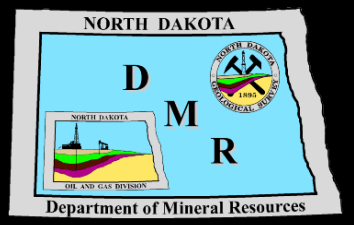
OIL & GAS ACTIVITY UPDATE

CHAMBER OF COMMERCE

Bismarck, ND – August 1, 2012

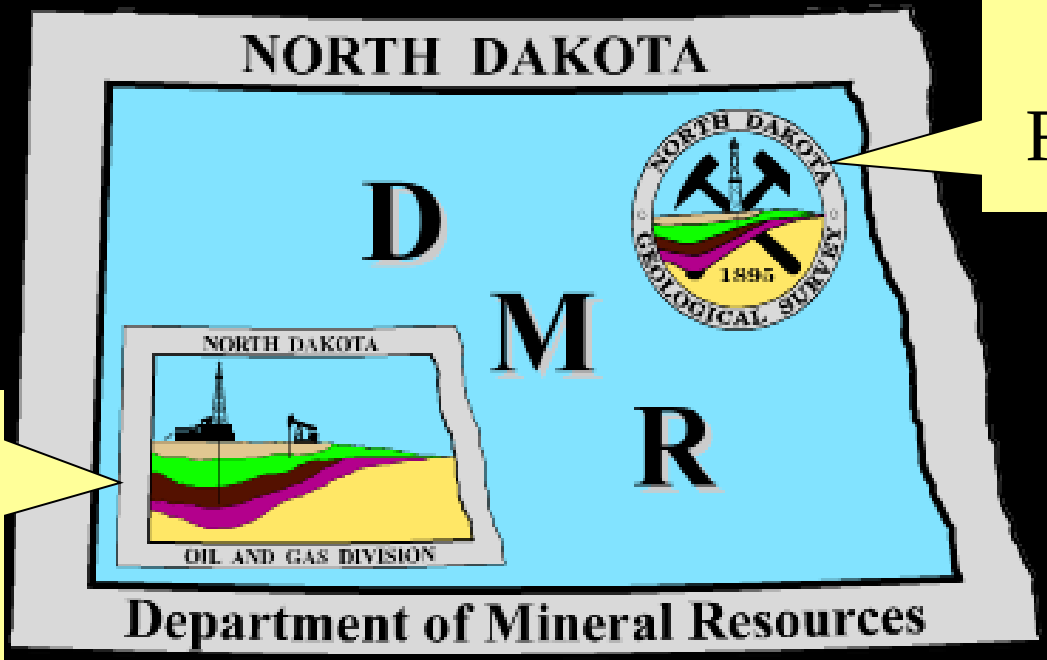


OIL & GAS UPDATE

- North Dakota Update
- Hydraulic Fracing
- Rigs
