

- 1 Sale Held: 2000
- 33,900 Acres Leased
- $440,000 in Bonus Bids
- 839,000 Acres Under Lease
- 5 Sales Proposed Over Next 5 Years

Alaska Oil & Gas Leasing Program




Arctic National Wildlife Refuge
DISCOVERIES
Oil
Gas, condensate, & oil
Gas
EXPLORATION WELLS
Predates 1987 assessment
Postdates 1987 assessment
Well data held confidential by industry
Pt. Thomson 1977–79
Flaxman Island 1975
Hammerhead 1985
Kuvlum 1993
Stinson 1990
Badami 1991
Sourdough 1994
Kavik 1969
Kemik 1969
Native lands
Camden Bay
Approximate location of 3-mile boundary between State and Federal jurisdiction
Canning River
Undeformed area
Marsh Creek anticline
1002 AREA
Deformed area
Aichilik River
Egaksrak River
Northern front of Brooks Range
Sadlerochit Mountains
Shublik Mountains
WILDERNESS AREA
0
30 MILES
D. Houseknecht, USGS Energy Resources Program 03/01

Improved Economics for Commercialization of Natural Gas

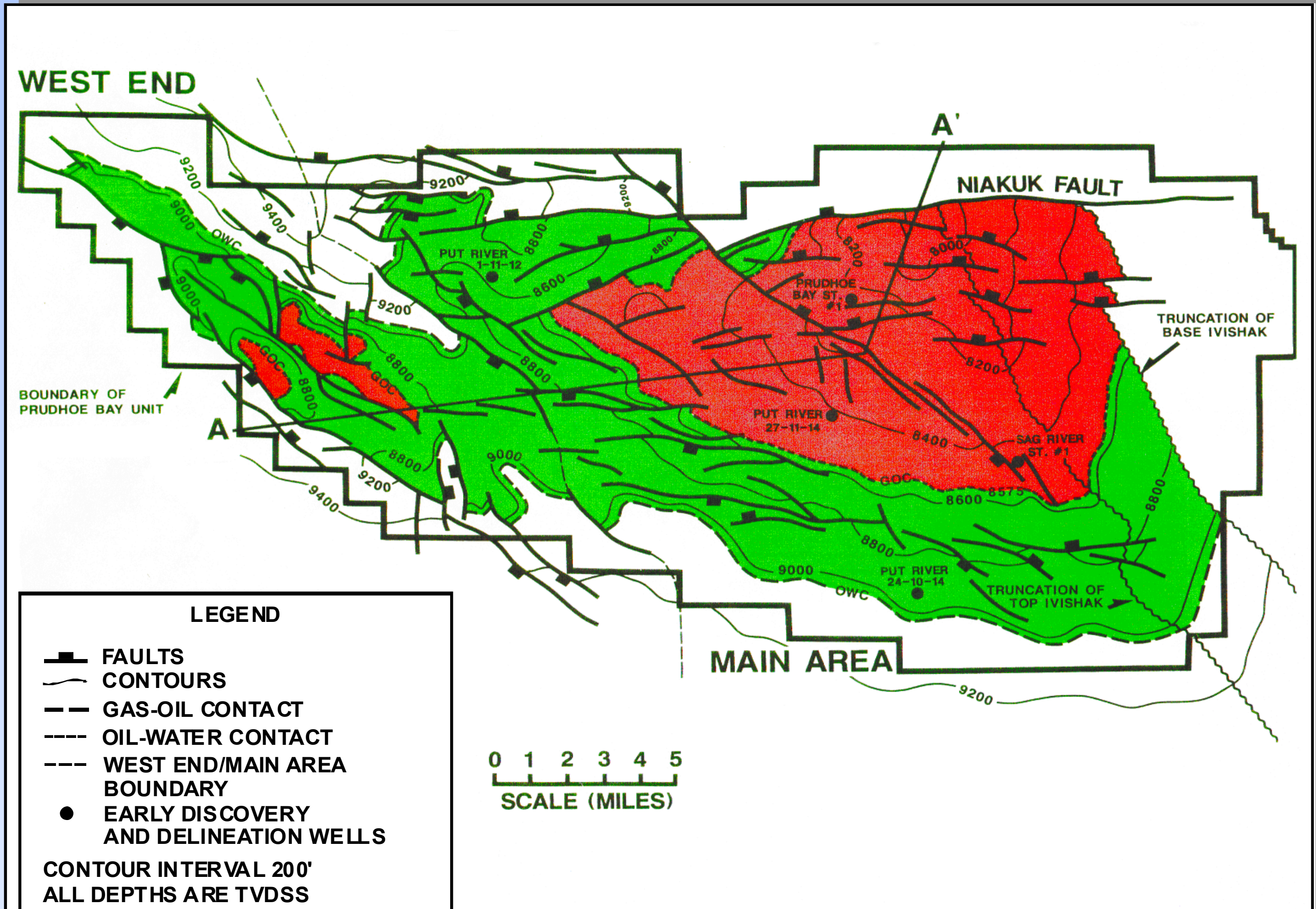
a. Royalty issues
b. Oil vs. gas in proven fields
c. Exploration in new areas and evaluation specifically with respect to *gas*

Proposed
- Division of Oil and Gas Studies-

- •Public Consultant Studies
- •Address Four Key Issues:
    - •In-State Demand
    - •Royalty Gas Valuation
    - •Prudhoe Bay – Pt. Thomson Reservoirs
    - •Potential Undiscovered Resources

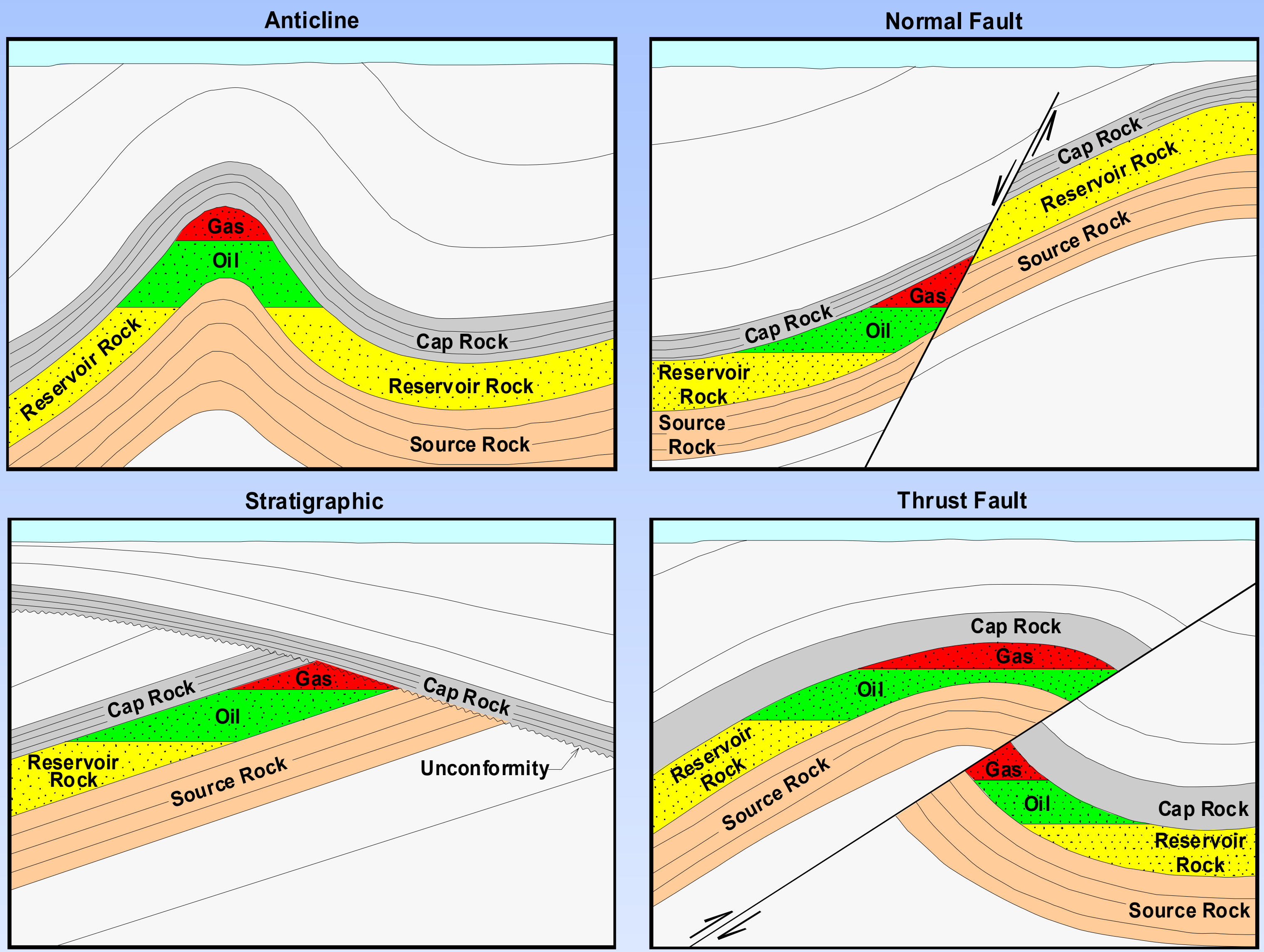
Prudhoe Bay Field

Top Ivishak Structure

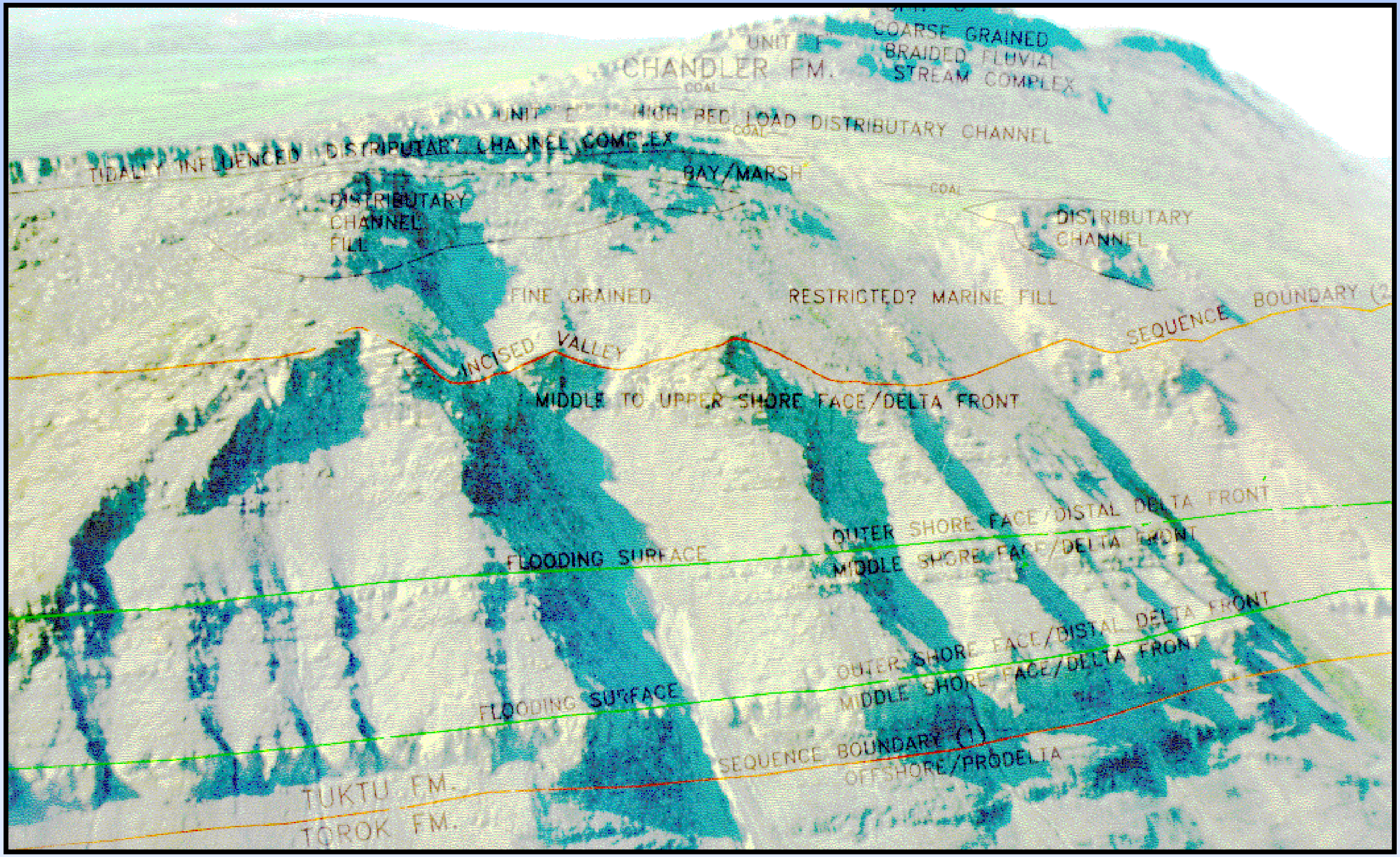


Modified from ARCO Exhibit A-6 to PBU MGP Expansion Application Testimony, DNR/AOGCC Hearing November 1991.

Oil and Gas Trapping Mechanisms



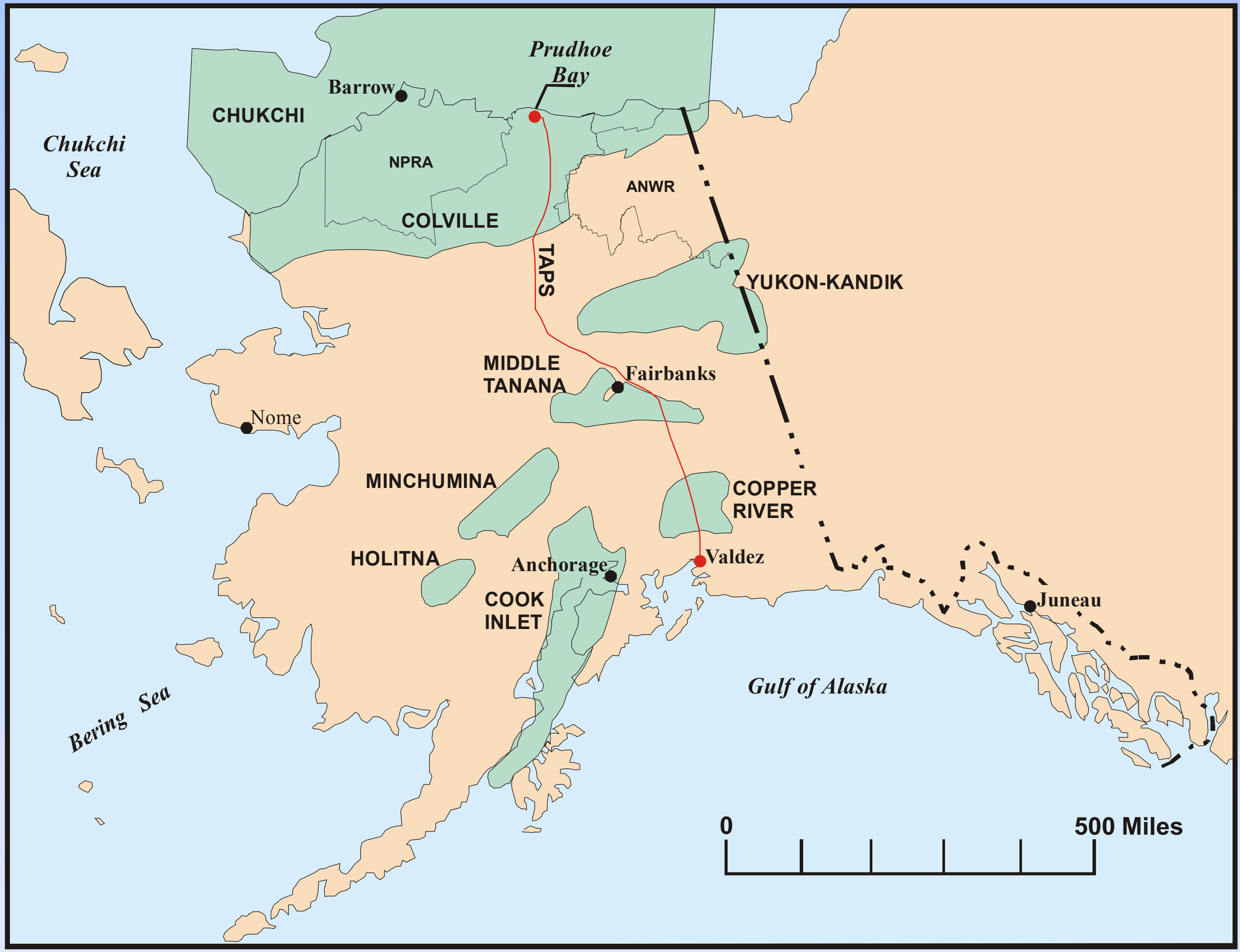
North Slope Foothills
Cretaceous Depositional System Study



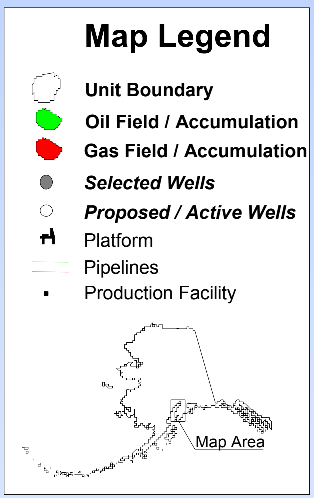
Ilingnorak Ridge

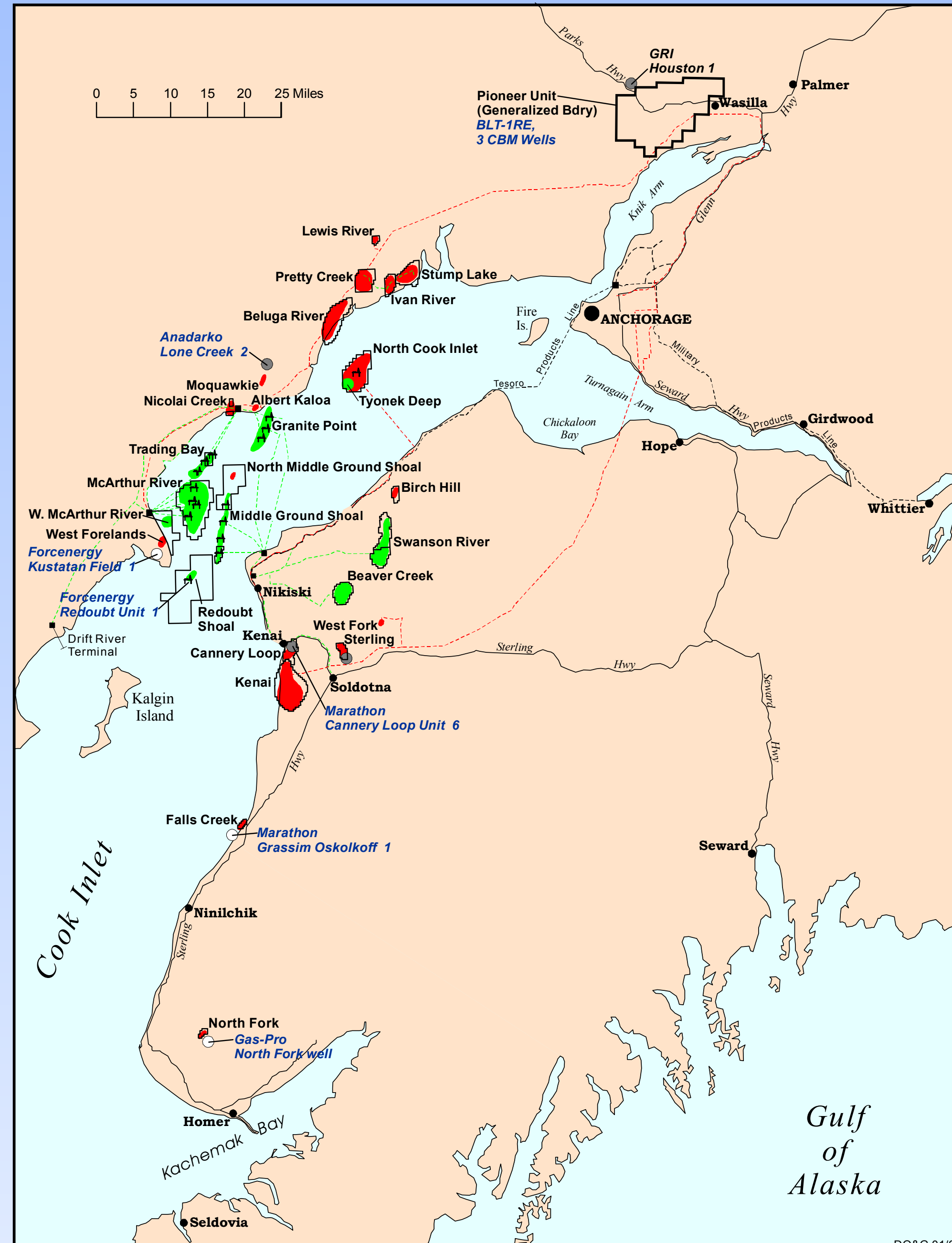
(view west)

Alaska's Onshore Basins

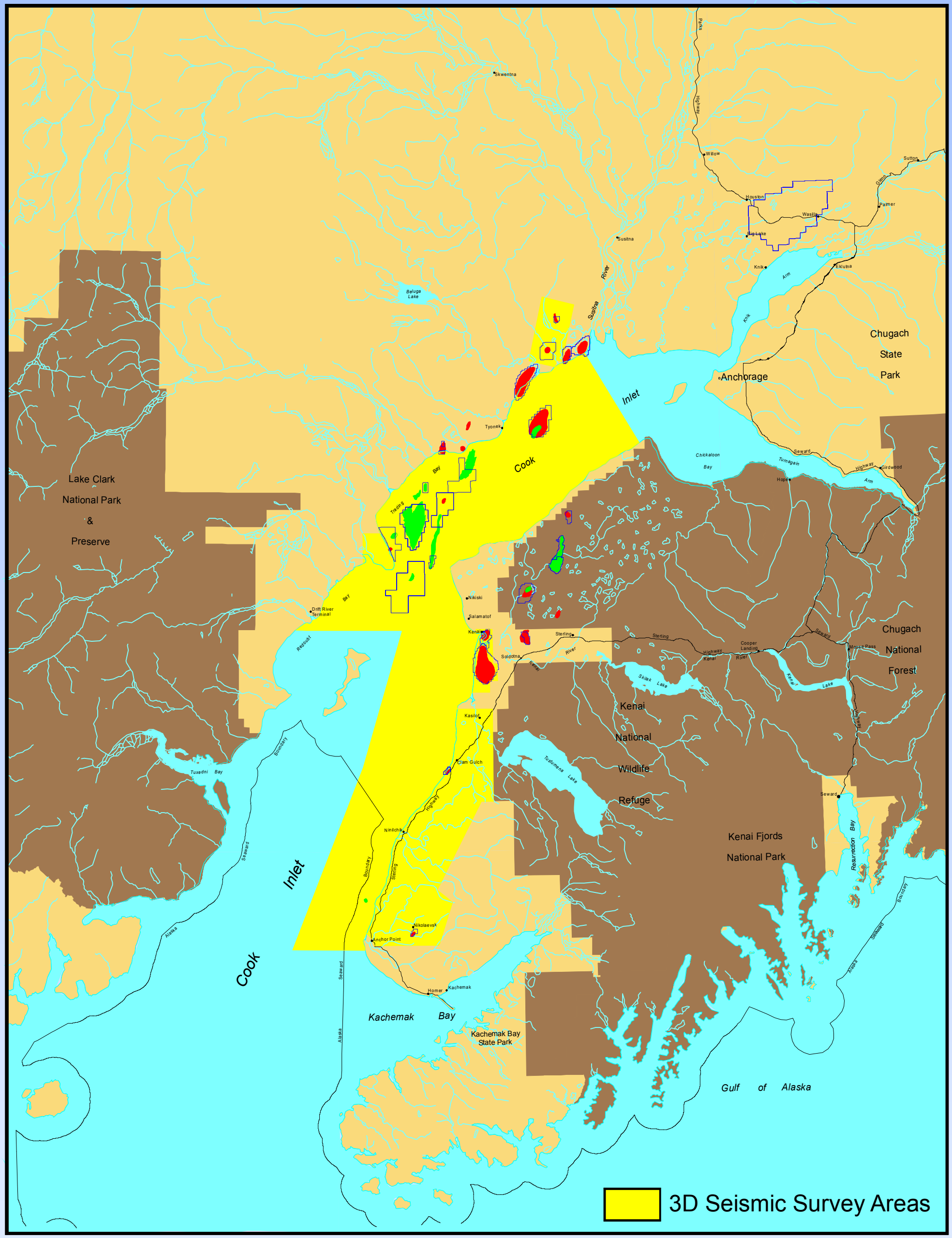


Cook Inlet Activity





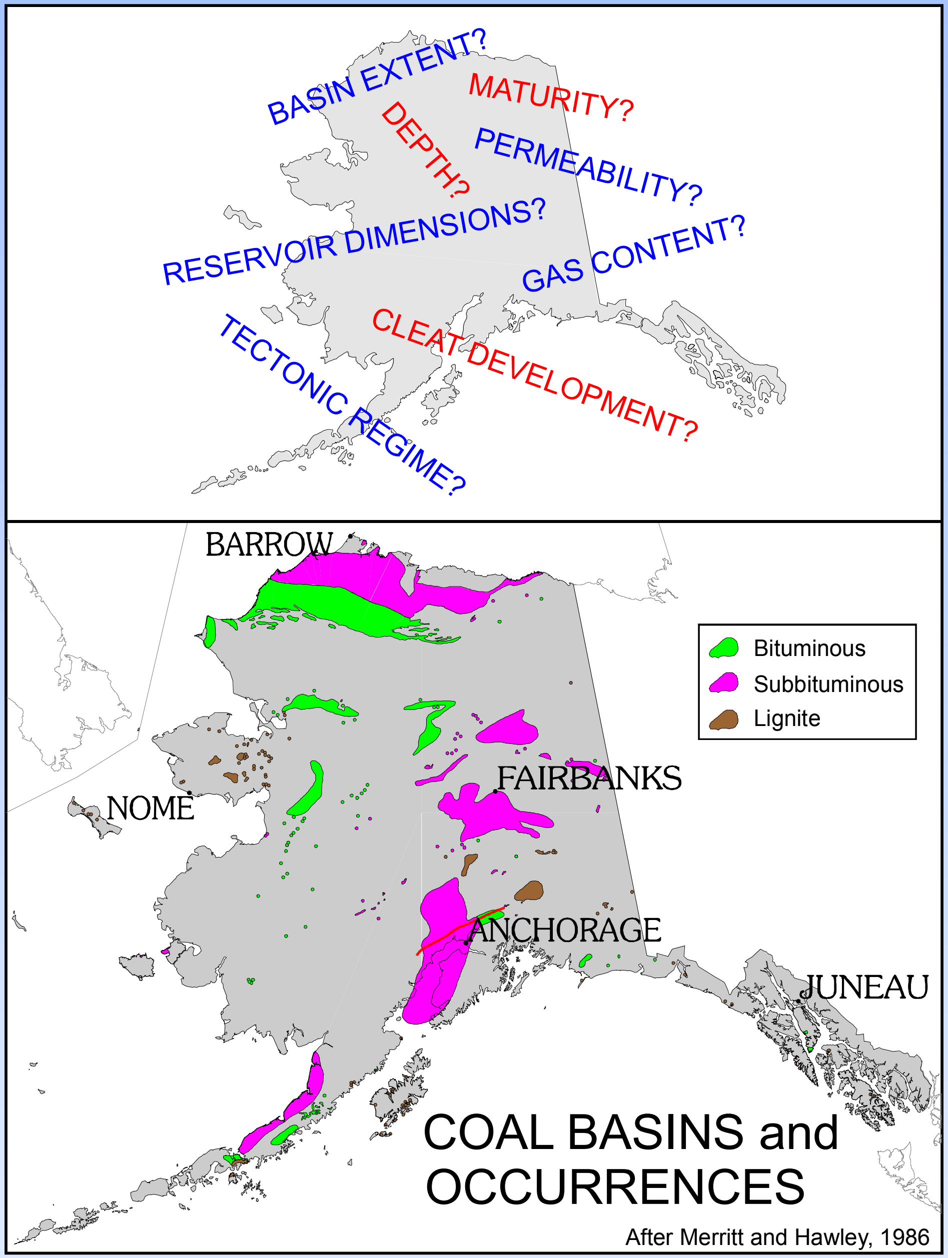
Cook Inlet 3-D Seismic Survey Areas



mep 01/2001

Cook Inlet
Tertiary Depositional System Study

Coalbed Methane Potential in Alaska



Alaska contains
nearly 1/2 of the United States coal reserves
or hypothetical resources that exceed
5.5 trillion short tons

Alaska's Coals

- Are mostly Cretaceous and Tertiary in age.
- Underlie about 9% of the land.
- Consist of 55% bituminous rank,
  40% subbituminous, and 5% lignite.

Alaska's coals could contain as much 1,000 TCF of gas

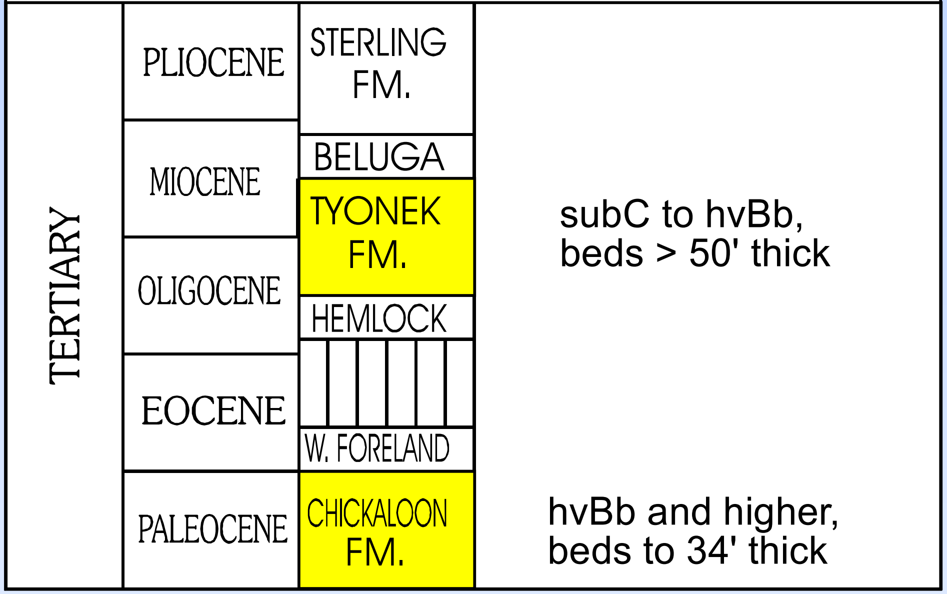
Cook Inlet Coals

Cook Inlet Coals

- Continental Tertiary deposits that exceed 26,000 feet in thickness.
- Occur in a 250 mile long by 70 mile wide area.
- Bituminous coals occur in the Matanuska Valley and deeper parts of the basin.
- Abundant, continuous beds exceeding 40 feet thick.
- Desorption values >100 cf/ton in subbituminous coal.
- Active tectonic regime with the basin margins recently uplifted.

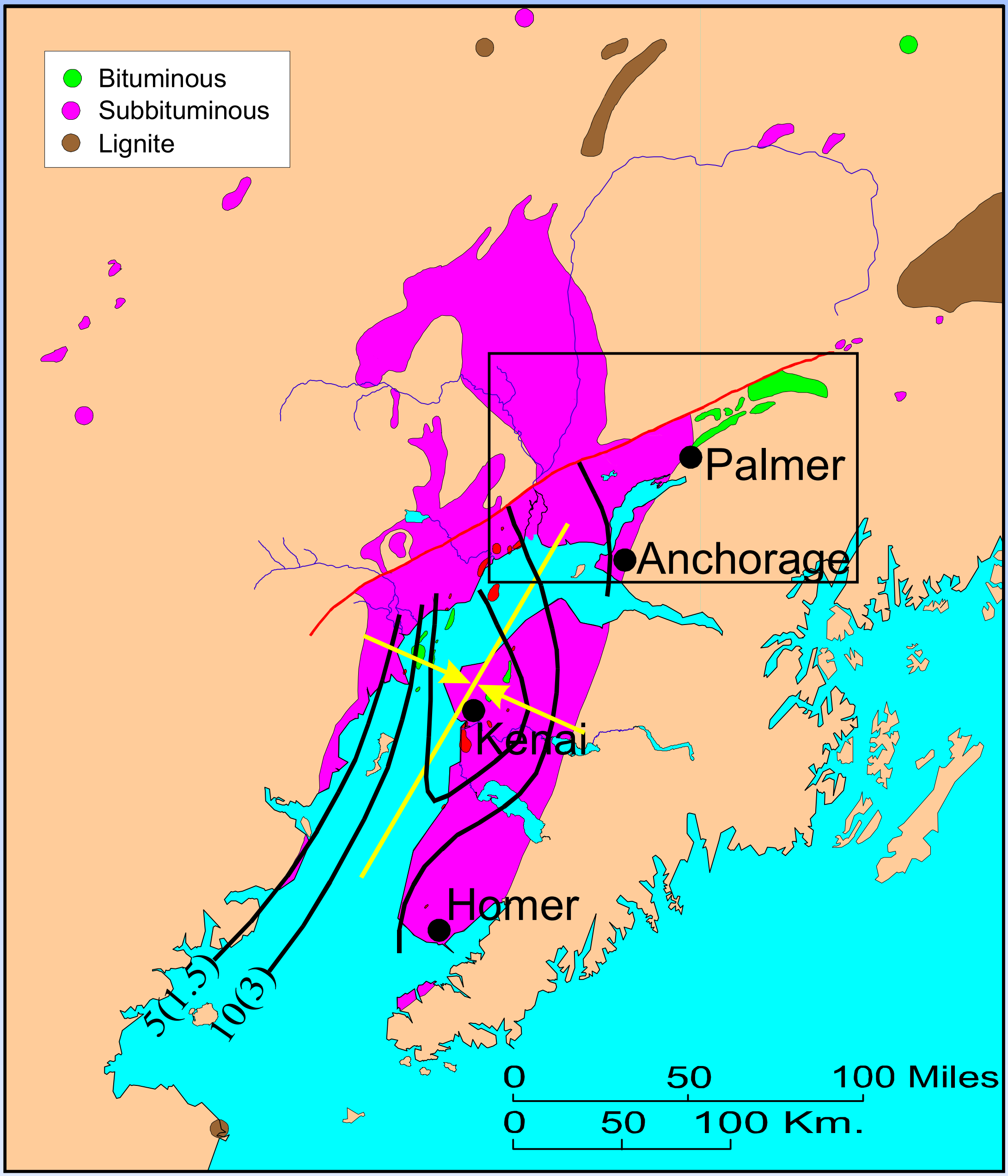
High potential for large gas reserves.

COOK INLET GENERALIZED STRATIGRAPHIC COLUMN



Cook Inlet Coals
Depth to 0.6 Ro

in thousands of feet (Km.)



AK CBM-1 Well rig
Shallow Gas Exploration

Conclusions from AK-94CBM-1

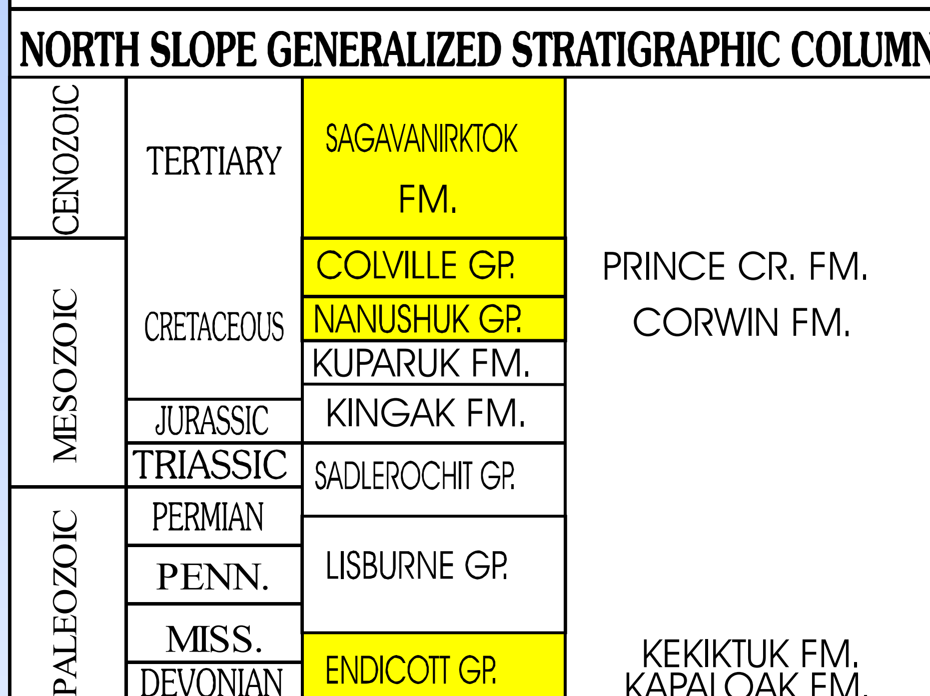
- Multiple seams encountered.
- Shallow reservoir targets.
- Increasing gas content with increasing depth.
- Excellent desorbed gas contents exceeding 245 cf/ton DAF.
- Coals are fractured and cleated.

North Slope Coals

North Slope Coals

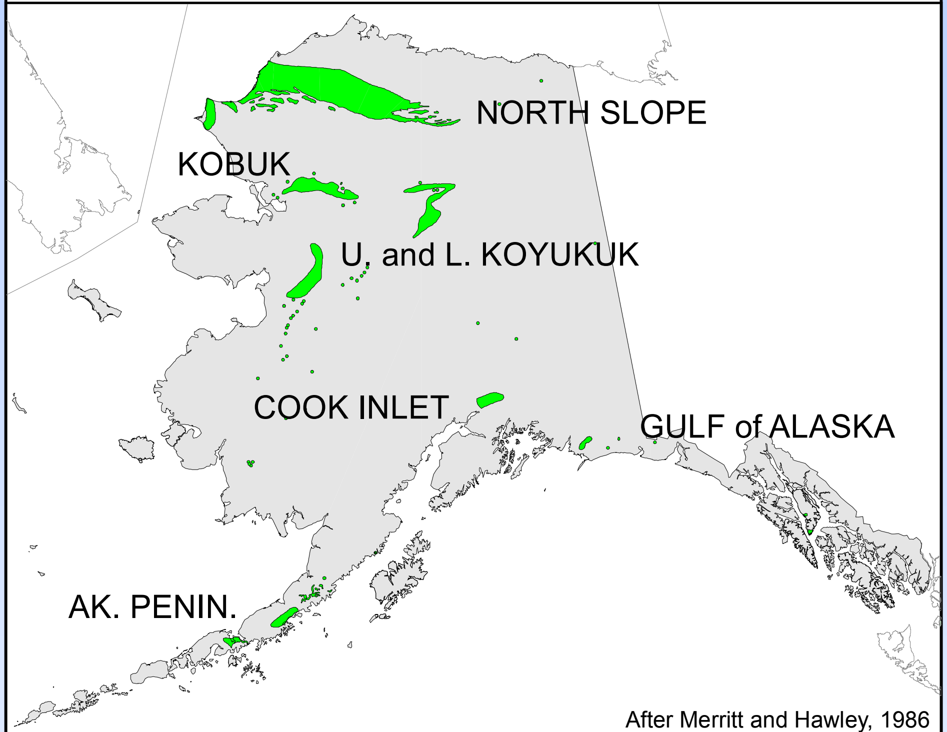
- Mississippian, Cretaceous, and Tertiary deltaic deposits.
- Occur in a 400 mile long by 150 mile wide area.
- Bituminous coals occur in the Brooks Range foothills.
- Abundant, continuous beds exceeding 20 feet thick.
- No gas content measurements available.
- Relaxed tectonic regime with uplift along the Brooks Range foothills.

High potential for huge gas reserves.



Bituminous and Higher Rank Coal

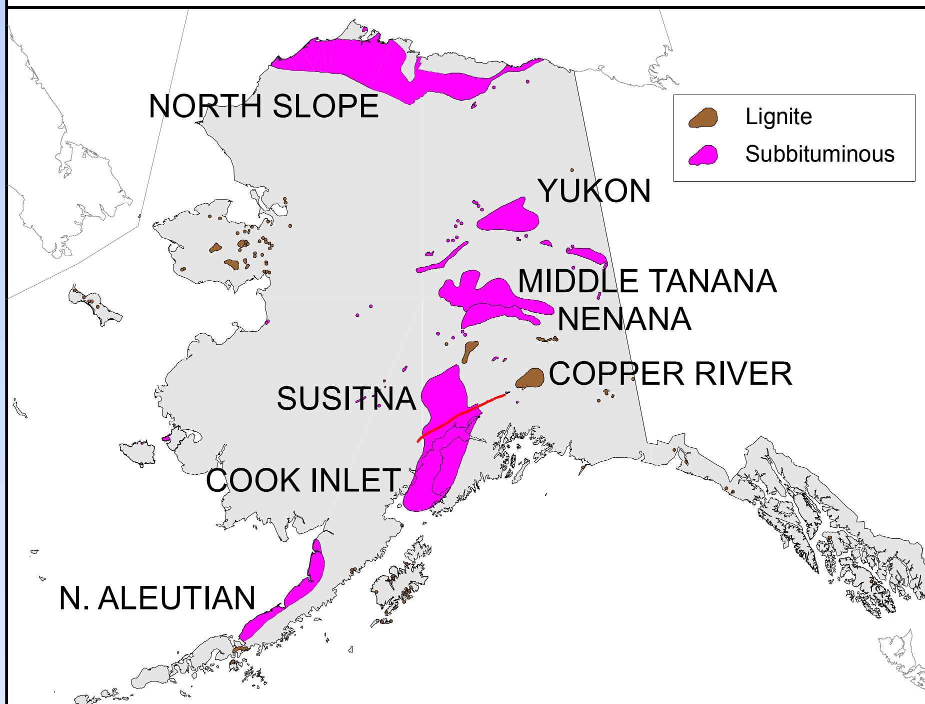
BITUMINOUS COAL	HYPOTHETICAL RESOURCES (Billion short tons)
North Slope	2,500
Cook Inlet	500
Alaska Penin.	3
Gulf of Alaska	4
U. and L. Koyukuk	1
Kobuk	1



After Merritt and Hawley, 1986

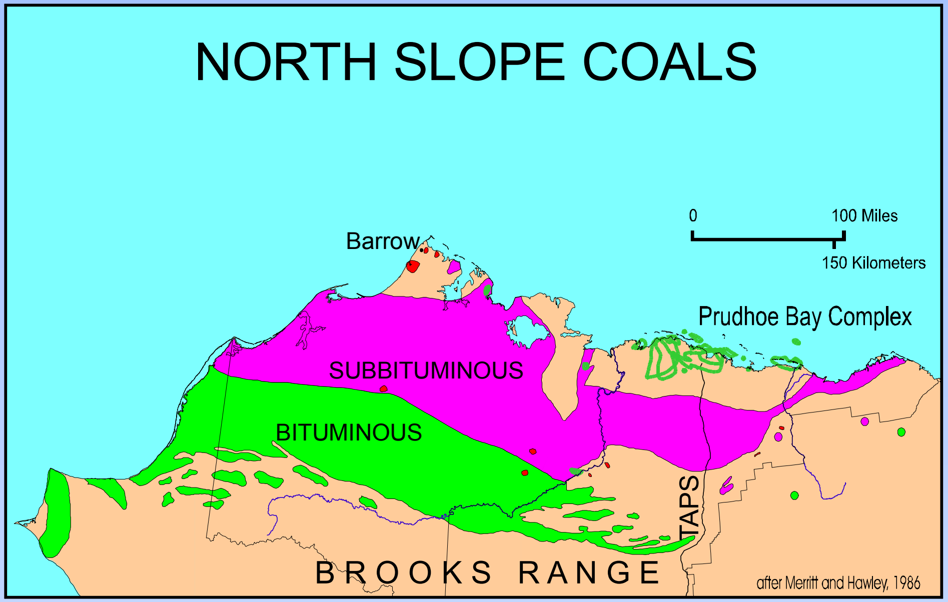
Lignite and Subbituminous Coal

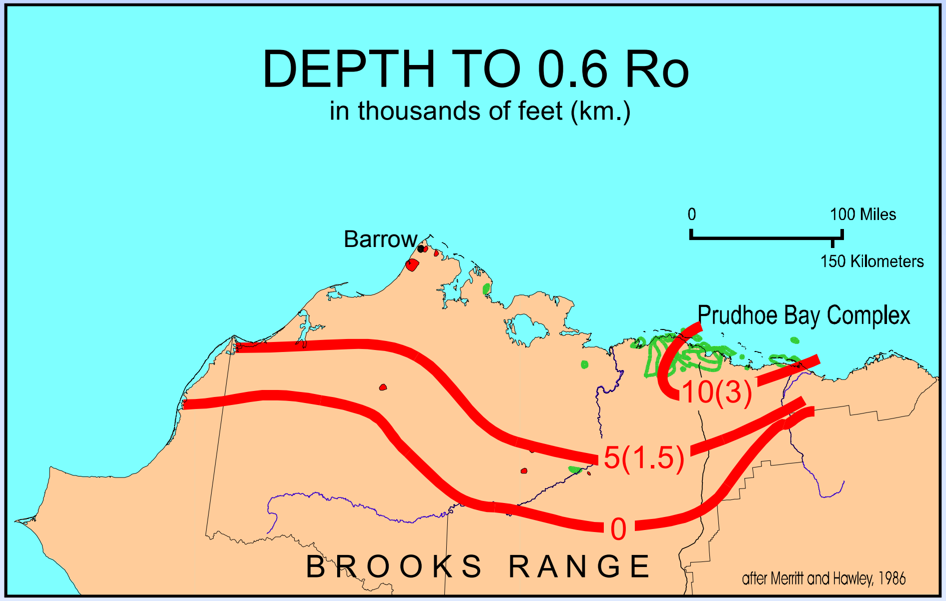
SUBBITUMINOUS COAL	HYPOTHETICAL RESOURCES (Billion short tons)
North Slope	1,500
Cook Inlet	1,000
Nenana	15
Susitna	3
Tanana	
Yukon	
North Aleutian	
LIGNITE COAL	
Copper River	
Seward Peninsula	



After Merritt and Hawley, 1986

North Slope Coals
Depth to 0.6 Ro
in thousands of feet (Km.)





Shallow Natural Gas Leasing

Statewide Program

- Allows drilling down to a depth of 3000 ft.
- Excludes areas included in Oil & Gas Leasing Program
- Purpose
  -- Provide energy supply to rural areas
  -- Encourage exploration in remote areas
  -- Supplement declining Cook Inlet reserves

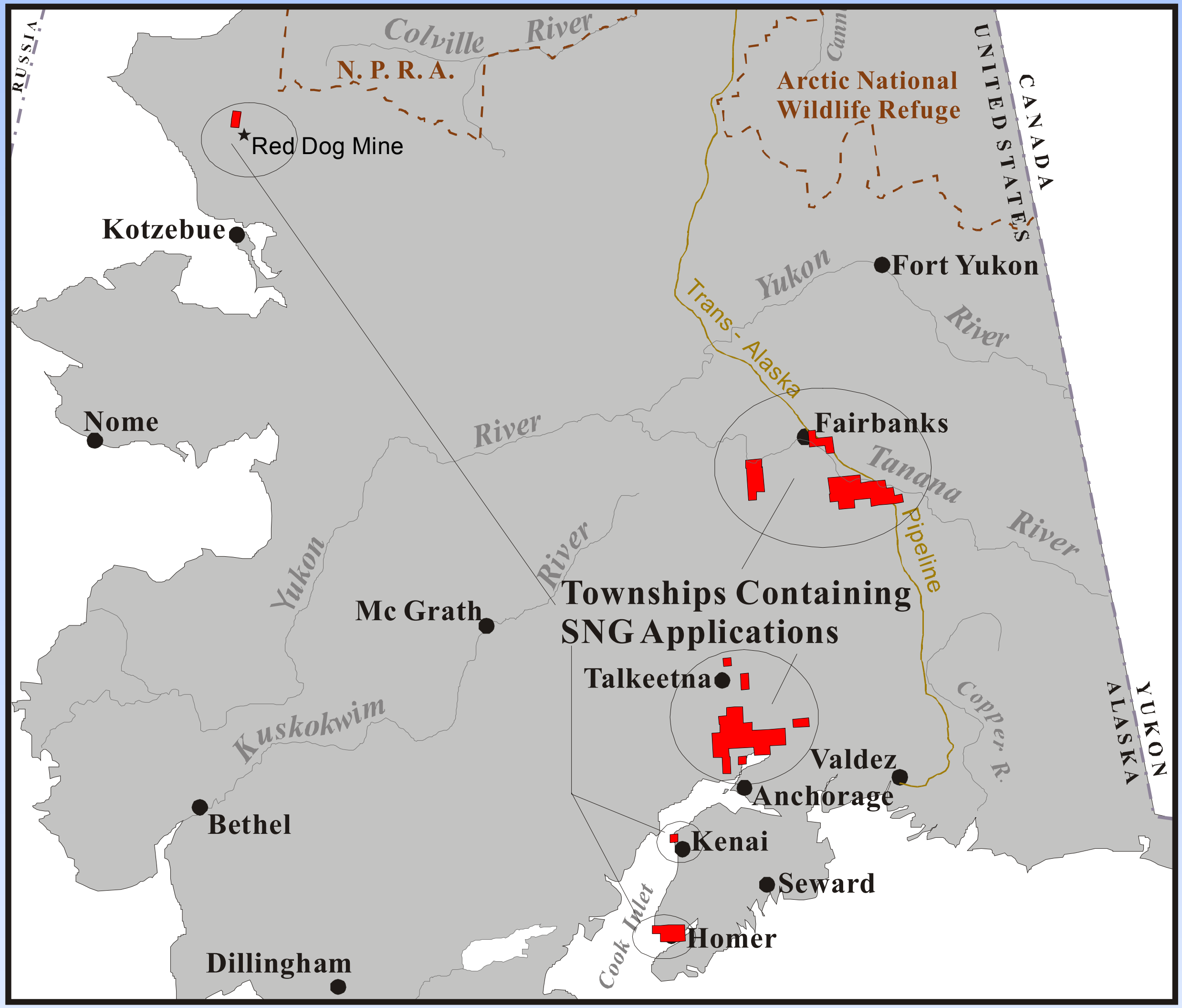
Incentives

- Reduced rents -- 50 cents/acre
- Reduced royalty -- 6.25%
- First-come, first-served
- No bonus bid, $500 application fee only
- Exempt from c-plan
- Exempt from Best Interest Finding
- Reduced financial responsibility requirement
- Exempt from waste discharge permit during drilling

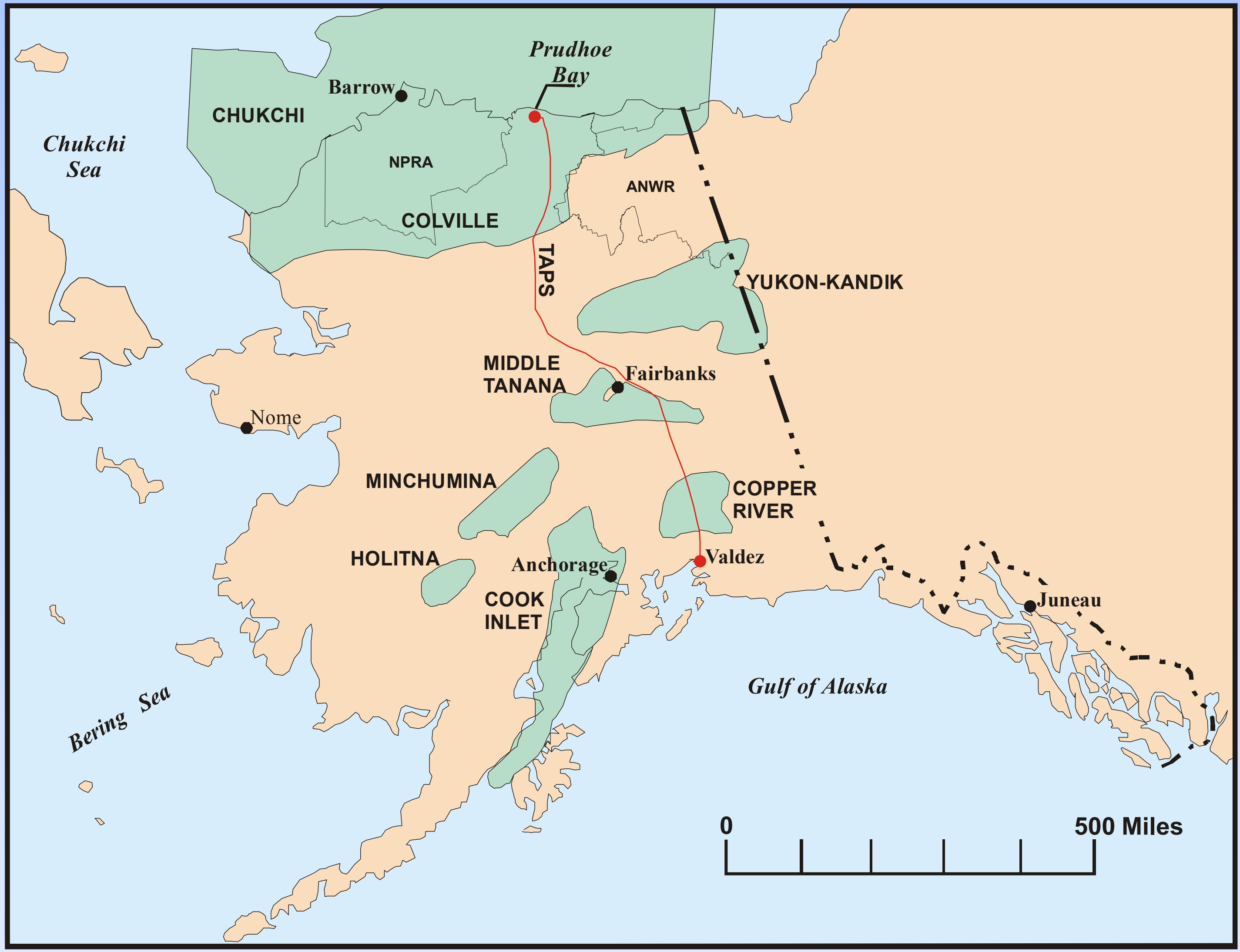
Applications to Date -- 302

- Northwest Arctic - 8 (Red Dog Mine)
- Interior - 100 (Nenana, Fairbanks, Big Delta)
- Railbelt - 194 (Talkeetna to Homer)

Shallow Natural Gas Lease Applications



Alaska's Onshore Basins



Exploration Licensing

Issued -- Copper River Basin

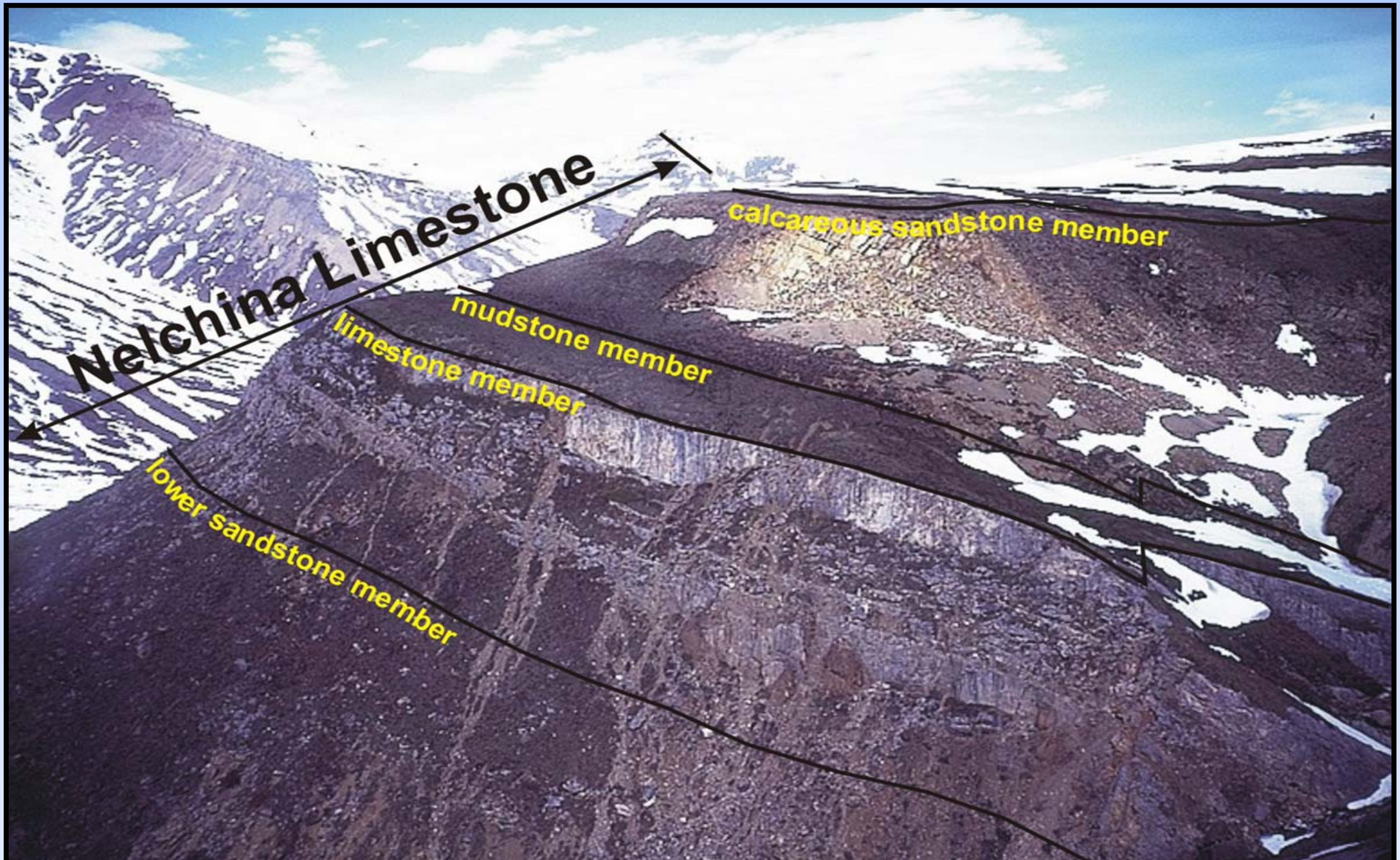
- State's first license: Issued October 1, 2000
- Anschutz Exploration Corp
- 318,756 Acres
- Exploration commitment: $1.42 million
- Term of license: 5 years

Proposed -- Susitna Valley

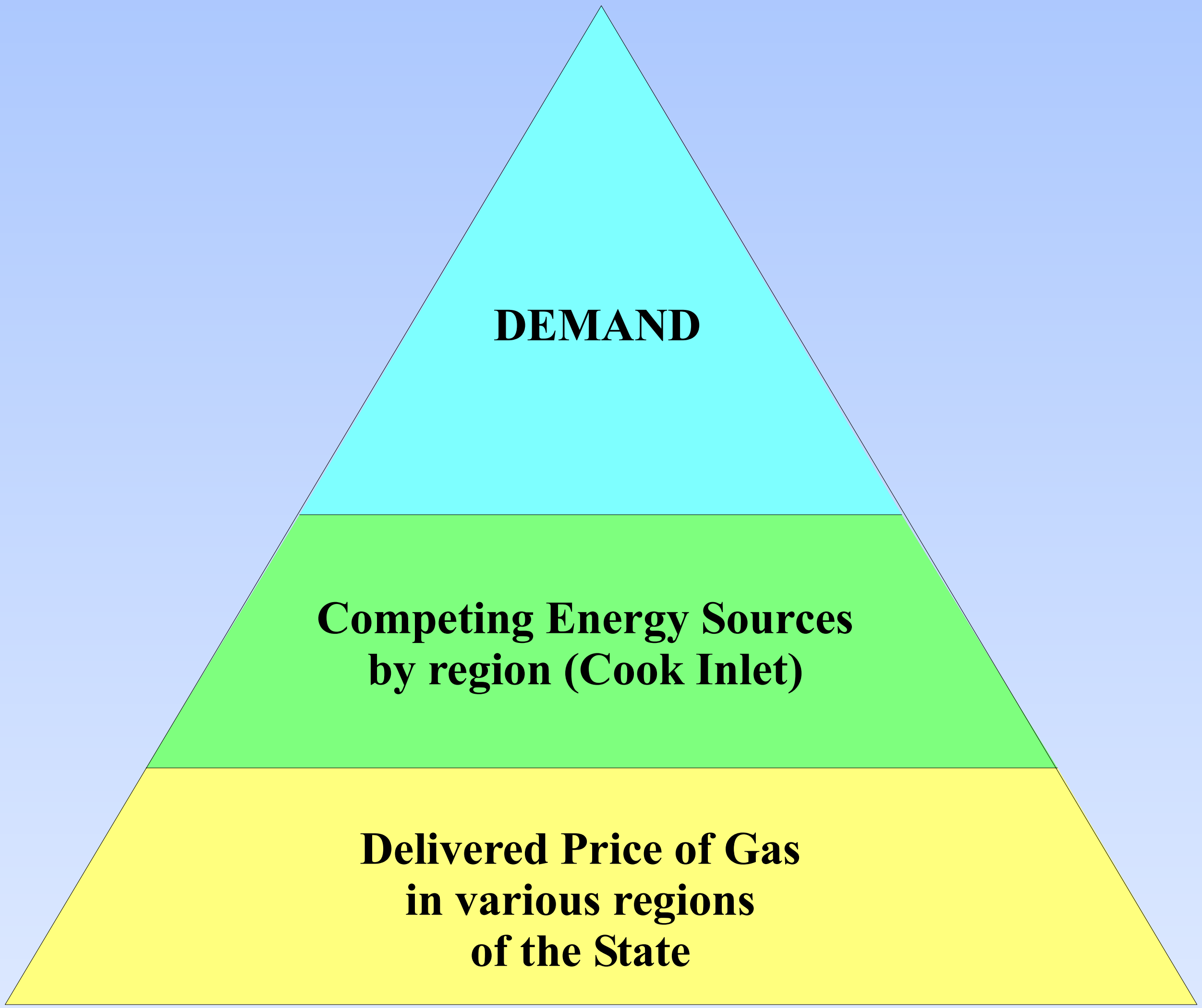
- Forest Oil Corp (Forcenergy Inc.) submitted two proposals
- 474,240 Acres each, located west of the Susitna River
- Exploration commitment for each: $3 million
- DNR will determine terms of licenses & final configurations
- Preliminary Best Interest Finding (BIF) to be issued in April
- Final BIF and Decision to be issued in October

Interior Basin Studies

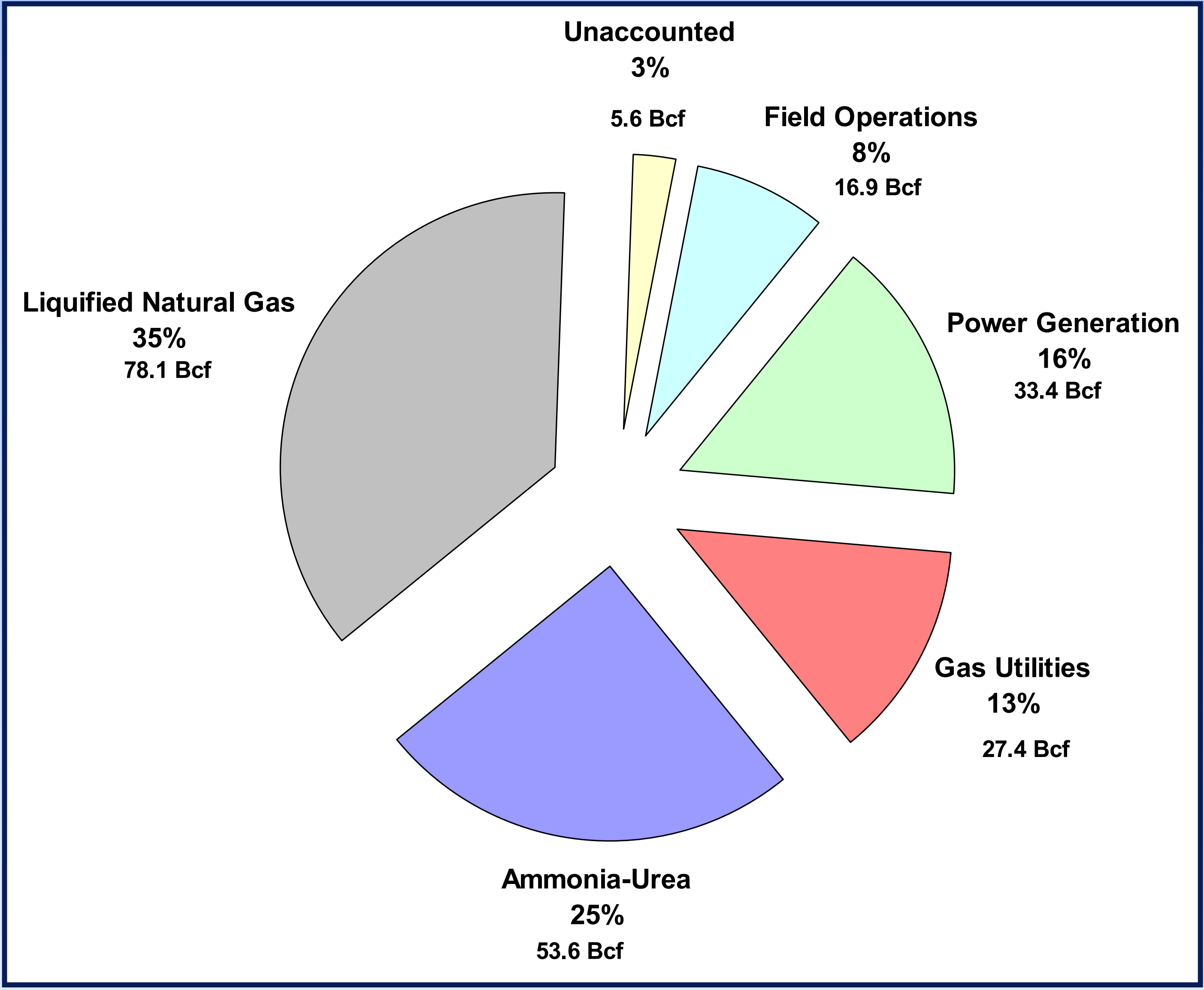
Nelchina Limestone, Copper River Basin



In-State Demand Study



Cook Inlet Historic Gas Consumption by Type
1998



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Royalty Gas Valuation Study

ANS Oil – Valued by Settlement

ANS Gas – Valued by Lease ("Major Gas Sale")

Study Will Examine the Netback Price of Gas

- **Markets**
- **Netback Mechanisms**
- **Value Drivers**

Royalty Share: In-Value vs. In-Kind

End

Attendance List

FirstName	LastName	Company	Email Address
Charles	Barker	USGS	barker@usgs.gov
Pirtle	Bates	DNR	pbj@dnr.state.ak.us
Greg	Beischer	Bristol Environmental & Engineering Serv. Corp.	gbeischer@beesc.com
Jerry	Booth	GG Booth & Associates	jerry@ggbooth.com
Bill	Brophy	Usibelli Coal Mine, Inc.	bbrophy@usibelli.com
Jim McCaslin	Brown	Alaska Pacific University	jbrown@alaskapacific.edu
Charles	Byrer	NETL	charles.byrer@netl.doe.gov
Jim	Clough	AK Div. Of Geological & Geophysical Sur.	jim@dnr.state.ak.us
Timothy	Collett	USGS	tcollett@usgs.gov
Robert (Bob)	Crandall	AK Oil & Gas Conservation Committee	bob_crandall@admin.state.ak.us
Jane	Crouch	White Eagle Exploration, Inc.	criuchs@interserv.com
Marshall	Crouch	White Eagle Exploration, Inc.	crouchs@interserv.com
Todd	Dallegge	University of Alaska, Fairbanks	bidahochi@yahoo.com
Stephen	Davies	AK, Oil & Gas Cons. Committee	
Don	Duttlinger	PTTC National	dduttlinger@pttcorg
Randy	Elger	Native Village Of Fort Yukon	randallman93@hotmail.com
Dr. Iraj	Ershaghi	WC PTTC	
Wade	Fennel	Chevron USA	wgfe@chevron.com
James	Hansen	Alaska Division of Oil & Gas	jjh@dnr.state.ak.us
Jack	Hartz	AK, Oil & Gas Cons. Committee	jack_hartz@admin.state.ak.us
Brian	Havelock	AK, Dept. of Natural Resource	brian_havelock@dnr.state.ak.us
Julie	Heusser	State of Alaska	Jody_Colombie@admin.state.ak.us
Teresa	Imm	Artic Slope Reg. Corp.	timm@arsc.com
James	Kendall	U.S. Dept. of Energy	james.kendall@eia.doe.gov
Michael	Langeler	Cross Timbers Oil Co.	mike_langeler@crosstimbers.com
Dave	Lappi	LAPP Resources	lapres@gci.net
Michael	Lilly	GW Scientific	mlilly@gwscientific.com
Wendy	Mahan	AK, Oil & Gas Cons. Committee	
Marc	Massengale	URS	marc_massengale@urscorp.com
W. Dallam	Masterson	Phillips Alaska, Inc.	wmaster@ppco.com
Tom	Maunder, P.E.	AK Oil & Gas Cons. Comm	Tom_Maunder@admin.state.ak.us

FirstName	LastName	Company	Email Address
David M.	McClement	NANA/Colt Engineering	david.mcclemont@nana.colt.com
Christy	McGraw	Backbone	backbone@alaska.net
Mike	Metz	Mike Metz & Associates	mcmetz@compuserve.com
John	Meyer	AK Div. Of Oil & Gas	john_meyer@dnr.state.ak.us
Mark	Myers	AK Div. Of Oil & Gas	mark_myers@dnr.state.ak.us
Kristen	Nelson	Petroluem News Alaska	nelson@gci.net
Phil	Nicoll	Royale Energy, Inc.	phil@royl.com
David	Ogbe	University Of Alaska, Fairbanks	ffdoo@uaf.edu
Fred	O'Toole	Chevron	fsot@chevron.com
Gene	Pavia	Lynx Enterprises	gpavia@lynxalaska.com
Norm	Phillips Jr.	Doyon Limited	phillips@doyon.com
Rocky	Reifenstuhl	AK Div. Of Geol. & Goephys. Survey	rocky@dnr.state.ak.us
Michael	Rocereta	BP Expl. (Alaska) Inc.	roceremd@bp.com
Marty	Rutherford	DNR	
Robert "Bob"	Scheidemann	Shell	scheid@ev1.net
Frank	Schuh	Drilling Technology,Inc.	fjschuh@gte.net
Alice	Schuh	Drilling Technology, Inc.	
Andrew	Scott	Altuda Geological Consulting	andrew@altuda.com
Daniel T.	Seamount	AK, Oil & Gas Cons. Committee	daniel_seamount@admin.state.ak.us
Kirk	Sherwood	Minerals Management Service	kirk.sherwood@mms.gov
Robert	Swenson	Phillips Alaska	rswenson@ppco.com
John	Tanigawa	Evergreen Resources	johnt@evergreen-res.com
Cammy	Taylor	AK, Oil & Gas Cons. Committee	
Bonnie K.	Thomas	Native Village Of Fort Yukon	bkthomas332@hotmail.com
David	Thomas	Gwitchyaa Zhee Utilities	
D.R.	Thompson	Consultant	pach@alaska.net
Maria	Valenzuela	WC PTTC	
Frank	Valenzuela	WC PTTC	
Nick	Van Wyck	Serf Geosciences	nvw@gci.net
Satya N.	Varadhi	Gas Technology Institute	satya.varadhi@gastechnology.org
Stephen S.	Wright	Chevron USA Prod. Co.	sswr@chevron.com

PTTC West Coast Resource Center
Petroleum Engineering Program
925 Bloom Walk - HED305
University of Southern California
Los Angeles, CA 90089-1211
Phone: (213) 740-8076   Fax: (213) 740-7982

www.westcoastpttc.org

Prof. Iraj Ershaghi, Regional Director
Phone: (213) 740-0321
Fax: (213) 740-0324
e-mail: ershaghi@usc.edu

Ms. Maria Valenzuela, Accounting
Phone: (213) 740-0322
Fax: (213) 740-0324
e-mail: peteng@archie.usc.edu

Mr. Frank Valenz, Consultant
Phone: (213) 740-8076
Fax: (213) 740-7982
e-mail: wcpttc@archie.usc.edu

Ms. Idania Takimoto, Secretary
Phone: (213) 740-8076
Fax: (213) 740-7982
e-mail: pttc@archie.usc.edu

Mr. Hamid Cheheltani, Webmaster
Phone: (213) 740-8076
Fax: (213) 740-7982
e-mail:hamidc@home.com

Petroleum Technology Transfer Council
West Coast Resource Center
Producer Advisory Group *(PAG)*

Mark S. Kapelke - Chairman
Tidelands Oil Production Co.
Phone: (562) 436-9918
Fax: (562) 495-1950
kapelke@altavista.net

Barry McMahan
Seneca Resources Corporation
Phone: (661) 399-4270
Fax: (661) 399-7706
pbrewer@ca.senecaresources.com

Glenn Swanson
Signal Hill Petroleum
Phone: (562) 595-6440
Fax: (562) 426-4587
gswanson@shpi.net

Tom Counihan
Texaco, Inc.
Phone: (661) 864-3226
Fax: (661) 864-3050
counitm@texaco.com

Marina Voskanian
CA State Lands Commission
Phone: (562) 590-5291
Fax: (562) 590-5295
voskanm@slc.ca.gov

Kent McBride
CCCOGP
Phone: (661) 635-0556
Fax: (661) 635-0558
concom@lightspeed.net

Robert E. Long
Pan Western Petroleum
Phone: (562) 595-6696
Fax: (562) 427-2050
oilman@geologist.com

Bryan F. Saunders
Ocean Energy
Phone: (713) 265-6787
Fax: (713) 265-8131
bryan.saunders@oceanenergy.com

David Brimberry
Marathon Oil Company
Phone: (907) 564-6402
Fax: (907) 564-6489
dlbrimberry@marathonoil.com

John Tanigawa
Evergreen Resources
Phone: (303) 298-8100
Fax: (303) 298-7800
johnt@evergreen-res.com

James C. Hall
Drilling and Production Co.
Phone: (310) 328-2405
Fax: (310) 328-2407
chrishall@prodigy.net

Donald Macpherson, Jr.
Macpherson Oil Co.
Phone: (310) 452-3880
Fax: (310) 452-0058
don_macpherson@macphersonoil.com

Mary Jane Wilson
WZI, Inc.
Phone: (661) 326-1112
Fax: (661) 362-0191
mjwilson@lightspeed.net

Steve Coombs
Pacific Operators Offshore
Phone: (805) 899-3144 x38
Fax: (805) 899-3166
coombs@pacops.com

Dan Kramer
CIPA
Phone: (916) 447-1185
Fax: (916) 447-1144
dpk@cipa.org

David Kilpatrick
Kilpatrick Energy Group
Phone: (661) 665-1698
Fax: (661) 665-1698
dkilpatrick@lightspeed.net

Behrooz Fattahi
Aera Energy LLC
Phone: (661) 665-5686
Fax: (661) 665-3339
bfattahi@aeraenergy.com

Jim Clough
AK Div. of Geological & Geophysical Surveys
Phone: (907) 451-5030
Fax: (907) 451-5050
jim@dnr.state.ak.us

Steve Davies
Alaska Oil & Gas Conservation Commission
Phone: (907) 276-4176
Fax: (907) 276-7542
steve_davies@admin.state.ak.us

TECHNOLOGY CONNECTIONS
PETROLEUM TECHNOLOGY TRANSFER COUNCIL

"Alaska Coalbed and Shallow Gas Resources"

A West Coast PTTC - Alaska DNR – USGS – BLM-Alaska Workshop

Friday, May 4, 2001

Opening Comments
Dr. Iraj Ershaghi, *West Coast PTTC*

MORNING TECHNICAL SESSION I
Moderator ***Jim Clough,*** *AK Div. of Geological & Geophysical Surveys*

EIA's Natural Gas Outlook: 35 tcf in 2020
Jim Kendell, *Energy Information Administration*

Overview of Alaska Gas Resources
Kirk Sherwood, *Mineral Management Services*

Gas Hydrates
Tim Collett, *USGS*

TECHNICAL SESSION II
Moderator ***Teresa Imm,*** *Arctic Slope Regional Corp*

.
Cook Inlet Coalbed Methane Potentia
Charles Barker, *USGS and* ***Daniel Seamount,*** *AOGCC*

Pioneer Project – Play to Execution
Daniel Seamount, *AOGCC*

Lessons Learned From Two Decades of Coalbed Methane Production in Lower 48 States
Rob Downey, *Energy Ingenuity Co.*

DOE's Arctic Research and Development Cost Share
Rhonda Lindsey, *NPTO*

Guest Speaker
Train Wreck – Energy Prices,
The Energy Infrastructure and the Consumer
John Schwager, CEO & President, *Belden & Blake Corp.*

PTTC West Coast Resource Center

" Alaska Coalbed and Shallow Gas Resources"
Workshop

PTTC
TECHNOLOGY CONNECTIONS
PETROLEUM TECHNOLOGY TRANSFER COUNCIL

Organized By:

West Coast PTTC
Alaska Department of Natural Resources
U.S. Geological Survey
Bureau of Land Management - Alaska

Co-Sponsored by:

B. J. Services
Bristol Bay Native Corporation
Cook Inlet Region, Inc.
Evergreen Resources, Inc.
University of Southern California

PTTC gratefully acknowledges that its primary funding comes through the US Department of Energy's (DOE) Office of Fossil Energy through the National Petroleum Technology Office (NPTO) and Strategic Center for Natural Gas (SCNG) within the National Energy Technology Lab (NETL).

May 4, 2001 – Anchorage, Alaska

"Alaska Coalbed and Shallow Gas Resources"

A West Coast PTTC - Alaska DNR – USGS – BLM-Alaska Workshop

Friday, May 4, 2001
Anchorage Marriott Downtown, Anchorage, Alaska

Co-Sponsored by: U.S. Department of Energy (DOE), University of Southern California (USC), Evergreen Resources, Inc., Bristol Bay Native Corporation, BJ Services, Cook Inlet Region, Inc.

AGENDA

8:30 am	***Opening Comments***	***Dr. Iraj Ershaghi****, West Coast PTTC*
	MORNING TECHNICAL SESSION I	
	Moderator	***Jim Clough****, AK Div. of Geological & Geophysical Surveys*
	EIA's Natural Gas Outlook: 35 tcf in 2020	***Jim Kendall****, Energy Information Administration*
	Overview of Alaska Gas Resources	***Kirk Sherwood****, Mineral Management Services*
	Gas Hydrates	***Tim Collett****, USGS*
	TECHNICAL SESSION II	
	Moderator	***Teresa Imm****, Arctic Slope Regional Corp.*
	Cook Inlet Coalbed Methane Potential	***Charles Barker****, USGS* and ***Daniel Seamount****, AOGCC*
	Pioneer Project – Play to Execution	***Daniel Seamount****, AOGCC*
	Lessons Learned From Two Decades of Coalbed Methane Production in Lower 48 States	***Rob Downey****, Energy Ingenuity Co.*
	DOE's Arctic Research and Development Cost Share	***Rhonda Lindsey****, NPTO*
12:15 pm	**LUNCHEON**	
	Guest Speaker	
	Train Wreck – Energy Prices, The Energy Infrastructure and the Consumer	***John Schwager****,* CEO & President*, Belden & Blake Corp.*
	AFTERNOON TECHNICAL SESSION III – ADVANCES IN COALBED METHANE TECHNOLOGY	
	Moderator	***David Ogbe****, University of Alaska Fairbanks*
	Rank, Maceral Content and Sorption of Gases in Tertiary Age Coals: New Data and New Exploration Models	***Raymond C. Pilcher****, Raven Ridge Resources, Inc.*
	Microbially Enhanced Coalbed Methane: Benefits and Limitations of a New Technology	***Andrew Scott****, Altuda Geological Consulting*
	Water Disposal Methods	***John Harju****, GTI E&P Services*
	PANEL DISCUSSIONS	
	Moderator	***Dave Lappi****, LAPP Resources*
	Application Processing Alaska's Paperwork, Regulatory Matters and Bottlenecks for Producers	***Pirtle Bates****, DNR*
	The Trans-Alaska Gas Pipeline: Impact on Exploration in Alaska	***Jim Hansen and Jim Haynes****, Alaska Div. of Oil and Gas*
	OPEN FORUM	
5:00pm	**ADJOURN**	

The Petroleum Technology Transfer Council (PTTC) was formed in 1994 by the U.S. oil and natural gas exploration and production (E&P) industry to identify and transfer upstream technologies to domestic producers. PTTC's technology programs help producers reduce costs, improve operating efficiency, increase ultimate recovery, enhance environmental compliance, and add new oil and gas reserves.
PTTC is a national not-for-profit organization with regionally focused programs that meet the technology needs of its primary customers - independent oil and natural gas producers. Independents face technology decisions every day, such as whether to address an opportunity or problem with technology, what solution to use, whether it is cost effective, and how to use it.

PTTC serves as the independent producer's **"Bridge to Solutions"** by fulfilling three roles:

- First, it helps identify and clarify producers' problems and makes them aware of technology opportunities.
- Second, it educates producers about technology options.
- Third, it connects producers to these solutions.

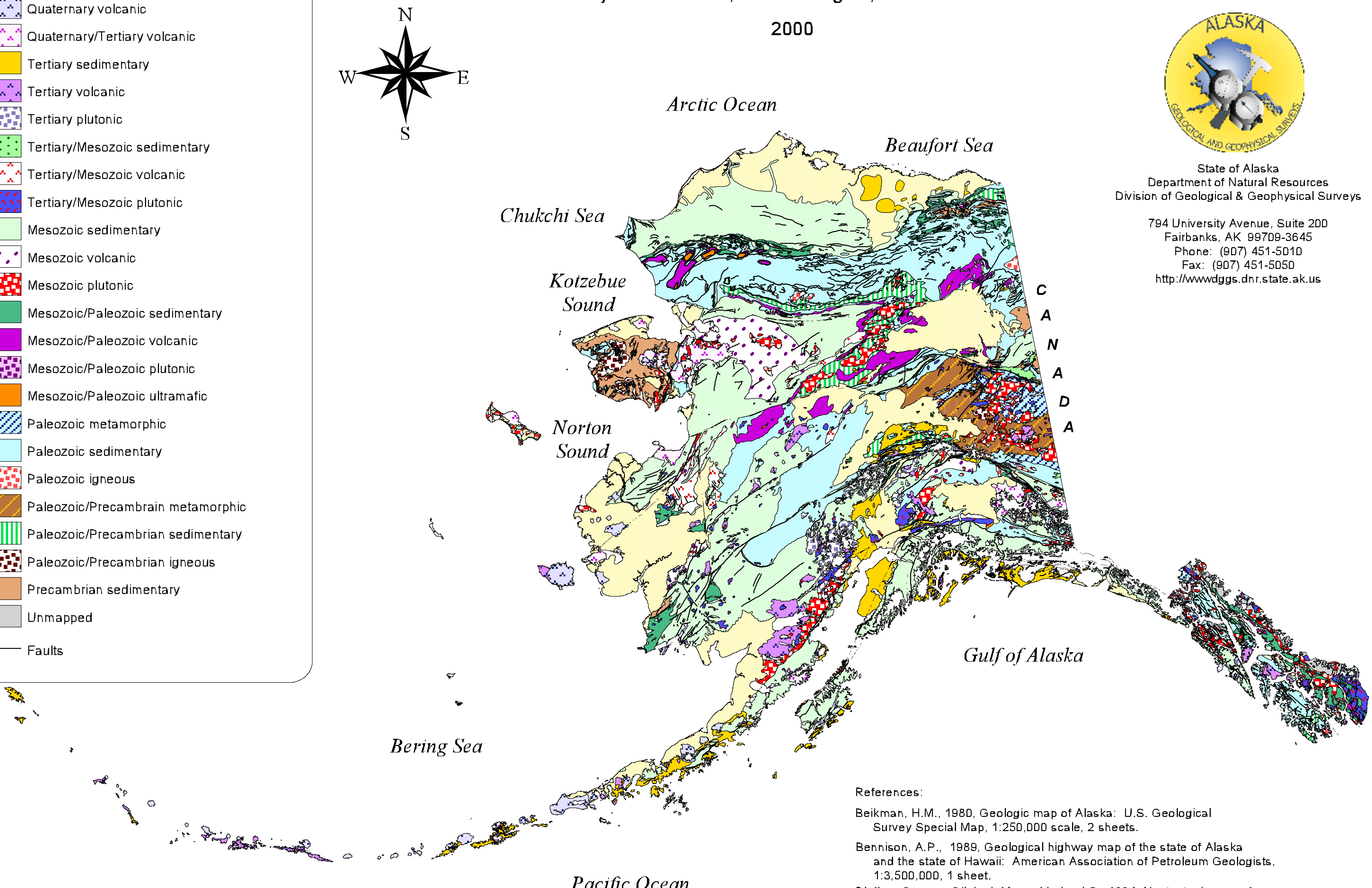
Thus, by providing problem identification, education, and connections, PTTC achieves its mission:

"PTTC benefits the nation by helping U.S. independent oil and natural gas producers make timely, informed technology decisions."

Generalized Geologic Map of Alaska

By M.B. Werdon, D.J. Szumigala, and G. Davidson

2000



Geologic Units

- Ice/Water
- Quaternary sedimentary
- Quaternary volcanic
- Quaternary/Tertiary volcanic
- Tertiary sedimentary
- Tertiary volcanic
- Tertiary plutonic
- Tertiary/Mesozoic sedimentary
- Tertiary/Mesozoic volcanic
- Tertiary/Mesozoic plutonic
- Mesozoic sedimentary
- Mesozoic volcanic
- Mesozoic plutonic
- Mesozoic/Paleozoic sedimentary
- Mesozoic/Paleozoic volcanic
- Mesozoic/Paleozoic plutonic
- Mesozoic/Paleozoic ultramafic
- Paleozoic metamorphic
- Paleozoic sedimentary
- Paleozoic igneous
- Paleozoic/Precambrain metamorphic
- Paleozoic/Precambrian sedimentary
- Paleozoic/Precambrian igneous
- Precambrian sedimentary
- Unmapped
- Faults

ALASKA
GEOLOGICAL AND GEOPHYSICAL SURVEYS

State of Alaska
Department of Natural Resources
Division of Geological & Geophysical Surveys

794 University Avenue, Suite 200
Fairbanks, AK 99709-3645
Phone: (907) 451-5010
Fax: (907) 451-5050
http://wwwdggs.dnr.state.ak.us

300 0 300 Miles

500 0 500 Kilometers

References:

Beikman, H.M., 1980, Geologic map of Alaska: U.S. Geological Survey Special Map, 1:250,000 scale, 2 sheets.

Bennison, A.P., 1989, Geological highway map of the state of Alaska and the state of Hawaii: American Association of Petroleum Geologists, 1:3,500,000, 1 sheet.

Plafker, George, Gilpin, L.M., and Lahr, J.C., 1994, Neotectonic map of Alaska: in Plafker, G., and Berg, H.C., eds., The Geology of Alaska, Geology of North America, v. G-1: Geological Society of America, plate 12, scale 1:2,500,000.

Opening Comments

Dr. Iraj Ershaghi
West Coast Petroleum
Technology Transfer Center

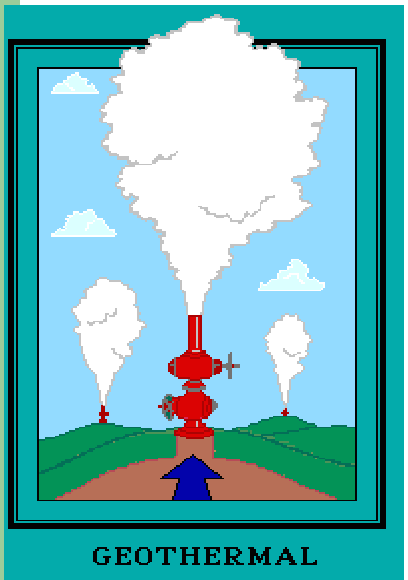
Alaska Coalbed and Shallow Gas Resources

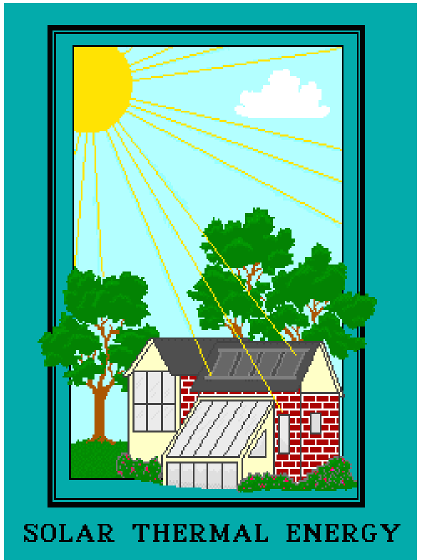
Iraj Ershaghi, West Coast Director, Petroleum Technology Transfer Council

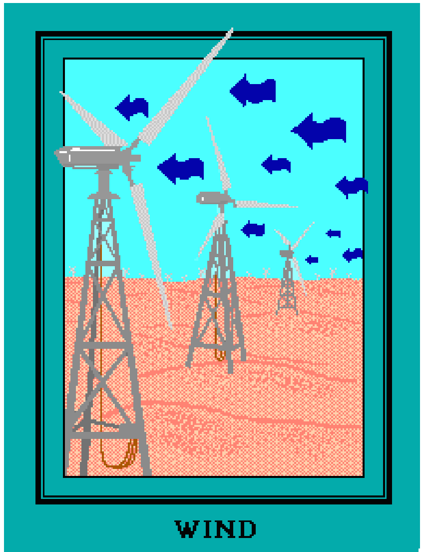
Brief Review

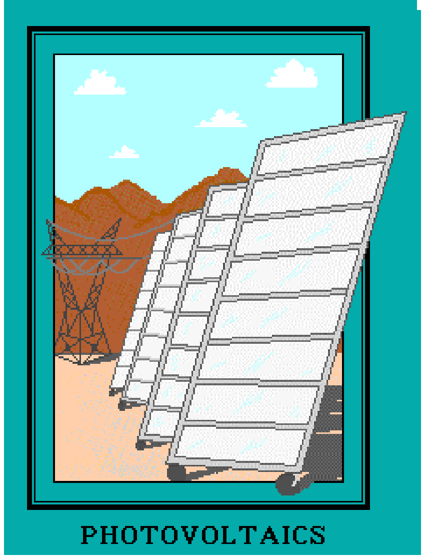
- Our National Energy Source Options
- Role of Oil and Gas and Current Investment in Related Research
- Role of Independent Producers
- Providing Assistance to the Independents
- Role of PTTC

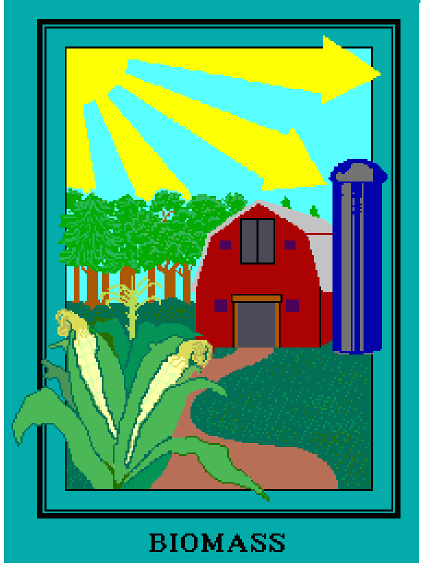
Alternatives?? Still A long way to go…





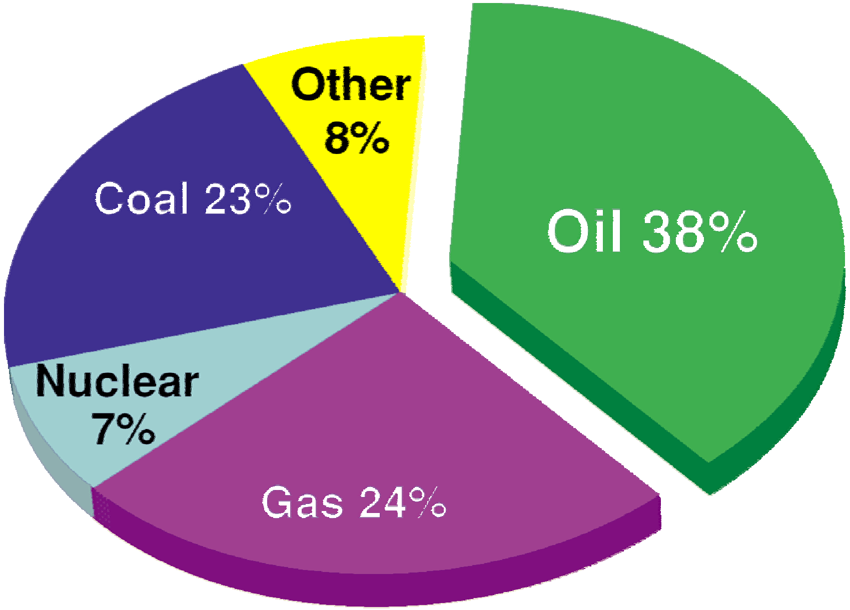




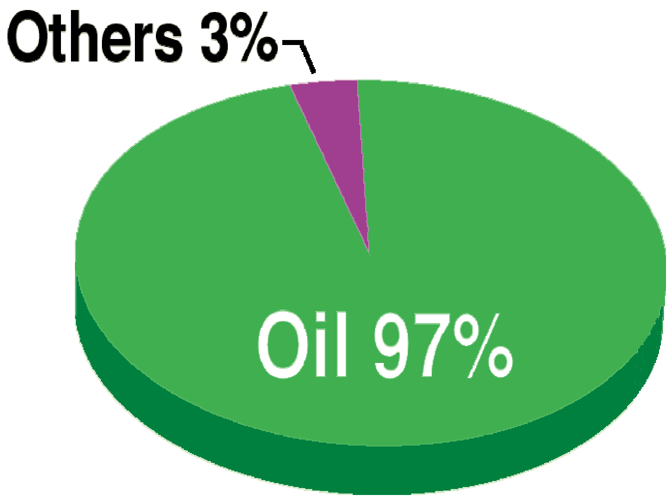


Source CEC

U.S. Energy Consumption



Transportation



Department of Energy's Current Annual Budget for Oil Research is 47 million dollars

47 million/18 billion= 0.26 % investment for 62 % 0f energy supplies

Company Size

Recent Years

Little Little Firms (independents)

Big Little Firms (superindependents)

Little Big Firms (integrated)

Big Big firms (megamajors)

Role of Independents- Domestic U.S.

