Alaska North Slope
State of Play
April 2012

Agenda

As new technologies and operations enhance the economics E&P companies are increasingly looking to the Arctic region to search for new oil and gas reserves. This book reviews the state of play on the Alaska North Slope for new Entrants

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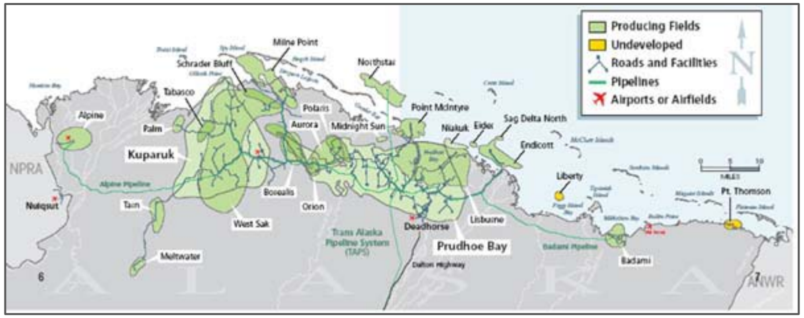
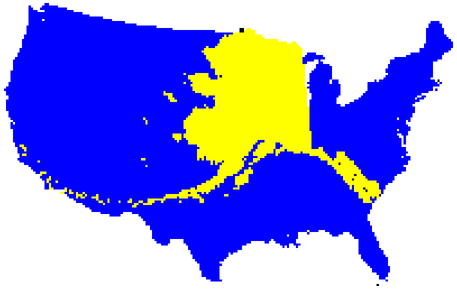
I - Introduction

Reintroducing the Potential on the Slope

Perceptions	Realities
Mature	■ ~3 Bbbls developed in the last 12 years ■ 10 fields greater than 100 MMbbls
Politics / Fiscal Regime	■ All the central north slope lands are Alaska State Lands – simple permitting ■ State dependent on oil & gas revenues, incentivizes government to act rationally
Tax Credits	■ State substantially subsidizes new company entrants
Geologically Complex	■ Central North Slope is one of the best petroleum provinces in the world with predictable geology and an elegant classic petroleum system ■ Structural complexities seen in the Foothills do not occur on the Coastal Plain
Harsh Physical Conditions Require Special Equipment	■ Ice pads & ice roads are unique, but standard practice for many years ■ 30+ year industry history of service providers with the North Slope as their primary business ■ Drilling rigs require winterization, but no special equipment
Logistics / Remote Location	■ Substantial existing infrastructure has been built in the region ■ "Frozen West-Texas" – established oil patch ■ Pad drilling limits the logistics demands ■ Home to the two largest oil fields in North America ■ 6,000+ wells drilled on the slope ■ 15.8 Bbbls produced to date





Alaska is the largest state, twice the size of Texas and one-sixth of the size of the lower 48. The Alaska North Slope (ANS) is located between the Brooks Mountain Range and the Arctic Ocean. The single largest oil field in the US, Prudhoe Bay, is found on the ANS. <u>The ANS continues to offer material oil and gas resource opportunities.</u>

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II - Background

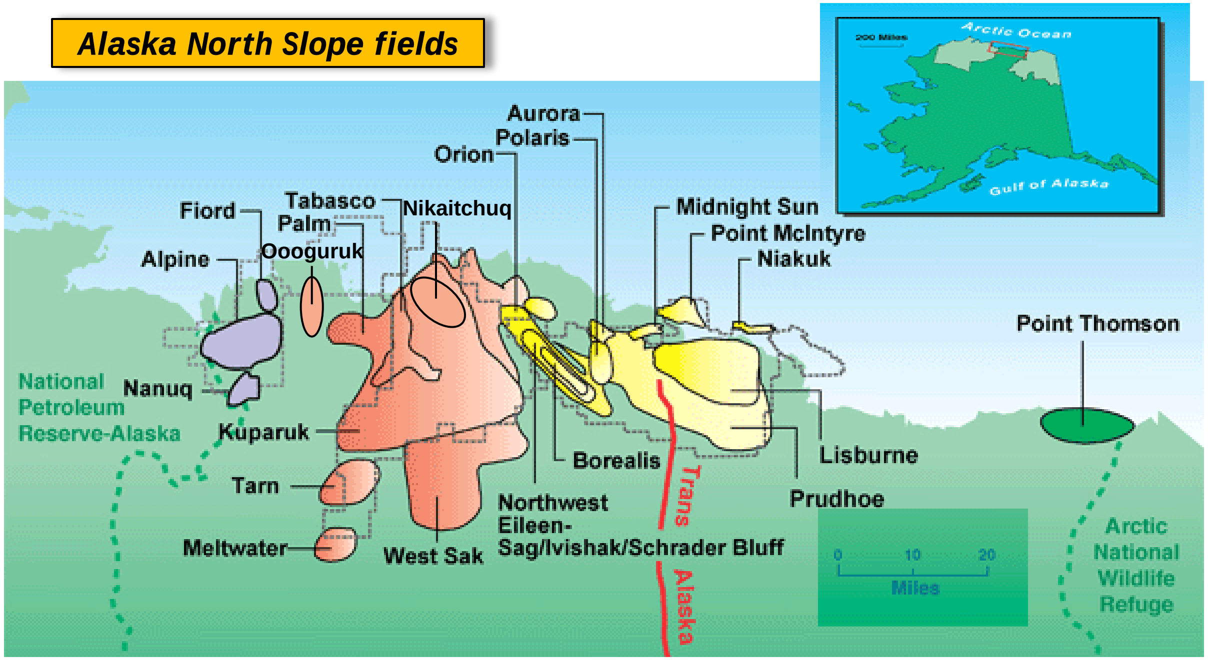
The Context of 42 Years of ANS History

In the 1970's oil and gas production in the lower 48 entered a decline and the discovery of oil at Prudhoe Bay offered significant domestic supply on a world class – since then Alaska grew into the nation's most significant supply of domestic oil with two of the largest oil fields in North America

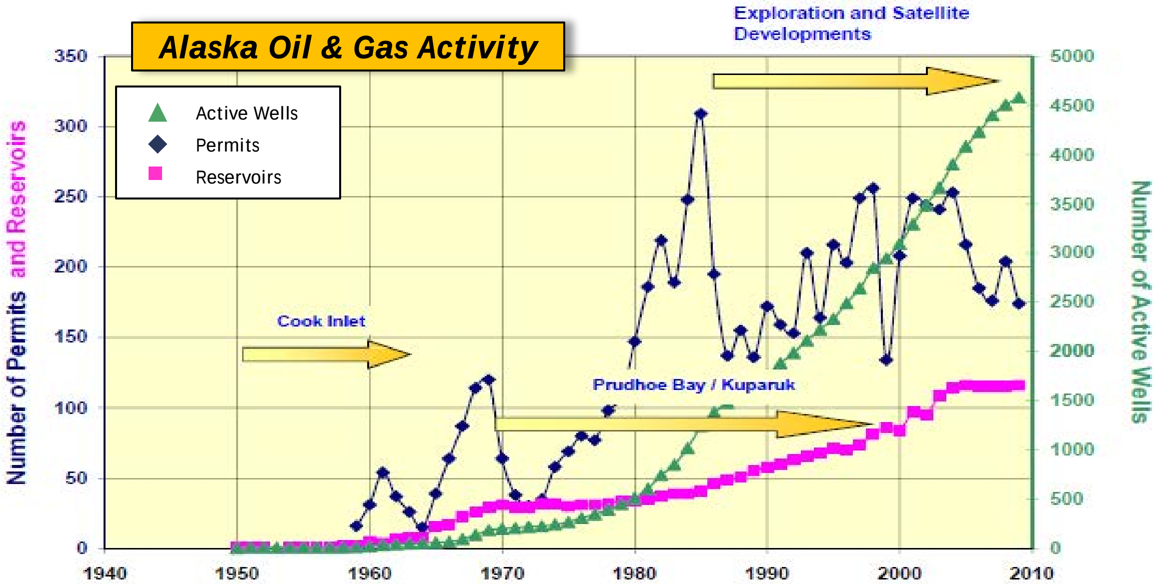
- Petroleum potential was recognized as early as 1923 – surface oil pools. Exploration began in 1944
- First oil discovered by ARCO at Prudhoe Bay 1968; Kuparuk was discovered in 1969 by Sinclair Oil
- TAPS completed July 1977
- North Slope oil Production peaked in 1988 at 2.01 mmbbls/d; Dec 2010 production 644 mbbls/d
- Alpine was discovered in 1994 by ARCO
- Exxon is moving forward with drilling and development activities at Pt. Thomson – production by YE 2014

Activity Levels Remain Robust

Alaska North Slope fields



Alaska Oil & Gas Activity



Activity on the Slope

- Central North Slope expands with artificial gravel island fields – most recently Oooguruk, Nikaitchuq and Northstar
- Independents arrive (AVCG/Armstrong initiates in early 2000)
- Horizontal technology brought up from the lower 48 has a major impact
- BP's Milne Point CHOPS ("Cold Heavy Oil Production with Sand") project starts up in 2010
- Development underway at Pt. Thomson
- Statute for royalty reduction for new projects
- State provides substantial tax credits for projects
- New leases being offered in previously closed areas: NPRA and some MMS lands

A Region Historically Dominated by the Majors

The North Slope's Central Gas Facility is the largest gas handling facility in the world

The North Slope operating environment has been historically dominated by the Majors, attributable to the huge capital costs required for infrastructure projects.

Influential events from the Majors

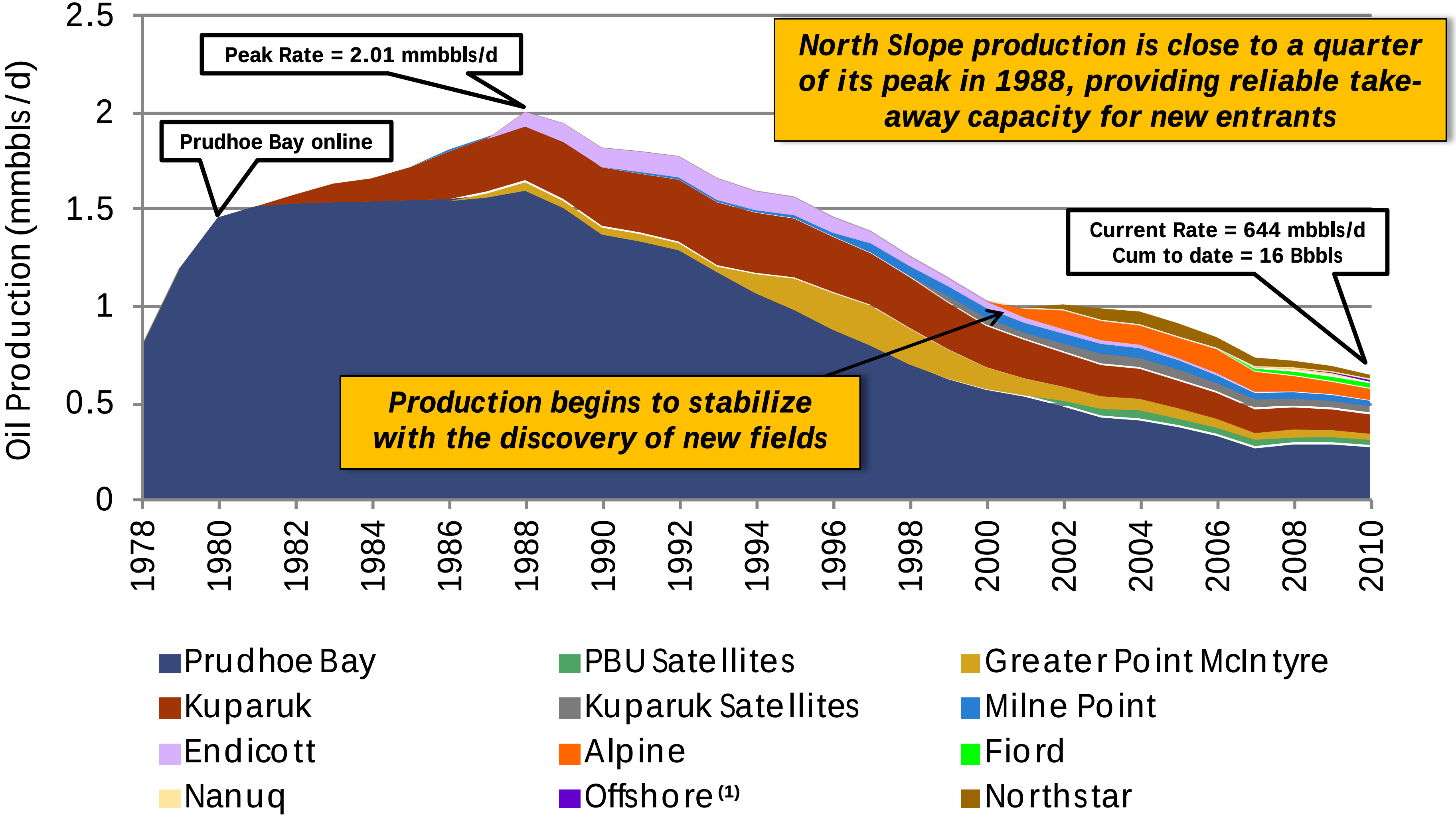
- Prudhoe Bay discovered in 1968 and subsequently developed by ARCO, BP, & Exxon
- Alaska Development Charter in 1999 to improve competition
- State agreed to BP-Arco merger with the condition of the sale of ARCO Alaska to Phillips in 2000
- Conoco returns to the slope with their merger with Phillips in 2002
- BP developed the first offshore field at Northstar, production begins in 2002
- Exxon and other leaseholders have focused on the Point Thomson project – production expected in 2014
- In 2008 Shell returned and dominated an Outer Continental Shelf lease sale with high bids totaling $2.1 billion
- Strong desire to bring gas to Lower 48 – TransCanada/Exxon and BP/ConocoPhillips compete for the Alaska gas pipeline project

Recent Activity by New Entrants

Company	Activity
Brooks Range	■ Management team with extensive operating history on the slope ■ Actively exploring all over the North Slope ■ Planning stages of Mustang development program
Armstrong	■ Substantial development project on Colville High with Repsol ■ Accumulated acreage position and caused development of Oooguruk, which is being actively developed by Pioneer, as well as Nikaitchuq, which is being actively developed by ENI ■ First independent to initiate new field development on the North Slope
ENI	■ First production from Schrader Bluff in Nikaitchuq Unit (January 2011 estimated peak production of 28 Mbbls/d) ■ Acquired Nikaitchuq interest from Armstrong and Anadarko ■ Acquired 30% interest in Oooguruk from Armstrong ■ Developed standalone processing facilities for Nikaitchuq
Great Bear	■ Secured approximately 500,000 acres on the North Slope, with strong positions in the unconventional play fairway south of the Kuparuk and Prudhoe Bay fields ■ Dominant unconventional resource player on the North Slope
Kerr McGee	■ Acquisition of interest in Nikaitchuq project from Armstrong ■ Initiated development of the Nikaitchuq field ■ After being acquired by Anadarko, all prospects sold to ENI (including Nikaitchuq)
Pioneer	■ Acquisition of interest in Oooguruk prospect from Armstrong ■ Executed development program & drilling continues at Oooguruk field ■ Nuiqsut & Kuparuk participation areas approved, Moraine participating area awaiting approval from DNR

A handful of independents have built a business on the Slope with substantial running room and upside in sight.