- Wells
- Associated Gas

Bruce E. Hicks
Assistant Director
NDIC-DMR-OGD
Bismarck, ND

North Dakota Department of Mineral Resources

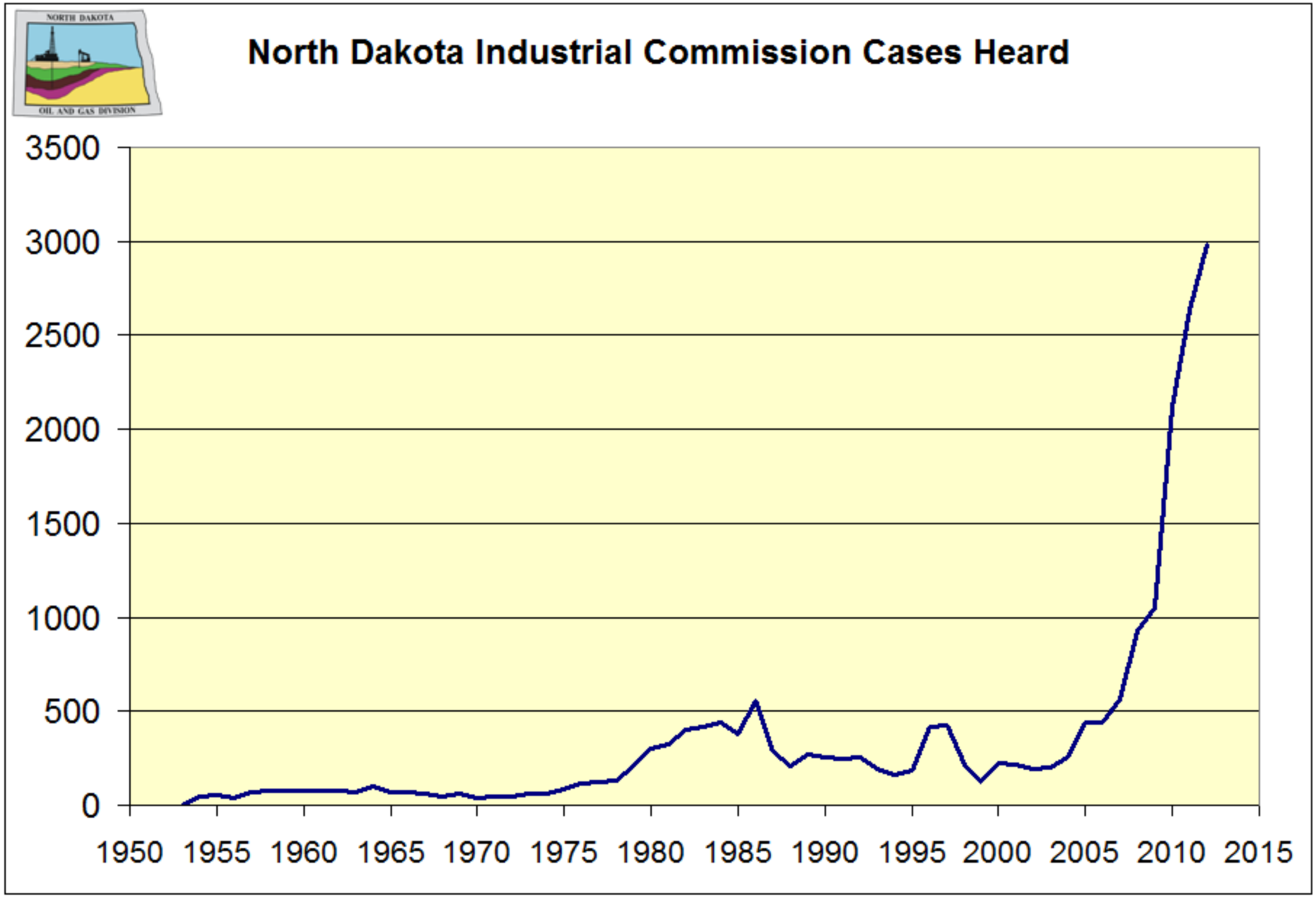


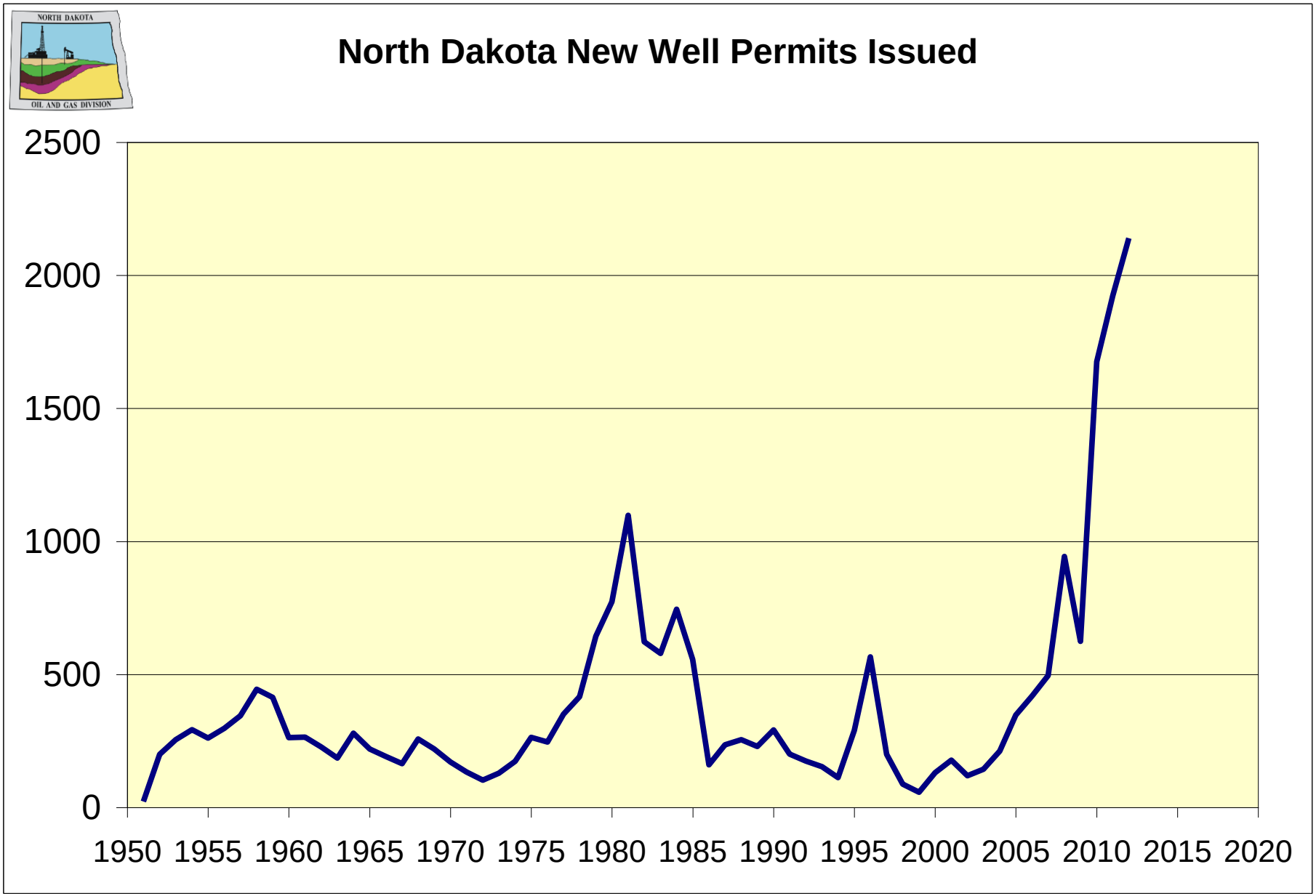
NDGS