Drill 85% of the wells
Produce 40% of the oil
Produce 65% of the gas

Key Factors

To Keep Independents Stay in Business

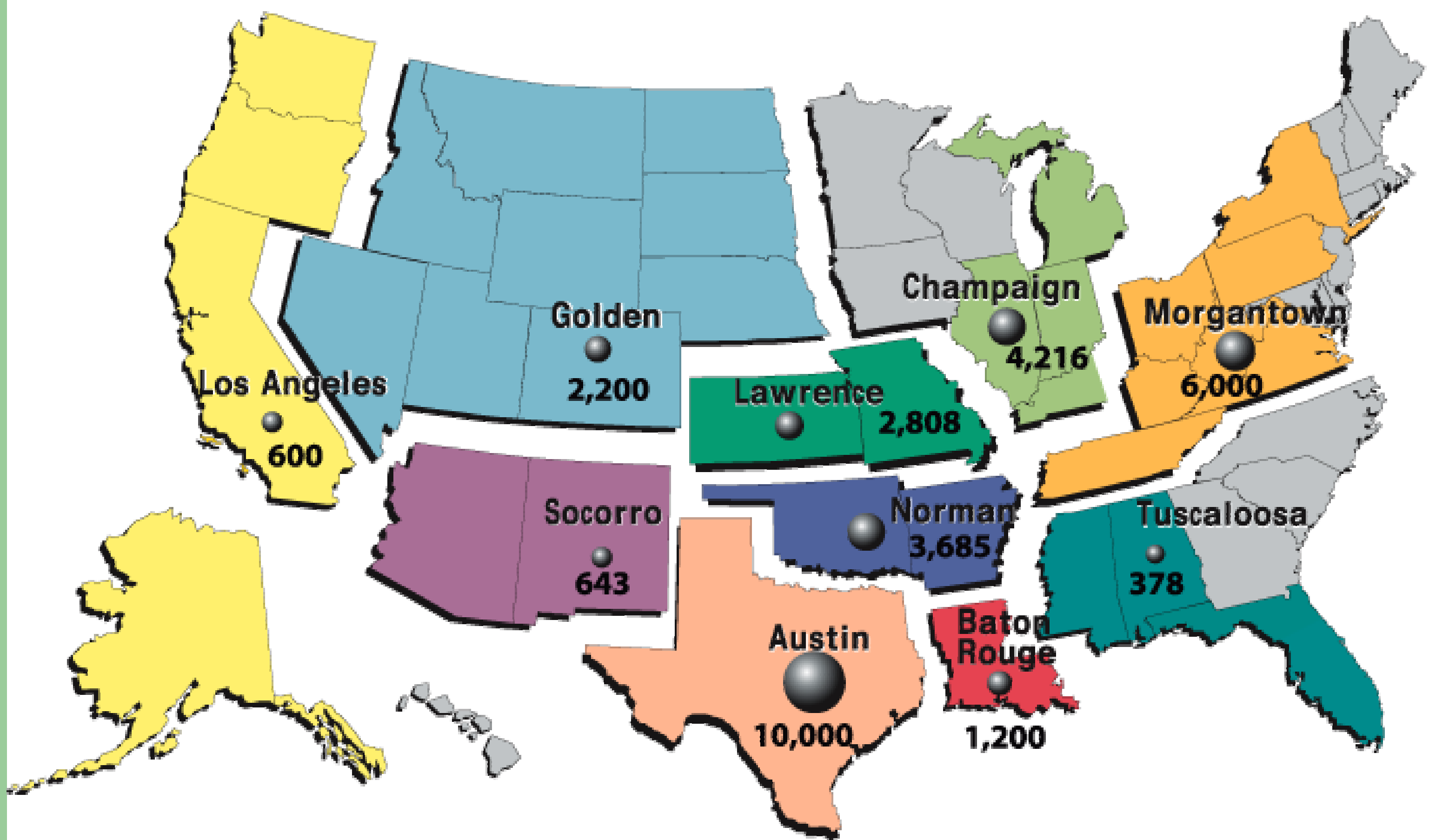
Access to Capital

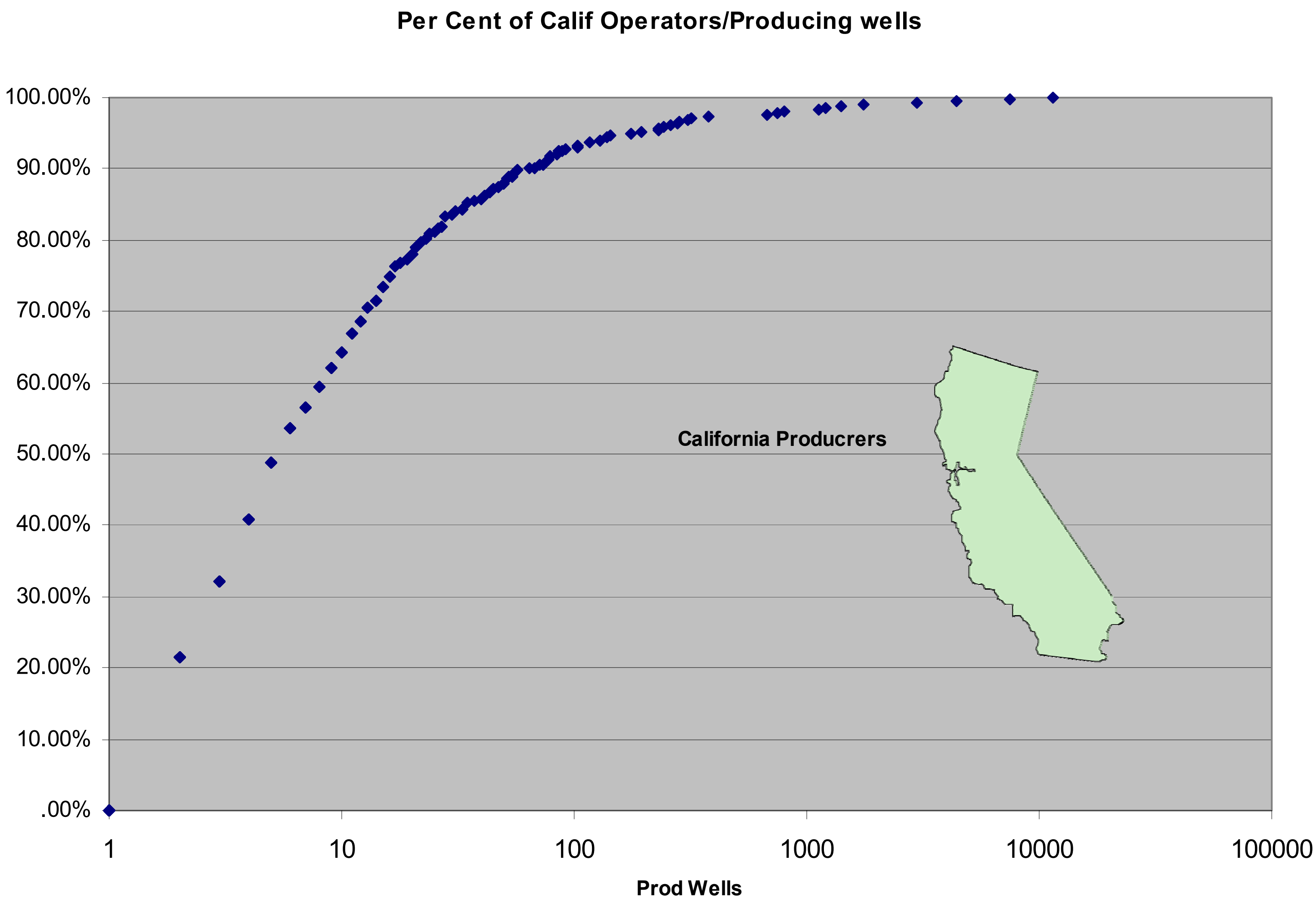
Access to Resources

Access to Technology

Access to Human resources

Reported number of Oil and gas producers in the U.S.

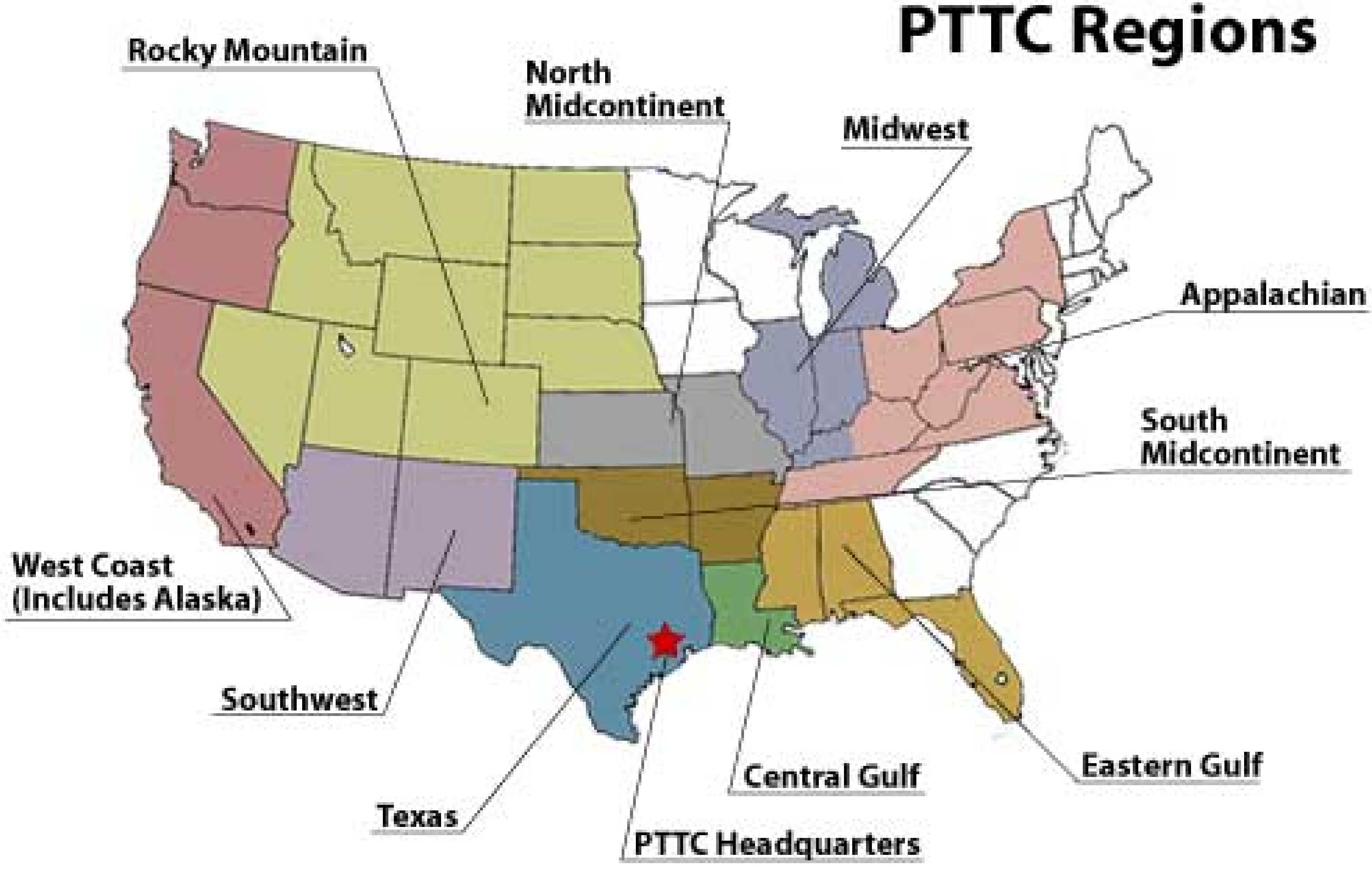




Per Cent of Calif Operators/Producing wells
100.00%
90.00%
80.00%
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
.00%
1
10
100
1000
10000
100000
Prod Wells
California Producrers

More than 80% of California producers operate only 20 wells or less.

PTTC Regional Organizations to Assist Independent Producers



http://www.westcoastpttc.org

Petroleum Technology Transfer Council

Timely, informed technology decisions...

PTTC TECHNOLOGY | CONNECTIONS

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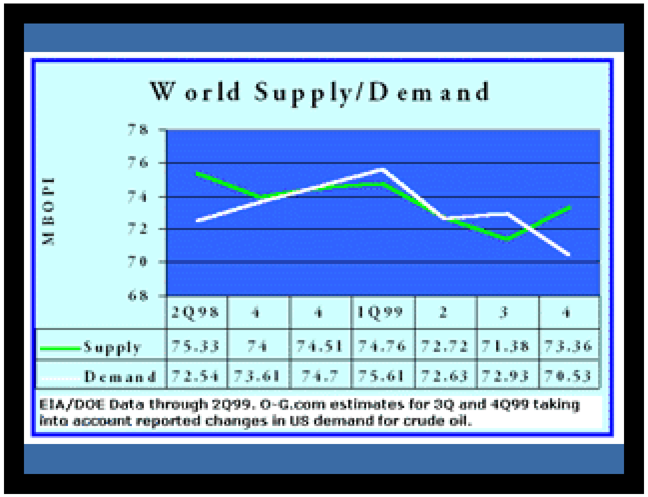


Charts Courtesy of Oil-Gasoline.com

Oil Boom Nears for

West Coast PTTC Workshop
Monterey Reservoirs of California, Past Performance and Future Potentials

COMET 2001
Teacher & Student Applications & Information

Microsoft Word Format

Archives

Click here to view the presentations on the January workshop. (PDF)

OPEC Summit - official site

Myth about Second Quarter Crude Oil Prices

OPEC: March 28, 2000 agreement

In My Opinion ...

Annual Energy Outlook 2000

Oil Price History and Analysis

California Oil Producers Electricity Cooperative (COPE)

OPEC Countries Production Statistics

CA Online Datebase of Production or Injection Data

Electric Cost Study
PTTC - EPRI Field Visits
Press Release

Sites to Visit Daily:
CA Posted Crude Oil Prices

Web site of the West Coast PTTC

Internet

Inbox - Outl... | Summary for... | Alaska Prese... | pouyatalk3 [... | 01-Ershaghi | PTTC West ... | 5:39

Purpose of the Workshop

- Assessment of Geologic Potential for Shallow Gas and Coal bed Methane Development
- Review of Incentive Programs offered by Federal and State Government to Invite in Independent Producers
- Review of Existing Rules and Regulations and Permitting Processes
- Technology issues and Solutions

Format of the Workshop

- Field Trip Was Conducted Monday and Tuesday
- Short Course on Hydraulic Fracturing Technology on Wednesday
- Short Course on Horizontal Drilling on Thursday
- Dinner workshop Thursday Night
- Full Day Workshop Friday

Organizers of This Workshop

PTTC

Alaska DNR

USGS

BLM

Mentors to PTTC

- Jim Clough, ADGGS
- Charles Barker, USGS
- Bob Fisk, BLM

Co-Sponsors

- Univ. of Southern California
- Evergreen Resources
- Bristol Bay Native Corporation
- Cook Inlet Region, Inc.
- B.J. Services

Helpers

- Dave Lappi
- Todd Dallegge
- Bob Swenson

PTTC Helpers

- Frank Valenzuela
- Maria Valenzuela
- Idania Takimoto
- Leslie Torrance-BLM

Today's Program at a Glance

- Morning Technical Sessions
- Luncheon Speaker
- Afternoon Technical Session
- Panel Discussion

Moderator

Jim Clough
Alaska Division of
Geological & Geophysical
Surveys

EIA's Natural Gas Outlook:
35 tcf on 2020

Speaker

Jim Kendall
Energy Information
Administration

Speaker Biography

JIM KENDALL
ENERGY INFORMATION ADMINISTRATION (EIA)

James M. Kendell is Director of the Oil and Gas Division of the Office of Integrated Analysis and Forecasting at the Energy Information Administration (EIA). He manages natural gas and oil forecasting and analysis and the development of the oil and gas models in the National Energy Modeling System (NEMS), including oil and gas supply, natural gas marketing and distribution, and oil refining and marketing.

In addition to managing oil and gas contributions to the *Annual Energy Outlook*, he manages special EIA oil and gas studies. His Division's latest study was *Accelerated Depletion: Assessing Its Impacts on Domestic Oil and Natural Gas Production*, issued in July 2000. His division's next major project will be an assessment of ultra-low-sulfur diesel regulations for the House Science Committee in May 2001.

He was Government co-chair of the Demand Task Group for the 1999 National Petroleum Council natural gas study, *Meeting the Challenges of the Nation's Growing Natural Gas Demand*. His most recent publication in July 2000 was an article on the prospects for a 30-tcf gas market in *Natural Gas Industry Analysis*, a new privately-published annual series.

Before his work on NEMS, he managed EIA's *Weekly Petroleum Status Report* and held positions at EIA as a petroleum supply analyst and an electric power analyst.

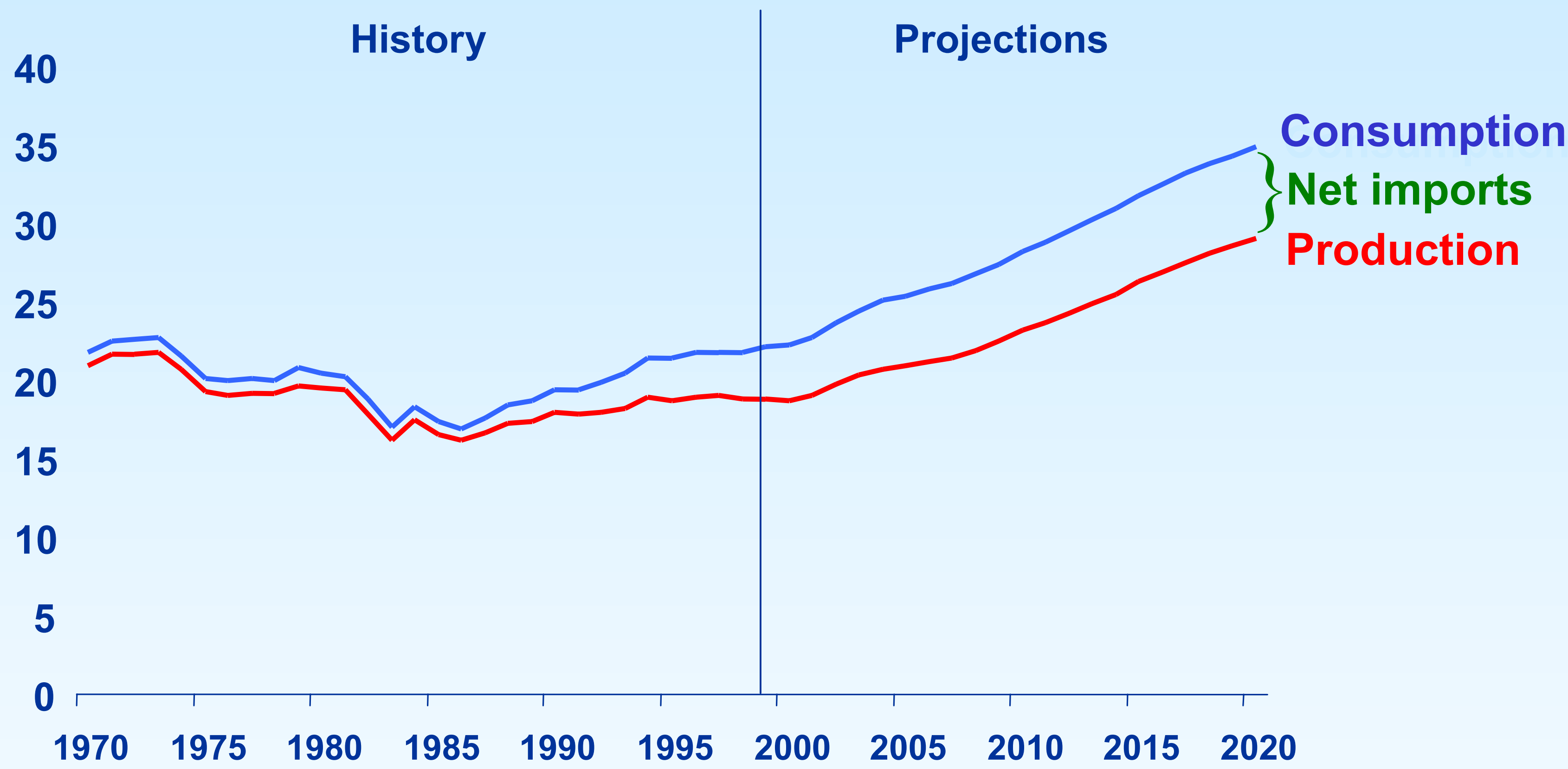
Mr. Kendell graduated with an M.A. in Public Policy and Administration and a certificate in Energy Analysis and Policy from the University of Wisconsin-Madison in 1983. He received a B.S.J. with highest distinction from the University of Kansas in 1975. He is a member of the International Association for Energy Economics and Presidential Management Alumni Group.

EIA's Natural Gas Outlook: 35 Tcf in 2020

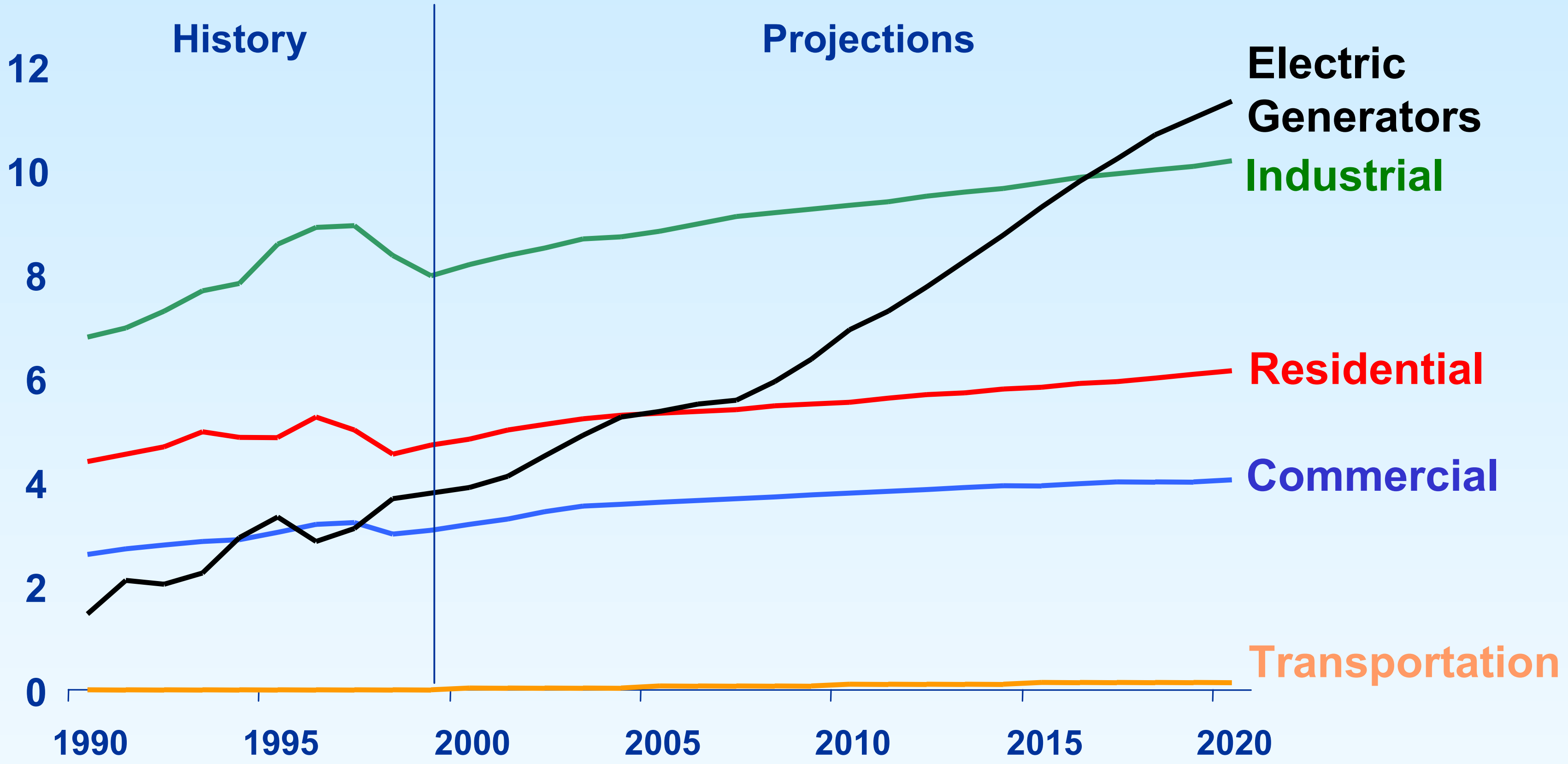
James M. Kendell
Energy Information Administration
James.Kendell@eia.doe.gov

Alaska Coalbed and Shallow Gas Resources Workshop
May 4, 2001

Natural Gas Production, Consumption, and Imports, 1970 - 2020 (trillion cubic feet)

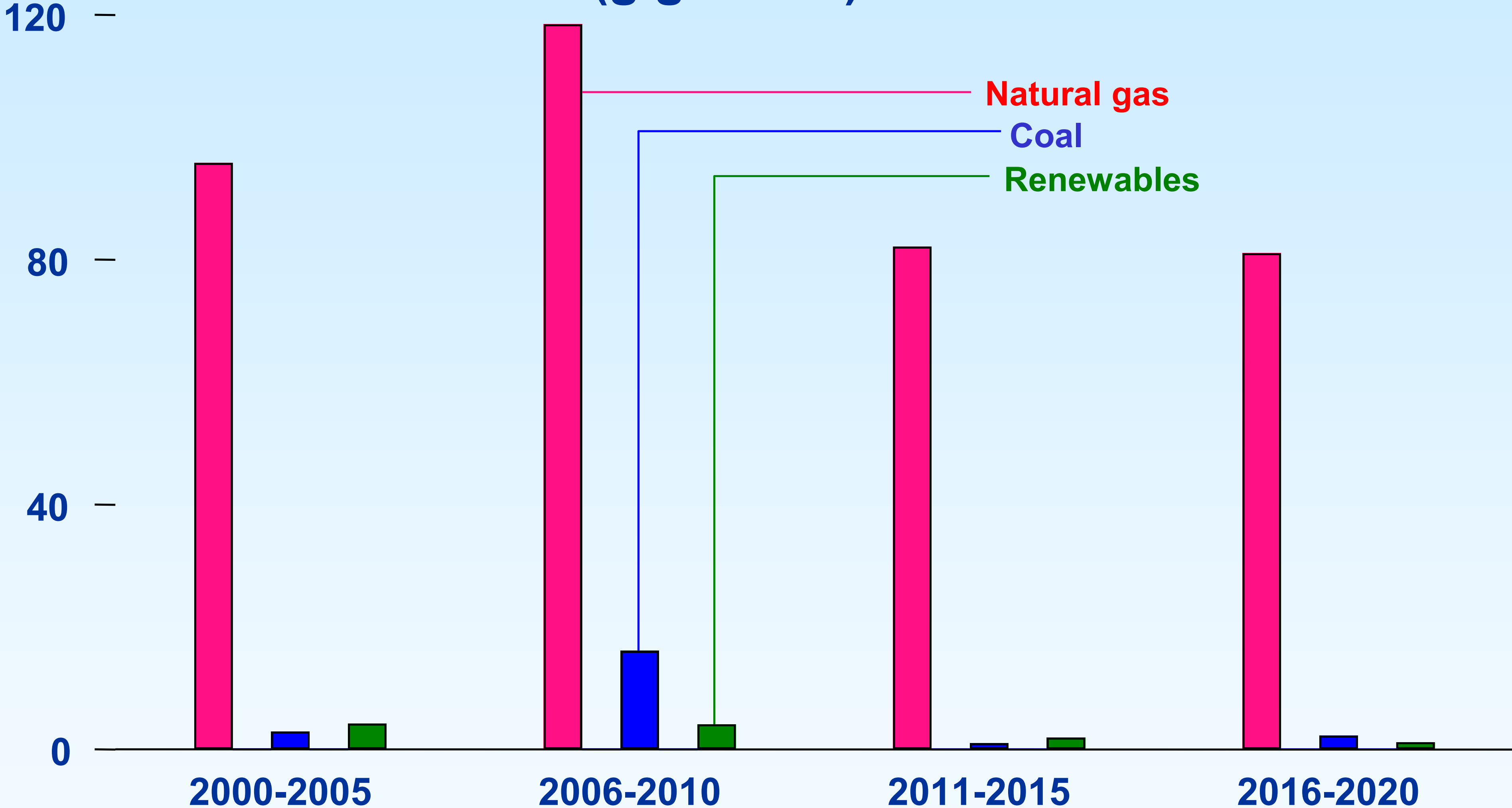


Natural Gas Consumption by Sector,1990 - 2020 (trillion cubic feet)

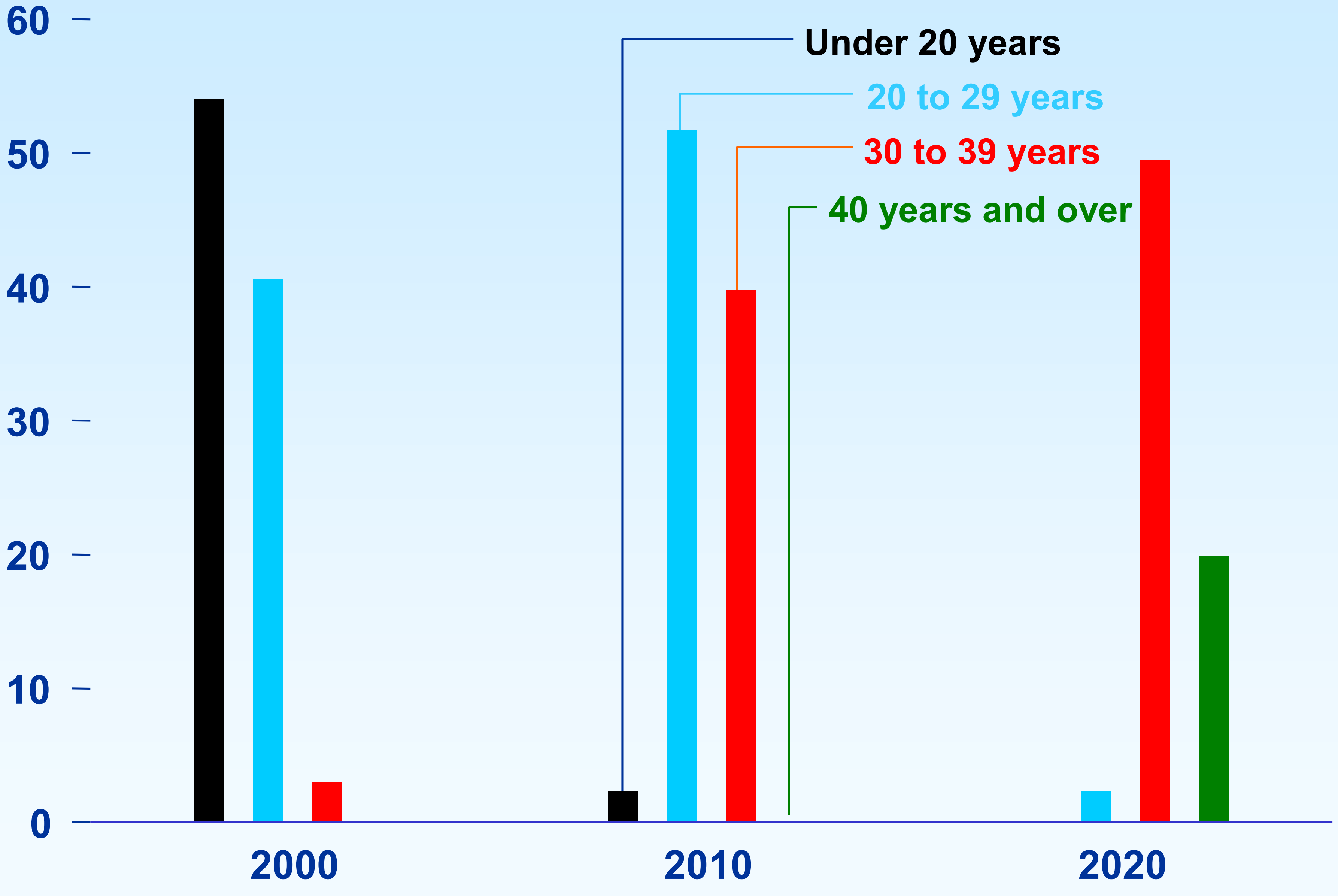


www.eia.doe.gov

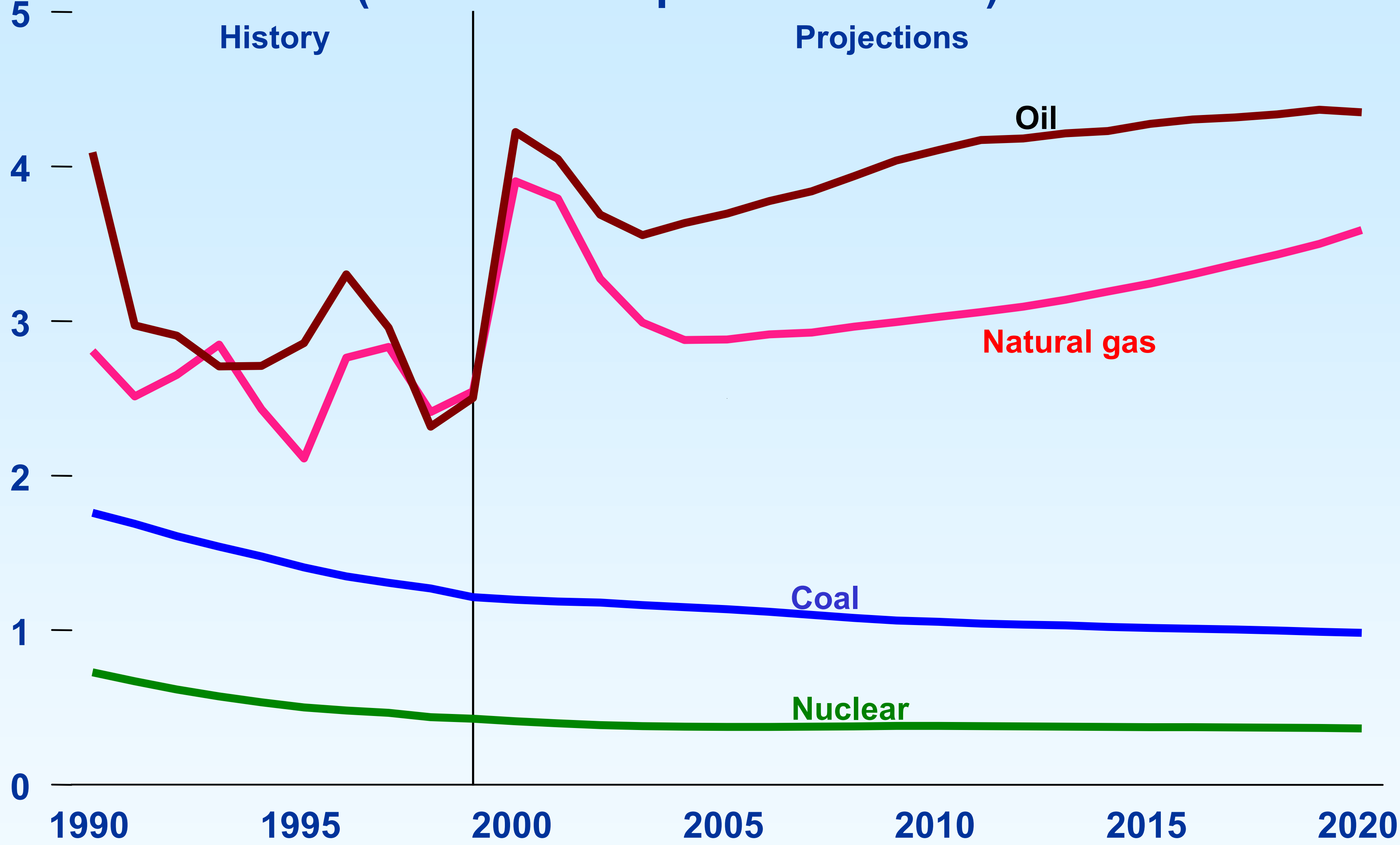
Projected Electricity Generation Capacity Additions by Fuel Type, Including Cogeneration, 2000-2020 (gigawatts)



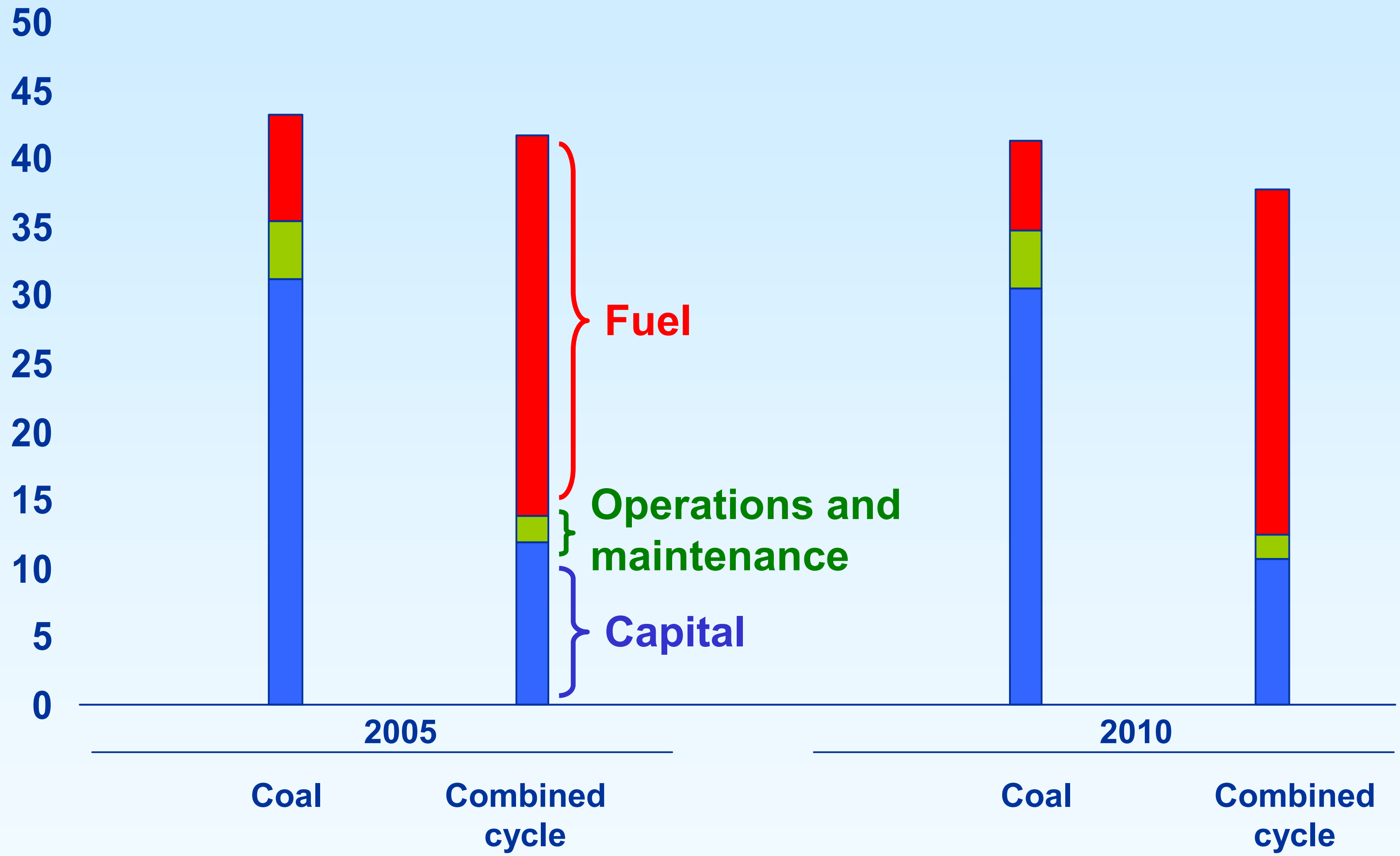
Operable Nuclear Power Capacity by Age of Plant, 2000, 2010, and 2020 (gigawatts)



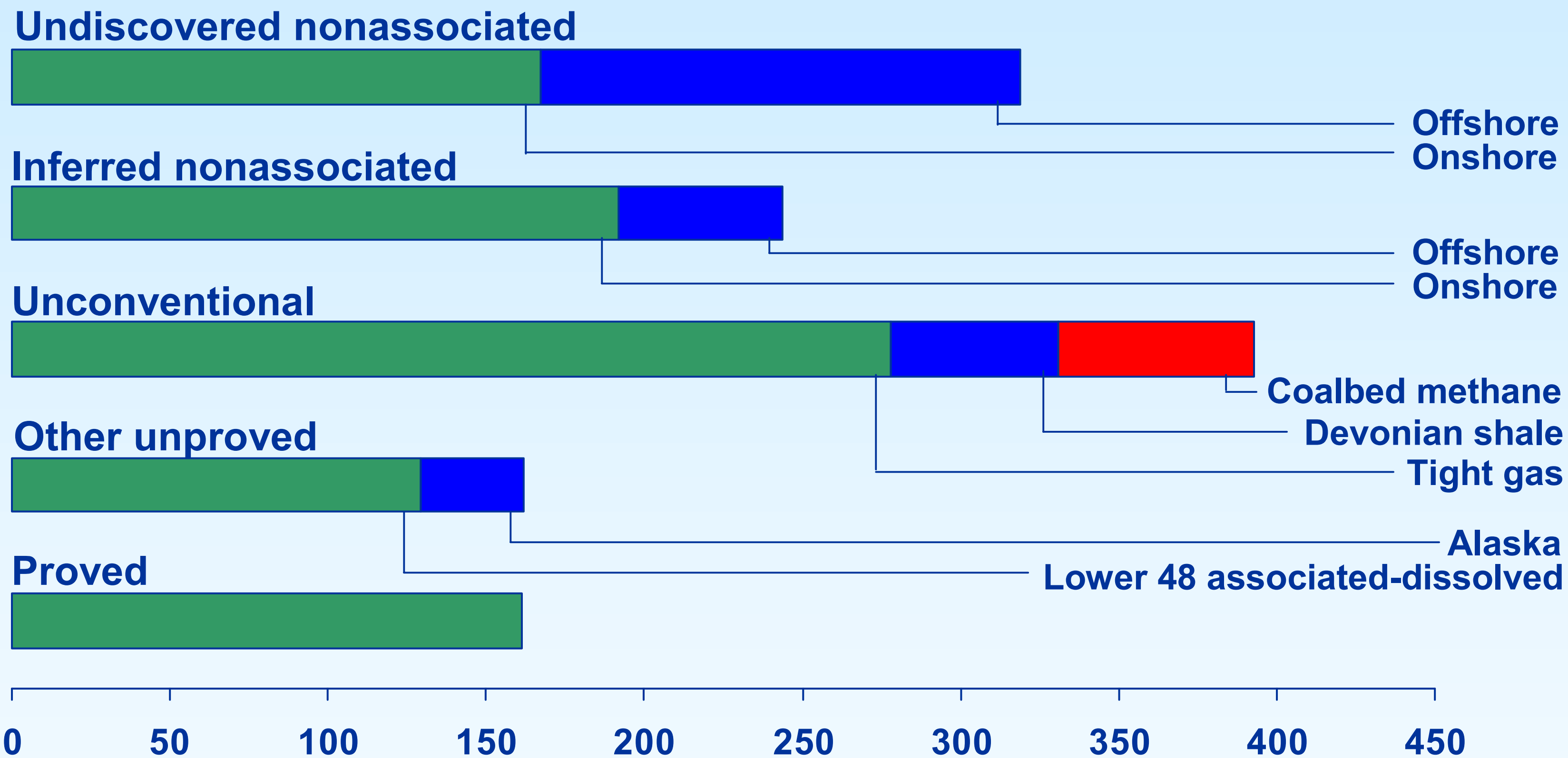
Fuel Prices to Electricity Generators, 1990-2020
(1999 dollars per million Btu)



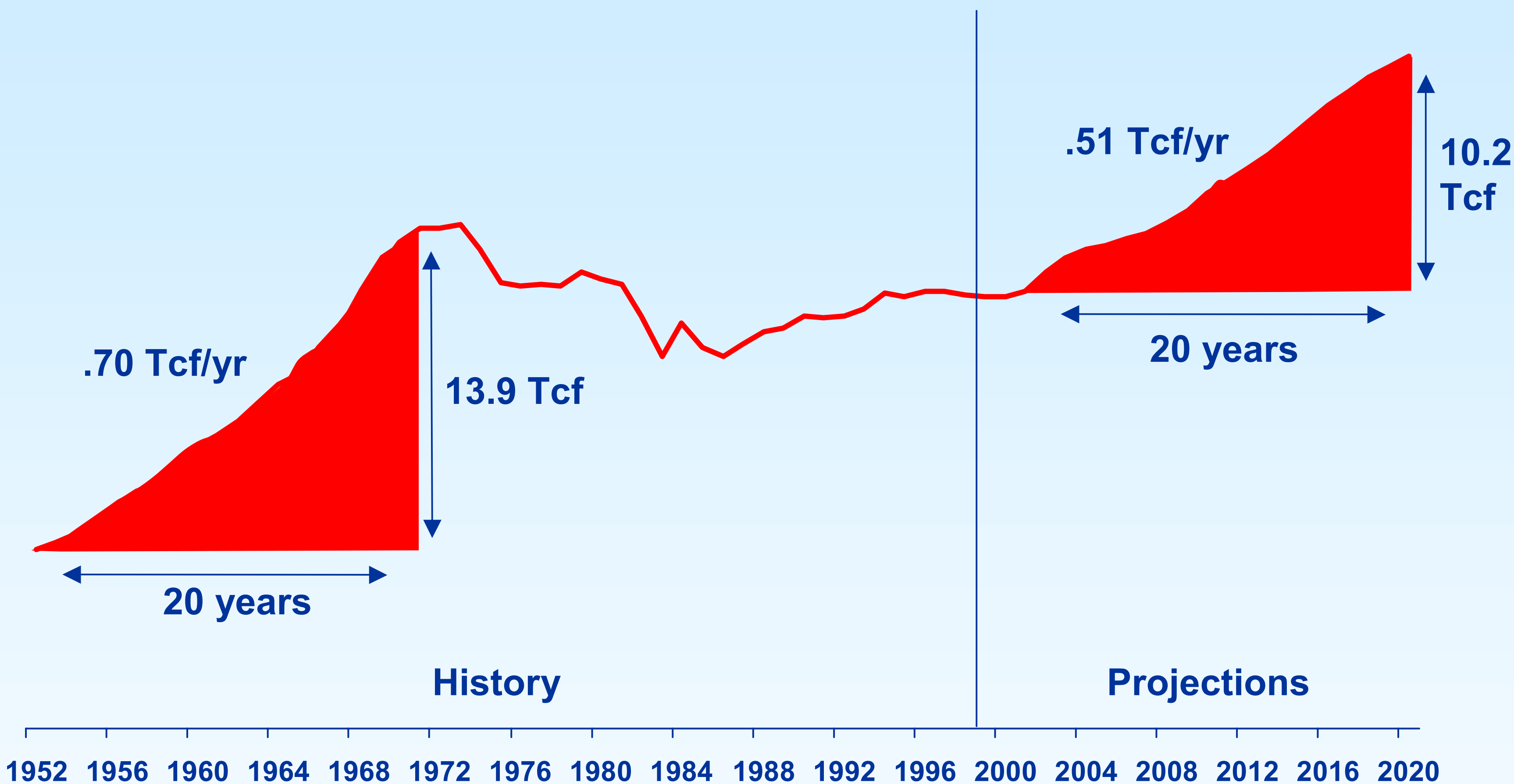
Projected Electricity Generation Costs, 2005 and 2010 (1999 mills per kilowatthour)



Technically Recoverable U.S. Natural Gas Resources, January 1, 1999 (trillion cubic feet)



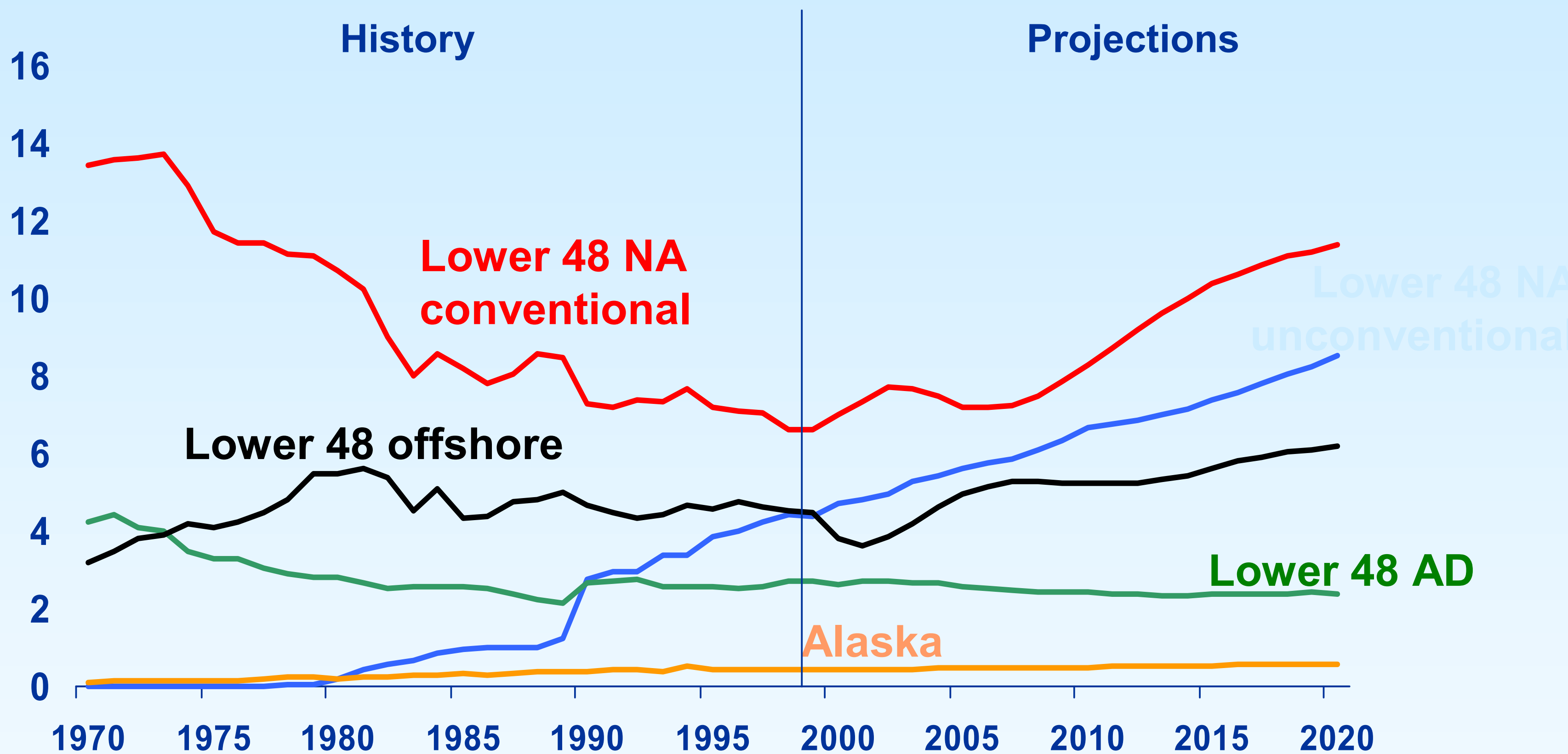
Natural Gas Production,1952 - 2020
(trillion cubic feet)



www.eia.doe.gov

Lower 48 Natural Gas Wells Drilled, 1970-2020
(number of wells)

Natural Gas Production by Source,1970 - 2020
(trillion cubic feet)



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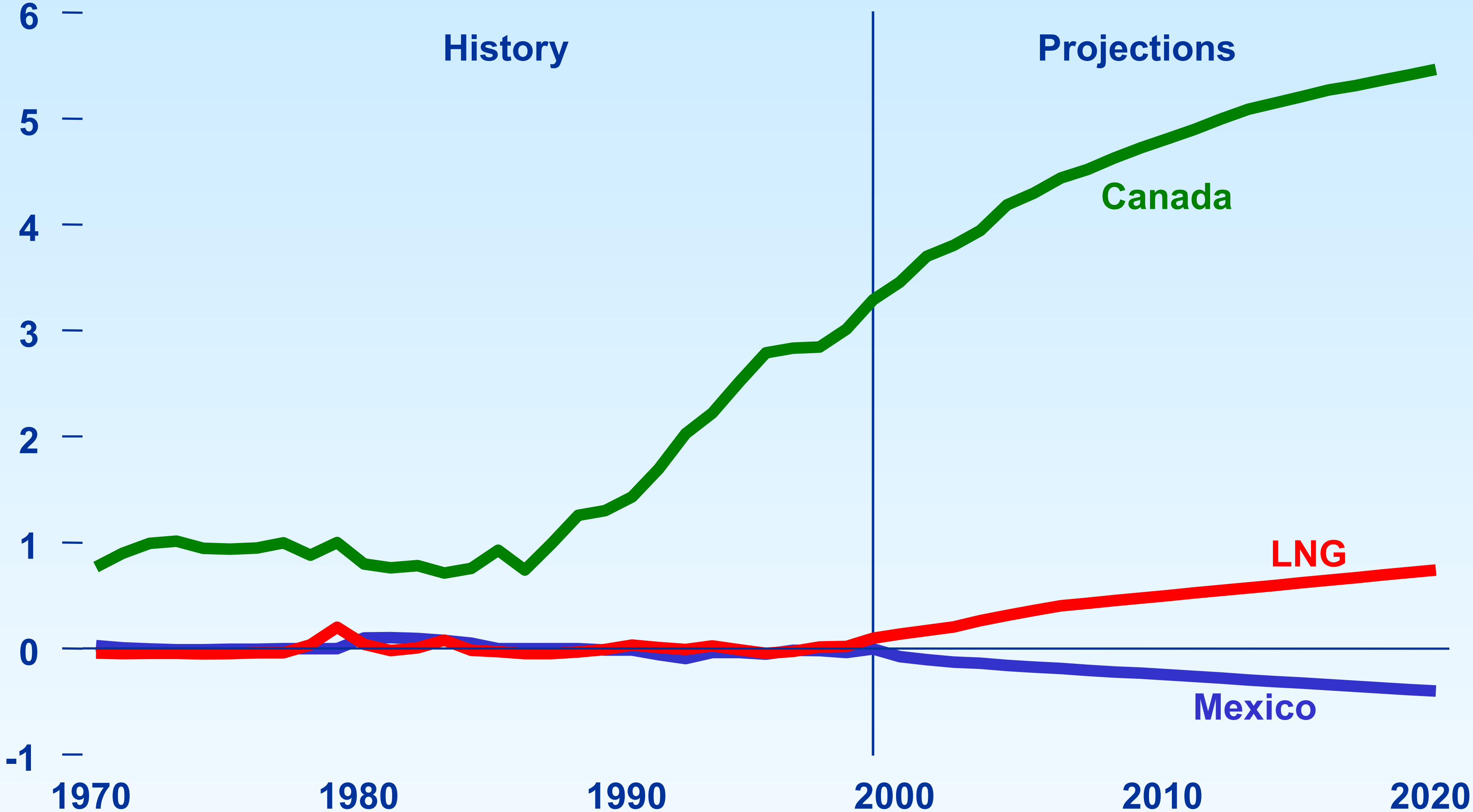
Net U.S. Imports of Natural Gas, 1970-2020
(trillion cubic feet)



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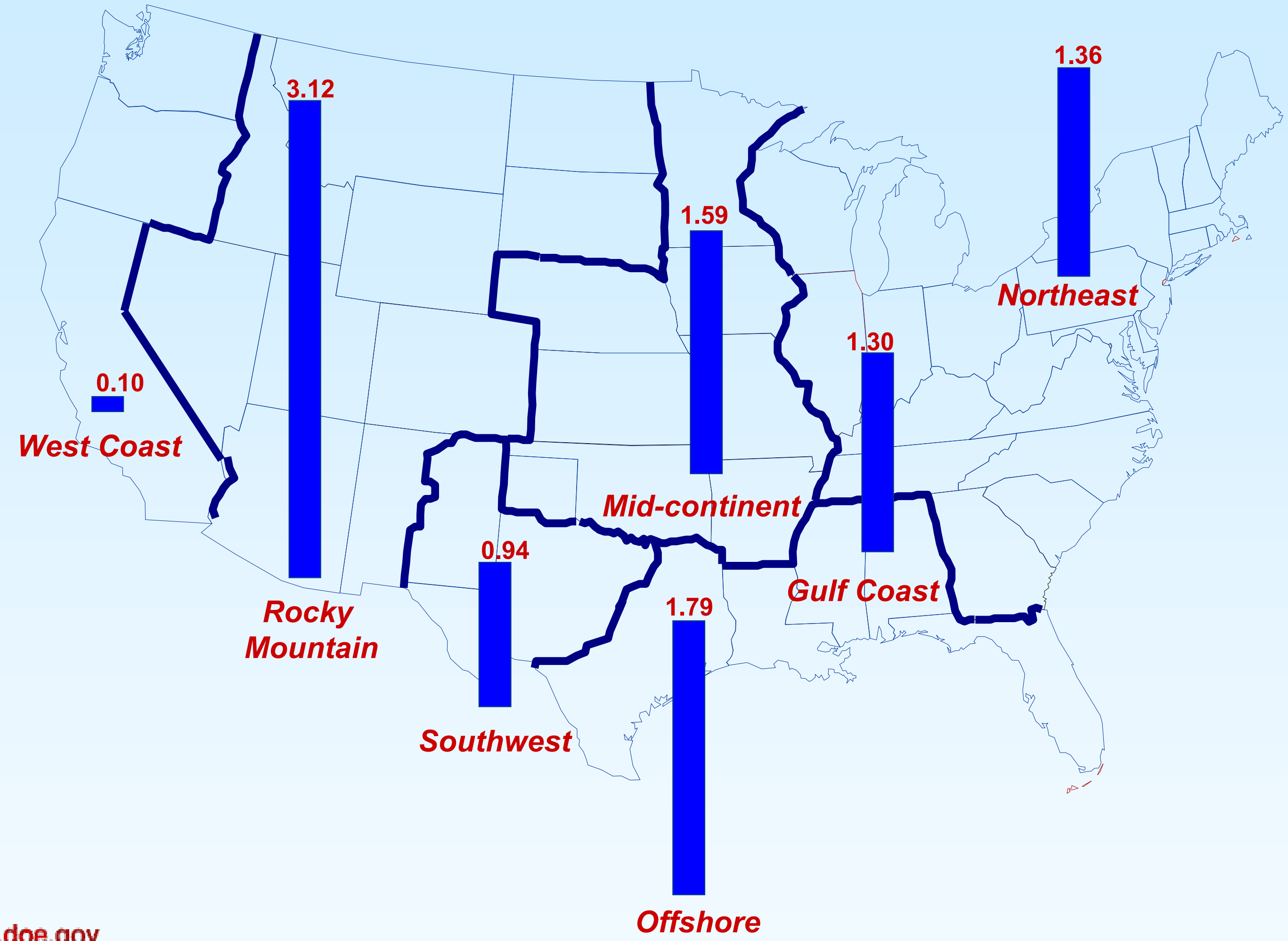
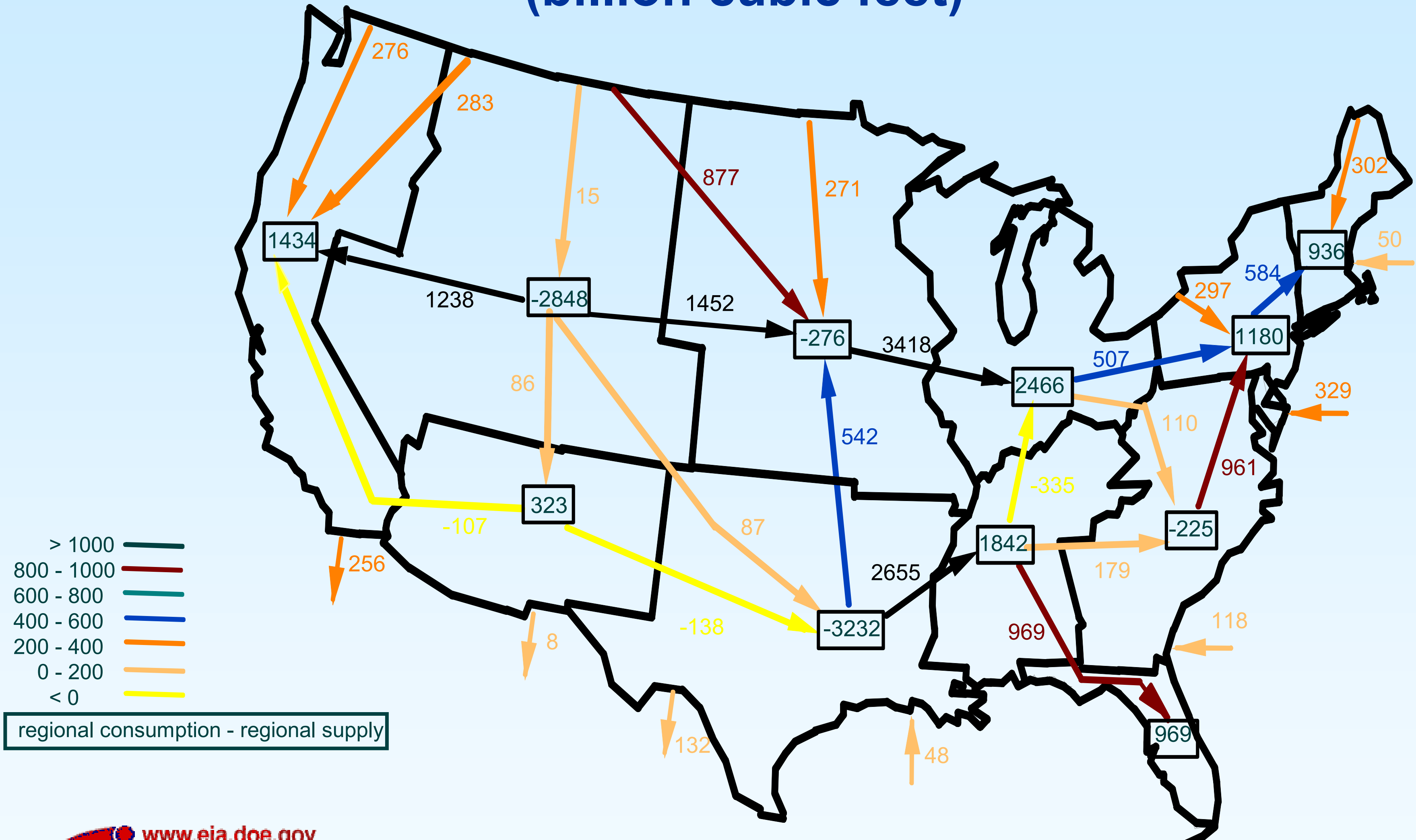
Incremental Natural Gas Production, 1999 - 2020 (trillion cubic feet)



Changes in Major Interregional Pipeline Flow,1999 - 2020
(billion cubic feet)



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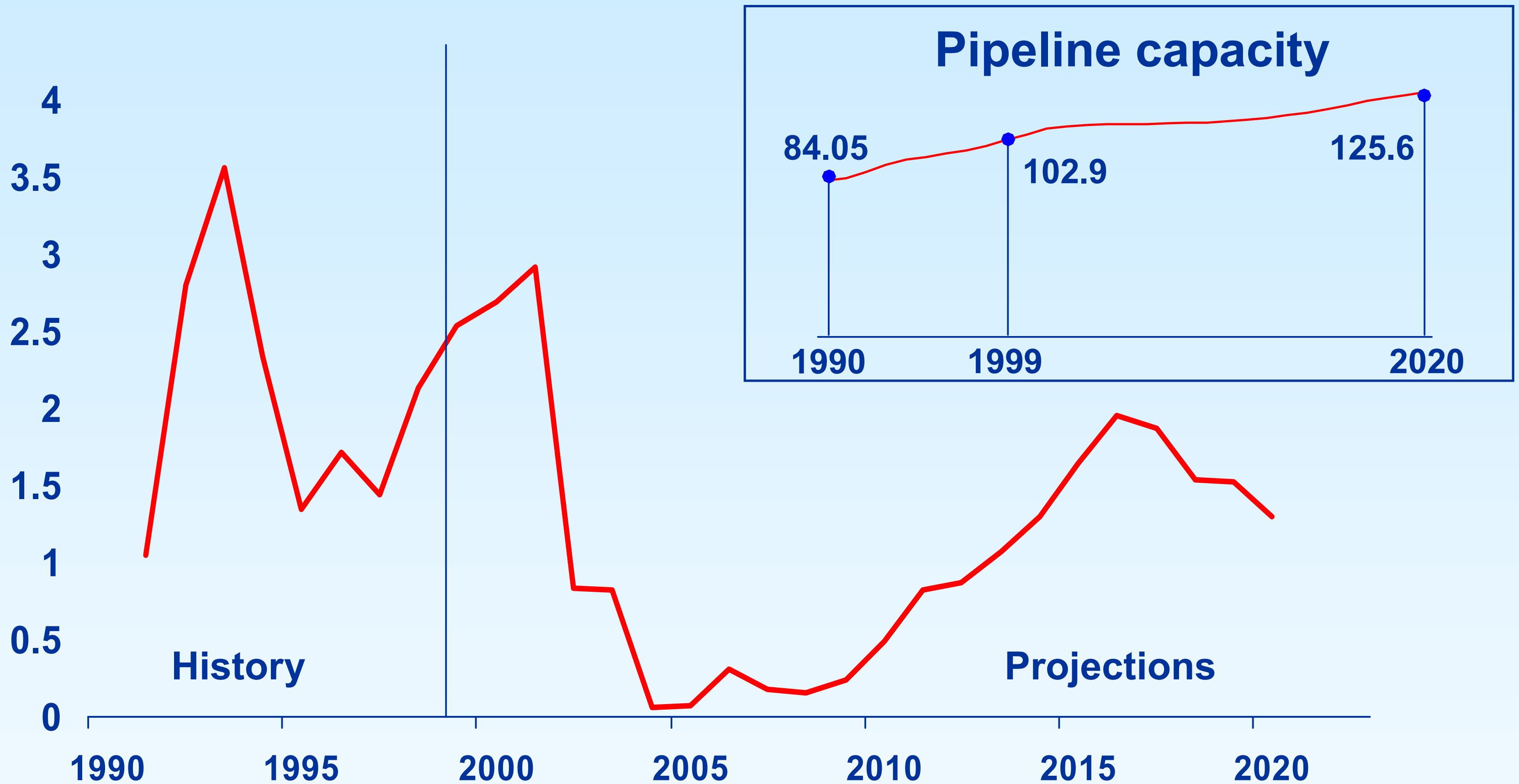
Additions of Interstate Natural Gas Pipeline Capacity, 1991-2020 (trillion cubic feet)



Oil and Gas Side Cases

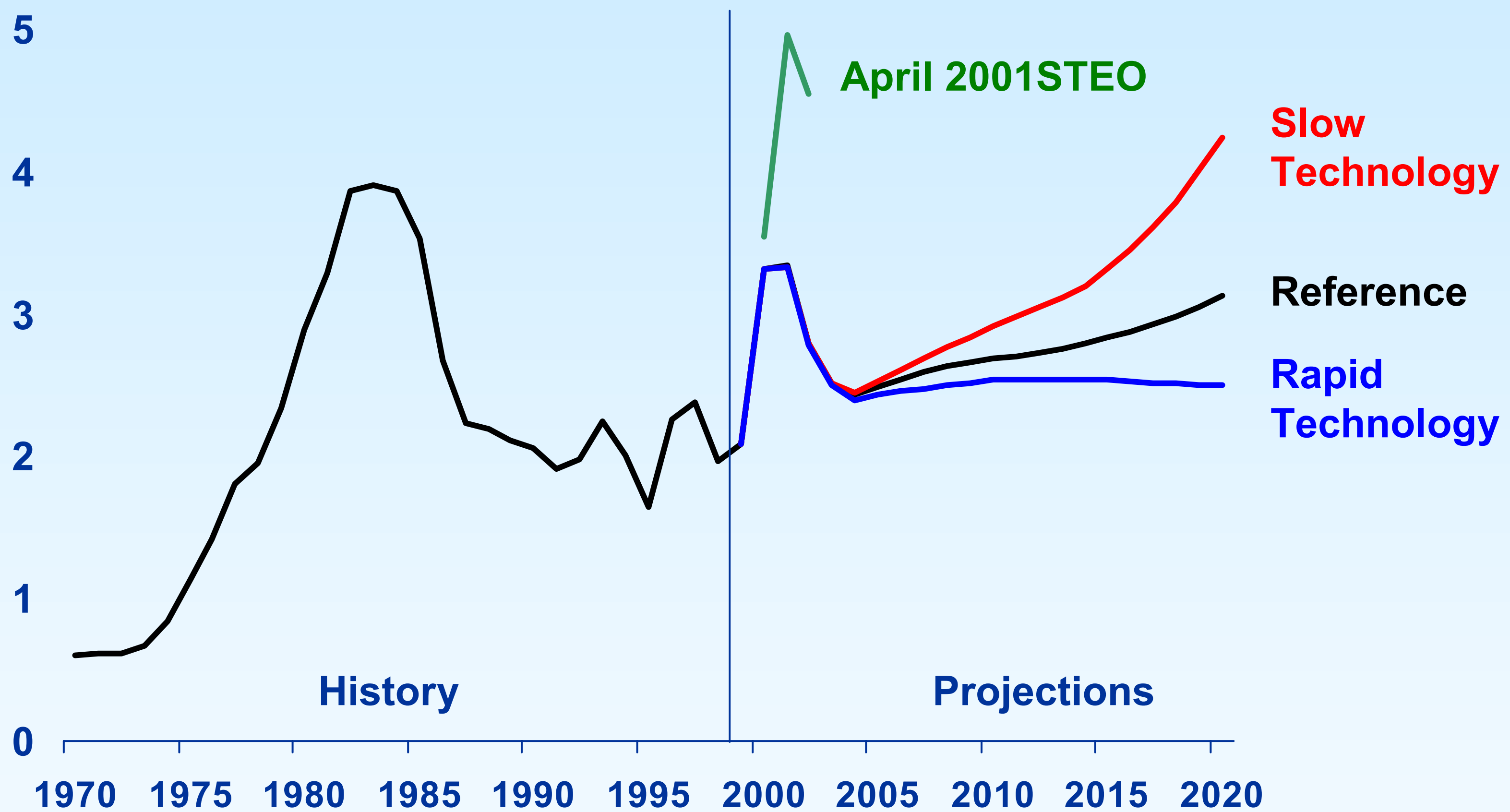
Rapid and Slow Technology

- Conventional natural gas technology parameters adjusted plus and minus 25 percent
  - finding rates
  - drilling
  - lease equipment and operating costs
  - success rates
- Unconventional natural gas
  - varying adjustments made for 11 separate technology groups

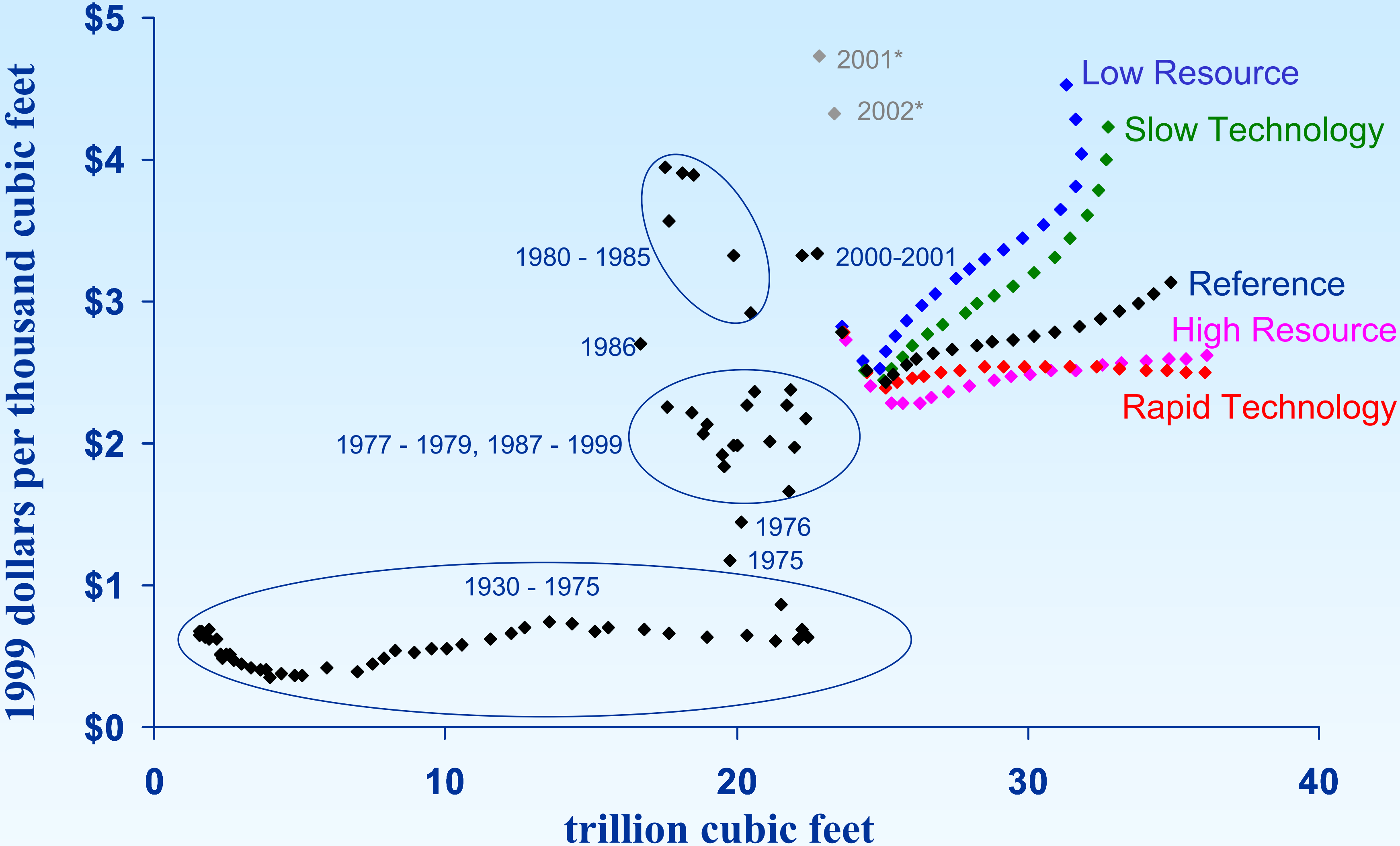
High and Low Resource

- Conventional onshore and offshore resources adjusted plus and minus 20 percent across all regions
  - undiscovered technically recoverable resource
  - inferred reserve estimates
- Unconventional gas resources adjusted plus and minus 40 percent across all regions
  - unproved resource estimates

Lower 48 Natural Gas Wellhead Prices,1970 - 2020 (1999 dollars per thousand cubic feet)

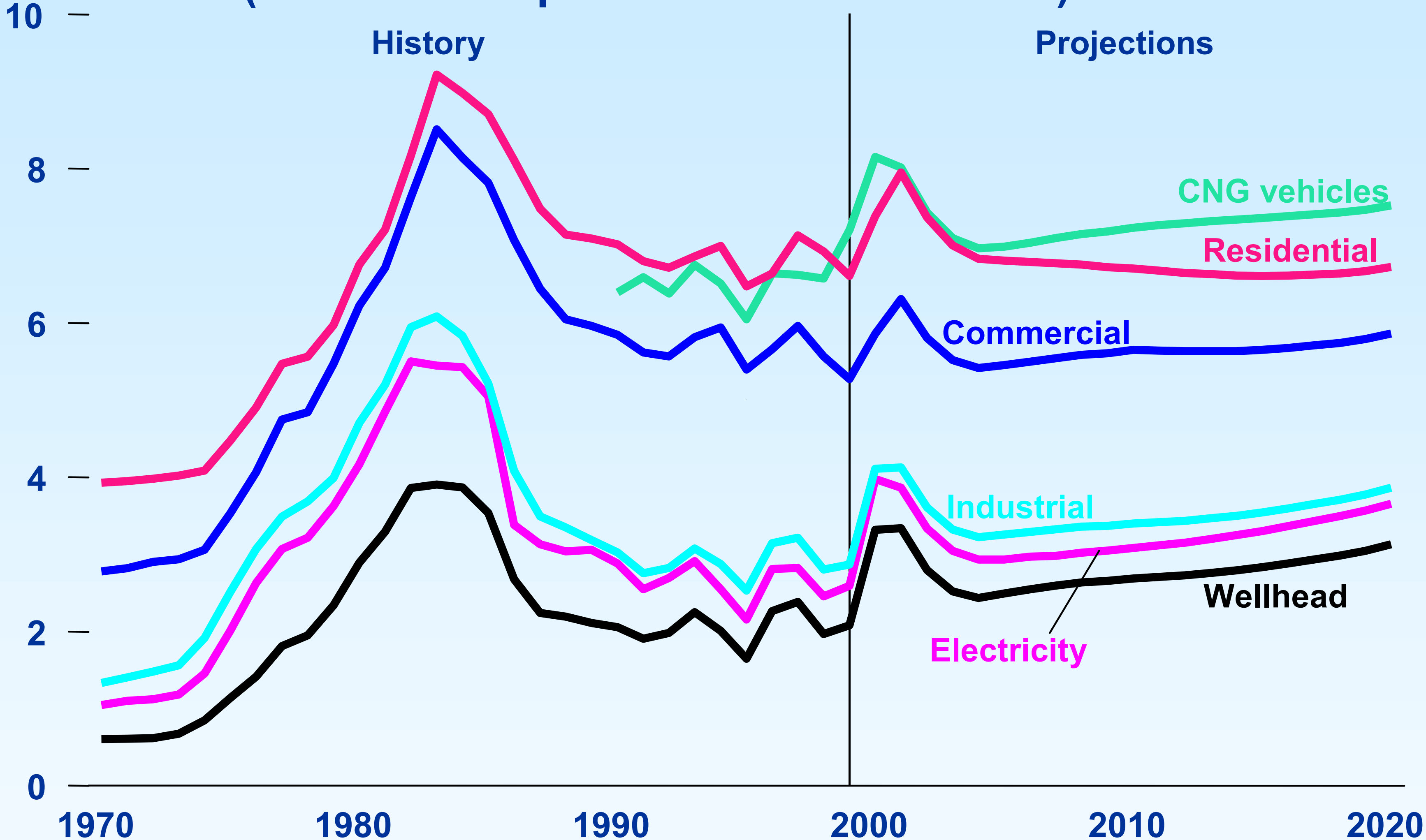


Natural Gas Wellhead Prices vs. Total Supply



* April 2001 STEO

Natural Gas End-use Prices by Sector, 1970-2020
(1999 dollars per thousand cubic feet)



Overview of Alaska Gas Resources

Speaker

Kirk Sherwood
Mineral Management Services

Speaker Biography

KIRK SHERWOOD
U. S. MINERAL MANAGEMENT SERVICES (MMS)

Kirk Sherwood received his PhD from the University of Wisconsin-Madison in 1979, based on studies in structural geology in the Alaska Range. He was employed by Amoco Production Company in Denver from 1976 to 1981, working on exploration projects in northern Alaska, the Alaska Peninsula, the Holitna basin, and development projects in the Idaho-Wyoming thrust belt and coal degasification pilot studies in the San Juan basin of northern New Mexico. From 1981 to 1983 he worked out of Amoco's Anchorage District office, mainly providing geological oversight to drilling projects in Cook Inlet and the North Slope. Since 1983, he has been employed by the U.S. Minerals Management Service, primarily in geologic studies and oil and gas assessments of the Chukchi shelf offshore northwestern Alaska.

OVERVIEW OF ALASKA NATURAL GAS RESOURCES

Kirk W. Sherwood and James D. Craig
Minerals Management Service
U.S. Department of the Interior
04 May 2001

Alaska Coalbed and Shallow Gas Resources Workshop
30 April to 04 May, 2001
Anchorage, Alaska

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REPORT AVAILABILITY

- **ALASKA REPORT** at ***http://www.mms.gov/alaska/re/reports/rereport.htm***

- **CD Available from Rance Wall at 907-271-6060, or e-mail: *rance.wall@mms.gov***

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Purpose of This Study

PREMISE: **U.S. Domestic Natural Gas Demand Will Rise Sharply**

QUESTION: **Can Natural Gas Exports from the Alaska Federal Offshore Help Meet This Rising Demand?**

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BASICS OF ALASKA GAS

- THERE'S LOTS OF GAS
- THE GAS IS REMOTE AND EXPENSIVE TO GET

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HOW FAR TO MARKET?

- 4,000 miles to Japan
- 1,600-2,100 miles to Canadian pipeline network
- 3,200 miles to Los Angeles, California

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BUT ALASKA IS A GAS EXPORTER!

- **Only U.S. exporter of LNG (0.074 TCF/A) (LNG shipped to Yokohama, Japan)**

- **Manufacture and export Ammonia-Urea (fertilizer) (0.052 TCF/A) to Pacific Rim**

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Source: AKDO&G, 1998

HIGH PRICE PREMIUM ALLOWS EXPORT

- **Japan pays $3.48/mcf for LNG imports (1993-1997 average)**
- **U.S. pays $2.43/mcf for LNG imports from Algeria (1993-1997 average)**
- **U.S. wellhead receives $1.99/mcf (1993-1997 average)**

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Sources: DOE, 1999, 2000; Swain, 1999

HOW MUCH GAS IN ALASKA?