North Slope Production Profile



Source: Alaska Department of Revenue – Tax Division.
Note: Excludes Cook Inlet
(1) Includes Nikaitchuq and Oooguruk

Major Pipelines

- **Trans Alaska Pipeline**
  - The lifeline for oil export on the slope
  - Has considerable additional capacity
  - All stakeholders – especially the people of Alaska have a vested interest in motivating more development and future production
- **Natural Gas Projects**
  - Ideas for moving Prudhoe Bay's natural gas off Alaska's North Slope are plentiful - Will they be built or won't they?
  - Many different perspectives out there – we provide the facts and the take-away that if and when built there will be a substantial resurgence on the Slope focused on gas.
  - Potential solutions range from trucking small amounts of gas to Fairbanks consumers to constructing a pipe to carry massive amounts to Lower 48 consumers – the most expensive North American private-sector construction project ever

Trans Alaska Pipeline System - Oil Pipeline

Overview

- Trans Alaska Pipeline System (TAPS) transports crude oil 800 miles from the North Slope to the ice-free port of Valdez
- Constructed from March 1975 to May 1977
- $8 billion for construction of entire system
- Alyeska Pipeline Service Company was incorporated in 1970 to design, build, operate and maintain the pipeline
- Owners – BP, ConocoPhillips, ExxonMobil, Koch and Chevron
- Carries ~15% of nation's domestic oil production and has transported ~16 Bbbls of oil

Parameters

- Throughput
  - 2.136 mmbbl/d maximum with 11 pump stations operating
  - 2.000 mmbbl/d maximum with 7 pump stations operating
  - Peak throughput - 2.055 mmbbl/d in 1988
  - Currently transports ~600 mbbl/d to the Lower 48
- Diameter – 48 inches
- Pressure maximum – 1,180 psi
- 4 pump stations currently operating with an additional pump station in operation as a relief station (12 pump stations with 4 pumps each in the original design)

Implications

- TAPS has considerable additional capacity
- Unless further sources of oil are developed, Alyeska will begin to close pump stations
- The minimum level of throughput is 200,000 bbl/d, which ultimately will create additional incentives for further activity
- Current operators are extending the effective life of the pipeline
- TAPS pipeline is the lifeline of the State of Alaska & existing producers

Source: Alyeska Pipeline Service Company Website.

Comparison of Proposals for Transporting Natural Gas

	Pipeline to Alberta	Pipeline to Southcentral	Pipeline to Valdez
Sponsor	▪ Transcanada and Exxon Mobil (minority interest) are operating together – announced July 2009	▪ Alaska Gasline Development Corp., a state agency the Legislature created in 2010	▪ Two separate propsals: □ TransCanada and ExxonMobil □ The Alaska Gasline Port Authority
Parameters	▪ 1,700-mile, 48-inch buried pipeline from the Prudhoe Bay field on Alaska's North Slope to the British Columbia-Alberta border in Canada ▪ Designed to have a capacity of ~4.5 bcfd, but could be expanded to 5.9 bcfd ▪ Estimated cost of between $32 bn and $41 bn	▪ 737-mile, 24-inch buried pipeline from the Prudhoe Bay field on Alaska's North Slope to the Big Lake area of Southcentral Alaska ▪ The pipeline would move up to 500 mmcf/d ▪ Estimated cost of $5.3 billion to $9.8 billion (includes a $1.84 billion gas treatment plant at the Prudhoe Bay field)	▪ An 803-mile, 48-inch buried pipeline from the Prudhoe Bay field on Alaska's North Slope to Valdez ▪ The pipeline would move up to 3 bcfd, with Alaskans using some and 2.8 billion arriving in Valdez for export ▪ Estimated cost of between $20 bn and $26 bn for the pipeline and ~$23 bn for the LNG plant and Valdez port
Status	▪ Project is in the development stage - Sponsor received multiple bids during its open season in 2010 and is currently in negotiations with major companies; an approved pipeline is scheduled to be in service in 2020	▪ Project is in its very early stages - Feasibility study issued in July 2011 provided a preliminary plan, and the sponsor recommends the state spend $370 million to firm up the design, cost estimates and engineering, acquire permits and seek customers that would ship gas through the pipeline	▪ The project appears to be dormant ▪ The TransCanada/ExxonMobil team in April 2011 told FERC that it is focused on design, engineering and regulatory approval for the pipeline to Alberta, not Valdez
Proposed Timeline	▪ October 2012 – Apply to FERC to allow pipeline construction and operation ▪ 2012 – 2014 – FERC reviews the application and produces an environmental impact statement ▪ 2014 - U.S. and Canadian approvals issued ▪ 2015-2020 - Construction and commissioning ▪ 2020 - First gas flows	▪ 2011-2015 - Sponsor sharpens engineering and cost estimate, obtains permits, solicits customers ▪ 2015-2018 - Construction and commissioning ▪ 2018-2019 - First gas flows	▪ NA
Pros	▪ Short-term economic boost during construction (estimated 7,000 jobs during peak construction) ▪ Long-term economic boost as billions of dollars in revenue flows to state treasury, the Alaska Permanent Fund and local governments along the pipeline route ▪ Outlet for natural gas now stranded on Alaska's North Slope should spur oil and gas exploration	▪ Short-term economic boost during construction ▪ Could deliver gas to Fairbanks and Southcentral two years sooner than the larger pipeline to Alberta	▪ Short-term economic boost during construction ▪ Valdez gets new industry based on LNG export ▪ Outlet for natural gas now stranded on Alaska's North Slope should spur oil and gas exploration
Cons	▪ High cost makes project risky for lenders that would supply construction financing ▪ Requires major gas shippers to commit to using the pipeline for at least 20 years ▪ Long term horizon makes project risky	▪ Likely requires state to issue billions of dollars in revenue bonds ▪ The project would produce far less new state revenue than the Alberta pipeline	▪ Most expensive option ▪ High cost makes project risky for lenders that would supply construction financing

Oil Fields of the North Slope

Four Tectonic Sequences

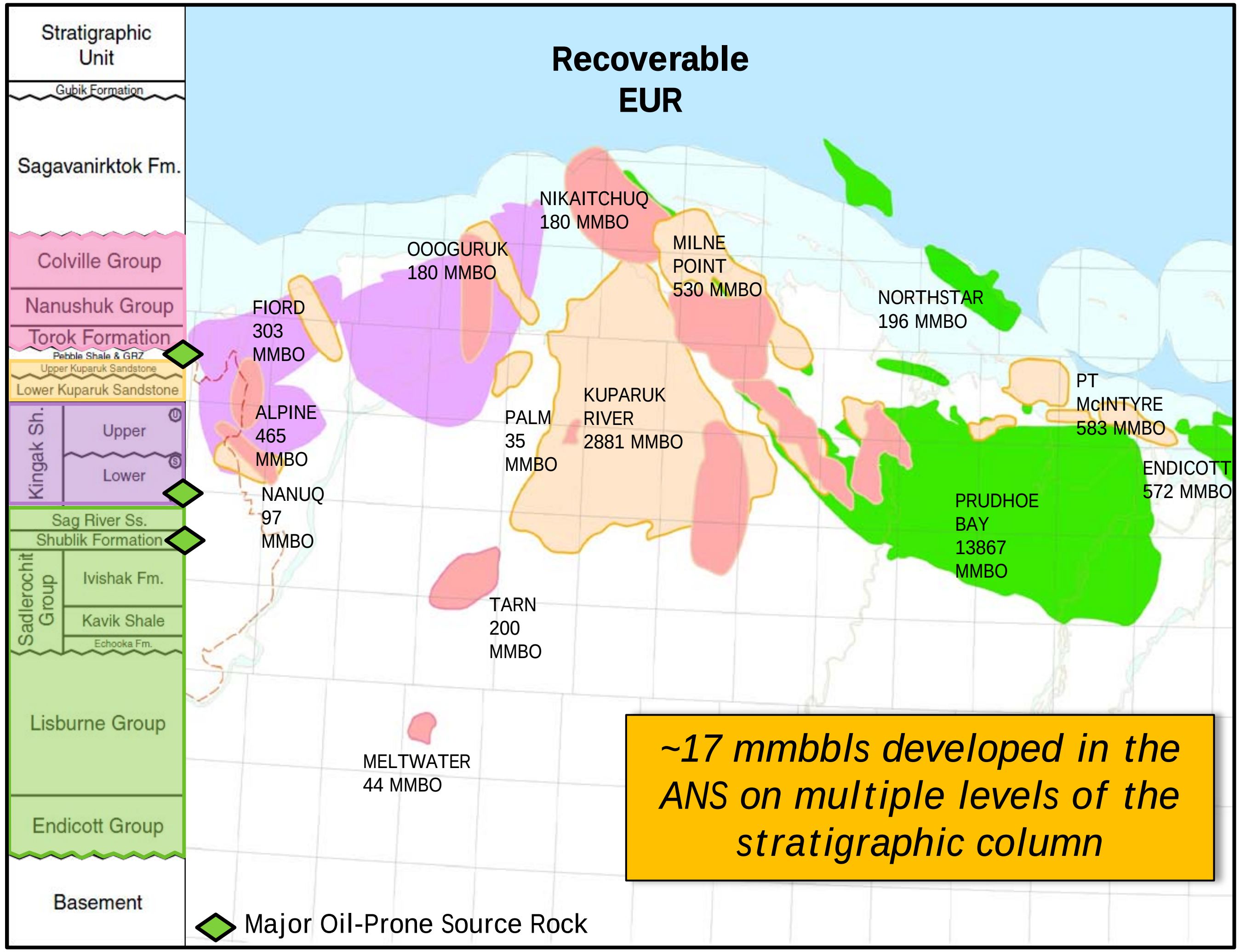
Brookian Sequence – Deltaic sediments

Lower Cretaceous Unconformity (LCU)

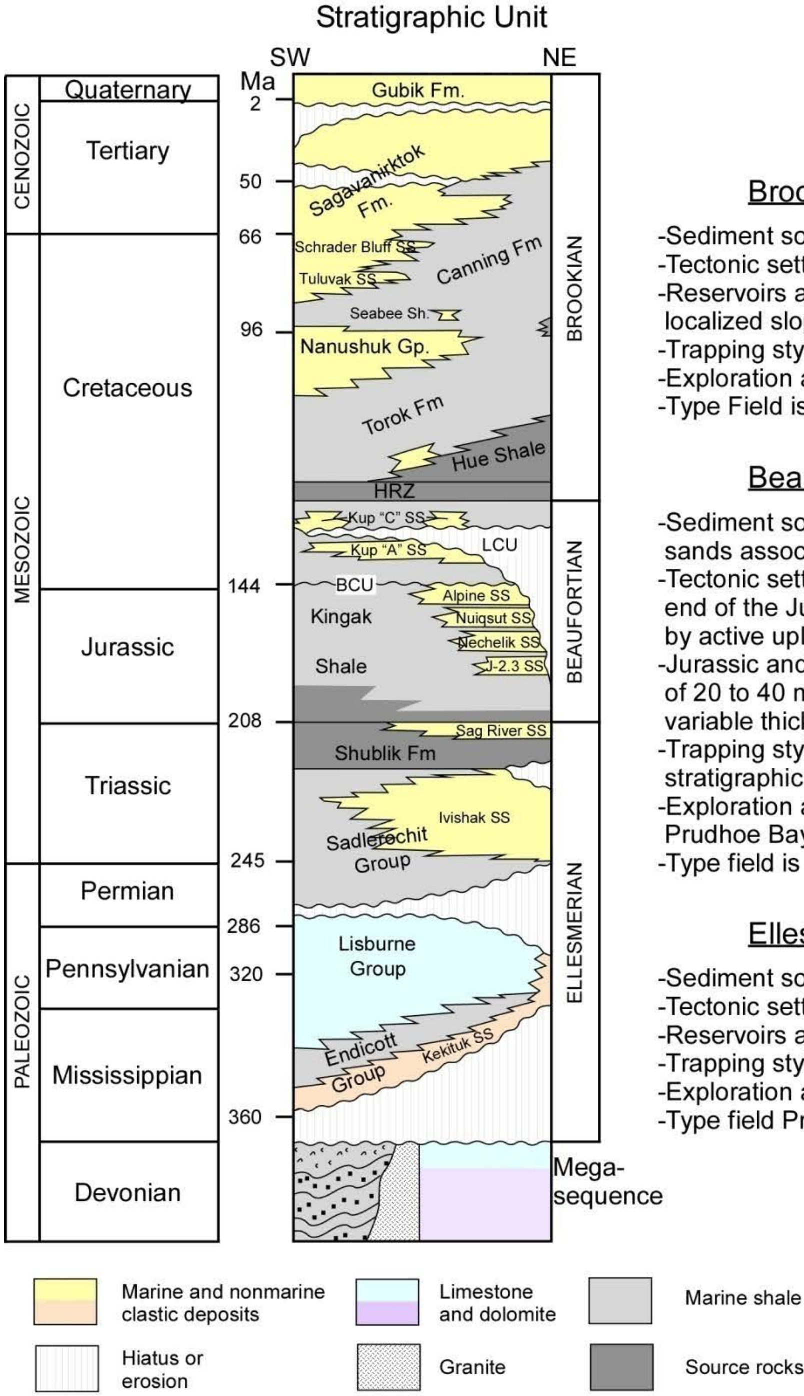
Beaufortian Sequence – syn-rift clastic

Ellesmerian Sequence – Primarily clastics with some carbonates

Basement – Meta-sediments and granite



Note: Recoverable EURs based on extrapolation of current estimates.



Modified from Bird, 2001

MEGASEQUENCE DESCRIPTION

Brookian:

-Sediment source is from the south in response to the Brooks Range uplift
-Tectonic setting a foreland basin with active thrusting and uplift of the Brooks Range to the south
-Reservoirs are laterally extensive, strike oriented, shallow marine shelf sands (topsets) and localized slope and basin-floor channel and fan complexes (bottom-sets)
-Trapping style is predominately stratigraphic with regional structural component
-Exploration and development status is immature
-Type Field is Milne Point-KRU Schrader Bluff Trend

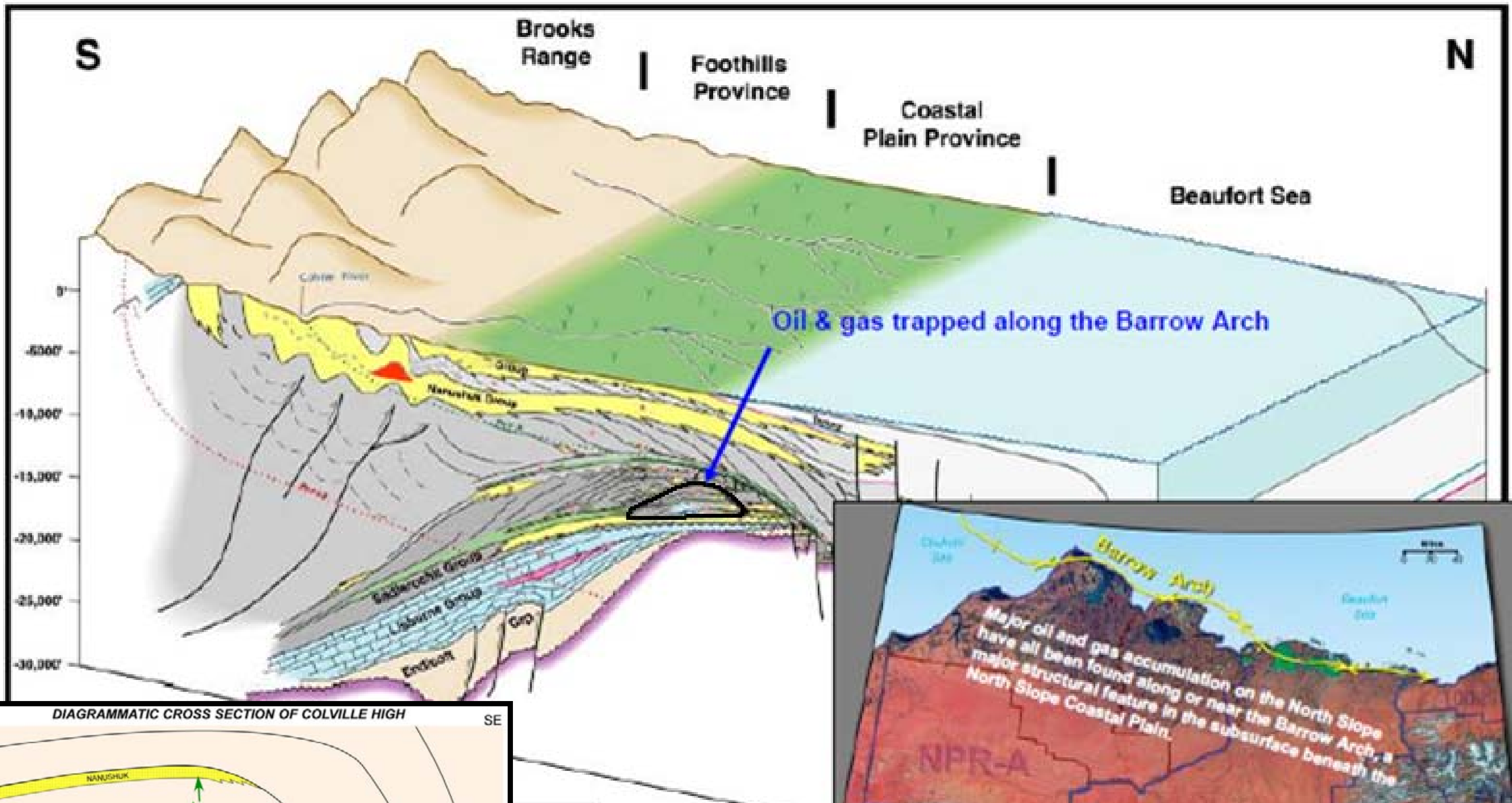
Beaufortian:

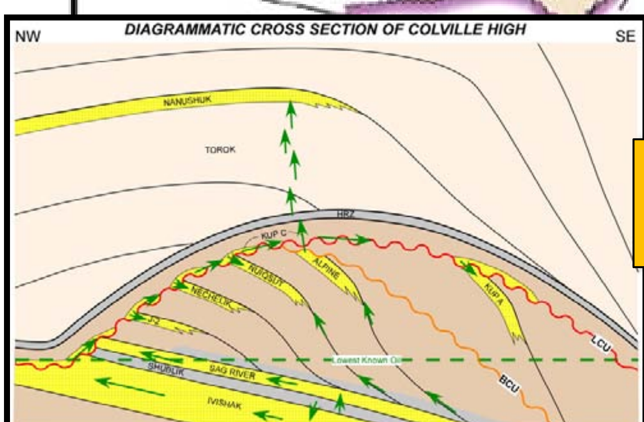
-Sediment source initially from the north through Kup "A" deposition, with locally derived syn-rift sands associated with LCU subcrops deposited in the Kup "C"
-Tectonic setting a south-facing passive margin during Jurassic with a failed rift episode at the end of the Jurassic. Cretaceous also a south-facing passive margin through Kup "A" time, followed by active uplift and rift faulting along Barrow Arch associated with opening of the Beaufort Sea.
-Jurassic and Kup "A" reservoirs are extensive shallow marine, shelf sands with strike lengths of 20 to 40 miles. Kup "C" reservoirs are highly productive, shallow marine, syn-rift sands with variable thickness and areal extent
-Trapping style is structural with a strong stratigraphic and erosional subcrop component, and stratigraphic
-Exploration and development status is predominately immature with mature areas around Prudhoe Bay and Kuparuk River Fields
-Type field is Kuparuk River Field

Ellesmerian:

-Sediment source from the north
-Tectonic setting a south-facing passive margin
-Reservoirs are predominately "blanket" sand bodies with some shallow shelf limestone/dolomite
-Trapping style strongly structural with erosional subcrop component
-Exploration and development status mature
-Type field Prudhoe Bay Field

North Slope Geology





Oil and gas trapped along the Barrow Arch in both pre and post LCU sand bodies

- Oil generated in Shublik is expulsed into Sag River SS and Ivishak where it migrates updip to LCU truncation
- Oil migrates updip along LCU filling all sand reservoirs within the Colville High closure
- Oil generated in the lower Kingak migrates updip along clinoform surfaces to shelf margin sands
- Oil leaks up along faults and fractures from underlying reservoirs to charge the Nanushuk sands

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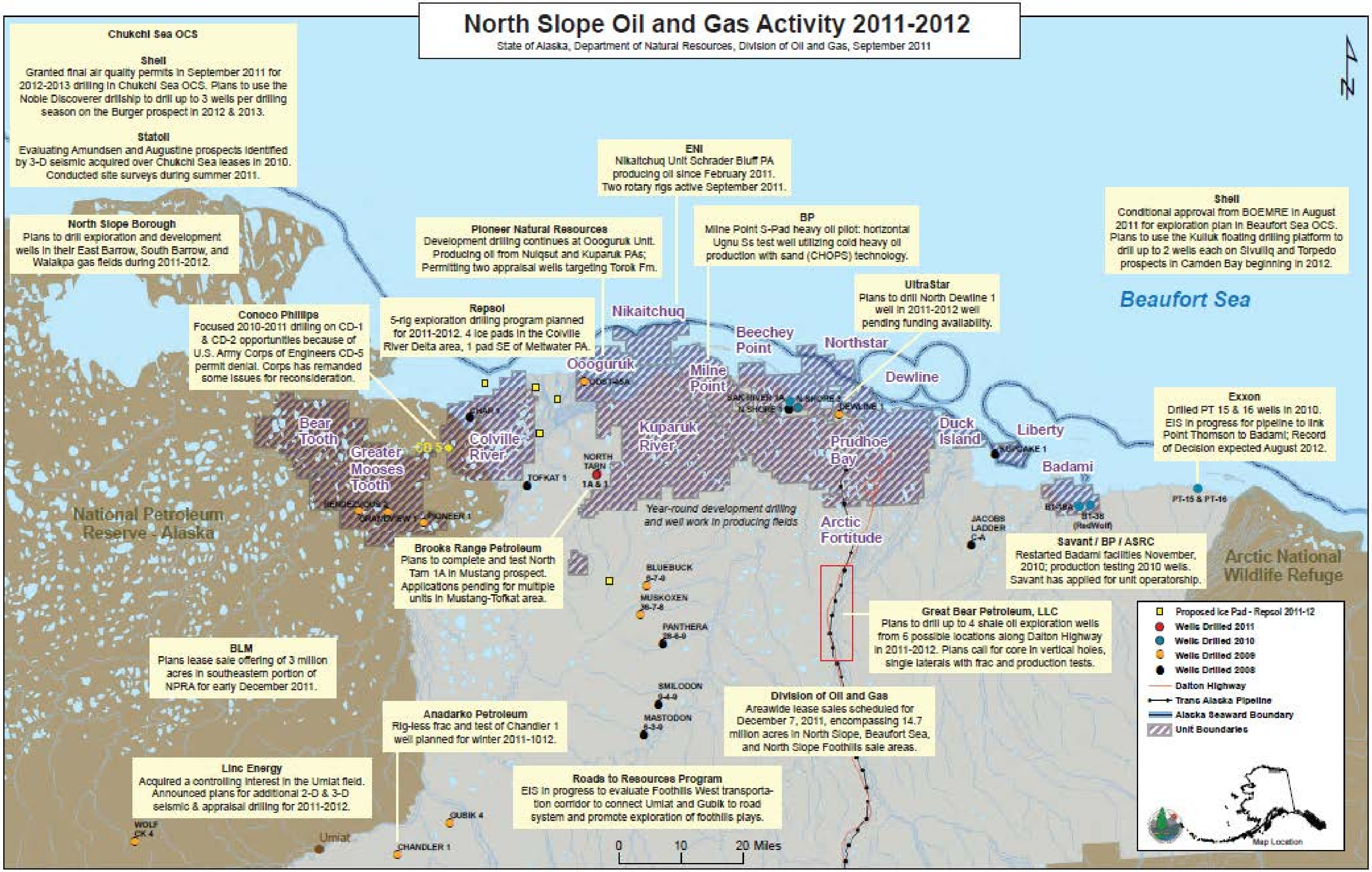
Exploration Coverage



Approx. 150 wells drilled per decade over an area of ~10 million acres. Vast areas are sparsely drilled, creating world class opportunities

Source: State of Alaska DNR, Division of Oil and Gas, Alaska Oil & Gas Conservation Commission.

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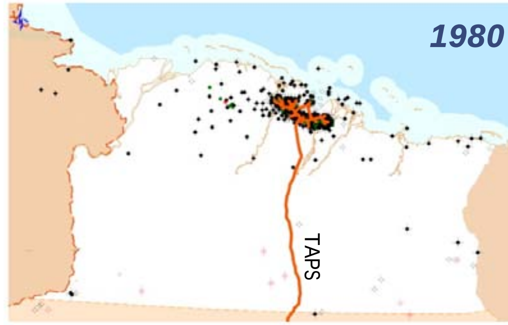
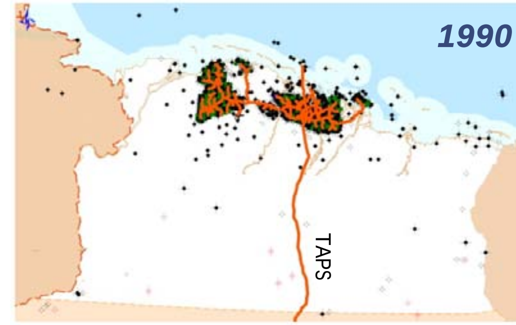
Year by Year North Slope Development

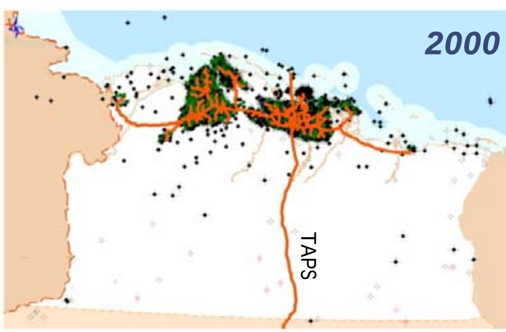
By 1970 – 60 completions



By 1980 – 442 completions



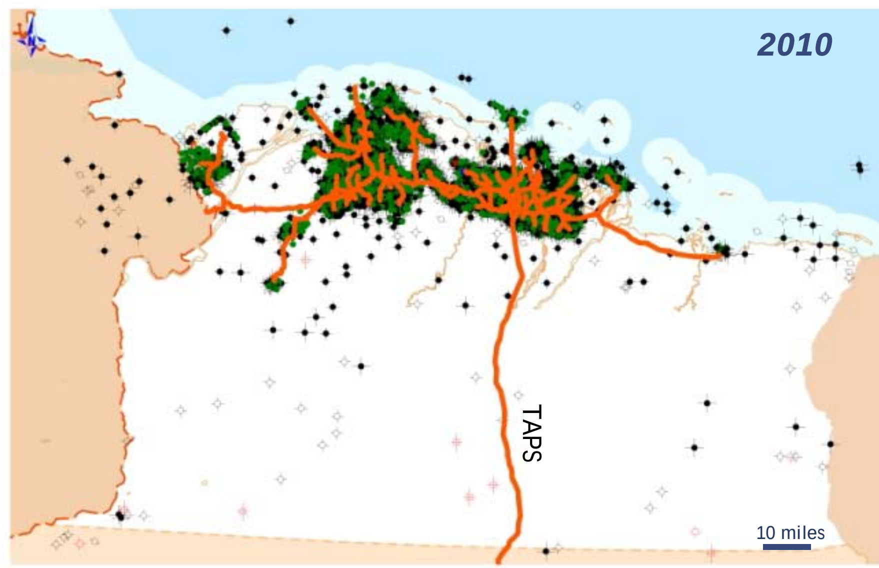
By 1990 – 2144 completions



By 2000 – 3793 completions

Legend

- Pipeline
- Completions



By 2010 – 5509 completions on Barrow Arch

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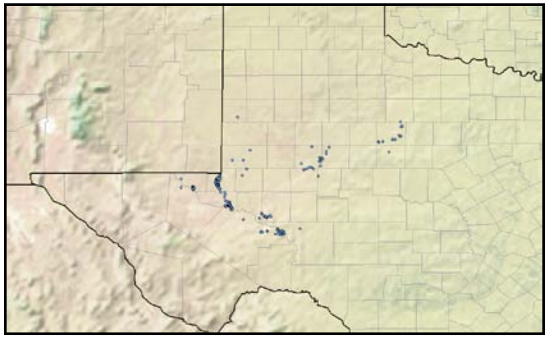
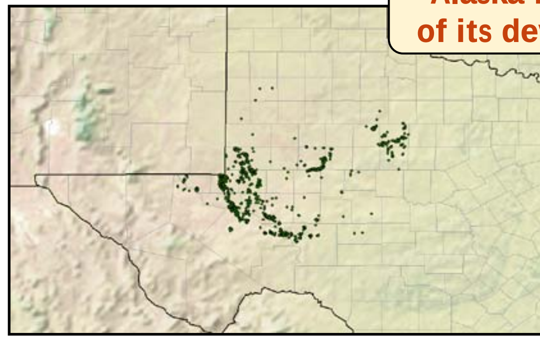
Year by Year Permian Basin West Texas Development

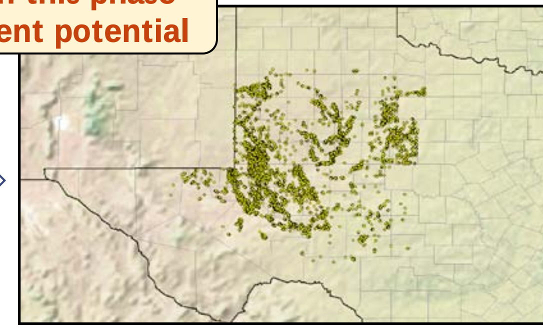
Alaska is only in this phase of its development potential



By 1940 – 464 Completions

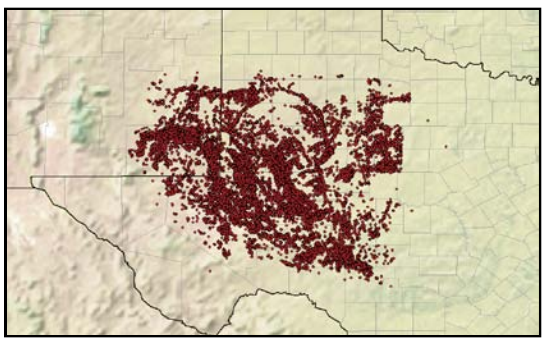


By 1950 – 3,126 Completions

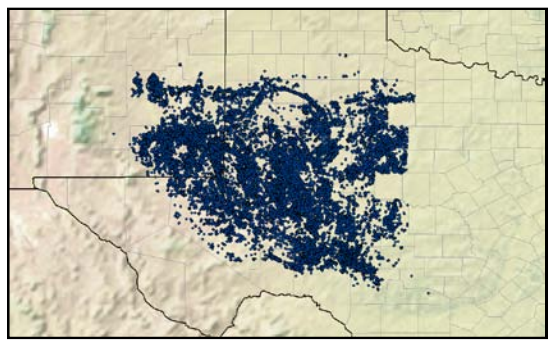


By 1960 – 21,684 Completions

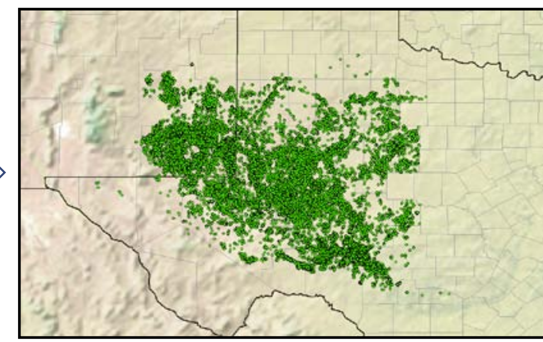
Alaska is expected to continue to expand in a similar fashion to the Permian