- **Reserves: 40 TCF or 25% of U.S. reserves (166 TCF)**
- **Undiscovered "conventional" gas: 191 TCF or 36% of U.S. resources (526 TCF)**
- **Coalbed Methane: 57-1,000 TCF**
- **Gas hydrates: 169,039 TCF (53% of U.S. Total [320,222 TCF])**

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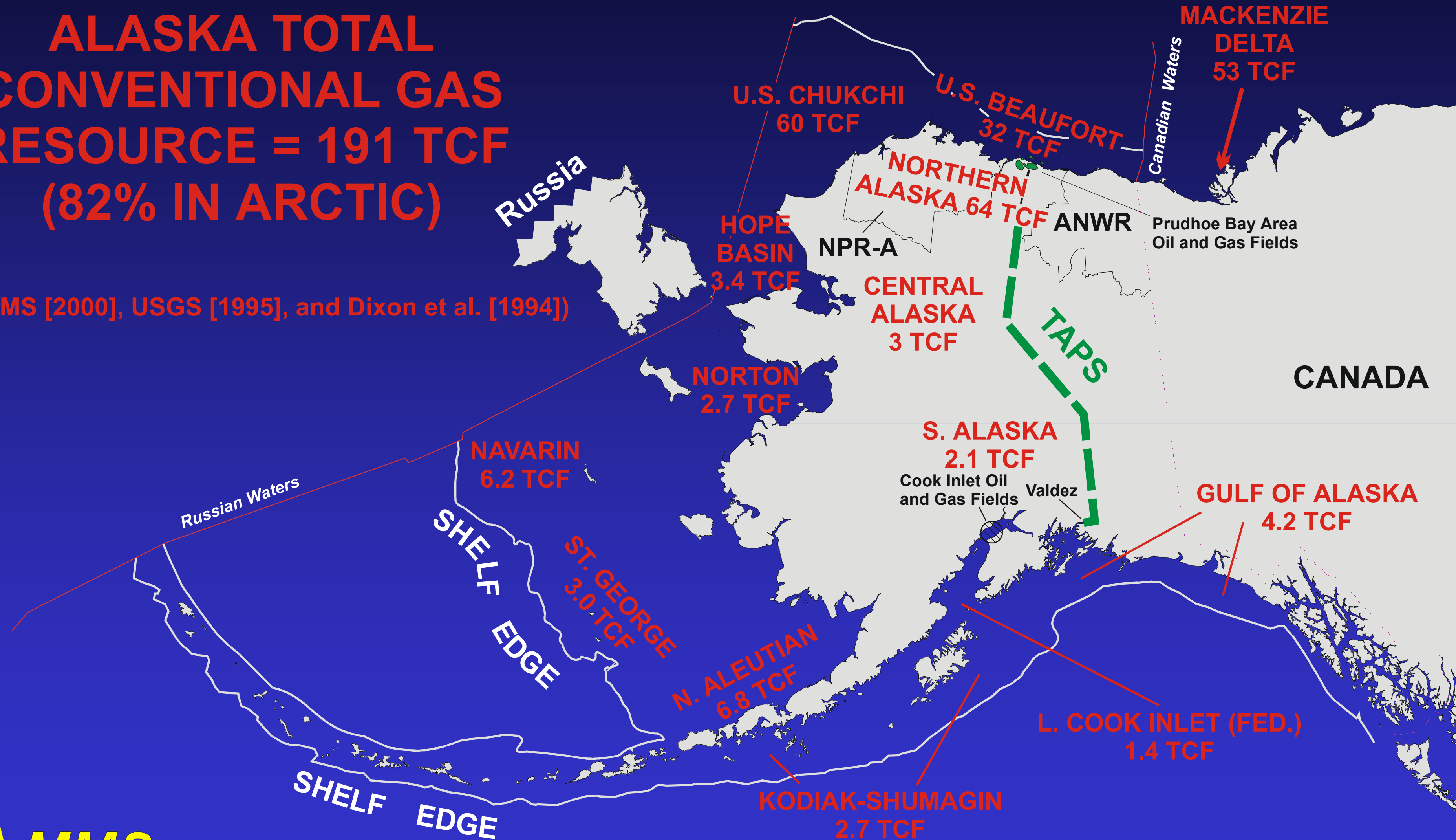
Sources: AK DOG, 2000; MMS, 2000; USGS, 1995; PGC, 1999

UNDISCOVERED GAS RESOURCES

ALASKA TOTAL CONVENTIONAL GAS RESOURCE = 191 TCF (82% IN ARCTIC)

(After MMS [2000], USGS [1995], and Dixon et al. [1994])



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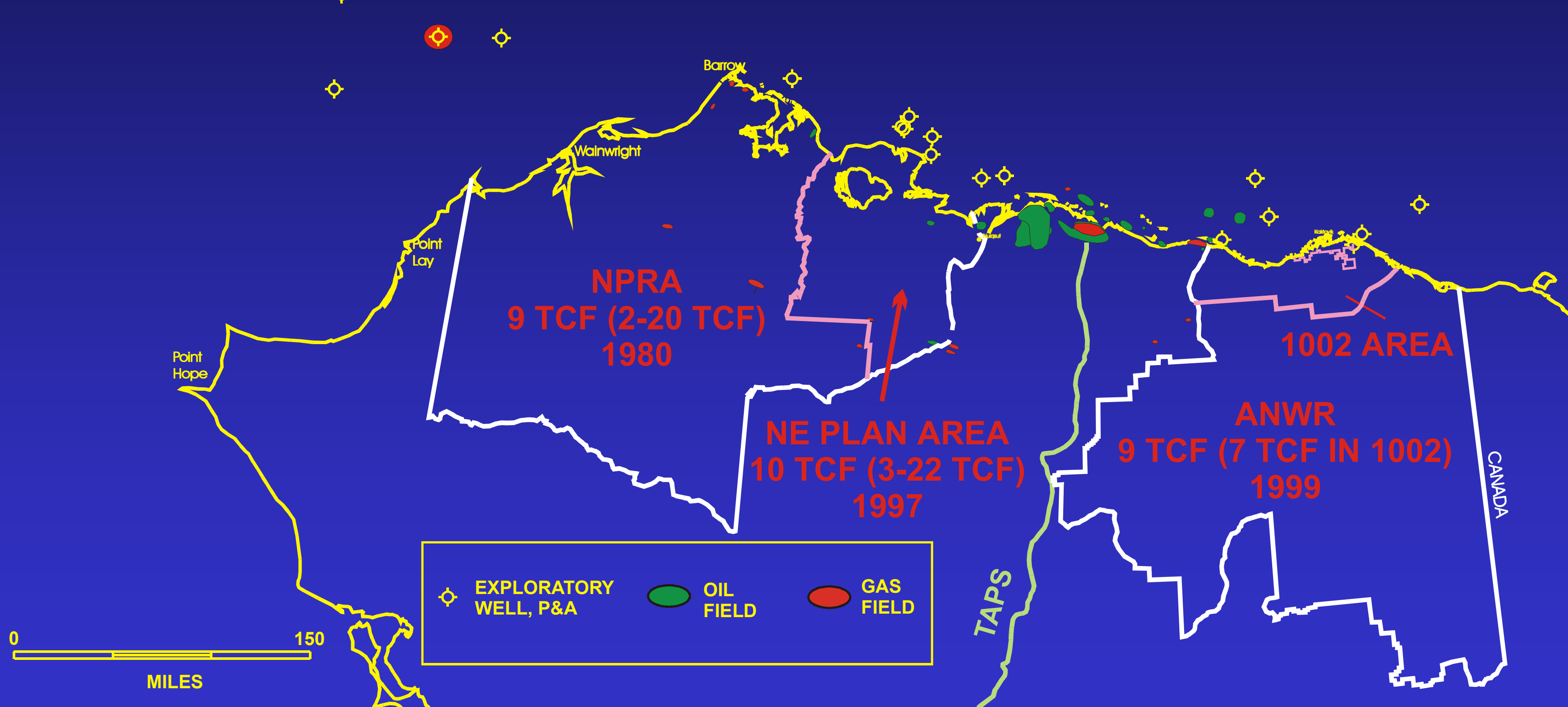
ENTIRE NORTH SLOPE

UNDISCOVERED = 64 TCF (23-124 TCF) 1995
ORIGINAL RESERVES = 35 TCF
TOTAL = 100 TCF



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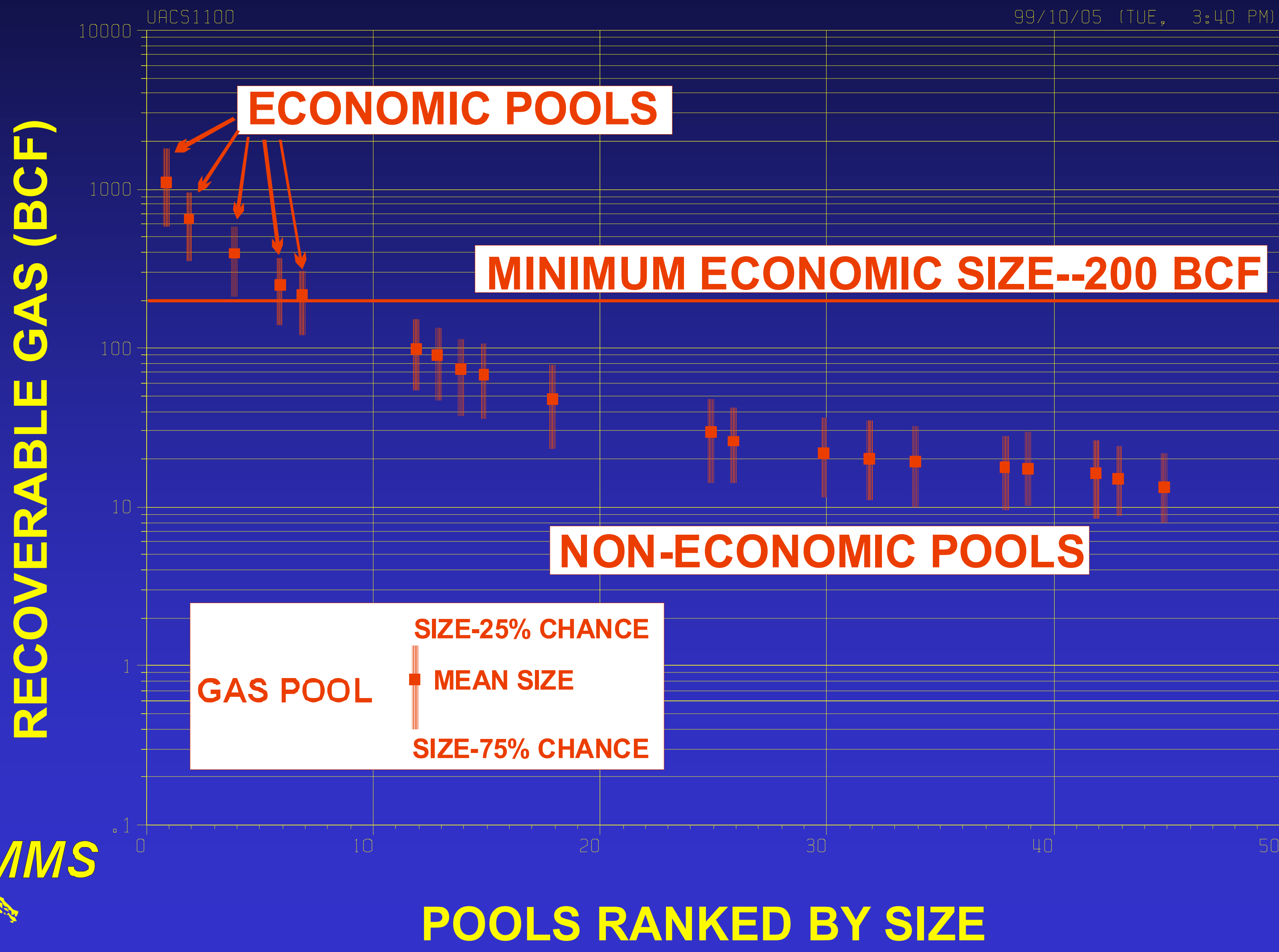
ECONOMIC VS. SUB-ECONOMIC GAS

POOL RANK PLOT
Foreland Foldbelt--Chukchi Sea



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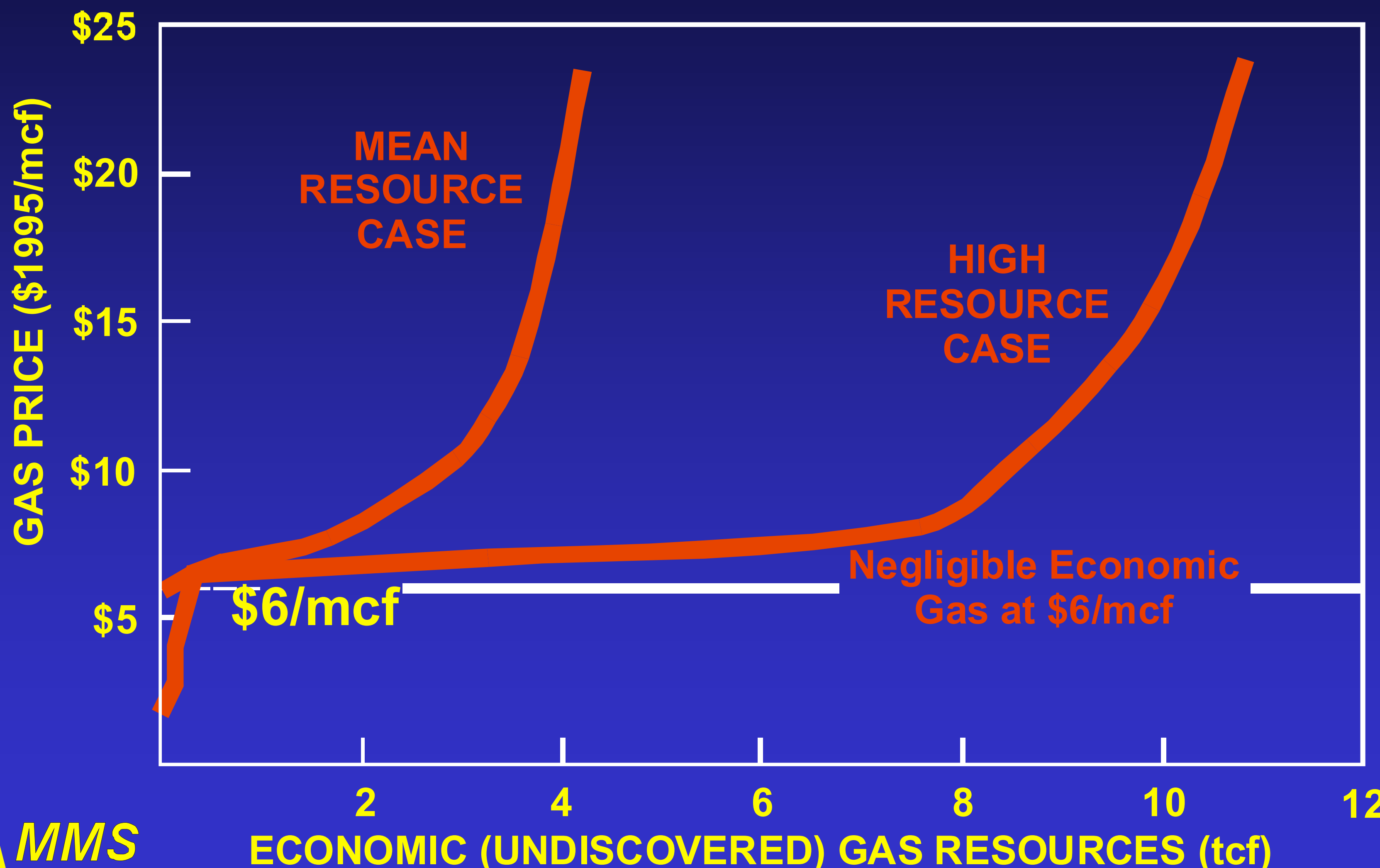
NAVARIN BASIN

Undiscovered Economically Recoverable Gas



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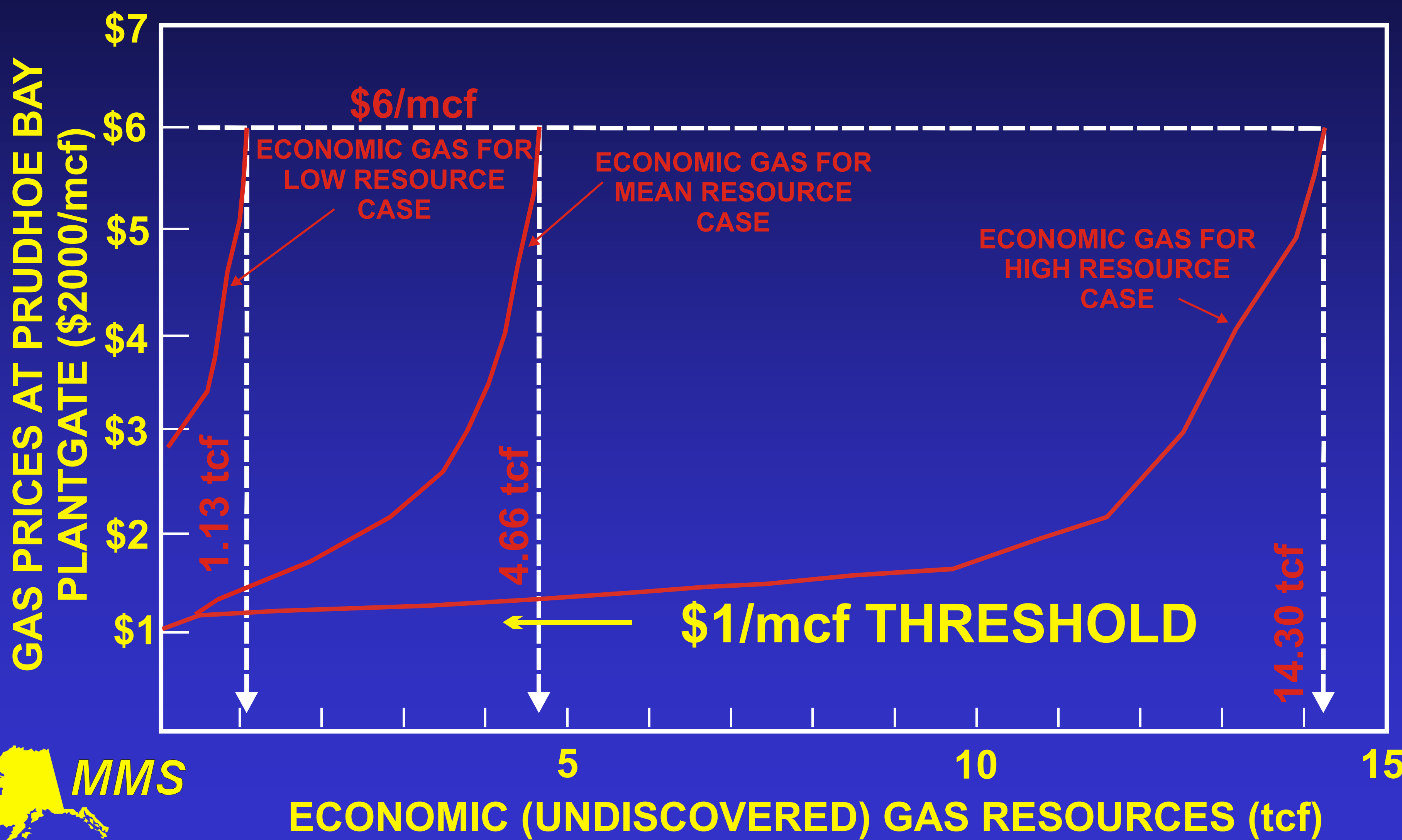
BEAUFORT SEA

Undiscovered Economically Recoverable Gas

(Total Undiscovered Gas Endowment = 32.1 TCF)



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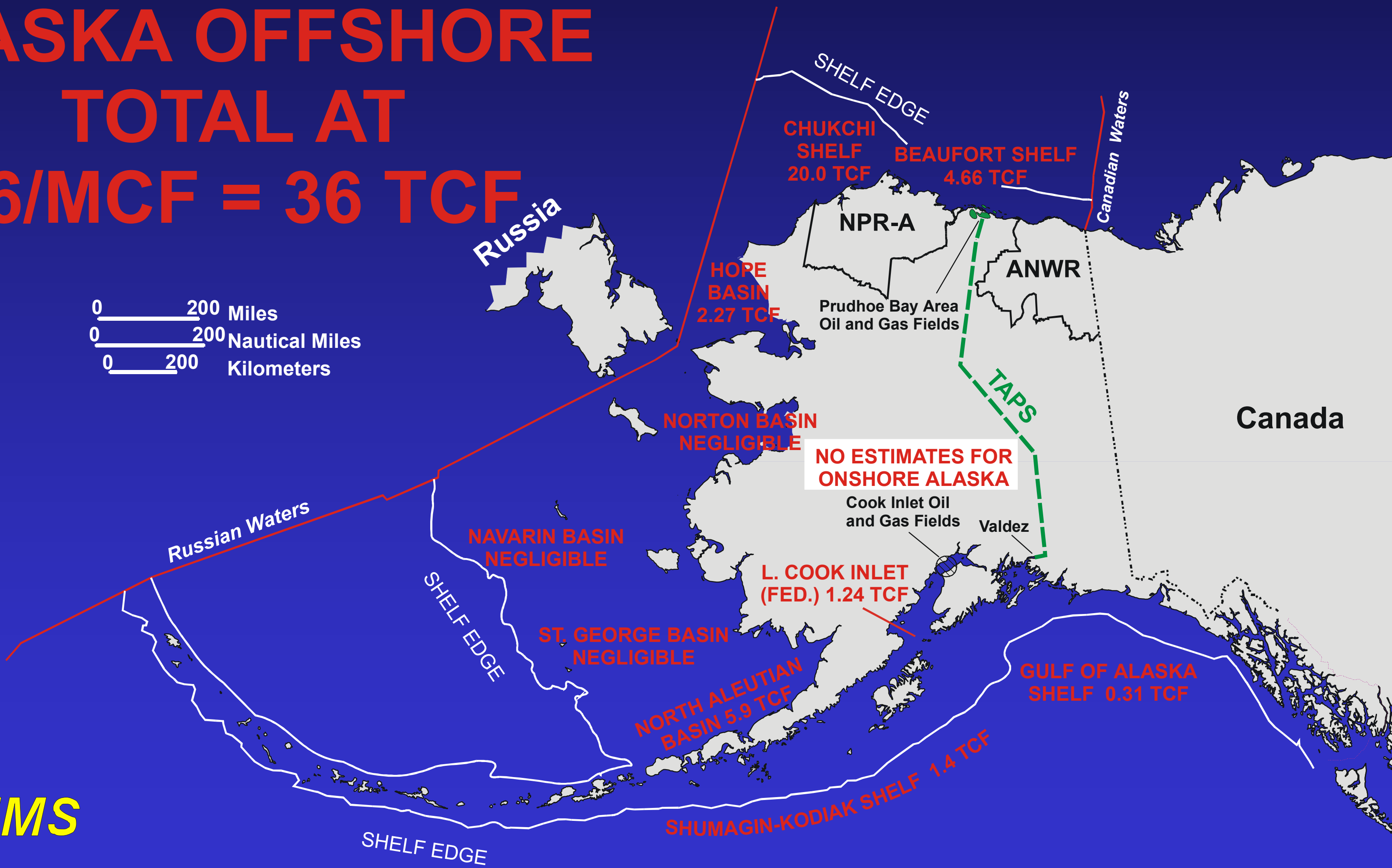
OFFSHORE GAS ECONOMIC AT $6/MCF ($2000)

ALASKA OFFSHORE TOTAL AT $6/MCF = 36 TCF



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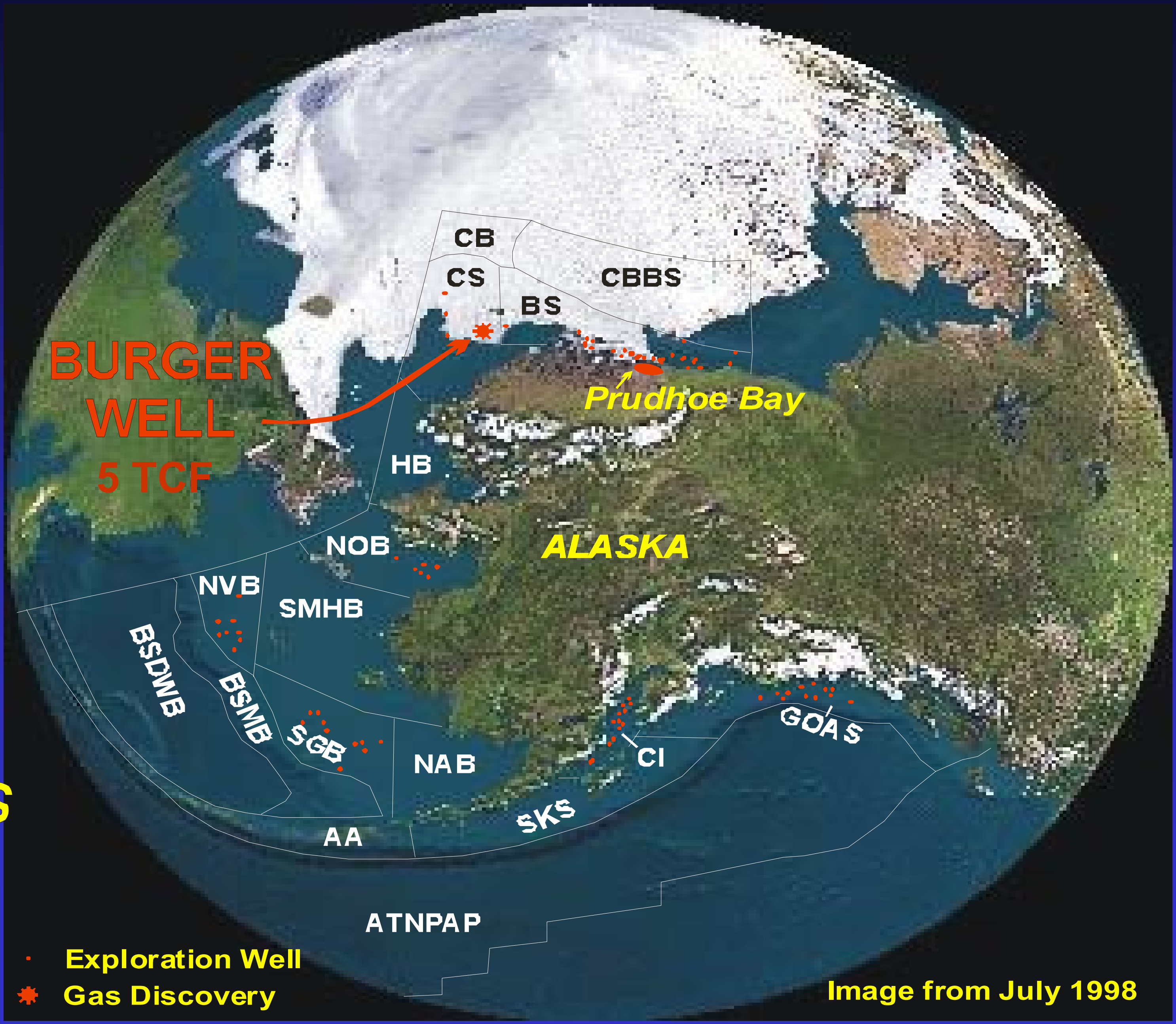
OFFSHORE GAS FINDS

83 EXPLORATION WELLS--ONE SIGNIFICANT GAS POOL AT BURGER STRUCTURE



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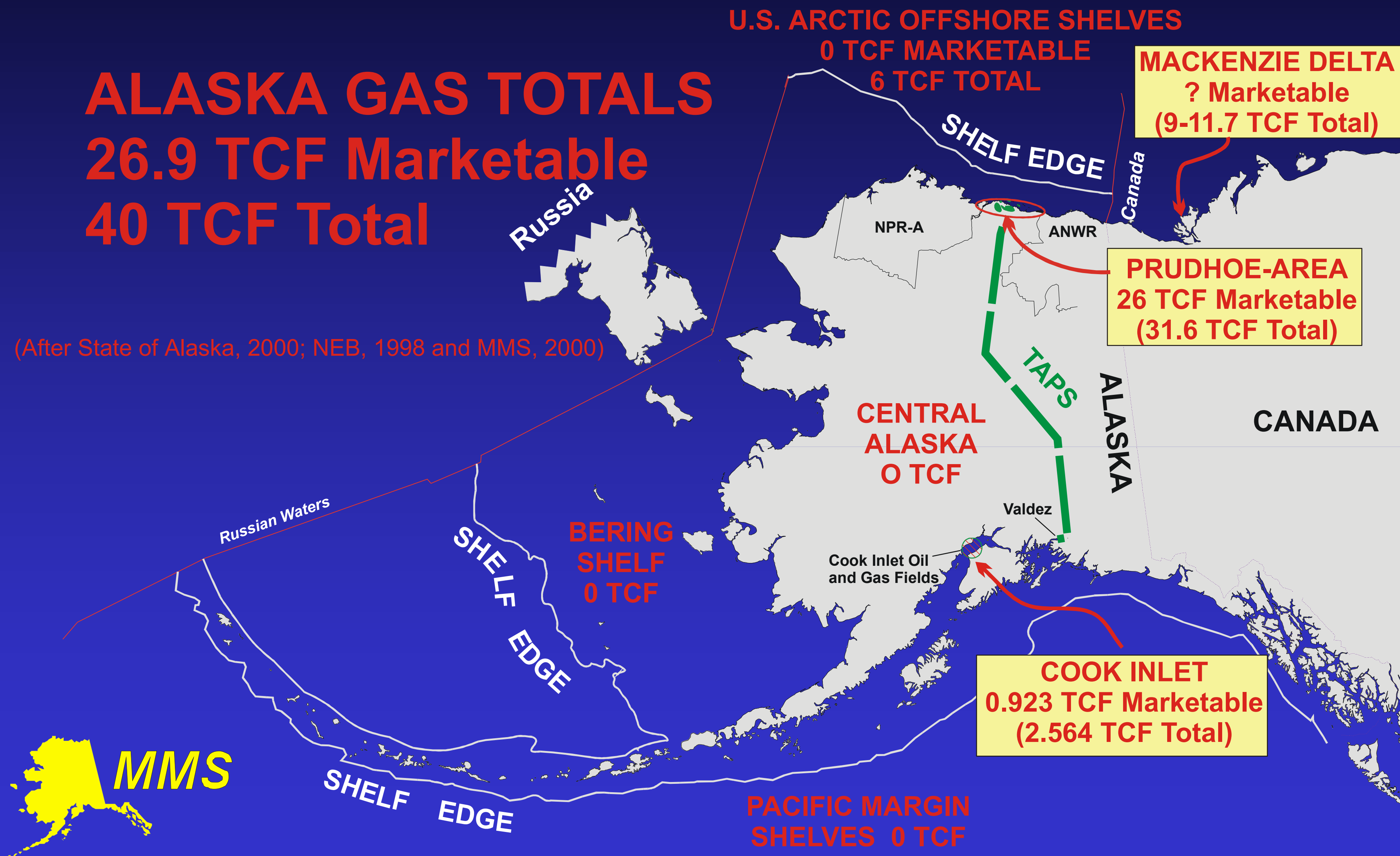
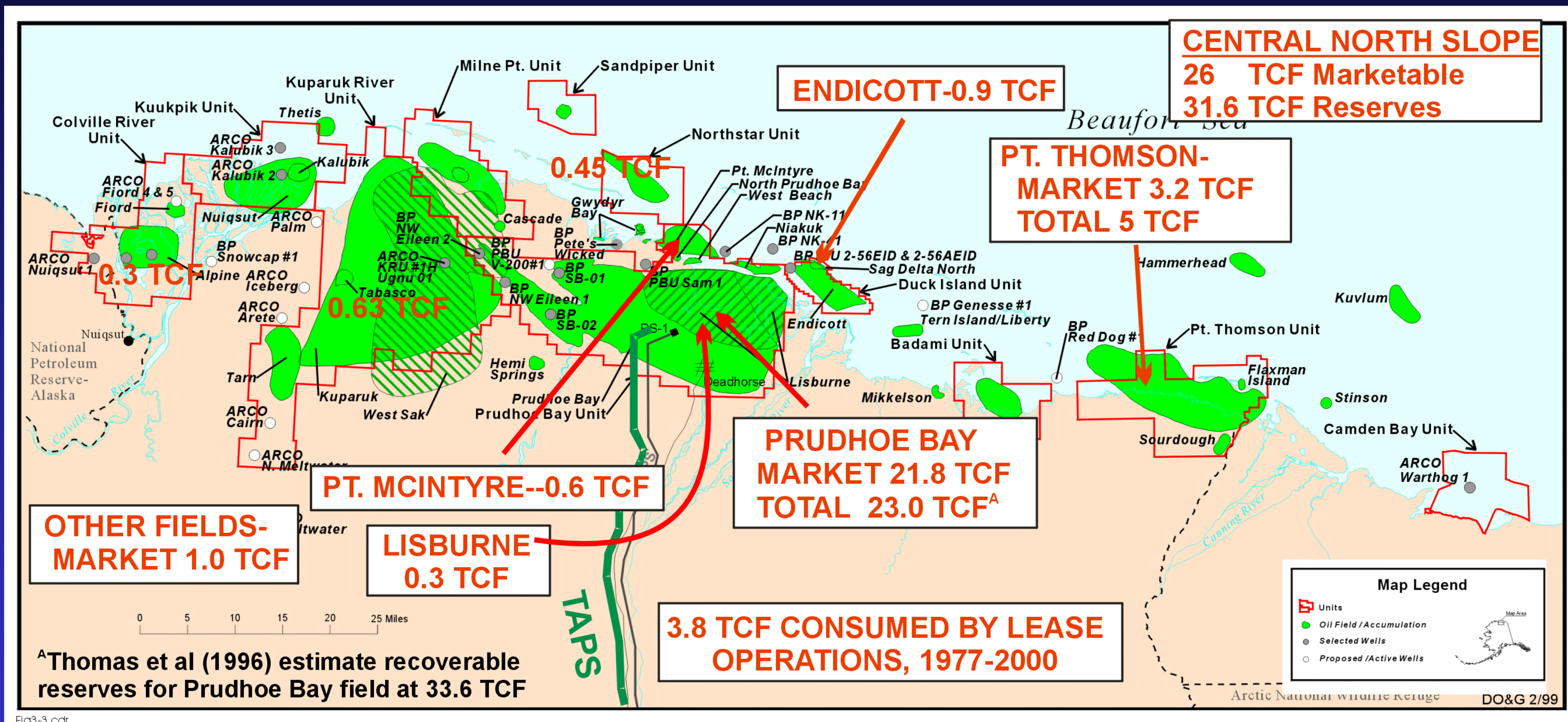
MARKETABLE AND TOTAL DISCOVERED GAS RESERVES



North Slope-26 TCF for Market



Marketable gas volumes from Thomas et al., 1996, tbl. 2.3

Map from State of Alaska, *http://www.dnr.state.ak.us/oil*

Recoverable (total) gas reserves from AKDO&G, 1998

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BACKGROUND ISSUES FOR NORTHERN ALASKA GAS DEVELOPMENT

- LOST OIL PRODUCTION?
- FUTURE OF OIL PIPELINE?
- EXCESS CAPACITY FOR NEW GAS?

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OIL PRODUCTION LOST IF GAS IS MARKETED TOO SOON

- Gas Sales Starting Year 2000: 0.9 Billion Barrels Lost
- Gas Sales Starting Year 2005: 0.4 Billion Barrels Lost
- Gas Sales Starting Year 2007: 0.2 to 0.4 Billion Barrels Lost
- Gas Sales Starting Year 2015: No Oil Lost

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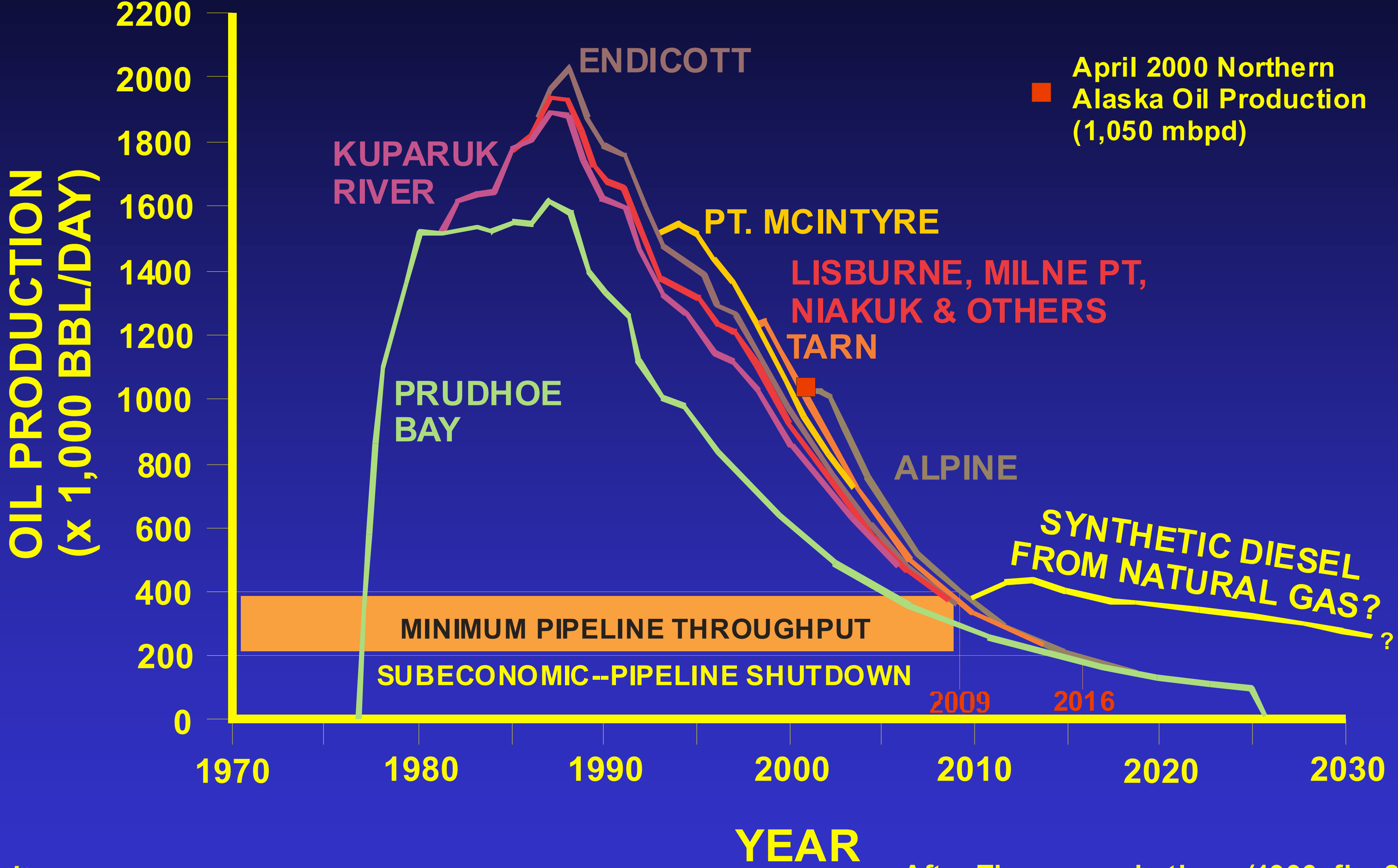
Sources: Meyers, 2000; Thomas and others, 1996, p. 2-13

IS PIPELINE SHUTDOWN IMMINENT?



After Thomas and others (1996, fig. 2)

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WHEN CAN NEW ARCTIC GAS GO TO MARKET?

- Gas export system will be sized to known reserves (26 tcf)
- New gas discoveries could remain stranded for decades

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SCHEMES FOR MARKETING OF NORTHERN ALASKA GAS

- **Pipe the gas to Canadian pipeline system, then to U.S.**
- **Pipe the gas to a southern Alaska port, liquefy (freeze) it, then ship it to Asia**
- **Convert the gas to diesel, then use existing pipeline and tankers to ship it to the U.S. west coast**

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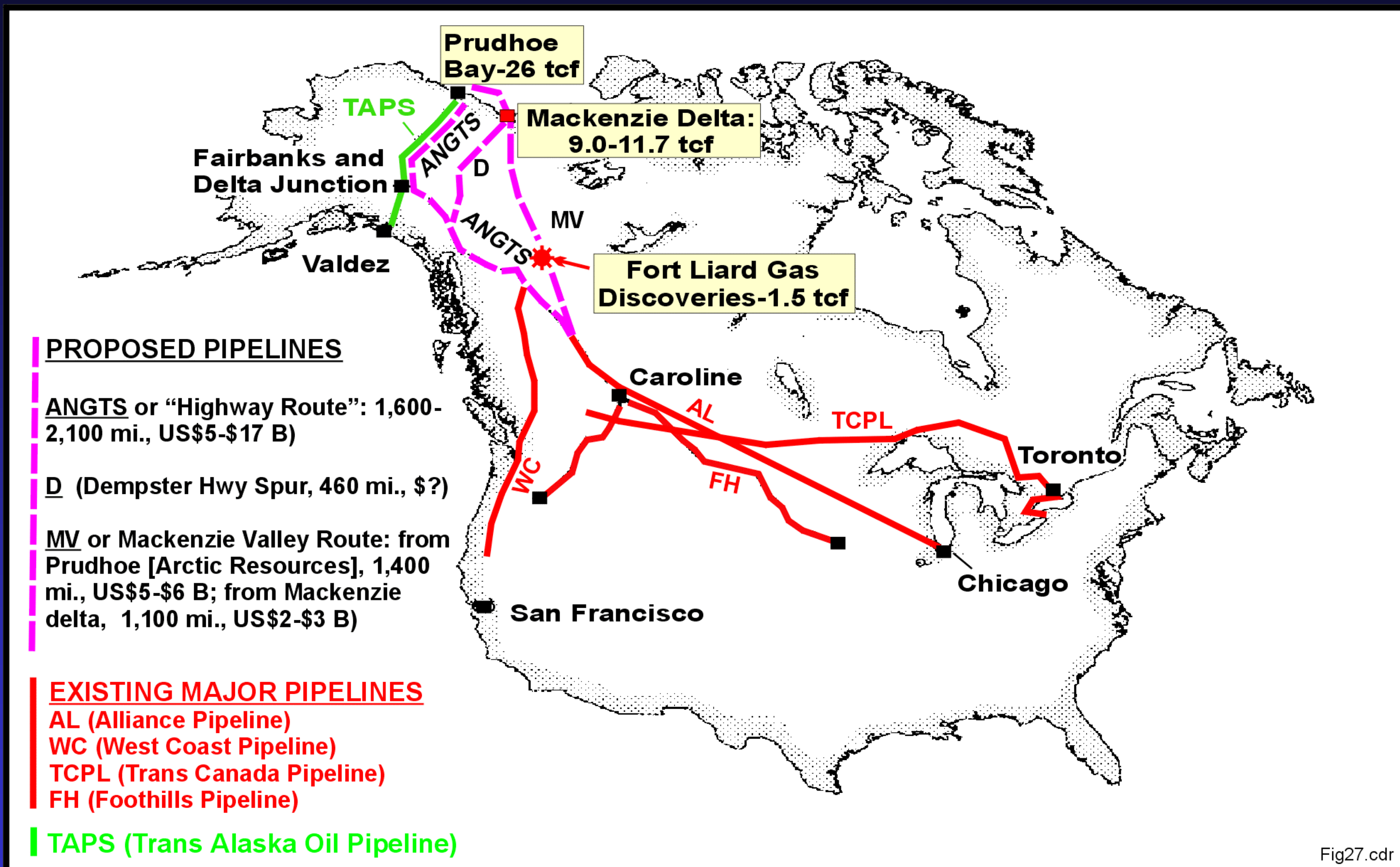
CANADIAN PIPELINE OPTIONS



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After Attanasi (1995) and Speiss (AND, 2000)

CANADIAN PIPELINE OPTIONS

Major Positives: Proven Technology
28+ TCF Market (2010)

Major Negatives: Price Volatility
High Costs?

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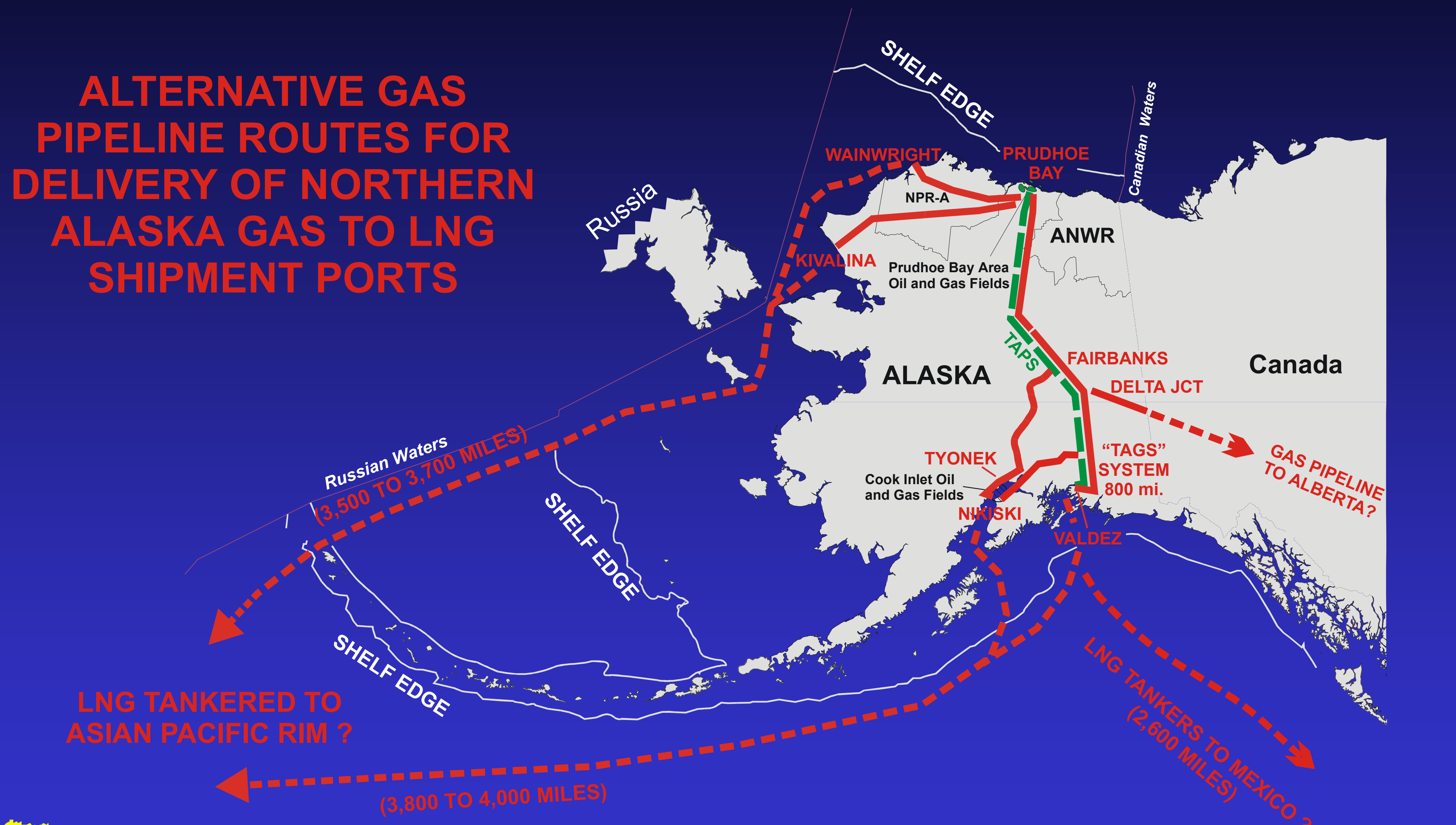
LNG TO ASIAN PACIFIC RIM



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WORLD LNG COMPETITION

VENEZUELA: PROJECT GAS 2000

- **146 tcf proven reserves**
- **2,400 miles to New York harbor**
- **Investor incentives: tax take 34% (vs 67% for oil)**
- **Two new LNG projects exporting 0.3 tcf/a to U.S. East Coast and Caribbean beginning in years 2004 and 2005**

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LNG TO ASIAN PACIFIC RIM

Major Positive: Proven Technology

Major Negative: Small LNG Market

Asian Pacific Rim Imports: 3.2 tcf in 1998

YPC LNG Model #1: 0.7 tcf per year
Model #2: 0.2 tcf per year
Model #3: 0.46-0.9 tcf per year
and ship some to Mexico

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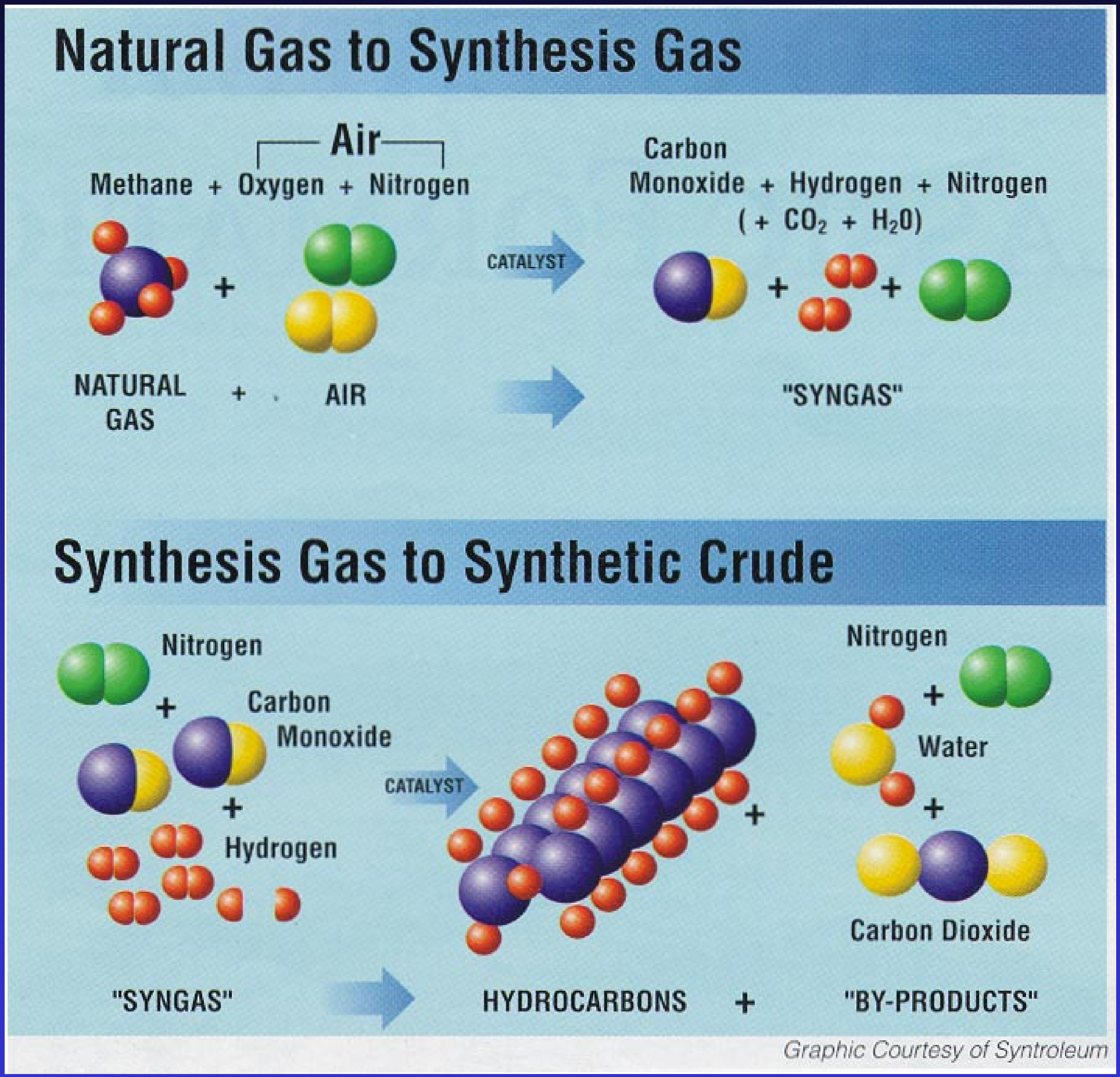
GAS TO LIQUIDS (GTL)



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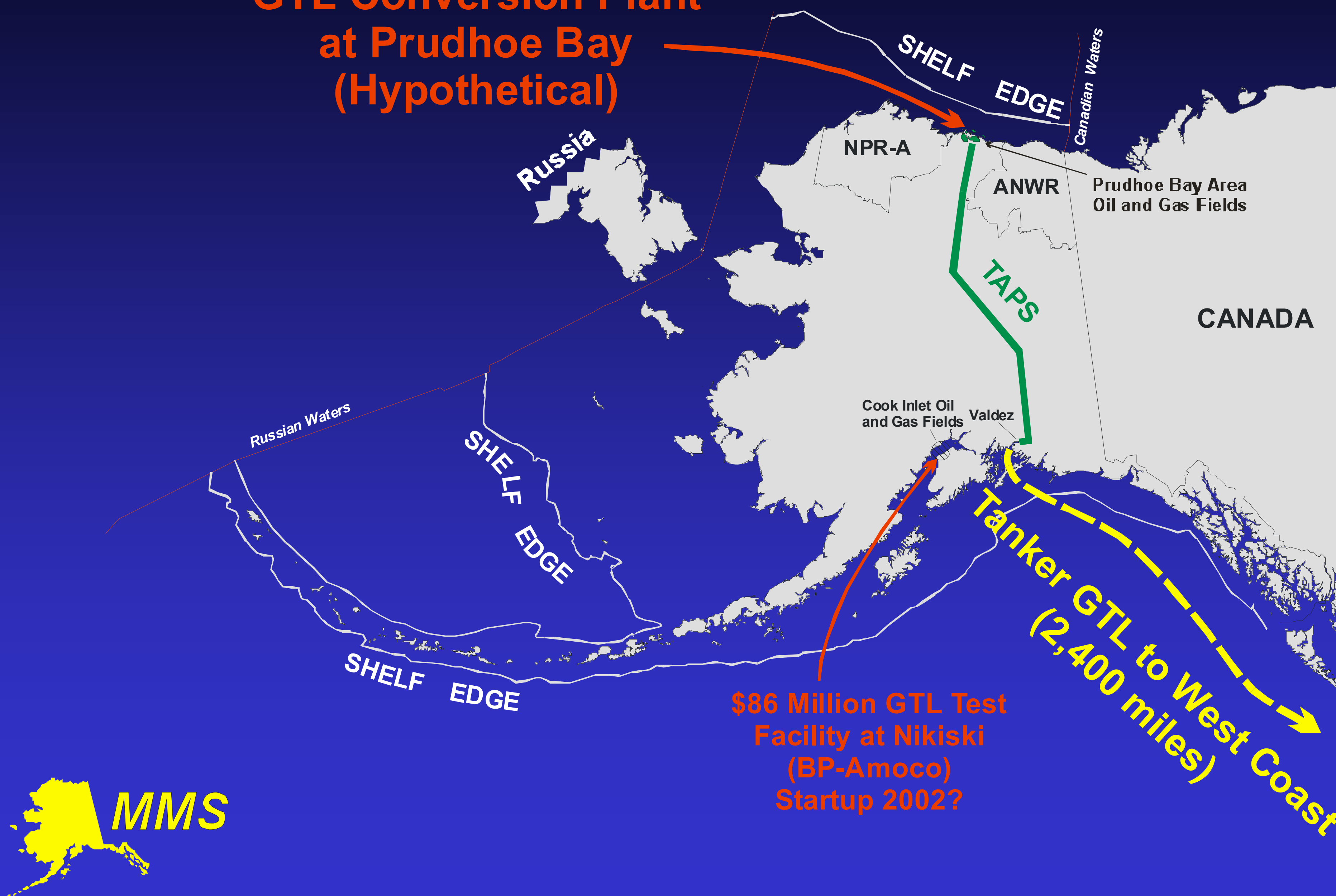
GAS TO LIQUIDS (GTL) EXPORT SYSTEM



THE GAS TO LIQUIDS (GTL) OPTION

Major Positives:

- Use Existing Transportation System
- Extend Operating Life of Oil Pipeline
- Large, Receptive Market

Major Negative: Unproven Technology at Commercial Scale

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ECONOMICS OF GAS EXPORT OPTIONS

PIPE TO U.S. VIA CANADA

- Delivery Costs $2.35[5]-$4.85[1]/mcf (in $2000)
- Chicago Gas in January 2001 >$9/mcf[2] (now >$5) and Socal Hub Spot Prices >$16/mcf ($2.50 in Jan 2000)

LNG TO ASIAN PACIFIC RIM

- DOE 1995 Breakeven (NPV_{10}=0) LNG Price = $4.39/mcf (in $2000)[4]
- Port Authority--0.7 tcfa--profitably delivered Japan for $3.10/mcf
- Japan Price Paid For Southern Alaska Gas = $4.50/mcf (December 2000)[3].

GTL FUELS TO U.S. WEST COAST

- Breakeven (NPV_{10}=0) World Oil Price = $23.23/bbl (in $2000)[3]
- World Oil Price = >$30/bbl (2000), now $23.07/bbl (31 Mar 01)[3]

[1] ANGTS (1995)
[2] O&G J online, 11dec00
[3] E.I.A Website, Apr 01
[4] DOE Model; Thomas et al. (1996)
[5] Meyers, Ziff. Conf. Oct 00

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CONCLUSIONS

- Given high sustained prices, significant offshore gas resources may be economic to develop.
- All gas export schemes are subject to risk from price volatility.
- U.S. energy politics will probably favor a pipeline through Canada accessing the lower 48, but economic viability is undemonstrated.
- Gas development in the Arctic offshore awaits North Slope gas development. 8-26 years before excess capacity.

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Gas Hydrates

Speaker

Tim Collett
U.S. Geological Survey

Speaker Biography

TIM COLLETT
RESEARCH GEOLOGIST
U.S. GEOLOGICAL SURVEY

Timothy Collett is a research geologist in the Geologic Division of the U.S. Geological Survey. He has been project chief of the North Slope of Alaska Gas Hydrate Project since 1985. Before joining the USGS in 1983, he was an instructor in the Petroleum Engineering Department at the University of Alaska. Most recently Collett was a co-chief scientist of an international cooperative gas hydrate research project that was responsible for drilling the Mallik 2L-38 gas hydrate research well in the Mackenzie Delta of Canada. Collett also sailed as the JOIDES Logging Scientists on the Ocean Drilling Program (ODP) Leg 164 gas hydrate research cruise. Collett holds a B.S. in geology from Michigan State University, a M.S. in geology from the University of Alaska, and a Ph.D. from the Colorado School of Mines.

GAS HYDRATES OF NORTHERN ALASKA

Timothy S. Collett
U.S. Geological Survey
Energy Resources Program
Box 25046, DFC, MS-939
Denver, CO 80225
Phone: 303.236.5731
E-Mail: tcollett@usgs.gov

The discovery of two large gas hydrate accumulations on the North Slope of Alaska near the Prudhoe Bay and Tarn oil fields have confirmed the possibility that gas hydrates may represent an important energy resource for the future. In review, 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. The volume of gas contained within the world gas hydrate accumulations is enormous, but estimates of the amounts are speculative and range over three orders-of-magnitude from about 100,000 to 270,000,000 trillion cubic feet. It is likely that the amount of gas in the hydrate reservoirs of the world greatly exceeds the volume of known conventional gas reserves. 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.

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 northwest part of the Prudhoe Bay Oil Field. Studies of pressurized core samples, downhole logs, and the results of formation production tests have confirmed the occurrence of three gas-hydrate-bearing stratigraphic units in the Northwest Eileen State-2 well. Gas hydrates are also inferred to occur in an additional 50 exploratory and production wells in northern Alaska based on downhole log responses. Most of these well-log inferred gas hydrates occur in six laterally continuous sandstone and conglomerate units; all of these gas hydrates 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 and downhole logs from wells in the western part of the Prudhoe Bay Oil Field indicate the presence of several large free-gas accumulations trapped stratigraphically downdip below four of the log inferred gas hydrate units. The gas hydrate accumulation along the western edge of the Prudhoe Bay Field is estimated to contain about 37 to 44 trillion cubic feet of gas.

Until recently, the gas hydrate accumulations along the western margin of the Prudhoe Bay Oil Field were the only known gas hydrate occurrences on the North Slope of Alaska. However, recently released data from wells along the western margin of the Kuparuk River Field reveals a relatively thick 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 (depth of about 720 m) possibly trapped below the base of the gas hydrate stability zone. Subsequent drilling of the Cirque-2 well confirmed the occurrence of gas hydrates in the area of the Cirque wells from a depth of about 250 m to 350 m. The gas-hydrate-bearing stratigraphic interval in the Cirque wells appears to be the up-dip equivalent of the West Sak and Ugnu sands which are estimated to contain more than 20 billion barrels of in-place heavy 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-Cirque Gas Hydrate Accumulation" may be much larger than the "Eileen Gas Hydrate Accumulation" located along the western margin of the Prudhoe Bay Field.

A growing body of evidence suggests that a huge volume of natural gas is stored as gas hydrates in northern Alaska and the 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.

Session II

Moderator

Teresa Imm
Arctic Slope Regional Corporation

Cook Inlet Coalbed Methane Potential

Speaker

Charles Barker
U.S. Geological Survey

Ongoing Coalbed Desorption Studies, Cook Inlet Basin, Alaska

by Charles E. Barker , Todd A. Dallegge (USGS, Denver and Fairbanks) and Dan Seamount (Alaska Oil and Gas Conservation Commission)

Abstract: Analysis of core and cuttings from nine wells around the northern edge of the Cook Inlet basin, Alaska, indicate 50 to 250 standard ft³ (SCF)/ton of biogenic and thermogenic coalbed methane (CBM). The apparent CBM potential is large: reports indicate up to 175 ft net coal thickness in portions of the basin buried at<6000 ft. deep.

The sub-bituminous coalbeds in the central and southern portions of the Cook Inlet basin contain, an average 60 scf/ton based on desorption of cuttings (dry ash-free basis, DAF). Reports suggest 750 billion tons of pure coal equivalent in these areas and simple calculation leads to a geologically indicated 45 trillion cubic feet (TCF) of gas in place (GIP). Adding a correction of 25% for cuttings gas content data to make it comparable to core data suggests about 60 TCF GIP. The higher rank coalbeds found in the Matanuska-Susitna (Mat-Su) Valley area contain about 350 billion tons with a gas content that averages 230 SCF/ton DAF based on desorption of core and cuttings data corrected to core equivalents. This geologically indicated resource is about 80 TCF GIP.

The indicated total Cook Inlet CBM resource estimate is about 140 TCF gas in place. If 10% of this resource is accessible for production and 50% of the accessible resource is recoverable, then the geologically indicated reserve is about 7 TCF. This is a 30 year supply to South-Central Alaska based on the current 220 BCF/yr consumption.

Slide: 1

Introduction

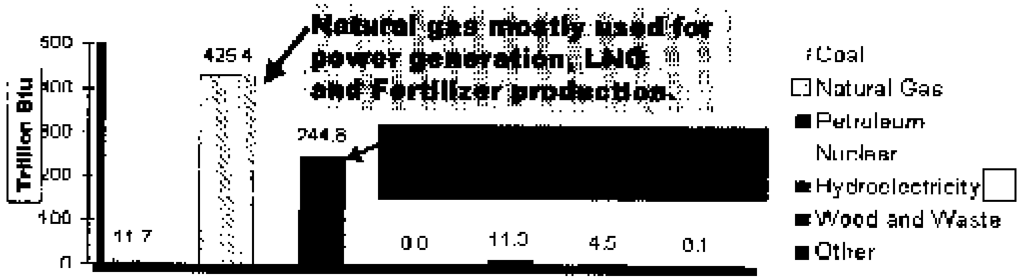
A major energy issue in the South-Central Alaska area is whether there is enough natural gas in coalbeds to justify development. South-Central Alaska is strongly dependent on natural gas for heating and electricity (slide 3) and faces energy shortages of natural gas (NG) due to declining production capacity and a lack of storage capacity. The NG supply problems are influenced by a lack of exploration incentive caused by the nation's lowest gas prices (slides 4 and 5). The low price is seemingly controlled by long term contracts and a relatively non-competitive marketing area limited to local area use, export as LNG, or as fertilizer made from natural gas. In 1998 there was some 2.15 to 2.95 trillion cubic feet (TCF) of producible conventional gas reserves. South-Central Alaska gas use is now about 220 BCF/ year. Thus, these 1998 reserves will apparently be depleted in 10 to 14 years (2008 to 2012) if new sources are not found (slide 6).

Although the reserves of natural gas in conventional traps is well known in the Cook Inlet, coalbed methane (CBM) reserves associated with the conventional gas fields are poorly known. Reports indicate Alaska contains widespread coal reserves, especially in the Cook Inlet and North Slope basins (slide 7), where a conventional oil and gas infrastructure is in place. Thus, CBM developed in the Cook Inlet basin could possibly use the existing infrastructure to rapidly develop and deliver new gas (slide 8).

Our project addresses the CBM reserve issue by measuring gas content in just-retrieved gas-bearing coal samples using canister desorption and the modified Bureau of Mines methods. We sampled coal cores and cuttings from wells drilled solely for CBM testing and also gleaned samples from oil and gas tests that drilled through shallow coalbeds (slide 8).

Slide: 2

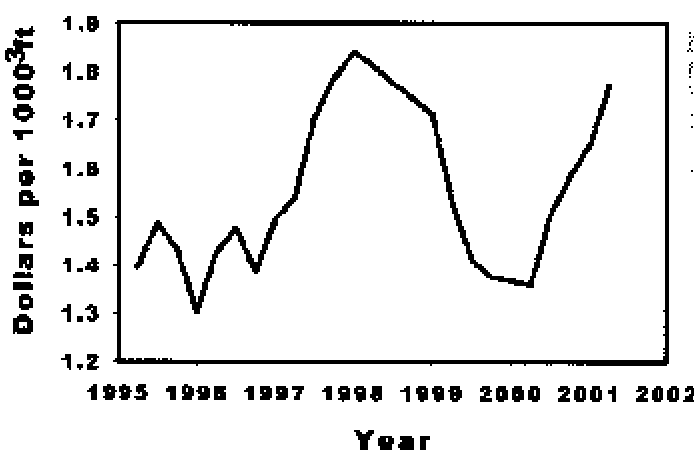
Energy Sources, Alaska, 1997



- At times of peak demand, spot gas shortages could occur by 2003 to 2005.
- Reports attribute initial shortages to a limited gas storage capacity
- In the future: shortages due to reduced production capacity

Slide: 3 *Data Source: EIA (2001) http://www.eia.doe.gov/emeu/sep/ak/*

[illegible]



- Delivered gas price approximately twice the City Gate price
- Long term contracts appear to control price
- Commercial users first to shut down during shortages

Data Source: AK Tax Revenue Division

Slide: 4

Alaska's Energy Prices & State Ranking (1997, in Dollars per Million Btu)

	Alaska	USA	Rank
All Energy	6.69	8.82	48
Gasoline	11.91	9.73	2
Petroleum	6.93	7.82	48
Natural Gas	2.07	4.62	51*
Coal	2.18	1.31	4
Electricity	29.57	20.15	8

* Includes Puerto Rico

Source: EIA (2001)

Slide: 5

Cook Inlet Gas Proven Reserves 1998

Source	Developed (BCF)	Undeveloped (BCF)	Years to Depletion*
Phillips-Marathon	2494	85	11.3 (11.7)
AK DNR	2947	119	13.4 (13.9)
UNOCAL	2277	528	10.4 (12.7)
ENSTAR	2150	286	9.8 (11.1)

*at the current 220BCF/yr rate of consumption. Value in parentheses includes undeveloped reserves but no reserve growth or new discoveries

Data Source: DOE Opinion and Order no. 1473 (1999)

Slide: 6

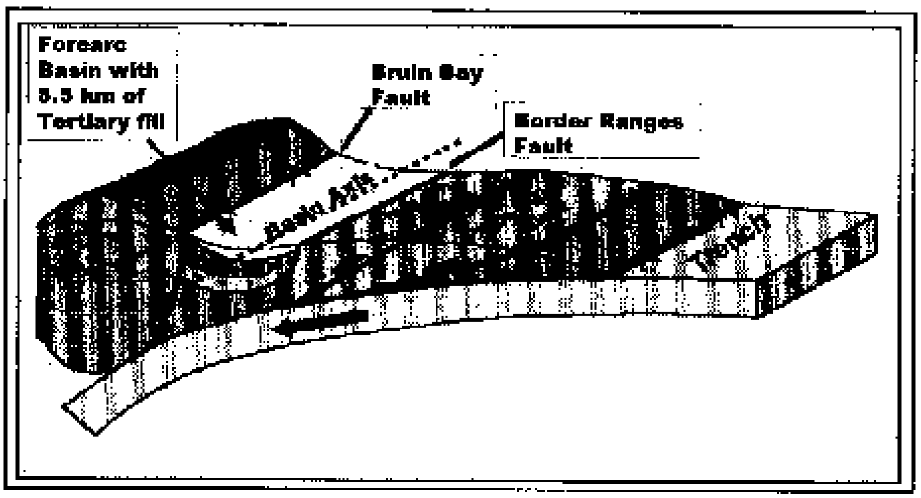
Cook Inlet Basin CBM Geology

The Cook Inlet Basin is an elongate, northeast-trending, fault-bounded forearc basin that contains 28,000 feet of Tertairy terrestrial sediment (Swenson, this volume; Slide 14). The basin is characterized by marginal alluvial fans feeding an axial fluvial depositional system. Rapid infilling of the basin is indicated by laterally discontinuous, interfingering beds of sandstone, siltstone, conglomerate, and coal (Slide 15). Coal bed methane production is strongly dependent upon the thermal maturity and depth to the coal bed. Optimal coal bed methane generation, maximum storage capacity occurs at a starting vitrinite reflectance value of 0.6 %Ro (Slide 16). Coalbeds, because of their plastic nature, tend to lose permeability and have non-economic production levels below a depth of about 6000 ft. These thermal maturity and depth to coalbed criteria suggest the most prospective areas of the Cook Inlet basin are to the north in the Mat-Su Valley area and to western and southern edge of the basin where coals are found at less than 6000 ft depth (Slide 16).

The Cook Inlet basin contains two basic types of CBM prospects: 1) thick immature coals of the Beluga and Tyonek Formations in the western and southern portions of the basin; and 2) thick mature coals of the Mat-Su valley area. So far we have identified only 1 ft to perhaps 15 ft thick, locally-discontinuous coals in the Sterling Formation. The generally immature Sterling coal, along with the deeply buried Tyonek coal onshore or offshore, and any coal remote to existing NG pipelines, are not thought prospective under current market conditions.

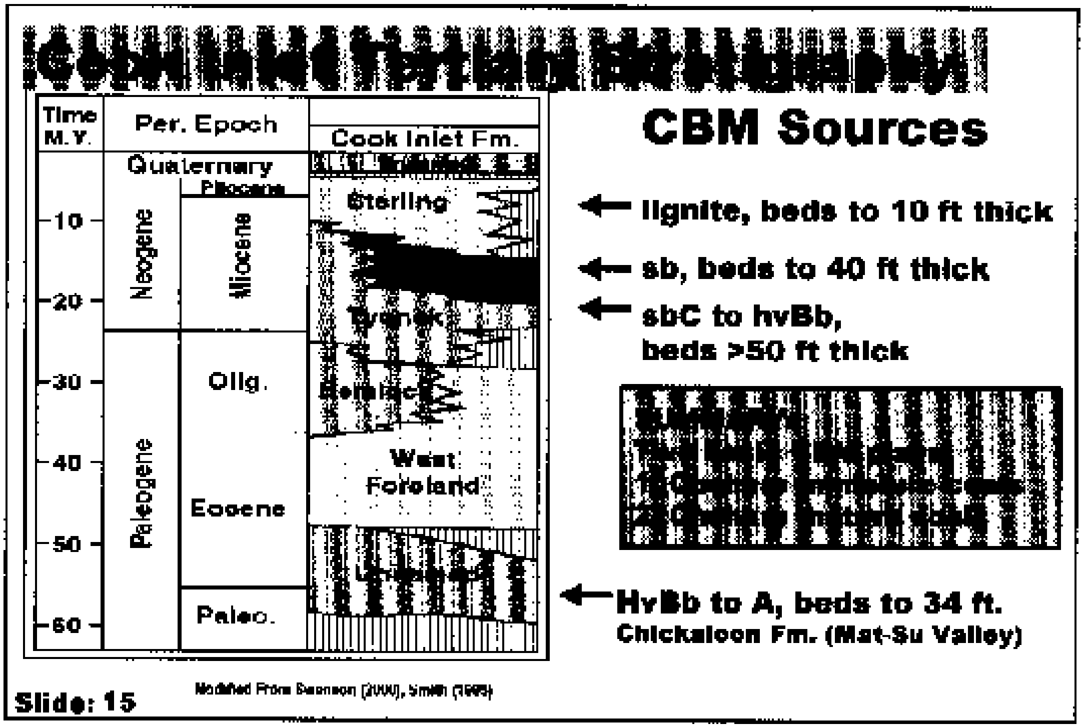
Slide: 13

Tectonic Regime, Cook Inlet, Alaska

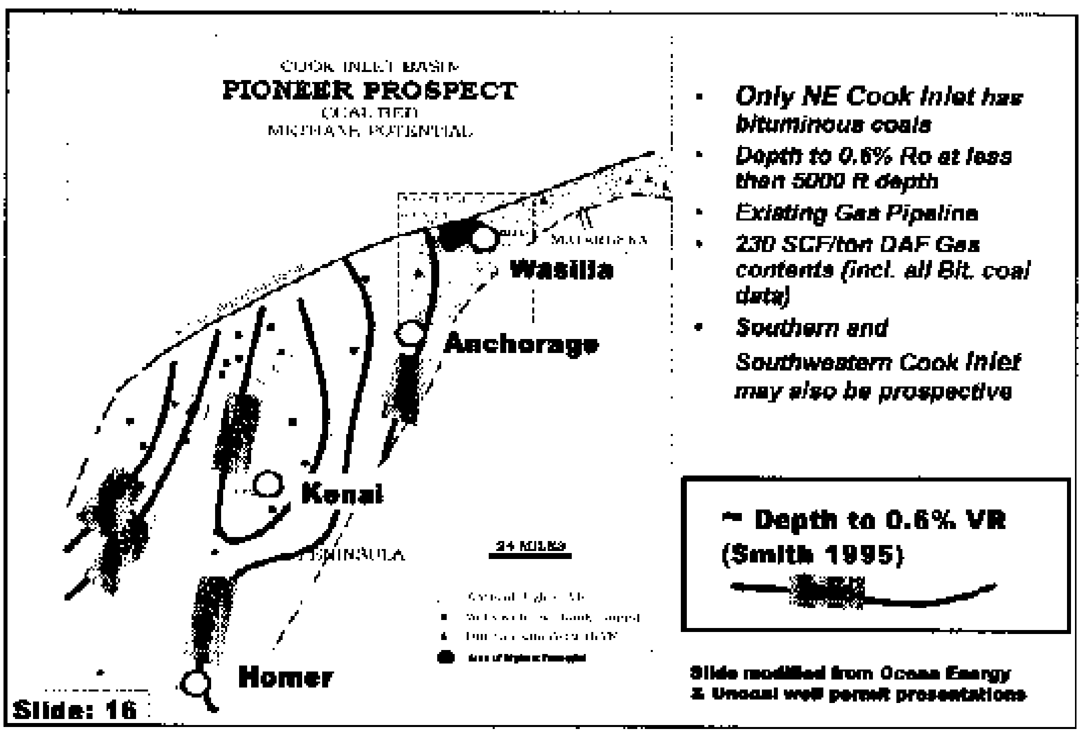


Modified from Doherty et al. (1994) and Swenson (2000)

Slide: 14



CBM Sources
Time M.Y.
Per. Epoch
Cook Inlet Fm.
Quaternary
Pliocene
Neogene
Miocene
Paleogene
Olig.
Eocene
Paleo.
Sterling
West Foreland
-10
-20
-30
-40
-50
-60
lignite, beds to 10 ft thick
sb, beds to 40 ft thick
sbC to hvBb,
beds >50 ft thick
HvBb to A, beds to 34 ft.
Chickaloon Fm. (Mat-Su Valley)
Slide: 15



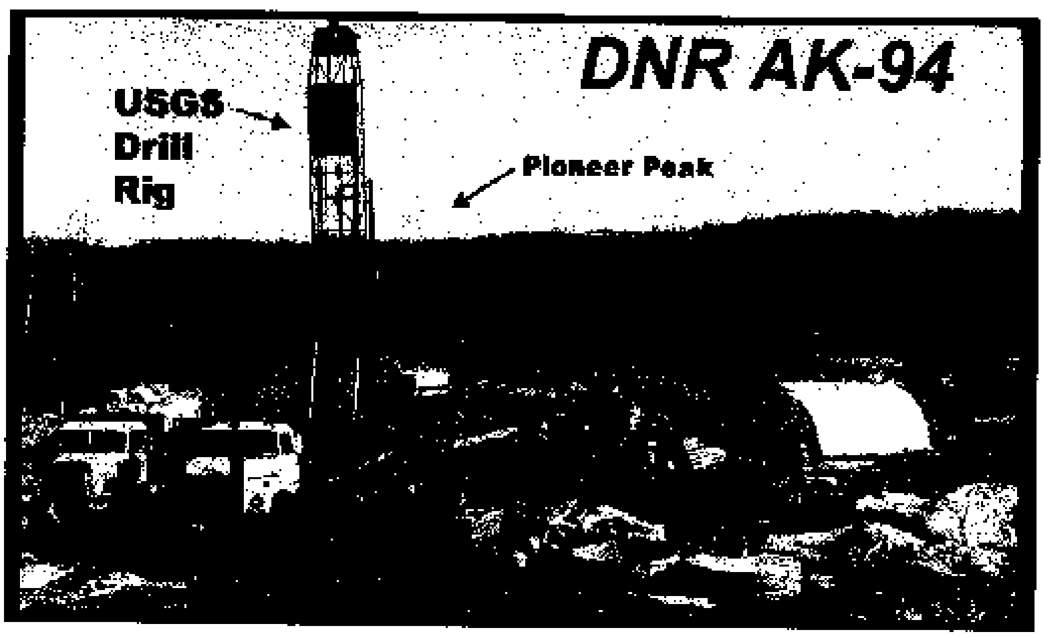
COOK INLET BASIN
PIONEER PROSPECT
COAL BED
METHANE POTENTIAL
Wasilla
Anchorage
Kenai
Homer
24 MILES
• Only NE Cook Inlet has bituminous coals
• Depth to 0.6% Ro at less then 5000 ft depth
• Existing Gas Pipeline
• 230 SCF/ton DAF Gas contents (incl. all Bit. coal data)
• Southern and Southwestern Cook Inlet may also be prospective
~ Depth to 0.6% VR
(Smith 1995)
Slide modified from Ocean Energy & Unocal well permit presentations
Slide: 16

A Brief History of Cook Inlet CBM Exploration

The Alaska Department of Natural Resources AK-94 well, cored and desorbed in cooperation with the USGS, was the first CBM test well drilled in Alaska (Slide 18). Desorption tests of core from this well used USGS canisters and methods modified for improved temperature control. The results of this test indicating 40 net feet of coal at less than 1300 ft depth are averaging about 160 SCF /ton DAF (Slide 19). Documentation of gas-bearing coals in the Mat-Su valley was seminal in the subsequent CBM developments at Houston prospect and the Pioneer Unit. The location of these developments was controlled by apparently gas-bearing coal near the surface and a play area crossed by the major natural gas pipeline supplying South-Central Alaska (Slides 20 and 21). Analysis of isotherm and desorption data from Pioneer prospect core indicates that the Tyonek bituminous coal is saturated (Slide 22) with a mixed thermogenic and biogenic methane source (Slide 23).

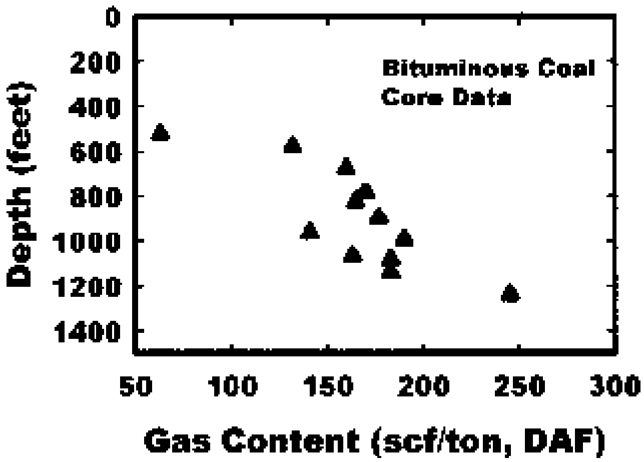
In 1997, measurements by the Forcenergy, UNOCAL and USGS of immature sub-bituminous CBM potential at the Coffee Creek 1 well indicate that the coals there may not be saturated (slide 24); possibly due to the effect of uplift and cooling (Slide 25) or to under-estimating gas content from cuttings. The CBM at Coffee Creek appears to have a biogenic origin (Slide 23). The concern is that under-saturated coals can require pumping large volumes of water to make the reservoir pressure decrease to the critical desorption point (Slide 25) for gas production. Water chemistry and disposal of the large amounts of produced water would be problematic (Slides 26 and 27).

Slide: 17



Slide: 18 **Photo by Smith, AK DNR, 1994**

AK-94 Desorption Data

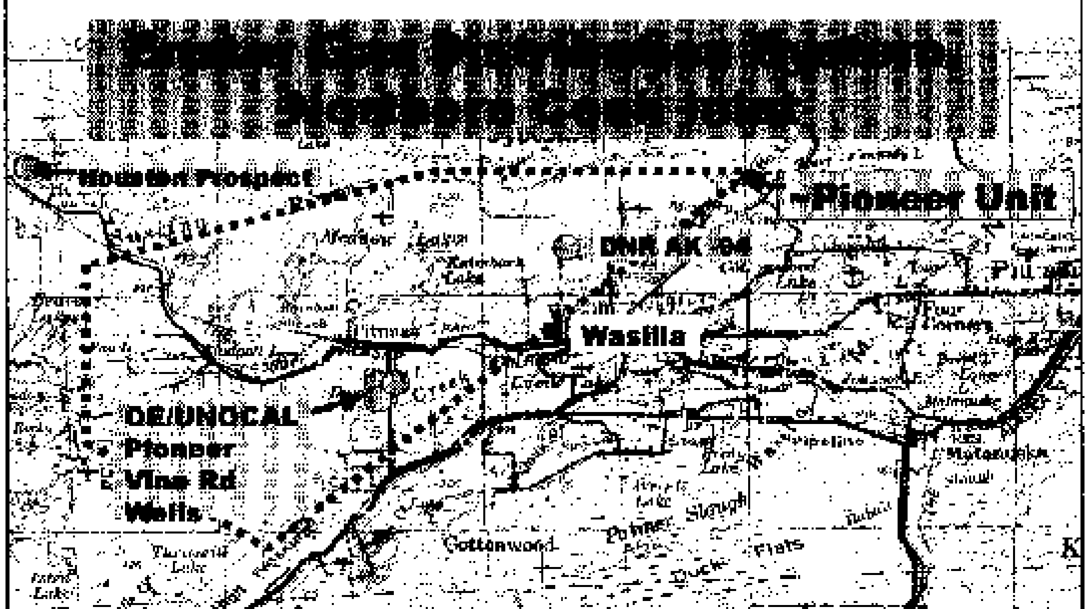


Key Results:

- 40 net feet of coal
- < 1380 ft depth
- Mixed Biogenic and Thermogenic gas
- Averages about 160 SCF /ton DAF

Data from Smith (1995) and AK Div. O&G files

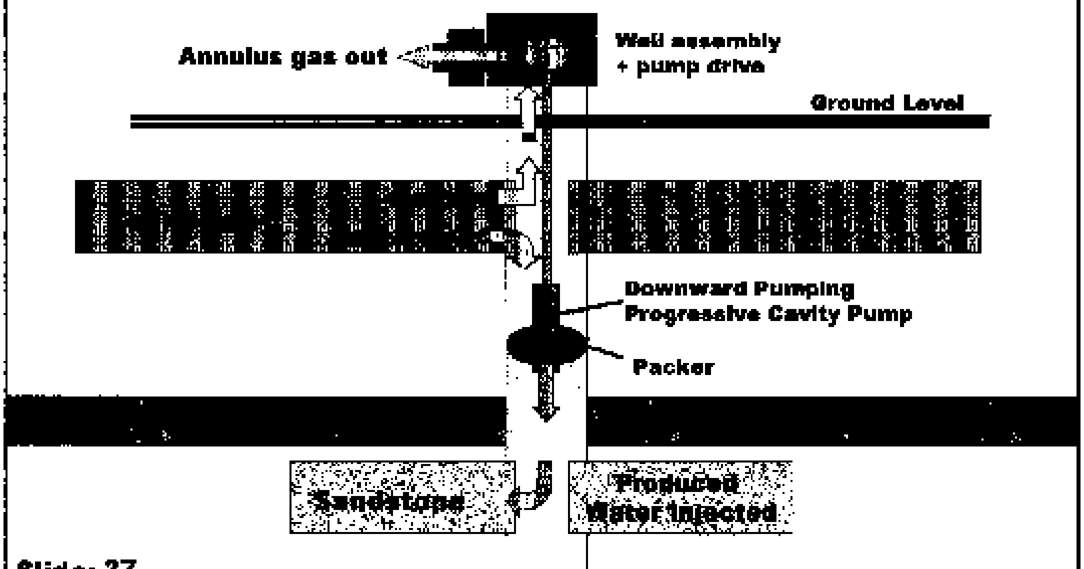
Slide: 19



Base pipeline map from Lapp Resources, Inc.

Slide: 20

GRI/Lappi Well Completion Concept



Slide: 27

Discussion:
Cuttings vs. Core to Estimate CBM Gas in Place?

Gas contents based on coal cuttings are typically (always?) low compared to values obtained from core or pressure core samples (Nelson, 1999; among others). The gas content appears to be lowered primarily because of sample contamination with drilling additives and admixture with caving materials as the cuttings are pumped up-hole. We also believe a major problem with cuttings is that the finer sizes of coal grains cut from the relevant seam are so small that complete gas diffusion is a rapid process and they lose all of their gas content while in the hole. These fine bits of now of dead coal (all gas lost on the trip up the well) plus the well contamination, when placed in the canister do not contribute gas; but they are included in the coal mass measured in the canister. Because gas content values are reported normalized to coal mass, those values that include dead coal or well contamination will be too low.

Unreleased data from Cook Inlet basin on gas contents from core with cuttings data that include a 25% correction show that the data fields overlap. The overlap suggests that the corrected cuttings data are comparable with the core data and apparently useful in estimating CBM gas content.