By 1980 – 64,325 Completions



By 2000 – 116,834 Completions

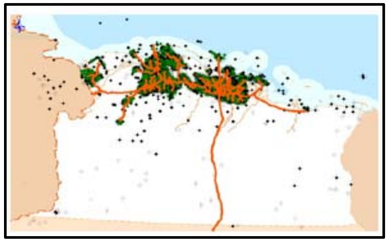


By 2011 – 147,459 Completions

Central North Slope Substantial Running Room

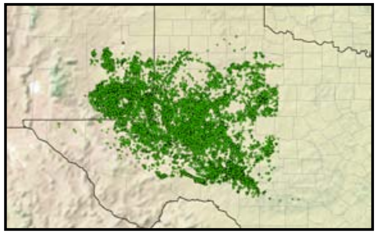
Central North Slope	Permian
USGS mean risked technically recoverable conventional estimate 4 bn bbls (2005)	USGS mean risked technically recoverable conventional estimate 0.75 bn bbls (2007)
USGS shale-oil estimate: 1.0 bn bbls (2012)	USGS continuous resource oil estimate: 0.5 bn bbls (2007)
Cumulative production: ~ 16 Bn bbls	Cumulative production: ~ 30 bn bbls
CNS area: 130 x 60 miles	Basin area: 300 x 250 miles
Rigs running: 10-14	Rigs running: 460-490
Reservoir Quality: Frequently Excellent – mean EUR 5 MMbbls	Reservoir Quality: Generally low – a good well EUR ~0.5 MMbbls
State pays out cash incentives up to 45c per dollar invested	State provides some severance tax incentives

Central North Slope



< 6,000 completions

Permian Basin

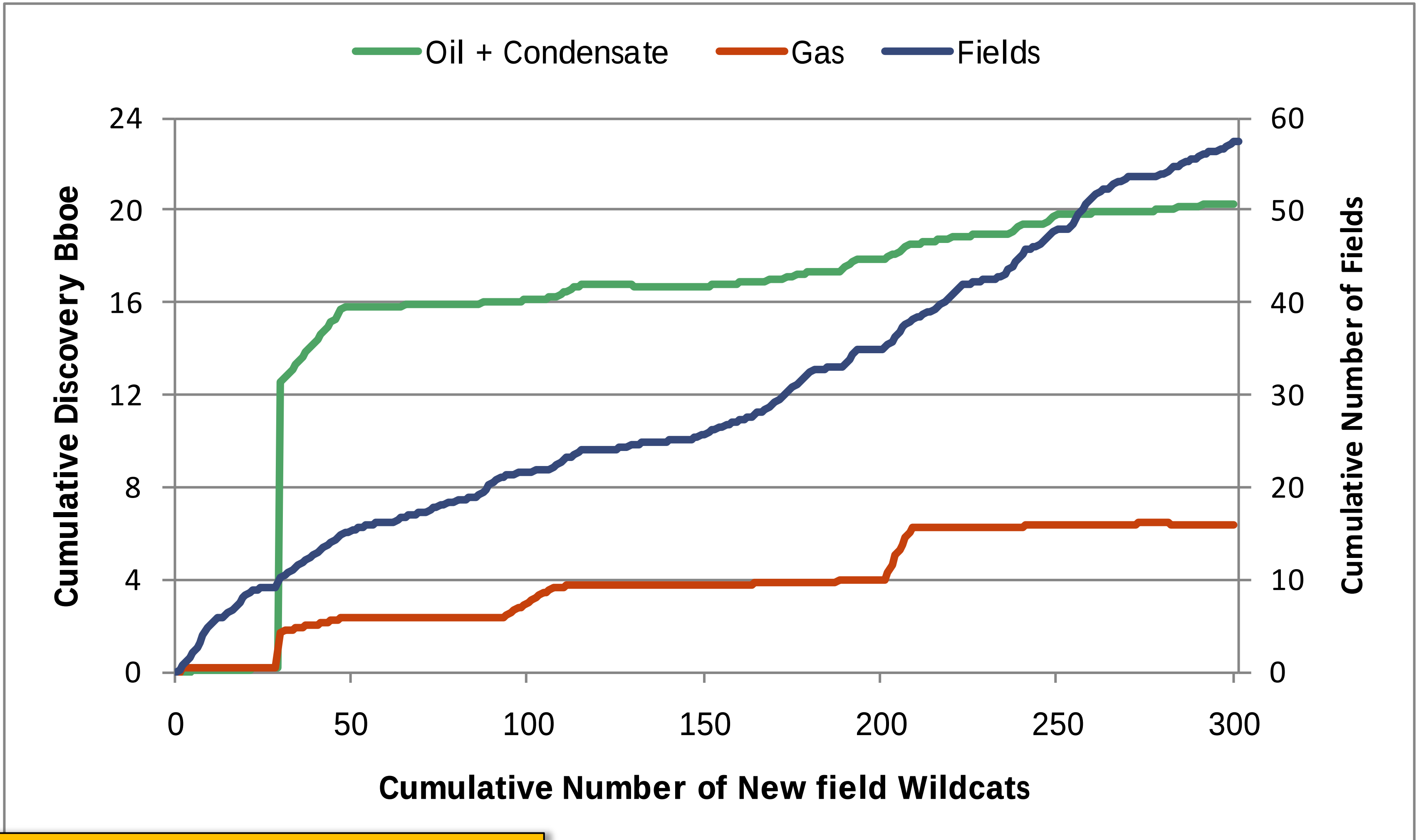


150,000 completions

Central North Slope is huge and largely un-exploited

Source: USGS Resources Assessments: Professional Paper 1732-A 2006. USGS 2007 Permian Factsheet, TPH Rig Report – May 2012

ANS Creaming Curve



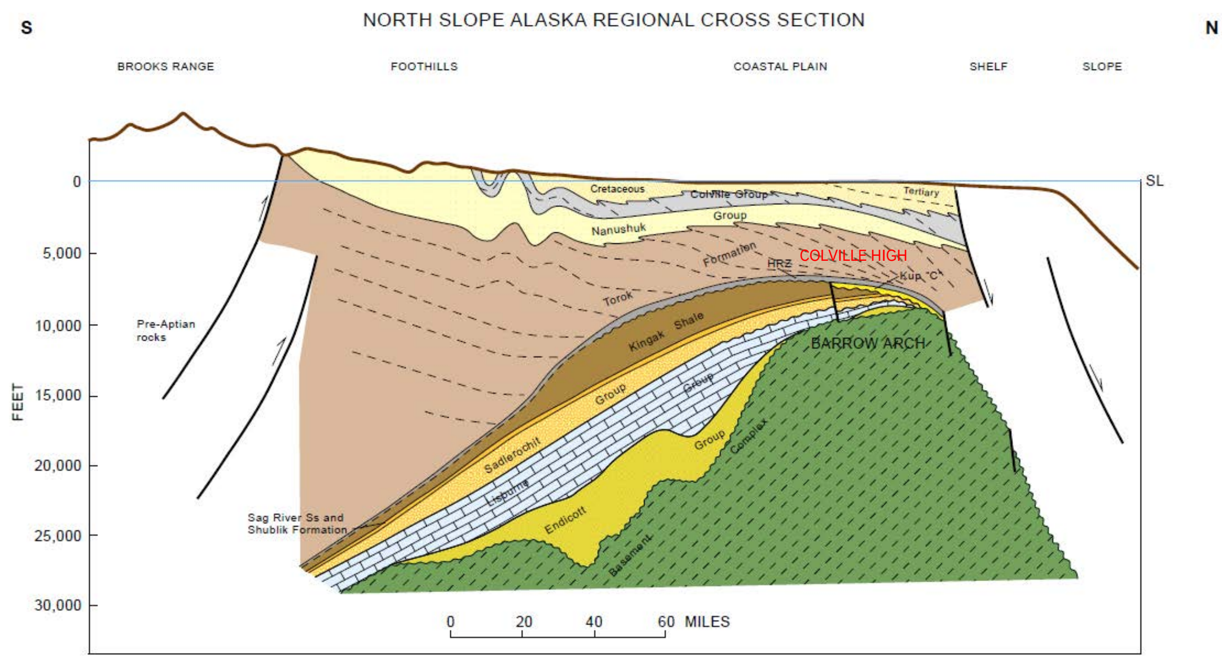
Every 50 wildcats discover ~1 Bbbls and ~10 fields

Source: Jean Laherrere 2008.

Alaska North Slope Resource Potential

USGS data on resource potential illustrates that there is substantial remaining oil and gas to be developed, the Colville High accumulates a substantial proportion of the migrating hydrocarbons.

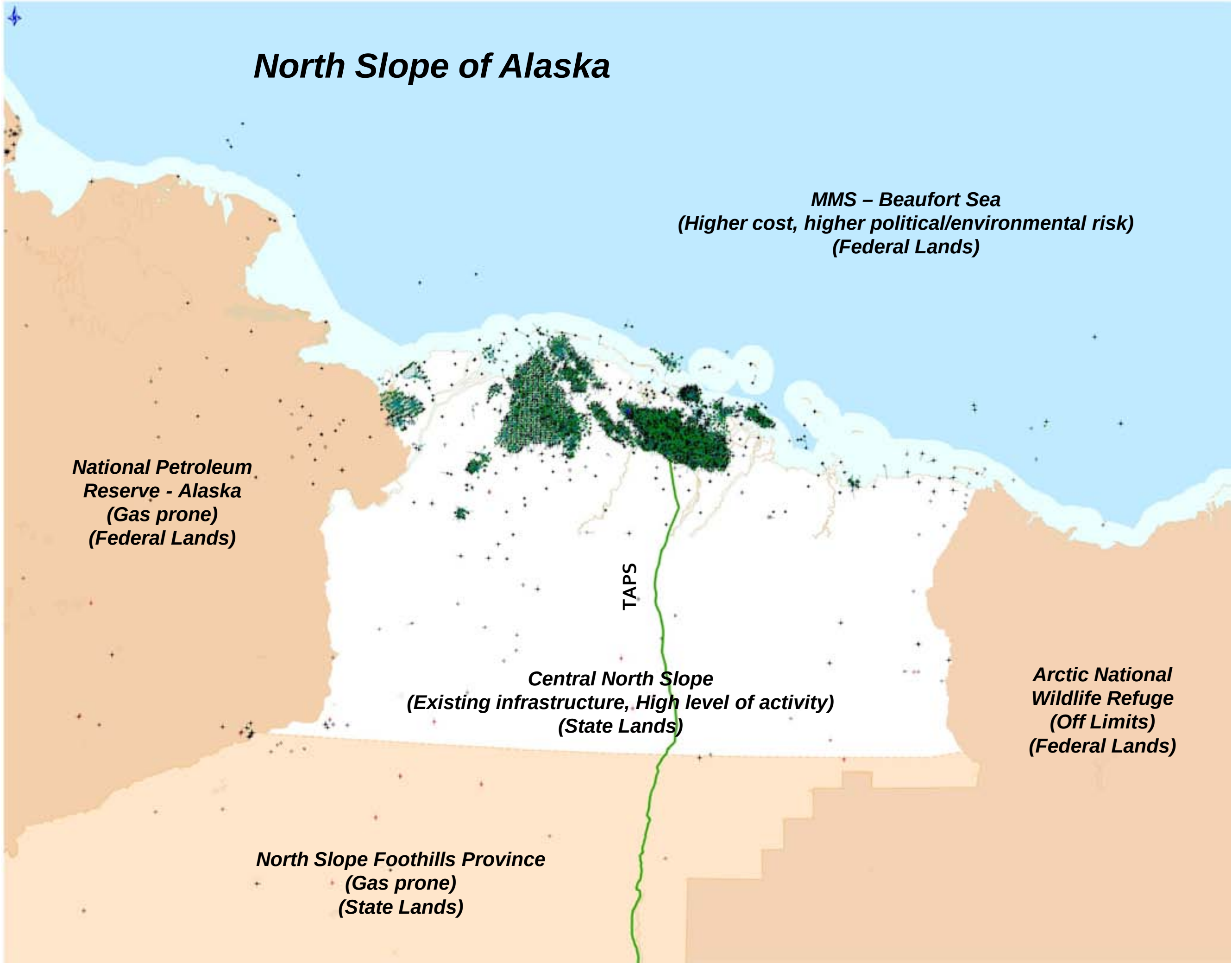
- "The arctic Alaska region is one of the most petroleum productive areas in the United States." USGS
- Approximately 16 billion barrels of oil have been produced up to date
- This is a geologically target rich environment, with prospective strata located in multiple reservoirs and trapping types
- Multiple source rocks occur. Both extensional and contractional structures and stratigraphic combinations provide traps



- USGS estimate of undiscovered resource is more than 50 billion bbls of oil and NGLs and 230 Tcf of gas. **50% onshore Arctic Alaska.** NPR-A is more gassy 0.9 billion of oil and 50 Tcf of gas
- This estimate represents ~ 20% of total US Oil Reserves and 20% of total US Gas Reserves
- **Woodmac 2P estimates at 1/1/2011 are of 3.6 billion bbls of oil and 31 Tcf of gas remaining onshore ANS recoverable**

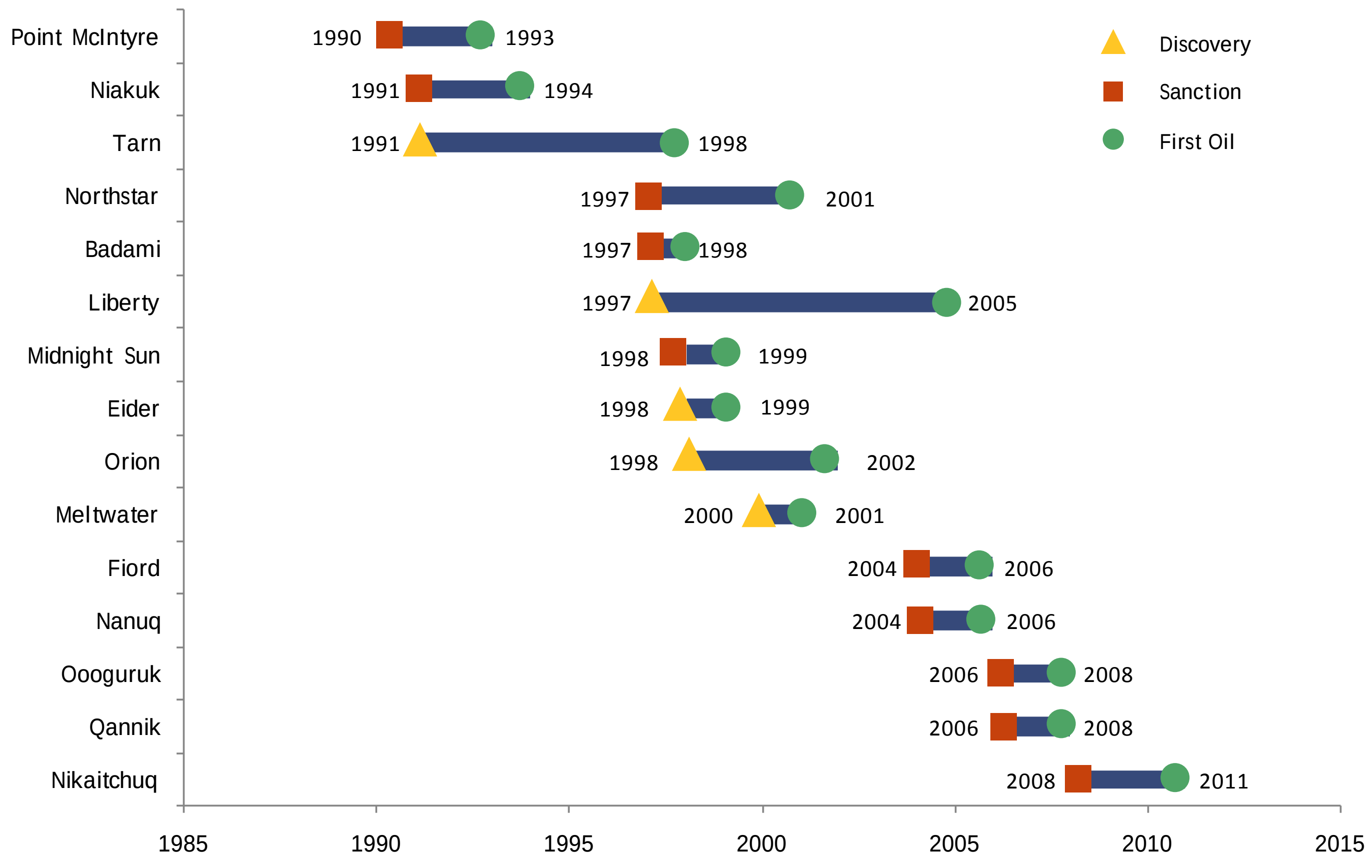
Source: Oil and Gas Resources of the Arctic Alaska Petroleum Province – USGS Professional Paper 1732-A 2006.

Regional Context for the North Slope



Central North Slope offers the most favorable and reasonable cycle time development opportunities in all of Alaska (i.e. Oooguruk sanctioned in 2006 to first production in 2008)

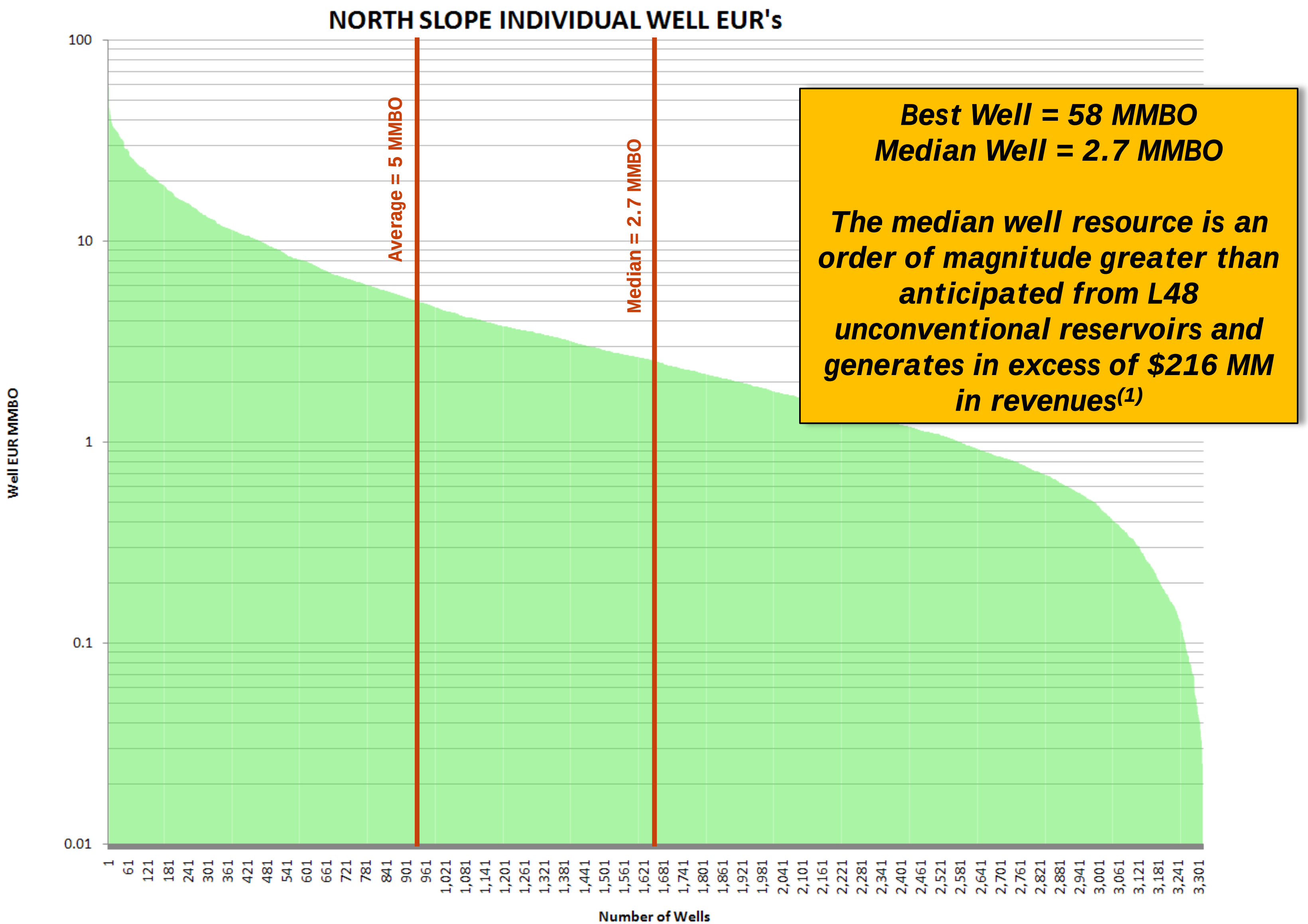
ANS Satellite Field Development Timeline



- 15 fields have been developed since 1990
- Field cycle times have been getting shorter
- Oooguruk – 2 years from sanctioning to first oil

Regular development of fields in Alaska continues and cycle time decreases

Mean Well Averages 5 MMbbls



Source: State of Alaska.
(1) Assuming $90/bbl oil and $10/bbl deduct for transport/quality.

Stand-Alone Field Development

New fields can be developed in one of two ways – with self-contained stand alone skid mounted production facilities or tied back to nearby legacy infrastructure – Stand-alone provides flexibility and substantial commercial advantages

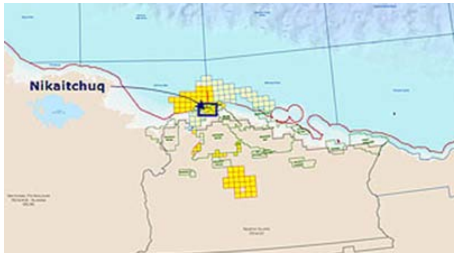
Advantages for Stand-Alone Facilities

- More control on capital costs
- Greater flexibility for additional field/reservoir development
- Additional profit stream
- State subsidizes through Loss Carry Forward ("LCF") and Qualified Capital Expenditure ("QCE") Credits
- Leverage for FSA negotiations
- Canadian and Alaskan contractors have the expertise
- FERC pipelines – generally in the vicinity
- More efficient sizing of production trains

ENI's stand-alone development processing facility at Oliktok Point Nikaitchuq

Nikaitchuq Facilities

- Stand-alone development Implemented by Eni from 2008-2011 - First oil expected in January 2011 peaking at 28,000 bbl/d, viscous oil from Shrader Bluff and future targeting of light oil from Sag River
- 50-80 extended reach producers and injectors drilled from two drilling pads are expected from both an onshore and offshore artificial gravel island
- 40,000 bbl/d processing facility at Oliktok point sends processed oil to the Kuparuk pipeline
- Contractors: INTECSEA for FEED, Nanuq for Gravel Island and roads, Price-Gregory for pipelines, ASRC for services, ATCO for on-site camp



Tie-back Field Development

Tie-back to nearby legacy infrastructure can be an option in some cases – Pioneer chose this option for Oooguruk

Tie-back Facilities

- Oooguruk is a recent example of a tie-back development by an Independent
- Oooguruk is located 5 miles offshore in Harrison Bay
- Pioneer - Operator with 70% WI, ENI with 30%
- First Oil June 2008
- Over 65 potential locations
- Implements the North Slope Facility Sharing Agreement
- Sanctioned in 2006, onstream by June 2008
- Contractors: 12" multiphase pipeline from Intec, installation by HC Price, Engineering by TriOcean, EEIS, Construction by VECO, Nanuq and Alcan

Oooguruk drill site

Oooguruk flowline onshore

Oooguruk tie-in pad

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Access to Facilities and Pipelines

Facility Sharing Access (FSA) Agreements

- Standard Reference Agreement is the Facility Sharing Access Agreement (FSA) facilitated by the Charter Agreement and Ballot 2555
- Only Kuparuk, Prudhoe Bay, Lisburne and Endicott production facilities have existing FSA among related owners, Pioneer's Oooguruk breaks the monopoly of majors
- Appendix D to Ballot 255 creates template for third party access – although FSA's remain securely confidential
- Unlike UK or Alberta – government interdiction has not been invoked to date in order to resolve disputes
- Issues of interest to independents are Backout calculations, access fee methodology, timeliness of access negotiations, insurance requirements and operatorship issues
- Agreements aim to maximize total oil production, problem is older high GOR, high WOR wells curtailed first – owners require compensation
- Owner/operators want to run Field Optimization model and also to avoid subsidizing new entrants and extract economic rent

Facility Sharing Access (FSA) agreement have been developed that allow access for third parties - most areas have capacity, and this increases with additional water knock out investment

Oil Facility - Alaska

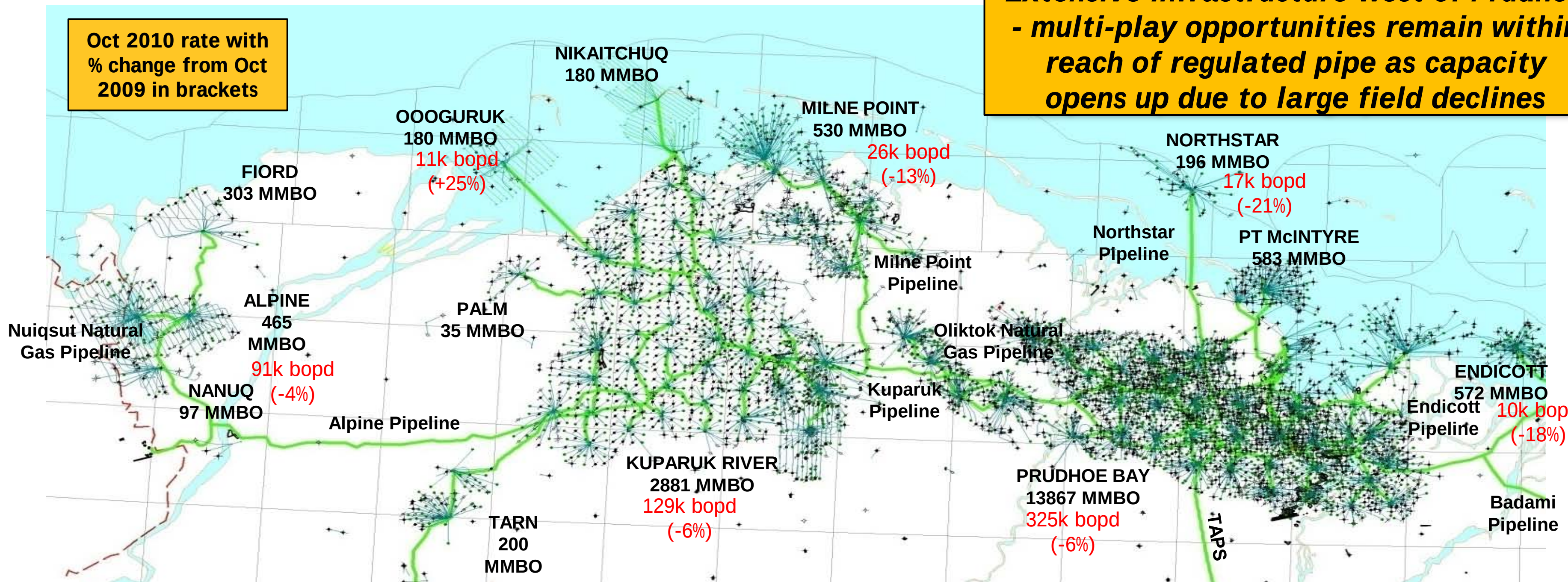
Options for Processing for Colville High Region

Facility	Capacity
Alpine	Substantial capacity available
Kuparuk	Substantial capacity available for oil, additional investment required for total liquids and gas
Nikaitchuq	40-50k bopd capacity, peak rate expected only 28k bopd

Source: DNR Facility Sharing Report 2004.

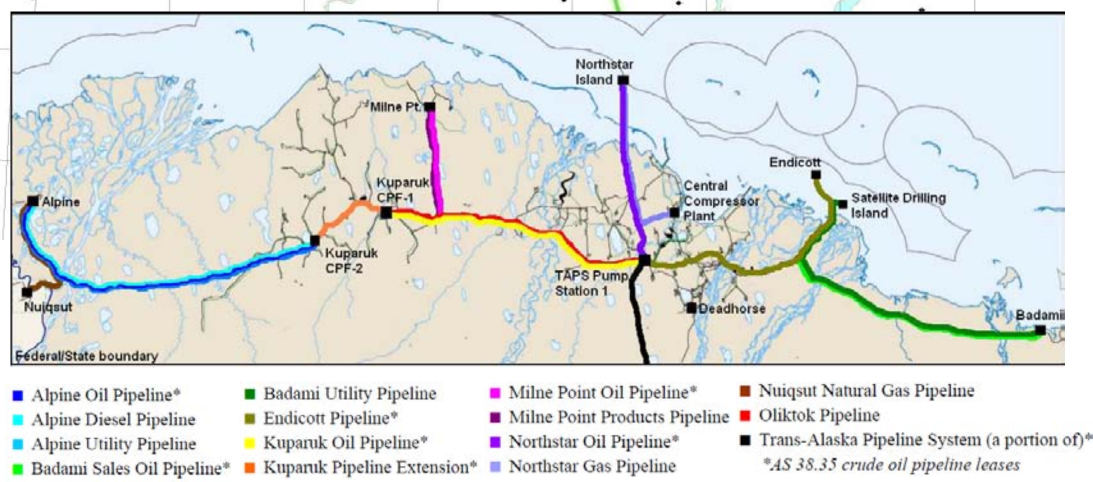
Pipeline Infrastructure and Capacities

Extensive infrastructure west of Prudhoe - multi-play opportunities remain within reach of regulated pipe as capacity opens up due to large field declines



Spare North Slope Pipeline Capacities

MBPD Year	Badami Pipeline	Endicott Pipeline	Milne Pt. Pipeline	Alpine Pipeline	Kuparuk Pipeline	North Star Pipeline	TAPS Pipeline
Current Capacity	35	100	65	100	400	65	1400
2003	0	29	51	98	361	62	994
2004	0	30	52	99	359	68	997
2005	0	29	53	98	364	60	982
2006	0	27	57	103	376	50	968
2007	0	25	58	117	390	40	954
2008	0	24	59	117	379	32	923
2009	0	22	59	104	367	27	878
2010	35	56	59	86	338	20	852
2011	50	70	58	71	322	17	824
2012	48	66	57	60	300	15	775
2013	38	55	56	51	290	12	734
2014	31	47	56	44	273	10	691
2015	27	42	55	38	267	9	663



Source: DNR Facility Sharing Report 2004, Joint Pipeline Office Publications.