Slide: 28

Discussion: Comparison of CBM Basins

Basin	Gas in Place (TCF)	Avg. Prod. (Mcfd/well)	Coal Rank	Typical Net Coal: Thickest bed (in ft)	Typical Desorption Time	Typical Gas Content (scf/ton)
San Juan	84	2000	hvb - Lvb	70:(50)	months	430
Raton	99	140	hvCb -mvb	40-70(<10)	weeks	2-500
Uinta	10	690	Sb - Hvb	24	weeks	400
Cherokee	6	100	Hvb	4	?	200
Black Warrior	20	100	Hvb - Lvb	25	?	350
Central Appalachian	5	120	Hvb - Lvb	11	?	250
Powder River	40	250	Sb	75	weeks	30
Cook Inlet (Bit.)	80	None (Yet)	Hvb - An	100's (30)	3 months (core)	230 bit.
Cook Inlet (Subbit)	115	None?	Sb	100's (30)	2 months (cuttings)	80 sb

Slide: 29 Base table from Nelson (1999); Cook Inlet data from unpublished sources

Cook Inlet CBM: Summary

- **Gas contents and net coal thickness are similar to producing CBM basins**
- **However, some sb coal beds appear to be undersaturated**
- **350 billion tons of pure bituminous coal so far averaging ~ 230 SCF/ton DAF of thermogenic gas = 80 TCF**

  (Note pure coal = in situ coal reserves minus an estimated mean 25% ash yield)
- **750 billion tons of pure subbituminous coal averaging ~60 SCF/ton DAF of biogenic gas = 45 TCF and corrected to core equivalents = 60 TCF**
- **Total geologically indicated CBM ~140 TCF gas in place**
- **Production and reinjection infrastructure in place**
- **In 1998, 2.15 to 2.95 TCF of conventional gas reserves.**
- **At 220 BCF/ year consumption, conventional gas reserves in south-central Alaska will apparently be depleted in 10 to 14 years (2008 to 2012).**

Slide: 30

Acknowledgements

Government Collaborators

J. Clough (AK DNR-DGGS), R. Tingook (USGS) &
V. Webb (AK DNR-DGGS)

Corporate Collaborators

Ocean Energy, Forcenergy (now Forest),
Unocal, Phillips, Marathon

Independent Geologists and Engineers

R. Downey, N. Waechter, D. Lappi and M. Belowicz

Slide: 31

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Slide: 32

Cook Inlet Coalbed Methane Potential

Speaker

Daniel Seamount
AK, Oil & Gas Cons.
Committee

Pioneer Coal Bed Methane Project

Play to Execution

3.6 TCFG GIP

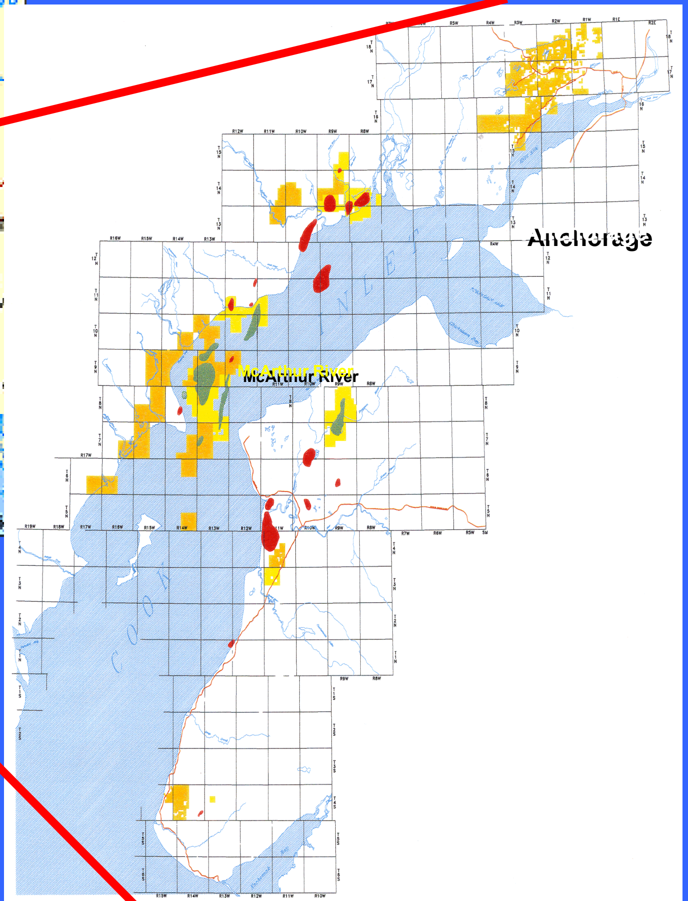
D. Seamount (AOGCC, formerly Unocal), Faye Sullivan (Unocal), T. Brandenburg (Unocal), R. Crandall (AOGCC), K. Tabler (Unocal), R. Downey (Independent, formerly w/ Ocean Energy), Debra Childers (Unocal), Steve Carson (Unocal), Larry Smith (Unocal), C. Barker (USGS), Dan Thomas (Unocal), R. Cross (Unocal), G. Pavia (Lynx Enterprises, Inc. formerly of DGC)

Pioneer Project- Play to Execution

- **Play Phase- Unocal/Marathon & Others- 1989 to 1995**
- **Hiatus 1995 to 1997**
- **Exploration Phase- Unocal, 1997 to 1999**
- **Permitting Phase- Unocal 1999 (6 months)**
  - **Alaska Division of Governmental Coordination (surface environment)**
  - **Alaska Oil & Gas Conservation Commission (subsurface environment)**
- **Drilling Phase- Ocean Energy/Unocal 1999- 2000 (4-5 months)**
- **Test Phase (Confidential/incomplete?)–Ocean Energy/Unocal**
- **Future?**

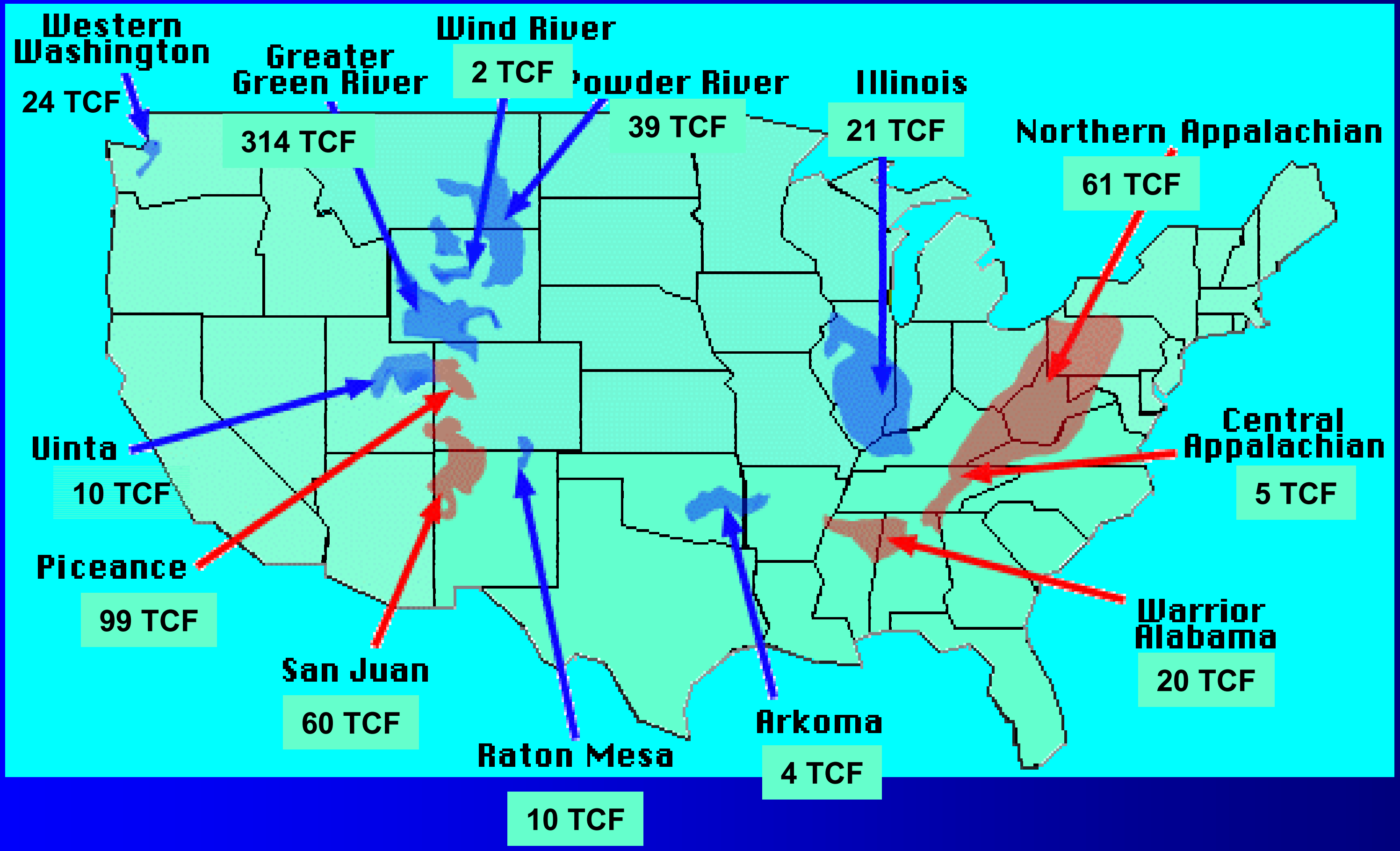
Cook Inlet Basin

Located in S. Central Alaska



Pioneer Prospect
Coal Bed Methane

Unconventional gas play proven in L48 and elsewhere (mid 90's view)



Pioneer Project- Play to Execution

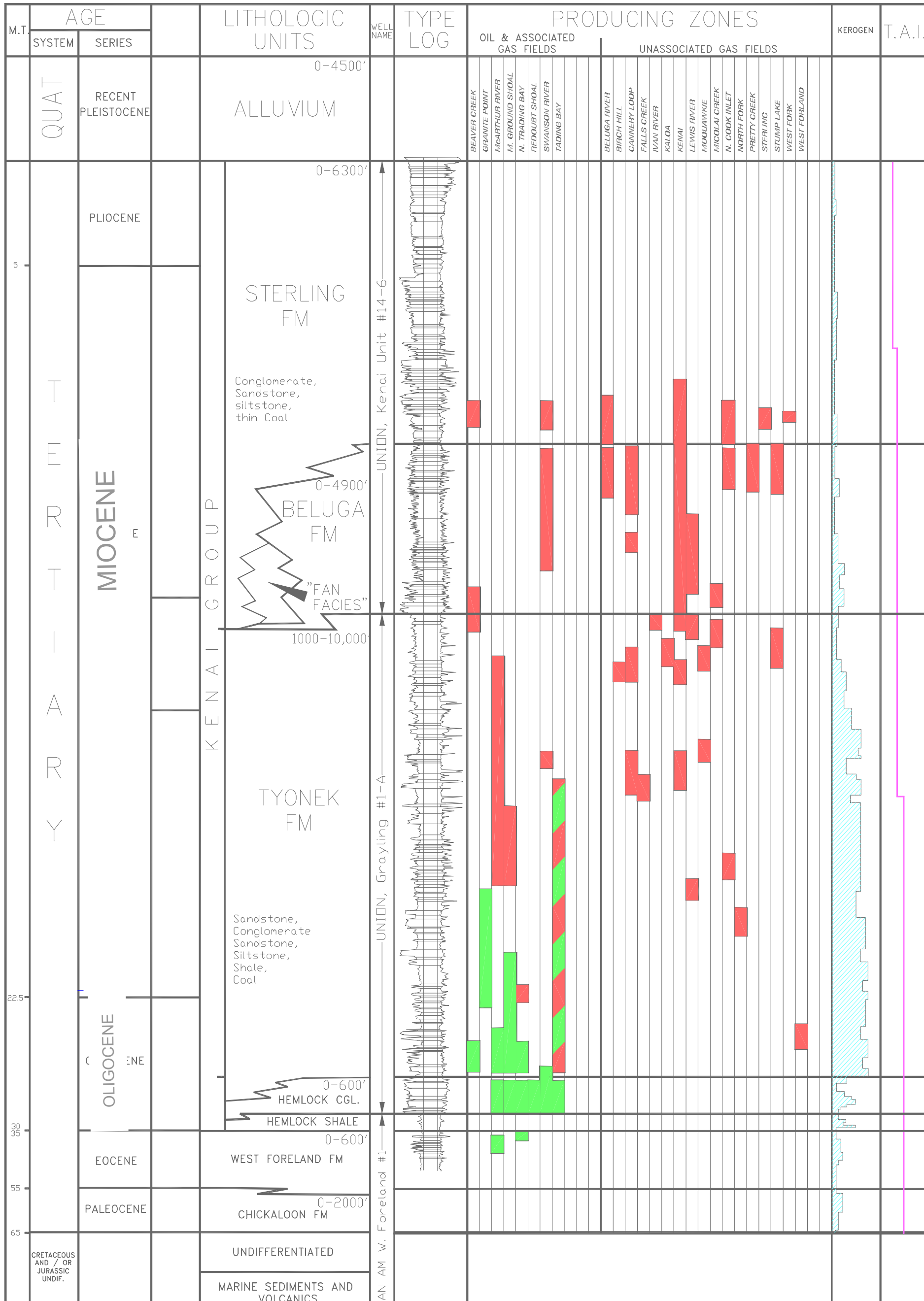
Play Phase- Unocal/Marathon- 1989 to 1995

- Regional work- Abundant CI Coal- VR, Wireline and Mud logs, net coal isopach & structure maps

- DNR CBM evaluation well (AK-94-1)
  - Relatively High Gas Content in Mat-su Valley; Gas Content increased from 63 cu-ft/ton @ sl to 245 cu-ft/ton @ -745'

- Leasing- Dept of Natural Resources (DNR), Fee, & Native 50,000+ Acres

100's of Tertiary coal seams in Cook Inlet

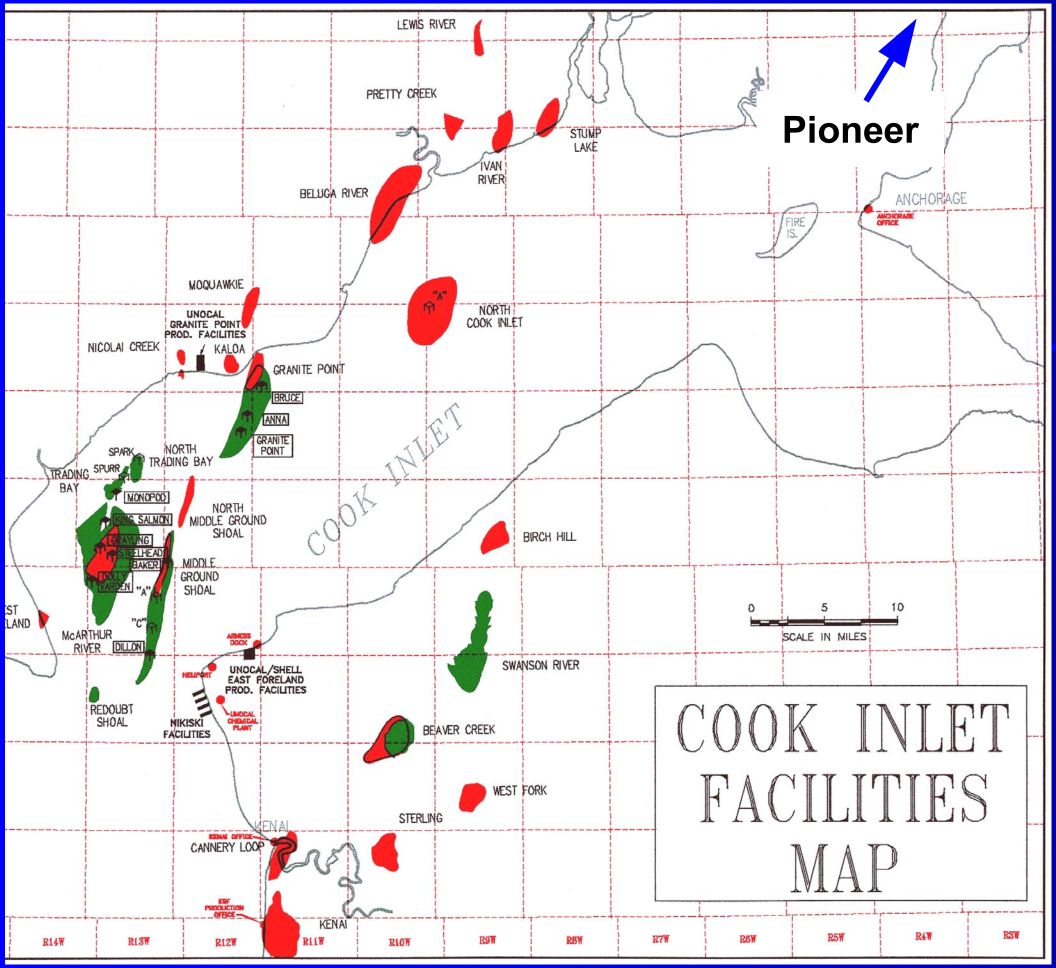


Absent AT Pioneer

- Upper Tyonek and younger sediments have been truncated in Mat-Su Valley
- Lower Tyonek with higher coal maturity preserved

COOK INLET STRATIGRAPHIC CHART

Pioneer Prospect
Coal Bed Methane



Coal is the source of up to 7.7 Tcf of Cook Inlet's 8.3 Tcf "conventional" gas

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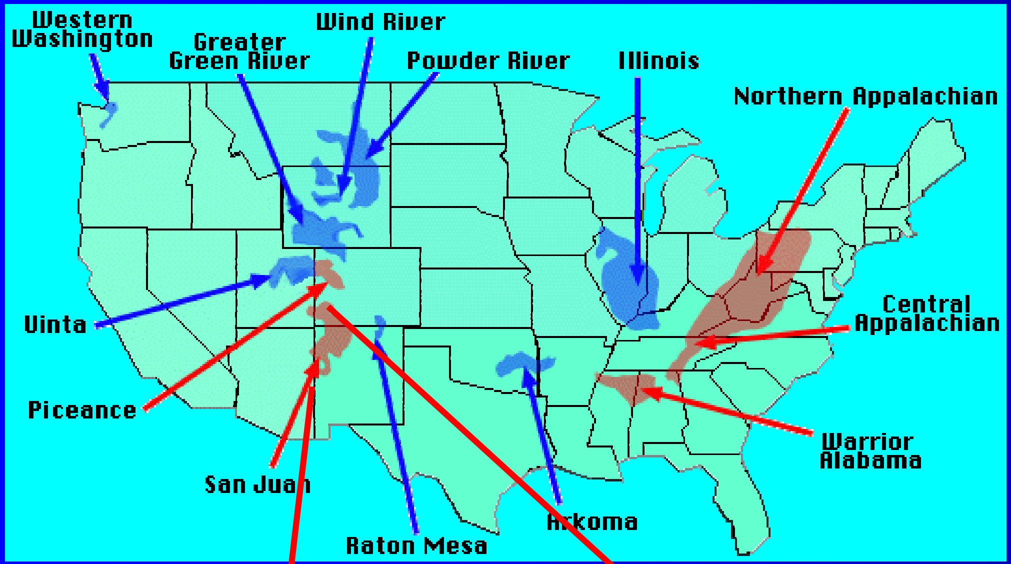
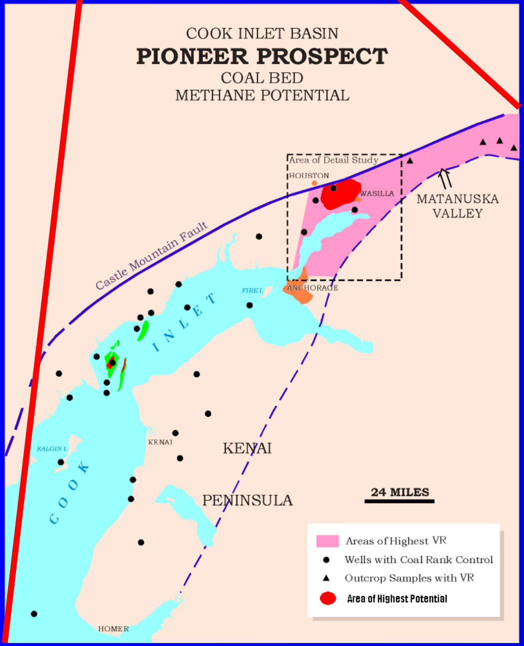
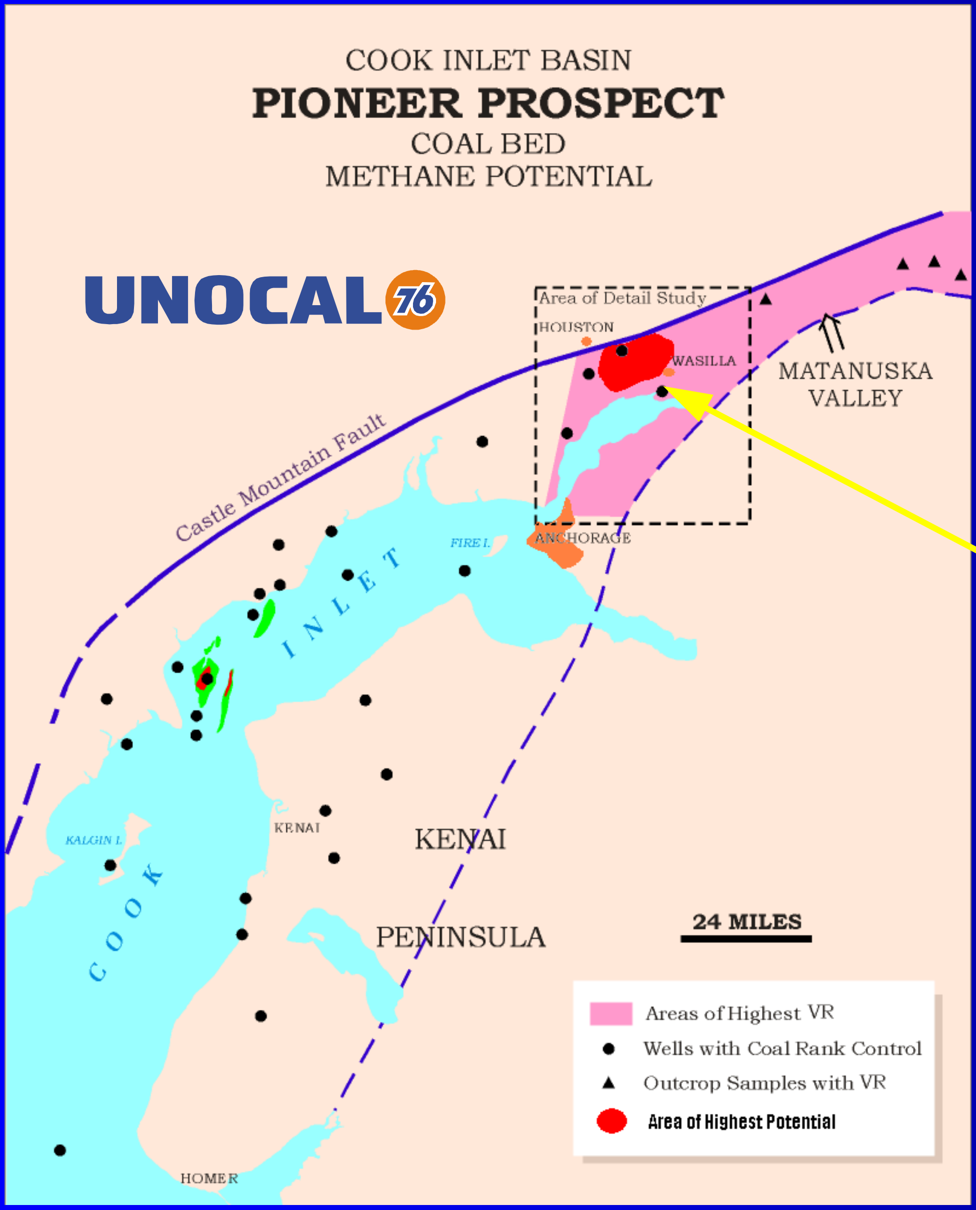
Pioneer Prospect Coal Bed Methane





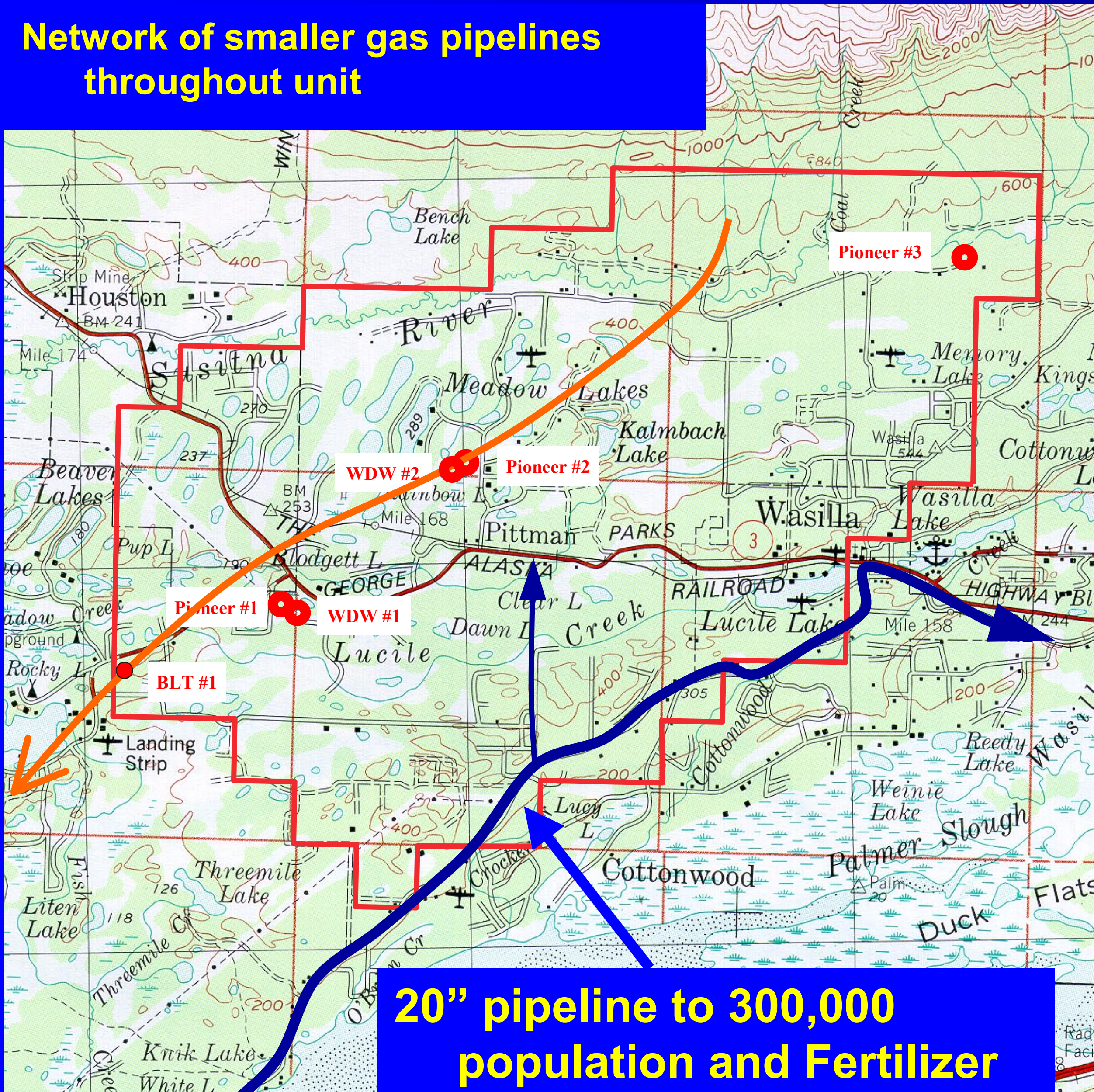
- 669 TCF GIP L 48 with production in 8 of 12 Basins
- 245 TCF GIP Cook Inlet 1/3 as much as entire lower 48 (mid 90's USGS Estimate)
- Area same size as San Juan Basin but 4X GIP (90's estimates)



- Located in NE Cook Inlet in area of maximum coal maturity
- Testing 72,000 acres (.8% of Coal Basin)
- If successful, could extend to rest of the Basin
- Unocal & MOC Leased ~50,000 acres in Mat-Su Valley- 1989 to 1995

Market Accessibility

Network of smaller gas pipelines throughout unit



20” pipeline to 300,000 population and Fertilizer and LNG plants

Axis of Pittman Anticline

1990’s Proposed CBM Well Location

Good Accessibility to Drilling Locations

6 miles

Pioneer Project- Play to Execution

Hiatus 1995 to 1997

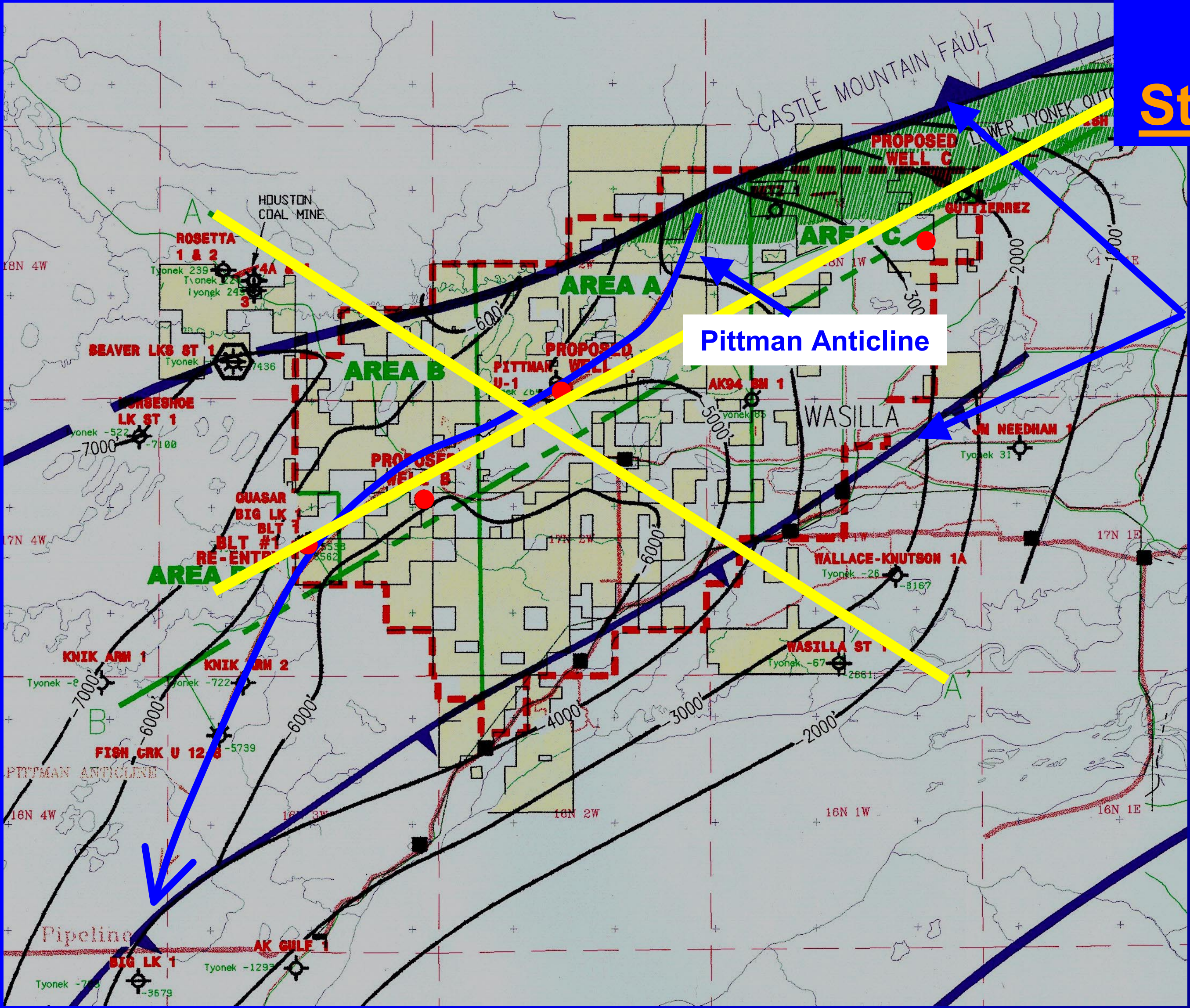
- Exploration De-emphasized
  - Dropped 5000+ acres in Pioneer

Pioneer Project- Play to Execution

Exploration Phase- Unocal, 1997 to 1999

- Structure, Gross Isopach, Net coal, VR & Net Coal Cut off maps refined for prospect focus
- Seismic Purchase & Evaluation
- Geochemical Analyses- C/O, Maturity
- Analogies- Raton Basin, Drunkards Wash
- Leasing & Unitization
  - DNR, FEE, Native
  - Unocal acquires MOC & other's interest
  - Total- 70,000+ Acres
  - Plan of Exploration- DNR Division of Oil & Gas

Tectonic & Structural Setting



Base Tyonek Structure

- Bounded by two active reverse faults
- Pittman Anticline bisects the unit

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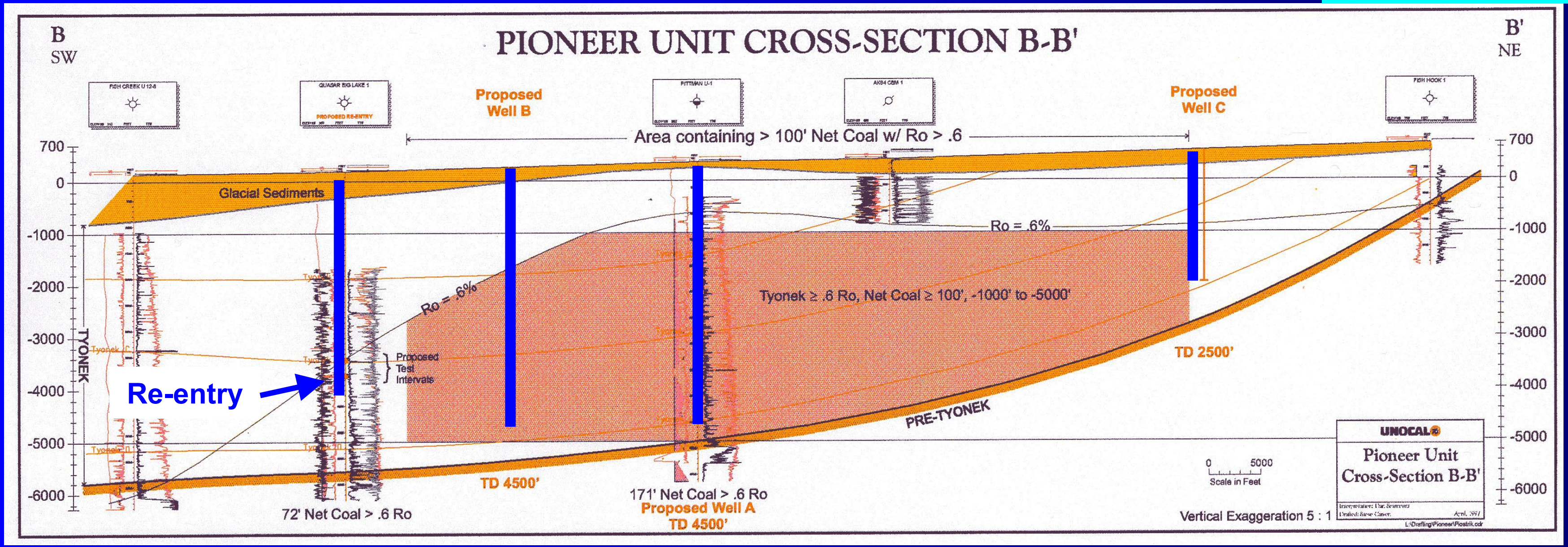
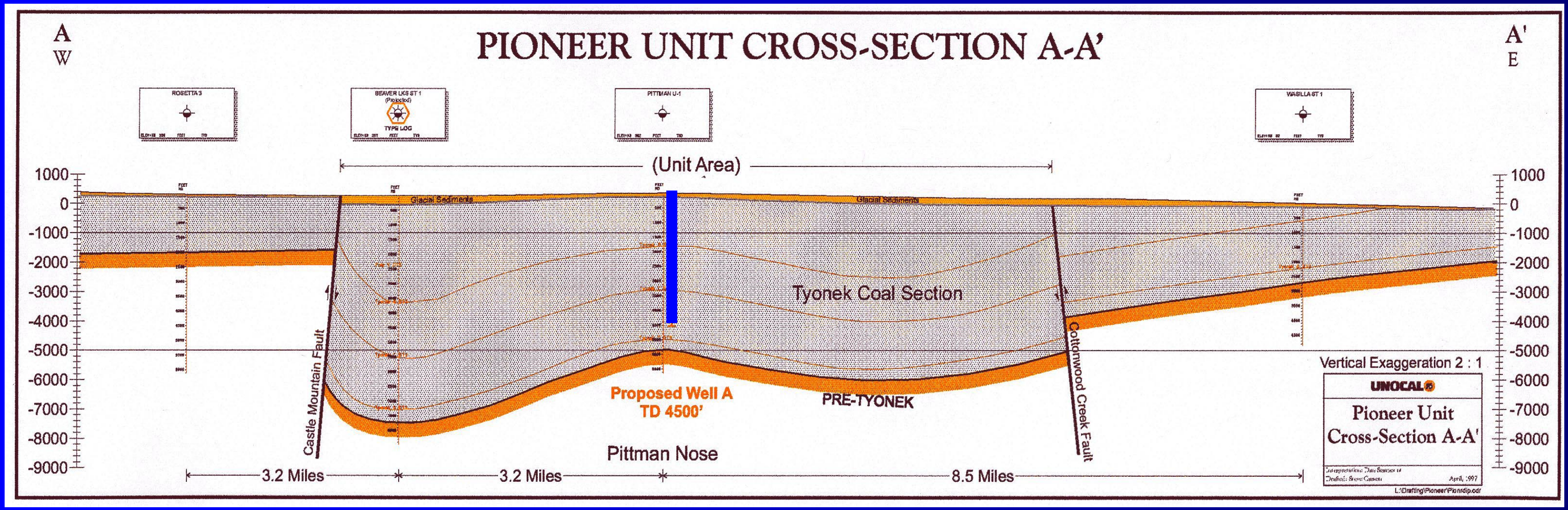
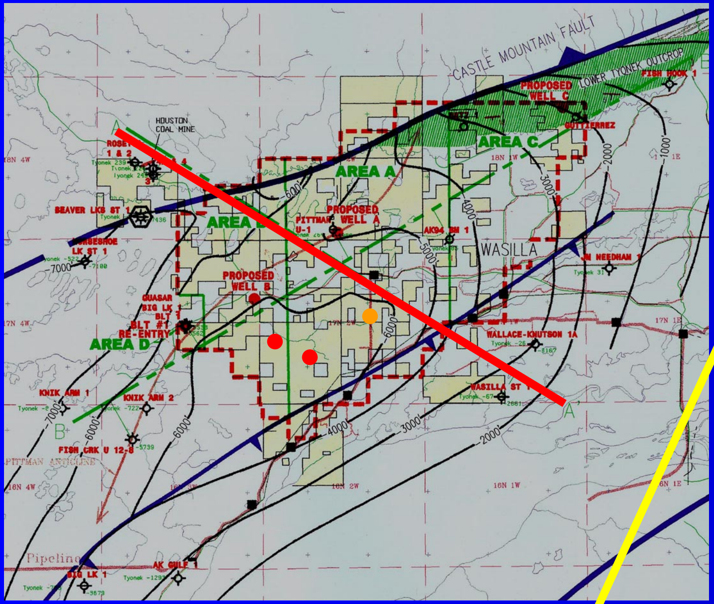
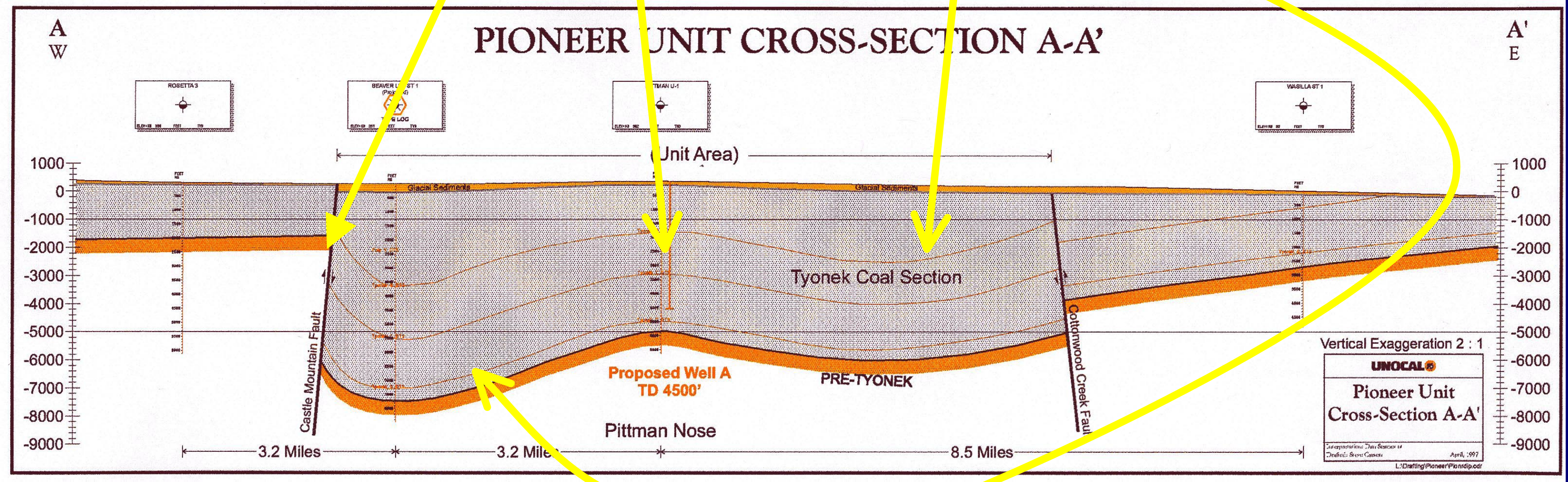




Cross-section View of 1999 Proposed Program



- Both CBM and Conventional targets exist on the axis of the anticline and traps along the faults
- CBM targets also exist in the lows



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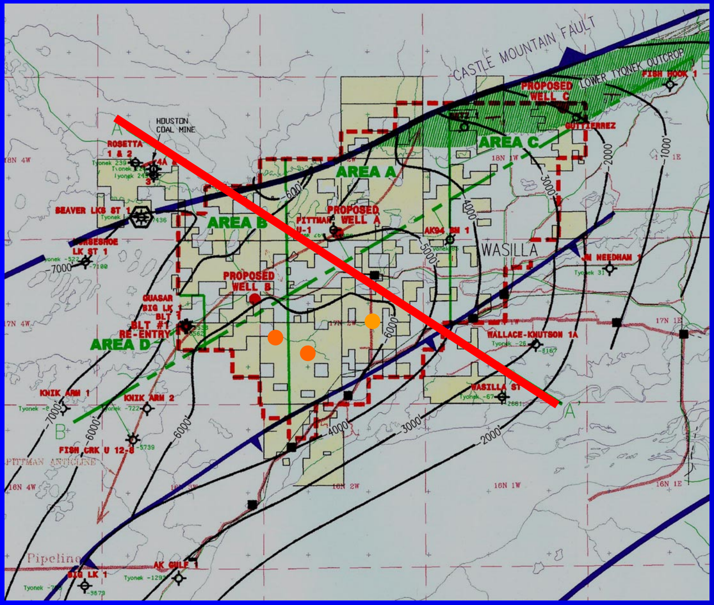
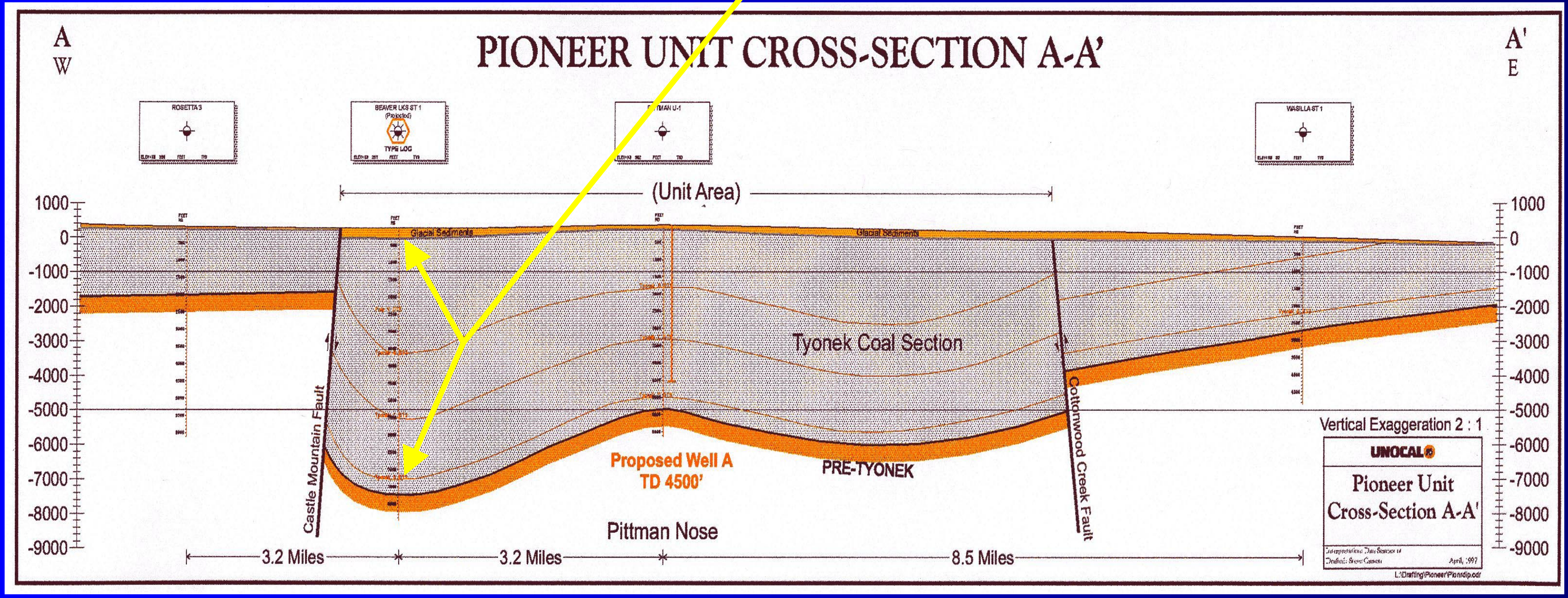
Depositional Setting & Coal Distribution

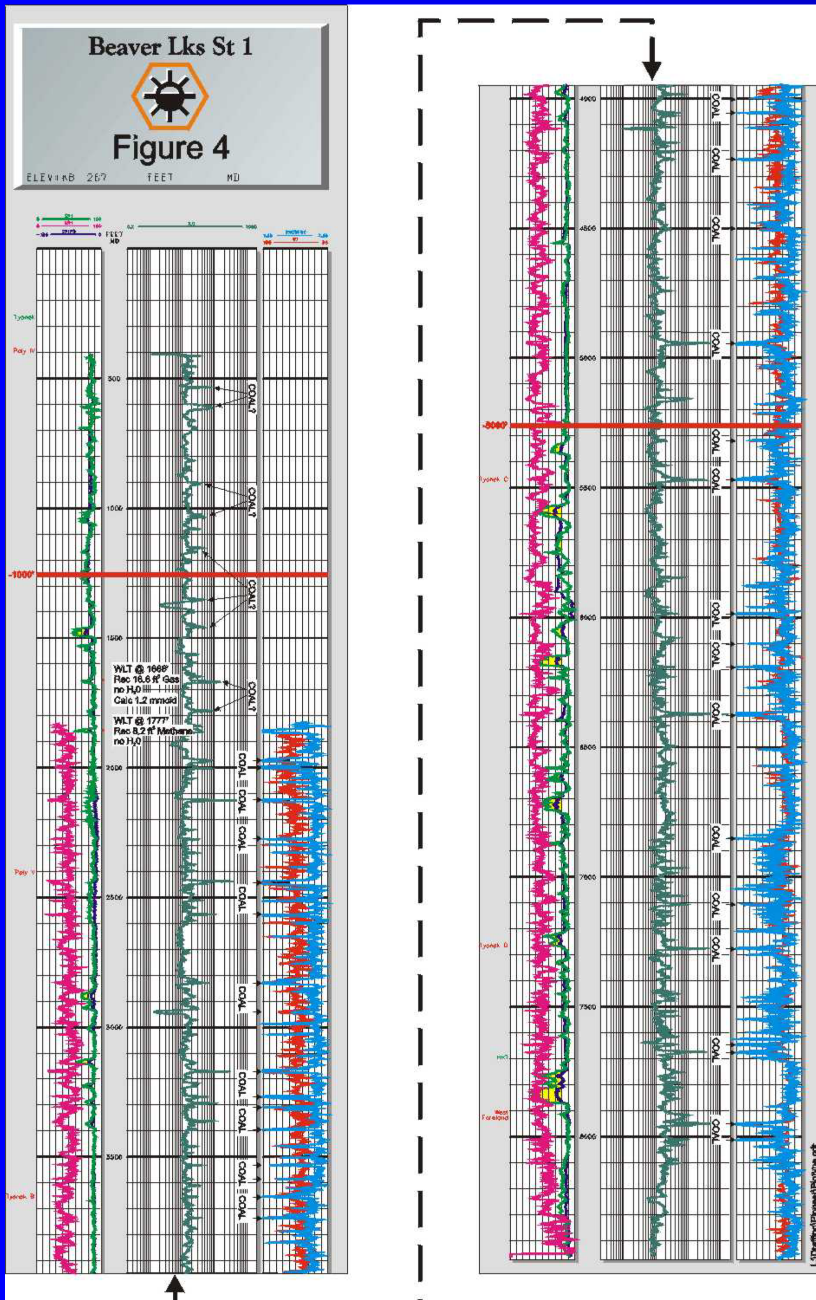


- Coal bearing Tyonek can exceed 7000' in thickness between the bounding faults



UNOCAL 76

Depositional Setting & Coal Distribution



- TYONEK FM GROSS THICKNESS- UP TO 7500', TYPICAL 5000'
- NET COAL THICKNESS- UP TO 300'
- NUMBER OF POTENTIAL ZONES- 15+
- INDIVIDUAL RESERVOIR NET THICKNESS 4' TO 30'
- TYPICAL RESERVOIR NET THICKNESS- 8'

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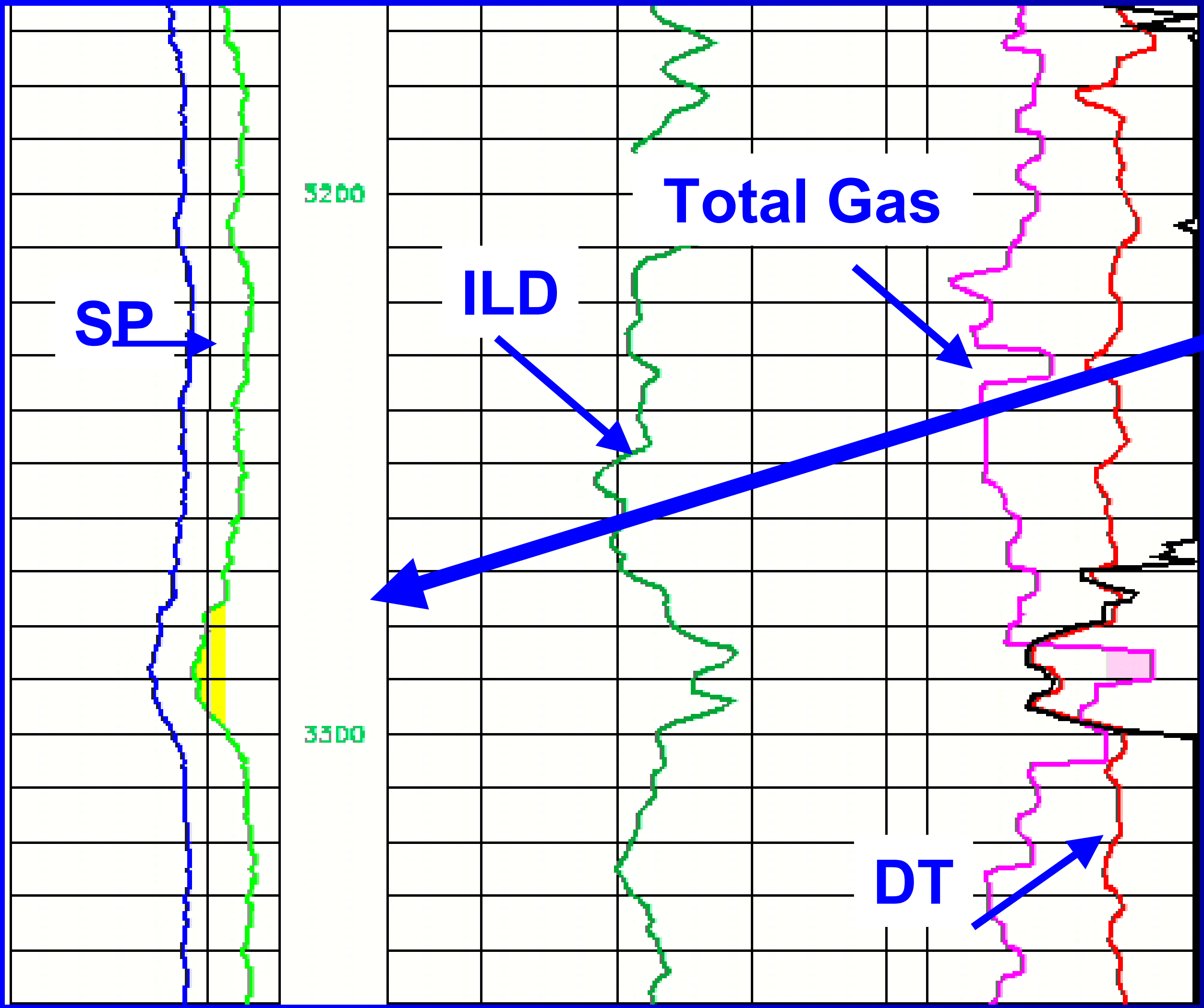
Unocal Pittman #1- 1962



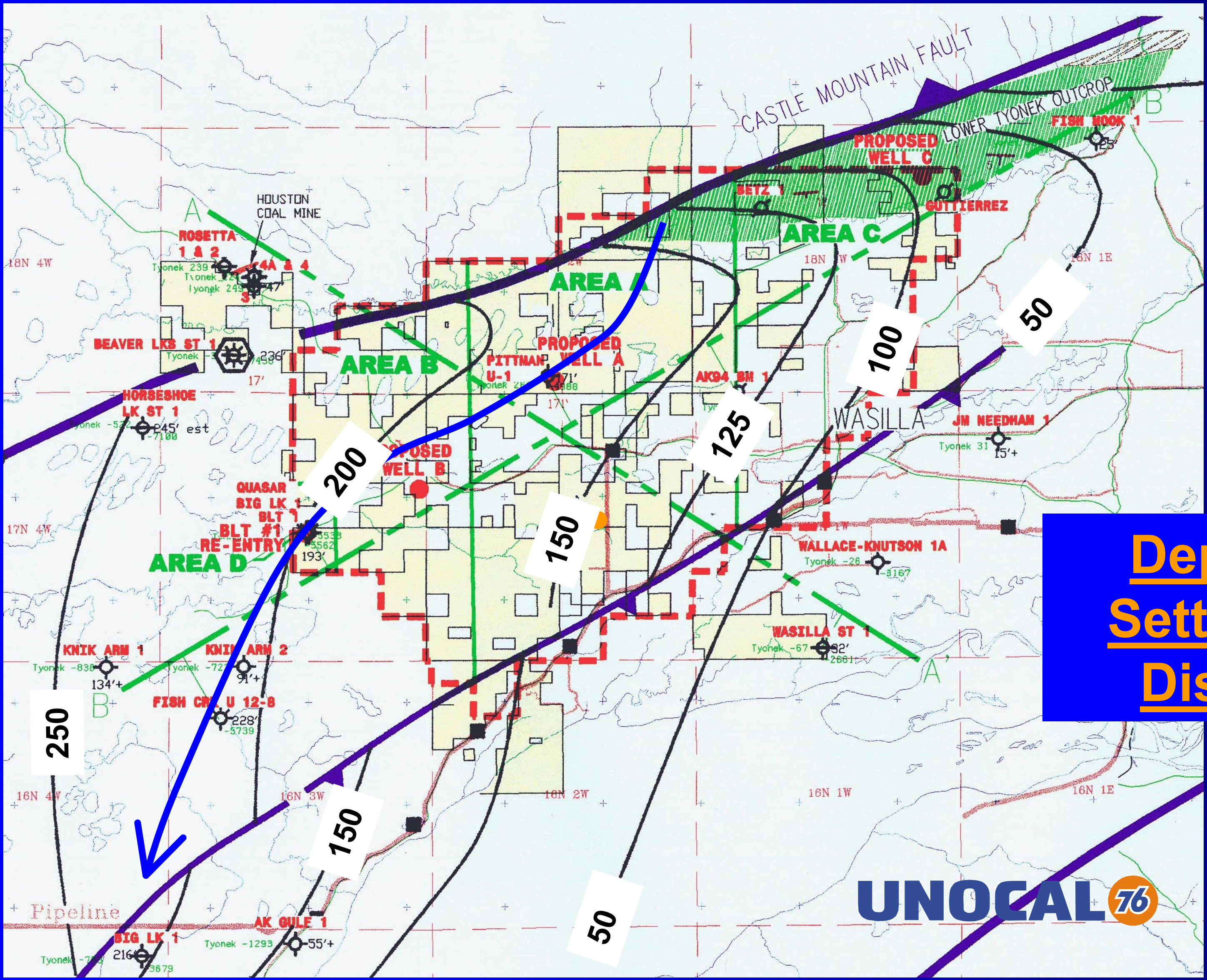
Depositional Setting & Coal Distribution

- SP development in some thick coals

Pioneer Prospect

UNOCAL 76

Net Coal Isopach
-1000' to -5000'

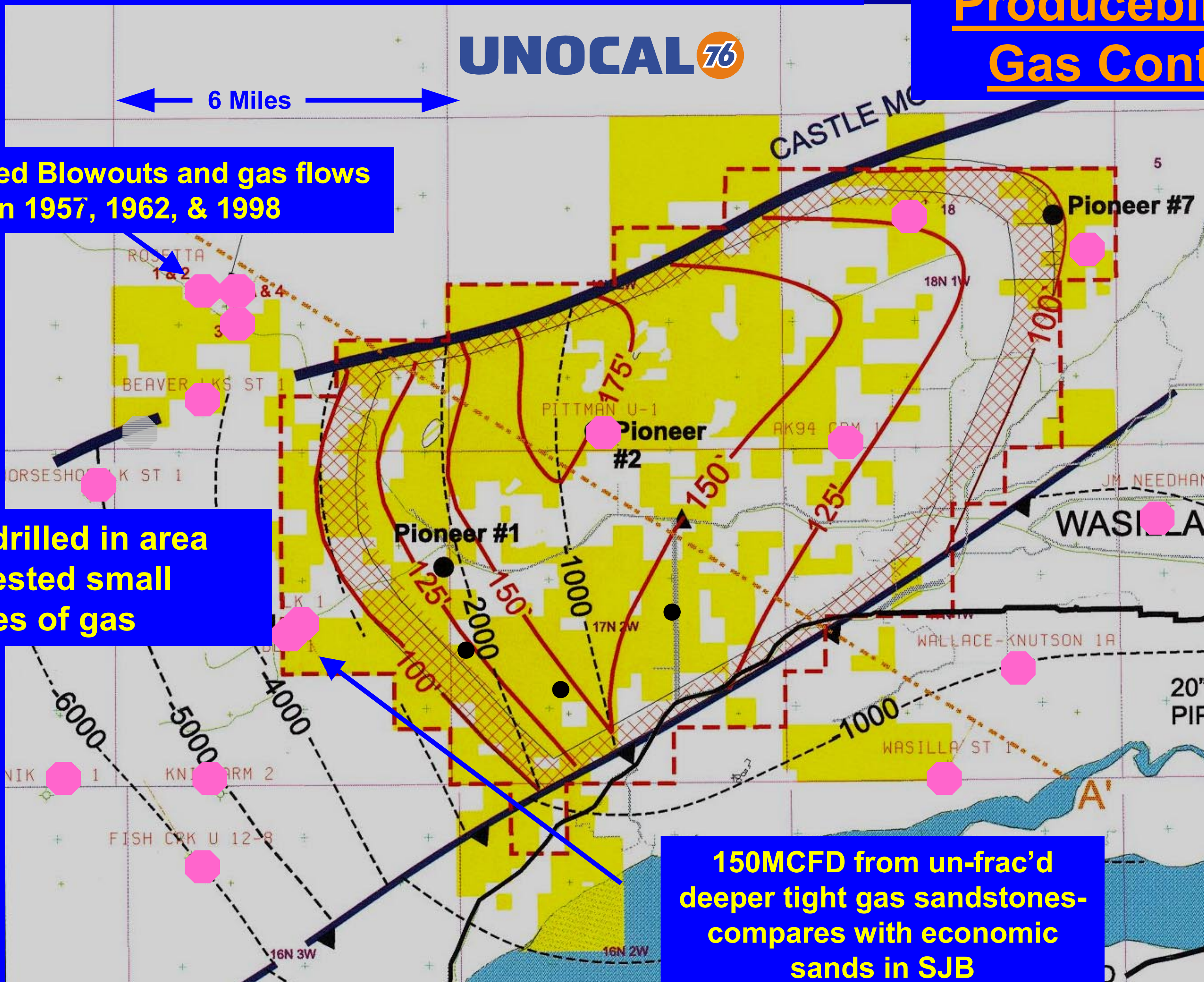


Depositional Setting & Coal Distribution

Area high-graded on foot-wall block between two reverse faults where coal section is thickest

Virtually all wells contained strong gas shows in coal seams

CBM Producebility? & Gas Content?



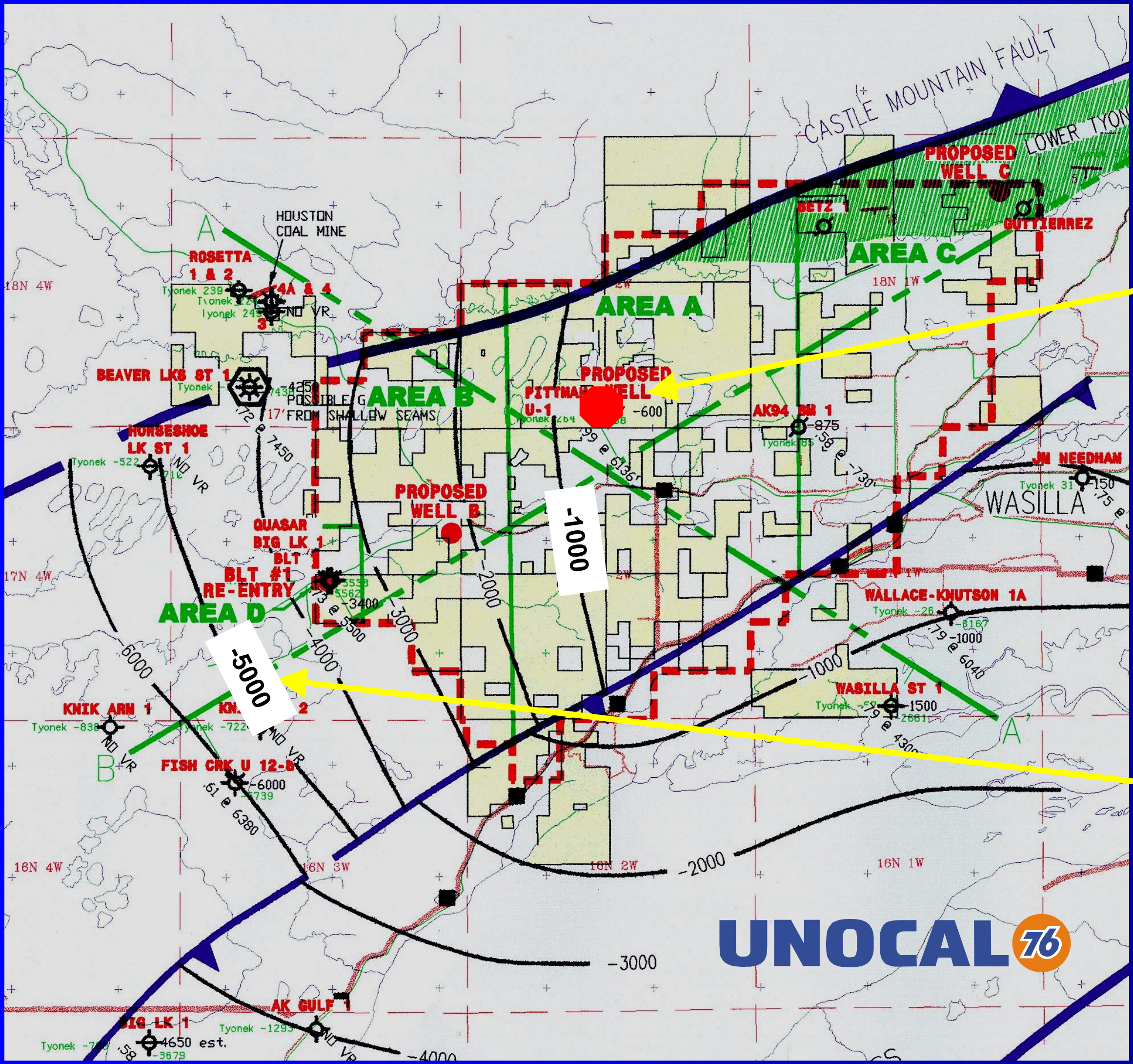
Reported Blowouts and gas flows in 1957, 1962, & 1998

Wells drilled in area have tested small volumes of gas

150MCFD from un-frac'd deeper tight gas sandstones- compares with economic sands in SJB

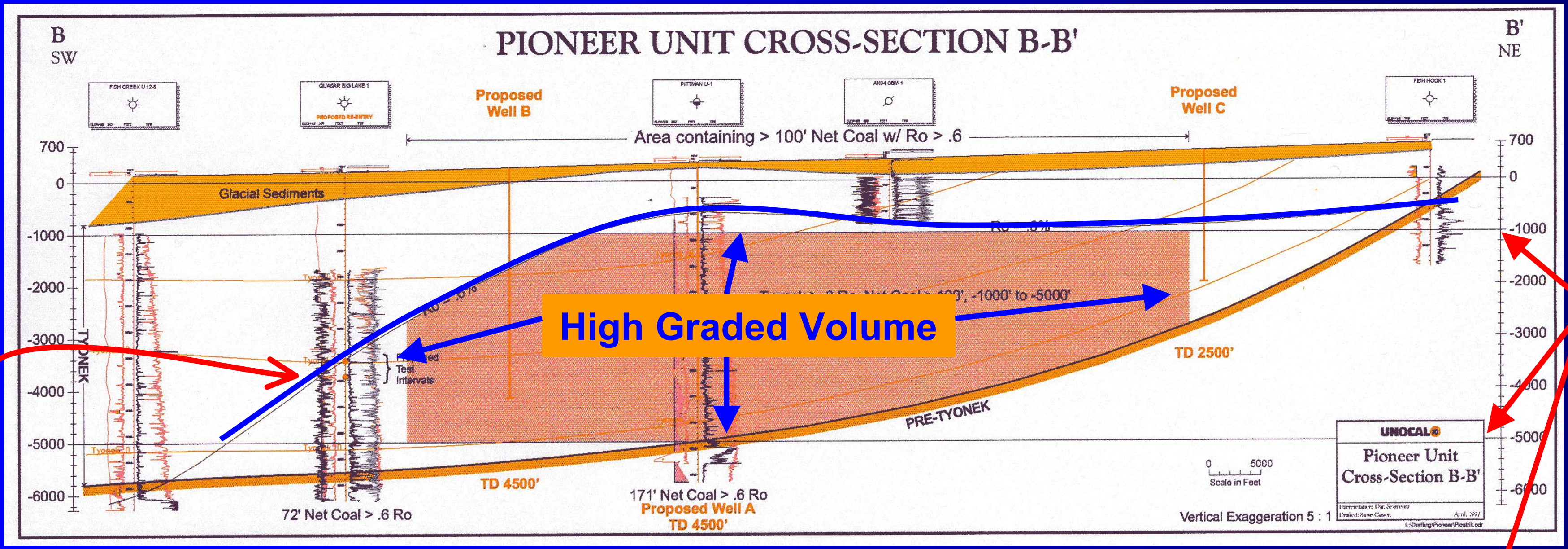
Coal Rank

Depth to Ro >.6%



- Thermogenic gas generation initiates at Ro of 6%
- Ro of .99% was measured at 6000' in Unocal Well Pittman #1, strong gas shows were recorded throughout the section
- Cut-off of -5000' used due to permeability assumptions

Cross-section along axis of Pittman Anticline



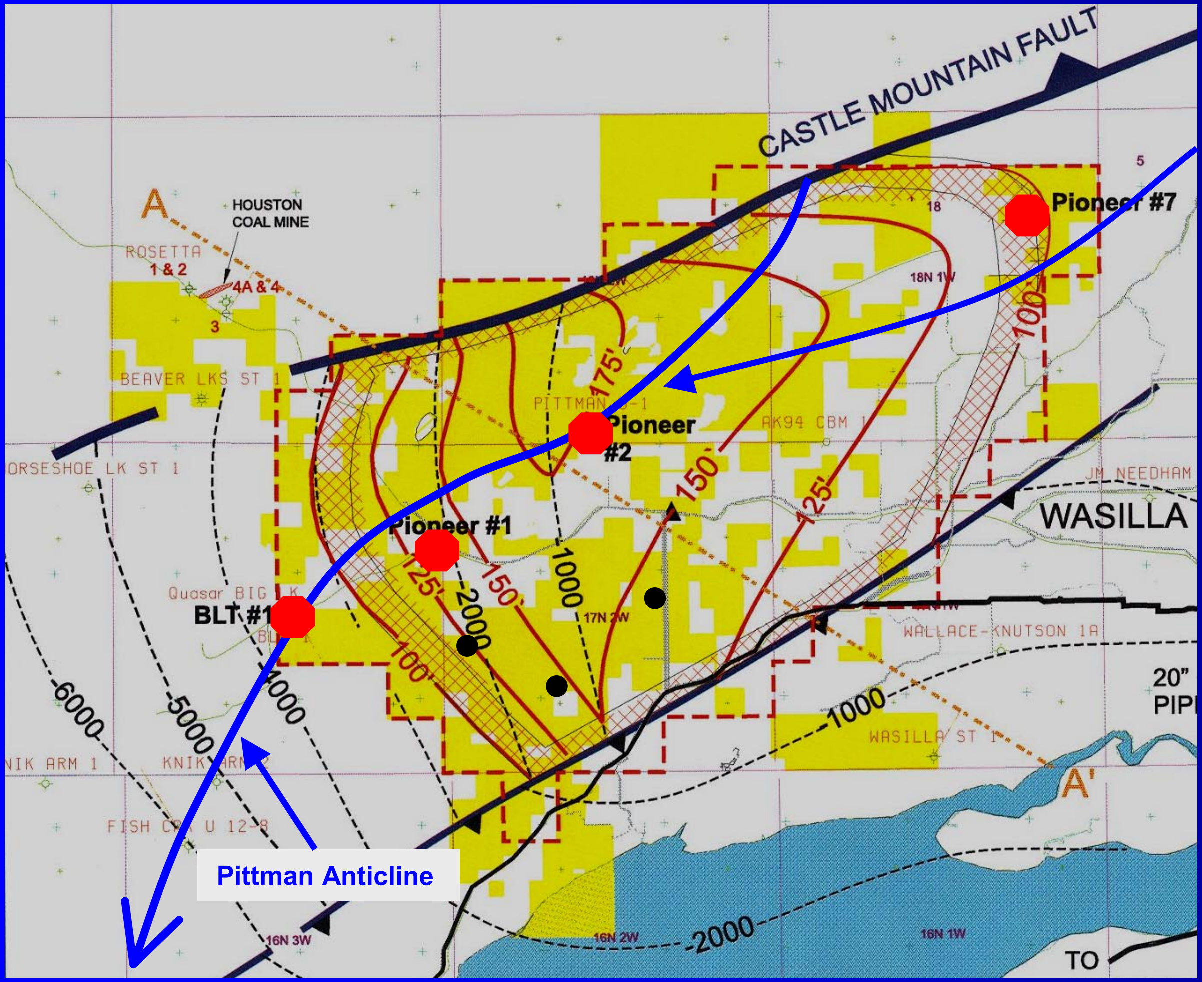
Cut-offs for high-grading and construction of

Anticipated Net Coal Pay Map

- Ro >.6% (onset of Thermogenic Generation)
- Depths from -1000 to -5000 (-1000 for adequate pressure, -5000 for permeability)
- Net Coal > 100'

UNOCAL 76

Anticipated Net Coal Pay Map



Map result of
Applying Cut-offs

Pioneer Prospect

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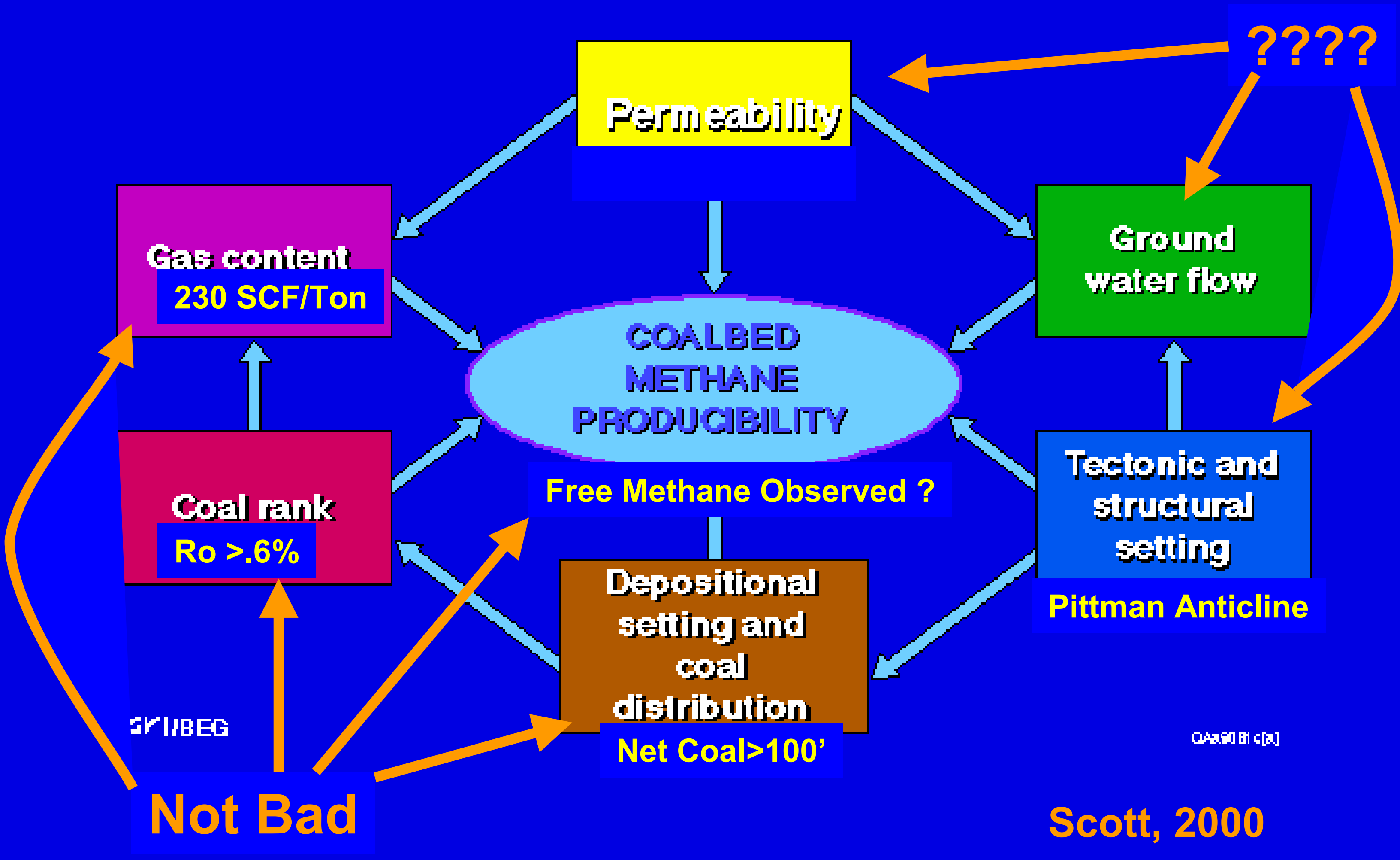
CONTROLS CRITICAL TO COALBED METHANE PRODUCIBILITY



Pioneer Potential Reserve Calculation

Assumptions

Ro- .6%

Depth -1000' to -5000'

Net thickness- 100'

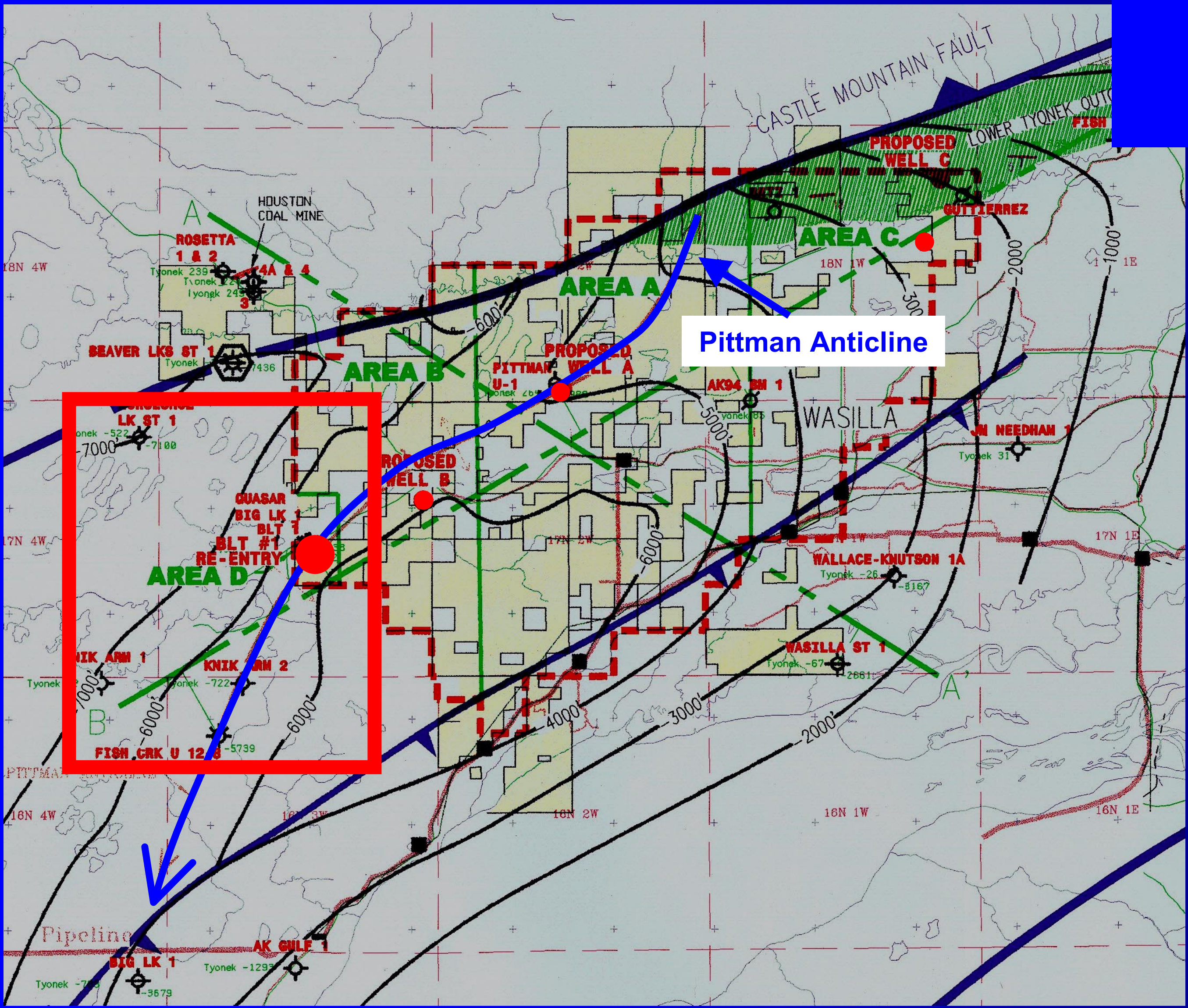
Ash Content	Gas Content	Density	Average Pay	Area
24%	300cu ft/ton	1.5gm/cc	137'	55,500 ac

GIP - 3.6 TCF

Recovery 40%

Recoverable Reserves- 1.425 TCF

Conventional Potential

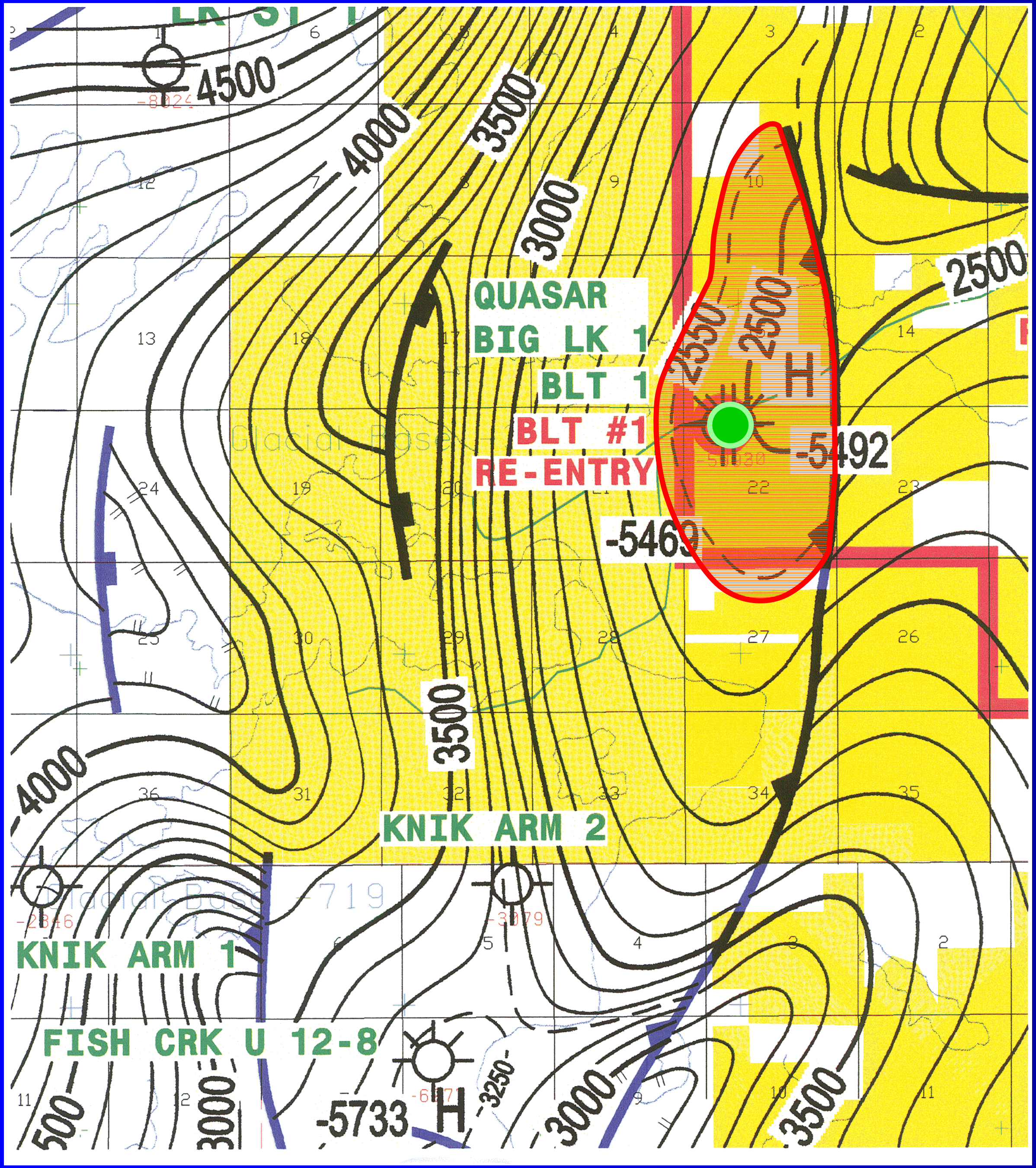


Base Tyonek Structure

Re-Entry

Arco BLT #1, Test Coal Seam at 3600’ and sand w/gas show at 3900’ on southern edge of unit.

UNOCAL 76

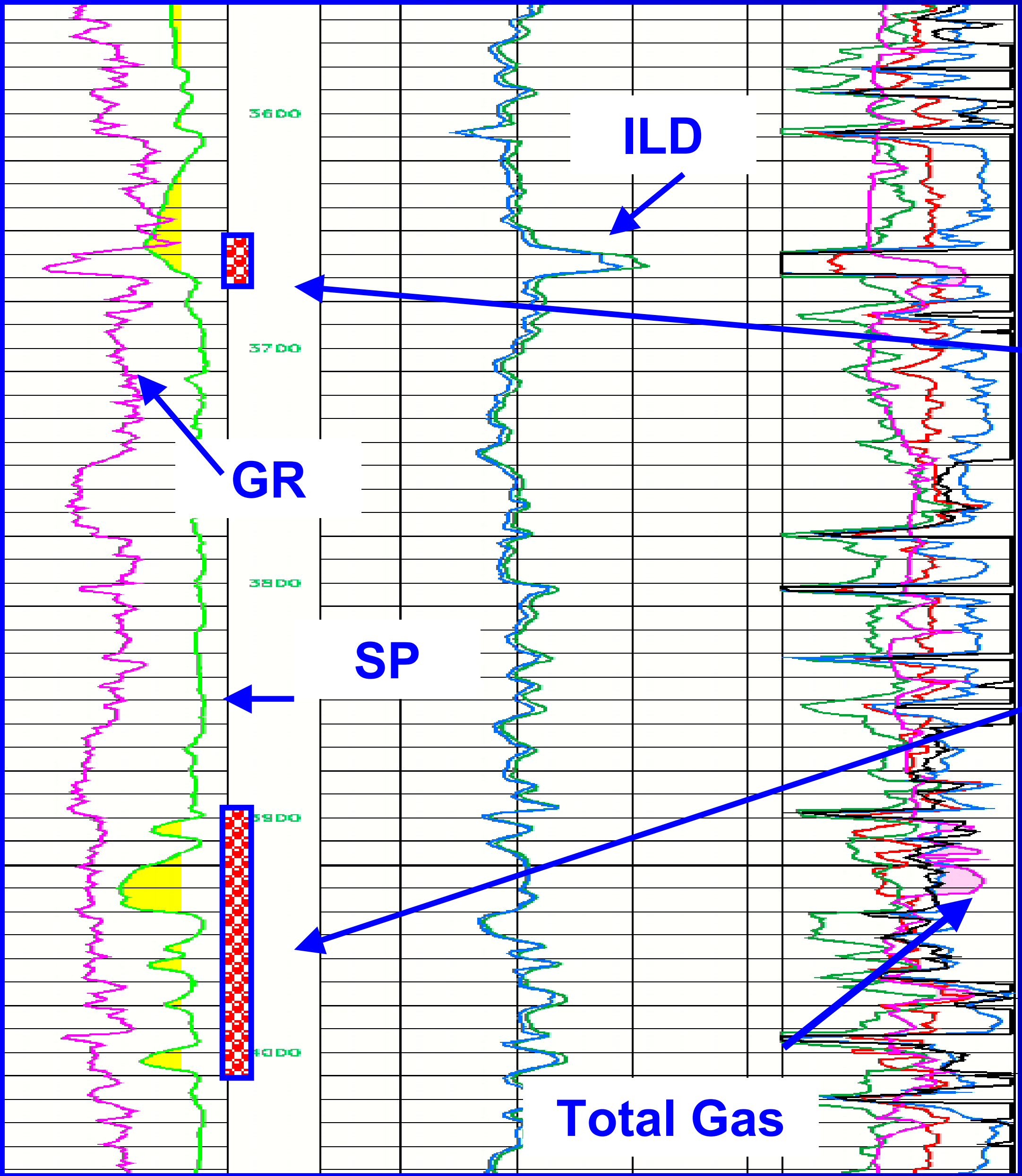


Big Lake Tyonek Gas

1645 acres

Near Top/Tyonek "C" Coal

ARCO BLT #1



Conventional Targets

Re-Entry:

Arco BLT #1, Test coal seam at 3660' and sand w/gas show at 3900' on southern edge of unit

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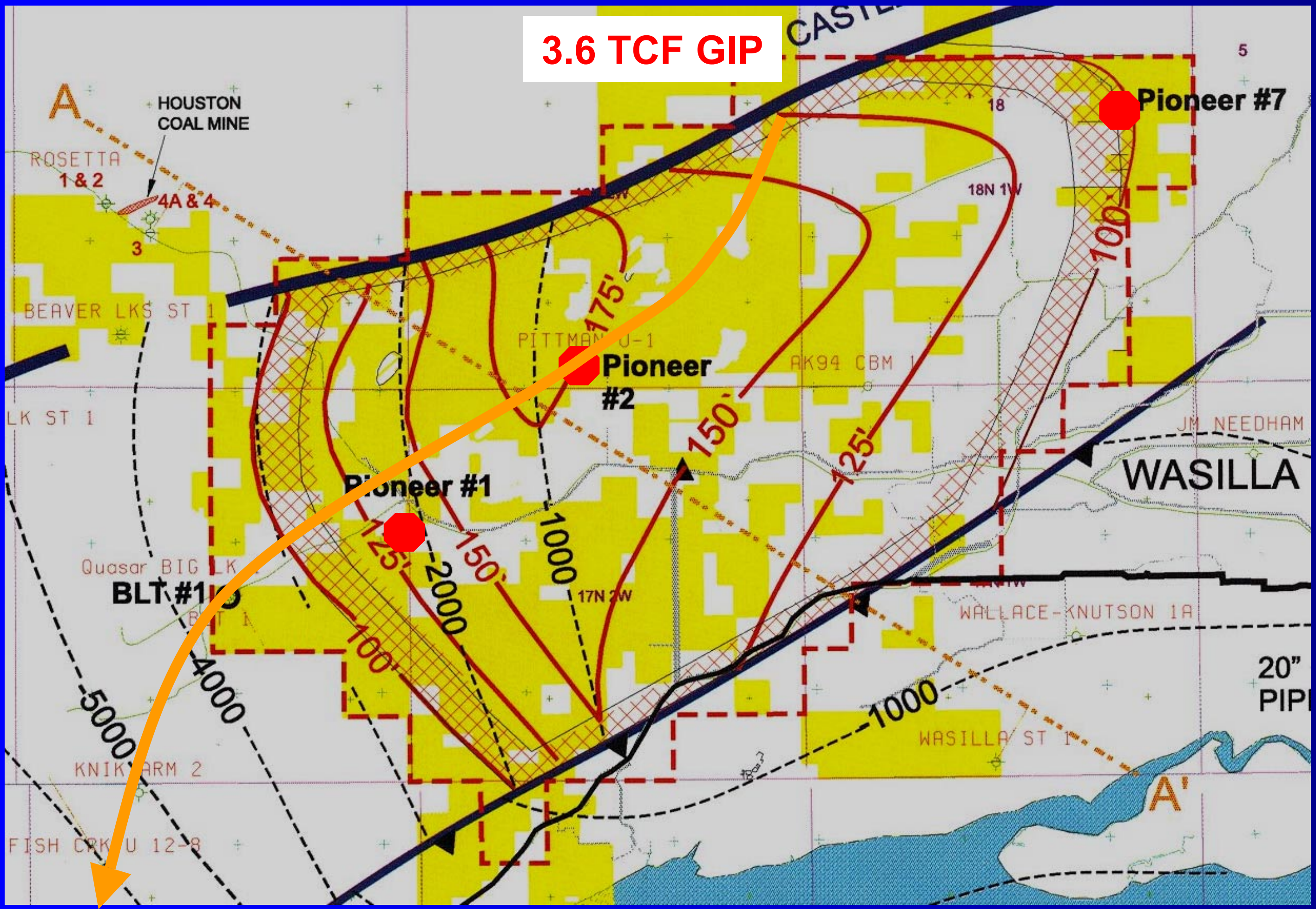
Pioneer CBM Strengths

- Estimated 3.6 Tcf in place at Pioneer
- Potential reserves of 1.4 TCF
- Large acreage position
- Existing infrastructure
- Good accessibility to drilling locations
- Encouraging data and well information
- Conventional sands may enhance productivity

1999 Exploration Plan

Anticipated Net Coal Pay Map



Grass Root Wells

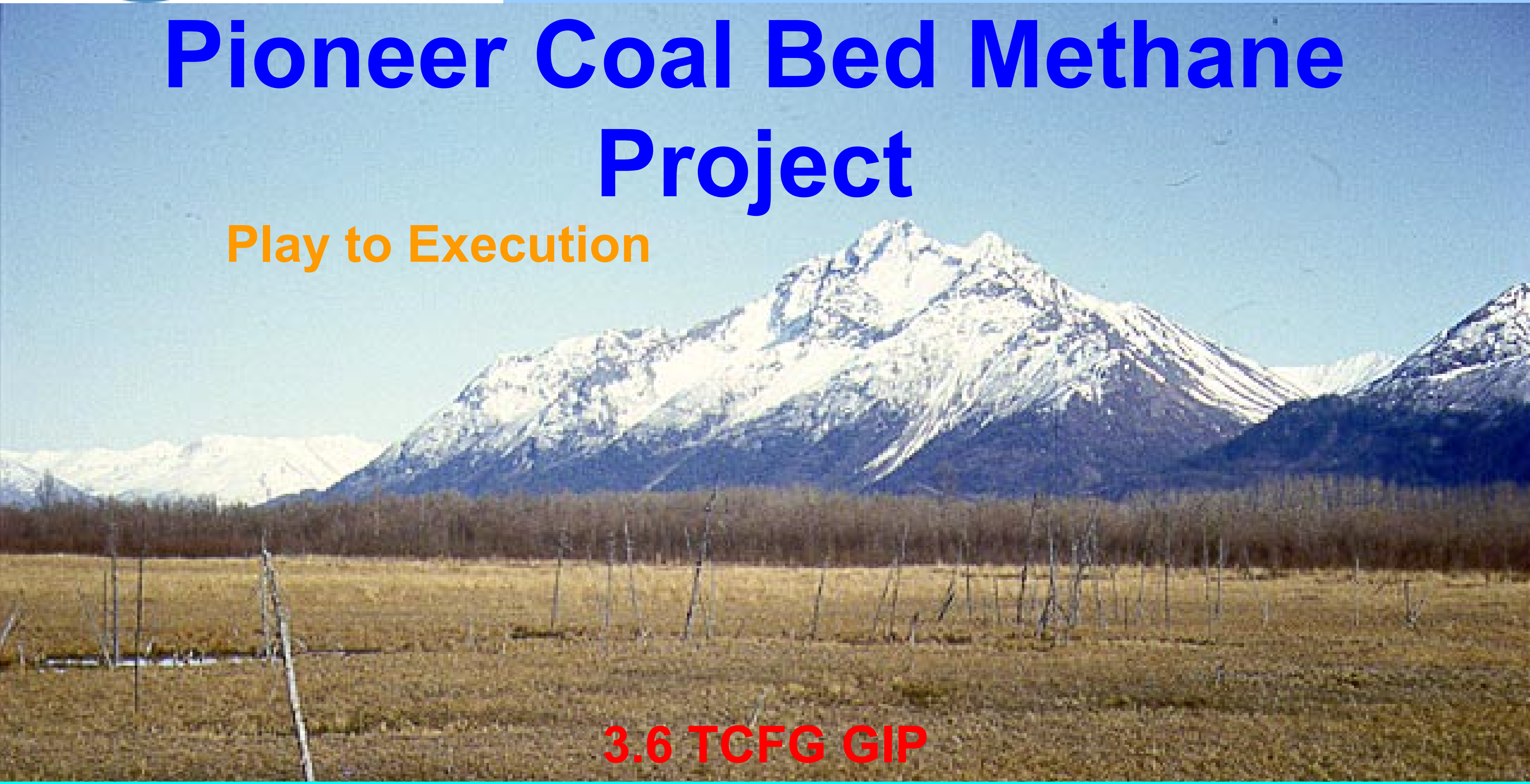
- 2500', near gassy water well
- 4500' offset to Pittman #1 for core control
- 4500' on Flank of anticline
- 4500' off structure nearer to Pipeline

UNOCAL 76

UNOCAL 76

Pioneer Coal Bed Methane Project

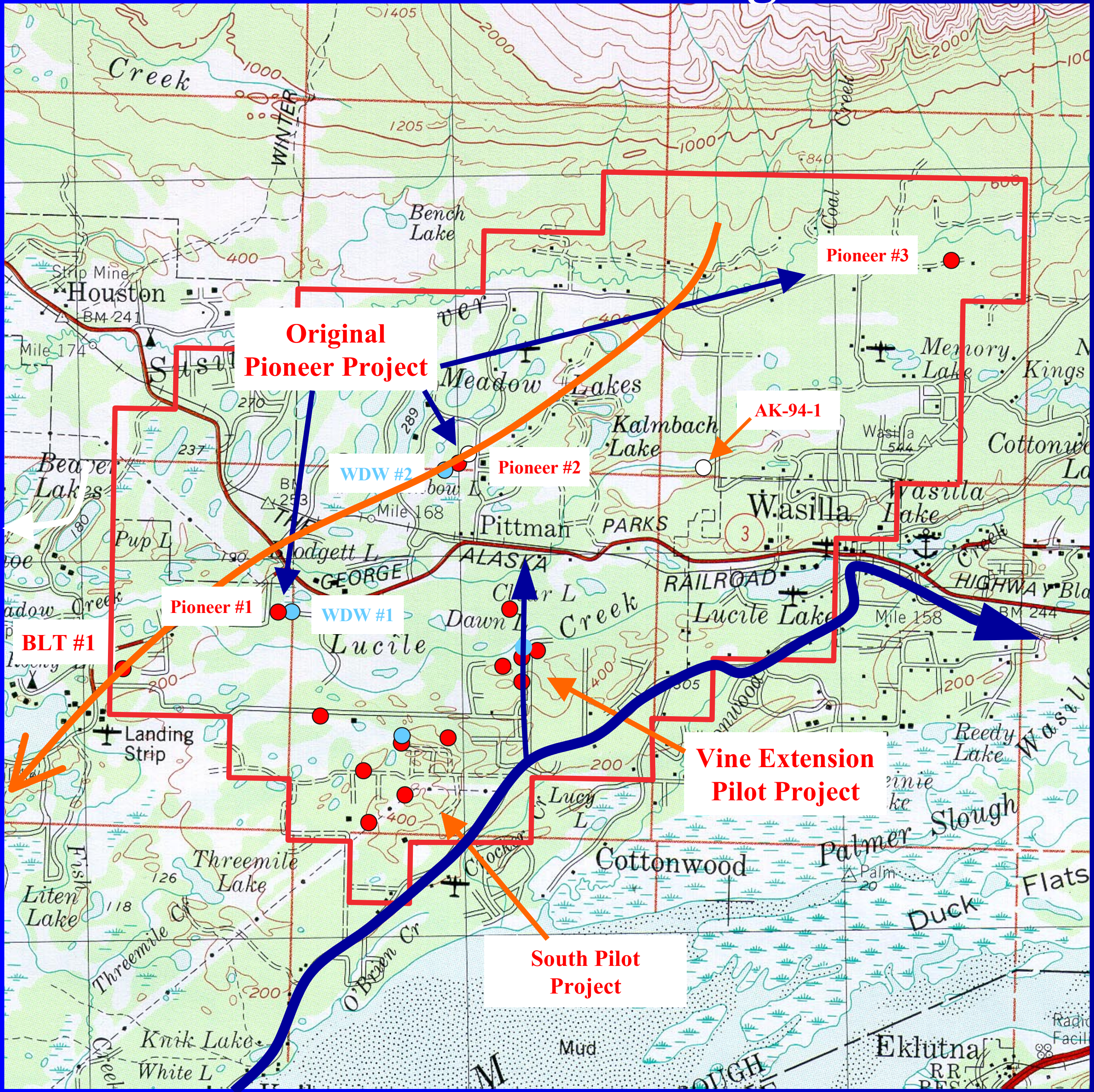
Play to Execution



3.6 TCFG GIP

D. Seamount (AOGCC, formerly Unocal), Faye Sullivan (Unocal), T. Brandenburg (Unocal), R. Crandall (AOGCC), K. Tabler (Unocal), R. Downey (Independent, formerly w/ Ocean Energy), Debra Childers (Unocal), Steve Carson (Unocal), Larry Smith (Unocal), C. Barker (USGS), R. Cross (Unocal), G. Pavia (Lynx Enterprises, Inc. formerly of DGC)

Permitting



Ocean/Unocal Proposed Well Locations

- CBM test Well Location
- Class II Waste Disposal Well Location
- Existing Exploration Wells

0 MILES 2
Scale

Permitting Phase- Unocal 1999 (6 months, team of 8)

Alaska Division of Governmental Coordination (DGC)- surface environment- 10 groups

Coastal Zone Consistency Determination

Plan of Operation (Three Submitted)

1. **Coastal Policy Questionnaire- Office of Management & Budget, DGC**
2. **404 Wetlands Fill Permit (not needed)- U.S. Army Corps of Engineers**
3. **Archeological survey/cultural Resources report- Alaska Division of Parks & Outdoor Recreation**
4. **Temporary Water Use Permit- Division of Mining, Land, & Water and Alaska Department of Fish & Game**

Permitting Phase (Continued)- Unocal 1999
(6 months, team of 8)

Alaska Division of Governmental Coordination (DGC)- surface environment- 10 groups

Coastal Zone Consistency Determination

5. Air Quality Permit (Below threshold) Alaska Department of Environmental Conservation (ADEF)
6. Solid Waste Program- ADEF
7. Notice- Office of the Governor
8. Planning Permit-Mat-Su Borough
9. C-Plan Exemption- Alaska Oil & Gas Conservation Commission (AOGCC) advises
10. Public- Outreach Meetings

Plan of Operation (Three Submitted)

Activities from site preparation through well suspension or plugging and abandonment

- **Description of the Area**
  - **Location of Proposed Wells**
  - **Climate**
  - **Geography and Topography**
  - **Surface Geology**
  - **Surface Hydrology and Groundwater**
  - **Existing Roads**

Plan of Operation (Three Submitted)-Continued

Activities from site preparation through well suspension or plugging and abandonment

- **Planned Activities**
  - Planned Access Roads
  - Road and Pad Construction
  - Well Site Layouts
  - Equipment Description
  - Water Supply
  - Down Hole Waste Disposal
  - Water and Waste Disposal
  - Surface Restoration
  - Timing
- **References**

Pioneer Public Meeting Topics- discussion of Plan of Operations and Public Concerns

- Introduction by Division of Coordination (DGC)
- What is Coal Bed Methane
- Summary of The Pioneer Coal-bed History
- Ocean/Unocal Plan of Operation in Mat-Su
- Project Timing
- Communications W/ Public
- Questions & Comments by Public
  - Protection of Water Supply
  - Waste and Injected Water
  - Surface Disturbances
  - Safety
  - Noise
  - Proximity to Residences

Permitting Phase (Continued)- Unocal 1999
(6 months, team of 8)

Alaska Oil & Gas Conservation Commission (AOGCC)- Sub-surface environment & Correlative Rights- 2 groups

1. **UIC (EPA involvement)**
   - Aquifer Exemption
   - Disposal Injection Order

2. **Permit to Drill**
   - Conventional Operation
   - CBM regulations w/ industry & other parties' input in Future

3. **Correlative Rights**
   - Spacing Exception

PIONEER CBM PROJECT

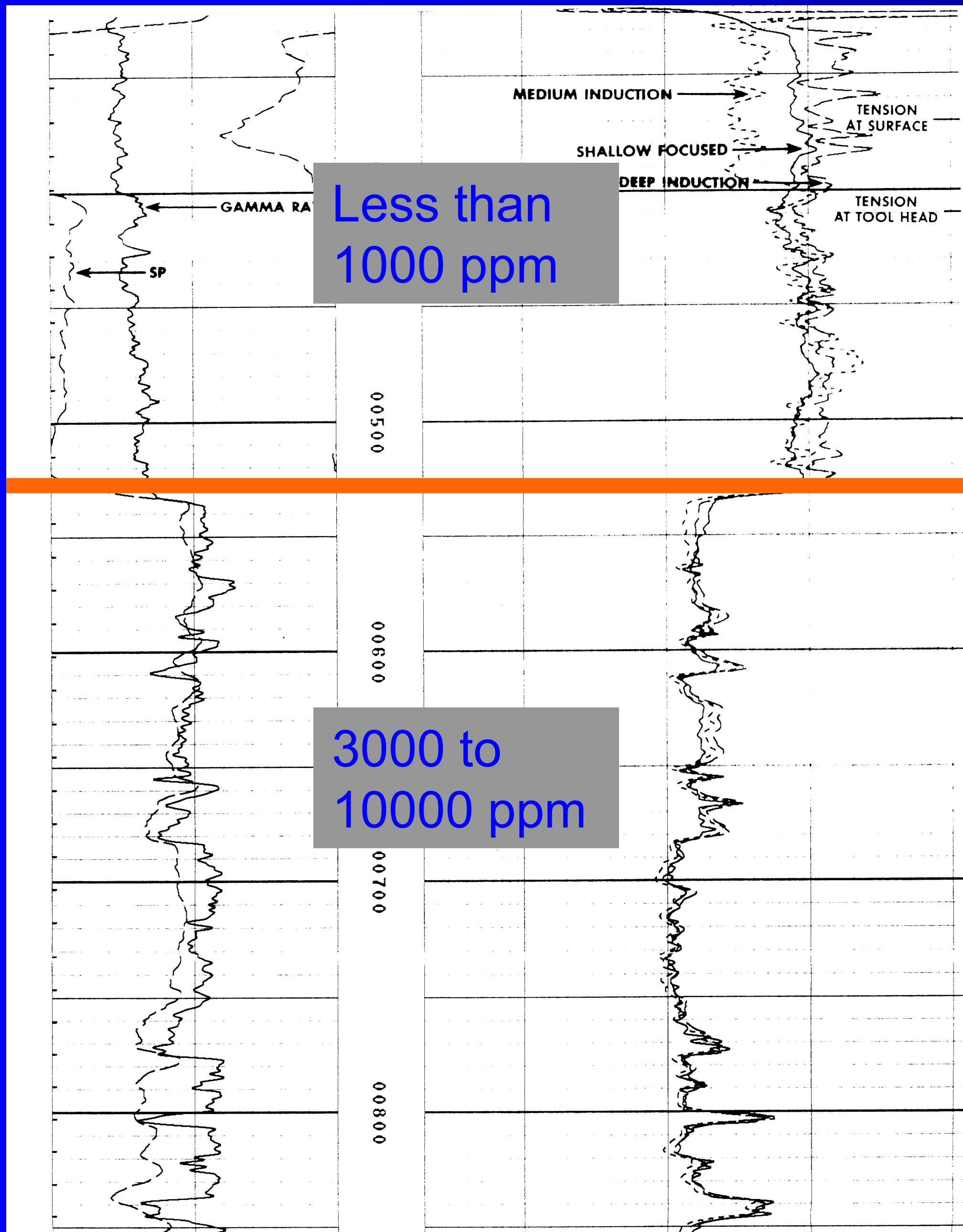
Class II Waste Disposal Well

- **Regional Picture**
  - **Coal Basin**
  - **Fresh Water Aquifer**
- **Application for Exemption and Disposal Order**
  - **Area Geology**
  - **Deep Tests**
  - **Water Analyses**
  - **Log Analyses**
- **Pioneer Well 1702-15DA-WDW**
  - **Well Logs of Disposal Zones**
  - **Activity & Status of Well**
- **Conclusions**

Aquifer Protection

- Produced Water injected at least 1500’ below the lowest Fresh Water
- Injected water quality very similar to that of Injection Zone @ 1500’ and greater Depths
- Injection Well To Be Monitored according to State and Federal Regulations
- Strict Adherence To Safe Cementing Procedures, surface casing through potable water aquifer (800’)
- Wells to be Drilled with water-based mud
- Baseline Study of Water Wells in Area was performed by third party geotechnical firm.