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Environmental Policy

Environmental controls reflect concerns regarding oil spills in sea ice environment or damage to sensitive ecosystems – however oil and gas producers in the North Slope are effective working within these controls

Aerial view of ConocoPhillips operated Alpine Field – note very small footprint, minimal impact to the environment

- Not significantly different than working in the Lower 48
- Exploration drilling activity occurs during a three month window when the ice is thick enough to support the facilities without damaging the tundra
- Ice roads built to reduce effects on the environment, ice road construction begins in November
- Pipelines are rarely buried under the surface, generally lifted on Vertical Support Members (VSM) to allow migration of caribou – expect more buried pipelines under gravel roads, preferred by Indigenous peoples
- Run off water from the facilities is collected and disposed of
- Stringent precautions are taken to minimize impact to wildlife; industry is efficient at working within precautions
- Oil-in-Ice industry consortium 2006-2010 examined the challenges of Arctic oil spills

Tax Rebates of Capital Expenditures

20% Qualified Capital Expenditure

25% Loss Carry Forward

True Capital Expenditures to the Operator

Development Capital

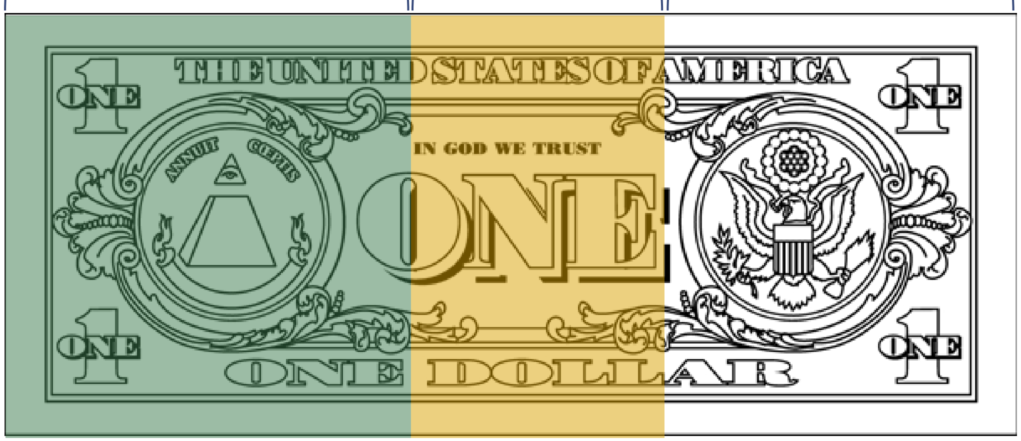
$0.45 of every dollar spent is rebated by the Company in the two subsequent years

40% Qualified Capital Expenditure

25% Loss Carry Forward

True Capital Expenditures to the Operator

Exploration Capital



$0.65 of every dollar spent is rebated by the State in the two subsequent years

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Fiscal Terms – Tax Credits Illustration

State tax credits are structured to increase investment in the Alaska North Slope. These are material incentives to New Entrants to the Alaska North Slope.

Qualified Capital Expenditures (QCE) - 20% QCE tax credit for upstream capital expenditures (i.e. exploratory wells and new seismic). 50% of credit can be taken in year 1 (year of tax credit certificate award) and the other 50% of credit can be taken in year 2. These credits do not expire and can be held, sold to third parties or sold back to the state.

Carry Forward Loss (CFL) Credits - 25% credit based on calendar year losses after the end of the calendar year in question. 50% of credit can be taken in year 1 (year of tax credit certificate award) and the other 50% of credit can be taken in year 2. These credits do not expire and can be sold to third parties or sold back to the state.

Small Producer Credit - small producers (less than 50,000 b/d or b/d BOE) are entitled to a $12MM per year production tax credit. This credit is in effect for 10 years after start of production (need to start production by 2016 to qualify).

Exploration Incentive Credits (EIC) - 30% or 40% credit depending on well location and the prospect traits. You can take EIC credit or the QCE credits, but not both. Work needs to be complete by July 1, 2016 to qualify.

- New Entrant Development
  - Single pad
  - 16 producing wells
  - $570 million in drilling costs
  - $105 million in infrastructure costs
  - $10 million in 3D seismic costs
- Cash flow positive in year 3

($ in millions)	2011	2012	2013	2014	2015	2016	2017		2022
Capex	$57	$162	$175	$140	$140	$-	$-	-->	$-
QCE	-	6	22	34	32	28	14	-->	-
CFL	-	14	41	-	-	-	-	-->	-
Small Producer	-	-	12	12	12	12	12	-->	12
EIC	-	2	2	-	-	-	-	-->	-

	PV10
QCE	$87
CFL	$43
Small Producer	$61
EIC	$3
Total Tax Credit Contribution	**$193**

Credits in this example provide $190MM PV 10 for a project with $675MM capex

Source: Alaska tax office.

Fiscal Terms - Taxes

$45 / bbl Case

ACES provides protection in a low commodity price environment

Owner's take $13.2 / bbl

$7.5 / bbl

$2.1 / bbl

$7.5 / bbl

$15.0 / bbl

Federal Income Tax – ~35%

State Income Tax – levied at 9.4% (maximum)

Alaska's Clear and Equitable Share (ACES) replaced severance tax. ACES is a tax on net profits. Tax begins at 25% increasing as the profit margin per barrel increases

$15 / bbl opex

$90 / bbl Case

Owner's take $25.2 / bbl

$13.6 / bbl

$4.0 / bbl

$32.3 / bbl

$15.0 / bbl

Excluded from above analysis: Royalties vary between 12.5% to 16.7%
State Property Ad Valorem Tax - levied at 2% of the tax value

Source: Alaska tax office.

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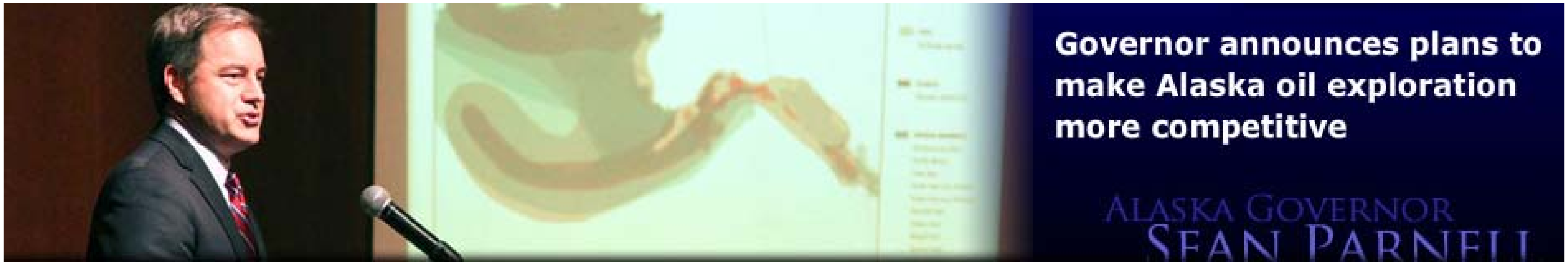
Political Climate Fosters Investment



Increasing TAPS Throughput is a Priority

- The State has been dependent on revenue from oil and gas for the last 30+ years.
- Giant fields on decline and lack of new production to replace reserves puts the State in a critical funding situation.
- Both Democrats and Republicans want to improve fiscal terms as they recognize the need for oil development – 90% of current state revenue generated from oil & gas
  - Parnell has proposed substantially reducing the production tax
  - Parnell has proposed increasing tax credits to oil companies
  - Focus on maintaining Alaska's fiscal competitiveness with other world-class resource development opportunities

New Entrants Shown Favorable Treatment

- Recent increase in North Slope exploration driven by significant resource and favorable investment environment
  - Up to 45% tax credits for capital invested in North Slope development
  - Up to 65% tax credits for capital invested in North Slope exploration
  - $10 million per year in severance tax offset for small producers (less than 10,000 bbls/d)
- State working to streamline permitting and environmental processes to decrease learning curve of new entrants

III – Arrival of the Independents

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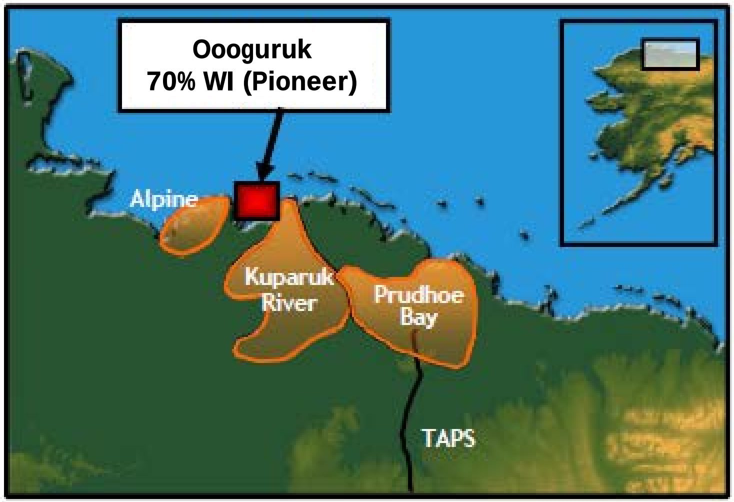
It is a New Era on the Slope

Alaska - Oooguruk

PIONEER NATURAL RESOURCES

Innovative technology, access to infrastructure, commodity prices, tax environment – these factors contribute to a new era capitalizing on the forgone opportunities of an old era



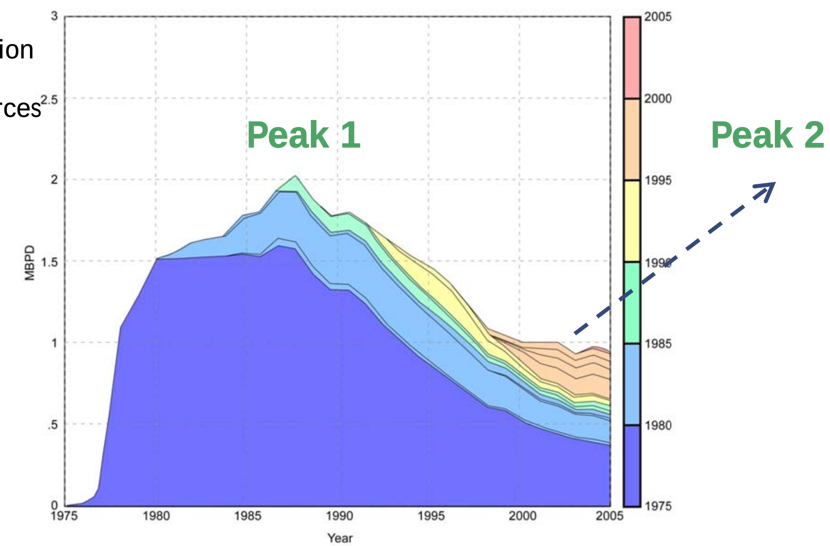
- Prudhoe Bay and Kuparuk fields are on decline - opening up capacity in the TAPS pipeline
- Smaller and more numerous reservoirs are tapping into existing infrastructure at progressively lower threshold reserve values
- This new reality has contributed to the interest of more Independents and the refocusing of the Majors
- Oooguruk field owned by Pioneer and ENI is the first commercial production from an independent – came on stream in 2008
- The Independents are on the precipice of changing the production profile on the North Slope by providing new thinking and cost synergies

North Slope New Entrants

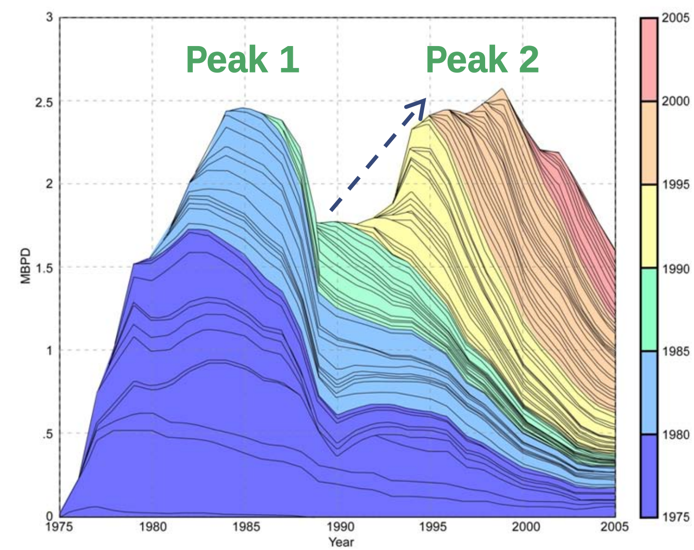
Private Companies	Public Independents	Integrated Companies
Armstrong Alaska (70 & 148, LLC)	Anadarko Petroleum	BG
Arctic Slope Regional Corporation	Apache	ENI
Brooks Range Petroleum	Linc Energy	Repsol
GMT	Murphy	Shell
Great Bear Petroleum	Pioneer Natural Resources	Statoil
Ocean Energy Resources	Suncor/PetroCanada	Total
Royale Energy		
Renaissance Alaska		
Savant Alaska		
Ultrastar Exploration		
Woodstone Resources		

The new entrants in Alaska will provide the same drive and revitalizing force they did in the North Sea - spurred by tax incentives and opportunities missed by majors

Alaska North Slope Oil Fields



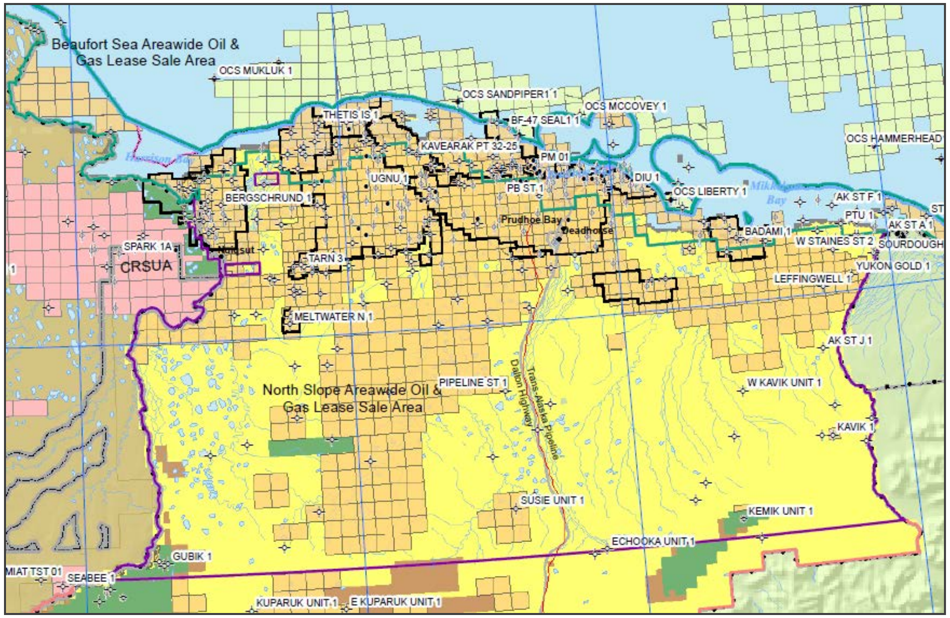
UK Oil Fields (North Sea)



Lease Sales

Lease sale activity for exploration acreage has increased since 2007 – upward trend in leasing is healthy for the region

- Area-wide lease sales are held annually
- All unleased acreage is available for sale
  - 4 section blocks have 7 year contracts and are closer to infrastructure
  - 9 section blocks have 10 year contracts and are further away from infrastructure
- 129 tracts covering ~600,000 acres were sold in most recent annual lease sale



Source: Division of Oil and Gas.