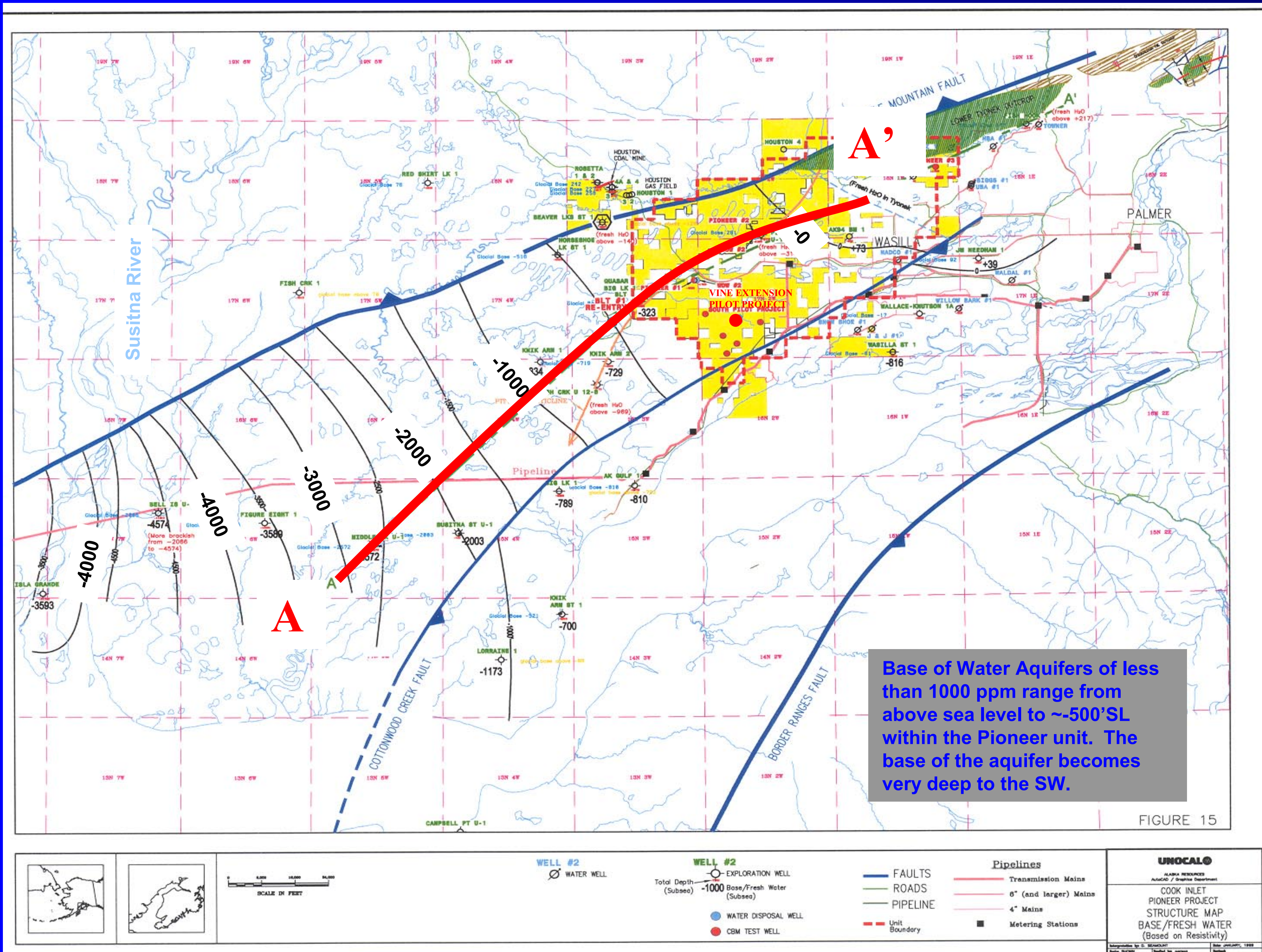
ARCO BLT #1



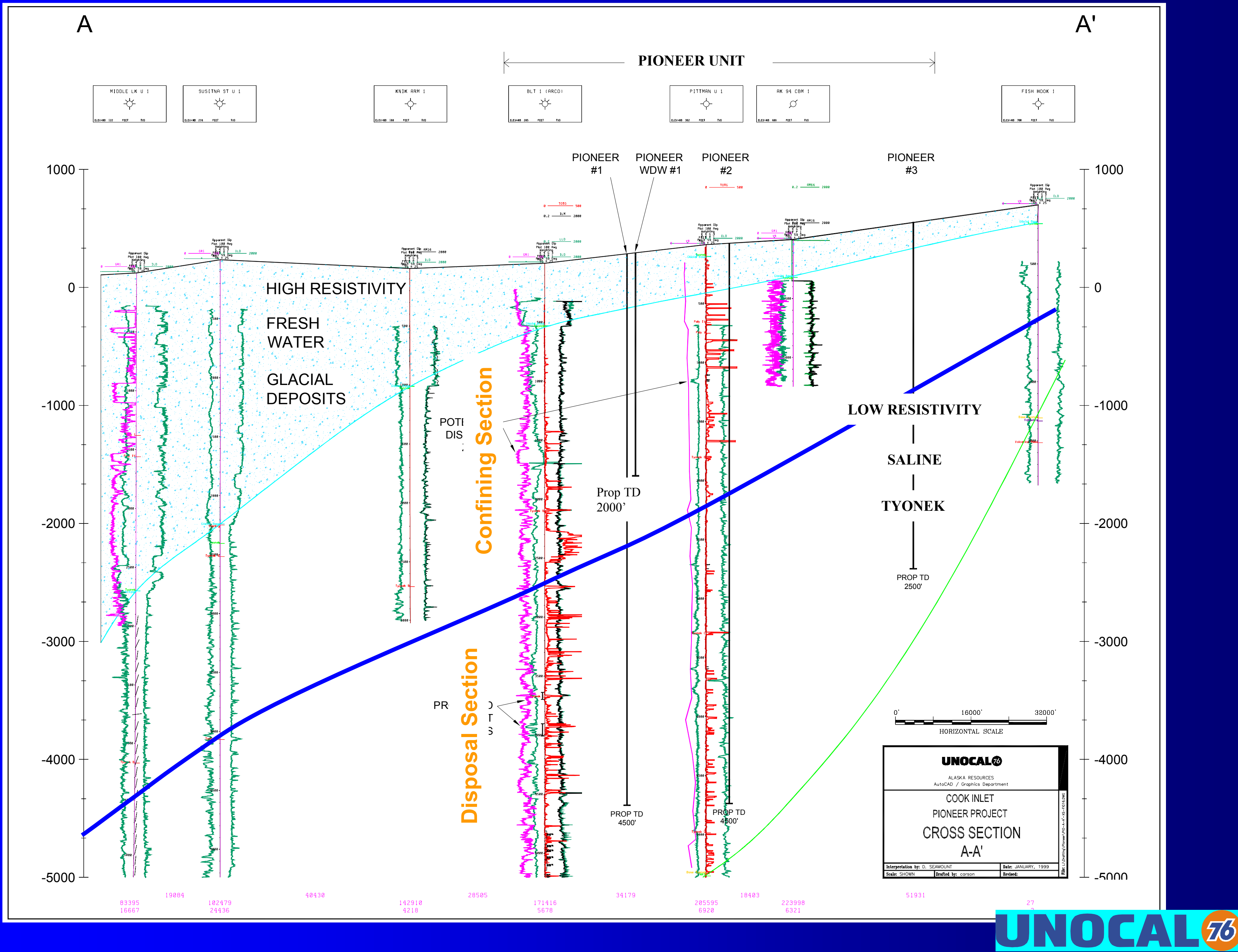
High Resistivity/Fresh Water Aquifer

Low Resistivity Exemptible Tyonek Section

Pioneer Aquifers



Sub-Sea Depth to Base of Fresh Water

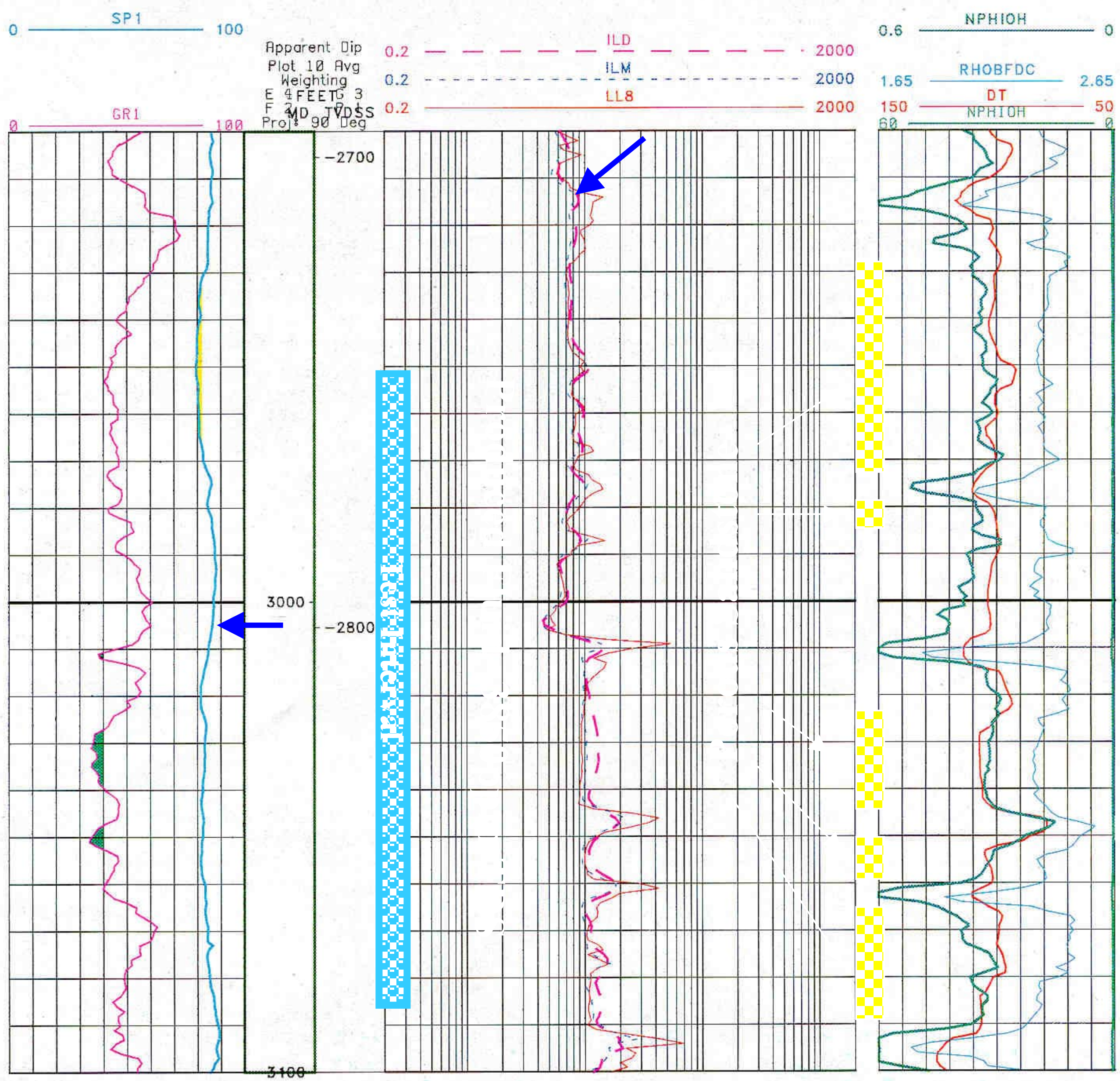


A
A'
PIONEER UNIT
MIDDLE LK U 1
SUSITNA ST U 1
KNIK ARM 1
BLT 1 (ARCO)
PITTMAN U 1
AK 94 CBM 1
FISH HOOK 1
PIONEER #1
PIONEER WDW #1
PIONEER #2
PIONEER #3
1000
0
-1000
-2000
-3000
-4000
-5000
HIGH RESISTIVITY
FRESH WATER
GLACIAL DEPOSITS
Confining Section
Disposal Section
Prop TD 2000'
LOW RESISTIVITY
SALINE
TYONEK
PROP TD 2500'
PROP TD 4500'
PROP TD 4500'
0' 16000' 32000'
HORIZONTAL SCALE
UNOCAL 76
ALASKA RESOURCES
AutoCAD / Graphics Department
COOK INLET
PIONEER PROJECT
CROSS SECTION
A-A'
Interpretation by: D. SEAMOUNT
Date: JANUARY, 1999
Scale: SHOWN
Drafted by: carson
Revised:
19084
40430
28505
34179
18403
51931
83395
16667
102479
24436
142910
4218
171416
5678
205595
6920
223998
6321
UNOCAL 76

Table 4: WATER RECOVERY FROM PIONEER UNIT AREA DEEP EXPLORATORY WELLS

WELL NAME	OPERATOR	INTERVAL	RECOVERY
BIG LAKE BLT-01	ARCO	3 tests: 4800' to 6100'	No water, small amounts of gas
AM QUASAR BIG LK 1	AM QUASAR	well kicked 1870'- 1930'	Two samples mud/reservoir fluid TDS of 3049 ppm and 1709 ppm Mud filtrate reported - 500 ppm Cl
HORSESHOE LK ST 1	GREAT PLAINS	2950'- 3084'	680' of muddy salt water TDS = 3850 ppm
		4246'- 4310'	354' of water cut drilling mud TDS = 3300 ppm
PITTMAN 1	UNION	1103'- 1158'	Gas to surface in 3 minutes Water to surface in 40 minutes at 120 b/d rate. No TDS measurement
		2709'-2747'	Flowed 100bbls of "salt water" at _____b/d rate. No TDS measurement
		3577'-3595'	1030' of "salt water" in pipe
		3577'-3595'	65' of "salt water" in pipe

Horseshoe Lake St #1



Total Depth	8226
Temp at TD	132
Temp @ Surface	35
Temp Gradient	1.18
Matrix Density	2.67
Matrix TT	53
Sonic Compaction Factor	1
a	0.62
m	2.15

Calculated TDS (Sonic) 3273ppm

Average

Depth	Rild	Sonic Porosity	TDS (Sonic)
2932	7.7	0.35	4364
2936	7.8	0.35	4346
2940	7.6	0.37	4032
2944	7.9	0.36	4022
2948	10.3	0.34	3488
2952	9.3	0.29	5666
2956	8.1	0.35	4251
2960	10.0	0.34	3567
2964	8.9	0.38	3205
2968	9.6	0.35	3474
2972	7.8	0.38	3622
2982	6.8	0.35	5052
2986	9.1	0.34	3931
3024	11.9	0.33	3083
3028	12.8	0.40	1940
3032	13.0	0.40	1876
3036	12.6	0.40	1957
3040	11.1	0.39	2333
3044	12.8	0.36	2378
3054	11.0	0.38	2443
3066	10.1	0.34	3433
3070	11.2	0.34	3146
3074	12.6	0.34	2797
3078	15.4	0.32	2590
3082	12.7	0.37	2242
3086	13.8	0.39	1777
3090	12.8	0.39	1930

TDS Calculation From Well Logs

Formation Factor

F = 0.81/ (porosity*porosity) (average of the density and neutron log porosity)

(Tixier Formula)

Resistivity of 100% Water Saturated Formation:

Ro = Rt (deep induction R value through analyzed zone assumed to be 100% water).

Resistivity of Formation Water

Rw = Ro / F

Archies Equation

Salinity (ppm):

$$\text{Salinity} = 10^{x}$$

$$x = \frac{3.562 - \log(RW@75DegF - 0.0123)}{.955}$$

A procedure to generate the salinity curve using the method has been developed for WDS.

TDS Calculation From Well Logs

Thermal Gradient Formula:

TG = (Tmax - MST) / (Depth Subsea / 100)

Tmax = Maximum recorded temperature from log header
MST = Mean Surface Temperature for Cook Inlet (= 35 deg. F
Depth Subsea = Meas. depth of Tmax converted to subsea depth

Formation Factor

F = 0.81/ (porosity*porosity) (average of the density and neutron log porosity)
(Tixier Formula)

Resistivity of 100% Water Saturated Formation:

Ro = Rt (deep induction R value through analyzed zone assumed to be 100% water).

Resistivity of Formation Water

Rw = Ro / F

Formation Temperature:

Tf = (Depth subsea / 100) x TG

Resistivity of Formation Water at 750 F:

Rw@75degF = Rw ((Tf + 6.77) / 81.77)

Salinity (ppm):

$$\text{Salinity} = 10^{x}$$

$$x = \frac{3.562 - \log(\text{RW@75DegF} - 0.0123)}{.955}$$

A procedure to generate the salinity curve using the method has been developed for WDS.


Figure 4: Aerial Photograph-
Vine Extension Pilot Project
Proposed Access Route
15
1702-15AB
Vine St
1702-15DA-WDW
1500' FSL, 515 FEL
1702-14CC
1702-15DD
22
23
1702-22AB
1702-22AD
UNOCAL 76

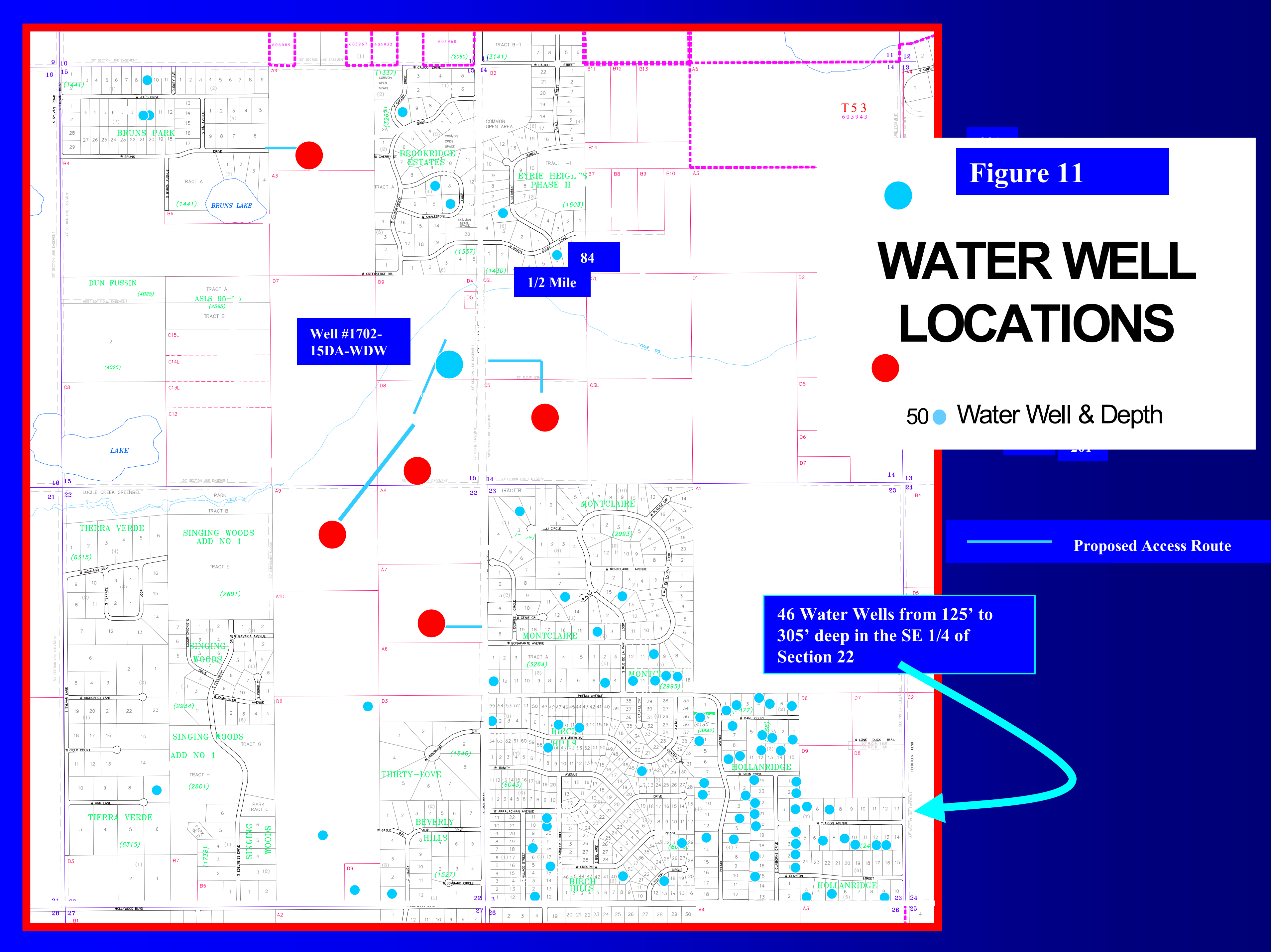


Figure 11
WATER WELL LOCATIONS
50 Water Well & Depth
Proposed Access Route
Well #1702-15DA-WDW
84
1/2 Mile
46 Water Wells from 125' to 305' deep in the SE 1/4 of Section 22

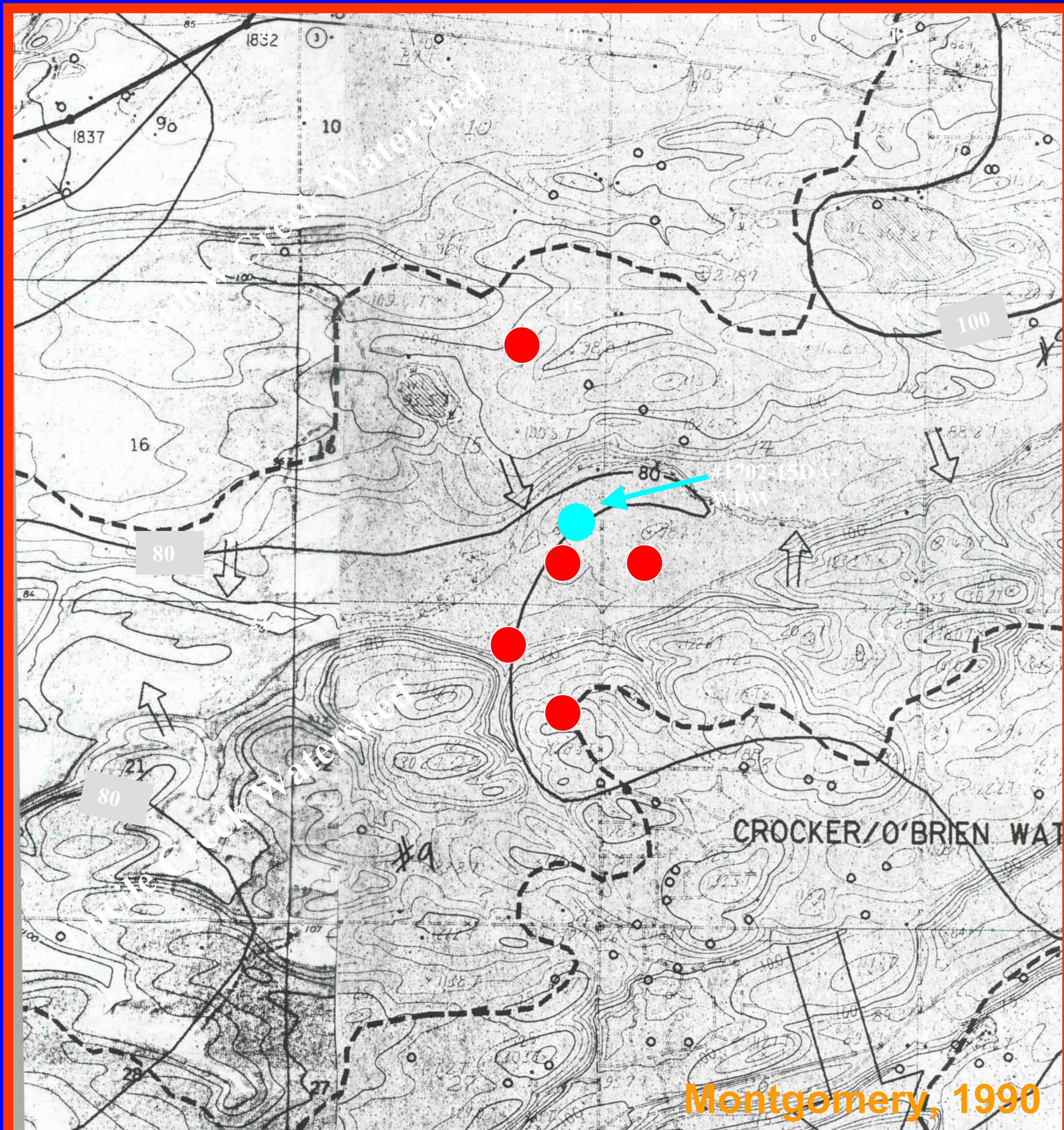


Figure7- Water Table Contour Map, Vine Extension Pilot Area-

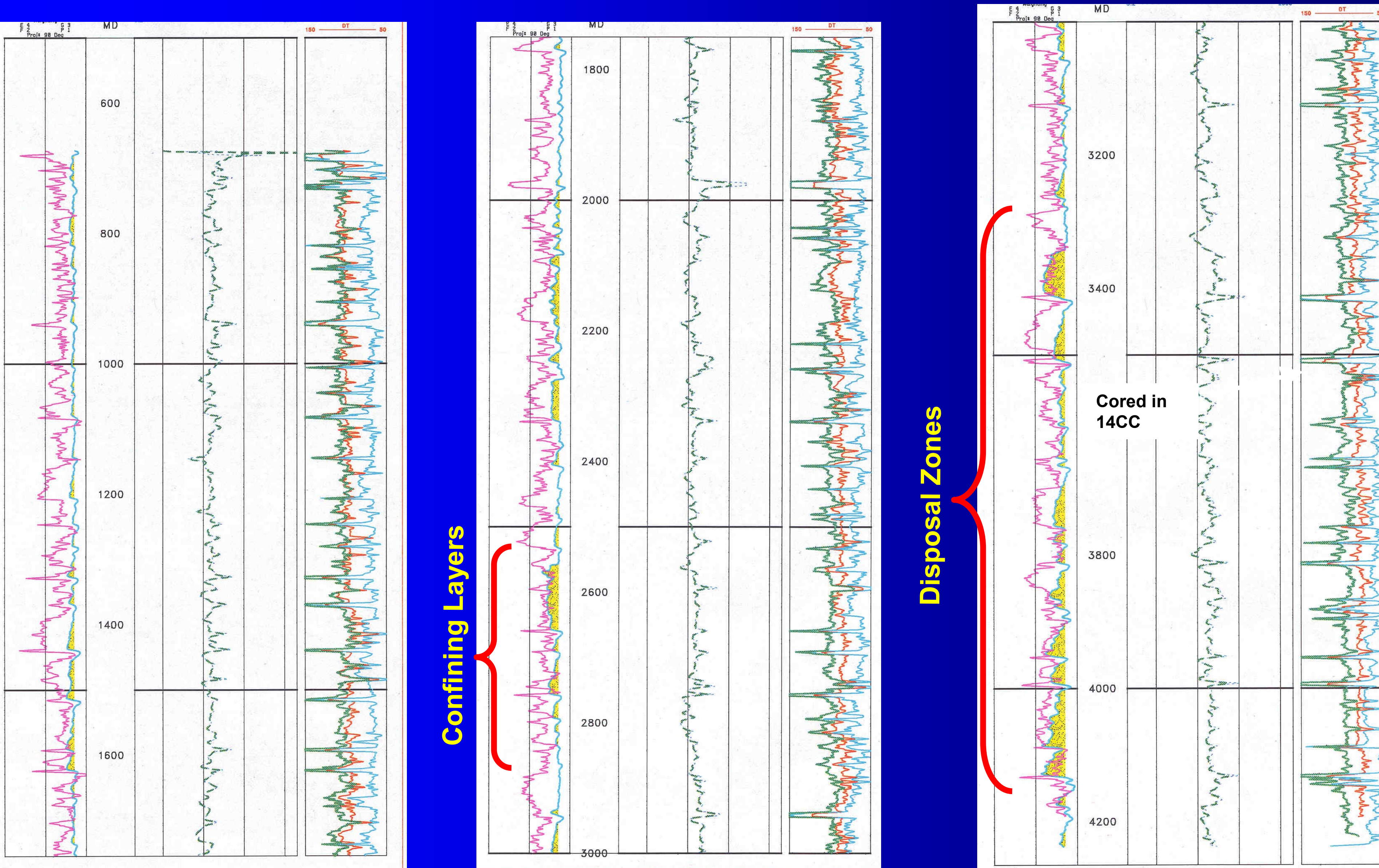
Arrows show flow direction of ground water in acquifers less than 150' deep. Contours in meters (from Montgomery, 1990)

Pioneer Well 1702-15DA-WDW

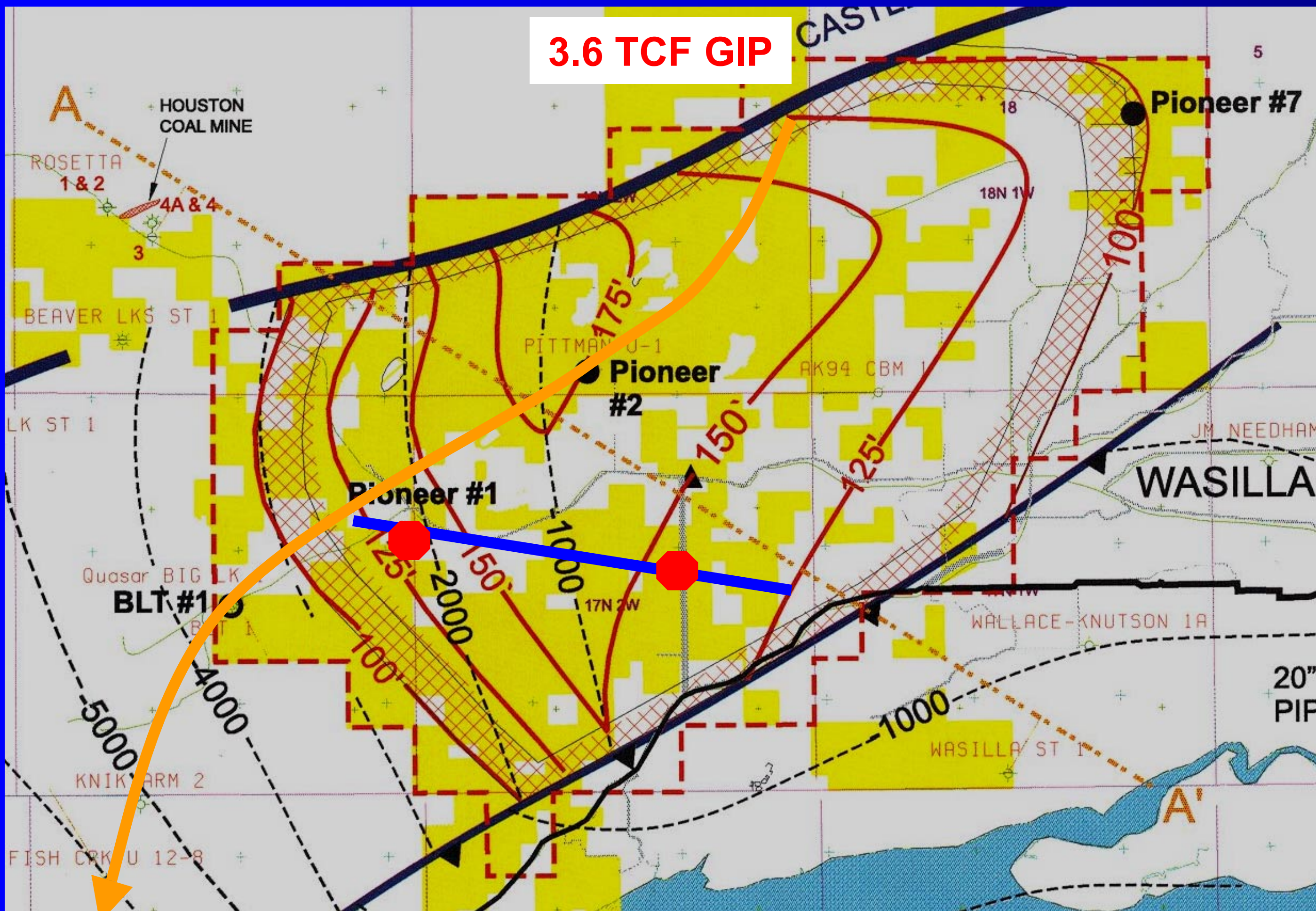
UNOCAL 76

26 Coal Seams >4’ thick

Total Net coal thickness 148’

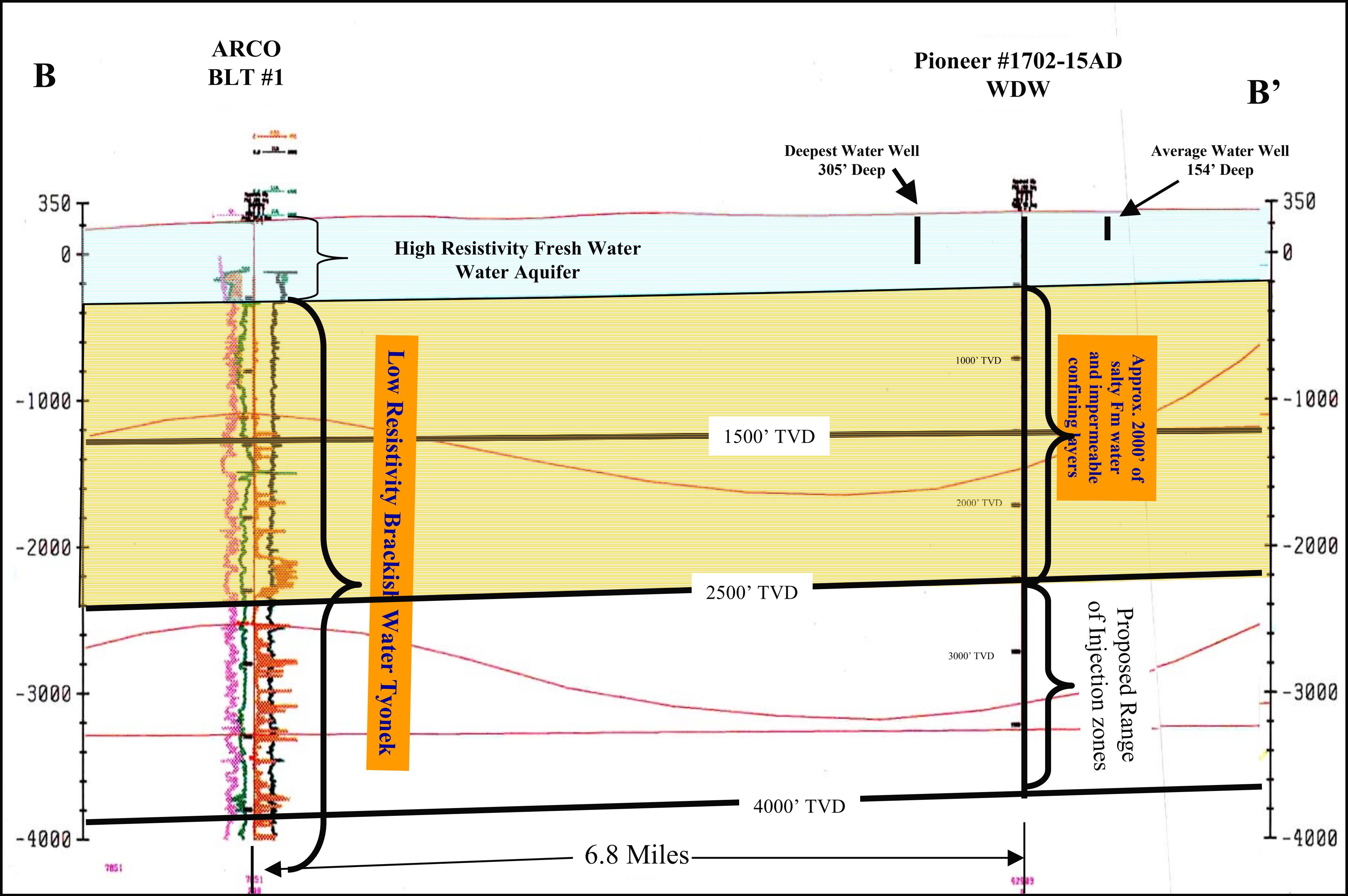


Anticipated Net Coal Pay Map



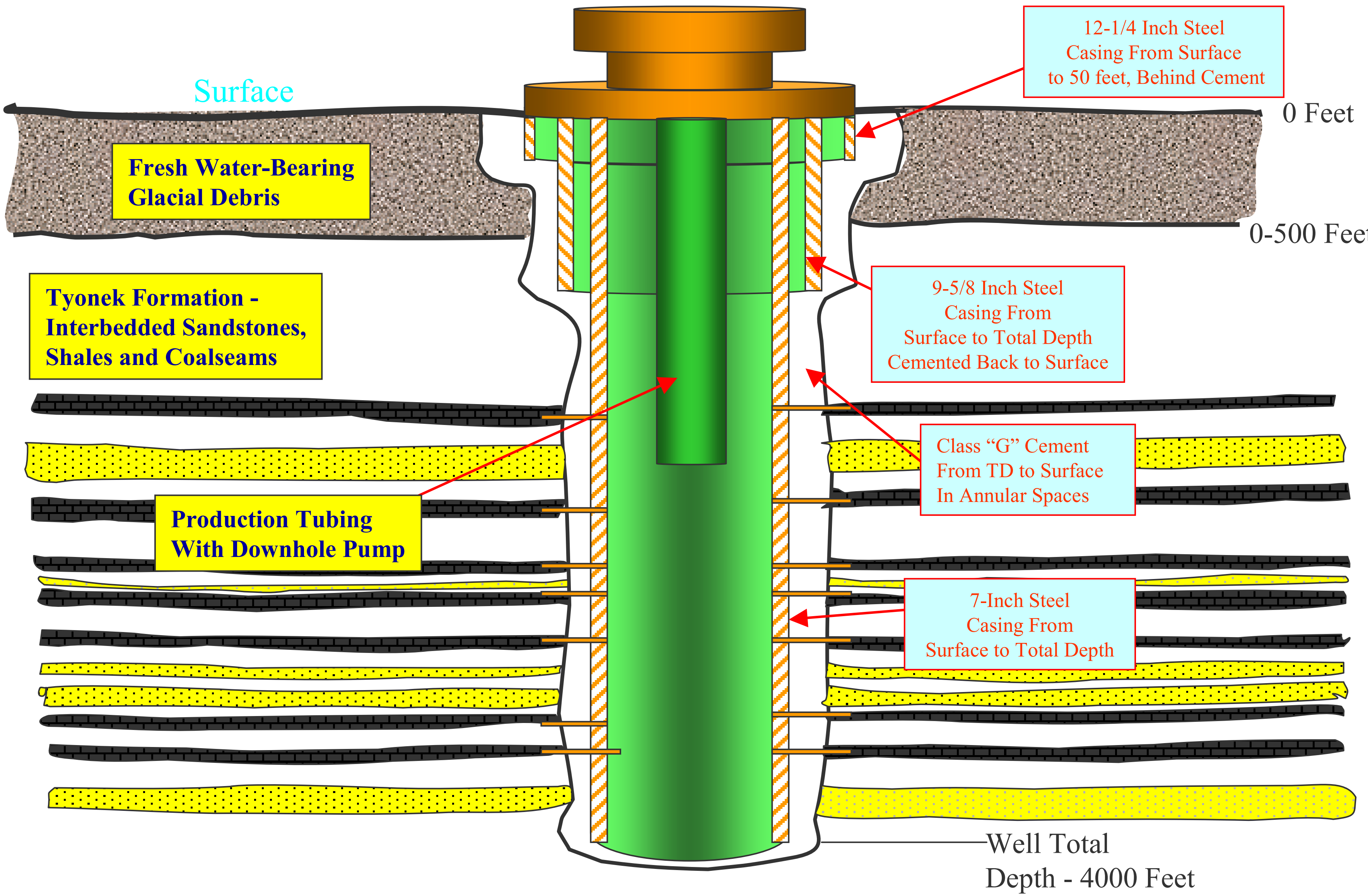
Correlation to nearest control from Vine Extension Project

UNOCAL 76

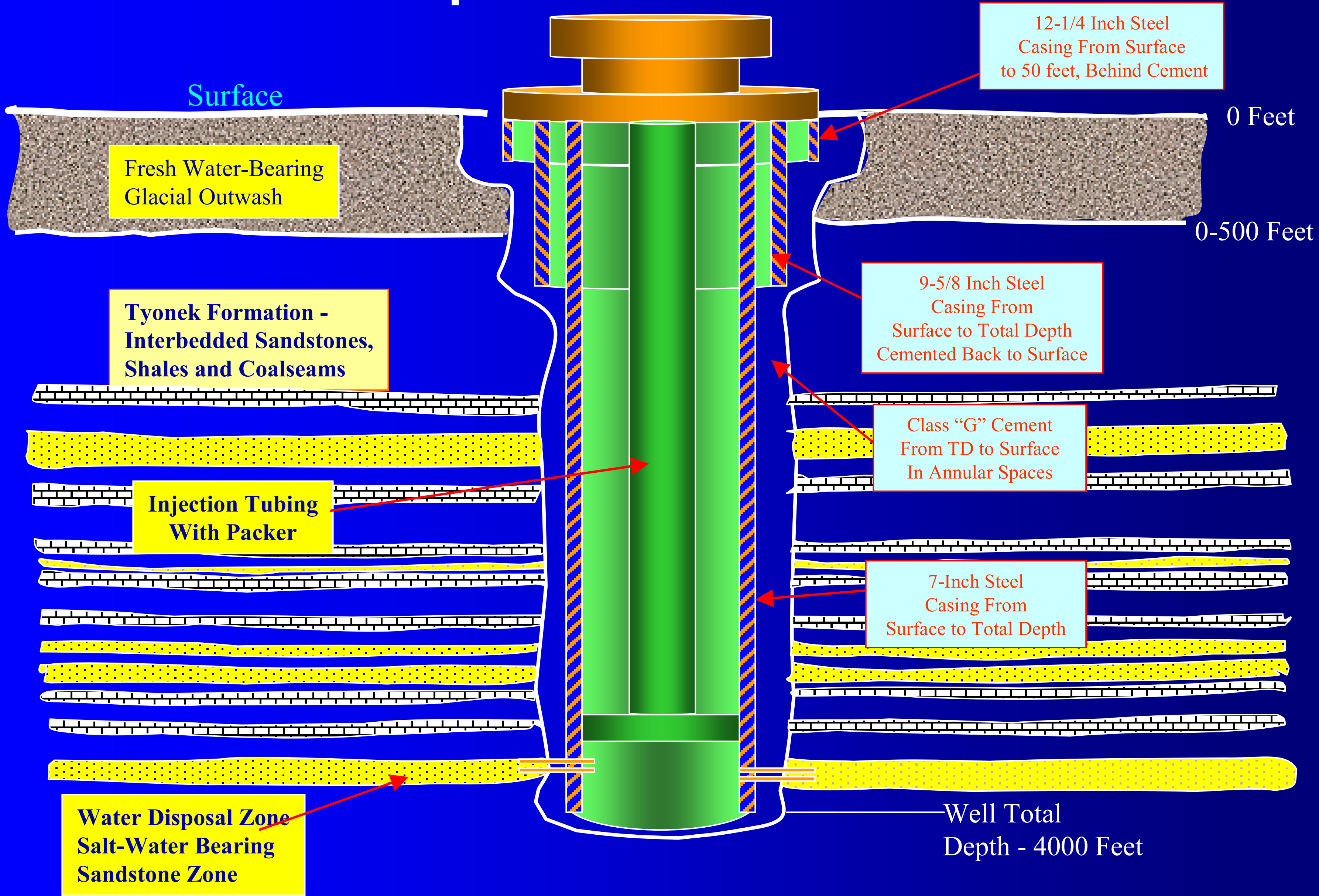


B
ARCO
BLT #1
Pioneer #1702-15AD
WDW
B'
Deepest Water Well
305' Deep
Average Water Well
154' Deep
350
0
-1000
-2000
-3000
-4000
High Resistivity Fresh Water
Water Aquifer
Low Resistivity Brackish Water Tyonek
Approx. 2000' of salty Fm water and impermeable confining layers
1000' TVD
1500' TVD
2000' TVD
2500' TVD
3000' TVD
4000' TVD
Proposed Range of Injection zones
6.8 Miles

Pioneer Unit
Coalbed Methane Producing Well
Simplified Wellbore Schematic



Pioneer Unit
Coalbed Methane Water Disposal Well
Simplified Wellbore Schematic



Drilling Phase- Ocean Energy (Operator) & Unocal 1999- 2000 (4 to 5 months)

- Conventional well control (BOPE & mud)
- Small Rig Imported from Michigan
- 3 Wells drilled (2 test, one disposal)- ~4000’
- One Well re-completed
- Drilled close to pipeline
- Core coals indicated relatively high gas content and rank

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Pioneer Coal Bed Methane Project

Operator- Ocean Energy
Unocal W.I. 50%
1999- 2000

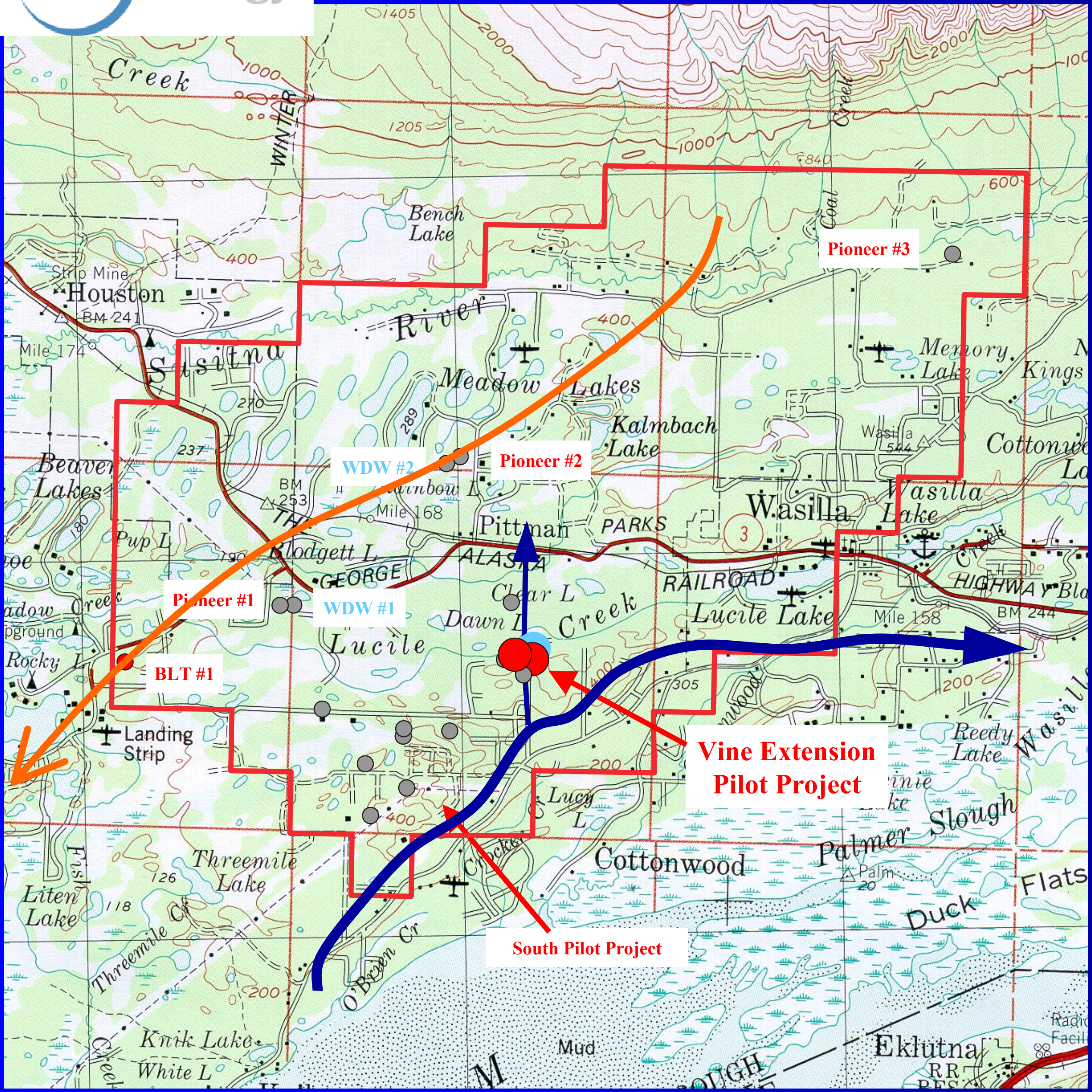
Pioneer Well 1702-15DA-WDW

Rig From Michigan
Spud - 7/31/99
TD- 4265 on 8/23/99
Presently Completed as Waste Disposal well

Ocean Energy™

CH&P #19

Wells Drilled in 1999-2000



- Drilled CBM test Well Location
- Drilled Class II Waste Disposal Well Location
- Proposed Wells not Drilled

6 miles

Ocean Energy™

UNOCAL 76

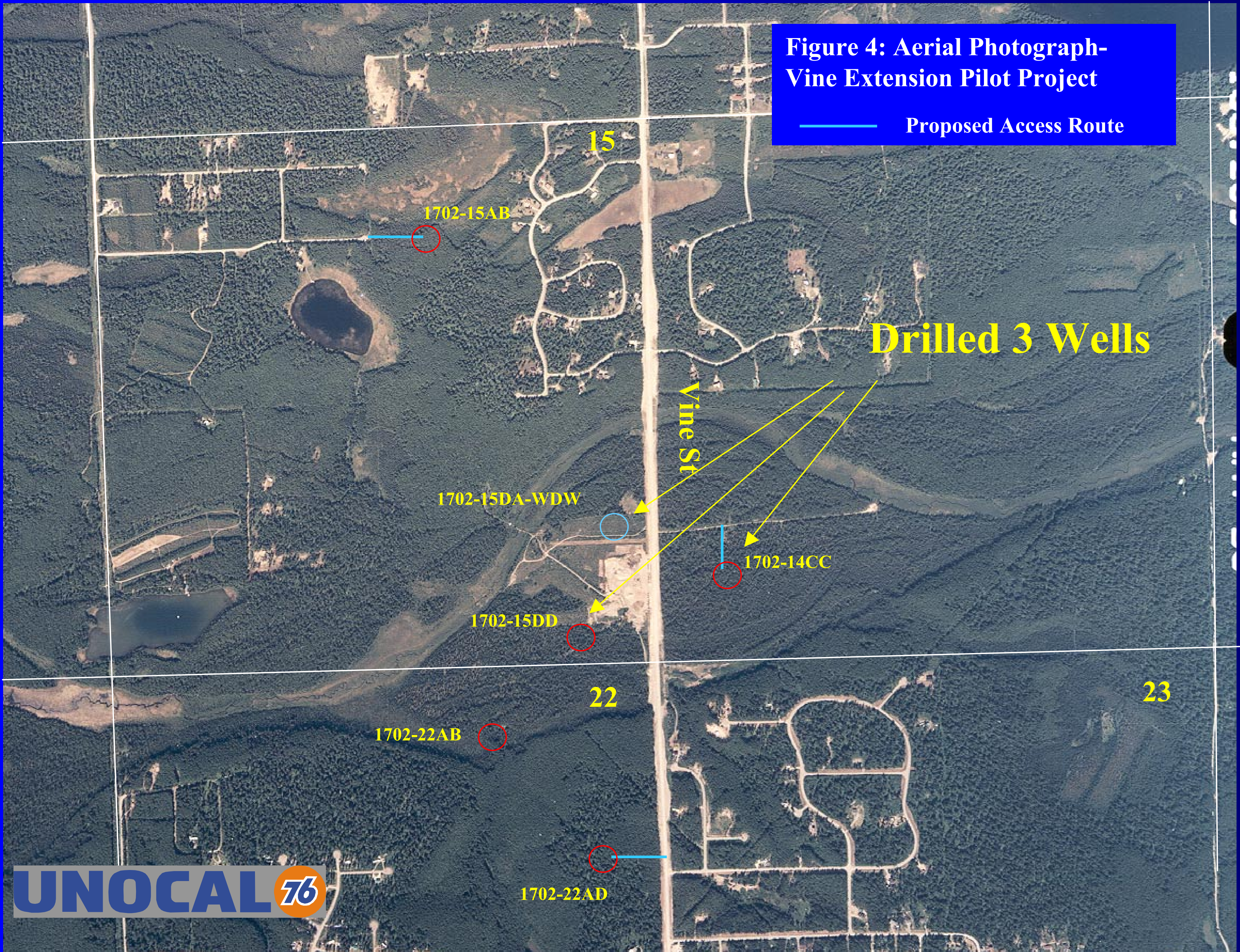


Figure 4: Aerial Photograph-
Vine Extension Pilot Project
Proposed Access Route
15
1702-15AB
Drilled 3 Wells
Vine St
1702-15DA-WDW
1702-14CC
1702-15DD
22
23
1702-22AB
1702-22AD
UNOCAL 76

Pioneer Well 1702-14CC

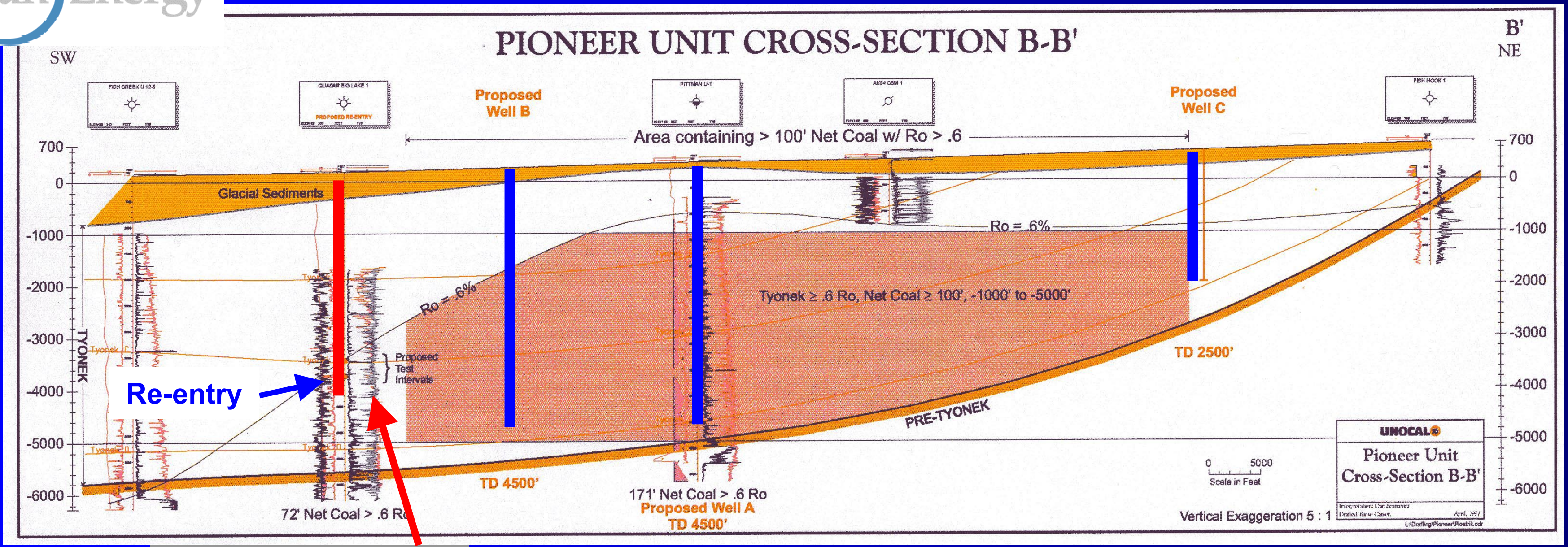
Pioneer Well 1702-15DD

WO Rig
Proposed TD- 4100'

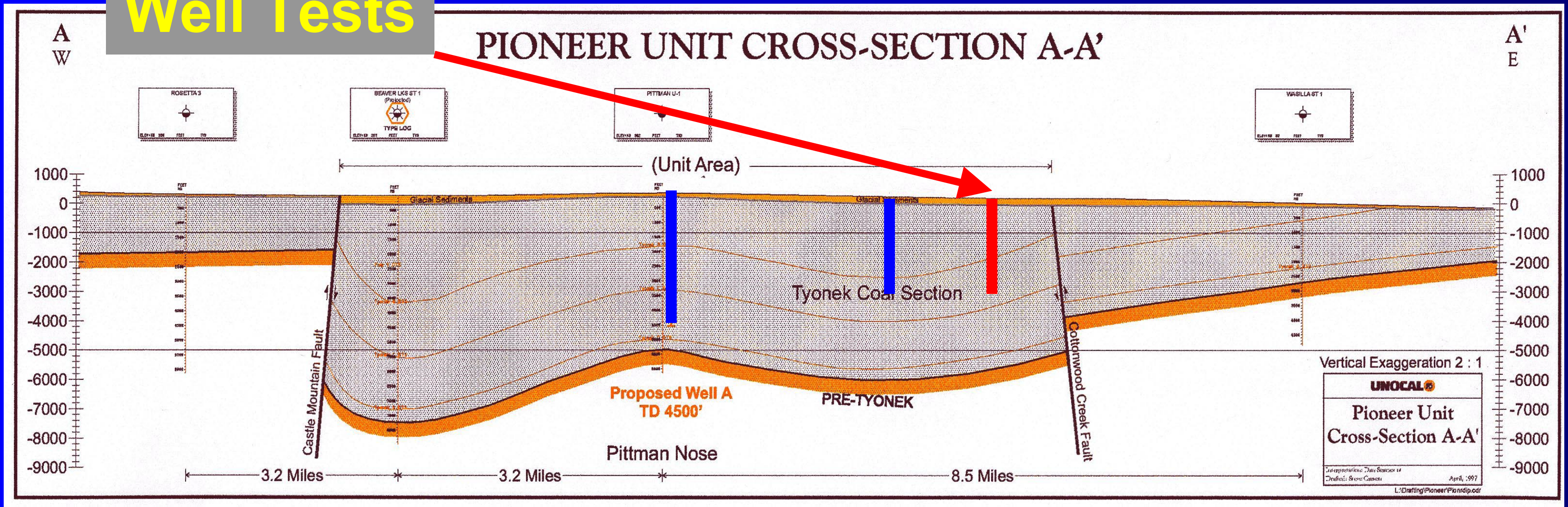
Pre- dirt Work

Ocean Energy™

UNOCAL 76



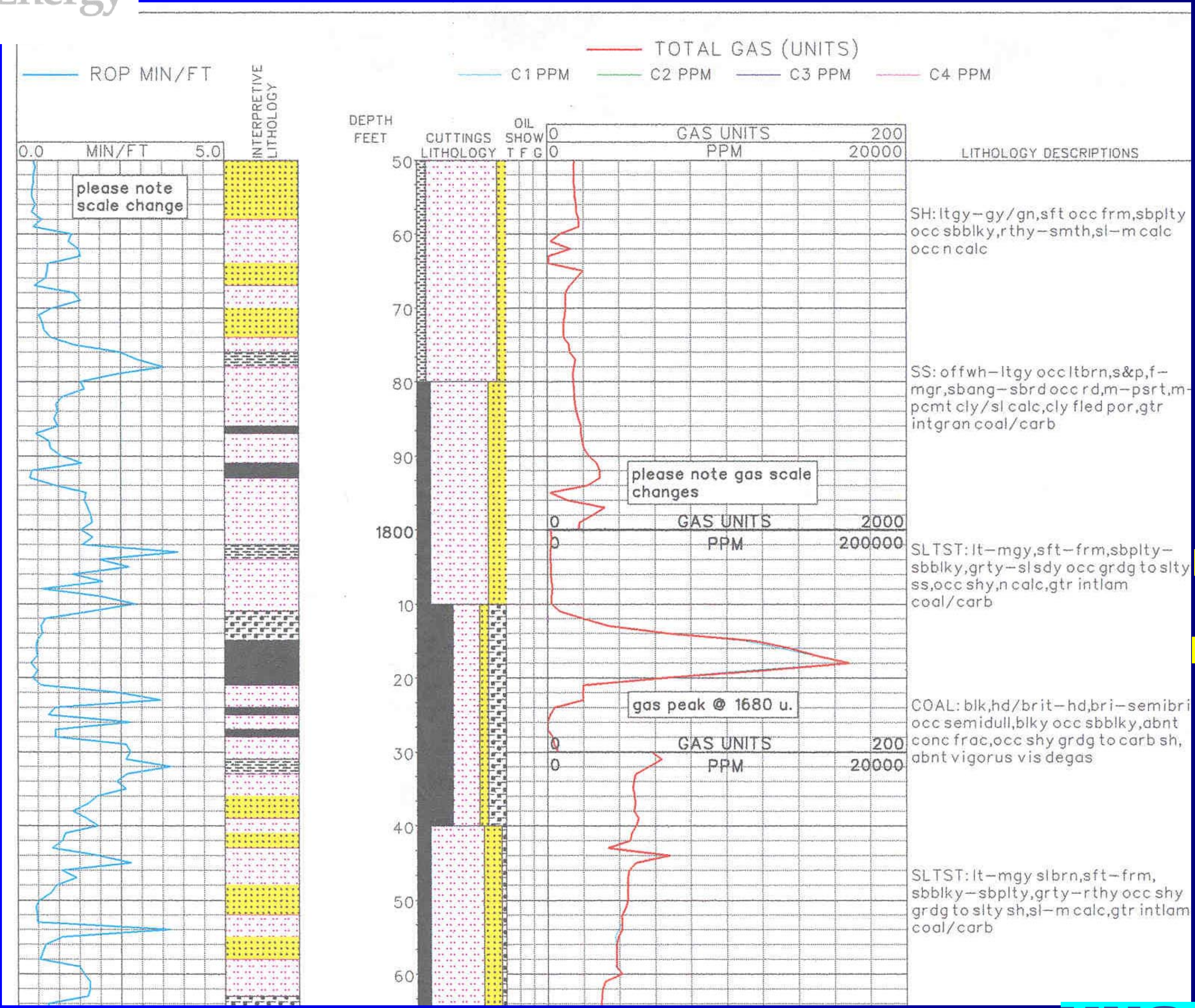
Well Tests



Cross-section View of 1999- 2000 Program

UNOCAL 76

Pioneer Well 1702-14CC



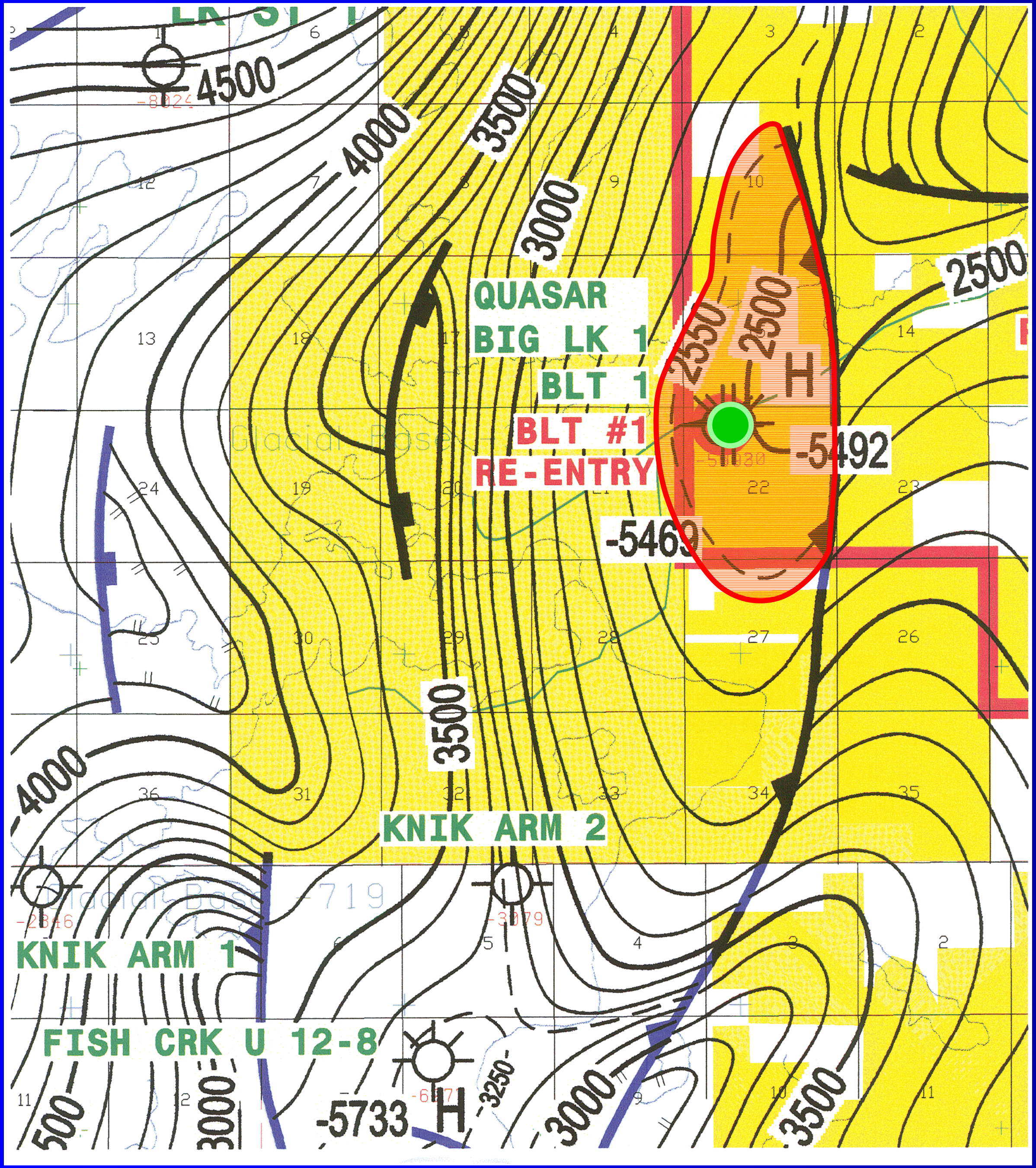
DA

I

Aerial Photo

Unocal Re-Entry of
ARCO BLT #1
793' FNL &
1,333'FWL
Sec 22, T17N R3W

One Mile



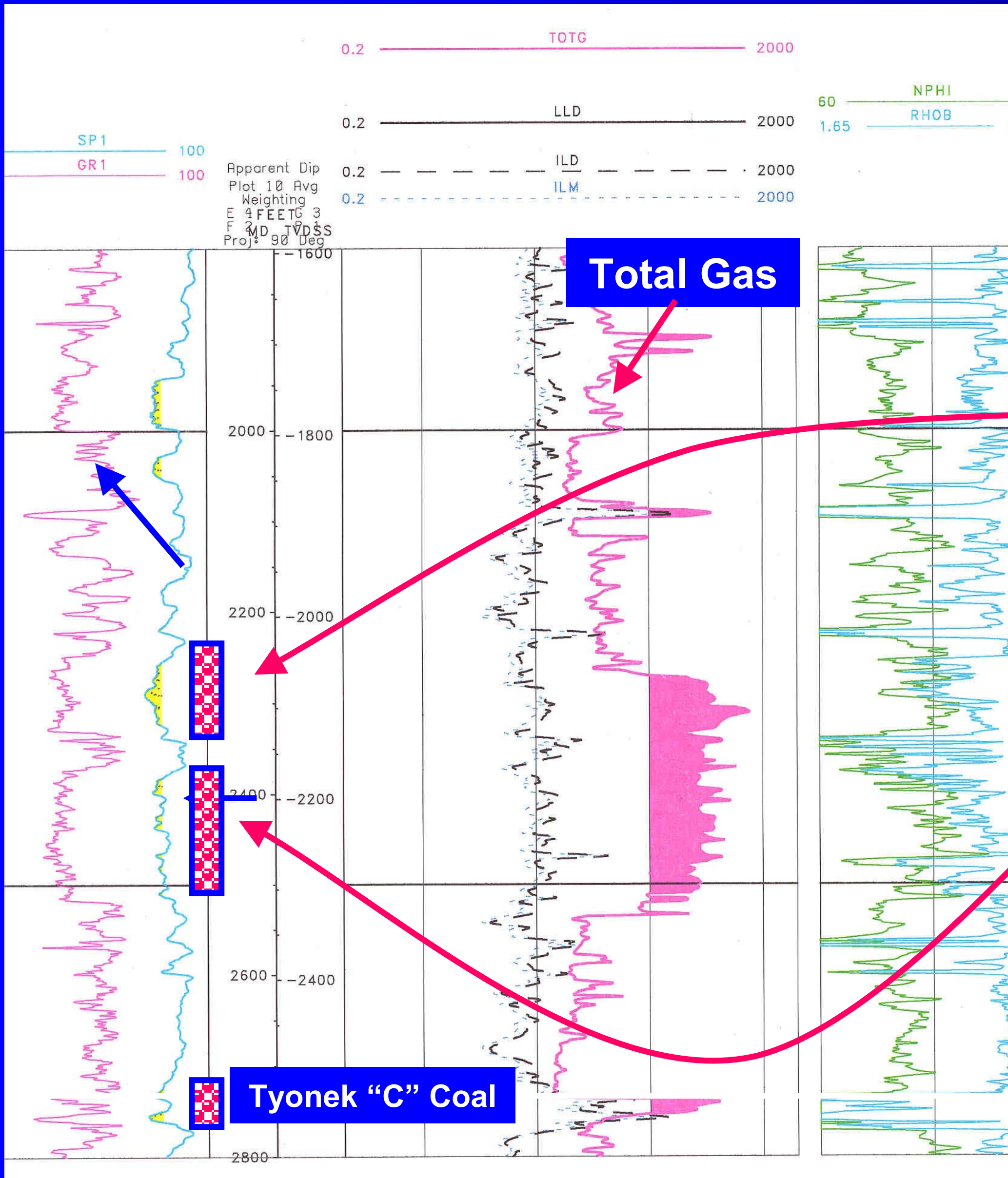
Big Lake Tyonek Gas

1645 acres

Near Top/Tyonek "C" Coal

UNOCAL 76

ARCO BLT #1



Re-Entry:

82' Net Sand

138' Net Sand

25% to 33% Porosity

UNOCAL 76

Testing Phase- Ocean Energy (Operator) & Unocal 1999- 2000 (Incomplete?)

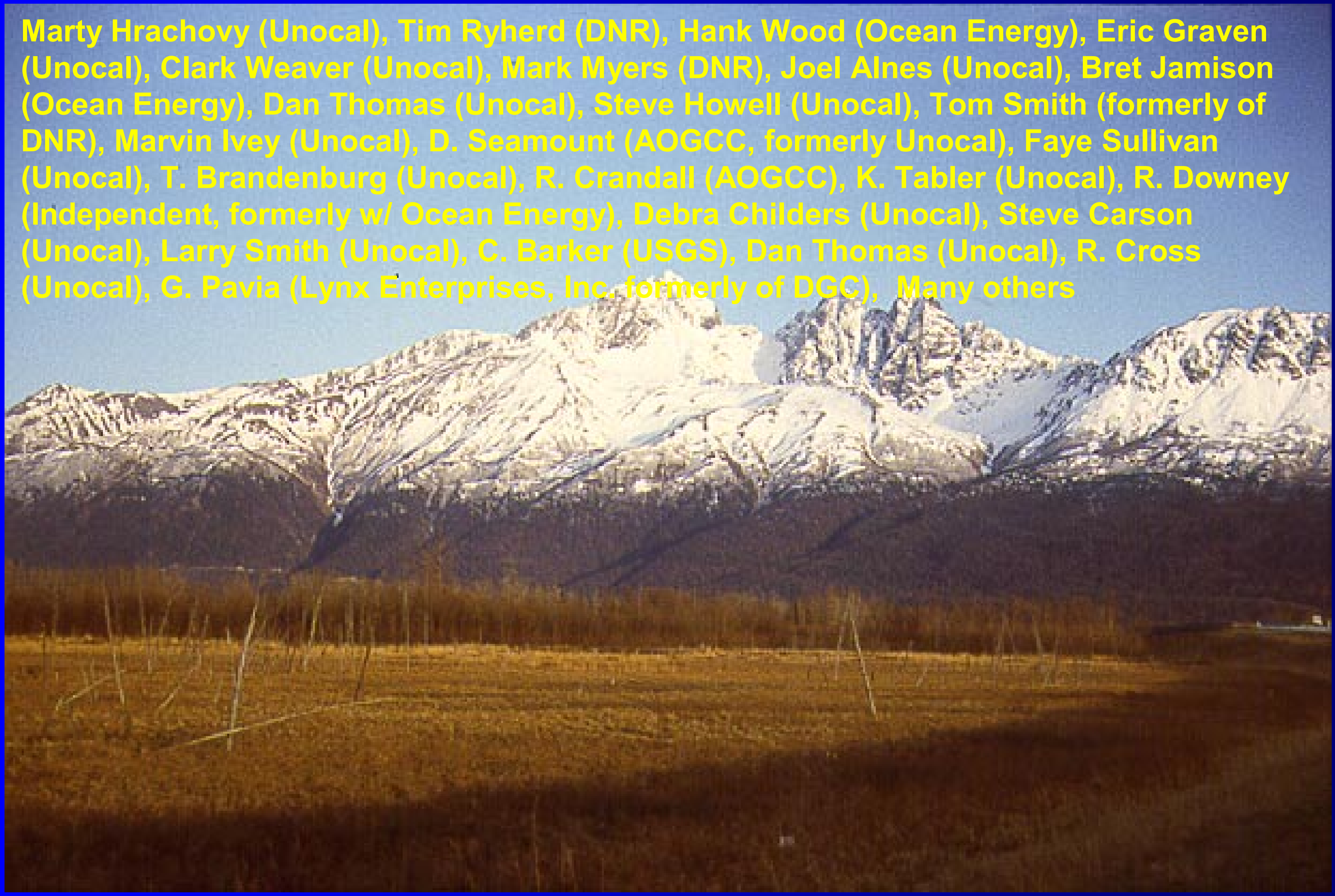
- Confidential

Possible Future Activity

- Fracture Stimulate Drilled Wells
- Drill new wells on Axis of Pittman Anticline
- Use non-damaging medium
- Evaluate need for regulations specific to CBM drilling & production operations

Acknowledgements to Ocean Energy & UNOCAL 76

Marty Hrachovy (Unocal), Tim Ryherd (DNR), Hank Wood (Ocean Energy), Eric Graven (Unocal), Clark Weaver (Unocal), Mark Myers (DNR), Joel Alnes (Unocal), Bret Jamison (Ocean Energy), Dan Thomas (Unocal), Steve Howell (Unocal), Tom Smith (formerly of DNR), Marvin Ivey (Unocal), D. Seamount (AOGCC, formerly Unocal), Faye Sullivan (Unocal), T. Brandenburg (Unocal), R. Crandall (AOGCC), K. Tabler (Unocal), R. Downey (Independent, formerly w/ Ocean Energy), Debra Childers (Unocal), Steve Carson (Unocal), Larry Smith (Unocal), C. Barker (USGS), Dan Thomas (Unocal), R. Cross (Unocal), G. Pavia (Lynx Enterprises, Inc. formerly of DGC), Many others



Pioneer Project

EVERGREEN

RECOGNIZED LEADER IN COAL BED METHANE TECHNOLOGY

Best Wishes for Success, Evergreen!

Lessons Learned From Two Decades of Coalbed Methane Production in Lower 48 States

Speaker

Robert Downey
Energy Ingenuity Company

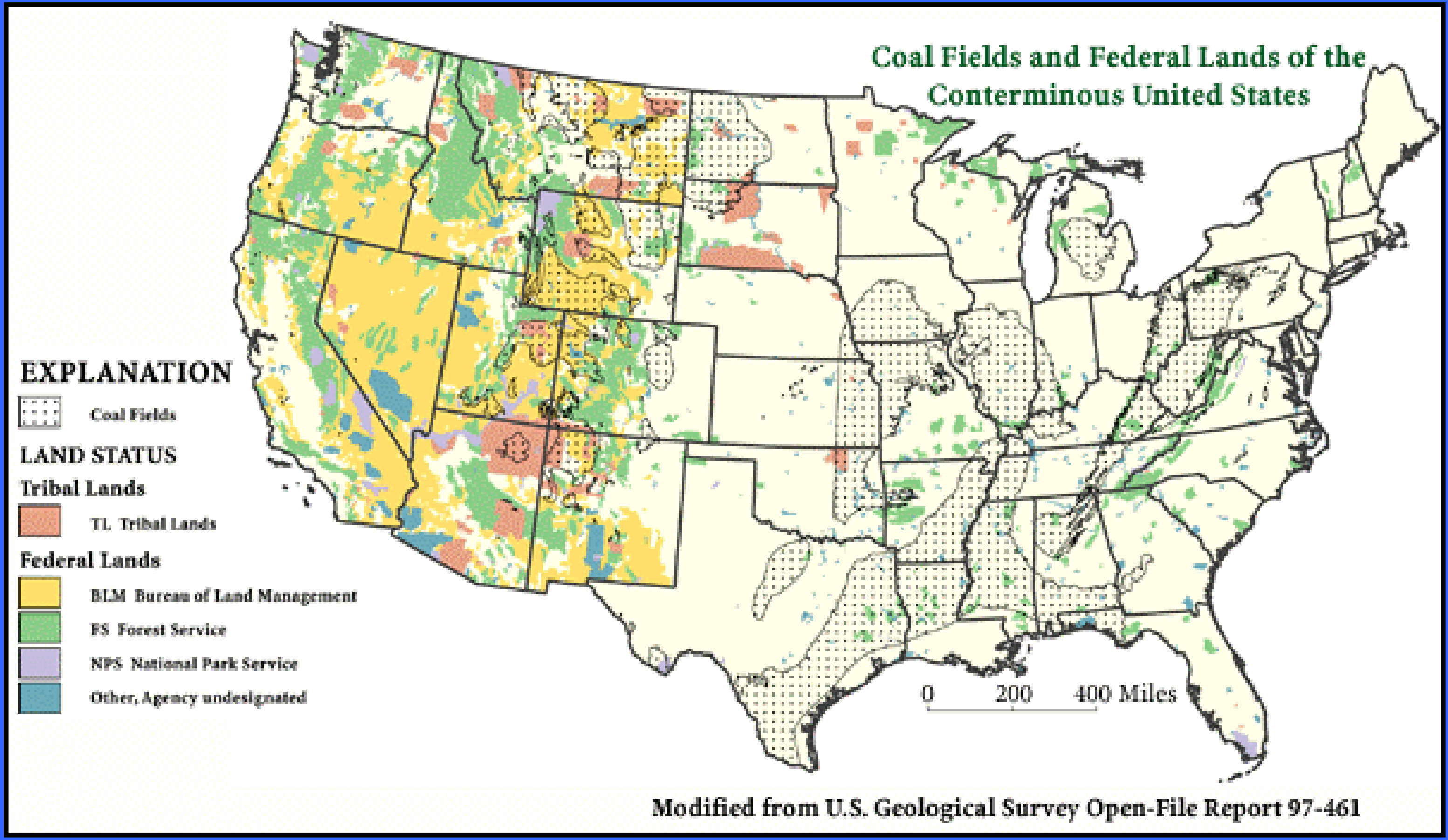
Lessons Learned From Two Decades of Coalbed Methane Production in the Lower 48 States

Robert A. Downey
Energy Ingenuity Company

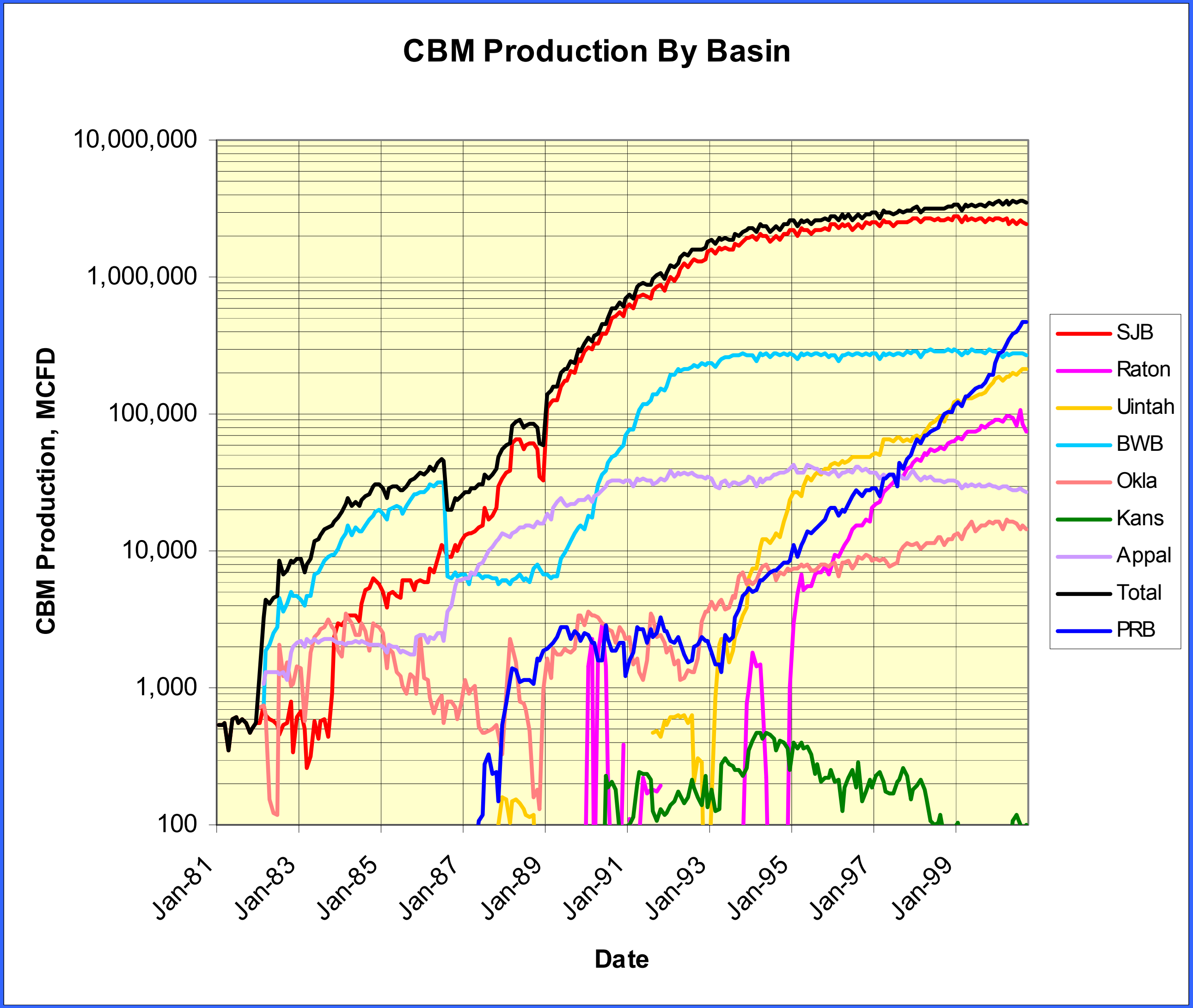
A Brief History of CBM Exploration and Development

- Coal Mine Degasification – 1960’s & 1970’s
- DOE CBM Basinal Resource Assessments – mid-1970’s
- Initial CBM Test Wells – BWB, SJB in late 1970’s
- Growth in CBM Exploration & Development and the Section 29 Tax Credit
- GRI Funded Programs and CBM Development in New Coal Basins such as Raton, Powder River, Arkoma and Central Applachia
- Second Round of Section 29 Tax Credit CBM Development, 1990-1992
- Full-Scale Development in the Raton Basin, Maturation of the BWB, CBM Enhanced Recovery in SJB, and Rapid Expansion of the PRB and Uintah CBM Plays.

Map of CBM Basins of the U.S.