Strategies for a Variety of Companies

Company	Strategy
bp	Largest investor and taxpayer in Alaska, investing $10bn over 10 years on existing fields, emphasis on gas and heavy oil and optimizing existing fields.
ConocoPhillips	Largest producer and reserve holder with 240 mboed production and 6.0 Bboe reserves, extended Alpine forward. Searching for satellite opportunities to Alpine and partnering with smaller companies.
ExxonMobil	Announced successful drilling of 2 Point Thomson development wells on October 27, 2010. Significant capital investment beginning in 2011.
Anadarko	2010 Capital investment has been tied to Arco/ConocoPhillips, explored in NPR-A and Foothills, also researching gas hydrates. Access to more than 4.7 MM gross acres with good satellite potential. Company has participated in over 35 exploration wells and continues to determine the commerciality of multiple discoveries.
eni	ENI started the development of the Nikaitchuq oil field in January 2008 obtained from Armstrong. ENI plans to build a significant position in Alaska, leveraging its international project experience.
Shell	Developing offshore discoveries in Beaufort and Chuckchi (shot 3-D in both areas). $2.2 billion Chuckchi lease program.
PIONEER NATURAL RESOURCES	Entered ANS in 2002 through Armstrong at Oooguruk, 70% W.I. and operator, first field developed by an independent operator. Production began in June 2008, expected to peak at 20,000-25,000 gross bbl/d.

Source: Company filings, IR presentations, websites.

Strategies for a Variety of Companies (cont'd)

Company	Strategy
Brooks Range Petroleum	Completing and testing its North Tarn #1A well, an exploration well drilled last winter. It will likely drill two more wells this winter to delineate its Mustang prospect.
REPSOL	Talking to regulators and stakeholders about a 5-rig program this winter, drilling up to 15 wells. All the rigs will be on separate ice pads on state acreage – one north of the Colville River unit; two onshore between the Oooguruk and Colville units but drilling to offshore targets; one onshore farther south, adjacent to the Colville unit and drilling to onshore targets; and one southeast of the Kuparuk River unit.
Great Bear Petroleum LLC	1-rig program, drilling up to four initial vertical wells from which 4,000-foot horizontal production sidetracks will later be drilled along the source rock strata and hydraulically fractured to prove oil can be profitably produced from the Shublik and possibly the HRZ shale.
LINC ENERGY	Planning a 1-rig program this winter, drilling a minimum of 4 wells. Drilling its wells at the undeveloped Umiat oil field in the Brooks Range Foothills along the southeastern border of the National Petroleum Reserve-Alaska.
Ultrastar Exploration	Seeking capital to drill a well at its Dewline unit this winter. If Ultrastar does not find sufficient capital this winter, the project will need to wait another year.

Source: Company filings, IR presentations, websites.

Business Models

Major Hub

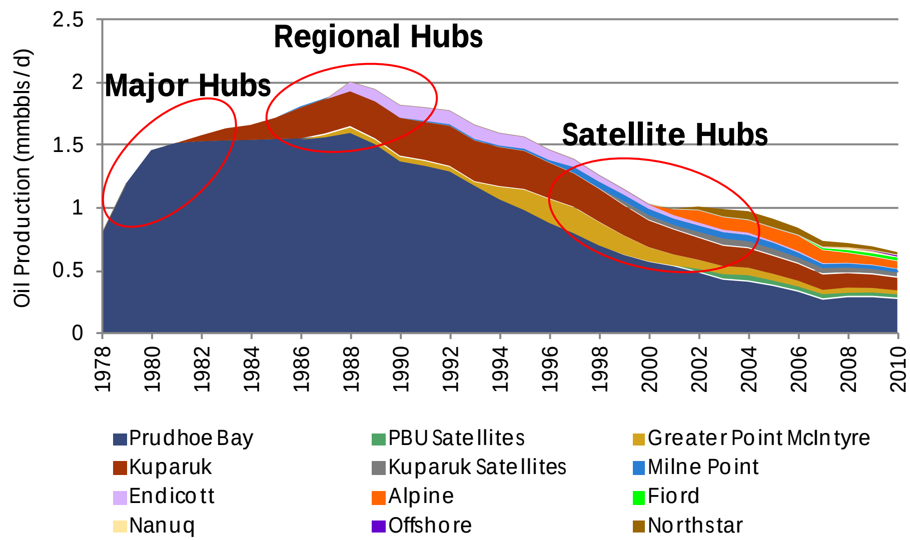
- Original major Hubs are Prudhoe Bay and Kuparuk
- Major infrastructure project
- Extension of common carrier pipe
- Typified by reserves of >0.5Bbbls and capital costs >$1B
- On decline, but must review capacity limitations
- Some operators still looking for these fields – exploring in the NPR-A, Foothills, and Beaufort Sea, far from existing infrastructure

Satellite Hub

- Satellite ties into gathering and processing units of a major or moderate sized hub
- Minimal pad based infrastructure
- Generally limited by 25-30 miles from existing pipe
- Theoretically a win-win situation – owner offsets O&M cost and can provide lighter oil blend
- Typified by reserves of 50-500 mmbbls and capital costs >$300MM
- Both Major and Independent Operators still looking for these size fields – ConocoPhillips, Anadarko & Pioneer
- BP tied in Sag Delta North, Eider, Aurora, Borealis, and Midnight Sun to Prudhoe Bay
- ConocoPhillips tied in Tarn, Palm, and Meltwater to Kuparuk, discoveries in the NPR-A, Moose's Tooth, Lookout, Rendezvous and Spark tie into Alpine
- BP Liberty to Badami, not Endicott

Regional Hub

- Examples include Alpine, Endicott, Milne Point, Point Thompson
- Fixed facilities – barged in
- Ties in to common carrier pipe
- Conventional Technology



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North Slope Growth Areas

- Central North Slope – continued tie-in of multi-pay satellite developments, implementation of staged fracs and new resources will ensure Alaska remains a critical source of America's energy for years to come
- Lisburne Formation – lies beneath Prudhoe Bay, but reservoir quality variable, few horizontal well results are encouraging (only significant carbonate formation in slope)
- Schrader Bluff – technology significantly improved commerciality – BP and COP relying on growing Schrader Bluff production
- Offshore Beaufort Sea – drilling ban in place but expected to be lifted relatively soon
- Chukchi Seas – needs major hub development to establish play – development decade or more away. Major's see this as the next big growth area
- NPR-A – significant potential (4Bbbls), but requires new EIS's and extension of pipeline and road infrastructure – requires investment from the Majors

In order of importance the growth areas are expected to be (1) satellite extension in the CNS, (2) Western CNS Jurassic/Cretaceous reservoirs, (3) NPR-A, (4) viscous and heavy oil, (5) offshore Chukchi and Beaufort, (6) unconventional, (7) gas resources and (8) ANWR

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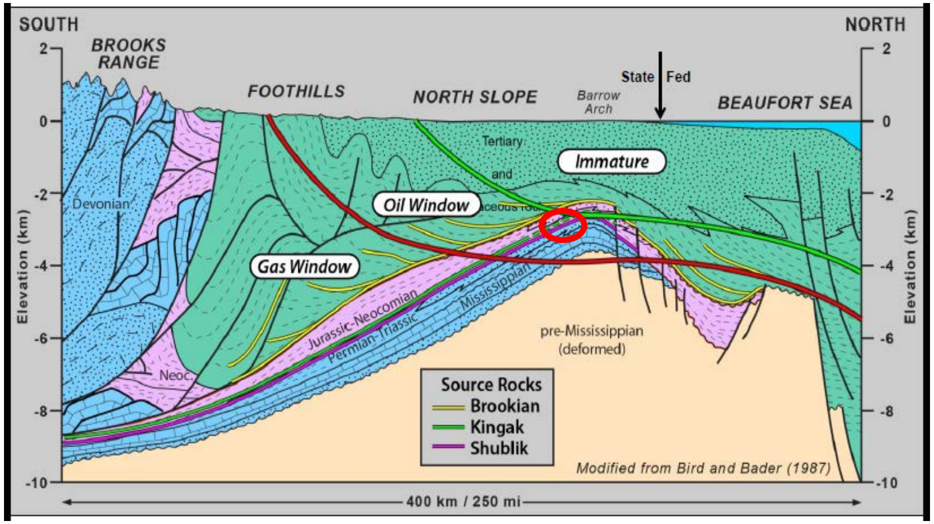
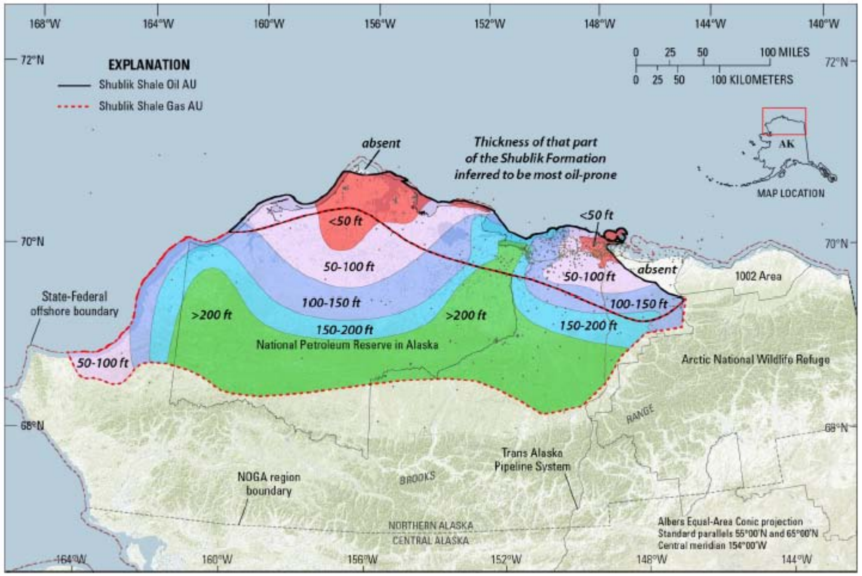
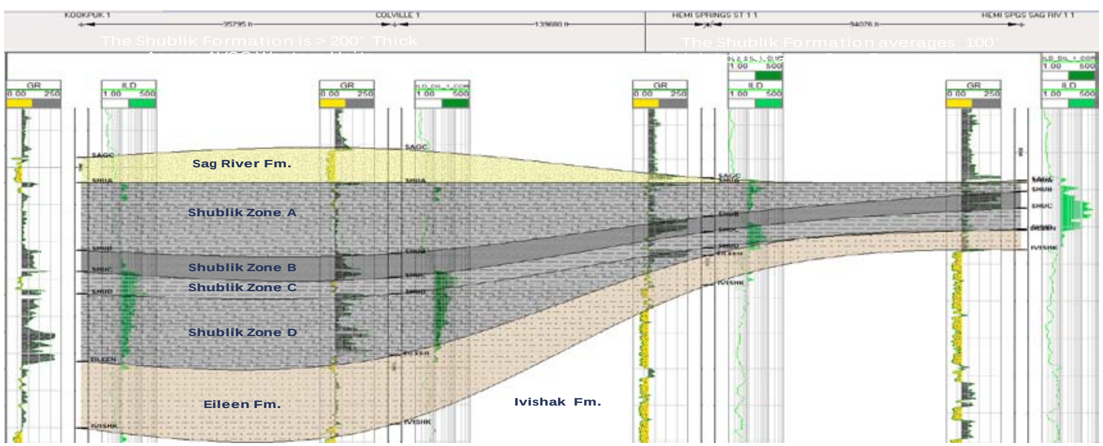
Shale Oil Provides Substantial Upside Potential







Shublik depth range 7,500 – 10,000

Shublik depth range 10,000 – 12,000

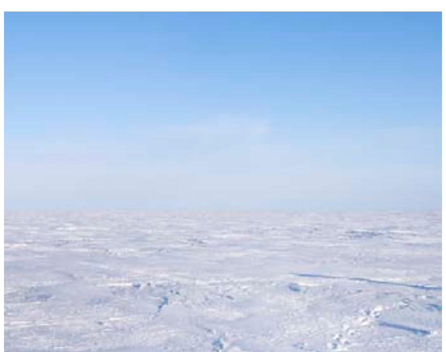
- USGS estimate the probability that essential petroleum system elements occur in at least part of the assessment unit (AU)
  - Shublik Oil and Gas AU's: 95% (best set of essential elements)
  - Brookian Oil and Gas AU's: 90% (risk – do source & reservoir rocks occur together?)
- **Shale Oil –** *USGS mean estimates of undiscovered oil*
  - **Bakken: 3,645 MMBO**
  - **North Slope: 940 MMBO**
  - **Eagle Ford: 853 MMBO**
  - **Woodford (Anadarko): 393 MMBO**
  - **Niobrara (Powder River B.): 227 MMBO**

Source: Bird and Bader (1987), Houseknecht et al. (2012b).

IV – Typical Field Considerations

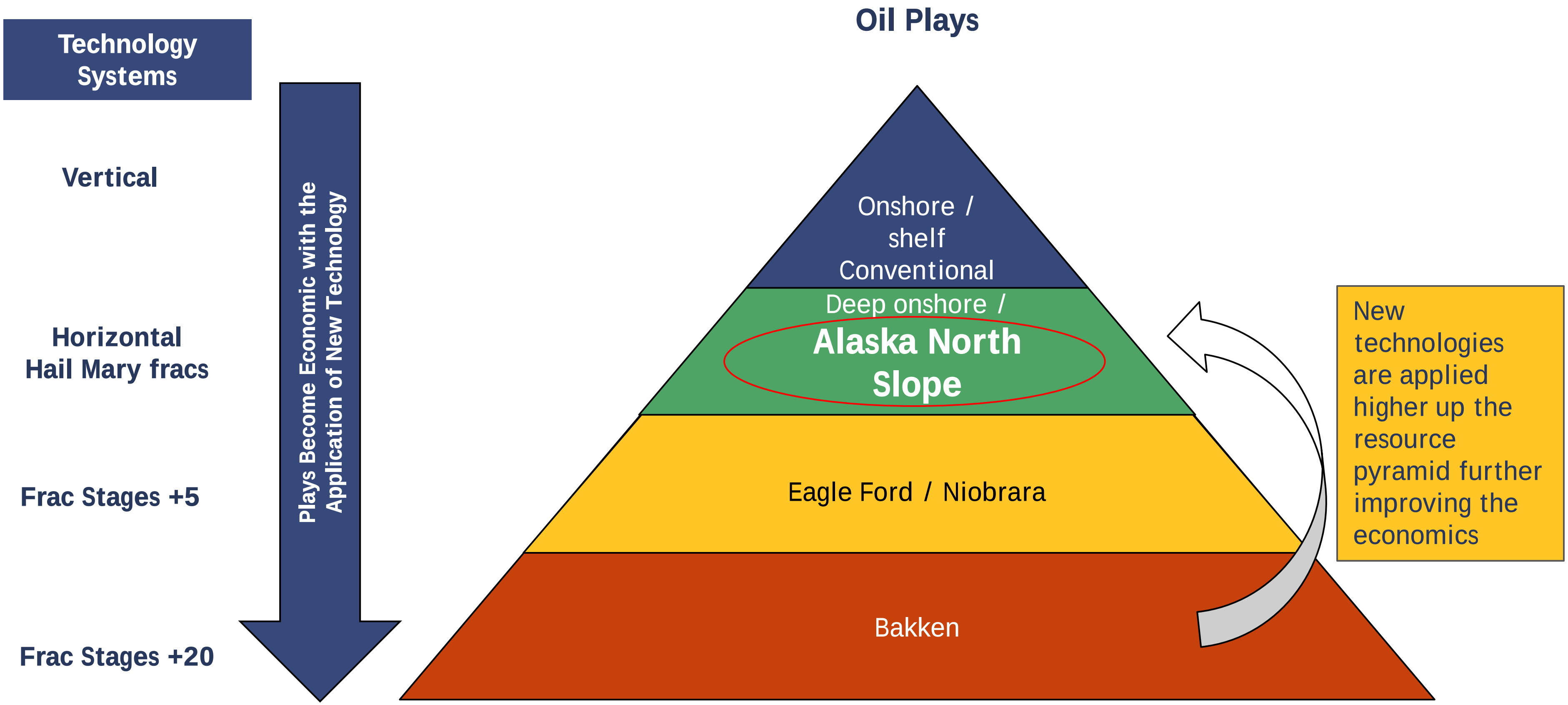
The Grass Roots Business Process

1. **Well Control - establish reservoirs, well logs are in public domain, identical bypassed zones**
2. **Seismic - Significant coverage, 2D from public providers (25,000 miles of 2D), 3D from the Majors - mostly proprietary**
3. **Leasing - Bid bonus in annual State sales**
4. **Unitization - Pool interests and royalties when prospect has been defined (negotiated with state, 3 well commitment)**
5. **Drilling activity begins**
6. **Plan of Exploration and Development - Contract with the State to optimize efficient operation**
7. **Participation Area - Prior to production - define limits and rules to production zone**
8. **Production start-up**