Number and Location of CBM Wells & Daily



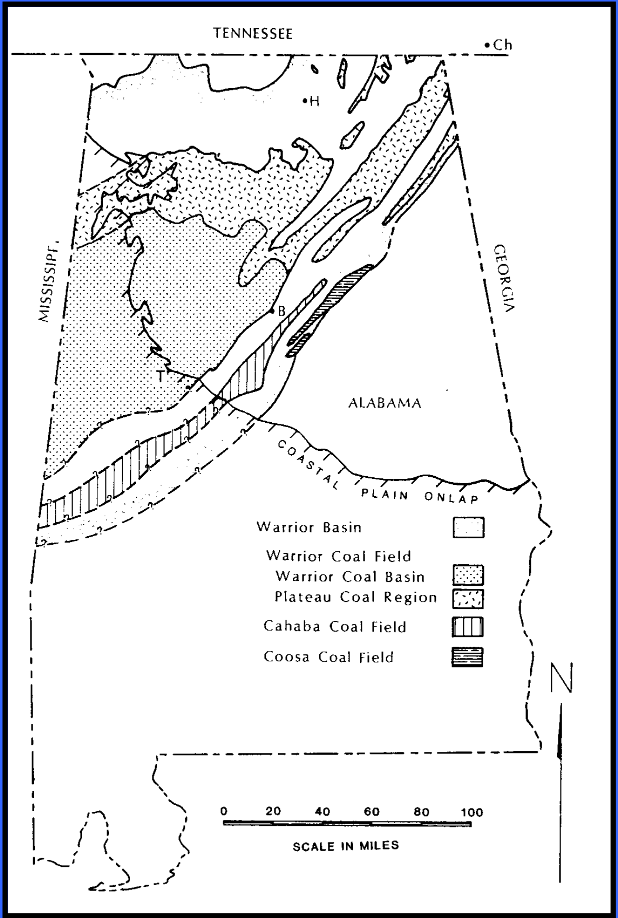
A Quick Overview of CBM Exploration & Development by Basin or Area

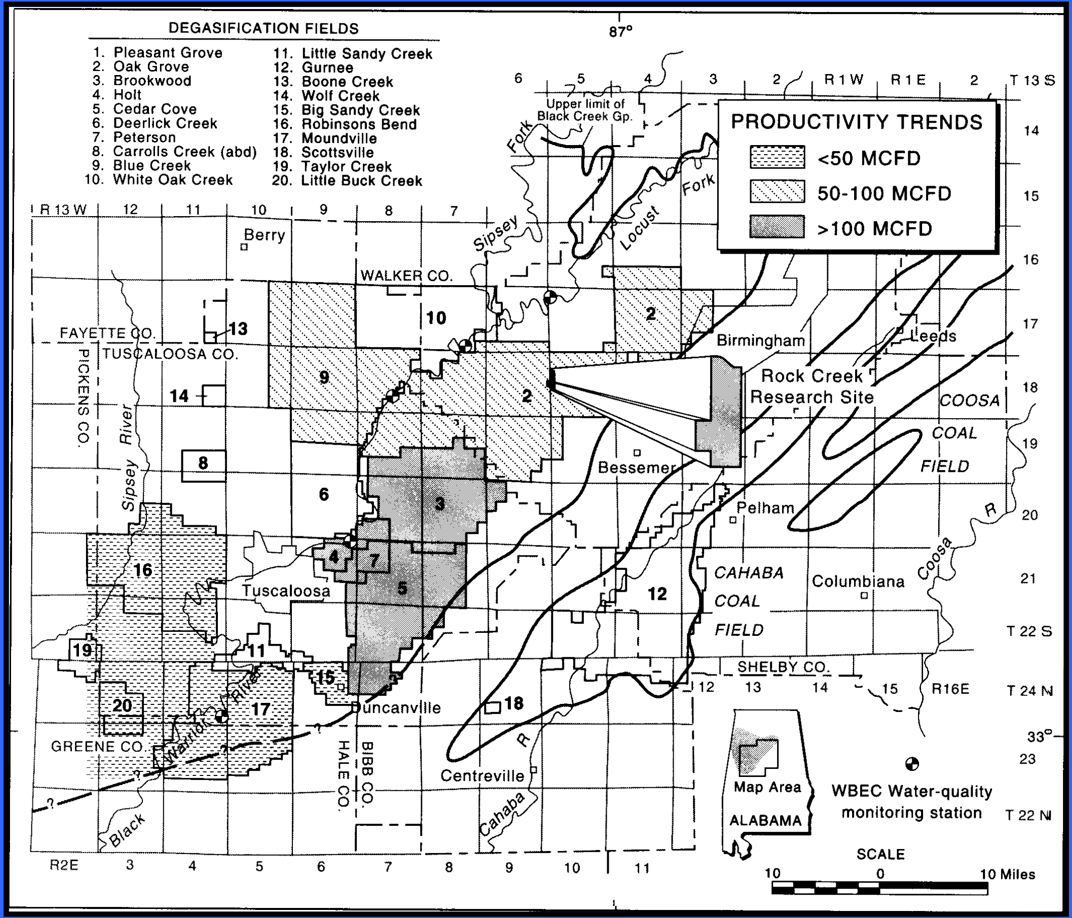
Some Lessons and Observations, by Basin

Appalachian Basin

- Some of the oldest CBM production, CBM producers include large coal mining companies, such as Consol, a few large independents, such as Equitable, and a large number of very small companies.
- Coalseams are Pennsylvanian age, high rank, generally relatively thin, with low permeability.
- Best production is structurally controlled, and may relate to secondary porosity development and gas migration updip.
- Best production is in western Virginia, some near underground coal mining operations.
- Production has been declining over the past 5 years.
- A difficult area to develop a significant leasehold position in due to metes and bounds tracts, divided ownerships, and questions about who has CBM rights – coal lessees or oil and gas lessees.
- Early research by U.S. Bureau of Mines led to development of first CBM reservoir simulation models, tests on coalseam hydraulic fracturing, gas content analyses methods.

Black Warrior Basin, Alabama



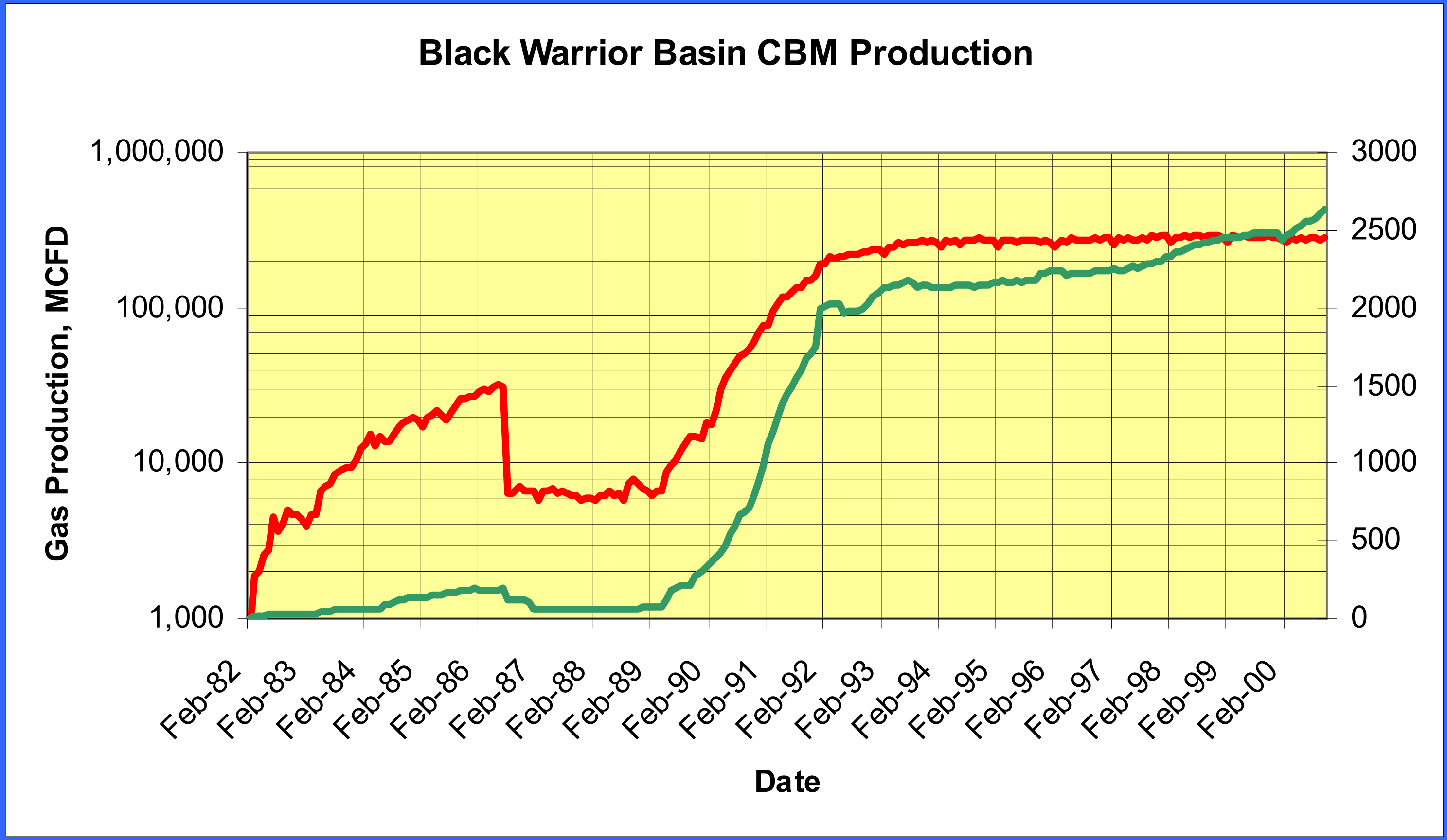


Energy Ingenuity Company

Black Warrior Basin

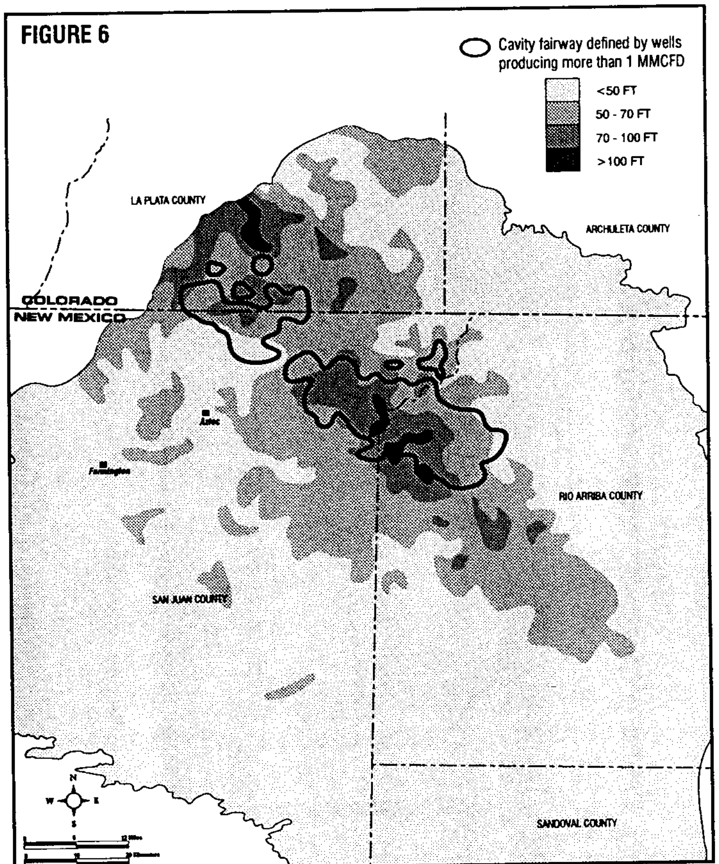
- First Large-Scale Development Play in Eastern U.S.
- Multiple Thin, High Rank, High Permeability Coalseams at 1000-2000 feet
- CBM Production Shown to be Influenced by Structure
- First Area to Contend with Surface Handling of CBM Produced Water in Sensitive Areas (On a Large Scale)
- First Application of PCP Pumps in CBM Wells
- Featured a Robust CBM Degasification Program in Advance of a Longwall Mining Program
- Led to the Development of the International CBM Symposium at University of Alabama
- Now a Mature Play with Slightly Declining Production

Black Warrior Basin Wells and Production Rates



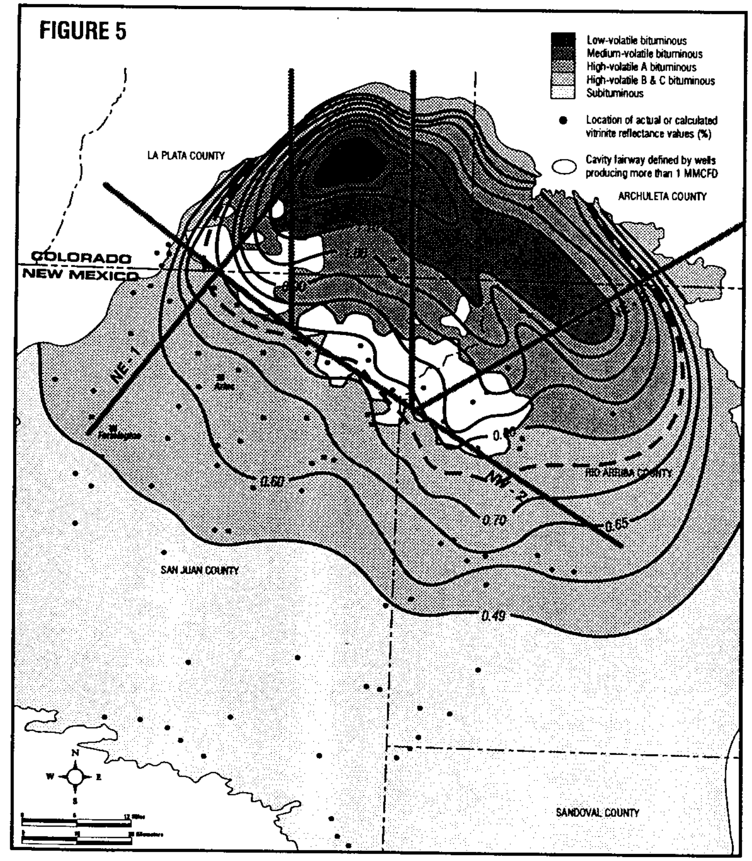
San Juan Basin

NET COAL THICKNESS OF FRUITLAND FORMATION



Modified After AYERS et al, 1991

VITRINITE REFLECTANCE OF THE FRUITLAND COALS

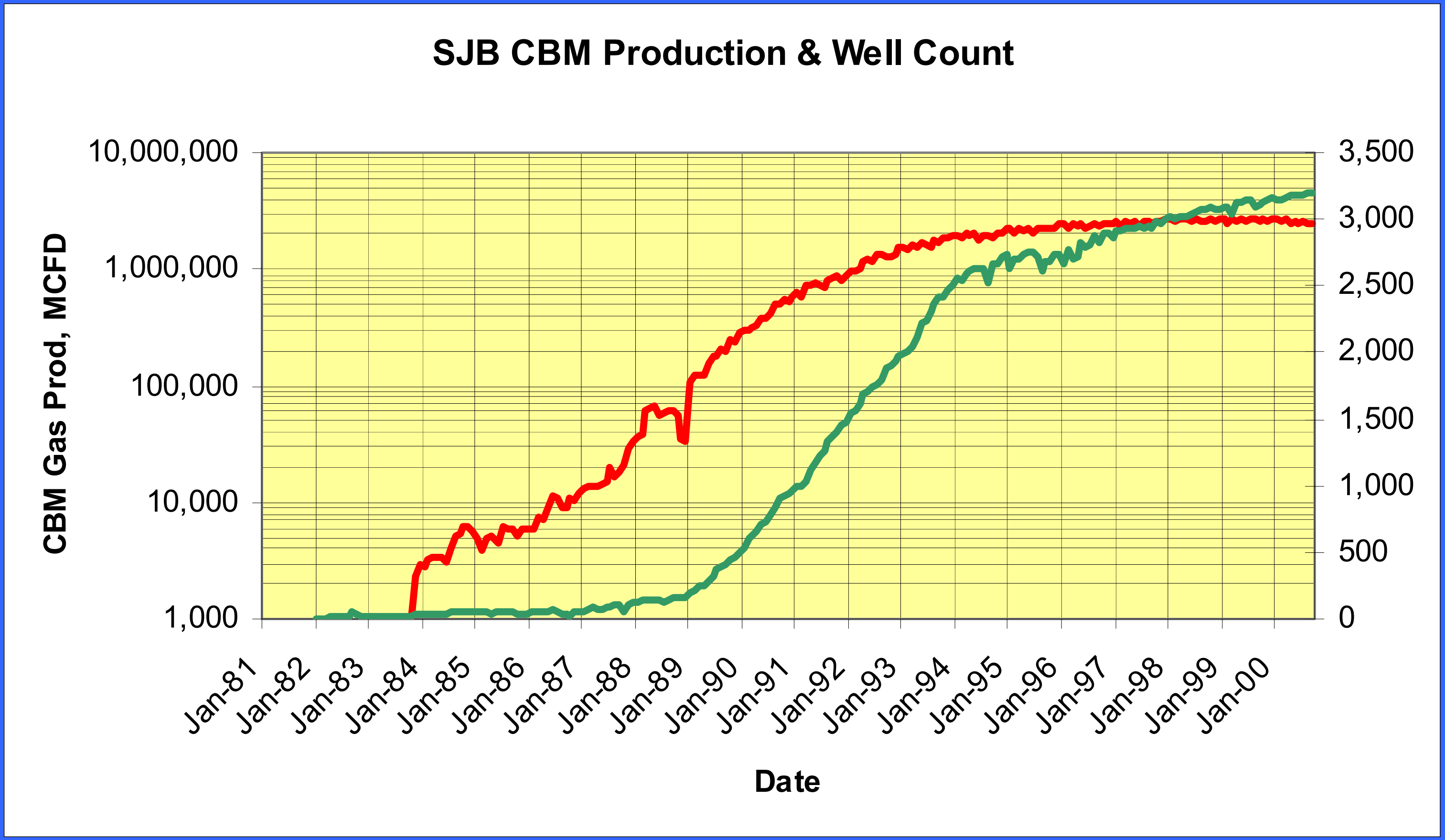


Modified After SCOTT et al, 1991

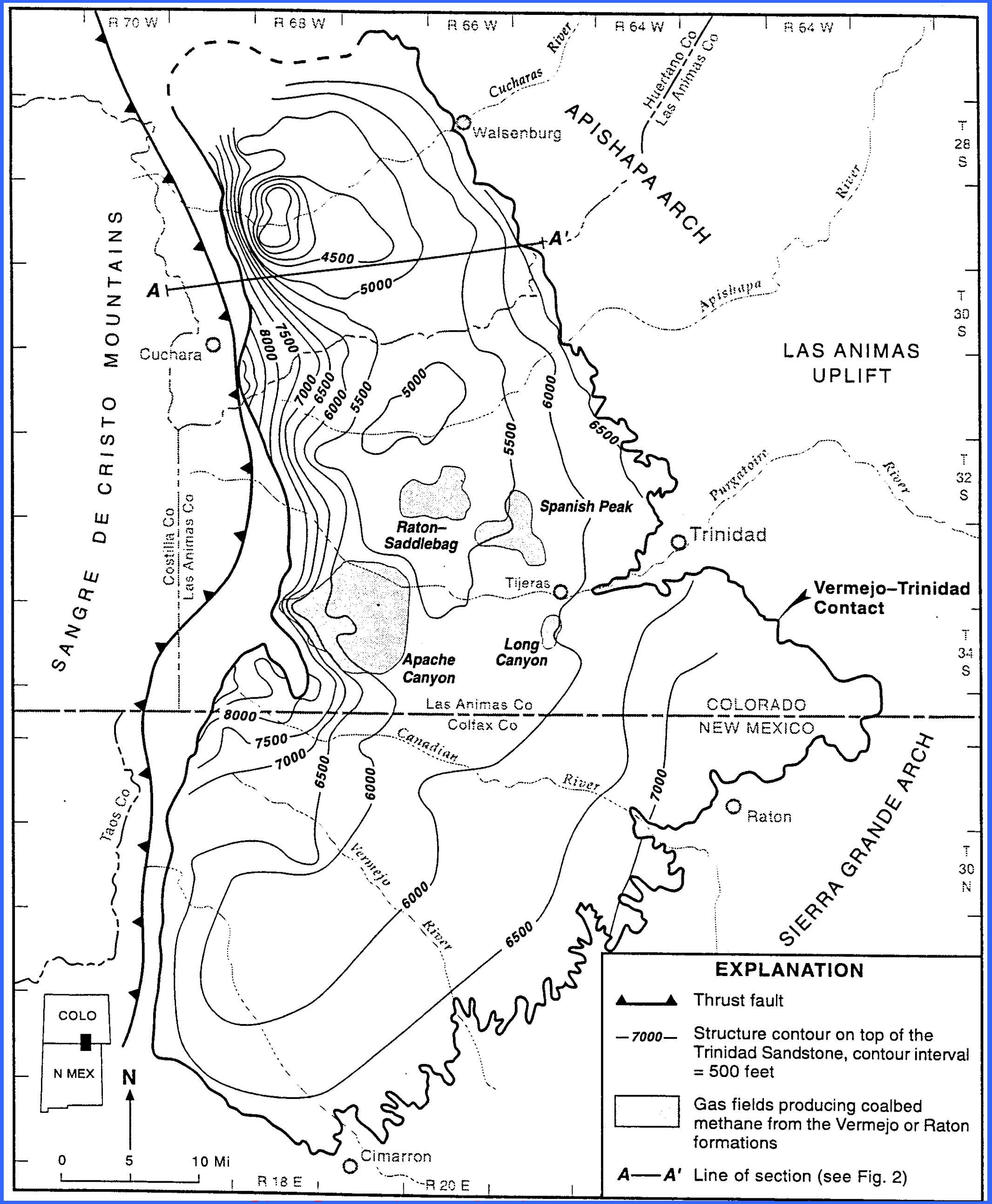
San Juan Basin

- World's Best Coalbed Methane Production – some wells > 30 BCF Cumulative Prod.
- Largest CBM Play in the World – about 2.4 BCFD of total 3.5 BCFD U.S. CBM Prod.
- About 3,200 out of 11,200 total U.S. CBM wells (~ 29%)
- Biggest CBM operator is Burlington, but major contributions from Amoco, Devon, Phillips, Conoco and others.
- First CBM Test in the Fruitland Formation following over 12,000 wellbore penetrations spanning 50+ years of gas exploration & development
- First CBM Basin Featuring Best CBM Production along the Synclinal Axis in an Overpressured "Fairway"
- First Well Completion Featuring Cavitation Technique – An Accident? – Which Dramatically Increased Well Production Rates
- First Big Controversy over Well Spacing – 320 Acres/Well vs. 160 Acres/Well
- First Test of Enhanced CBM Recovery Process using Nitrogen
- First Nitrogen Enhanced CBM Recovery Project – Very Successful

SJB CBM Production



Raton Basin

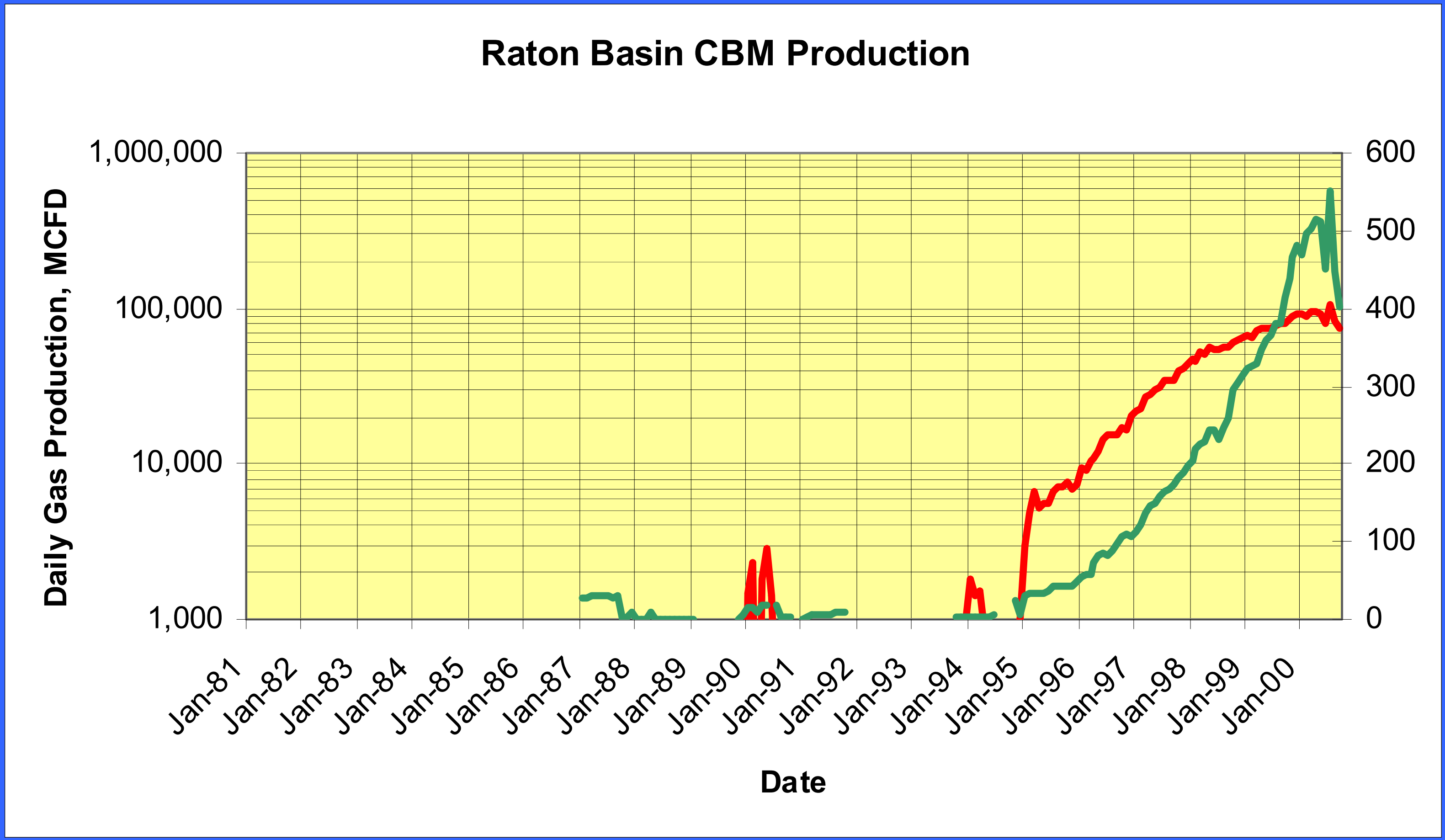


R 70 W
R 68 W
R 66 W
R 64 W
R 64 W
T 28 S
T 30 S
T 32 S
T 34 S
T 30 N
R 18 E
R 20 E
Cucharas River
Huerfano Co
Las Animas Co
Walsenburg
APISHAPA ARCH
A
A'
Apishapa
LAS ANIMAS UPLIFT
SANGRE DE CRISTO MOUNTAINS
Cuchara
Costilla Co
Las Animas Co
Raton–Saddlebag
Spanish Peak
Purgatoire River
Trinidad
Tijeras
Vermejo–Trinidad Contact
Long Canyon
Apache Canyon
Las Animas Co
Colfax Co
COLORADO
NEW MEXICO
Canadian River
Taos Co
Raton
SIERRA GRANDE ARCH
Vermejo River
Cimarron
COLO
N MEX
N
0
5
10 Mi
EXPLANATION
Thrust fault
7000 Structure contour on top of the Trinidad Sandstone, contour interval = 500 feet
Gas fields producing coalbed methane from the Vermejo or Raton formations
A—A' Line of section (see Fig. 2)

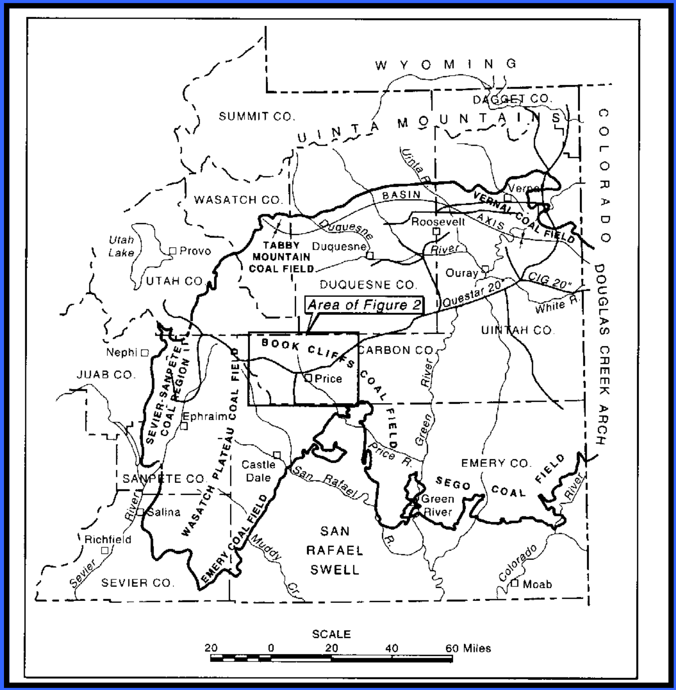
Raton Basin

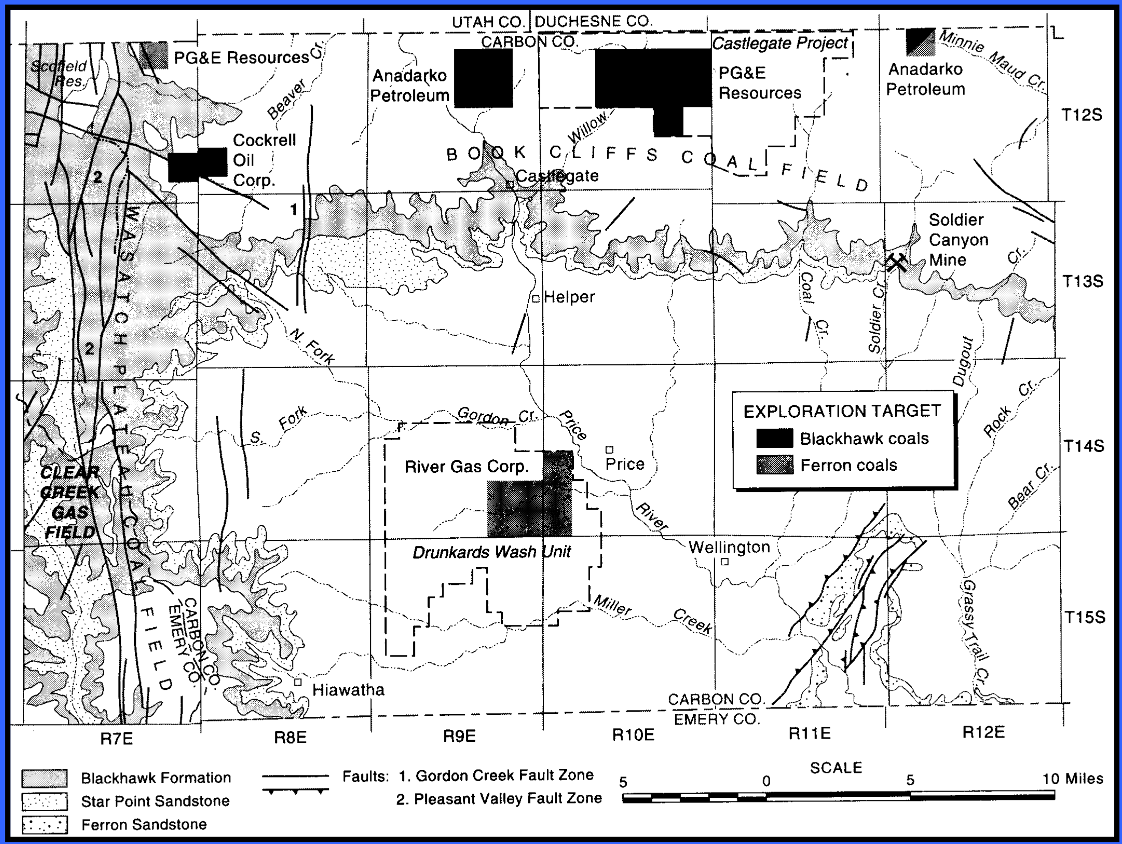
- Perhaps lowest cost ($/MCF) CBM play in U.S.
- Evergreen is the dominant operator with the largest and most prospective acreage position.
- Play took off when Evergreen applied novel drilling, completion and production techniques to increase production & trim costs
- Production is from multiple, thin, high rank coals in both the Vermejo and Raton formations.
- Water production is fresh and can be surface-discharged
- Southern, New Mexico portion of the basin is still largely undeveloped, but has seen favorable results to date.
- Has prolific gob gas production (~ 2 MMCFD) from the abandoned & sealed Golden Eagle coal mine.
- Production has recently experienced a decline, but will likely increase with renewed drilling activity.

Raton Basin CBM Production



Uintah Basin

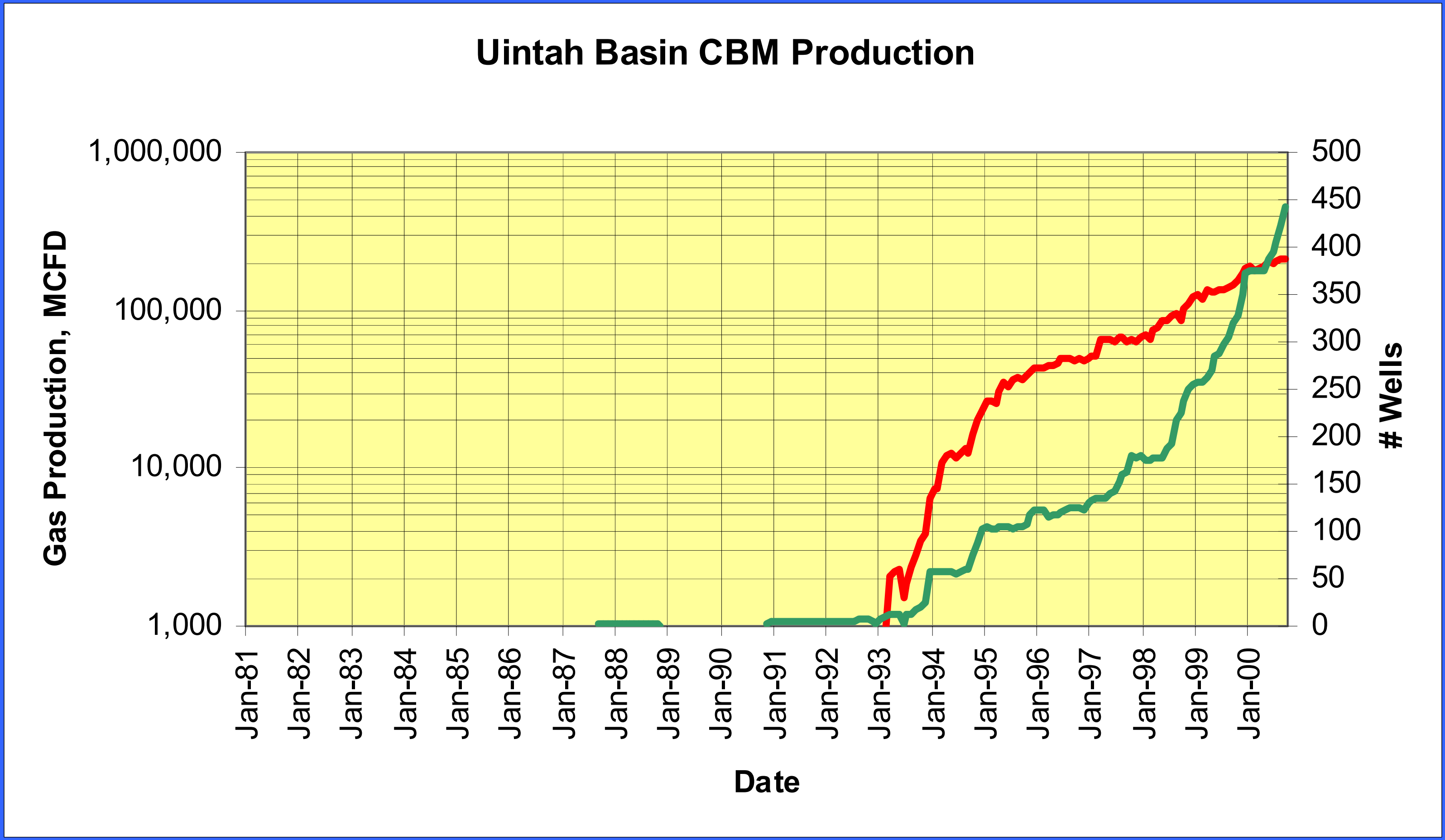




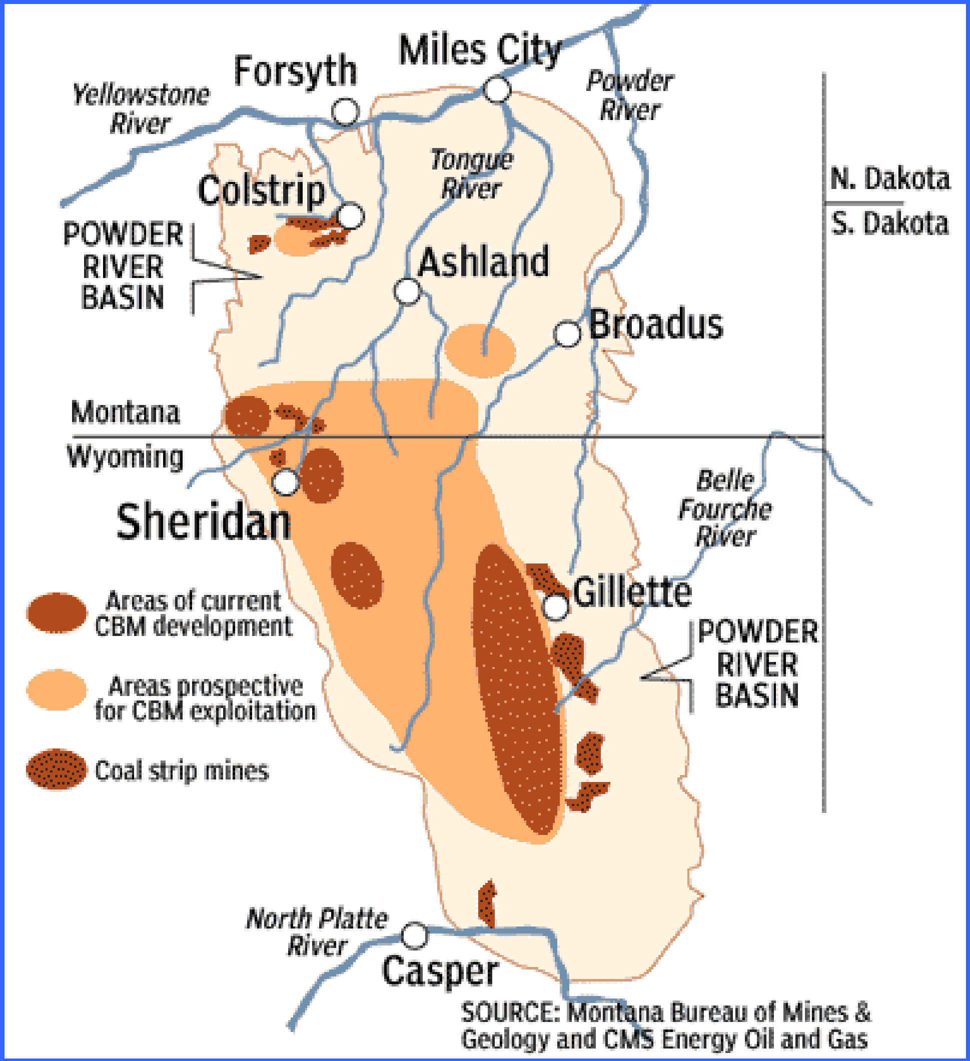
Uintah Basin

- Second most prolific CBM wells in the U.S.
- Total gas production continues to increase.
- Production is controlled by structure and depositional controls on the Ferron coalseams.
- Mesaverde coalseams may yet prove commercially viable with renewed exploration efforts.
- Significant development potential in the Ferron coalseams remains.
- Production on southern end of the Ferron trend not as prolific as Drunkards Wash Unit.
- Subject of extensive research effort by the U.S.G.S. to understand the geology and controls on production rates and reserves.
- This play was exploited effectively by River Gas Corporation, relying on expertise gained from the Black Warrior Basin. River Gas was not the first company in the play, but proved to be the most efficient.

Uintah Basin CBM Production



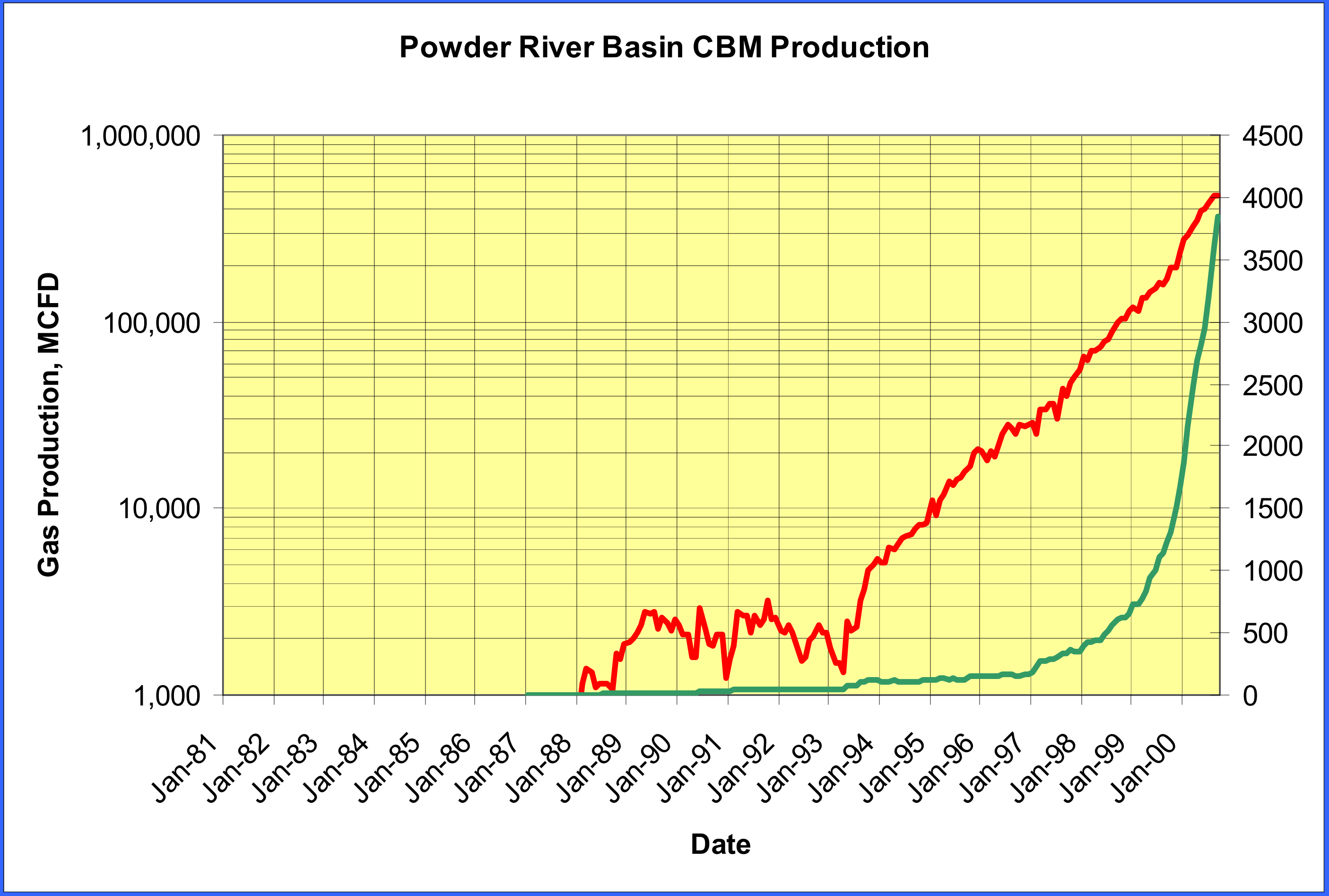
Powder River Basin



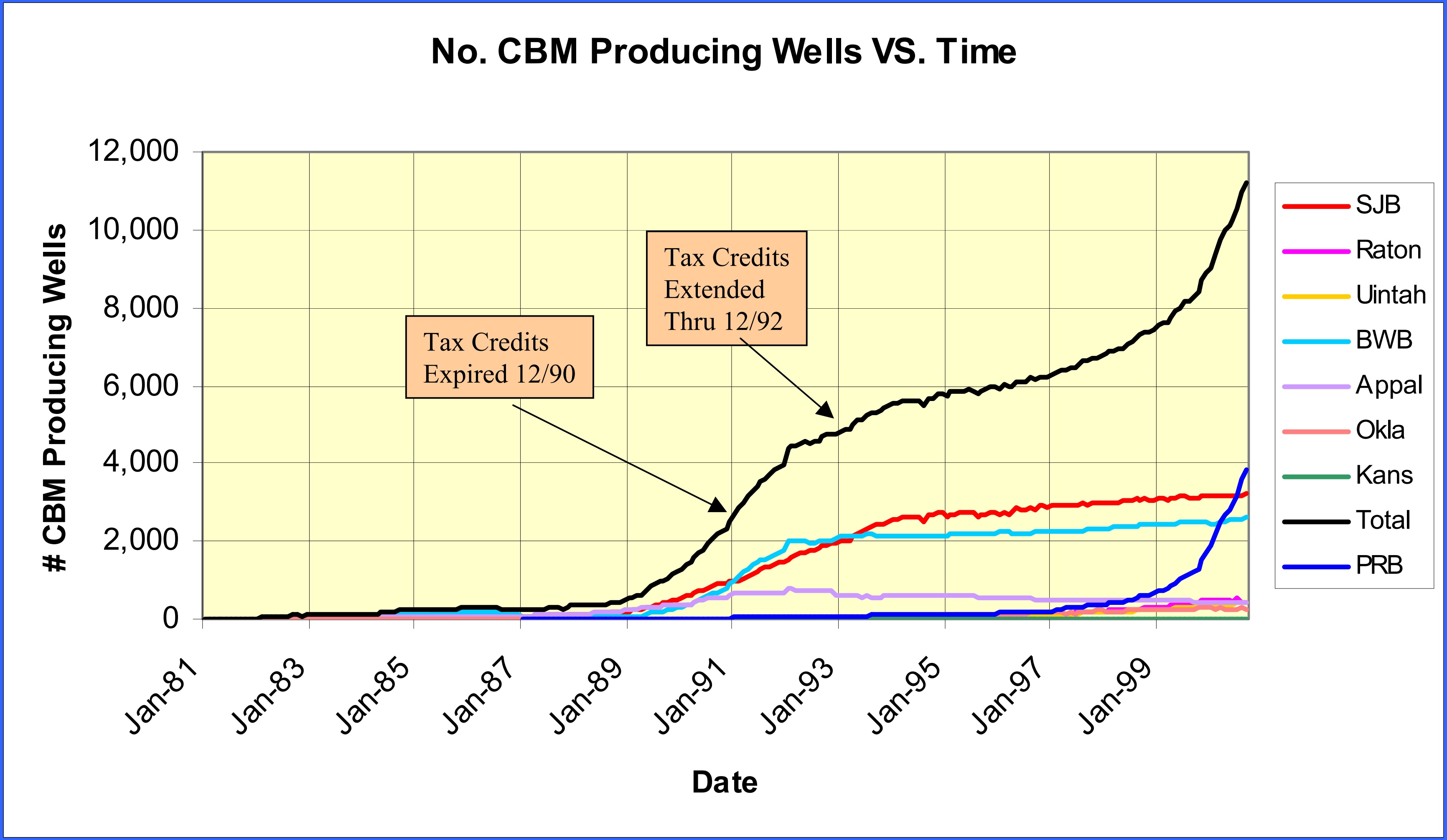
Powder River Basin

- Most overlooked CBM play – totally ignored by the CBM industry for years.
- First commercial development was by two very small private independents, Betop and Martens & Peck. They initially searched for structures on the top of the Wyodak coalseam, thinking that free gas accumulations would be present and production would be more water-free.
- Newest Major CBM Play; largest onshore natural gas play in the U.S. now. Over 130 CBM operators, but consolidation has begun with buyout of several companies.
- Only major CBM play from Eocene age sub-bituminous coalseams having very high permeability and low gas contents, but very thick coalseams at shallow depths.
- Over 4,000 CBM wells now on production.
- Features production of fresh water; water issues and federal lands (~55% of total) are major issues in this development.
- Production increased to 555 MMCFD in 12/2000, has started to decline. Expected to increase again with renewed activity and completion of EIC in 2002.
- EIS is expected to allow for up to 75,000 additional CBM wells.
- Many challenges to address with migration of the play into deeper areas of the basin and areas where there are multiple but thinner coalseams.

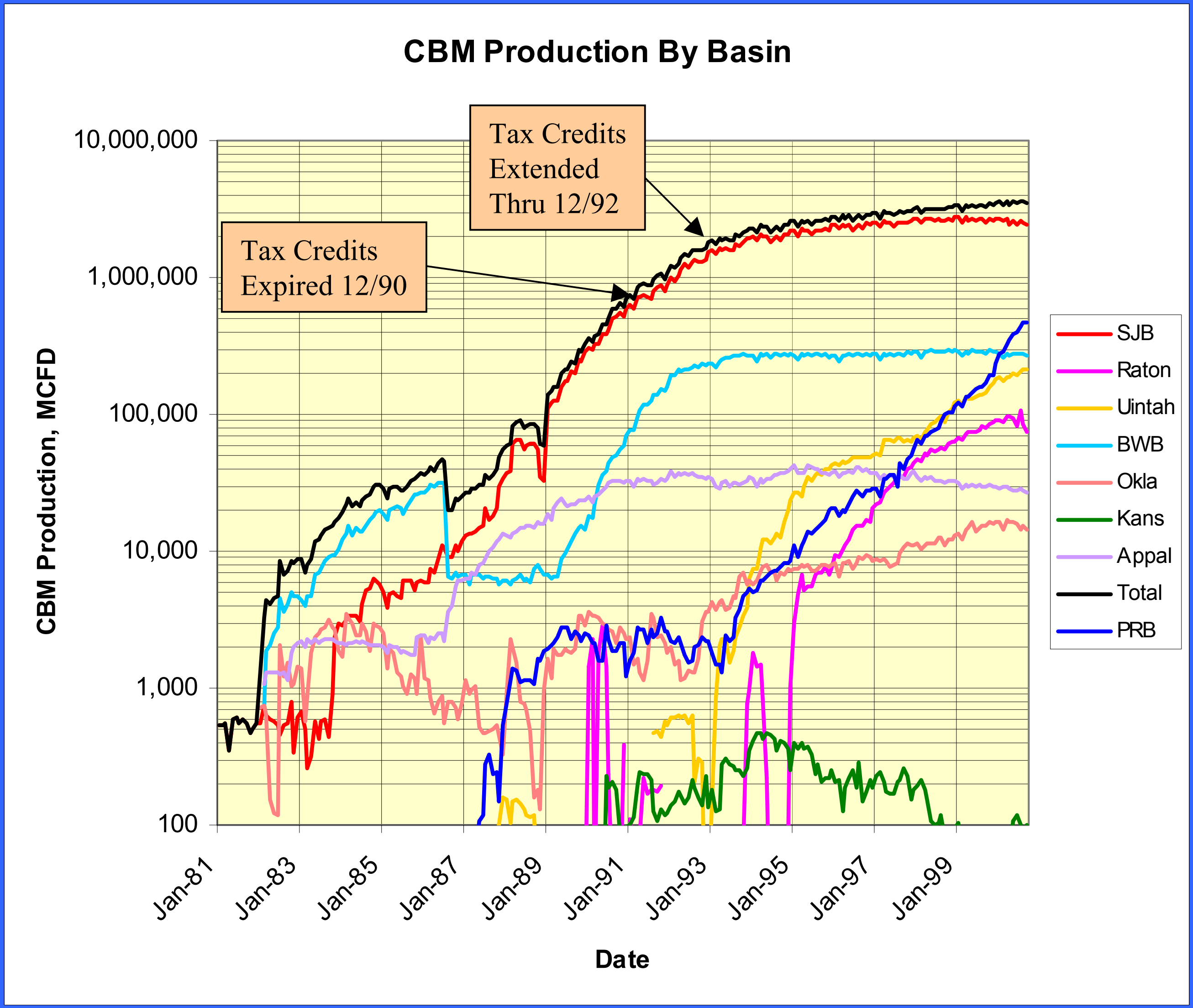
Powder River Basin



CBM Development VS. Time



CBM Gas Production Vs. Time



Energy Ingenuity Company

Some CBM Rules of Thumb That Sometimes Work

- It’s good to have either high gas contents with lower net coalseam thickness (Raton, BWB) or very thick coalseams with low gas content (PRB), and best to have very thick coalseams with very high gas content (SJB, Uintah).
- The higher the permeability, the better. (Piceance has high gas contents and good net coalseam thickness, but lacks decent permeability.)
- Patience and innovative thinking are required to be successful in exploration and development of CBM. Pioneers usually come up short in one or both areas. (Examples are: 1. Amoco in the Raton Basin, 2. Texaco in the Uintah Basin, 3. Pretty much everyone in the Powder River Basin)
- Just when you think an area doesn’t have potential based upon “conventional” thinking, mother nature changes the rules and demonstrates CBM production. (PRB)
- It’s generally not a good idea to do what everyone else is or has been doing. (Everyone fraced CBM wells with cross-linked guar gum gel in the SJB for a while, because that’s what Amoco was doing.)
- Coalbed methane exploration & development has considerable risk – not geologic risk, but leasehold risk, drilling & completion cost risk, permeability risk, and operational cost (water disposal) risk, among others.
- Tax credits and improved natural gas prices have probably done more for CBM than technology advances, but technology advancement has helped. It’s important to try and learn from the mistakes of others, but keep an open mind and willingness to try new ideas.
- Don’t use polymer muds to drill coalbed methane wells. The polymers damage the coal.
- Massive frac jobs don’t do well in coalbed methane wells. Foam and slickwater fracs work well, but caution should be used when selecting chemicals.
- PCP pumps usually work best on CBM wells, particularly with coal fines production.

Some Observations and Wild Projections

- There will be at least two major new CBM plays emerging in the next few years. Prospective areas include Cook Inlet, North Slope, and Interior Basins of Alaska; western Washington, eastern Uintah Basin, Texas & Louisiana Gulf Coast, Illinois Basin, Green River Basin and Montana.
- There will be renewed/increased production from several of the existing CBM plays with application of new technologies. Examples include N2 injection, CO2 injection, improved completion &stimulation techniques, and changes in surface operations (such as reduced wellhead pressure).
- The Canadians will eventually figure out how to drill, complete and produce coalbed methane and will be a major producer in the next 10-20 years.
- Production from deeply buried (>6,000 feet) coalseams will not be significant due to lack of permeability.
- As gas prices continue to rise with increased demand for natural gas, coalbed methane will continue to be very competitive with other sources of natural gas. Tax incentives such as the Section 29 tax credit may be reinstated to help spur gas production.
- Patience and innovative thinking will continue to be the keys to success in developing coalbed methane. Companies will continue to collect arrows and bow out of new exploration areas when immediate success is not achieved, and successes will again come with those follow-on companies that learn from past mistakes and apply critical thinking and new ideas to increase production rates and reduce costs.

DOE's Arctic Research and Development Cost Share

Speaker

Rhonda Lindsey
National Petroleum
Technology Office

Speaker Biography

RHONDA P. LINDSEY
TECHNOLOGY MANAGER
NATIONAL PETROLEUM TECHNOLOGY OFFICE
U.S. DEPT. OF ENERGY

An alumna of both Slippery Rock University in Pennsylvania and Ohio State University, Mrs. Rhonda Lindsey is technology planning manager for several teams at the National Petroleum Technology Office of the Department of Energy in Tulsa. Rhonda joined the DOE in January, 1991 to work at the Metairie Site Office in Louisiana and later transferred to the Oklahoma Office. She represents her office at this meeting as the coordinator for Arctic initiatives in the Oil Program. In addition, she manages the Drilling, Completion, Stimulation and Operations Program, the Exploration Program, Native American Initiatives Program, and the Field Demonstration Program.

Her prior government experience was as a regulatory specialist in the Department of the Interior's Office of Surface Mining Reclamation and Enforcement for four years. There she worked with the States of Texas, Oklahoma, and Arkansas to ensure proper enforcement of the federal and state regulations regarding surface coal mining.

Rhonda participated in the Federal Executive Leadership Program. As part of the program, she served on assignments to the Washington office of OSM, the Washington office of the National Park Service and the Southwestern Power Administration.

Qualifying her to work in The DOE’s Fossil Energy Division, Mrs. Lindsey worked for ARCO Oil and Gas in Anchorage, Tulsa, and Denver as an exploration/extension geologist. She conducted field research, generated drilling prospects, assisted team engineers in field development decisions, monitored wellsite drilling, and served as ARCO's expert witness before state commissions. She was chosen, in 1981, as ARCO's first woman field geologist in Alaska.

When not working or caring for her family, Rhonda can be found either out in the barn or on the trails with her horses.

Alaska Coalbed and Shallow Gas Resources

May 4, 2001

Rhonda P. Lindsey

National Petroleum Technology Office

National Petroleum Technology Program

The National PetroleumTechnology Office is responsible for carrying out the National Petroleum Technology Program in accordance with the policies being drafted by Vice President Cheney's National Energy Plan.

Mission

The Mission of the NPTP is to move our Nation toward a reliable, economic oil supply, enhance U.S. technological leadership and protect the environment.

The NPTP promotes key activities and policies that move us closer to our goal to improve efficiency and environmental quality of domestic oil operations.

Arctic Initiative

Target oil and gas related RD&D activities required to find new resources, increase production rates, and more efficiently recover existing reserves, and develop technologies that will allow production of Northern Alaskan gas and heavy oil resources in an environmentally sound and friendly manner.

Conduct all activities in a manner that balances the State and National needs to develop these natural resources with the unique geographic, climatic, environmental and cultural heritages present in Northern Alaska's arctic regions.

Established Oil & Gas
Practices and Technologies
on Alaska's North Slope
Contents
ReadMe.txt file
Alaska Workshop
Proceedings
(PDF Format)
U.S. Department
of Energy
National Energy
Technology Laboratory
National Petroleum
Technology Office
April 2000

NANA Regional Corporation

A Well System for Exploration and Development of Unconventional Gas Resources in the Alaskan Arctic

- **DOE, NANA, COMINCO Alaska, and ARI**
- **Low-cost, small-footprint drilling system**
- **Develop unconventional gas resources**
- **Minimize the drilling footprint**
- **Reduce exploration and development costs**
- **Provide natural gas to local communities**
- **Alaska has an estimated 1,000 TCF of CBM gas resources**
- **Alaska has large volumes of shale gas and tight gas sand gas resources**

A Well System for Exploration and Development of Unconventional Gas Resources in the Alaskan Arctic

- Low-cost coring, logging, and in-situ testing technologies exist.
- Diamond drill rigs are used to drill small diameter holes (less than 3-inch diameter).
- Slim-hole coring and logging systems are relatively well developed.
- Slim-hole testing procedures, tools, and analytical techniques not well developed.
- Develop small diameter well testing tools and equipment.
- Develop techniques for analyzing well test data obtained from smaller hole sizes.
- Develop non-damaging and environmentally benign drilling fluids for arctic use.
- Design, construct and field test a well drilling and testing system in a large shale gas resource.

The Red Dog Mine

- The mine is operated by COMINCO LTD.
- The mine is one of the most profitable zinc mines in the world.
- Developed on land owned by the NANA Regional Corp.
- The mine has resources for another 40 years of production.
- Mine Expansion plans may require an additional 150 MW of energy needs.
- Replacing existing 30 MW of diesel-fired generation with natural gas would lower fuel costs.
- Provide environmental benefits of gas over diesel.

Technology Development with Independents

- DOE supports the successful demonstration of technologies which are beneficial to smaller independent oil producers and the transfer of those technologies to the oil industry, especially to other small independents.

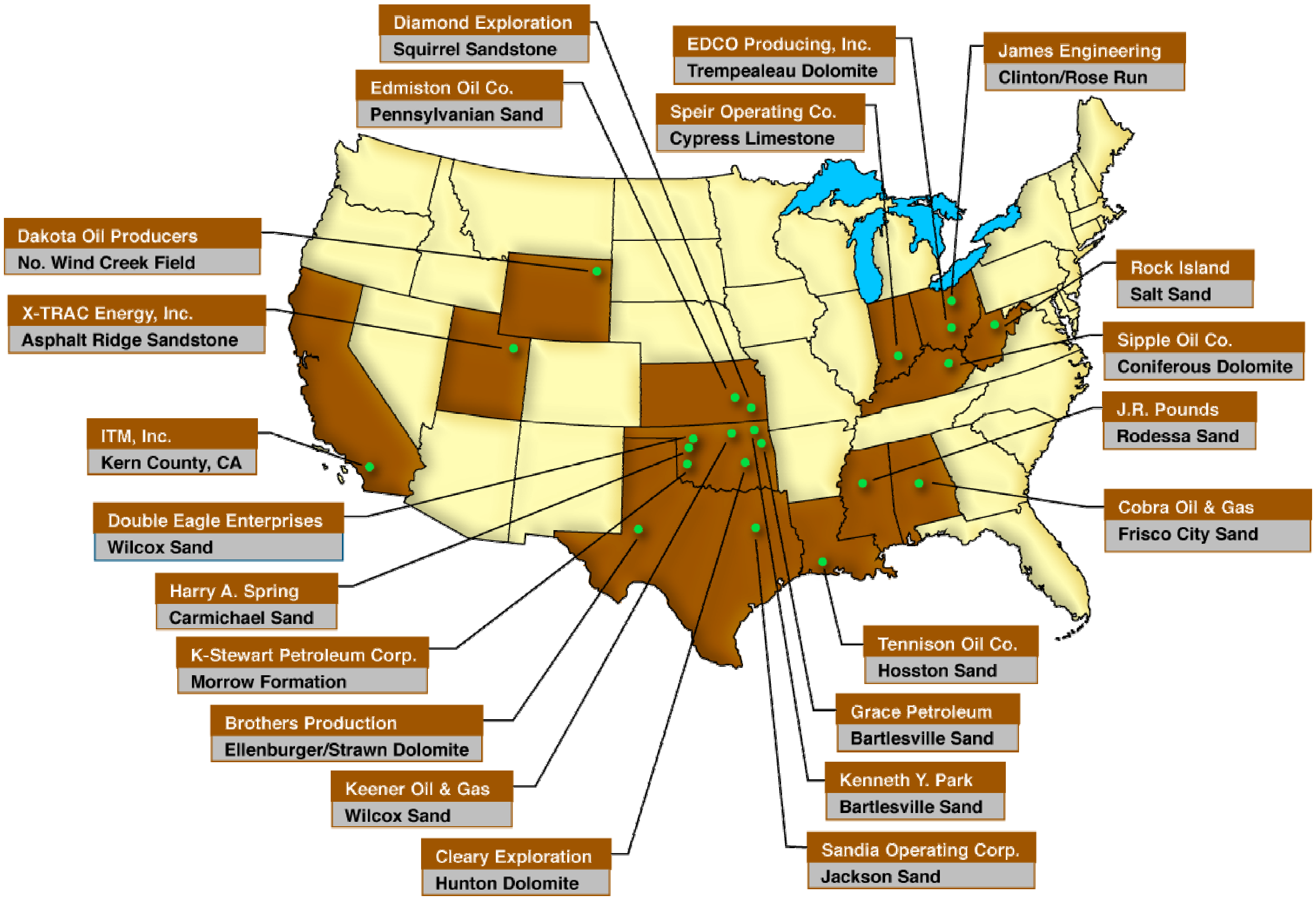
- Through cost sharing programs, DOE encourages the application of new, unfamiliar, and unique technologies to solve local production problems by reducing the financial risk to smaller independent oil producers who lack access to R&D facilities and resources necessary to test and develop new technologies on their own.

- Goals of the program are to increase oil production, reduce operating costs, and reduce environmental risks.

- Information regarding the program solicitation and application to participate can be found on the www.netl.doe.gov website.

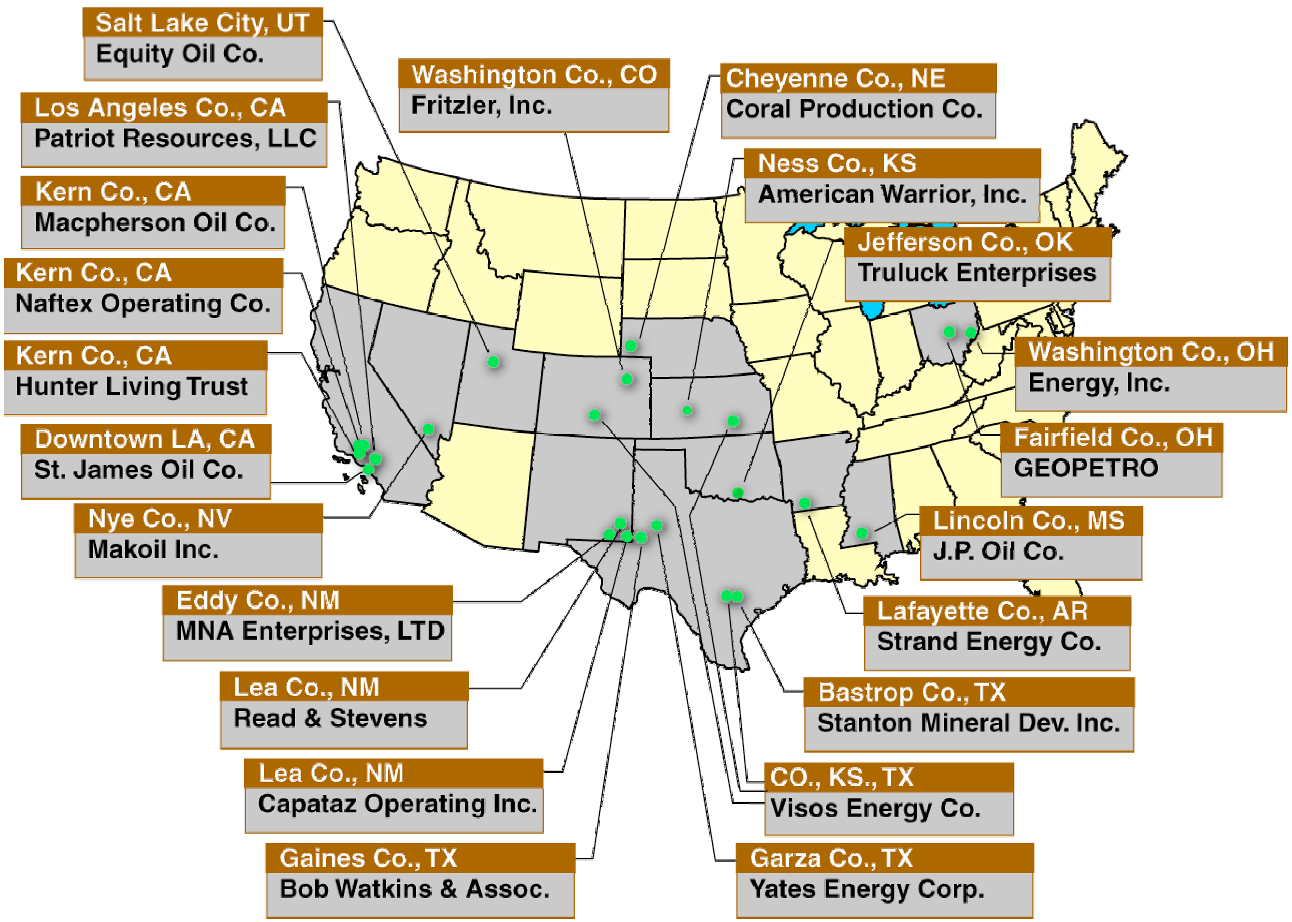
NPTO Support To Independents Program

The 22 Phase 1 Project Locations



NPTO Support To Independents Program

The 21 Phase 2 Project Locations



NPTO Contact Information

U. S. Department of Energy
National Petroleum Technology Office
One West Third Street, Suit 1400
Tulsa, OK 74103-3519

Phone: 918-699-2000
e-mail: www.npto.doe.gov

NETL

Tulsa, Oklahoma

Train Wreck – Energy Prices,
The Energy Infrastructure and the American Consumer

Speaker

John Schwager
CEO & President
Belden & Blake Corporation

“Train Wreck”
Energy Prices, the Energy Infrastructure and the American Consumer

by: John Schwager
President & CEO
Belden & Blake Corporation

In a compelling 45-minute presentation, John Schwager, President and CEO of Belden & Blake Corporation, shares how the combined forces of energy prices, the U.S. energy infrastructure and the American consumer are converging into an inevitable "Train Wreck". Through over 30 years of energy industry experience and personal research, Schwager explains where the country is today with respect to its energy environment, how we got there, and why it’s going to be difficult to meet future energy requirements. He provides an insightful analysis of the country's energy situation with a focus on electricity. His overview also includes the six energy fuels: petroleum, coal, nuclear, hydro, renewables, and natural gas.

Schwager's understanding of the U.S. energy infrastructure is evidenced by his early predictions over the past two years of the California power crisis, high oil and natural gas prices and gasoline shortages/price spikes.

This presentation will allow you to analyze the country's energy situation without having to cut through government hypocrisy and media distortion and bias. You will also be challenged to look more closely at our environmental programs and what they are costing you as an American consumer.

"Train Wreck"

Energy Prices, the Energy Infrastructure and the American Consumer

West Coast PTTC

May 4, 2001

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— AND THOUSANDS WILL FREEZE TO DEATH!

1. Where we are today.

2. How we got there.

3. Why it will be tough to fix.

1. Where we are today.

OPEC

- Hugo Chavez, President of Venezuela, has brought a measure of cohesiveness
- Target pricing of $25 – $30 per barrel WTI
- Cohesiveness beginning to fray?

Inventory/Price Snapshot

	3/15/99	3/25/01	
Total Oil Inventory (MMB)	870	785	Down 10%
Total Heating Oil Inventory (MMB)	132	110	Down 17%
Natural Gas in Storage (BCF)	1,459	688	Down 53%
Crude Oil Price – WTI ($/BBL)	14.45	26.55	Up 84%
East Coast Heating Oil – FOB NYC (¢/Gallon)	43	73.0	Up 70%
Natural Gas – Henry Hub, LA ($/MMBtu)	1.717	4.927	Up 187%

Source: U.S. Energy Information Administration

Gasoline Snapshot

	4/07/00	4/6/01	
Total Motor Gasoline Inventory (MM Gal.)	205	194	Down 5%
Motor Gasoline Price – Regular, Unleaded FOB NYC (¢/gallon)	70.9	96.5	Up 36%

Source: U.S. Energy Information Administration

Supply of all major energy sources has been declining.

The infrastructure that makes it all work is inadequate for modern needs; the infrastructure is not being modernized.

2. How we got there.

Critical Factors and Trends

- Per capital consumption of energy up over 6% in last ten years
- We haven't built a major refinery in this country in over 20 years
- We aren't building enough pipelines
- No new nuclear facilities since the 70s

Critical Factors and Trends

- The electric transmission grid is outdated nationally
- U.S. electric demand is up 23% since 1992
- U.S. electric generation supply is up 6% over the same period
- 95% of the new electric generation demand over the next four years will have to be satisfied by natural gas

Critical Factors and Trends

- The natural gas may not be there in a healthy economy
- Regulatory apparatus prohibits utilities from entering into long-term supply arrangements

California First; Guess Who Next

- California is now a "third-world" country in terms of its energy infrastructure
- California hasn't built a significant new electric generation facility since 1990
- Their gas pipeline infrastructure is woefully inadequate
- Their electric transmission grid is in awful shape

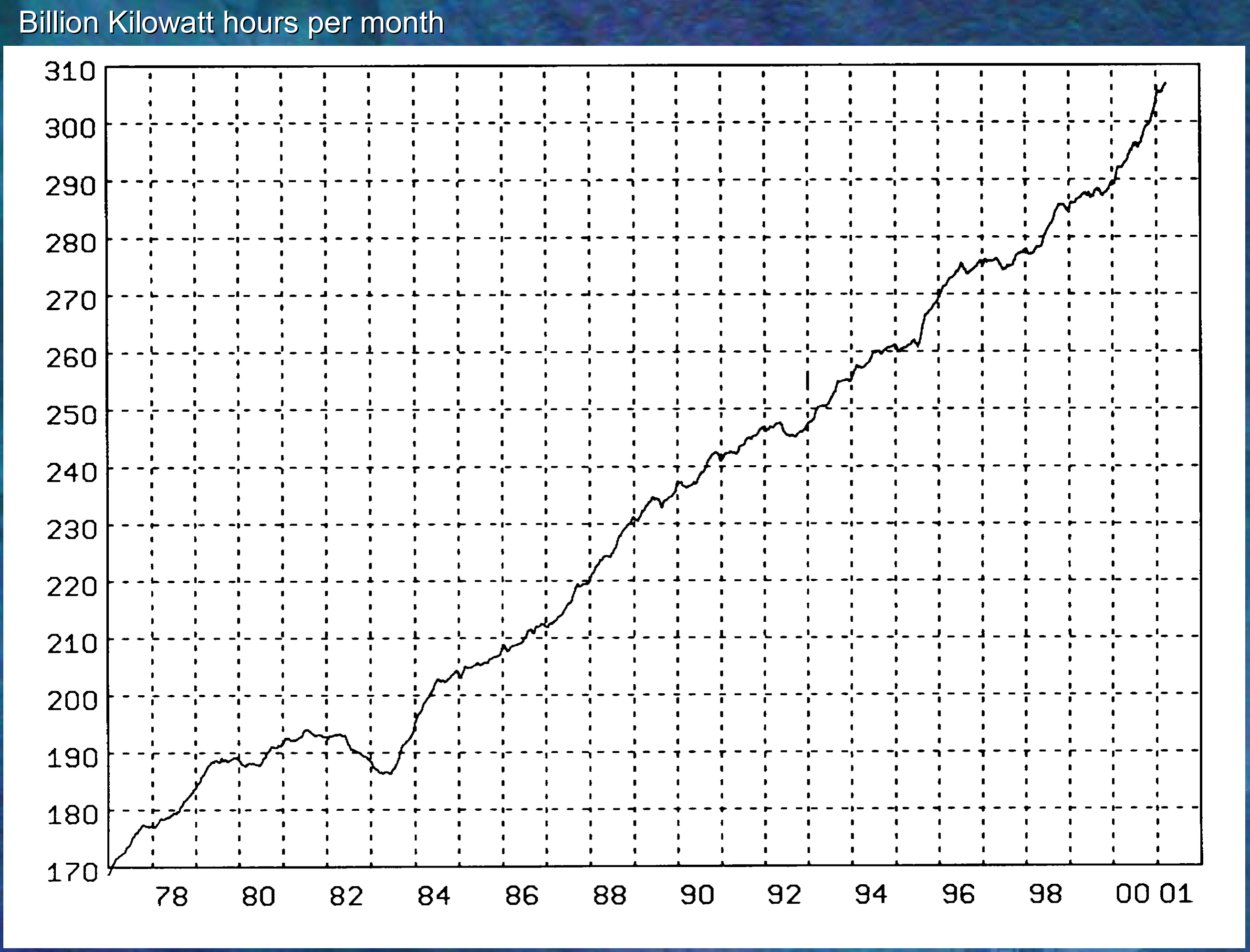
California First; Guess Who Next

- In spite of two rate increases this year for electricity of 15% and 40% +/- and a scheduled 10% increase next year, they may still need cash in excess of projected budget surpluses to pay for electricity between now and June, 2002.
- Substantial decreases in other public services or tax/ rate increases possible.
- California is the 6th largest economy in the world and 13% of U.S. GDP. This may now start to change.
- Almost one-third of their electric generation capacity was offline this past winter.

High Tech Power Usage

- “High-Tech’s” use of electric power was less than 1% of total electric demand in 1993
- It is now 10-12%
- It will be over 20% by the end of the decade

U.S. Weekly Electricity Generation



Source: Energy Directions, Inc.

3. Why it will be tough to fix.

– Political considerations

Observations About the American Consumer

- He (she) believes the energy supply is abundant
- It should be very inexpensive
- He (she) is a committed environmentalist and expects no incremental costs for energy associated therewith
- He (she) are now the major polluters in our country

Observations About the American Consumer

- NIMBY – Not In My Back Yard
- 57% of Californians still believe there is no shortage of electricity
- 51% think it is all caused by deregulation and profiteering (AKA – gouging)

Observations About Hard Working Environmentalists

- BANANA – Build Absolutely Nothing Anywhere Near Anything
- They have never seen a cost/benefit analysis that they really like
- They are crusaders, perhaps the most committed movement not only in America but worldwide
- NOPE – Not On Planet Earth

Observations About American Politicians

- They know that higher energy prices are the real "third" rail
- They have been most skillful the past 30 years hiding the true costs of the environmental movement from their constituents
- It's fixin' to get a lot tougher to hide

Observations About American Politicians

- We desperately need leadership and it is not there – Gray Davis
- It is absolutely amazing how poorly informed they are about energy
- There are no shortages, only price-fixers and gougers
- Why are SUVs considered trucks?

Great Energy Fallacies of Our Time

- Electric cars generate less pollution
- OPEC is the problem/solution
- Nuclear power is unsafe
- Methanol and Ethanol are good; gasoline is bad
- Fuel cells will save us
- Wind and solar will save us

Great Energy Fallacies of Our Time

- Price fixing/gouging is rampant across the entire energy industry landscape
- Building electric power generation facilities will cure the problem
- High voltage transmission lines cause cancer
- Energy conservation is easy to obtain

Short Term Horizon

Energy prices are dropping due to lower demand/slowing U.S. (and world) economies.

The high prices for natural gas and oil have significantly dampened demand for energy.

Industries Directly Damaged

- Agriculture Industry (Entire)
- Aluminum Smelters
- Ammonia Plants
- Brick Makers
- Carbon Black Plants
- Cement Makers
- Chemical Plants
- Citrus Farms
- Copper Mines/Milling
- Dairy Farms
- Electric Utilities
- Fertilizer Plants
- Glass Plants
- Greenhouses (Flower Industry)
- Methanol Refineries
- Paper Mills
- Plastic Plants
- Potato Processors
- Steel Industry

Danger!

- A recession only sweeps the energy problem under the rug to return when the economy recovers
- Another energy price collapse will worsen things later when the economy recovers
- Capital markets still living in fear of energy industry; part of problem

- Invest $100 in DJIA stocks in 1981
- Now have $1,025
- Invest $100 in independent oil and gas companies in 1981
- Now have $52
- If you want to make a little bit of money in oil and gas; invest a lot of money

The First Decade of the 21st Century – The Tough Options to be Balanced

- U.S. economic well being
- The breadth and scope of the environmental movement
- High energy costs

3. Why it will be tough to fix.

 – Physical considerations

U.S. Total Energy Demand

- Increased 1.2% per year over past five years
- Expected to increase 1.7% per year over next five years
- Warm winters held down growth, especially natural gas

U.S. Total Energy Demand – Compounded Annual Growth

	1995-2000	2000-2005	Share Total	Share Electric
Petroleum	0.9%	1.5%	38%	2%
Natural Gas	1.0%	3.5%	24%	11%
Coal	2.1%	0.5%	23%	55%
Nuclear	1.4%	(0.3%)	8%	21%
Hydro	(1.0%)	0.0%	3%	9%
Renewables	2.3%	2.1%	4%	2%

Source: Gas Research Institute

U.S. Energy Consumption by Application

	Compounded Annual Growth		Share	
	1995-2000	2000-2005	Total	Electric
Residential	0.4%	2.1%	15%	37%
Commercial	1.9%	1.9%	11%	49%
Industrial	0.9%	0.9%	39%	15%
Transportation	0.8%	1.6%	35%	0%

Source: Gas Research Institute

The Six Energy Fuels

- Petroleum
- Coal
- Nuclear
- Hydro
- Renewables
- Natural Gas
- (Electricity)

Petroleum

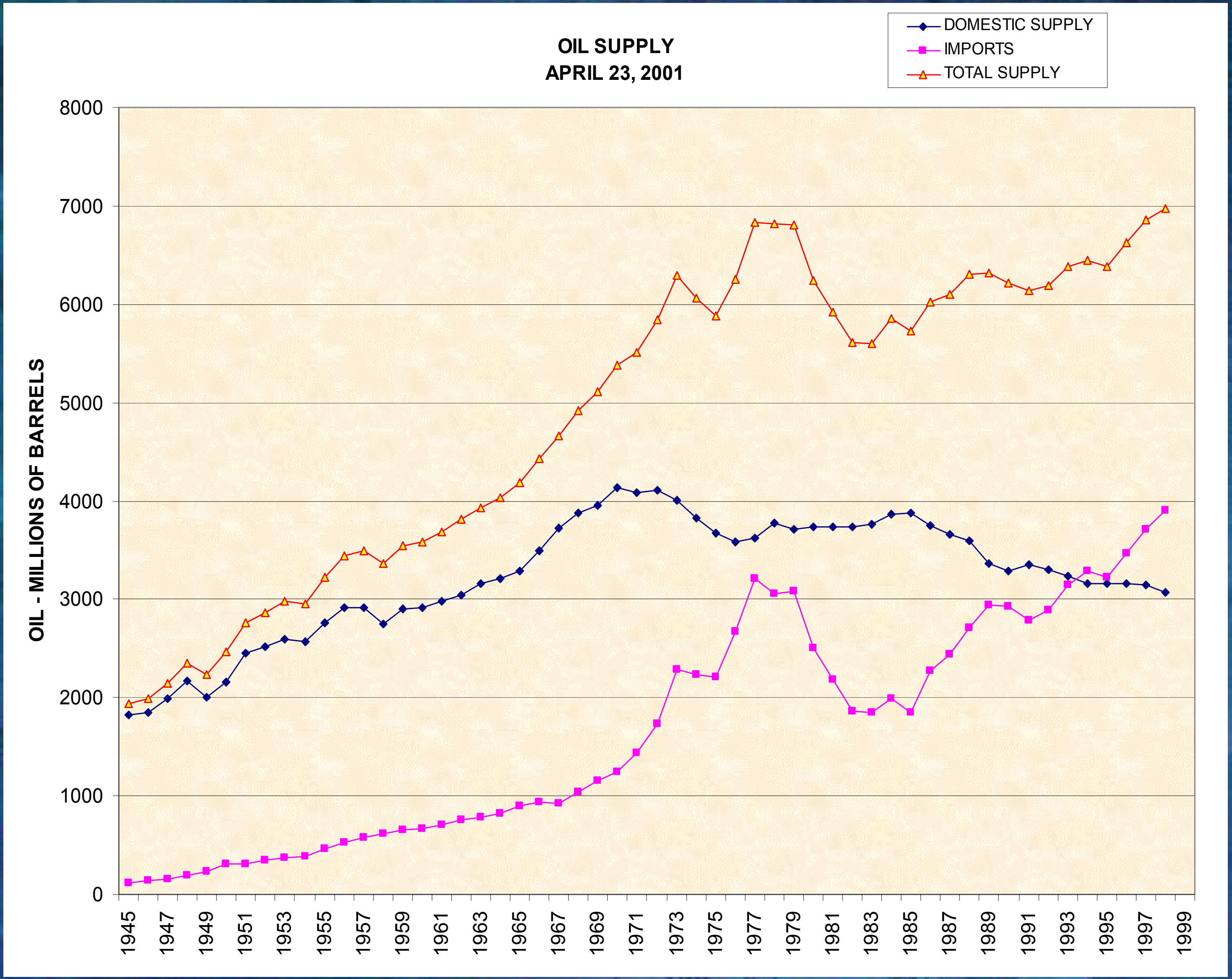
- Fulfills 38% of total U.S. energy needs
- Only 2% of electric generation
- Many new gas-fired electric generation facilities will also be able to burn distillate/home heating oil
- This will pressure home heating oil supplies (22% yield at refinery)
- Now pressuring summer 2001 gasoline supplies

Petroleum

- No new refineries built in this country in over 20 years (300 then to less than 150 now)
- Must now import refined products to meet demand
- RFG is complicating matters, especially to meet regional political interests
- We import almost 60% of the crude oil consumed in this country

Petroleum

- Drilling wells – NIMBY, BANANA
- Building refineries – NIMBY, BANANA
- Building oil-fired electric generation facilities – NIMBY, BANANA



Source: DeGolyer and MacNaughton

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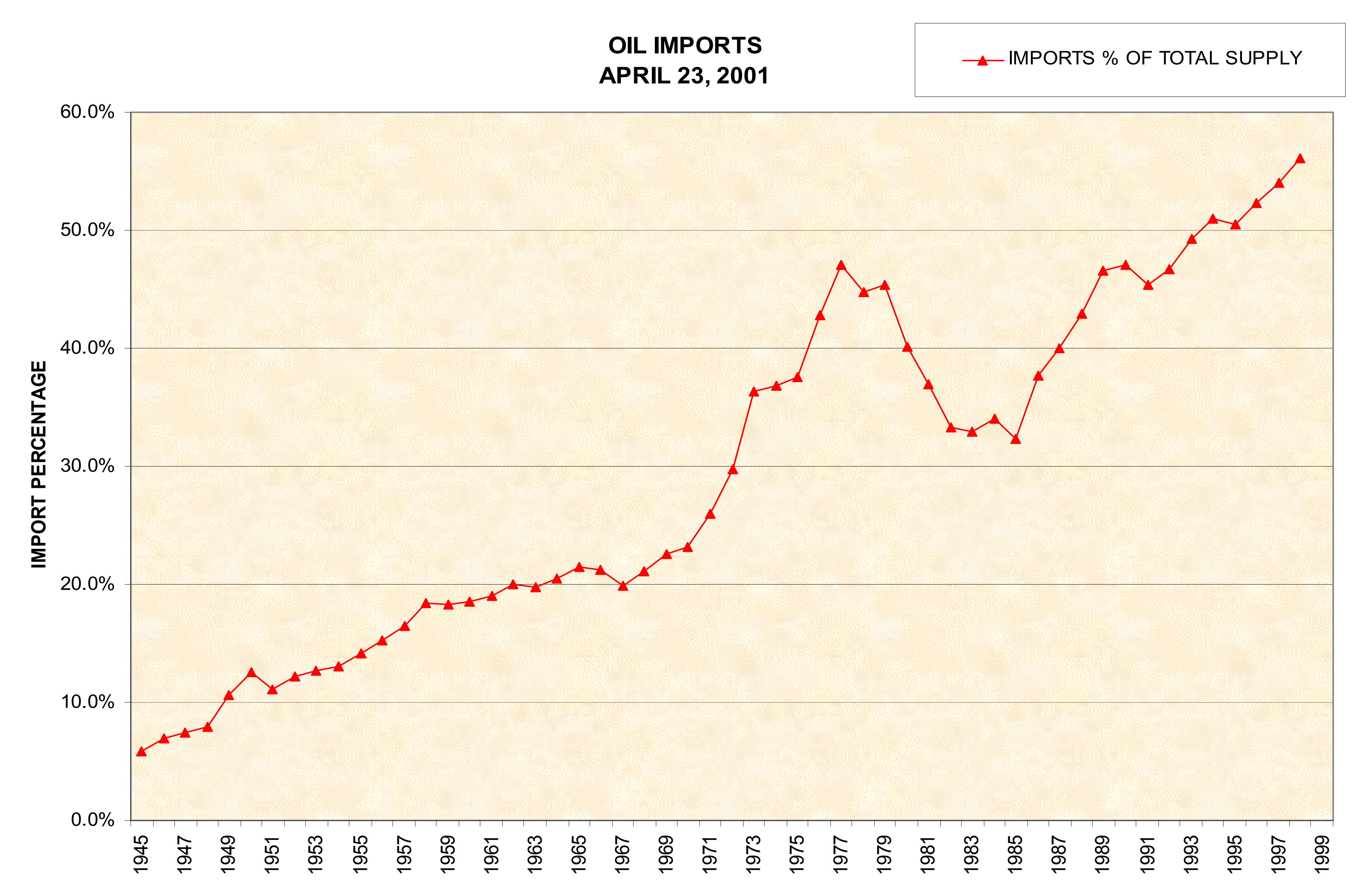

Source: DeGolyer and MacNaughton

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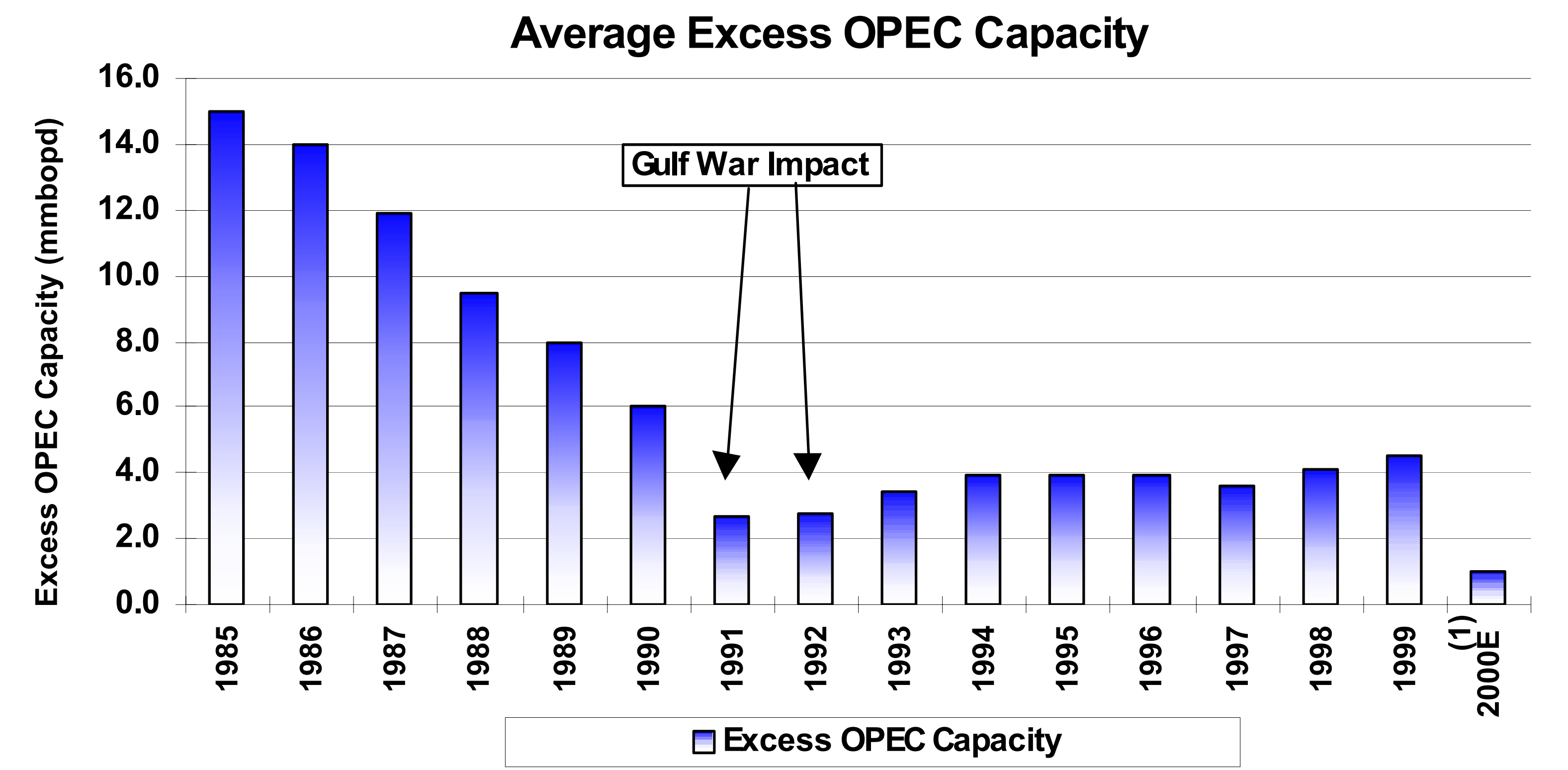
OPEC – Middle East

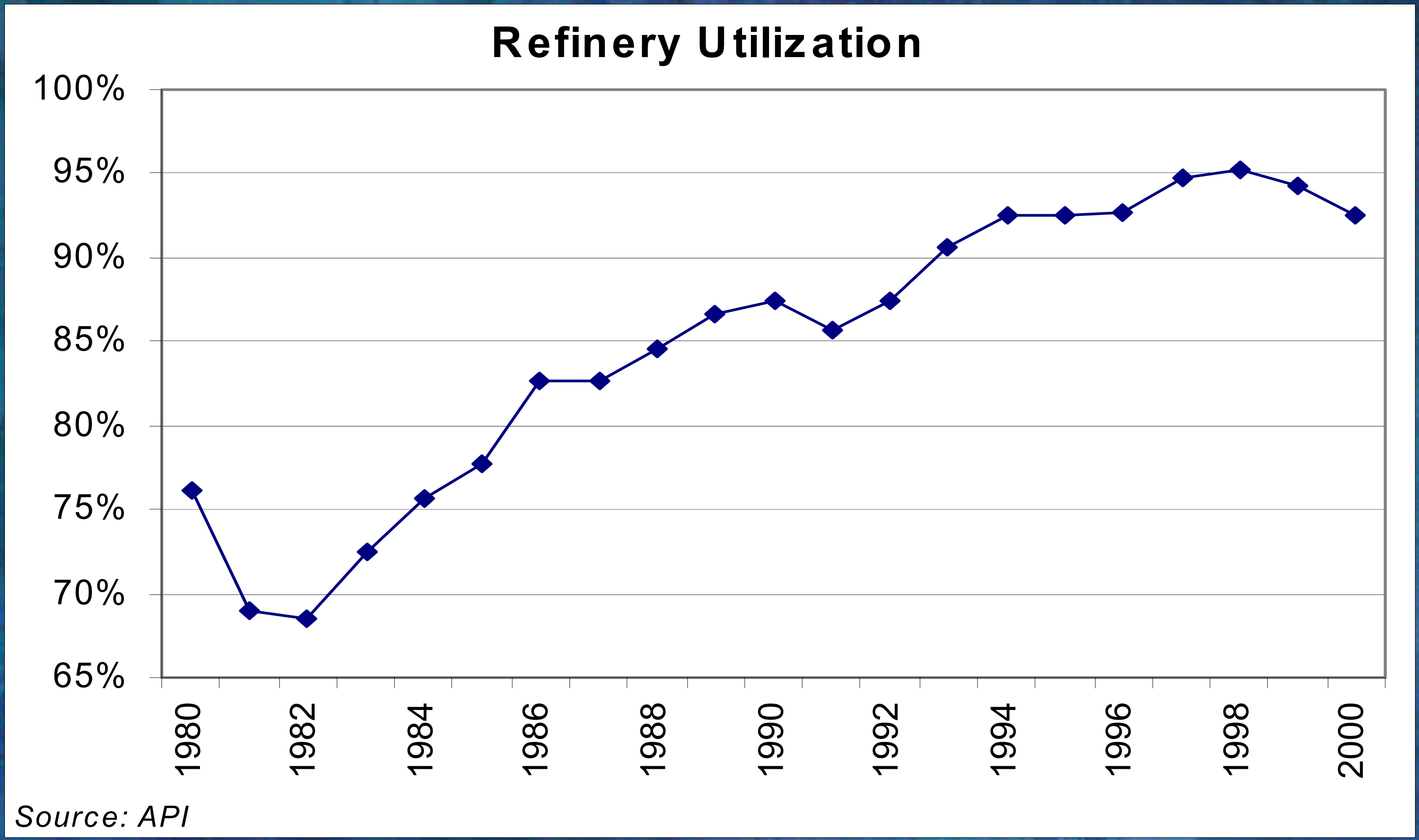
- One of the most politically unstable regions on the planet.
- Will American lives be lost fighting to preserve the availability of <u>their</u> oil?
- How many?

First Truly Balanced Oil Market in Decades!



Notes: 1999 and 2000E excess capacity is at the end of the year;
(1) OPEC production increases of 1.4, 0.8 and 0.5 mmbopd in 2Q, 3Q, & 4Q:00.
Sources: IEA, BP, RJ&A, Bloomberg.

Refineries Have Been Running All Out!



Coal

- Fulfills 24% of total U.S. energy needs
- 55% of electric generation
- If you're willing to pay for it, it doesn't have to be dirty
- It burns cleaner when co-fired with natural gas

Coal

- Will have to step up later in the decade
- Enviros/Consumers – NIMBY and BANANA
- Virtually no new plants being built

Nuclear Power

- Still fulfills 8% of total U.S. energy needs
- 21% of electric generation
- More people will die today on U.S. highways than have died in U.S. nuclear power accidents throughout the industry's history
- No new plants since the early 70s
  - TMI
  - China Syndrome
  - Chernobyl

Nuclear Power

- Nuclear waste disposal remains biggest problem
- Environmentalists/consumers – NIMBY, BANANA, NOPE
- Definitely the fuel of the early 21st century

Hydropower

- Fulfills 3% of total energy needs
- 9% of electric generation – most in western U.S.
- Low inventory for Western U.S. this summer ("Train Wreck")
- No more dams (BANANA, NOPE)

Renewables

- Fulfill 4% of total U.S. energy needs
- 2% of electric needs
- Enviros love them!
- Some progress being made but still requires subsidies

Renewables

- Consumers have not been willing to pay higher prices necessary to make them competitive
- Windmills are killing more birds than the oil industry ever has
- *I have yet to see one dead bird killed by a windmill on television!*

Electricity – "Train Wreck"

- Problems are critical in California and entire western U.S.
- Over-reliance on gas generation facilities for the next five years
  - Much higher natural gas prices
  - Continued shortages of natural gas
  - Shortages of electricity, probably spreading nationally (New York City next?)

Electricity – "Train Wreck"

- Will require big reductions in demand growth
  - Higher prices
  - Economic slowdown
  - Forced conservation
- Only two options
  - Nuclear (7 – 10 years)
  - Coal (5 – 7 years)
- We have a major "wire" shortage too! Public believes high voltage lines cause cancer (NIMBY). Maybe more critical than generation capacity shortfall (much longer term problem).

Natural Gas – “Train Wreck”

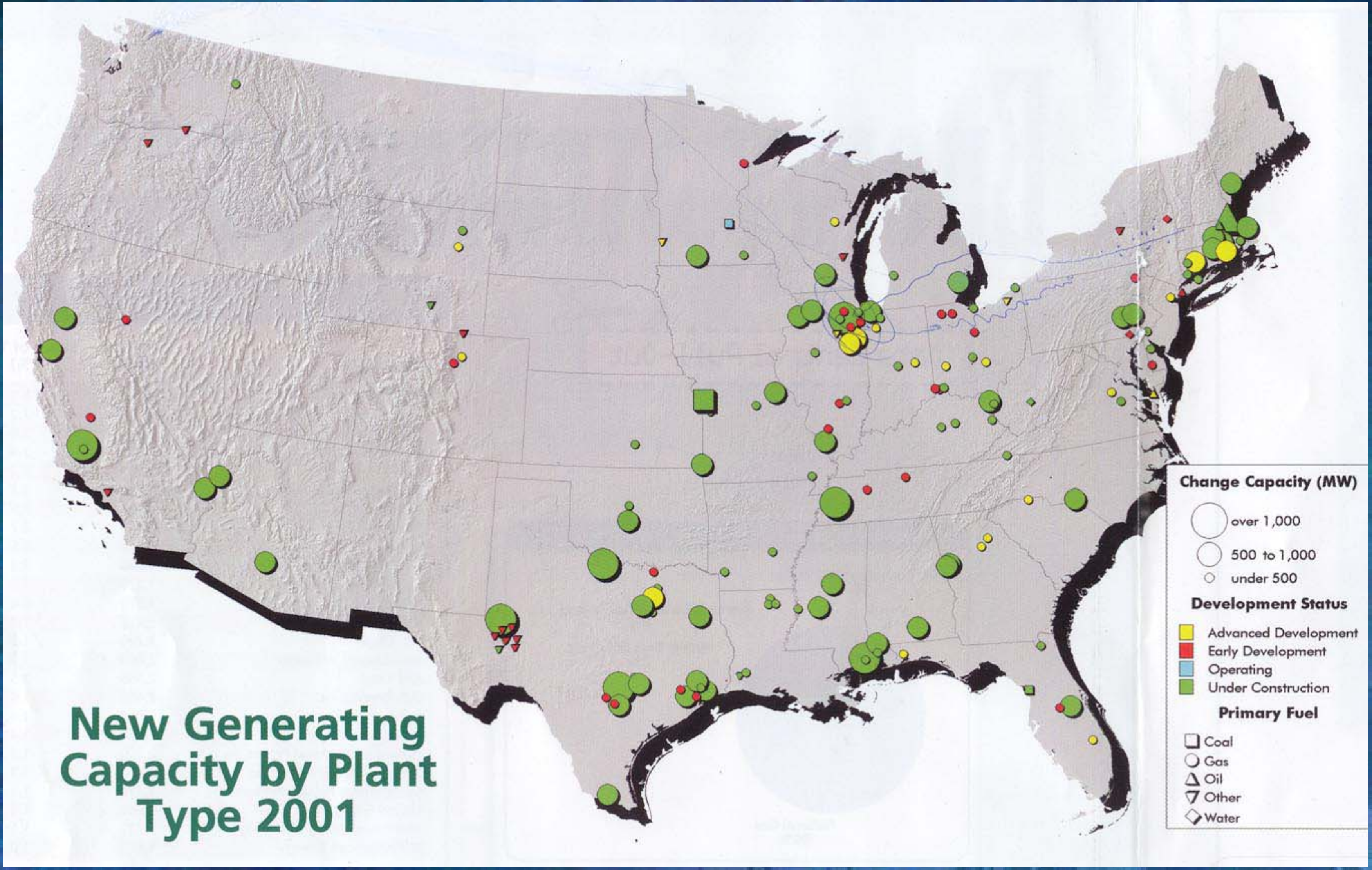
- Fulfills 24% of total U.S. energy needs
- 11% of electric generation
- Use for electricity increasing rapidly
- Calpine alone will require over 10% of U.S. natural gas supply to fuel their generation needs in 2003/2004
- Fuel of choice politically
- Fuel of choice environmentally

Natural Gas – "Train Wreck"

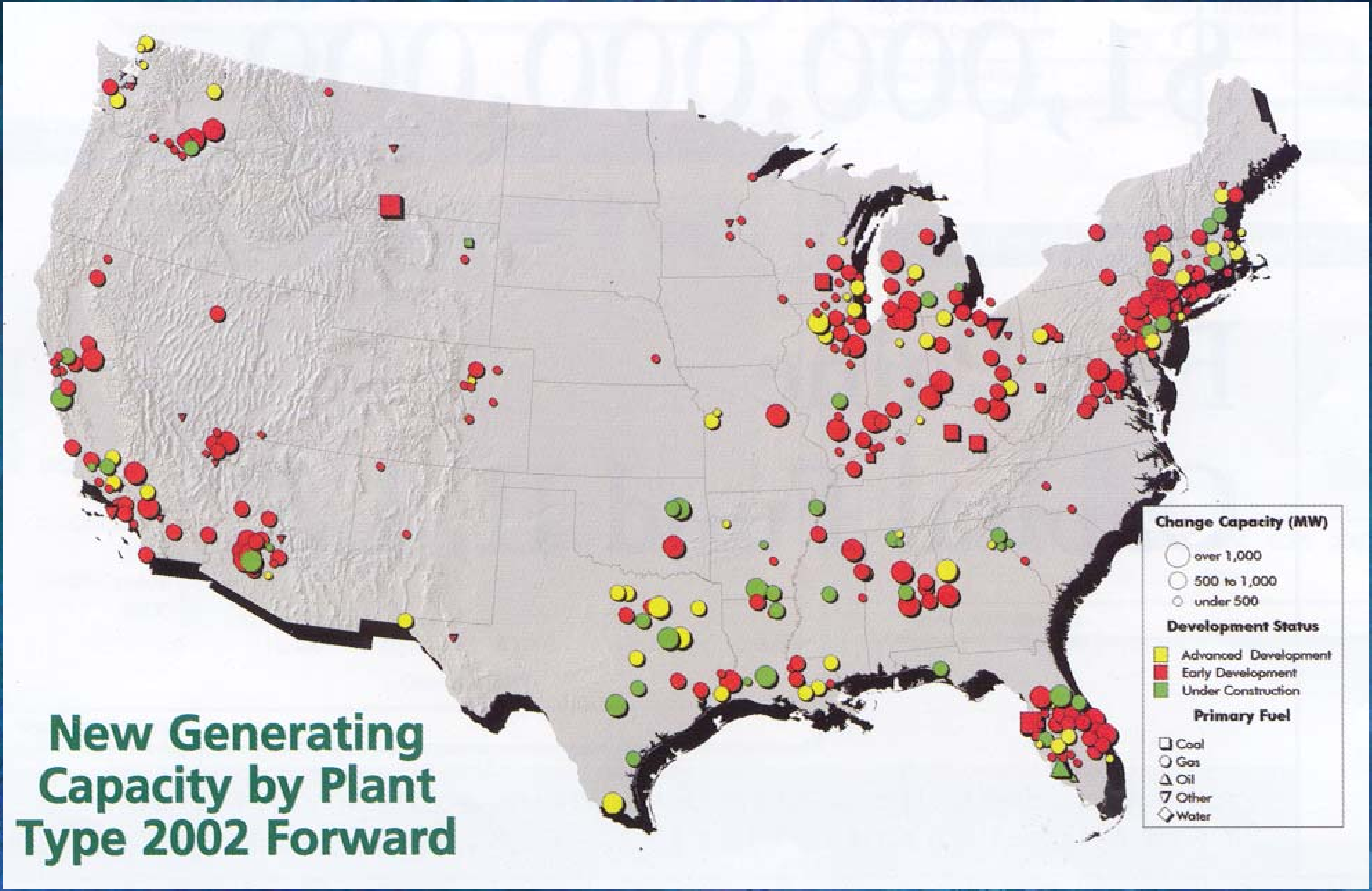
- Most friendly of hydrocarbon fuels, CO_2, SO_2, NO_x
- Not enough pipelines to move it around, especially California, problem is worsening nationally (Beware East Coast)
- Major U.S. accumulations placed off limits by government
- We almost ran out of it this winter. Next winter could be real interesting.
- Used to be a fuel for heating and industrial processes

Natural Gas – "Train Wreck"

- Now a year-round fuel due to electric load
- Due to political and environmental policies, we now over-rely on it
- California gas generation facilities – NIMBY, BANANA
- Not enough available to meet needs



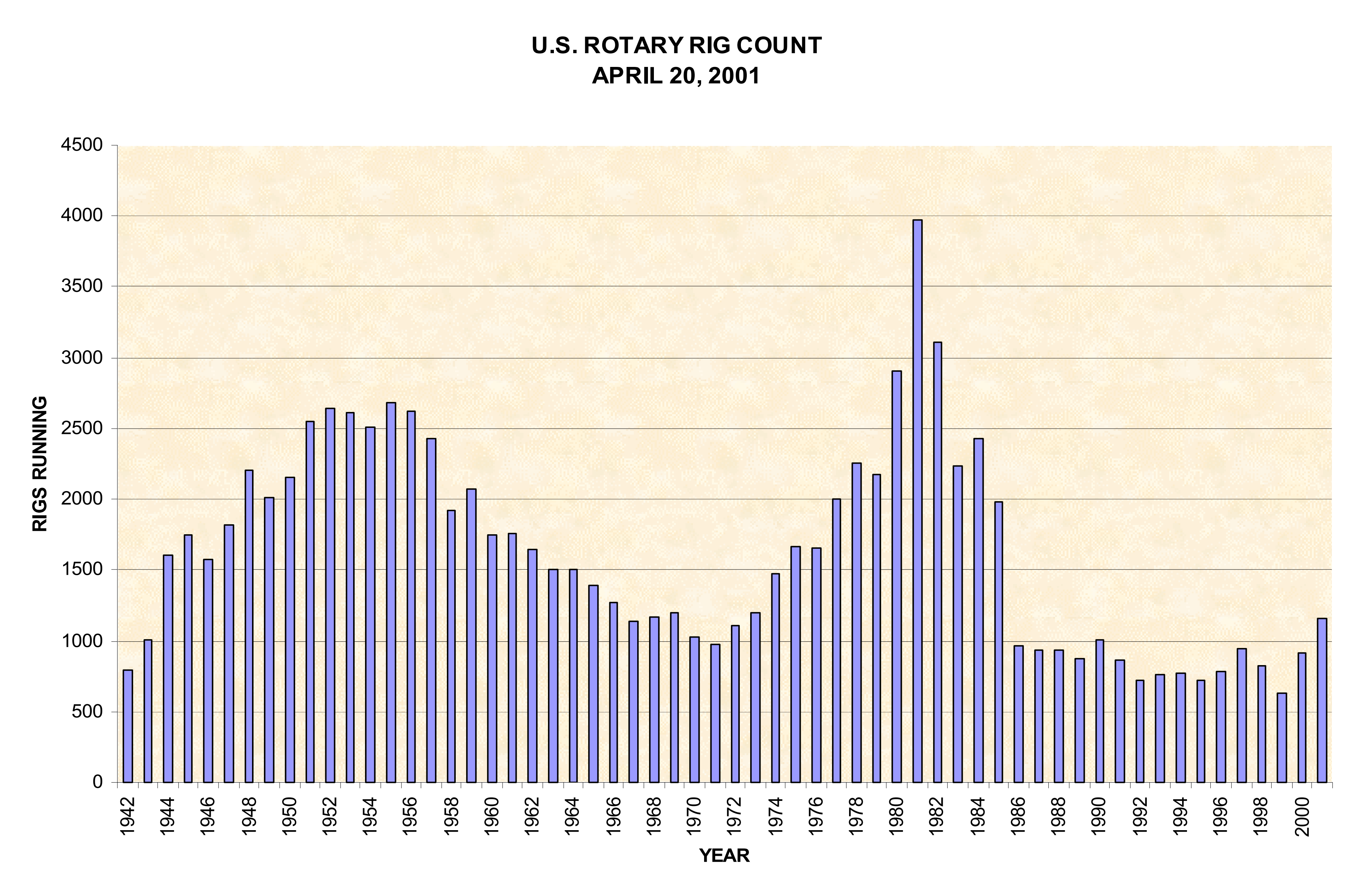
Source: RDI NEWgen



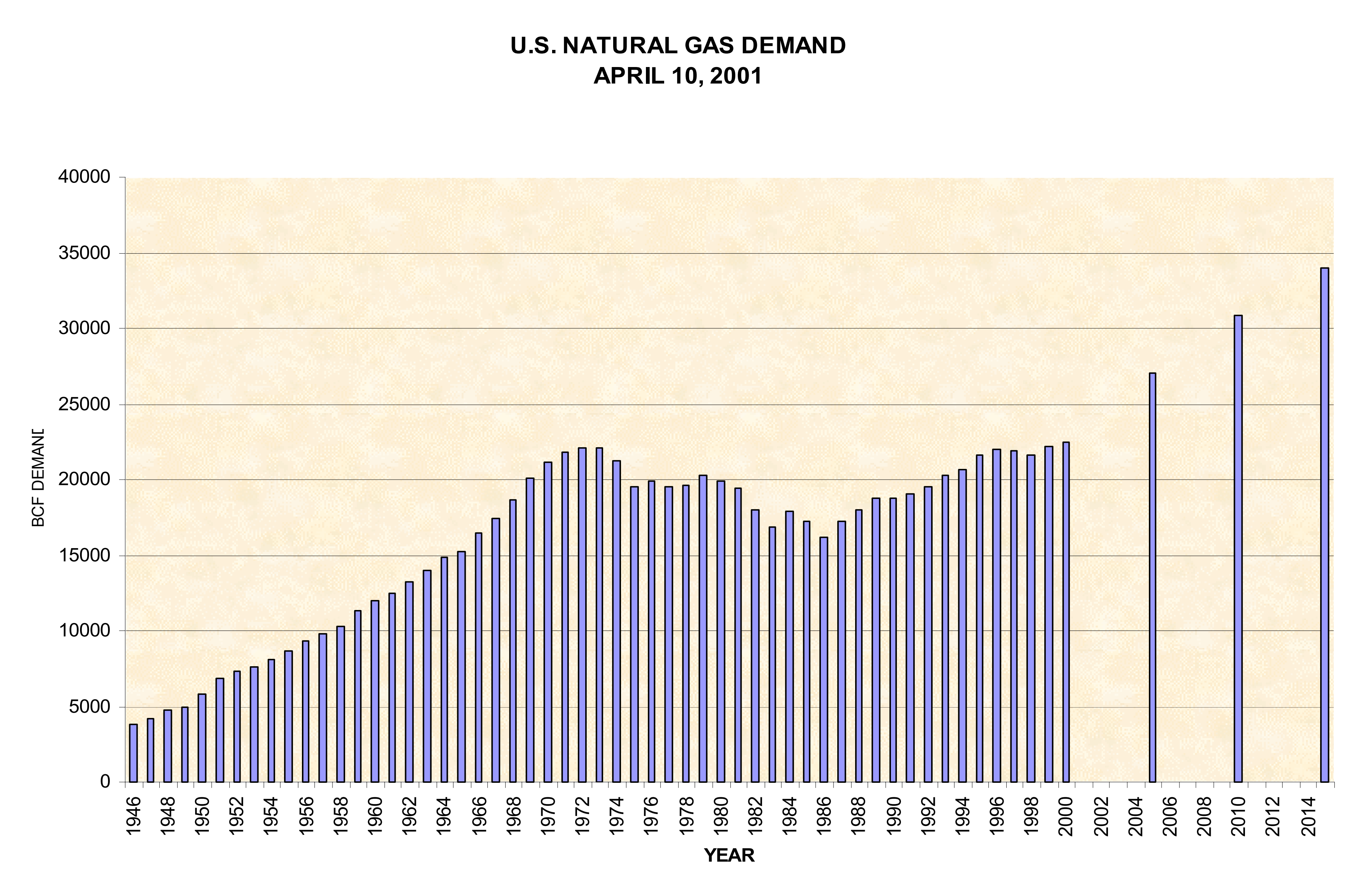
Source: RDI NEWgen

Natural Gas

- How did we get in this predicament so quickly?
- Actually, the seeds were planted 15 years ago.
- The problem was here in 1996, we just got lucky.



Source: Baker-Hughes



Source: Gas Research Institute

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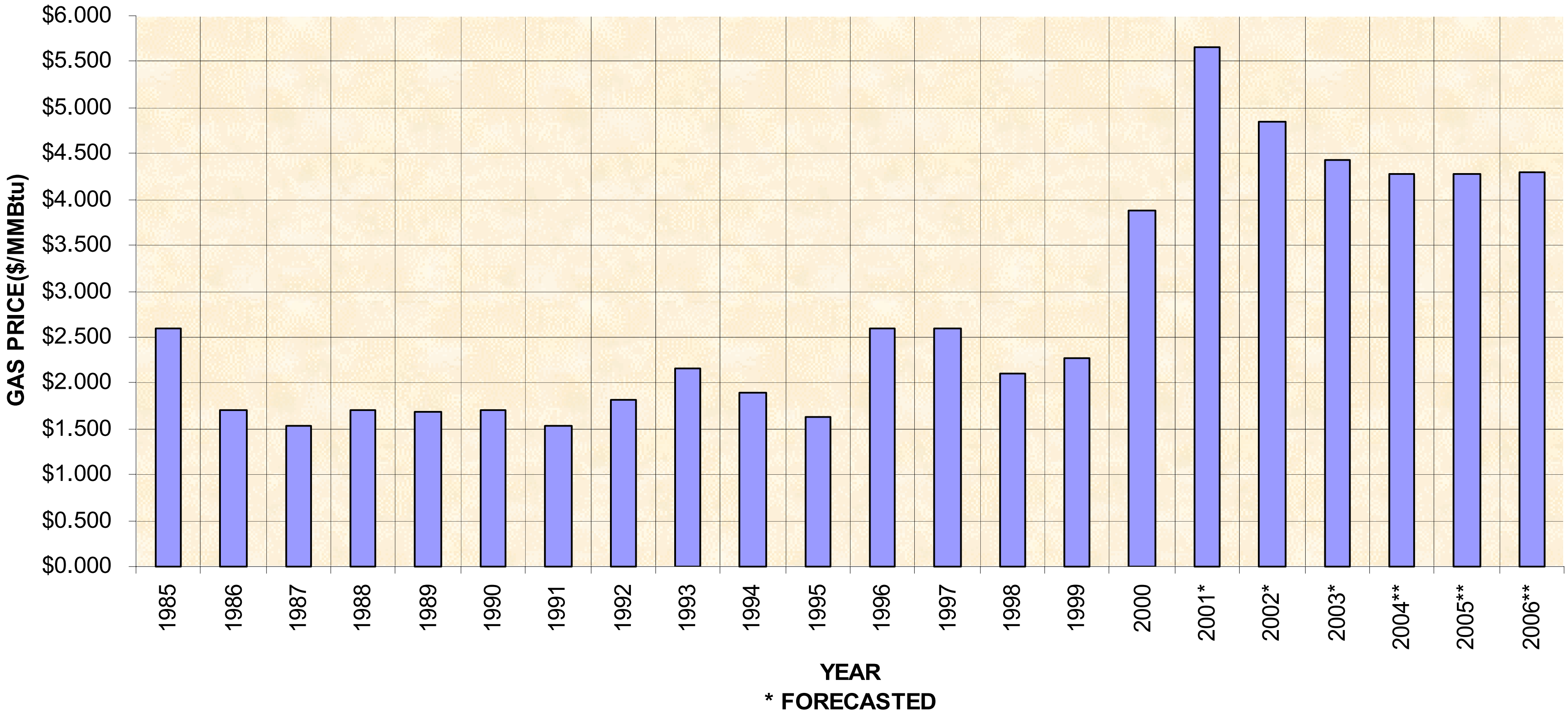
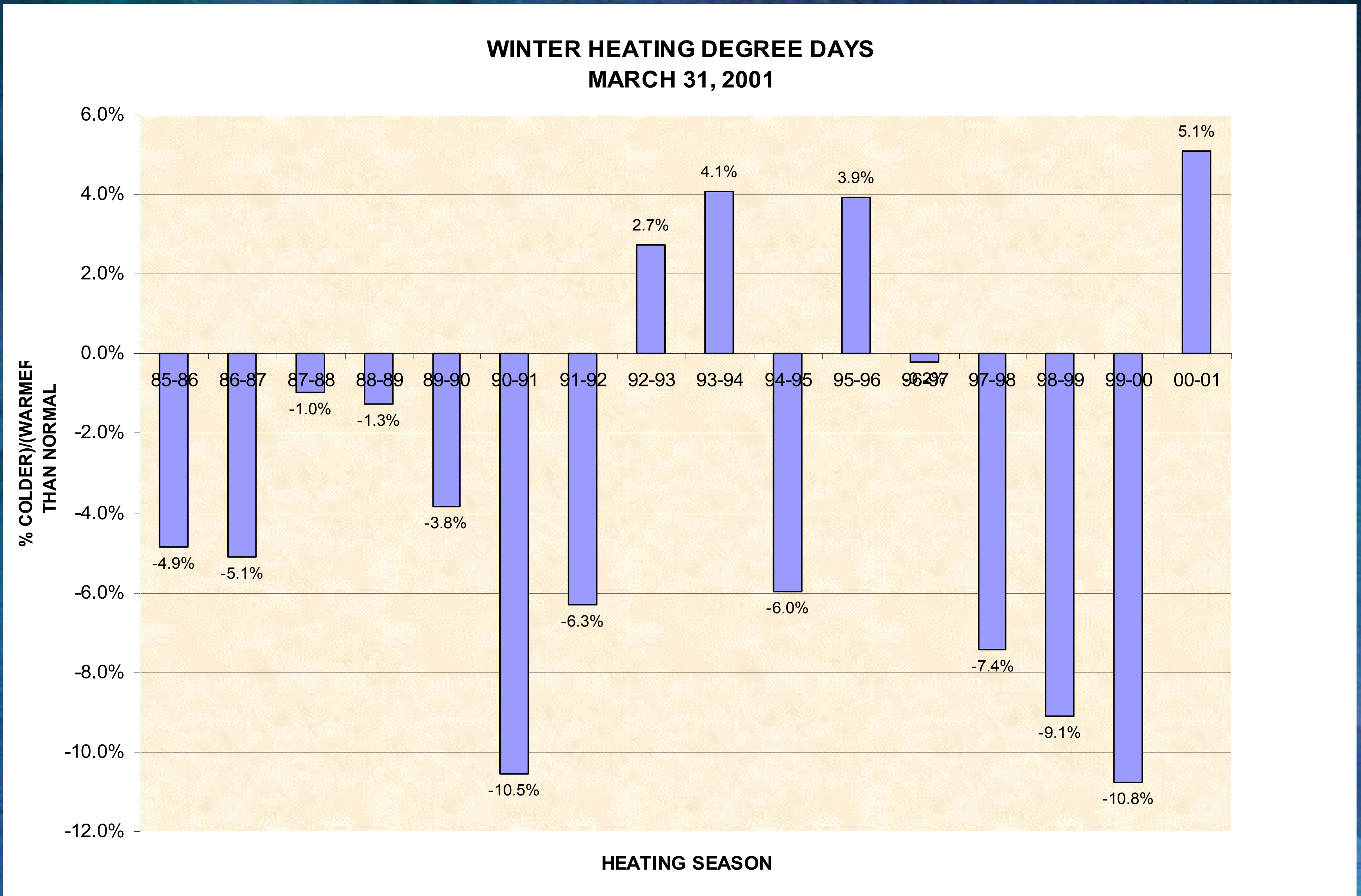
YEARLY NYMEX GAS PRICE HISTORY/FORECAST
Note: Pre-1990 based upon published indices
DATA AS OF 2:09 p.m. APRIL 25, 2001
NOTE: DATA FOR 2004 - 2006 FROM CHASE





Source: NOAA

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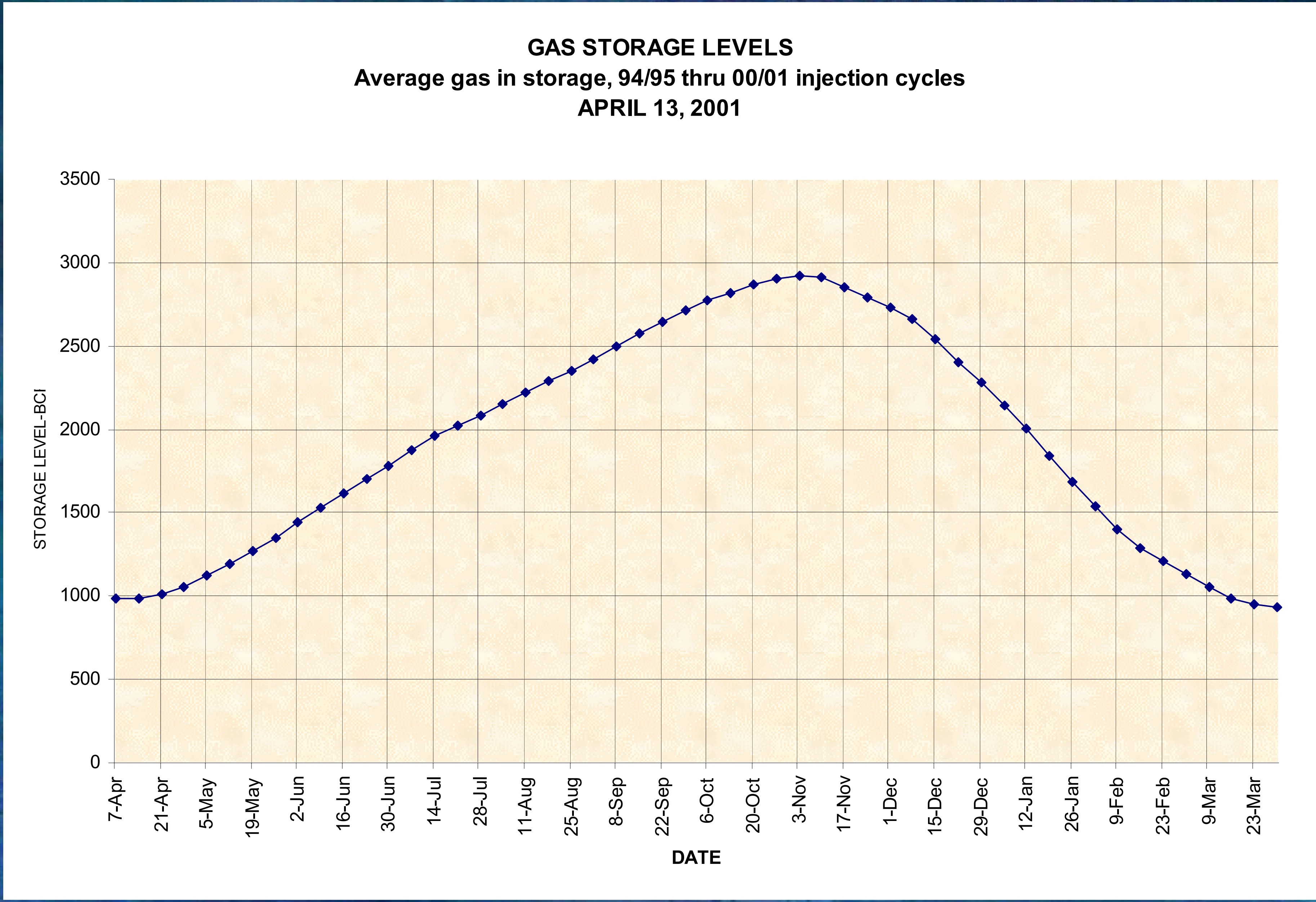
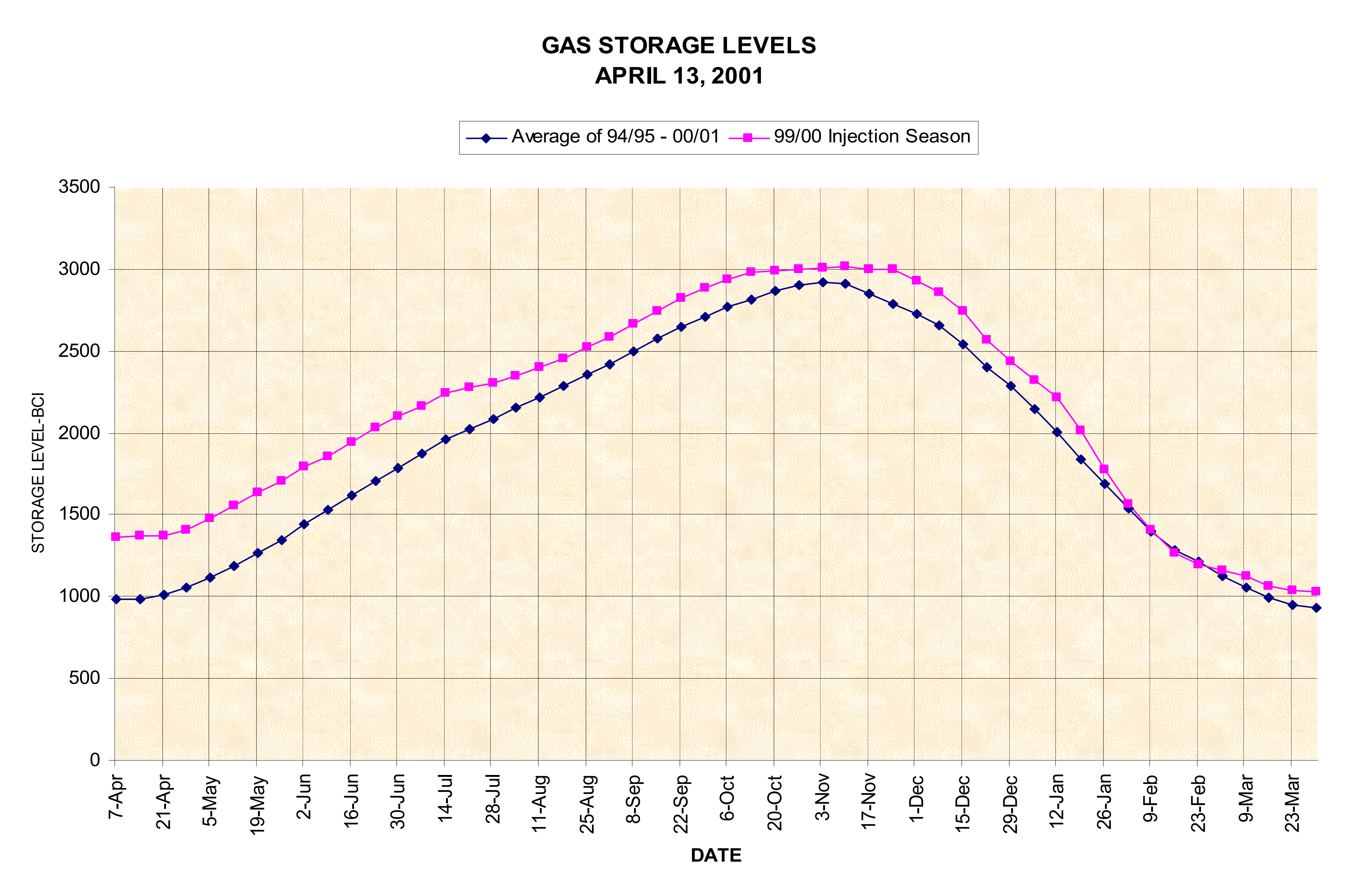
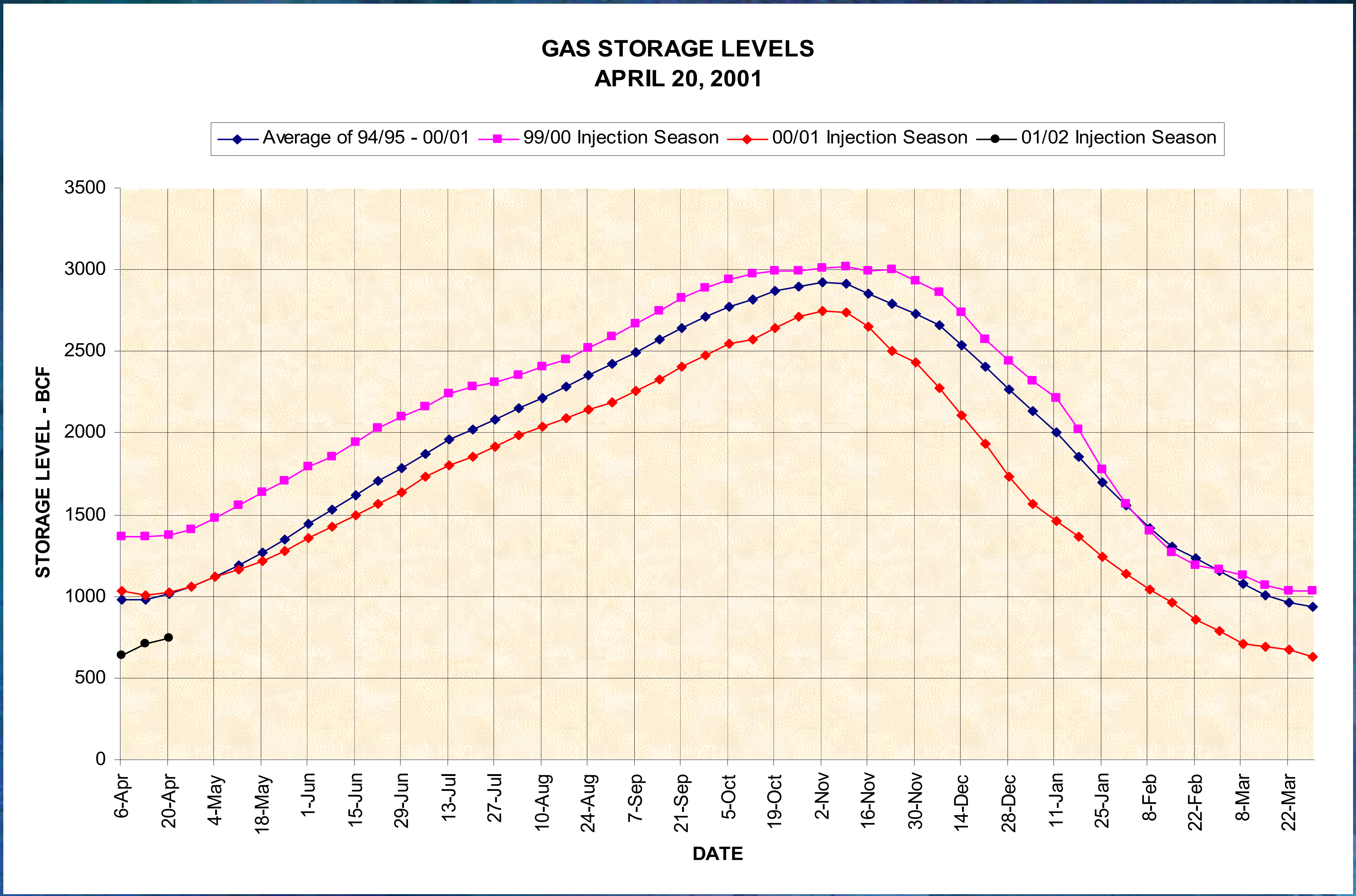

GAS STORAGE LEVELS
Average gas in storage, 94/95 thru 00/01 injection cycles
APRIL 13, 2001
STORAGE LEVEL-BCI
3500
3000
2500
2000
1500
1000
500
0
7-Apr
21-Apr
5-May
19-May
2-Jun
16-Jun
30-Jun
14-Jul
28-Jul
11-Aug
25-Aug
8-Sep
22-Sep
6-Oct
20-Oct
3-Nov
17-Nov
1-Dec
15-Dec
29-Dec
12-Jan
26-Jan
9-Feb
23-Feb
9-Mar
23-Mar
DATE

Source: AGA



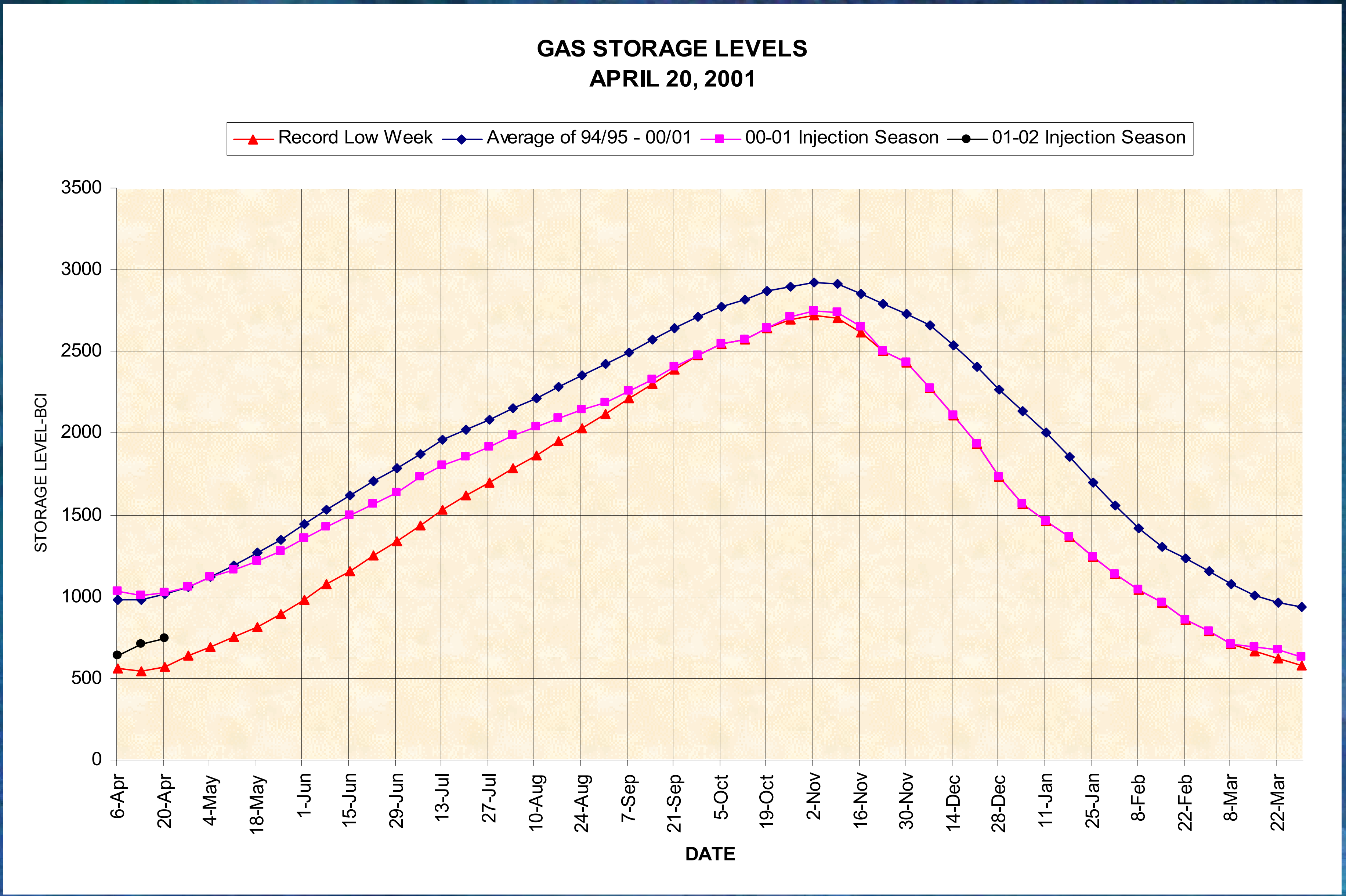
GAS STORAGE LEVELS
APRIL 13, 2001
Average of 94/95 - 00/01
99/00 Injection Season
STORAGE LEVEL-BCI
0
500
1000
1500
2000
2500
3000
3500
7-Apr
21-Apr
5-May
19-May
2-Jun
16-Jun
30-Jun
14-Jul
28-Jul
11-Aug
25-Aug
8-Sep
22-Sep
6-Oct
20-Oct
3-Nov
17-Nov
1-Dec
15-Dec
29-Dec
12-Jan
26-Jan
9-Feb
23-Feb
9-Mar
23-Mar
DATE

Source: AGA



Source: AGA

BELDEN & BLAKE CORPORATION



GAS STORAGE LEVELS
APRIL 20, 2001
Record Low Week
Average of 94/95 - 00/01
00-01 Injection Season
01-02 Injection Season
STORAGE LEVEL-BCI
3500
3000
2500
2000
1500
1000
500
0
6-Apr
20-Apr
4-May
18-May
1-Jun
15-Jun
29-Jun
13-Jul
27-Jul
10-Aug
24-Aug
7-Sep
21-Sep
5-Oct
19-Oct
2-Nov
16-Nov
30-Nov
14-Dec
28-Dec
11-Jan
25-Jan
8-Feb
22-Feb
8-Mar
22-Mar
DATE

Source: AGA

Why we may be

in deep trouble

with natural gas supply.

High rig activity in early

80s plus low demand

equals

Huge

Oversupply by 1986

Eight Things Happened Between 1986 and 1996

1. Improved completion technology
2. Horizontal drilling
3. 3-D seismic
4. Coalbed methane production
5. Gulf of Mexico production
6. Pipeline deregulation
7. Rapid import growth
8. Historically low rig counts

1. Improved completion technology
2. Horizontal drilling
3. 3-D seismic
4. Coalbed methane production
5. Gulf of Mexico production

- Gradually changed the production profile of our gas well inventory from low volume/low decline to high volume/high decline
- Artificially propped up deliverability with very low gas rig count
- Coupled with gas bubble to provide ten years of substantial oversupply

Exacerbated by:

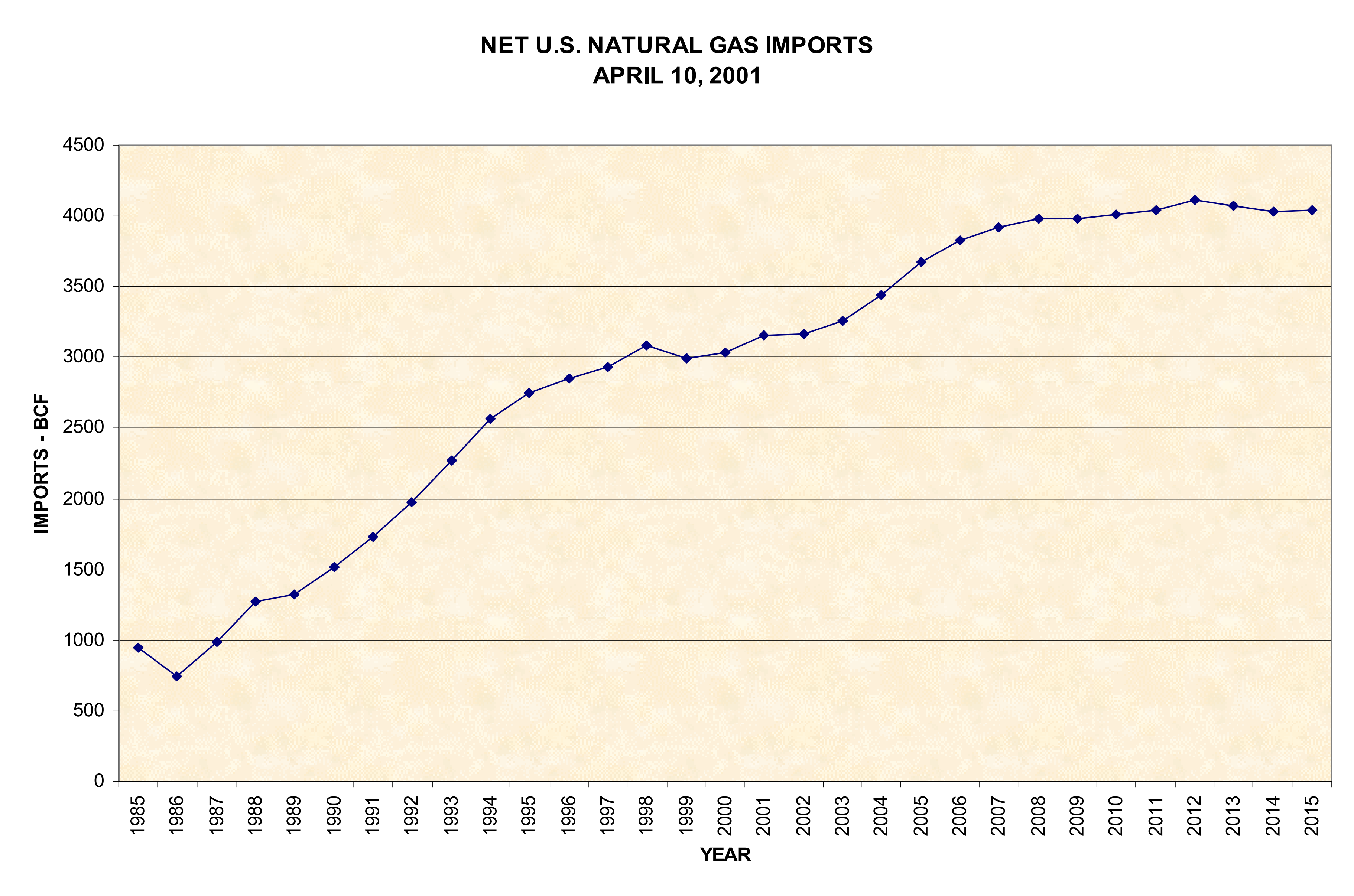
6. Pipeline deregulation

- Substantial efficiencies gained from:
  - Pipeline interconnections
  - End of “dedication” to interstate commerce
  - Hubs
  - Price transparency

Plus:

7. Rapid import growth

- Supply further supported by large Canadian import growth



Source: Gas Research Institute

And:

8. Historically low rig counts

Conclusion – 1986-1996

We got away with low rig counts due to:

- Large oversupply after early 1980s drilling boom
- New technology changing the well decline profile
- Huge growth in Canadian imports
- Pipeline infrastructure improvements

- Capital investment/oil and gas price collapse in 1998/1999 +
- Low rig counts +
- High deliverability decline profile +
- No new pipeline efficiency gains +
- Minimal import gains

2000 Supply Crunch

The Big Question

How long will it take gas

supply to catch up to gas demand?

Gas Supply/Demand/Price *(All Volumes in TCF)*

Date	Prior Period Gas Rigs[1]	U.S. Well Deliverability	**PLUS:** Imports[2]	**LESS:** Pipeline Constraints[2]	**EQUALS:** Net Supply[3]	Demand[2,4]	Price
1986	-----	23.7	0.7	3.5	20.9	16.2	$1.71

1 Baker-Hughes
2 Gas Research Institute
3 Includes storage inventory changes adding 0.7 TCF to supply in 2000 and 0.1 TCF in 1996
4 2001 assumes 25 BCF/week (1.3 TCF/Yr.) of demand lost due to economic slowdown
Estimated

Gas Supply/Demand/Price *(All Volumes in TCF)*

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1996	383	18.9	2.9	0.5	21.4	22.0	$2.59

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1996	383	18.9	2.9	0.5	21.4	22.0	$2.59
2000	522	18.8	3.0	0.4	22.1	22.5	$3.89

[1] Baker-Hughes
[2] Gas Research Institute
[3] Includes storage inventory changes adding 0.7 TCF to supply in 2000 and 0.1 TCF in 1996
[4] 2001 assumes 25 BCF/week (1.3 TCF/Yr.) of demand lost due to economic slowdown
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2005	???	24.3	3.7	0.9	27.1	27.1	???

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Estimated

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2000	522	18.8	3.0	0.4	22.1	22.5	$3.89
2001	720	19.4	3.2	0.6	22.0	21.8	↓
2005	???	24.3	3.7	0.9	27.1	27.1	???

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Estimated

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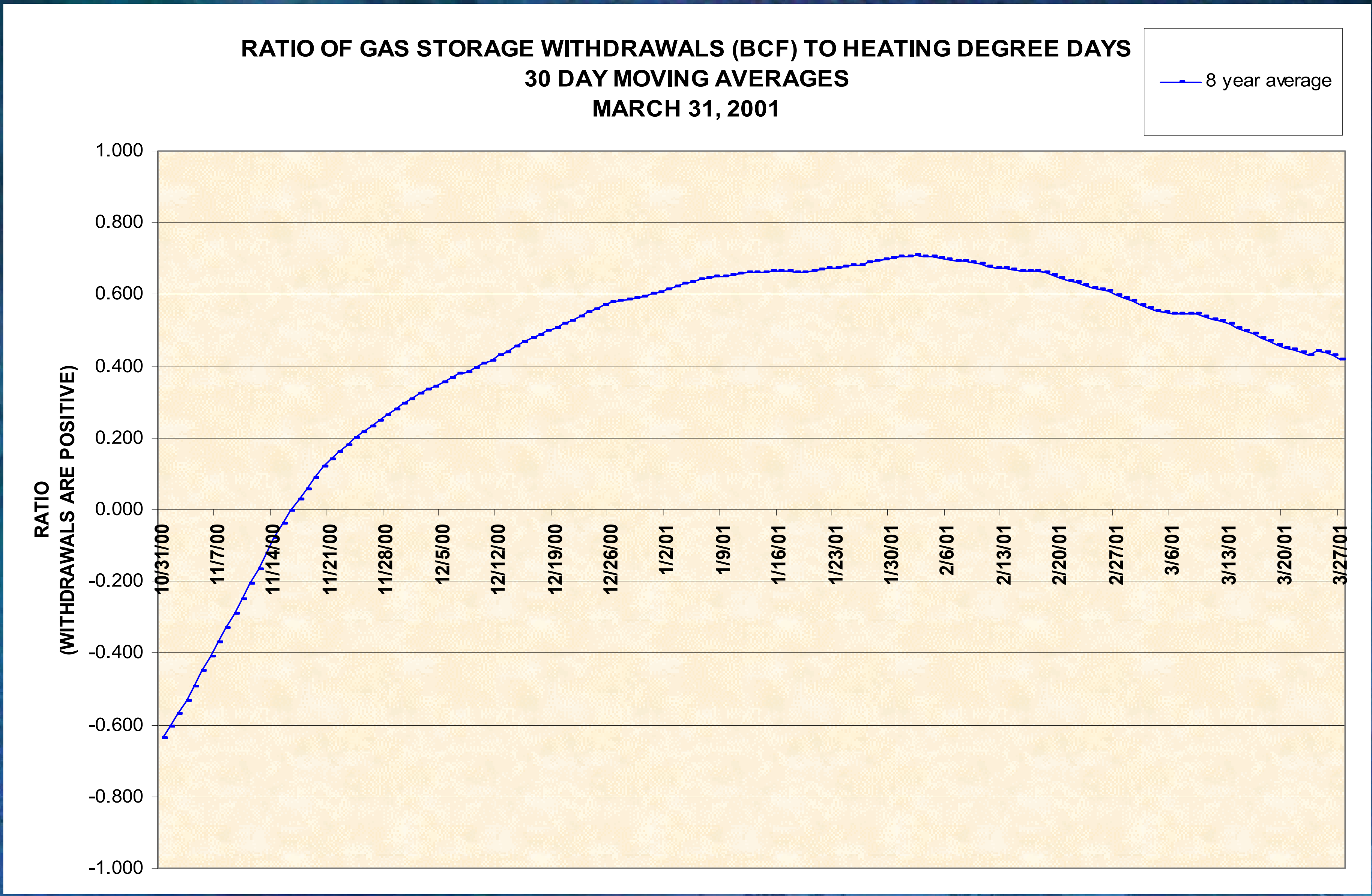

RATIO OF GAS STORAGE WITHDRAWALS (BCF) TO HEATING DEGREE DAYS
30 DAY MOVING AVERAGES
MARCH 31, 2001
8 year average
RATIO
(WITHDRAWALS ARE POSITIVE)
1.000
0.800
0.600
0.400
0.200
0.000
-0.200
-0.400
-0.600
-0.800
-1.000
10/31/00
11/7/00
11/14/00
11/21/00
11/28/00
12/5/00
12/12/00
12/19/00
12/26/00
1/2/01
1/9/01
1/16/01
1/23/01
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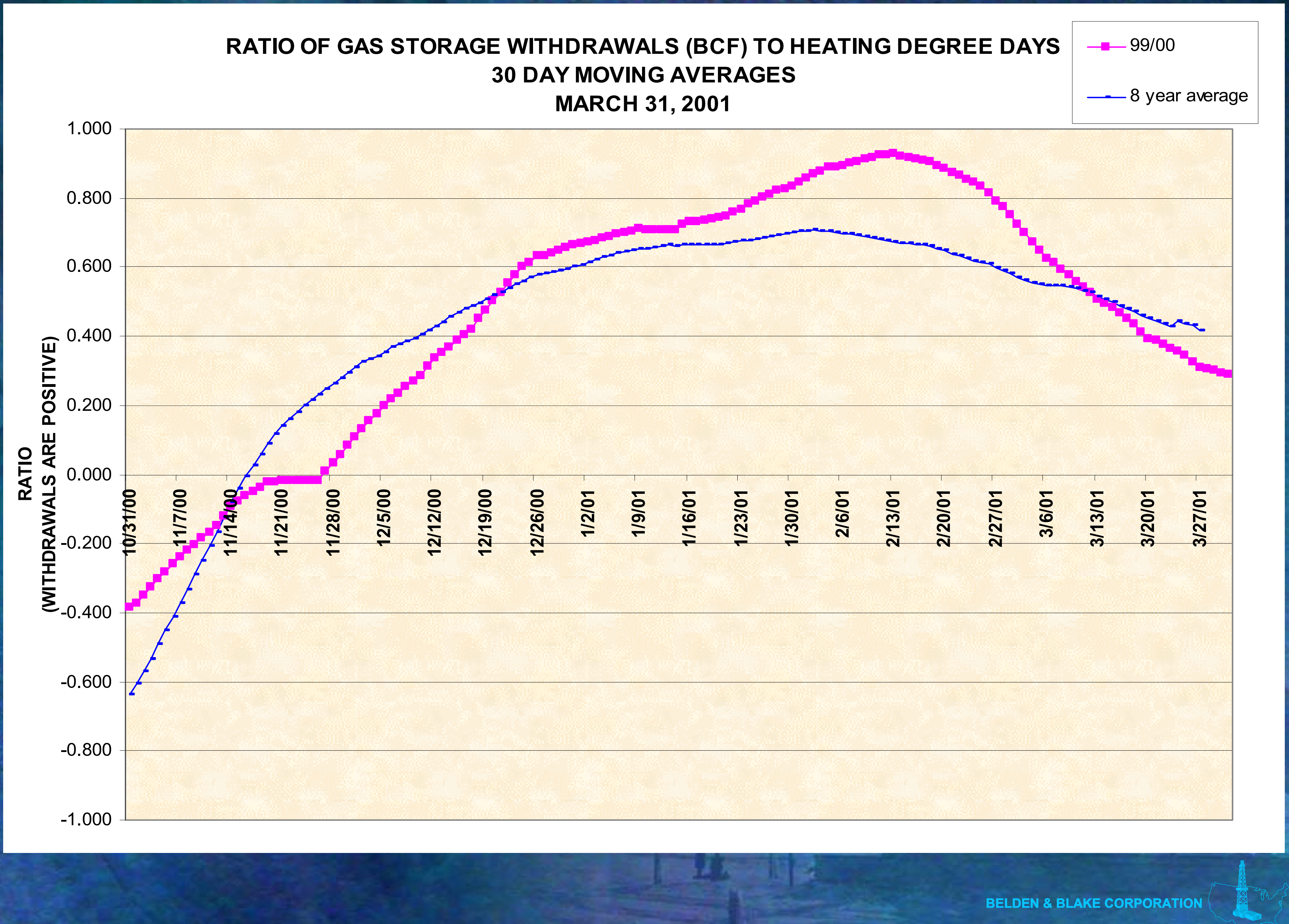
3/13/01
3/20/01
3/27/01


RATIO OF GAS STORAGE WITHDRAWALS (BCF) TO HEATING DEGREE DAYS
30 DAY MOVING AVERAGES
MARCH 31, 2001
99/00
8 year average
RATIO
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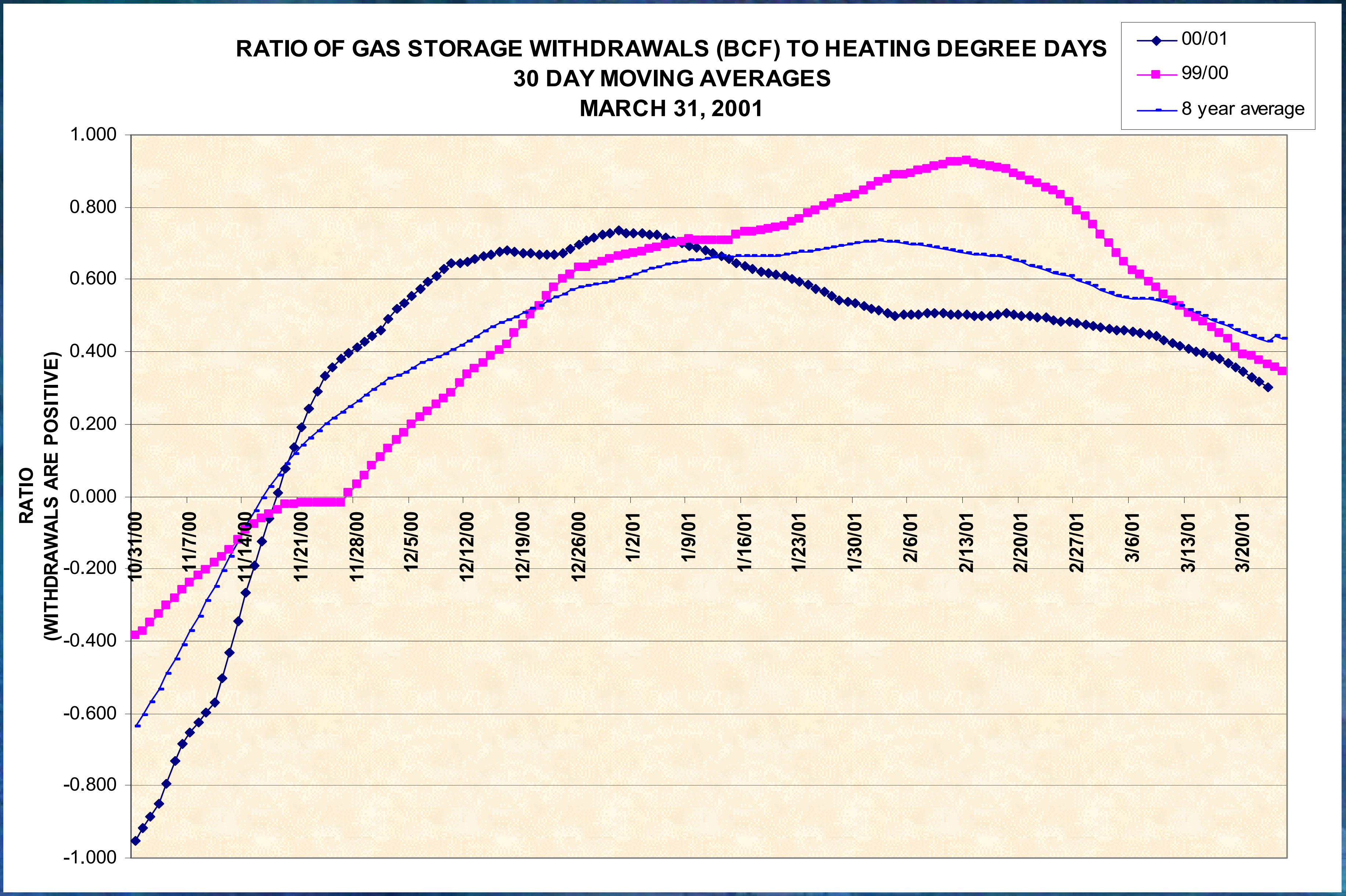
1.000
0.800
0.600
0.400
0.200
0.000
-0.200
-0.400
-0.600
-0.800
-1.000
10/31/00
11/7/00
11/14/00
11/21/00
11/28/00
12/5/00
12/12/00
12/19/00
12/26/00
1/2/01
1/9/01
1/16/01
1/23/01
1/30/01
2/6/01
2/13/01
2/20/01
2/27/01
3/6/01
3/13/01
3/20/01
3/27/01
BELDEN & BLAKE CORPORATION


RATIO OF GAS STORAGE WITHDRAWALS (BCF) TO HEATING DEGREE DAYS
30 DAY MOVING AVERAGES
MARCH 31, 2001
00/01
99/00
8 year average
RATIO
(WITHDRAWALS ARE POSITIVE)
1.000
0.800
0.600
0.400
0.200
0.000
-0.200
-0.400
-0.600
-0.800
-1.000
10/31/00
11/7/00
11/14/00
11/21/00
11/28/00
12/5/00
12/12/00
12/19/00
12/26/00
1/2/01
1/9/01
1/16/01
1/23/01
1/30/01
2/6/01
2/13/01
2/20/01
2/27/01
3/6/01
3/13/01
3/20/01
BELDEN & BLAKE CORPORATION

???????

- Rig count gains ⬇
- Current low capital inflows ⬆
- E&P industry infrastructure problems ⬆
- Busy environmentalists ⬆
- Restrictions on competing fuels ⬆
- Deliverability profile ⬆
- U.S. economy ⬇
- Crude oil prices ⬇

⬆ Higher Gas Prices

⬇ Lower Gas Prices

Conclusions

- We are stuck with natural gas for the next three to five years to meet electric demand growth in addition to gas' traditional uses for home and commercial heating and industrial processes
- Supply may be inadequate
- Aggressive steps must be taken

What Must Happen

- The capital spigot must be opened wide
- Must rebuild the drilling rig/industry personnel infrastructure
- We must drill a lot of wells in places now off limits
- Current environmental rules must be subjected to rigorous cost/benefit scrutiny and analysis

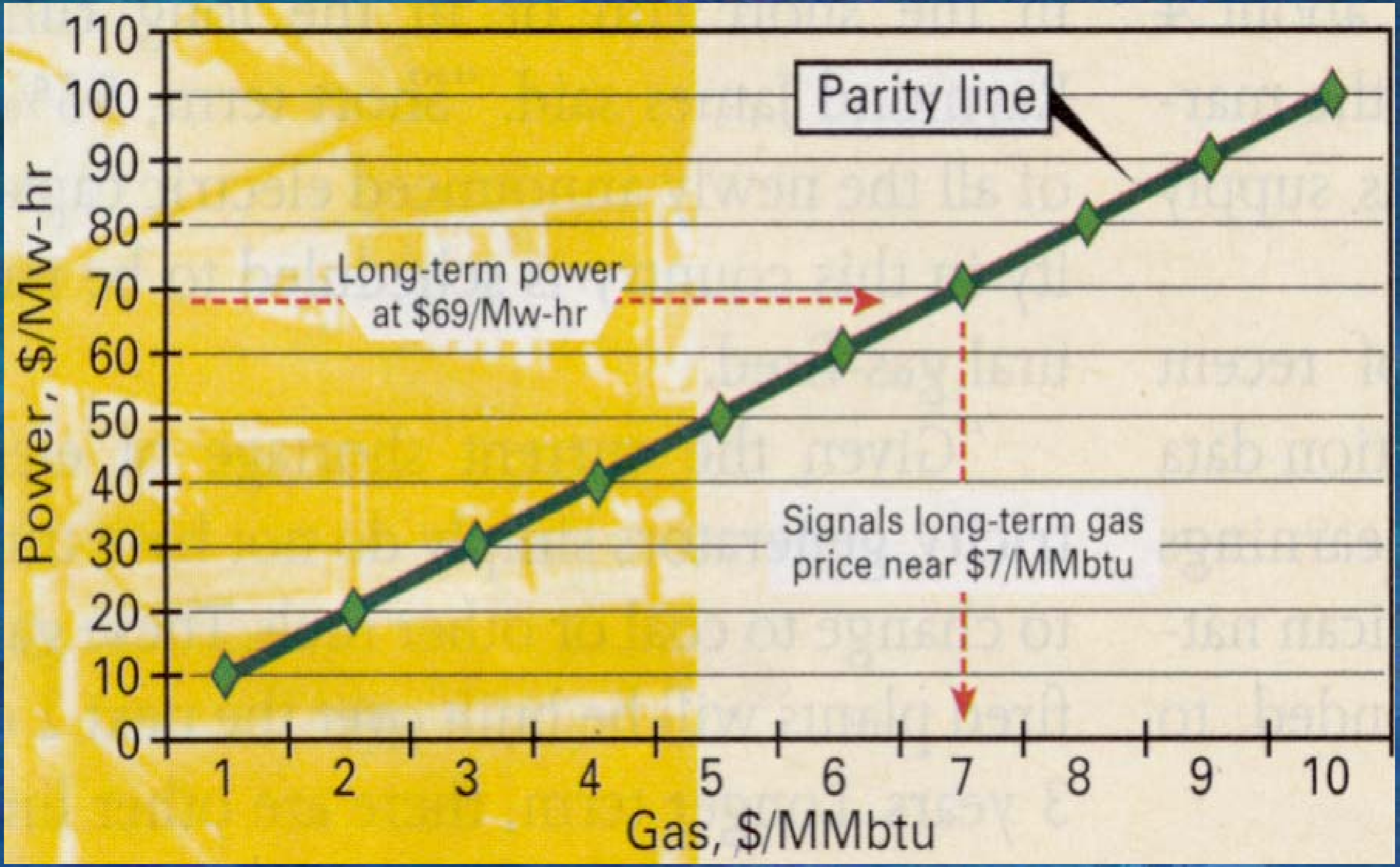
What Must Happen

- The consumer must be educated and his or her voice heard. What we are willing to pay for a clean environment?
- Politicians must be brave and forthcoming. Quit demonizing the entire energy industry.
- BANANA, NIMBY and NOPE must be minimized.
- Coal and nuclear must come to the rescue as soon as possible (by late in decade?).

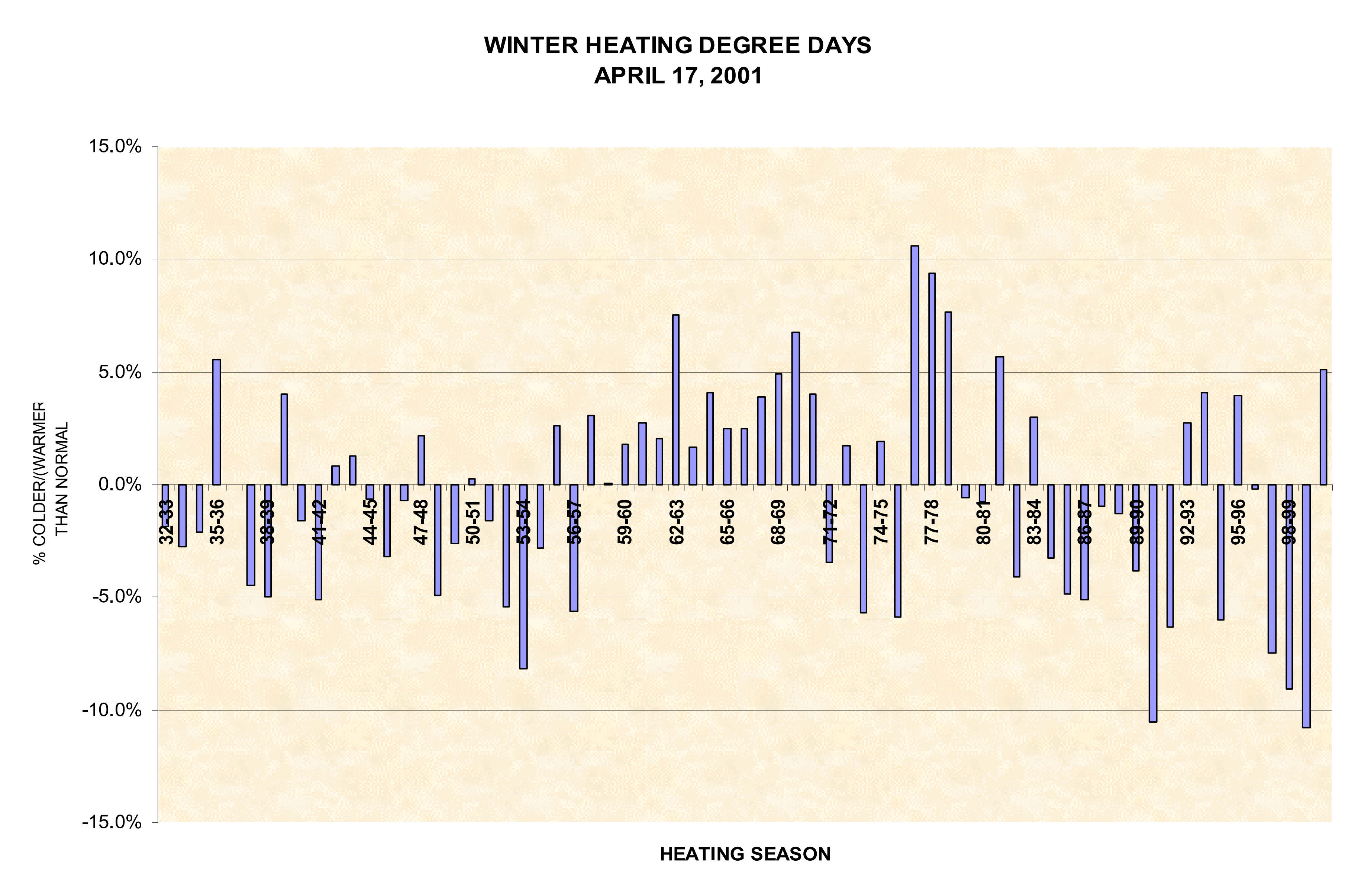
What Must Happen – Regulatory Rules
(<u>Most</u> Critical)

- Utilities <u>must</u> be able to enter into long-term supply arrangements and be able to pass through the costs <u>even when</u>, over the contract term, spot prices end up being lower

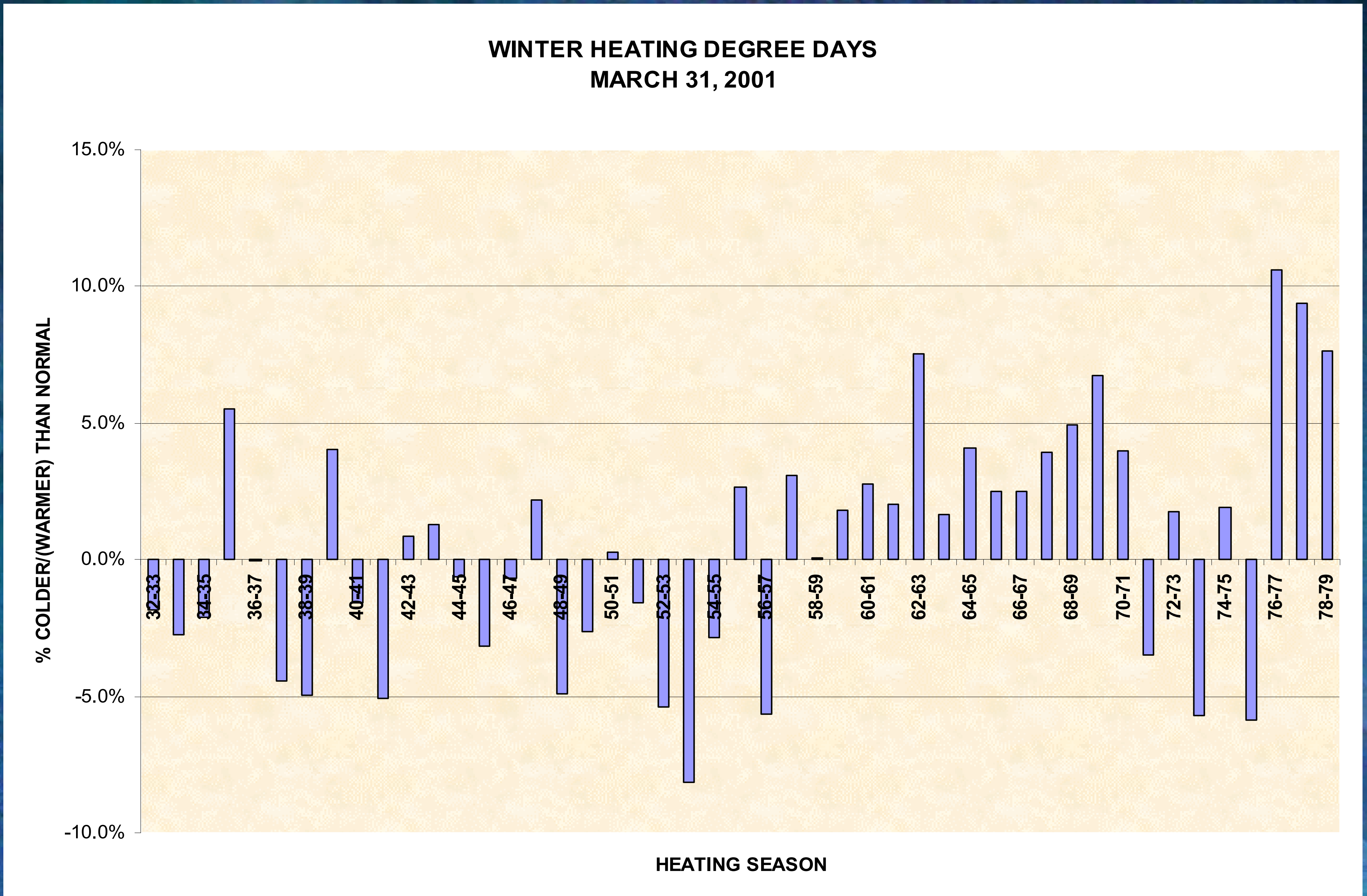
Theoretical Prices for Long-Term Gas, Power
(Based on a heat rate basis of 10,000)



Source: Raymond James & Associates, Inc.


WINTER HEATING DEGREE DAYS
APRIL 17, 2001
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
% COLDER/(WARMER THAN NORMAL
32-33
35-36
38-39
41-42
44-45
47-48
50-51
53-54
56-57
59-60
62-63
65-66
68-69
71-72
74-75
77-78
80-81
83-84
86-87
89-90
92-93
95-96
98-99
HEATING SEASON

Source: NOAA


WINTER HEATING DEGREE DAYS
MARCH 31, 2001
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
% COLDER/(WARMER) THAN NORMAL
32-33
34-35
36-37
38-39
40-41
42-43
44-45
46-47
48-49
50-51
52-53
54-55
56-57
58-59
60-61
62-63
64-65
66-67
68-69
70-71
72-73
74-75
76-77
78-79
HEATING SEASON

Reference

Hot Talk Cold Science

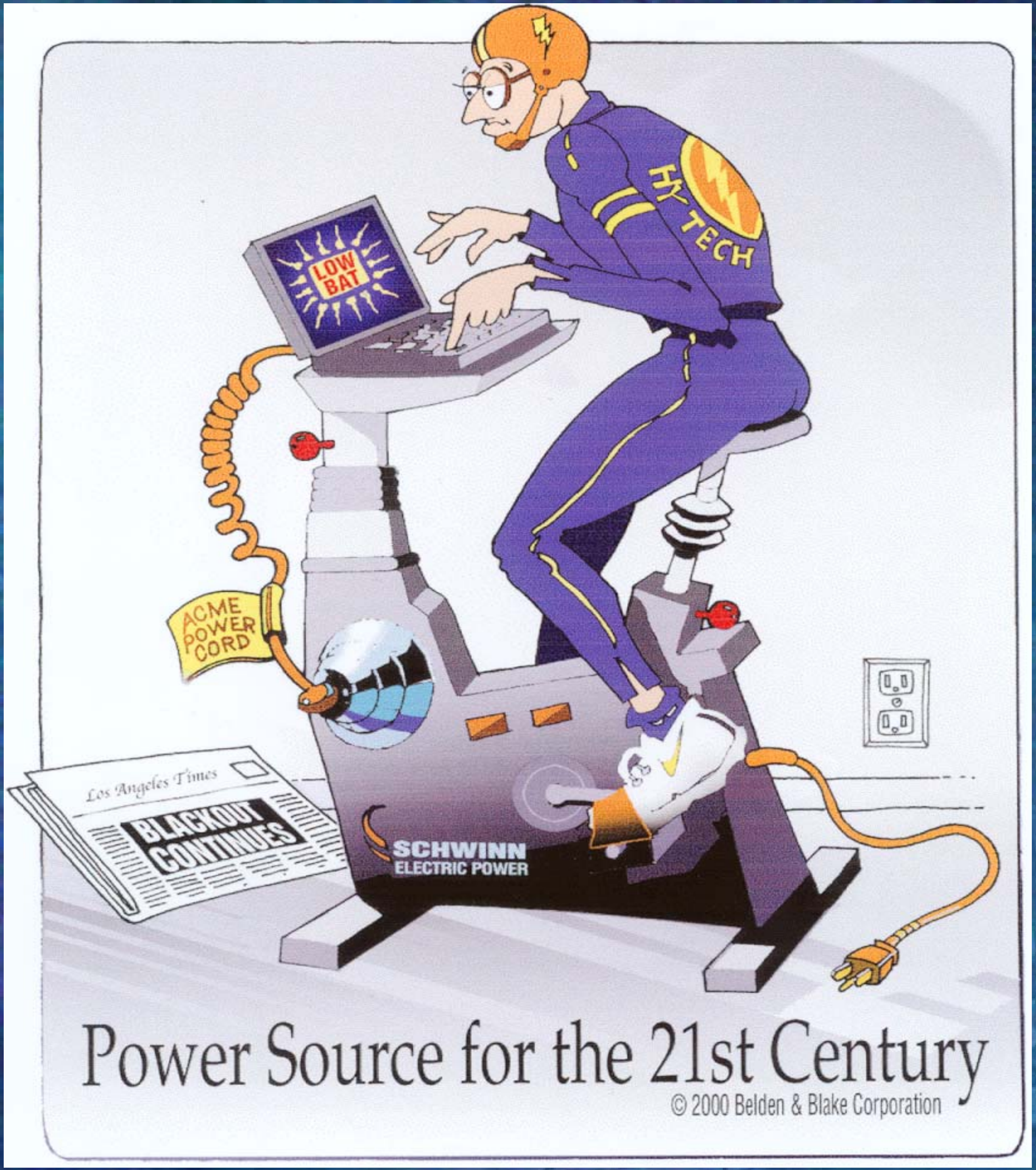
Global Warming's Unfinished Debate

by: S. Fred Singer

Climate of Fear

Why We Shouldn't Worry About Global Warming

by: Thomas Gale Moore


HY-TECH
LOW BAT
ACME POWER CORD
Los Angeles Times
BLACKOUT CONTINUES
SCHWINN ELECTRIC POWER
Power Source for the 21st Century
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John L. Schwager
President and CEO

jschwager@beldenblake.com

Afternoon Technical Session
Advances in Coalbed Methane Technology

Moderator

David Ogbe
University of Alaska, Fairbanks

Rank, Maceral Content and Sorption of Gases on Tertiary Age Coals: New Data and New Exploration Models

Speaker

Raymond Pilcher
Raven Ridge Resources, Inc.

Speaker Biography

RAYMOND C. PILCHER
President, Raven Ridge Resources, Incorporated

Ray Pilcher has worked more than 25 years in the petroleum and mining-related industries. He graduated with a B.S in Geology from the University of Texas at Austin in 1975. As President of Raven Ridge Resources, Incorporated, his experience includes domestic and international project management, economic evaluation, and corporate planning. Mr. Pilcher first worked on a coalbed and coal mine methane project in 1981 in Colorado, and since has focused on coalbed, coal mine methane, and unconventional gas projects in the U.S. and abroad.

NOTES:

Microbially Enhanced Coalbed Methane :
Benefits and Limitations of a New Technology

Speaker

Andrew Scott
Altuda Geological Consulting

NOTES:

Water Disposal Methods

Speaker

John Harju
GTI E&P Services

Speaker Biography

John Harju

John Harju is a Principal in GTI E&P Services' Produced Water Management Group and is a cofounder and Vice President of Crystal Solutions, LLC. He has been at GTI (formerly GRI) since 1997, and has been with Crystal Solutions since its creation in 1999. Prior to these positions, he led the Oil & Gas Group at the University of North Dakota's Energy & Environmental Research Center, where he was employed for 8 years. His formal training is in Geology, and he has extensive knowledge and expertise in the fields of waste management, environmental geochemistry, hydrology, technology development, and analytical chemistry, especially as applied to the upstream oil and gas industry.

EVALUATING PRODUCED WATER MANAGEMENT STRATEGIES FOR ALASKAN CBM AND SHALLOW GAS

Presented by:
John Harju,
Gas Technology Institute and Crystal Solutions, LLC

May 4, 2001 **PTTC's Alaska Coalbed and Shallow Gas Resources Workshop**

gti[SM]

Outline

- Produced Water Costs
- Holistic Economic Analysis
- Technical Analysis
- Regulatory Analysis
- Intangibles
- Balance Economic / Technical / Regulatory Factors
- The FTE Process –
  - History
  - Alaska Potential

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Produced Water Costs are Significant and Often Poorly Understood

- Capital
- Operations
- Compliance
- Environmental

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Holistic Economic Analysis

- **Capital**
  - **If 15 % ROI is used for evaluating prospects, it should also be used here**
    - Injection Wells, Pipelines, Surface Facilities, Tanks, Bonding
    - In Turn, Less Reserves per Exploration $
- **Operations**
  - **Labor (internal and outsourced)**
  - **Transportation**
  - **Disposal Fees**
  - **Chemical Treatment**
  - **Production Impacts**
  - **Scale / Corrosion**
  - **Electricity**

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Holistic Economic Analysis (Continued)

- **Compliance**
  - **Labor**
  - **Bonding (Capital ??)**
  - **Permit Fees (UIC, NPDES, MIT)**
  - **Lost Production**
- **Environmental**
  - **Fines**
  - **Judgements**
  - **Lawsuits**
    - Civil (Salt Damage is a Frequent Subject)
    - Criminal

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Technical Analysis

- **Consider <u>All</u> Options**
  - **UIC**
    - Accessibility / Injectivity of Strata
    - Chemical / Physical Treatment Needs
  - **Downhole Separation**
    - Appropriate Strata ?
  - **Waterflood**
    - Feasibility / Suitability
    - Chemical / Physical Treatment ?
  - **Production Optimization**
    - Well Completion / Workover Alternatives
    - Reverse Coning
  - **Surface Evaporation**
    - Climatic Performance

Technical Analysis (Continued)

- **Consider <u>All</u> Options**
  - **Surface Discharge / Stock Water**
    - NPDES
    - Stock Tanks
  - **Treatment / Recycling / Other Reuse**
    - Freeze -Thaw / Evaporation
    - RO/ED
    - Deoiling
      - offshore
      - fresh onshore waters
  - **Water Shut-Off / Conformance Technology**
  - **Commercial Disposal**
  - **Hybrids**

Regulatory Analysis

- UIC Regulations
- Bonding
- NPDES
- Surface Facility Guidelines
- Waste Minimization Credits
- Pollution Prevention Credits
- Permitting Timelines
- Water Quality Standards
- Location

Intangibles

- Touchy Landowner Issues
- Phase of Operation
  - Late in Operable Production Cycle (Near Divesture) ?
- Other Internal Resource Demands / Abundances
  - Equipment
  - Staff Experience
- Other Internal Mandates
- Externalities

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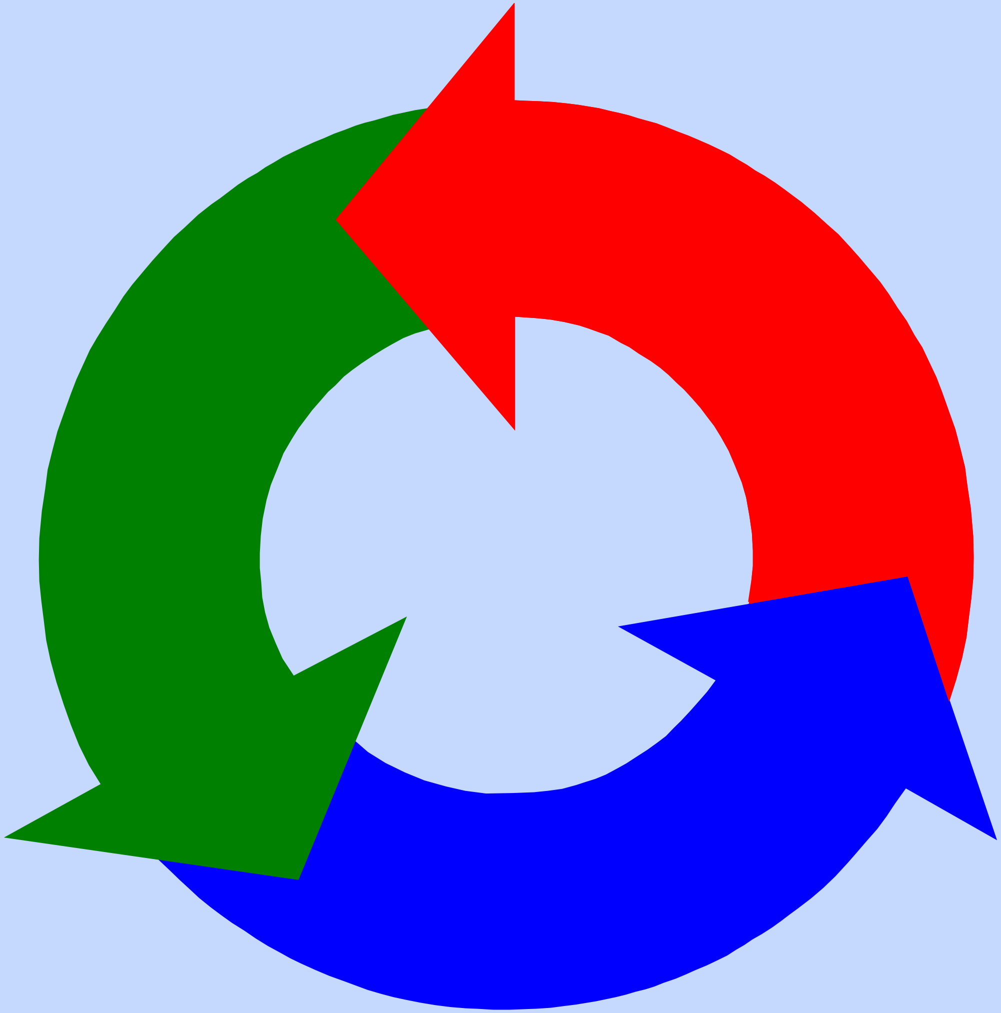
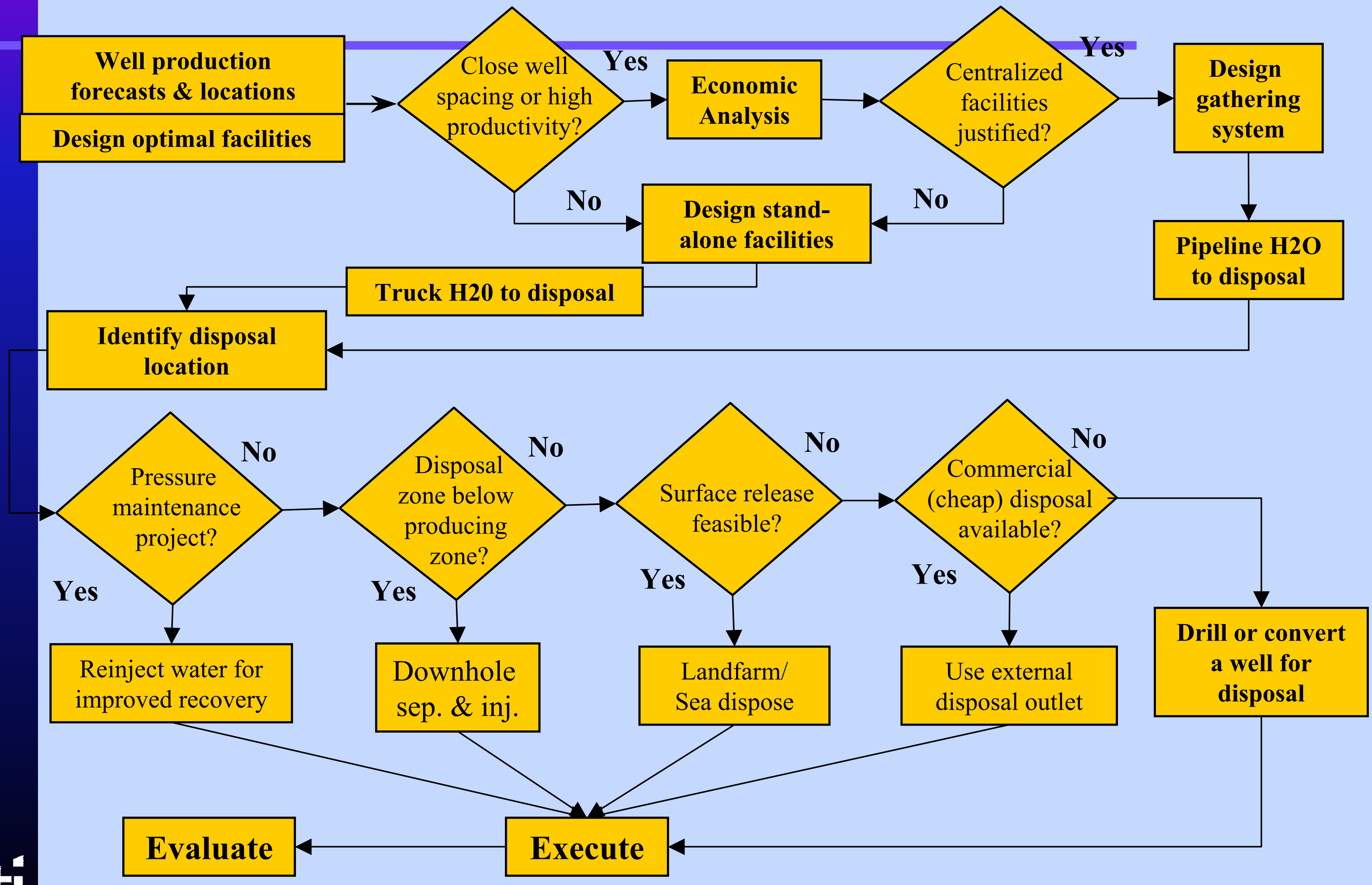
Balance Technical / Economic / Regulatory Concerns



Example: Surface Development Process



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Produced Water Management Utilizing the FTE® Process

Acknowledgements

- Coauthors
  - John Boysen, BC Technologies / Crystal Solutions
  - Deidre Boysen, BC Technologies / Crystal Solutions
  - Jon Rudolph, GTI

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  - USDOE
  - GRI (now GTI)
  - Jim Sorensen
    - UND-EERC
  - Ames Grisanti
    - UND-EERC (now SEA)
  - Buddy Shaw
    - Amoco Production CO (now BP)
  - Mike Fosdick
    - McMurry Oil CO (now MEC)

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The FTE® Process - Conceptually Simple

- Salts or other constituents that are dissolved in water lower the freezing point of the solution below 32 degrees F.
- Partial freezing occurs when the solution is cooled below 32 degrees F, but not below the depressed freezing point of the solution.
- Relatively pure ice crystals form, and an unfrozen solution (brine), containing elevated concentrations of the dissolved constituents, drains from the ice.