Well Completions – Impacts the Bottom Line

Proven tight oil/shale play technology employed in the lower 48 can be used to improve the economics of North Slope reservoirs



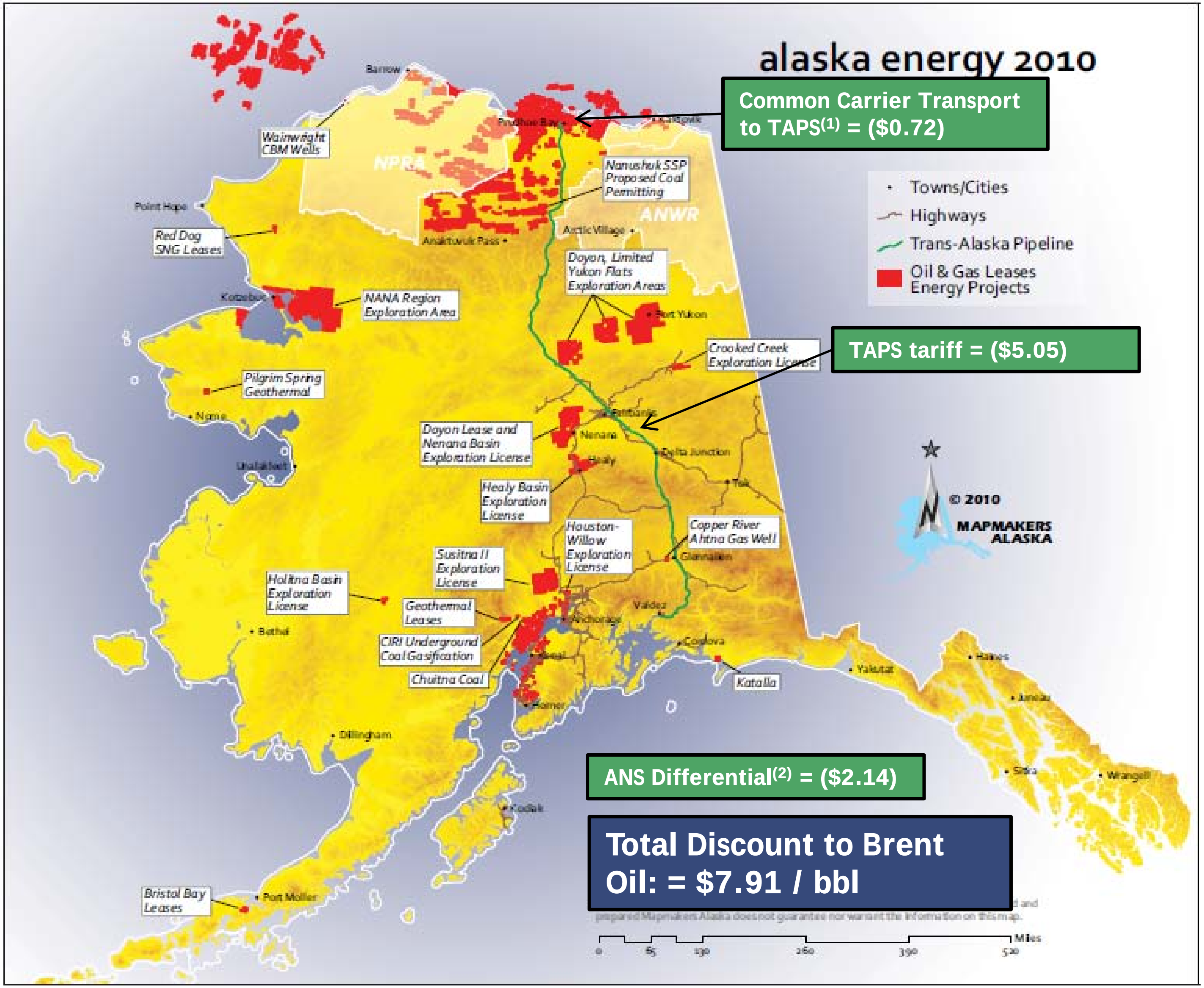
Field Development Process

Fiord Field – satellite to Alpine operated by ConocoPhillips

What's happening in Arctic developments

- Ice roads provide early access, however new developments such as sky crane helicopters, Rolligons from barges and insulated pads for rig storage are recent innovations
- Initial exploration during 90 days (Jan-Mar) on ice pads – site then cleared before ice melts
- Several gravel islands have been built in the Beaufort sea
- Offshore pipelines are trenched to prevent ice gouging and can be buried in up to 200 ft water
- Fiord and other new fields are being developed with horizontal technology
- Fiord and Ooguruk are two fields that were developed in less than 2 years from corporate approval
- Fiord enhances recovery with WAG flood, production is processed at COP's Alpine facility – gas is generally re-injected on the Slope
- Fiord has a permanent gravel airstrip, Ooguruk is accessed via a boat or ice road
- Onshore Pipelines are generally built on VSM although local people have voiced issues relating to snowmobile passage

Alaska Price Netbacks



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(1) Alpine common carrier transportation rate.
(2) 1-year average differential to Brent Crude Oil.

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Comparisons with Resource Plays

Characteristics	North Slope	Resource Play
OOIP	Resource certainty in conventional plays	Resource certainty from legacy wells
Geological Character	Top set deltaic sands are laterally contiguous and geologically predictable	Basin center shales are lithologically and stratigraphically consistent across wide areas
Sizeable aerial extent	Top set marine sands can be elongated over 100 miles	Foreland organic rich basins can be 3-30 million acres
Multi-zone targets	Multiple stacked transgressive sand bodies provide numerous reservoirs	Generally only one source rock play with conventional mostly exploited overlying sands
Sweet spot definition	Depositional setting plays the major role in determining the higher quality areas – imaged successfully with seismic, largely defined by existing well control in most cases	Multiple factors determine tiers - dependent on depth, isopach, reservoir quality, pressure, natural fracturing and thermal maturity
Reservoir producibility	Reservoirs are of moderate to high quality and capable of substantial flow rates of light to heavy oil **(without stimulation)**	Natural fracturing and nanodarcy matrix permeability defines short lived IP's with hyperbolic flow profile, limited to light oil/condensates **(stimulation required)**
Recovery efficiency	High recoveries achieved by pattern drilling with waterflood or WAG	Modest recoveries but can be improved with increasing reservoir stimulated volume – ultimately requires large number of wells
Drill Plan	Logistical and environmental conditions necessitate pad based operations	Legacy leasehold configurations impacts the drill plan – generally a combination of pad and single well drilling
Operations environment	No urban or historical factors and 30 years of petroleum operations provide an effective operational platform	Services and midstream infrastructure may lag new play development but rapidly becomes sufficient

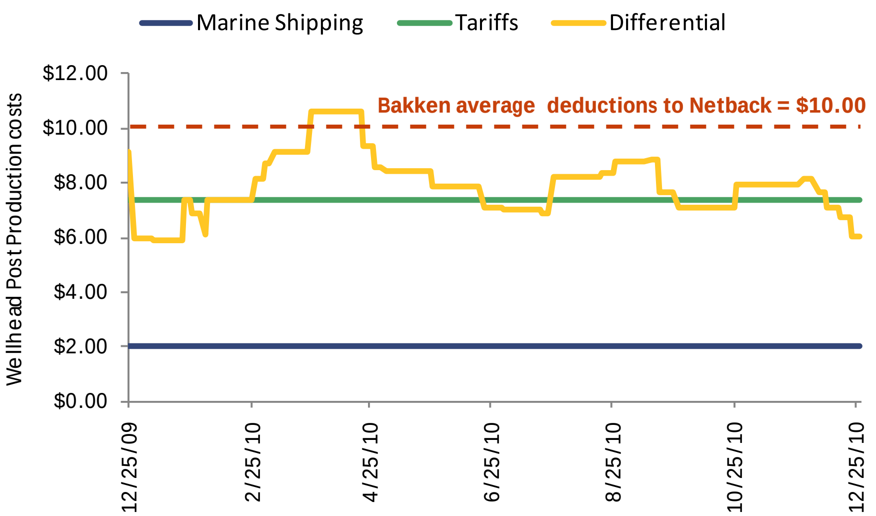
Resource Plays Commercial Comparison

Economic Comparison at $80/bbl & $5/Mcf flat

	ANS Base Case	Niobrara DJ Basin	Eagle Ford Condensate	Eagle Ford Oil	Bakken Tier 1
D&C CapEx ($MM)	$32.5	$3.5	$7.8	$5.0	$7.0
LOE ($/boe)	$15.00	$7.24	$5.61	$4.99	$4.77
Capital / Net Acre	$13.0	$29.2	$64.6	$41.7	$32.8
NPV10 ($MM)	$97.4	$3.9	$10.2	$3.5	$8.0
IRR	140% [1]	64%	85%	41%	53%
F & D ($/boe)	$5.07	$15.57	$9.47	$20.87	$13.19

1 Burdened with allocated midstream capex

Aggregate Post Production Costs



ANS Economics Relative to Resource Plays

- ANS not capital intensive - capital / net acre very low
- ANS high rate of return (140%)
- ANS F & D costs are significantly lower

Post Production Costs Summary

- Marine shipping and tariffs average $2.05 and $5.32, respectively
- Alaska differential fluctuates from a $2 premium to WTI to a $3 discount to WTI
- Aggregate wellhead post production costs are generally less than the Bakken

Note: ANS base case is modeled on Fiord satellite field to Alpine operated by ConocoPhillips

Producer/Injector Well Economics – Fiord Nechelik

Summary Details

Total Resource

Gross EUR (MMbbl)	7.9
5-Yr Cum (MMbbl)	5.0
30-day IP (bbl/d)	3,270
Peak Production (bbl/d)	3,700
Life (years)	24

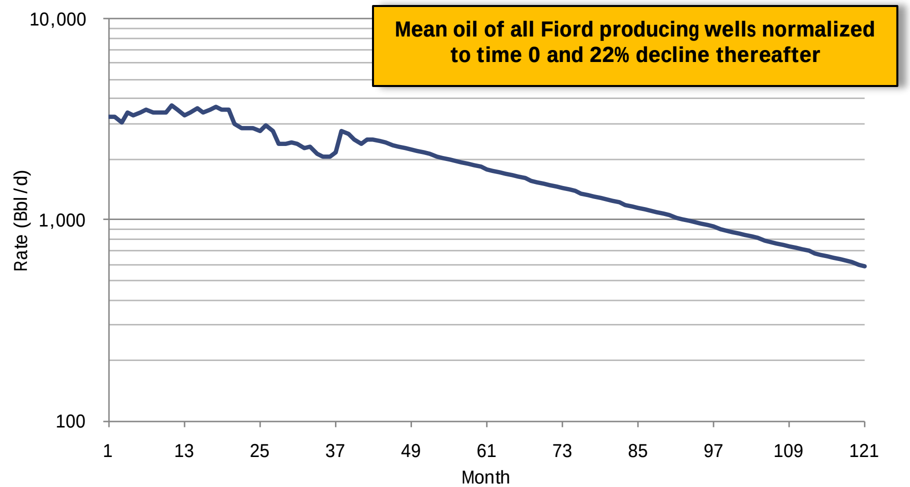
Economics

D&C CapEx ($MM)	
Without allocated midstream	$32.5
With allocated midstream	$40.0
LOE ($/boe)	$15.00
Oil Diff ($/bbl)	
ANS discount	$0.54
Marine shipping	$2.05
Tariff (excl. Producer's Pipeline)	$5.32

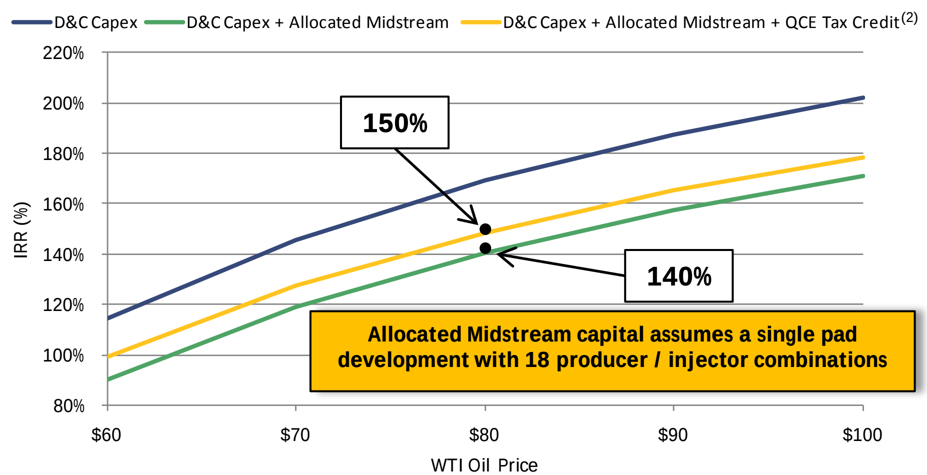
Results with Allocated Midstream Capex (no QCE Tax Credit)

NPV10 ($MM)(1)	$97
IRR(1)	140%
F & D ($/boe)	$5.07

Type Curve



Economics



Note: Includes production taxes, but excludes property taxes, state and federal income taxes, and tax credits.

(1) Economics run at $80/bbl flat WTI.

(2) Qualified Capital Expenditures (QCE) - 20% QCE production tax credit for upstream capital expenditures (i.e. exploratory wells and new seismic). 50% of credit can be taken in year 1 (year of tax credit certificate award) and the other 50% of credit can be taken in year 2. These credits do not expire and can be held, sold to third parties or sold back to the state.

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V – Conclusion

Alaska Business Drivers – State of Play

Business Driver	Comments
Resource Available	Multiple reservoirs waiting to be developed
Field Extensions	On-going
Exploration Potential	Excellent
Taxation	Significant fiscal incentives for new development
Land Access	Good
Maintaining Inventory	Abundant opportunities
Permitting Process	Streamlined
Repeatability of operations	Operational efficiency per “shale development” is the new norm
Cost of operations	New innovations helping to control costs
Environmental issues	Workable within Central ANS
Project cycle time	Short relative to International and GOM Deepwater
Pipeline Access	Common Carrier, State improving ROW permitting process
Facilities	Tax credits mitigate capex risk
Contractor community	Long track record on the ANS – Nabors relationship
Gas influence	When gas line built – growth will be compounded
State involvement	Very supportive of new entrants and new field development

In Summary

Looking to the next decade operational and technological innovation in the Arctic to sustain oil production is likely to be a pivotal skill set - in many ways similar to the current global trend to building shale expertise.

When we look at the business drivers for Alaska North Slope, this area offers the most attractive and competitive prospects for adding reserves and production.

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About The Firm

Tudor, Pickering, Holt & Co., LLC is an integrated energy investment and merchant bank, providing high quality advice and services to institutional and corporate clients. Through the company's broker-dealer, Tudor, Pickering, Holt & Co. Securities, Inc., the company offers securities and investment banking services to the energy community.

The firm, headquartered in Houston, Texas, has approximately 90 employees and offices in Denver, Colorado; and in New York, New York. Its affiliate, Tudor, Pickering Holt & Co. International, LLP, is located in London, England.

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Disclosure Statement