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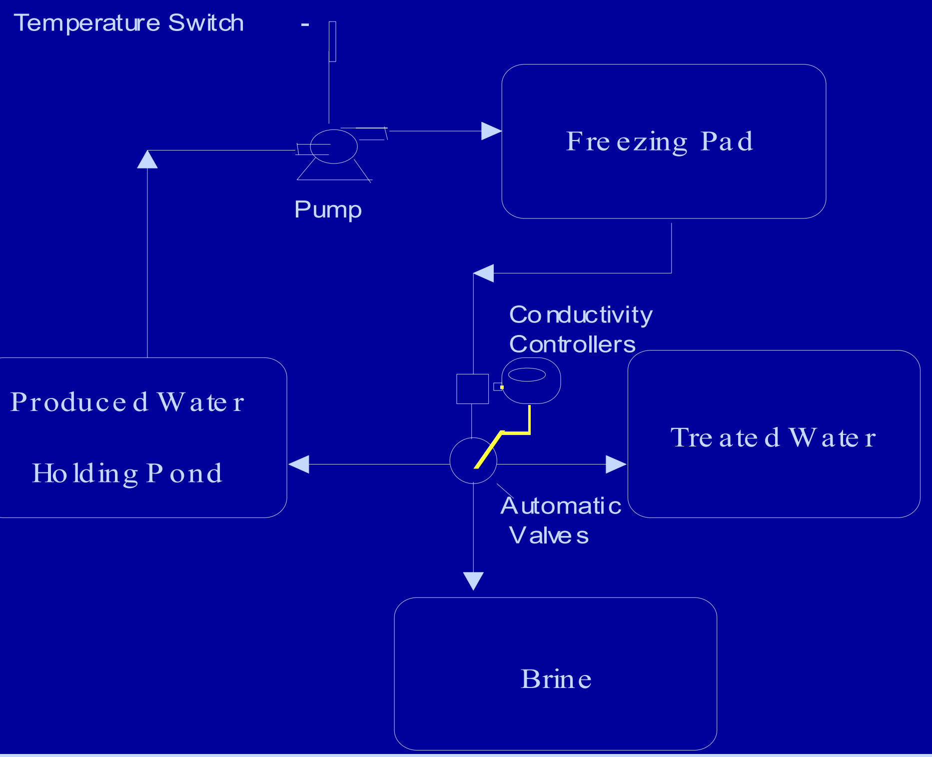
The FTE® Process

- **Coupling this freeze / thaw cycling with conventional evaporative technology allows treatment / disposal on a year round basis.**

FTE® Process Block Flow Diagram



Benefits of the FTE® Process

- Reduced Produced Water Management Costs
- Extend Injection Well Performance
- Extend Production in Economically Marginal Fields
- Expansion of Non-Conventional Resources (CBM)
- Beneficial Uses of Treated Water and Brine Products

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New Mexico FTE® Site, 1997

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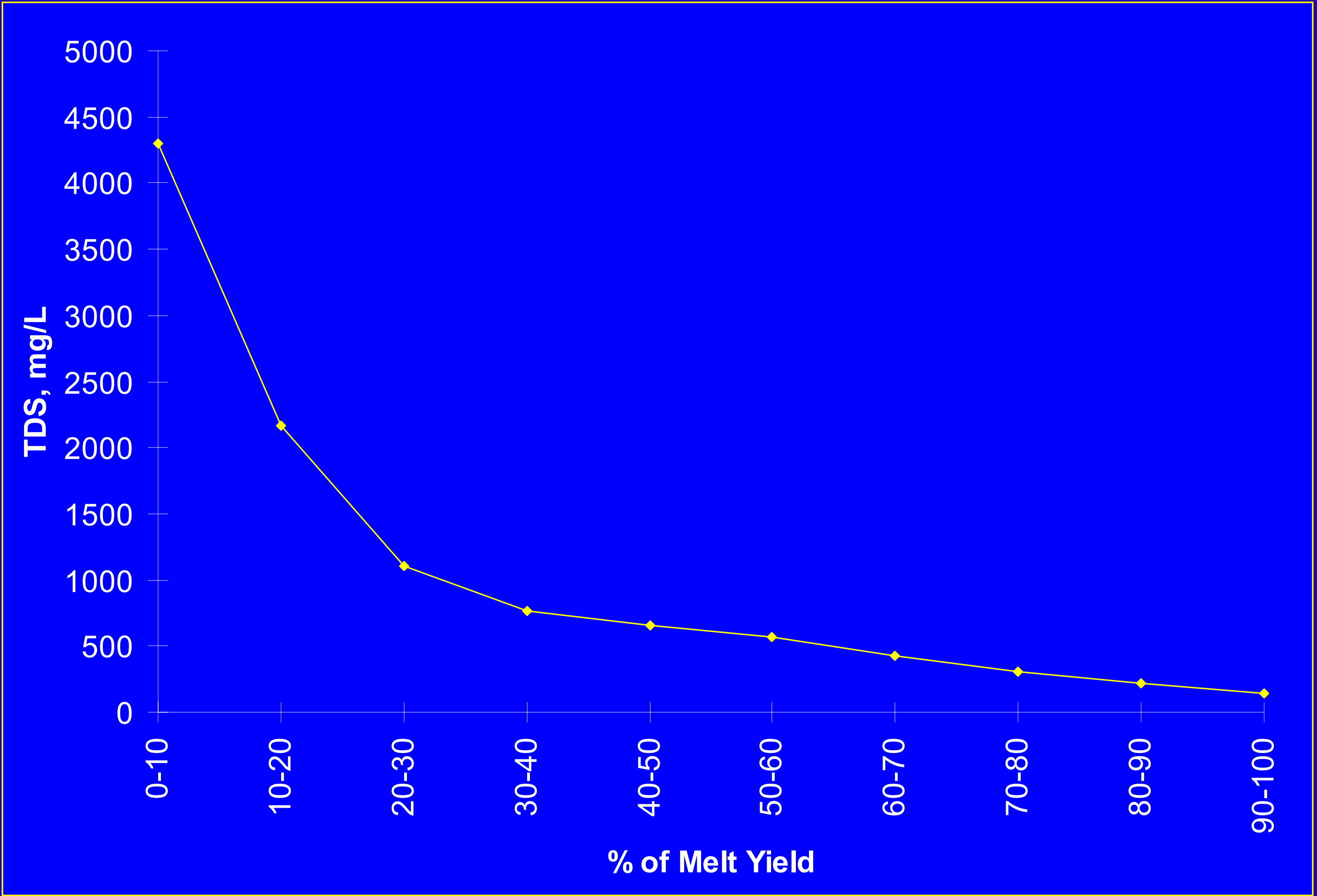
TDS of Treated Water -New Mexico -Winter of 1996-97



Quality of Process Streams - FTE^{SM} Field Evaluation in New Mexico's San Juan Basin during the Winter of 1996-97

	Feed	Treated Water	Brine
TDS, mg/L	12,800	1,010	44,900
EC, µS	16,200	1,670	45,700
Total Alkalinity ($CaCO_3$), mg/L	9,380	700	35,550
% of Feed	-	52.9	20.1

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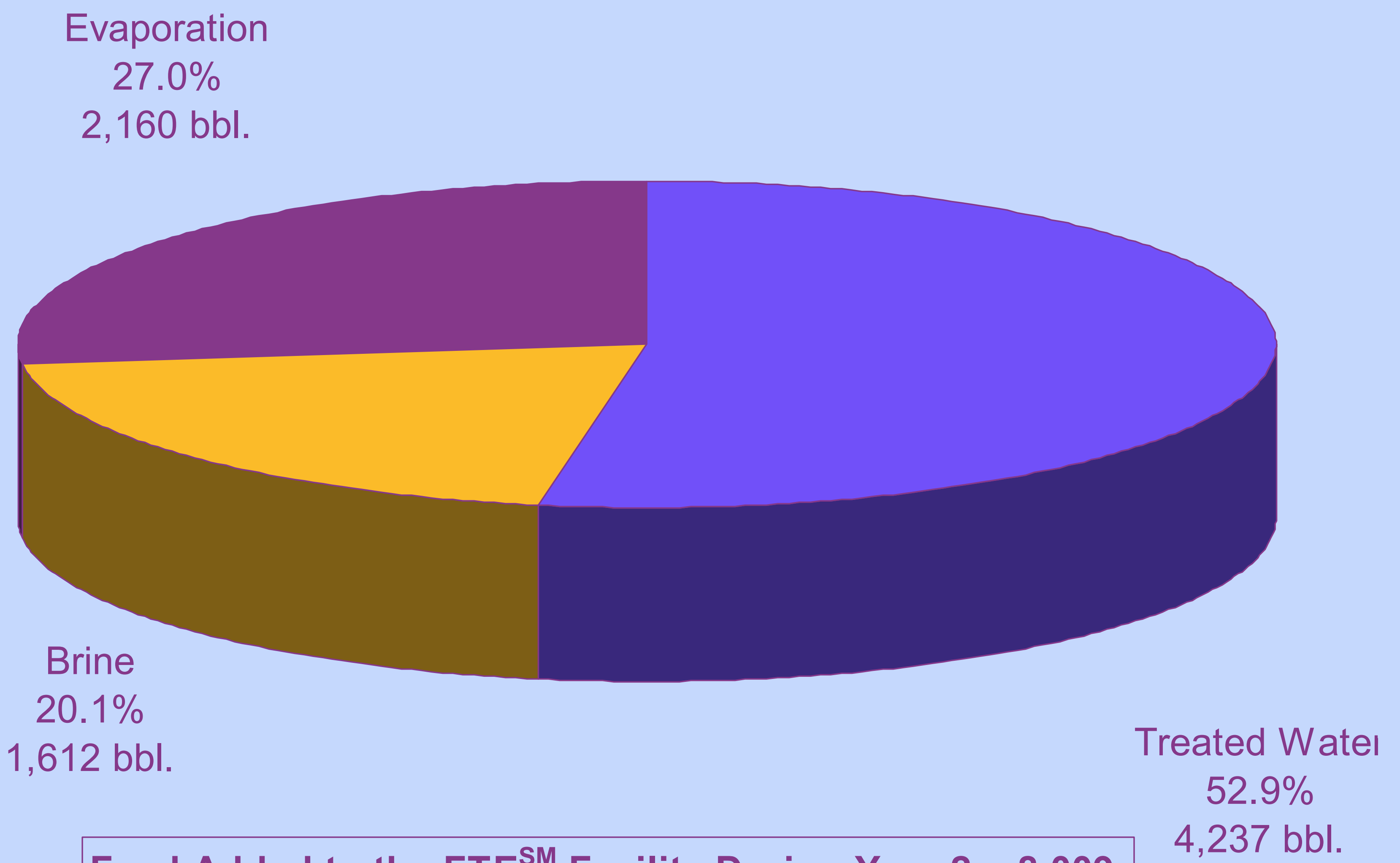
Product Yield from the FTE® Field Evaluation in New Mexico's San Juan Basin during the Winter of 1996-97

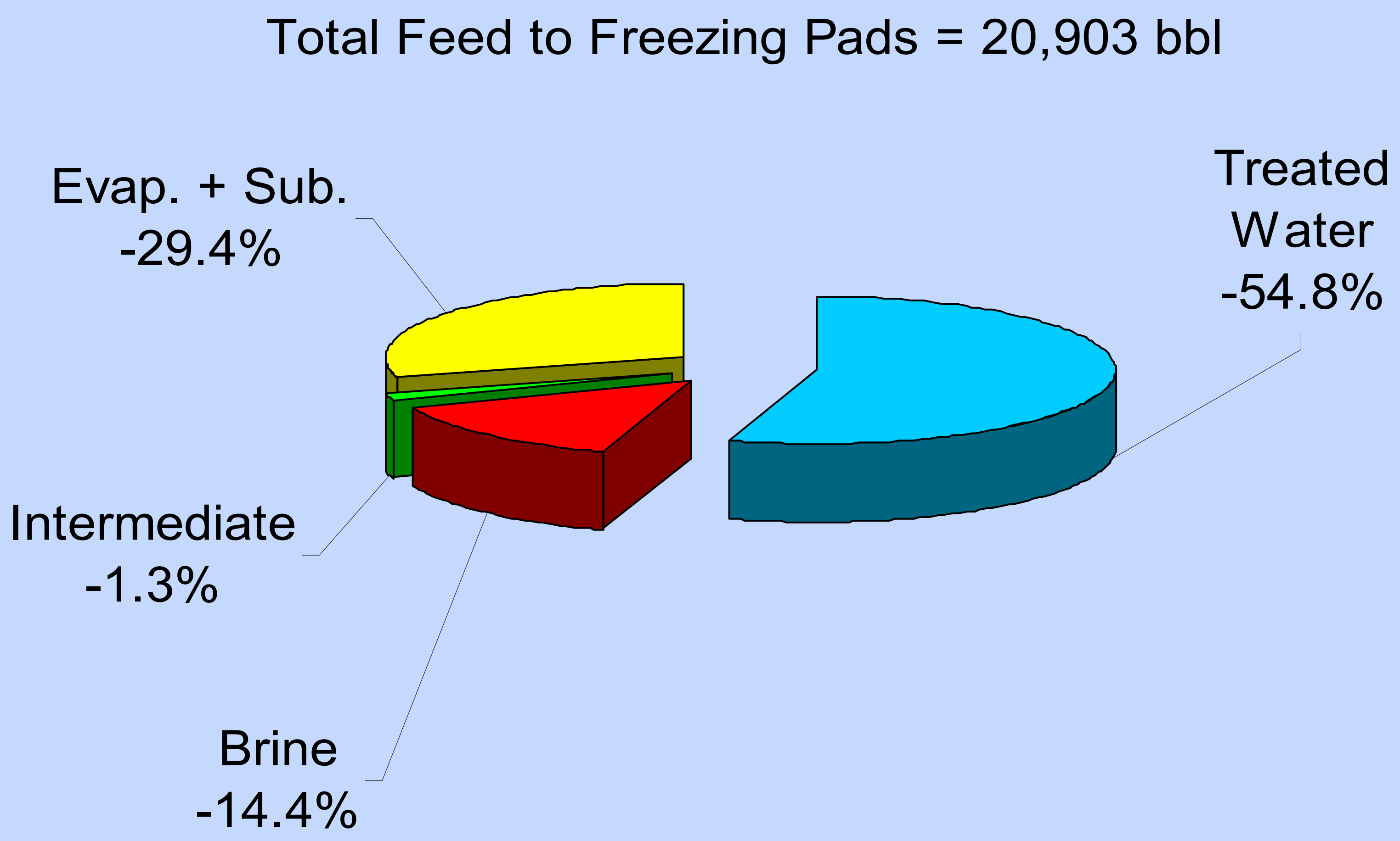


Feed Added to the FTE℠ Facility During Year 2 = 8,009

New Mexico FTE® Site - 1997

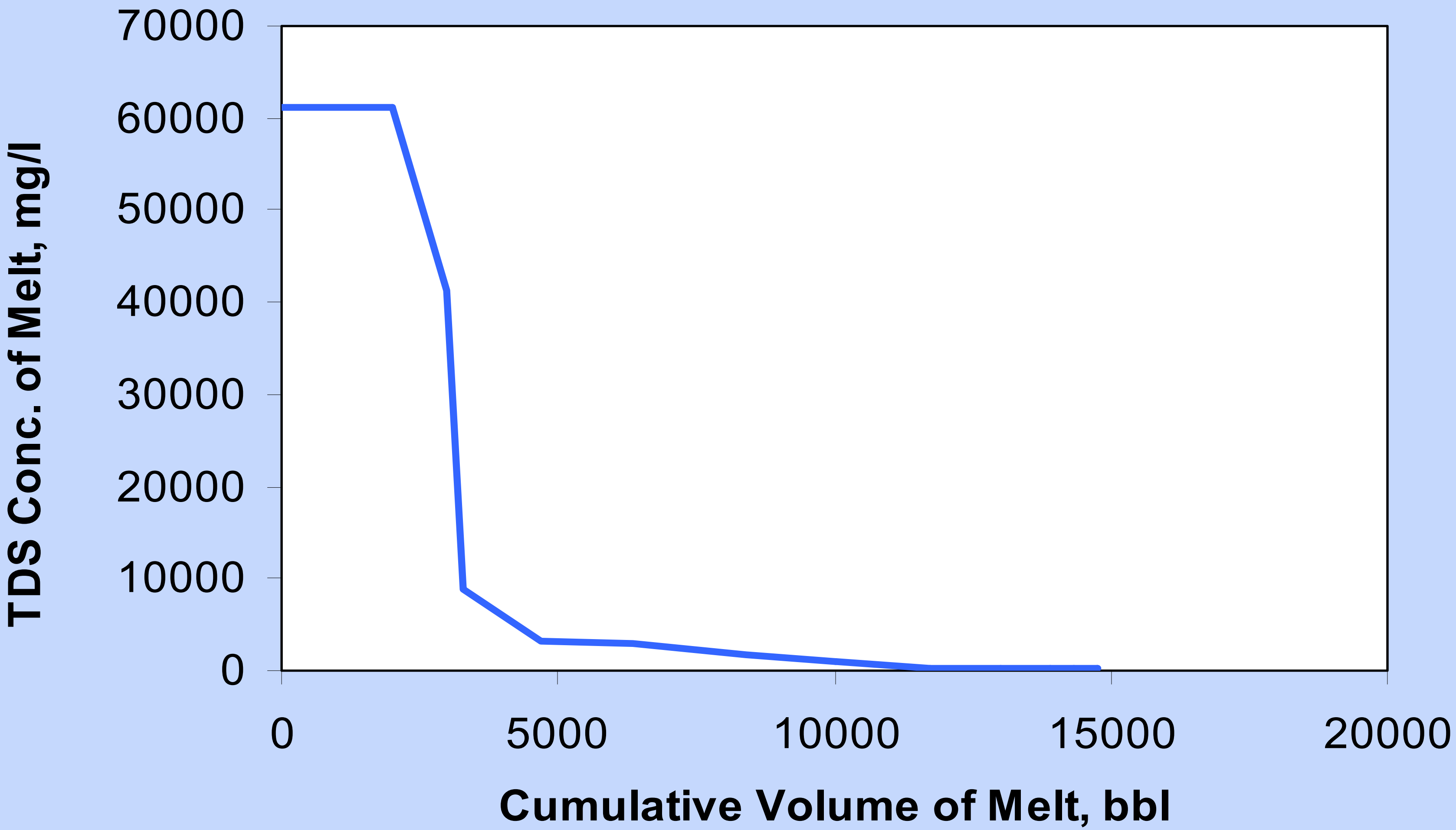
Jonah Field , November 1999

Jonah Field FTE® Yield Summary for the 1999-2000 Winter



Jonah Field FTE® Process Summary for the 1999-2000 Winter

Total Dissolved Concentration (TDS) of Melt versus Volume of Melt



Jonah Field FTE® Performance for the 1999-2000 Winter

	Na, mg/l	K, mg/	Cl, mg/l
Feed	2,690	2,790	7250
Brine	13,100	15,100	35,200
Treated Water	125	120	320

Crystal Solutions, LLC - Wamsutter

Crystal Solutions, LLC - Wamsutter

Crystal Solutions, LLC Site - Wamsutter

- A 600 bbl/day facility has been operating near Wamsutter, WY since December of 1999.
- The freezing process was not operated in the winter of 1999-2000, due to excess pond capacity.
- Current customers include 9 Producers in the Great Divide / Red Desert Basins.
- The freezing process has recently been completed for the winter of 2000-2001, preliminary data indicate another successful winter. Approximately 50,000 bbl of quality usable water was created from produced waters delivered to and processed at the facility.

gti

Crystal Solutions, LLC

- **Currently permitting an expansion of the Wamsutter facility**
- **Currently negotiating potential new facilities in Wyoming (3), Utah (1), Colorado (2), New Mexico (2)**

Conclusions

- Produced water costs are often hidden.
- Produced water costs are significant and pervasive in an overall production life cycle.
- Significant opportunities for economical, alternative approaches and/or beneficial uses are often overlooked/not considered due to these oversights, and occasionally due to regulatory uncertainty.
- The FTE® Process has proven its applicability in regions that experience seasonal subfreezing conditions – Alaska may be ideal, dependent on thorough consideration of technical, regulatory, and economic factors.

PANEL DISCUSSIONS

Moderator

Dave Lappi
LAPP Resources, Inc.

Application Processing Alaska's Paperwork,
Regulatory Matters and Bottlenecks for Producers

Speaker

Pirtle Bates
State of Alaska,
Department of Natural Resources

Speaker Biography

PIRTLE BATES, JR.
STATE OF ALASKA, DEPT. OF NATURAL RESOURCES

Pirtle Bates, Jr. is a Natural Resource Manager with the State of Alaska, Department of Natural Resources, Division of Oil and Gas. His primary responsibilities include the conduct of oil and gas lease sales, processing shallow natural gas lease applications and coordinating the land title work necessary for the issuance of oil and gas leases and licenses on state land. He has been with the Department of Natural Resources for twelve and one-half years, with the last five and one-half years spent in the Division of Oil and Gas. He holds a B.A. in Economics.

Comparison of State's Competitive and SNG Leasing Programs

STANDARD LEASES		SNG LEASES
Competitive	**DISPOSAL**	Non-Competitive
Best Interest Finding (State's best interest)	**DECISION CRITERIA**	No written finding required
Oil, gas, and associated substances	**MINERALS LEASED**	Gas, whether methane associated with and derived from coal deposits or otherwise
Full permitting required	**PERMITTING**	Exempt from waste discharge permit & discharge prevention and contingency plan
DNR - $10,000/well (minimum) AOGCC - $100,000/well or $200,000/statewide DEC - $1,000,000/exploration facility	**FINANCIAL RESPONSIBILITY (BONDING)**	DNR - $10,000/well (minimum) AOGCC - $100,000/well or $200,000/statewide DEC - $25,000/exploration facility
Entire subsurface	**LEASE HORIZON**	Within 3,000 feet of the surface
500,000 acres onshore & offshore	**ACREAGE LIMITATION**	46,080 acres
5,760 acres maximum	**LEASE SIZE**	5,760 acres maximum
None (minimum bonus of at least $5/acre)	**FILING FEE**	$500
5 – 10 years	**LEASE TERM**	3 years (director may extend once for up to three years)
12.5% minimum	**ROYALTY RATE**	6.25% (12.5% if produced in direct competition with gas having royalty of 12.5% or greater)
Escalating from $1 to $3 per acre	**RENTAL RATE**	50 cents per acre
None (courtesy notices are sent, but non-receipt does not excuse late payments)	**RENTAL BILLING**	Lessee Billed (sent certified, return receipt requested, three weeks prior to due date)
Yes	**TRANSFERRABLE**	No (unless producing or a well certified capable of production exists)
For production, certified well or if unitized	**EXTENDED TERM**	For production, certified well or if unitized

State of Alaska

Division of Oil and Gas

Department of Natural Resources

Title 38. PUBLIC LAND.

Chapter 05. ALASKA LAND ACT.

Section:
38.05.177.
Shallow natural gas leases.

(a) The provisions of this section

(1) apply to gas, whether methane associated with and derived from coal deposits or otherwise, developed from a source that is onshore and within 3,000 feet of the surface; and

(2) do not apply to authorize lease of

(A) land

(i) that is subject to an oil and gas exploration license or lease issued under AS 38.05.131 - AS 38.05.134; or

(ii) that is leased under AS 38.05.180 ;

(B) the land (i) that is proposed to be subject to an oil and gas exploration license or lease issued under

AS 38.05.131 - AS 38.05.134; or (ii) that is described in and part of a proposed oil and gas leasing program prepared under AS 38.05.180 (b); however, the commissioner may waive the limitations of this subparagraph;

(C) the land that is held under a coal lease entered into under AS 38.05.150, unless the applicant for a shallow natural gas lease is also the lessee under AS 38.05.150 of that land; or

(D) the valid existing selections of the Alaska Mental Health Trust Authority made for the purpose of reconstituting the mental health trust established under the Alaska Mental Health Enabling Act, P.L. 84-830, 70 Stat. 709 (1956), that become subject to management under AS 38.05.801, or of land that has been designated by law for or is subject to designation for conveyance to the Alaska Mental Health Trust Authority; however, after consultation with the Alaska Mental Health Trust Authority, the commissioner may waive the limitations of this subparagraph.

(b) For the purpose of exploring for and developing shallow natural gas reservoirs, upon application, the director may lease to a person land for which the state owns the subsurface rights. A person applying for a lease under this subsection

(1) shall specify the area to be leased; the area to be leased may not exceed 5,760 acres; a lessee may not hold more than 46,080 acres of land under leases entered into under this section;

(2) may be required to pay a reasonable application fee of up to $500.

(c) Within 20 days of receipt of a lease application, the director shall give notice under AS 38.05.945 of receipt of the lease application and call for comments from the public. The director's call for public comments must provide opportunity for public comment for a period of 60 days. If, after review of information received during the public comment period, the director determines that the discovery of a local source of natural gas would benefit the residents of an area, the director shall execute a lease for the area described in (b) of this section. The director shall execute the lease within 90 days after the close of the public comment period or, if review is required under AS 46.40, within 30 days after the final consistency determination is made under AS 46.40, whichever is later. A lease entered into under this subsection gives the lessee the exclusive right to explore for, develop, and produce, for a term of three years, natural gas on the state land described in the lease; the right to explore for, develop, and produce is limited to gas derived from natural gas within 3,000 feet of the surface.

(d) A lease shall be automatically extended if and for so long thereafter as gas is produced in paying quantities from the lease and the lessee continues to meet all requirements of the lease. A lease issued under this section covering land on which there is a well capable of producing gas in paying quantities does not expire because the lessee fails to produce gas unless the lessee is allowed reasonable time to place the well on a producing status. If drilling has commenced on the expiration date of the primary term of the lease and is continued with reasonable diligence, including such operations as redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location, the lease is extended for one year and for so long thereafter as gas is produced in paying quantities. A gas lease issued under this section that is subject to termination by reason of cessation of production does not terminate if, within 90 days after production ceases or a longer period determined at the discretion of the director, reworking or drilling operations are commenced on the land under lease and are thereafter conducted with reasonable diligence during the period of nonproduction. In addition, upon application by the lessee, the director may once extend a lease issued under (c) of this section for a period of not more than three years.

(e) The director may, following the procedures described in (c) of this section, adjust the boundaries of a lease entered into under this section as may be necessary to ensure development of natural gas within a reasonably compact area; a lease as adjusted under this subsection remains subject to the acreage limitations set out in (b)(1) of this section.

(f) A shallow gas lease must provide for payment to the state of annual rent in the amount of 50 cents per acre. The rent is due and payable on the dates determined in the lease. The director shall mail the lessee one written notice, certified return receipt requested, three weeks before the due date of the rent. If the lessee fails to pay rent, the director shall terminate the lease.

(g) The royalty payable on natural gas produced from a lease

(1) is

(A) 12.5 percent of the value of production removed or sold from the lease for gas exported from the state or gas that is produced in direct competition with gas on which a royalty at a rate of at least 12.5 percent is payable; and

(B) except as provided in (A) of this paragraph, 6.25 percent of the value of the production removed or sold from the lease; and

(2) shall be based upon production delivered in pipeline quality and free of all lease expenses, including but not limited to separation, cleaning, dehydration, gathering, salt water disposal, and preparation for transportation off the lease.

(h) A lease issued under this section is subject to the following terms and conditions and may be terminated by the director in the event of a breach of a term or condition:

(1) the lessee may surrender the lease or relinquish part of the lease at any time;

(2) the lease may not be transferred or assigned until a well capable of production of gas in paying quantities has been drilled on the lease; however, this paragraph does not prohibit the lessee from entering into a farm out agreement or similar arrangement with a third party under which the third party assists in exploration and development of production from the lease if the agreement or arrangement does not require a payment of consideration by the third party to the lessee, except that the lessee may retain an overriding royalty interest in the lease or may retain a net profit or other production payment.

(i) The applicant for a lease is responsible for conducting a title search for the area described in the lease application.

(j) A lease does not give the lessee the right to produce oil. A lease does not give the lessee the right to produce gas from sources that are not within 3,000 feet of the surface. If a well drilling for natural gas under a lease authorized by this section penetrates a formation capable of producing gas below 3,000 feet of the surface or penetrates a formation capable of producing oil, the owner or operator

(1) shall notify the department and the Alaska Oil and Gas Conservation Commission; and

(2) may not conduct further operations in the drilled well until the facility complies with all applicable laws and regulations relating to oil and gas exploration and production; however, this paragraph does not prevent the owner or operator from conducting activities that may be required by the Alaska Oil and Gas Conservation Commission to plug, plug-back, or abandon a well.

(k) The commissioner of natural resources may adopt only the regulations that are reasonable and that are necessary to implement, interpret, or make specific the provisions of this section or to establish procedures to govern application of the provisions of this section.

(l) A lessee obtaining a lease under this section may exercise the rights authorized by this section and the lease. The rights granted by the lease must be exercised in a manner that does not unreasonably interfere with eventual development of other mineral deposits on the land leased. However, in a lease entered into under AS 38.05.150 for land that is already leased under this section, coal may not be mined or extracted by the coal lessee from the coal lease without prior agreement with the lessee holding the lease issued under this section.

(m) Except as otherwise specifically provided in this section, the provisions of AS 38.05.135 - 38.05.184 apply to leases entered into under this section.

(n) In this section, "lease" means a shallow gas lease authorized by this section.

Maintained By: Judy Stanek CLOSE *Last Revised April 15, 1999*

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES

Noncompetitive Shallow Natural Gas Lease ADL No.

THIS NONCOMPETITIVE SHALLOW NATURAL GAS LEASE (“this lease") is entered into , between the State of Alaska acting through the Department of Natural Resources ("the state"), and

("the lessee") whether one or more, whose sole address for purposes of notification is as shown in Paragraph 30.

In consideration of the cash payment made by the lessee to the state, which payment includes the first year's rental, and subject to the provisions of this lease, including applicable stipulation(s) and mitigation measure(s) attached to this lease and by this reference incorporated into this lease, the state and the lessee agree as follows:

1. GRANT. (a) Subject to the provisions in this lease, the state grants and leases to the lessee, without warranty, the exclusive right to explore for, develop, and produce natural gas from the surface to a true vertical depth of 3,000 feet below the surface and excluding all greater depths in or under the tract of land, described in subparagraph (b), below, containing approximately acres, more or less, and the non-exclusive right to install pipelines and build structures on the leased area to find, produce, save, store, treat, process, transport, take care of, and market all natural gas and to house and board employees in its operations on the leased area. The rights granted by this lease are to be exercised in a manner which will not unreasonably interfere with the rights of any permittee, lessee or grantee of the state consistent with the principle of reasonable concurrent uses as set out in Article VIII, Section 8 of the Alaska Constitution and must be exercised in a manner that does not unreasonably interfere with eventual development of other mineral deposits on the leased area.

(b) The tract of land subject to this lease (the “leased area”) is described as:

(c) For the purposes of this lease, the leased area contains the legal subdivisions as shown on the attached plat marked Exhibit A. If the leased area is described by protracted legal subdivisions and, after the effective date of this lease, the leased area is surveyed under the public land rectangular system, the boundaries of the leased area are those established by that survey, when approved, subject, however, to the provisions of applicable regulations relating to those surveys. If for any reason the leased area includes more acreage than the maximum permitted under applicable law (including the rule of approximation authorized in AS 38.05.145 and defined in AS 38.05.965(18)), this lease is not void and the acreage included in the leased area must be reduced to the permitted maximum. If the state determines that the leased area exceeds the permitted acreage and notifies the lessee in writing of the amount of acreage that must be eliminated, the lessee has 60 days after receipt of the such notice to file an instrument surrendering at least the amount of acreage that must be eliminated from the leased area, which must be one or more legal subdivisions or other shape approved by the state. Any subdivision surrendered must be located on the perimeter of the leased area as originally described. If an instrument surrendering the acreage is not filed within 60 days, the state may terminate this lease as to the acreage that must be eliminated by mailing notice of the termination to the lessee.

(d) If the state's ownership interest in the natural gas in the leased area is less than an entire and undivided interest, the grant under this lease is effective only as to the state's interest in that natural gas, and the royalties and rentals provided in this lease must be paid to the state in the proportion that the state's interest bears to the entire undivided fee.

(e) The state makes no representations or warranties, express or implied, as to title, or access to, or quiet enjoyment of, the leased area. The state is not liable to the lessee for any deficiency in title to the leased area, nor is the lessee or any successor in interest to the lessee entitled to any refund due to deficiency in title for any rentals**,** royalties or other fees paid under this lease.

2. RESERVED RIGHTS. (a) The state, for itself and others, reserves all rights not expressly granted to the lessee by this lease. These reserved rights include, but are not limited to:

(1) the rights to explore for, develop, and produce natural resources other than natural gas on or from the leased area;

(2) the rights to establish or grant easements, leases, permits, and rights-of-way for any lawful purpose, including without limitation for facilities, well sites, well bores, shafts and tunnels necessary or appropriate for the working of the leased area for natural resources and minerals, other than natural gas, or other lands for natural resources and minerals including natural gas;

(3) the right to dispose of land within the leased area for facilities, well sites and well bores of wells drilled from or through the leased area to explore for or produce oil, natural gas, or other minerals and natural resources, in and from lands not within the leased area; and

(4) the rights otherwise to manage and dispose of the surface of the leased area or interests in that land by grant, lease, permit, or otherwise to third parties.

(b) The rights reserved may be exercised by the state, or by any other person or entity acting under authority of the state, in any manner that does not unreasonably interfere with or endanger the lessee's operations under this lease.

3. TERM. This lease is issued for an initial primary term of three years from the effective date of this lease. The term may be extended as provided in Paragraph 4 below and additionally, upon application by the lessee, the state may extend the primary term once for a period of not more than three years.

4. EXTENSION. (a) This lease will be extended automatically beyond the primary term if and for so long as natural gas is produced in paying quantities from the leased area and the lessee continues to meet all requirements of this lease.

(b) This lease will be extended automatically beyond the primary term if it is committed to a unit agreement approved or prescribed by the state. It will remain in effect for so long as it remains committed to a valid unit agreement.

(c) If the lessee has started to drill a well whose bottom hole is in the leased area before the expiration date of the primary term and continues to drill with reasonable diligence, this lease will continue in effect for 90 days after expiration of the primary term or for so long thereafter as natural gas is produced in paying quantities from the leased area. For purposes of this paragraph, “drilling” includes testing, redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location.

(d) If the lessee stops producing natural gas in paying quantities after the expiration of the primary term, this lease will not terminate if the lessee starts drilling within 90 days or a longer period determined at the discretion of the state. This lease will remain in effect for so long as the lessee continues drilling and operations with reasonable diligence. If the drilling results in the production of natural gas, this lease will remain in effect for so long as natural gas is produced in paying quantities from the leased area. For purposes of this paragraph, “drilling” includes testing, redrilling, sidetracking, or other means necessary to reach the originally proposed bottom hole location.

(e) If there is a well certified by the commissioner as capable of producing natural gas in paying quantities on the leased area, this lease will not expire because the lessee fails to produce the natural gas. If, however, the state gives written notice to the lessee, allowing a reasonable time, which will not be less than six months after notice, to place the well into production, and the lessee fails to do so, this lease terminates automatically at the end of the last day of the time specified by the state. If production is established within the time allowed, this lease is extended only for so long as natural gas is produced in paying quantities from the leased area.

(f) If the state directs or approves in writing a suspension of all operations on or production from the leased area (except for a suspension necessitated by the lessee's negligence), or if a suspension of all operations on or production from the leased area has been ordered under federal, state, or local law, the lessee's obligation to comply with any express or implied provision of this lease requiring operations or production will be suspended, but not voided, and the lessee shall not be liable for damages for failure to comply with that provision. If the suspension occurs before the expiration of the primary term, the primary term will be extended at the end of the period of the suspension by adding the period of time lost under the primary term because of the suspension. If the suspension occurs during an extension of the primary term under this paragraph, upon removal of that suspension, the lessee will have a reasonable time, which will not be less than six months after notice that the suspension has been removed, to resume operations or production. For the purposes of this subparagraph, any suspension of operations or production specifically required or imposed as a term of sale or by any stipulation(s) or mitigation measure(s) made a part of this lease will not be considered a suspension ordered by law.

(g) If the state determines that, after efforts made in good faith, the lessee has been prevented by force majeure from performing any act that would extend this lease beyond the primary term, this lease will not expire during the period of force majeure. If the force majeure occurs before the expiration of the primary term, the primary term will be extended at the end of the period of force majeure by adding the period of time lost under the primary term because of the force majeure. If the force majeure occurs during an extension of the primary term under this paragraph, this lease will not expire during the period of force majeure plus a reasonable time after that period, which will not be less than 60 days, for the lessee to resume operations or production.

(h) Nothing in subparagraphs (f) or (g), above, suspends the obligation to pay royalties to the state from operations on the leased area that are not affected by any suspension or force majeure, or suspends the obligation to pay rentals.

5. RENTALS. (a) The lessee shall pay annual rental to the state of $0.50 per acre or fraction of an acre.

(b) The lessee shall pay the annual rental to the state (or any depository designated by the state in writing with at least 60 days notice to the lessee), on or before the annual anniversary of the effective date this lease ("anniversary date"). The state shall mail to the lessee one written notice that rentals are due, by certified mail with return receipt requested, three weeks before the anniversary date. If the state's (or depository's) office is not open for business on the anniversary date, the time for payment is extended to include the next day on which that office is open for business. If the annual rental is not paid timely when due, this lease automatically terminates as to both parties at 11:59 p.m., Alaska Standard Time, on the date on which the rental payment was due.

6. ROYALTY ON PRODUCTION. Except for natural gas used on the leased area by the lessee for development and production of natural gas or unavoidably lost, the lessee shall pay to the state as a royalty:

(a) 12.5 percent in amount or value of the natural gas removed or sold from the leased area where the natural gas is exported from Alaska or that is produced and marketed in direct competition with gas on which a royalty at a rate of at least 12.5 percent is payable; or

(b) except as provided in (a) of this paragraph, 6.25 percent of the amount or value of the natural gas removed or sold from the leased area.

7. VALUE. (a) To compute royalties due under this lease, the value per Mcf of royalty natural gas shall be determined each month at the lease or unit boundary. Royalty $\text{Value}_{\text{gas}}$ (RVG) is determined monthly for each lease. To calculate RVG, the lessee first determines whether the Minimum Value of Gas (MVG) or the Transaction Value of Gas (TVG) is higher for each separate transaction. The higher of MVG or TVG is then multiplied by the volume of gas disposed of in that transaction during that month. The total of all of the products of the MVG or TVG times the volume for each transaction that month is then divided by the total volume of gas produced by the lessee and disposed of that month to determine the RVG for that month.

(1) MVG is determined for each lease according the following formula:

$\text{MVG} = \$1.40/\text{mcf X (WC Gasoil}_{\text{Current Month}} \div \$22.50)$

where WC $\text{Gasoil}_{\text{Current Month}}$ is the average of West Coast Waterborne Gasoil prices ($/bbl) as reported in Platt's Oilgram Price Report for the production month.

(2) TVG is determined for each disposition of gas. TVG is equal to the cash value of all consideration received during the production month for the sale or exchange of the gas.

(b) The state may change the methodology for calculating the components of the royalty value formula in (a) above by regulation.

(c) RVG may never be less than zero.

(d) Exhibit B to this lease demonstrates how this paragraph shall be applied to calculate RVG.

8. ROYALTY IN VALUE. (a) Except to the extent that the state elects to receive all or a portion of its royalty in kind as provided in Paragraph 9, below, the lessee shall pay to the state the value of all royalty natural gas as determined under Paragraph 7, above. The amount of Royalty to be paid in value shall be based upon the volume of production delivered in pipeline quality at the point of delivery. Royalty in value shall be free and clear of all lease expenses (and any portion of those expenses that is incurred away from the leased area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, compression, processing and preparing the natural gas for transportation off the leased area.

(b) All royalty payable in money to the state must be paid on or before the last federal banking day of the calendar month following the month in which the natural gas is produced. Royalty in value payments which are not paid when due under this lease or the amount which is subsequently determined to be due to the state or the lessee as the result of a redetermination will bear interest from the last federal banking day of the calendar month following the month in which the natural gas was produced, until the obligation is paid in full. The amount of all royalty in value payments that are not paid when due under this lease or that are subsequently determined to be due as the result of a redetermination shall bear interest from the date the obligation accrued, until paid in full, at the rate provided in AS 38.05.135(d) or AS 38.05.135(d) as later amended.

(c) Royalty payments must be accompanied by such information relating to valuation of royalty as the state may require including, but not limited to, sales contracts, metering data, evidence of sales, shipments, and amounts of gross natural gas produced.

9. ROYALTY IN KIND. (a) At the state's option, which may be exercised from time to time upon not less than 90 days notice to the lessee, the lessee shall deliver all or a portion of the state's royalty natural gas produced from the leased area in kind. The state's royalty natural gas delivered in kind shall be delivered to the state at the lease or unit area, or other place mutually agreed to by the state and the lessee, and must be delivered to the state or other entity designated by the state.

(b) Royalty natural gas delivered in kind must be delivered in good and merchantable condition, of pipeline quality, and free and clear of all lease expenses (and any portion of those expenses incurred away from the leased area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, compression, processing and preparing the natural gas for transportation off the leased area.

(c) After having given notice of its intention to take, or after having taken its royalty natural gas in kind, the state, at its option and upon 90 days notice to the lessee, may elect to receive a different portion or none of its royalty in kind. If, under federal regulations, the taking of royalty natural gas in value by the state creates a supplier-purchaser relationship, the lessee hereby waives its right to continue to receive royalty natural gas under that relationship, and further agrees that it will require any purchasers of the royalty natural gas likewise to waive any supplier-purchaser rights.

(d) The lessee shall furnish storage for royalty natural gas produced from the lease or unit area to the same extent that the lessee provides storage for the lessee's share of natural gas. The lessee shall not be liable for the loss or destruction of stored natural gas from causes beyond the lessee's reasonable control.

(e) If a state royalty purchaser refuses or for any reason fails to take delivery of natural gas, or in an emergency, and with as much notice to the lessee as is practical or reasonable under the circumstances, the state may elect without penalty to underlift for up to six months all or a portion of the state's royalty natural gas which otherwise would be produced from the lease or unit area and taken in kind. The state's right to underlift is limited to the portion of royalty natural gas that the royalty purchaser refused or failed to take delivery of, or the portion necessary to meet the emergency condition. Underlifted natural gas may be recovered by the state at a daily rate not to exceed 10 percent of its royalty interest share of daily production at the time of the underlift recovery.

10. REDUCTION OF ROYALTY. Lessee may request a reduction of royalty in accordance with the applicable statutes and regulations in effect on the date of application for the reduction.

11. RECORDS. The lessee shall keep and have in its possession books and records showing the development and production (including records of development and production expenses) and disposition (including records of sale prices, volumes, and purchasers) of all natural gas produced from the leased area. The lessee shall permit the state or its agents to examine these books and records at all reasonable times. Upon request by the state, the lessee's books and records shall be made available to the state at the state office designated by the state. These books and records of development, production, and disposition must employ methods and techniques that will ensure the most accurate figures reasonably available without requiring the lessee to provide separate meters for each well. The lessee shall use generally accepted accounting procedures consistently applied.

12. PAYMENTS. Payments to the state under this lease must be made payable to the state in the manner directed by the state, and unless otherwise specified, must be tendered to the state at:

DEPARTMENT OF NATURAL RESOURCES
550 WEST 7TH STREET, SUITE 1410
ANCHORAGE, ALASKA 99501-3561
ATTENTION: FINANICAL SERVICES SECTION

or to depository designated by the state with at least 60 days written notice to the lessee.

13. PLAN OF OPERATIONS. (a) This lease is subject to the provisions of 11 AAC 83.158 or 11 AAC 83.346.

(b) No lease operations may be undertaken on the leased area until a plan of operations has been approved by the state. All of the lessee’s operations on or in the leased area must be in conformance with the approved plan of operations. Approval by the state of a plan of operations or any modifications to a plan of operations signifies only that the state has no objection to the operations outlined in the plan. The state’s approval does not relieve the lessee of its obligation to obtain approvals and permits required by other governmental agencies having regulatory authority over those operations.

(c) Before undertaking operations on privately owned land in the leased area, the lessee shall provide for full payment of all damages sustained by the owner of the surface estate by reason of entering on the land. The lessee may satisfy this requirement by either obtaining written consent of the surface owner, or posting a surety bond determined by the director to be sufficient to secure the owner for damages. This requirement applies to all privately owned surface areas regardless of whether the rights in the surface estate devolve from a state or federal conveyance.

(d) If the lessee undertakes any operations on the leased area without having first complied with subparagraph (c) of this section, the director may issue a verbal or written Notice of Cessation notifying the lessee to cease all operations within 24 hours. Upon issuing a Notice of Cessation, the director shall schedule a hearing to determine the amount of surety bond the lessee will be required to post before recommencing operations on the leased area. If the lessee fails to cease all operations as directed, the state may immediately and without further notice revoke the operating permit pending a hearing and a bond determination.

14. PLAN OF DEVELOPMENT. (a) Except as provided in subparagraph (d), below, within 12 months after certification of a well capable of producing natural gas in paying quantities, the lessee shall file two copies of an application for approval by the state of an initial plan of development that must describe the lessee's plans for developing the leased area. No development of the leased area may occur until a plan of development has been approved by the state.

(b) The plan of development must be revised, updated, and submitted to the state for approval annually before or on the anniversary date to the previously approved plan. If no changes from an approved plan are contemplated for the following year, a statement to that effect must be filed for approval in lieu of the required revision and update.

(c) The lessee may, with the approval of the state, subsequently modify an approved plan of development.

(d) If the leased area is committed to a unit agreement**,** the lessee will not be required to submit a separate lease plan of development for unit activities.

15. INFORMATION ACQUIRED FROM OPERATIONS. (a) Within 30 days following the completion, suspension, operational shut-down or abandonment of each well, the lessee shall file with the state all logs, geological, geophysical, engineering and other technical data, a description of all tests run for each well drilled on the leased area, and a plat showing the exact location of each well. The state may, in its discretion, require the lessee to submit additional data the state determines necessary or waive the requirement to submit data from specified development, service or injection wells.

(b) Any information the lessee files with the state in connection with this lease will be available at all times for use by the state and its agents. The state will keep information confidential as provided in AS 38.05.035(a)(9) and applicable regulations. In order for geological, geophysical, engineering, well and bore hole data, and interpretations of those data filed in compliance with subparagraph (a) of this section**,** to be held confidential, the lessee must submit the information in compliance with 11 AAC 82.810.

16. DIRECTIONAL DRILLING. This lease may be maintained in effect by directional wells whose bottom hole locations are on or in the leased area but that are drilled from locations on other lands not covered by this lease. In those circumstances, drilling will be considered to have commenced on the leased area when actual drilling is commenced on those other lands for the purpose of directionally drilling into the leased area. Production of natural gas from the leased area through a directional well located on the those other lands, or drilling or reworking of that directional well, will be considered production or drilling or reworking operations on the leased area for all purposes of this lease. Nothing contained in this paragraph is intended or will be construed as a grant to the lessee of any interest, license, easement, or other right in or with respect to the other lands not within the leased area as it is described in Paragraph 1 of this lease.

17. DILIGENCE AND PREVENTION OF WASTE. (a) The lessee shall exercise reasonable diligence in drilling, producing, and operating wells on the leased area unless consent to suspend operations temporarily is granted by the state.

(b) Upon discovery of natural gas on the leased area in quantities that would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing, and producing an additional well in the same geologic structure at another location on the leased area or an adjacent state shallow natural gas lease held by the lessee with a reasonable profit to the operator, the lessee must drill such well or wells as a reasonable and prudent operator would drill, having due regard for the interest of the state as well as the interest of the lessee.

(c) The lessee shall perform all operations under this lease in a good and workmanlike manner in accordance with the methods and practices set out in the approved plan of operations, with due regard for the prevention of waste of oil, natural gas and the entrance of water to oil and gas-bearing sands or strata to the destruction or injury of those sands or strata, and to the preservation and conservation of the property for future productive operations. The lessee shall carry out at the lessee's expense all orders and requirements of the state relative to the prevention of waste and to the preservation of the leased area. If the lessee fails to carry out these orders, the state will have the right, together with any other available legal recourse, to enter the leased area to repair damage or prevent waste at the lessee's expense.

(d) Before abandoning any well, the lessee shall securely plug or otherwise close the well in a manner satisfactory to the state.

18. OFFSET WELLS. The lessee shall drill such wells as a reasonable and prudent operator would drill to protect the state from loss by reason of drainage resulting from production on other land. Without limiting foregoing sentence, if natural gas is produced from a well on land not owned by the state or on which the state receives a lower rate of royalty than the rate under this lease, and that well is within 1,500 feet of lands then subject to this lease, and that well produces natural gas for a period of 30 consecutive days in quantities that would appear to a reasonable and prudent operator to be sufficient to recover ordinary costs of drilling, completing, and producing an additional well in the same geological structure at an offset location with a reasonable profit to the operator; and if, after notice to the lessee and an opportunity to be heard, the state finds that production from that well is draining lands then subject to this lease, the lessee shall within 30 days after written demand by the state begin in good faith to diligently prosecute drilling operations for an offset well on the leased area. In lieu of drilling any well required by this paragraph, the lessee may, with the state's consent, compensate the state in full each month for the estimated loss of royalty through drainage in the amount determined by the state.

19. UNITIZATION. (a) The lessee may unite with others, jointly or separately, in collectively adopting and operating under a cooperative or unit agreement for the exploration, development, or operation of the field, or like area or part of the field, or like area that includes or underlies the leased area or any part of the leased area when the state has determined and certified that the cooperative or unit agreement is in the public interest.

(b) Within six months after demand by the state, the lessee agrees to subscribe to a reasonable cooperative or unit agreement that will adequately protect all parties in interest, including the state. The state reserves the right to prescribe such an agreement.

(c) With the consent of the lessee, and if the leased area is committed to a unit agreement approved by the state, the state may establish, alter, change, or revoke drilling, producing, and royalty requirements of this lease as the state determines necessary or proper to secure the proper protection of the public interest.

(d) Except as otherwise provided in this subparagraph, where only a portion of the leased area is committed to a unit agreement approved or prescribed by the state, that commitment constitutes a severance of this lease as to the unitized and nonunitized portions of the leased area. The portion of the leased area not committed to the unit will be treated as a separate and distinct lease having the same effective date and term as this lease and may be maintained only in accordance with the terms and conditions of this lease, statutes, and regulations. Any portion of the leased area not committed to the unit agreement will not be affected by the unitization or pooling of any other portion of the leased area, by operations in the unit, or by suspension approved or ordered for the unit. If the leased area has a well certified as capable of production in paying quantities on it before commitment to a unit agreement, this lease will not be severed. If any portion of this lease is included in a participating area formed under a unit agreement, the entire leased area as it exists at that time will remain committed to the unit and this lease will not be severed.

20. APPORTIONMENT OF ROYALTY FROM APPROVED UNIT. The state’s royalty share of the unit production allocated to each separately owned tract shall be regarded as royalty to be distributed to and among, or the proceeds of or paid to, the state, free and clear of all unit expense and free of any lien for it. Under this provision, the state's royalty share of any unit production allocated to the leased area will be regarded as royalty to be distributed to, or the proceeds of it paid to, the state, free and clear of all unit expenses (and any portion of those expenses incurred away from the unit area), including, but not limited to, expenses for separating, cleaning, dehydration, gathering, saltwater disposal, compression, processing and preparing natural gas for transportation off the unit area, and free of any lien for them.

21. INSPECTION. The lessee shall keep open at all reasonable times, for inspection by any duly authorized representative of the state, the leased area, all wells, improvements, machinery, and fixtures on the leased area, and all reports and records relative to operations and surveys or investigations on or with regard to the leased area or under this lease. Upon request, the lessee shall furnish the state with copies of and extracts from any such reports and records.

22. SUSPENSION. The state may from time to time direct or approve in writing suspension of production or other operations under this lease.

23. ASSIGNMENT, PARTITION, AND CONVERSION. (a) This lease, or an interest in this lease, may not be transferred or assigned until a well capable of production of natural gas in paying quantities has been drilled on this lease. Notwithstanding the foregoing restriction, the lessee is not prohibited from entering into a farmout agreement or similar arrangement with a third party under which the third party assists in exploration and development of production from this lease if the agreement or arrangement does not require a payment of consideration by the third party to the lessee, except that the lessee may retain an overriding royalty interest in this lease or may retain a net profit or other production payment.

(b) Subject to the provisions of subparagraph (a), above, with the approval of the state, this lease, or an interest in this lease may be assigned, subleased, or otherwise transferred to any person or persons qualified to hold a state natural gas lease. No assignment, sublease, or other transfer of an interest in this lease, including assignments of working or royalty interests and operating agreements and subleases, will be binding upon the state unless approved by the state. The lessee shall remain liable for all obligations under this lease accruing prior to the approval by the state of any assignment, sublease, or other transfer of an interest in this lease. All provisions of this lease will extend to and be binding upon the heirs, administrators, successors, and assigns of the state and the lessee. Applications for approval of an assignment, sublease, or other transfer must comply with all applicable regulations and must be filed within 90 days after the date of final execution of the instrument of transfer. The state will approve a transfer of an undivided interest in this lease unless the transfer would adversely affect the interests of the state or the application does not comply with applicable regulations. The state will disapprove a transfer of a divided interest in this lease if the transfer covers only a portion of this lease or a separate and distinct zone or geological horizon unless the lessee demonstrates that the proposed transfer of a divided interest is reasonably necessary to accomplish exploration or development of this lease, this lease is committed to an approved unit agreement, this lease is allocated production within an approved participating area, or this lease has a well certified as capable of production in paying quantities. The state will make a written finding stating the reasons for disapproval of a transfer of a divided interest. Where an assignment, sublease, or other transfer is made of all or a part of the lessee's interest in a portion of the leased area, this lease may, at the option of the state or upon request of the transferee and with the approval of the state, be severed, and a separate and distinct lease having the same effective date and terms as this lease will be issued to the transferee.

24. SURRENDER. The lessee at any time may file with the state a written surrender of all rights under this lease or any portion of the leased area comprising one or more legal subdivisions or, with the consent of the state, any separate and distinct zone or geological horizon underlying the leased area or one or more legal subdivisions of the leased area. That surrender will be effective as of the date of filing, subject to the continued obligations of the lessee and its surety to make payment of all accrued royalties and to place all wells and surface facilities on the surrendered land or in the surrendered zones or horizons in a condition satisfactory to the state for suspension or abandonment.

25. DEFAULT AND TERMINATION; CANCELLATION. (a) The lessee's failure to timely perform any obligation under this lease or to otherwise comply with any express or implied provision of this lease is a default of the lessee's obligations under this lease. If the director determines the lessee has defaulted on any obligation under this lease, and the default continues for 60 days after the lessee receives written notice from the state (except for a provision that, by its terms, provides for automatic termination), the director may terminate the lease by either:

(1) mailing written notice of termination to the lessee if there is no well on the leased area that has been determined under 11 AAC 83.361 to be capable of producing natural gas in paying quantities; or

(2) instituting a judicial proceeding to terminate the lease if there is a well on the leased area that has been determined under 11 AAC 83.361 to be capable of producing natural gas in paying quantities.

(b) The state may cancel this lease at any time after the state has suspended or prohibited operations under this lease continuously for a period of five years (or a lesser period upon request of the lessee) and state determines, after notice and a reasonable opportunity to be heard, that:

(1) continued operations under this lease threaten to cause serious harm or damage to biological resources, mineral resources, property or the environment (including the human environment);

(2) the threat of harm or damage will likely not cease or decrease to an acceptable extent within a reasonable period of time; and

(3) the advantages of cancellation outweigh the advantages of continuing this lease in effect.

(c) Termination or cancellation of the lease under this section does not release the lessee from any liability for abandonment or clean-up costs or damages incurred by the lessee to restore the leased area or to plug and abandon any well or wells and remove personal property from the lease within a reasonable time.

26. RIGHTS UPON TERMINATION. Upon the expiration, termination or cancellation of this lease as to all or any portion of the leased area, the lessee will have the right to remove from the leased area or portion of the leased area all machinery, equipment, tools, and materials. This right does not include removal of property or improvements needed for producing natural gas wells from well bores capable of producing natural gas in paying quantities at the time of expiration, termination or cancellation of this lease. This right will last for one year from the date of expiration, termination or cancellation. Upon the expiration of that period or extension of that period, any machinery, equipment, tools, and materials that the lessee has not removed from the leased area or portion of the leased area become the state's property. The lessee shall, however, remove any and all such property or improvements when directed by the state. If the lessee does not remove the property or improvements when directed, the state may remove them at the lessee's expense. Subject to the above conditions, the lessee shall return the leased area or those portions of the leased area in a condition satisfactory to the state.

27. DAMAGES AND INDEMNIFICATION. (a) The lessee shall indemnify the state for, and hold it harmless from, any claims, demands, liabilities, and expenses, including claims for loss or damage to property or injury to any person caused by or resulting from any act or omission committed under this lease by or on behalf of the lessee arising from or in connection with such damages. The lessee is not responsible to the state under this subparagraph for any loss, damage, or injury caused by or resulting from the sole negligence of the state.

(b) The lessee expressly waives any defense to an action for breach of a provision of this lease or for damages resulting from an oil spill, a well blow out, or other harm to the environment that is based on an act or omission committed by an independent contractor in the lessee's employ. The lessee expressly agrees to assume responsibility for all actions of its independent contractors.

28. BONDS. (a) If required by the state, the lessee shall furnish a bond prior to the issuance of this lease in an amount equal to at least $5 per acre or fraction of an acre contained in the leased area, but no less than $10,000, and must maintain that bond as long as required by the state.

(b) The lessee may, in lieu of the bond required under subparagraph (a), above, furnish and maintain a statewide bond in accordance with applicable regulations.

(c) The state may, after notice to the lessee and a reasonable opportunity to be heard, require a bond in a reasonable amount greater than the amount specified in subparagraph (a), above, where a greater amount is justified by the nature of the surface and its uses and the degree of risk involved in the types of operations being or to be carried out under this lease. A statewide bond will not satisfy any requirement of a bond imposed under this subparagraph, but will be considered by the state in determining the need for and the amount of any additional bond under this subparagraph.

(d) If the leased area is committed in whole or in part to a cooperative or unit agreement approved or prescribed by the state, and the unit operator furnishes a statewide bond, the lessee need not maintain any bond with respect to the portion of the leased area committed to the cooperative or unit agreement.

29. AUTHORIZED REPRESENTATIVES. The Director of the Division of Oil and Gas, Department of Natural Resources, and the person executing this lease on behalf of the lessee shall be the authorized representatives for their respective principals for the purposes of administering this lease. The state or the lessee may change the designation of its authorized representative or the address to which notices to that representative are to be sent by a notice given in accordance with Paragraph 30, below. Where activities under a plan of operations are underway, the lessee shall also designate, pursuant to a notice under Paragraph 30, below, by name, job title, and address, an agent who will be present in the state during all lease activities.

30. NOTICES; PROTEST. (a) Notices required or permitted under this lease must be by electronic media producing a permanent record or in writing and must be given personally or by registered or certified mail, return receipt requested, addressed as follows:

TO THE STATE: DIRECTOR, DIVISION OF OIL AND GAS
DEPARTMENT OF NATURAL RESOURCES
550 W. 7TH AVENUE, SUITE 800
ANCHORAGE, ALASKA 99501-3560

TO THE LESSEE:

(b) Any notice given under this paragraph will be effective when delivered to the above-authorized representative.

(c) A lessee who wishes to protest the amount of money due the state under this lease or any action of the state regarding a provision of this lease must file a written appeal with the Division of Oil and Gas under 11 AAC 02.010 - 11 AAC 02.080.

31. STATUTES AND REGULATIONS. This lease is subject to all applicable state and federal statutes, rules and regulations in effect on the effective date of this lease, and to all statutes and regulations placed in effect after the effective date of this lease. A reference to a statute or regulation in this lease includes any change in that statute or regulation whether by amendment, repeal and replacement, or other means. This lease does not limit the power of the state or the United States of America to enact and enforce legislation or to promulgate and enforce regulations affecting, directly or indirectly, the activities of the lessee or its agents in connection with this lease or the value of the interest held under this lease. In case of conflicting provisions, statutes and regulations take precedence over this lease.

32. APPEALS. The lessee shall appeal decisions of the commissioner related to this lease in accordance with 11 AAC 02.

33. INTERPRETATION. This lease is to be interpreted in accordance with the rules applicable to the interpretation of contracts made in the State of Alaska. The paragraph headings are not part of this lease and are inserted only for convenience. The state and the lessee expressly agree that the law of the State of Alaska will apply in any judicial proceeding affecting this lease.

34. INTEREST IN REAL PROPERTY. It is the intention of the parties that the rights granted to the lessee by this lease constitute an interest in real property in the leased area.

35. WAIVER OF CONDITIONS. The state reserves the right to waive any breach of a provision of this lease, but any such waiver extends only to the particular breach so waived and does not limit the rights of the state with respect to any future breach; nor will the waiver of a particular breach prevent cancellation of this lease for any other cause or for the same cause occurring at another time. Notwithstanding the foregoing, the state will not be deemed to have waived a provision of this lease unless it does so in writing.

36. SEVERABILITY. If it is finally determined in any judicial proceeding that any provision of this lease is invalid, the state and the lessee may jointly agree by a written amendment to this lease that, in consideration of the provisions in that written amendment, the invalid portion will be treated as severed from this lease and that the remainder of this lease, as amended, will remain in effect.

37. LOCAL HIRE. To the extent they are available and qualified, the lessee is encouraged to employ local and Alaska residents and contractors for work performed on the leased area.

38. CONDITIONAL LEASE. If all or a part of the leased area is land that has been selected by the state under laws of the United States granting lands to the state, but the land has not been patented to the state by the United States, then this lease is a conditional lease as provided by law until the patent becomes effective. If for any reason the selection is not finally approved, or the patent does not become effective, any rental, or royalty payments made to the state under this lease will not be refunded.

39. NONDISCRIMINATION. The lessee and its contractors and subcontractors may not discriminate against any employee or applicant because of race, religion, marital status, change in marital status, pregnancy, parenthood, physical handicap, color, sex, age, or national origin as set out in AS 18.80.220. The lessee and its contractors and subcontractors must, on beginning any operations under this lease, post in a conspicuous place notices setting out this nondiscrimination provision.

40. DEFINITIONS. All words and phrases used in this lease are to be interpreted where possible under AS 01.10.040. Notwithstanding the foregoing, the following words have the following meanings unless the context unavoidably requires otherwise:

(1) "drilling" means the act of boring a hole to reach a proposed bottom hole location through which natural gas may be produced if encountered in paying quantities, including redrilling, sidetracking, deepening or other means necessary to reach the proposed bottom hole location, and testing, logging, plugging, and other operations necessary and incidental to the actual boring of the hole;

(2) "force majeure" means war, riots, acts of God, unusually severe weather, or any other cause beyond the lessee's reasonable ability to foresee and control. It includes operational failure of existing transportation facilities and delays caused by judicial decisions or lack of them.

(3) "natural gas" means all hydrocarbons gaseous at standard temperature and pressure, including gas associated with coal deposits, and all other hydrocarbons produced incidental to production by ordinary methods that are not defined in this lease as oil;

(4) "oil" means crude petroleum oil and other hydrocarbons, regardless of gravity, that are produced in liquid form by ordinary production methods, including liquid hydrocarbons known as distillate or condensate recovered by separation from gas other than at a gas processing plant;

(5) "paying quantities" means quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking considered as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities; and

(6) "reworking operations" means all operations designed to secure, restore, or improve production through some use of a hole previously drilled, including, but not limited to, mechanical or chemical treatment of any horizon, and plugging back to test higher strata;

41. EFFECTIVE DATE. This lease takes effect on .

BY EXECUTING THIS LEASE, the state as lessor and the lessee agree to be bound by its provisions.

STATE OF ALASKA

By: ______________________________________
Kenneth A. Boyd
Director, Division of Oil and Gas

STATE OF ALASKA)
) ss.
Third Judicial District)

On , before me appeared Kenneth A. Boyd of the Division of Oil and Gas of the State of Alaska, Department of Natural Resources, and who executed this lease and acknowledged voluntarily signing it on behalf of the State of Alaska as lessor.

____
Notary public in and for the State of Alaska
My commission expires

LESSEE: ____

Signature: ____

Printed Name/Title: _________________________________

INSERT NOTARY ACKNOWLEDGMENT OF LESSEE'S SIGNATURE HERE.

LESSEE: ____

Signature: ____

Printed Name/Title: _________________________________

INSERT NOTARY ACKNOWLEDGMENT OF LESSEE'S SIGNATURE HERE.

LESSEE: ____

Signature: ____

Printed Name/Title: _________________________________

INSERT NOTARY ACKNOWLEDGMENT OF LESSEE'S SIGNATURE HERE.

Exhibit A

ADL_____________

(Lease Legal Description and Map)

Exhibit B
Illustrative Calculation of Value under Paragraph 7
(For Illustrative Purposes Only)

Royalty Value$_{gas}$

Assume for the purposes of calculating Royalty Value$_{gas}$ (RVG) that:

1) The lessee owns an 80 percent interest in seven shallow gas leases in the Broken Bone Unit near the community of Cecily, Alaska. The lessee developed the unit to supplement the energy requirements for nearby Stone Quarry, a small construction marble and specialty stone cutting operation owned by the lessee.

2) The production month is March 1999.

3) Platt's Oilgram Price Report provides a high and low product price assessment for every trading day for West Coast Waterborne Gasoil expressed in dollars per barrel. Table 1 illustrates the calculation of the average price assessment of West Coast Waterborne Gasoil for the production month of March 1999. The high and low product price assessments are averaged for each trading day and the sum of these averages are divided by the number of trading days in the calendar month to calculate the monthly average product price assessment. This value is rounded to the nearest cent. In Table 1 the average price assessment for West Coast Waterborne Gasoil for March 1999 is $19.46.

4) To calculate the Minimum Value of Gas (MVG) of the Transaction Value of Gas (TVG) per Mcf, the lessee has to evaluate each disposition its gas delivered during the production month. For the purposes of this illustration, assume that the lessee's March 1999 transactions occurred as follows:

Table 1: Lessee Oil Dispositions in March 1999

Transaction and Point of Sale		March Delivery Volume	Lessee's Contract Price Term
1.	Stone Quarry - Delivered	108,500 Mcf	Lessee's partners in the quarry have agreed to a transfer price of $1.00 per Mcf.
2.	The lessee sells gas to the Island School District – Delivered	110 Mcf	Gas supplied and metered at the Cecily Elementary School under a one-year contract for $3.50 per Mcf.
3.	The lessee sells gas to the Cecily Gas and Electric Company – Sold at the Unit.	6,250 Mcf	Lessee supplies gas to the Cecily Gas and Electric Company under a five-year contract for 100,000 Mcf supplied as needed. Price is based on $1.85 per Mcf adjusted by an oil price index with a premium required for volumes in excess of 500 Mcf per month.

Notes on Table 1:

Transaction 1 This is a non-arm's length transaction. The lessee and its partners in Stone Quarry have agreed to a price of $1.00 per Mcf for as long as Stone Quarry is in operation. There are separate supply agreements between Stone Quarry and the other owners in the Broken Bone Unit but they are not relevant to the calculation of the lessee's TVG for this transaction.

Transaction 2 The lessee sells gas to the Island School District to supply Cecily Elementary School. The school pays $3.50 per Mcf at the meter at the school. The lessee pays a $2.00 per Mcf Transportation charge to the Cecily Gas and Electric Company to transport the gas to the school. The lessee deducts this charge in its calculation of TVG.

Transaction 3 The lessee has a five-year contract with the Cecily Gas and Electric Company. Under the agreement the lessee will supply up to 100,000 Mcf to the utility for $1.85 per Mcf adjusted quarterly by an oil price index. If the utility uses more than 500 Mcf in any month, it must pay the lessee a 15 percent premium for the volume in excess of 500 Mcf. In March 1999, the utility paid $1.80 per Mcf on average for its volumes. This is the price reported by the lessee as its TVG.

MVG is calculated by applying the formula in Paragraph 7(A)(1) using the WC Gasoil$_{March}$ from Table 2.

MVG = \$1.40/Mcf X (WC Gasoil$_{March}$ ÷ \$22.50)

MVG = \$1.40/Mcf X (\$19.46 ÷ \$22.50)

= \$1.21084/Mcf = \$1.21/Mcf

Table 3 illustrates how the higher of TVG and MVG are calculated for each of the lessee's transactions. TVG from the information about the lessee's transactions in Table 1 is compared to MVG for each transaction. If TVG is not known at the time the royalty payment is due, the lessee must estimate his RVG on the basis of MVG and submit a revision later to account for TVG, if higher than MVG.

RVG is the volume-weighted average of the higher of MVG and TVG for each transaction, i.e., the higher of MVG and TVG for each transaction is multiplied by the volume delivered during the production month for each transaction. The products of the MVG or TVG times the volumes for each transaction are summed and divided by the lessee's total volume sold to determine RVG. RVG is multiplied by the royalty volume produced by the lessee. The royalty payment calculation appears at the bottom of Table 3.

Table 2: Calculation of the Monthly Average West Coast Waterborne Gasoil Price

March 1999			
Effective Date	ANS West Coast Low	ANS West Coast High	ANS WC Daily Average
03/01/99	$15.00	$15.50	$15.250
03/02/99	$15.75	$16.25	$16.000
03/03/99	$15.75	$16.25	$16.000
03/04/99	$16.50	$17.25	$16.875
03/05/99	$17.50	$18.25	$17.875
03/08/99	$19.00	$19.50	$19.250
03/09/99	$20.00	$21.00	$20.500
03/10/99	$19.50	$20.25	$19.875
03/11/99	$19.50	$20.25	$19.875
03/12/99	$19.00	$20.00	$19.500
03/15/99	$19.00	$20.00	$19.500
03/16/99	$18.75	$19.25	$19.000
03/17/99	$18.75	$19.25	$19.000
03/18/99	$19.50	$20.25	$19.875
03/19/99	$20.00	$20.75	$20.375
03/22/99	$20.00	$20.75	$20.375
03/23/99	$21.00	$22.00	$21.500
03/24/99	$20.50	$21.50	$21.000
03/25/99	$20.50	$21.50	$21.000
03/26/99	$21.00	$22.00	$21.500
03/29/99	$21.50	$22.50	$22.000
03/30/99	$21.50	$22.50	$22.000
03/31/99	$22.75	$24.00	$23.375
		Sum of daily averages =	$451.500
		Monthly Average = $451.500/23 =	$19.460
		WC Gasoil$_{March}$ =	$19.46 1/

1/ The value for WC Gasoil is rounded to the nearest cent before it is included in subsequent calculations.

Source: "Platt's Oilgram Price Report." Published by Standard and Poor's McGraw-Hill Companies.

Table 3: Calculation of Royalty Value of G as (RVG)
Based on the Higher-of the Minimum Value of Gas (MVG) and the Transaction Value of Gas (TVG)

Transaction	TVG (Contract, Exchange or Internal Transfer Price)	MVG Paragraph 7(A)(1)	Higher-of TVG or MVG	Volume (Mcf)	Volume times Higher-of TVG or MVG
1. Supply to Stone Quarry	$1.00	$1.21	$1.21	108,500	$131,285.00
2. Cecily School District Contract	$1.50 (=$3.50 - $2.(	$1.21	$1.50	110	$165.00
2. Cecily Village Gas and Electric	$1.80	$1.21	$1.80	2,250	$4,050.00
				110,860	$135,500.00
				$135,500/110,860 =	$1.22226
				RVG =	$1.22 1/

1/ The value for RVG is rounded to the nearest cent before it is included in subsequent calculations.

The Lessee's royalty payment is calculated as follows:

Product Description	(a) Gross Unit or Lease Production (mcf)	(b) Working Interest Ownership %	(c) (a) x (b) (mcf)	(d) Royalty Rate (%)	(e) Royalty (c) x (d) (mcf)	(h) RVG	(I) (g) x (j) Royalty in-Value Dollars
Shallow Gas	138,575.00	80.00000%	110,860	6.25000%	6,928.75	$1.22	$8,468.75

Department of Natural Resources

Division of Oil and Gas

550 West 7th Ave., Suite 800
Anchorage, AK 99501-3510
Phone: (907) 269-8800
Fax: (907) 269-8938

APPLICATION FOR SHALLOW NATURAL GAS LEASE

Under the provisions of AS 38.05.177 the undersigned applicant(s) apply for a Shallow Natural Gas Lease of the land described in Section 2 below. The undersigned applicant(s) certify that the information provided in this application is true, accurate and complete, and that the applicant(s) listed in Section 3 of this application are qualified to hold an interest in a lease under 11 AAC 82.200 and 11 AAC 82.205, or have included the required documents and information for qualification with this application, and have signed this application. The undersigned applicant(s) hereby authorize the person identified in Section 1 below to act as their designated agent for receipt of all notices and all communication with the Department of Natural Resources concerning this application.

SECTION 1: Applicant(s) Designated Agent

Name: ______________________________

Physical Address | Mailing Address

______________________ ______________________
______________________ ______________________
______________________ ______________________

Telephone: ____________________ Fax (optional): ____________________

nail (optional): ______________________________

The designated agent will be the only point of contact for official correspondence between the state and the applicants during the application process.

SECTION 2: Land Requested in the Application

SECTION	TOWNSHIP	RANGE	MERIDIAN

The area of land requested in the application may not exceed 5,760 acres (9 sections) and must be described by section, township, range and meridian. It must be compact in form, consisting of full sections which are contiguous (sections touching only at a point are not contiguous), and the overall length of the land requested must not exceed four times the width of the land. 11 AAC 82.510. If a lease is issued on the basis of this application, it will include only the land that is available for lease within the requested area.

This application must be typewritten or printed in ink and be accompanied by the $500.00 filing fee, payable to Alaska Department of Revenue.

SHALLOW NATURAL GAS LEASE APPLICATION FORM (continued)

SECTION 3: Applicant(s)

% of Lease Interest	Name of Applicant	Authorized Signature	Date

All persons (including corporations and associations) who will receive an interest, by virtue of any agreement or understanding, oral or written, in a Shallow Natural Gas Lease issued on the basis of this application, must be identified as an applicant in this section and provide an authorized signature. Each applicant must be qualified to hold an interest in a lease under 11 AAC 82.200 and 11 AAC 82.205, or have included the required documents and information for qualification with this application. The lease-interest percentages listed in this section must be represented by numbers with the fractional interest carried out to no more than five decimal places. The total of all lease-interests must equal 100.00000 percent.

Shaded Area is for Official Use Only

(1) Application received:

Date: ____________________

Time: ____________________

By: ____________________

Title: ____________________

(2) Receipt # for Filing Fee

____

ADL ____________________

(3) When application was determined complete, if not complete at time of filing:

Date: ____________________

Time: ____________________

By: ____________________

Title: ____________________

SECTION 4: Information Required for Processing Shallow Natural Gas Applications

1) List all communities consisting of 25 people or more that are located within 25 miles in any direction of the land described in the application.

2) List all ANCSA Village and Regional Corporations that own land within 25 miles in any direction of the land described in the application.

3) Describe how discovery of a source of natural gas on the land described in the application would benefit the residents of each area identified above?

(Continue on reverse)

4) Is any part of the land described in the application within a Coastal Resource District (AS 46.40)?

Yes ______ No ______

If yes, in what district or districts?

____

5) Is any part of the land described in the application within a specially designated area, such as a State Park, State Game Refuge, Critical Habitat Area, or other designated area?

Yes ______ No ______

If yes, identify each designated area in which any part of the land described in the application is located?

___________________________________ _______________________________________

6) Is any part of the land described in the application within a borough, municipality or city?

Yes ______ No ______

If yes, in which ones? __________________________ ___________________________

7) Does any part of the land described in the application contain University Lands?

Yes ______ No ______

If yes, identify the location of the University Lands by section, township and range.

____

8) Does any part of the land described in the application contain Mental Health Trust Lands?

Yes ______ No ______

If yes, identify the location of the Mental Health Trust Lands by section, township and range.

____

9) Attach a USGS 1:63,360 Topographic Map showing the land described in the application.

The Trans-Alaska Gas Pipeline:
Impact on Exploration in Alaska

Speakers

Jim Hansen
Jim Haynes
State of Alaska
Division of Oil & Gas

NOTES:

Attendance List

May 4, 2001

FirstName	LastName	Company	Email Address
Charles	Barker	USGS	barker@usgs.gov
Art	Barnet	Bureau of Land Managment	
Pirtle	Bates	DNR	pbj@dnr.state.ak.us
Greg	Beischer	Bristol Environmental & Engineering Serv. Corp.	gbeischer@beesc.com
Mike	Belowich	Horizon Natural Resources, Inc.	kim@hnrinc.com
John	Billings	Galena City School Dist.	jeno@galenanet.com
Jerry	Booth	GG Booth & Associates	jerry@ggbooth.com
Bill	Brophy	Usibelli Coal Mine, Inc.	bbrophy@usibelli.com
Jim McCaslin	Brown	Alaska Pacific University	jbrown@alaskapacific.edu
Jim	Clough	AK Div. Of Geological & Geophysical Surveys	jim@dnr.state.ak.us
Timothy	Collett	USGS	tcollett@usgs.gov
Robert (Bob)	Crandall	AK Oil & Gas Conservation Committee	bob_crandall@admin.state.ak.us
Marshall	Crouch	White Eagle Exploration, Inc.	crouchs@interserv.com
Jane	Crouch	White Eagle Exploration, Inc.	criuchs@interserv.com
Todd	Dallegge	University of Alaska, Fairbanks	bidahochi@yahoo.com
Stephen	Davies	AK, Oil & Gas Cons. Comm.	
Ed	DeWitt	Point Lodge	
Robert	Downey	Energy Ingenuity Co,	
Don	Duttlinger	PTTC National	
Arlen	Ehm	Geological Consultant	arlenhm@gcc.net
Randy	Elger	Native Village Of Fort Yukon	randallman93@hotmail.com
Nick	Enos	Calista Corp.	nenos@calistacorp.com
Dr. Iraj	Ershaghi	WC PTTC	ershaghi@usc.edu
Bob	Fisk	Bureau of Land Management	
Mike	Franger	AK Mental Health Trust Land	mikefr@dnr.state.ak.us
Paul S.	Glavinovich	NANA Development Corp.	glav@worldnet.att.net
James	Hansen	Alaska Division of Oil & Gas	jjh@dnr.state.ak.us
John	Harju	GTI E & P Services	john.harju@gastechnology.org
Jack	Hartz	AK, Oil & Gas Cons. Comm.	jack_hartz@admin.state.ak.us
Brian	Havelock	AK, Dept. of Natural Resource	brian_havelock@dnr.state.ak.us
Tony	Hillegeist	Phillips Alaska, Inc.	thilleg@ppco.com
Robert	Hunter	BP Exploration (Alaska) Inc.	HunterRB@BP.com
Teresa	Imm	Artic Slope Reg. Corp.	timm@arsc.com
Scott	Jepson		
James	Kendall	U.S. Dept. of Energy	james.kendall@eia.doe.gov
Michael	Langeler	Cross Timbers Oil Co.	mike_langeler@crosstimbers.com
Dave	Lappi	LAPP Resources	lapres@gci.net
Michael	Lilly	GW Scientific	mlilly@gwscientific.com

FirstName	LastName	Company	Email Address
Brit	Lively	Mapmakers Alaska	mapalaska@ak.net
Thomas	Lovas	Chugach Electric Association	shannon_napier@chugachelectric.com
Donald	Mahon	Alaska Gas and Telephone	
Marc	Massengale	URS	marc_massengale@urscorp.com
W. Dallam	Masterson	Phillips Alaska, Inc.	wmaster@ppco.com
Tom	Maunder	AK Oil & Gas Cons. Comm	Tom_Maunder@admin.state.ak.us
June	McAtee	Calista Corp.	jmcatee@calistacorp.com
David M.	McClement	NANA/Colt Engineering	david.mcclemont@nana.colt.com
Christy	McGraw	Backbone	backbone@alaska.net
Mike	Metz	Mike Metz & Associates	mcmetz@compuserve.com
Kristen	Nelson	Petroluem News Alaska	nelson@gci.net
Phil	Nicoll	Royale Energy, Inc.	phil@royl.com
David	Ogbe	University Of Alaska, Fairbanks	ffdoo@uaf.edu
Fred	O'Toole	Chevron	fsot@chevron.com
Gene	Pavia	Lynx Enterprises	gpavia@lynxalaska.com
Norm	Phillips Jr.	Doyon Limited	phillips@doyon.com
Raymond	Pilcher	Raven Ridge Resources	pilcher@ravenridge.com
Matt	Rader	AK Div of Oil & Gas	matt_rader@dnr.state.ak.us
Rocky	Reifenstuhl	AK Div. Of Geol. & Geophys.	rocky@dnr.state.ak.us
Michael	Rocereta	BP Expl. (Alaska) Inc.	roceremd@bp.com
Rob	Retherford	Alaska Earth Science	
Paul C.	Roehl	Bristol Bay Native Corp.	roehlp@bbnc.net
Robert	Scheidemann	Shell	scheid@ev1.net
John	Schwager	Belden & Blake Corp.	jschwager@beldenblake.com
Andrew	Scott	Altuda Geological Consulting	andrew@altuda.com
Daniel T.	Seamount	AK, Oil & Gas Cons. Comm.	daniel_seamount@admin.state.ak.us
David	Seitz	Phillips Alaska	bseitz@ppco.com
Kirk	Sherwood	Minerals Management Service	kirk.sherwood@mms.gov
Ernie	Siemoneit	Usibelli Coal Mine, Inc.	ernie@usibelli.com
Sharmon	Stambaugh	AK, Dept. of Env. Conservation	sharmon_stambaugh@envirocon.state.ak.us
Richard	Stanley	U.S. Geological Survey	rstanley@usgs.gov
Robert	Swenson	Phillips Alaska	rswenson@ppco.com
John	Tanigawa	Evergreen Resources	johnt@evergreen-res.com
Bonnie K.	Thomas	Native Village Of Fort Yukon	bkthomas332@hotmail.com
D.R.	Thompson	Consultant	pach@alaska.net
Leslie	Torrence	Bureau Land Management	ltorrence@ak.blm.gov
Maria	Valenzuela	WC PTTC	
Frank	Valenz	WC PTTC	
Nick	Van Wyck	Serf Geosciences	nvw@gci.net
Satya N.	Varadhi	Gas Technology Institute	satya.varadhi@gastechnology.org
Arthur	Watts	PRA	
Tao	Zhu	University of AK, Fairbanks	fftz@uaf.edu

Petroleum Technology Transfer Council
West Coast Resource Center

Producer Advisory Group
(PAG)

James C. Hall - Chairman
Drilling & Production Co.
Phone: (310) 328-2405
chrishall@prodigy.net

Barry McMahan
Seneca Resources Corporation
Phone: (661) 399-4270
pbrewer@ca.senecaresources.com

Glenn Swanson
Duke Engineering & Services
Phone: (310) 979-4777
gswanson@dukeengineering.com

Tom Counihan
Texaco, Inc.
Phone: (661) 864-3226
counitm@texaco.com

Marina Voskanian
CA State Lands Commission
Phone: (562) 590-5291
voskanm@slc.ca.gov

Kent McBride
CCCOGP
Phone: (661) 635-0556
concom@lightspeed.net

Robert E. Long
Pan Western Petroleum
Phone: (562) 595-6696
oilman@geologist.com

Bryan F. Saunders
Ocean Energy
Phone: (713) 265-6787
bryan.saunders@oceanenergy.com

David Brimberry
Marathon Oil Company
Phone: (907) 564-6402
dlbrimberry@marathonoil.com

Mark S. Kapelke - Vice Chairman
Tidelands Oil Production Co.
Phone: (562) 436-9918
kapelke@altavista.net

Donald Macpherson, Jr.
Macpherson Oil Co.
Phone: (310) 452-3880
drmacpherson@earthlink.net

Mary Jane Wilson
WZI, Inc.
Phone: (661) 326-1112
mjwilson@lightspeed.net

Steve Coombs
Pacific Operators Offshore
Phone: (805) 899-3144
coombs@pacops.com

Dan Kramer
CIPA
Phone: (916) 447-1185
dpk@cipa.org

David Kilpatrick
Consultant
Phone: (661) 665-1698
dkilpatrick@lightspeed.net

Behrooz Fattahi
Aera Energy LLC
Phone: (661) 665-5686
bfattahi@aeraenergy.com

Jim Clough
Alaska Division of Geological
and Geophysical Surveys
Phone: (907) 451-5030
jim@dnr.state.ak.us

PTTC West Coast Resource Center
Petroleum Engineering Program
925 Bloom Walk - HED305
University of Southern California
Los Angeles, CA 90089-1211
Phone: (213) 740-8076   Fax: (213) 740-7982

www.westcoastpttc.org

Prof. Iraj Ershaghi, Regional Director
Phone: (213) 740-0321
Fax: (213) 740-0324
e-mail: ershaghi@usc.edu

Ms. Maria Valenzuela, Accounting
Phone: (213) 740-0322
Fax: (213) 740-0324
e-mail: peteng@archie.usc.edu

Mr. Frank Valenz, Consultant
Phone: (213) 740-8076
Fax: (213) 740-7982
e-mail: wcpttc@archie.usc.edu

Ms. Idania Takimoto, Secretary
Phone: (213) 740-8076
Fax: (213) 740-7982
e-mail: pttc@archie.usc.edu

Mr. Hamid Cheheltani, Webmaster
Phone: (213) 740-8076
Fax: (213) 740-7982
e-mail:hamidc@home.com

WEST COAST PTTC CALENDAR OF ACTIVITIES
Year 2000 – 2001

Activity	*Topic*	*Location*	*Date*
Focused Tech Workshop	FRACTURE STIMULATION OF CALIFORNIA DIATOMITES	Bakersfield	Thursday, January 25, 2001
Field Visits	TROUBLESHOOTERS VISITS	Bakersfield & Long Beach	Monday, February 12, 2001 to Friday, February 16, 2001
Co-op Workshop	MIDWAY – SUNSET DEMONSTRATION PROJECT	Bakersfield	Tuesday, February 20, 2001
Focused Tech Workshop	COST EFFECTIVE TECHNOLOGIES TO COMBAT CORROSION IN OIL FIELDS	Bakersfield Long Beach	Thursday, February 22, 2001 Friday, February 23, 2001
Workshop	ENERGY CRISIS AND SOLUTIONS FOR CALIFORNIA OILFIELD PRODUCERS	Stevenson Ranch, Santa Clarita	Thursday, March 15, 2001
Co-op Workshop	OFFSHORE CALIFORNIA REVISITED	Ventura	Wednesday, April 25, 2001
Focused Tech Workshop	ALASKA COALBED AND SHALLOW GAS RESOURCES	Anchorage Alaska	Monday, April 30, 2001 to Friday, May 4, 2001
Workshop & Field Trip	MONTEREY RESERVOIRS -ONSHORE AND OFFSHORE- WORKSHOP AND FIELD TRIP	Santa Barbara	Wednesday, June 20, 2001 & Thursday, June 21, 2001
Outreach	COMET 2001	Los Angeles	Sunday, June 24, 2001 to Friday, June 29, 2001
Focused Tech Workshop	EPRI-PEAC ELECTRIC COST REDUCTION IN OIL FIELD OPERATIONS	Bakersfield Ventura Long Beach	Tuesday, July 17, 2001 Wednesday, July 18, 2001 Thursday, July 19, 2001
Forum	TROUBLESHOOTER'S FORUM	Bakersfield	Friday, September 21, 2001