Research Arm

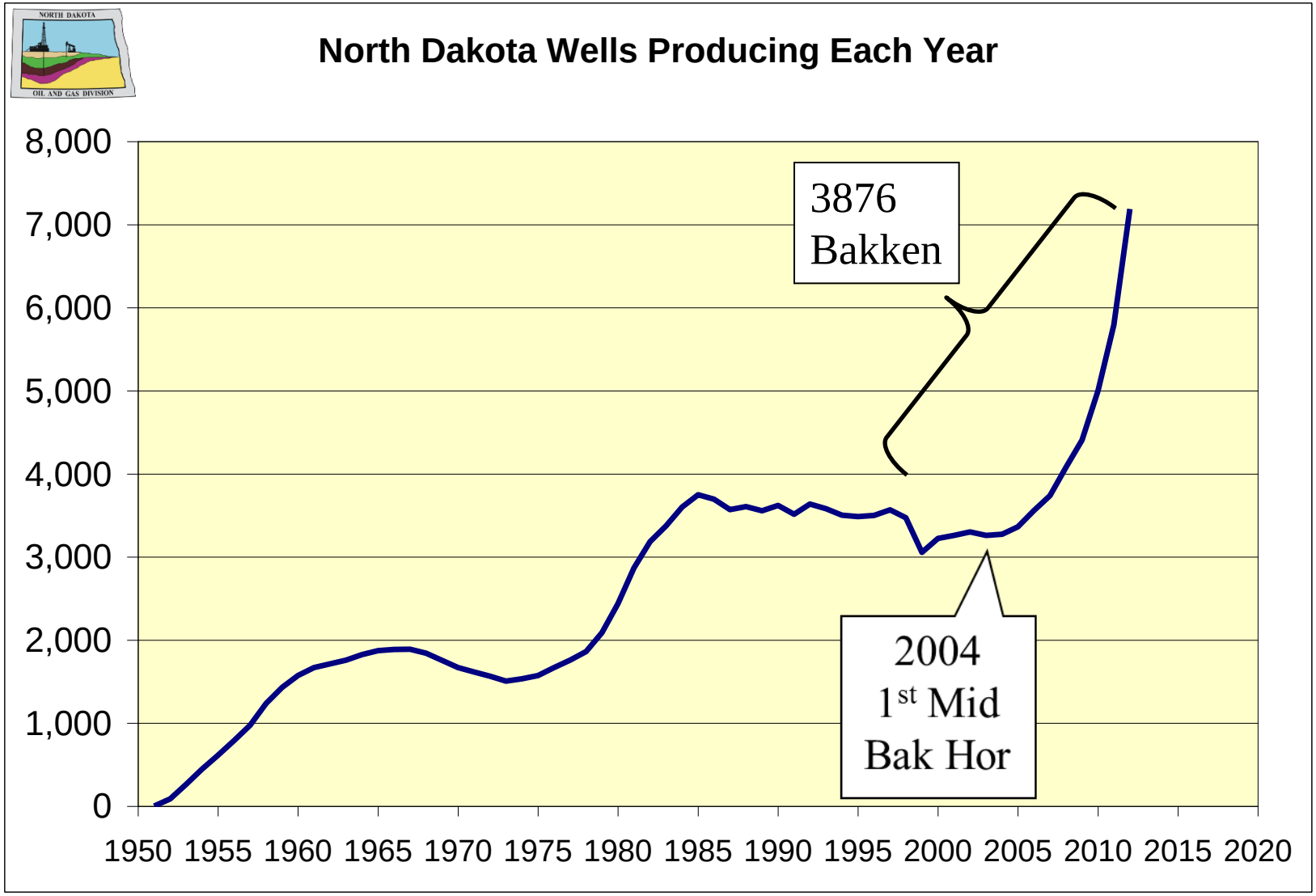
OGD
Regulatory
Arm

https://www.dmr.nd.gov/oilgas/ *https://www.dmr.nd.gov/ndgs/*

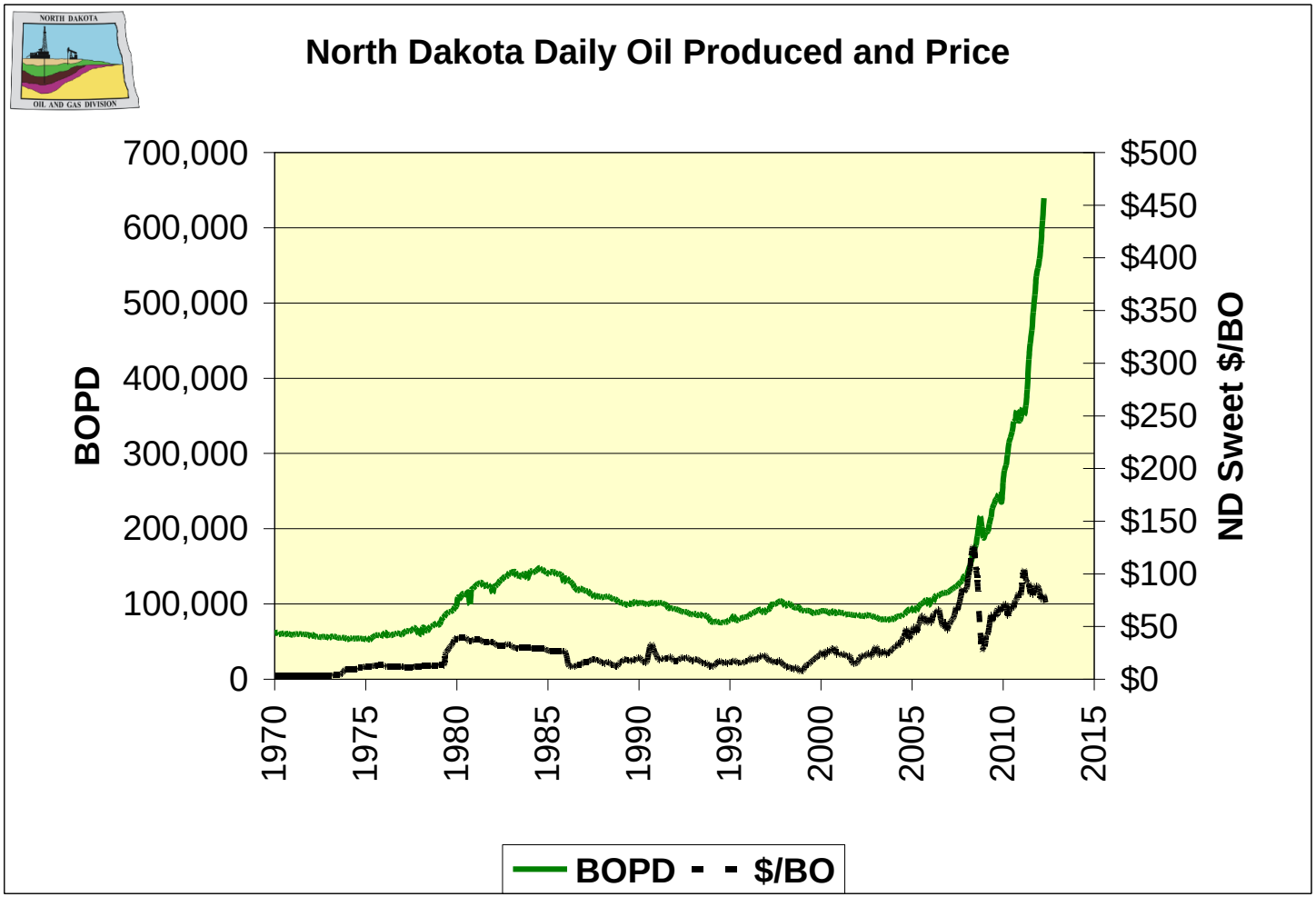
600 East Boulevard Ave. - Dept 405
Bismarck, ND 58505-0840
(701) 328-8020 *(701) 328-8000*


NORTH DAKOTA
OIL AND GAS DIVISION
North Dakota Industrial Commission Cases Heard
3500
3000
2500
2000
1500
1000
500
0
1950
1955
1960
1965
1970
1975
1980
1985
1990
1995
2000
2005
2010
2015

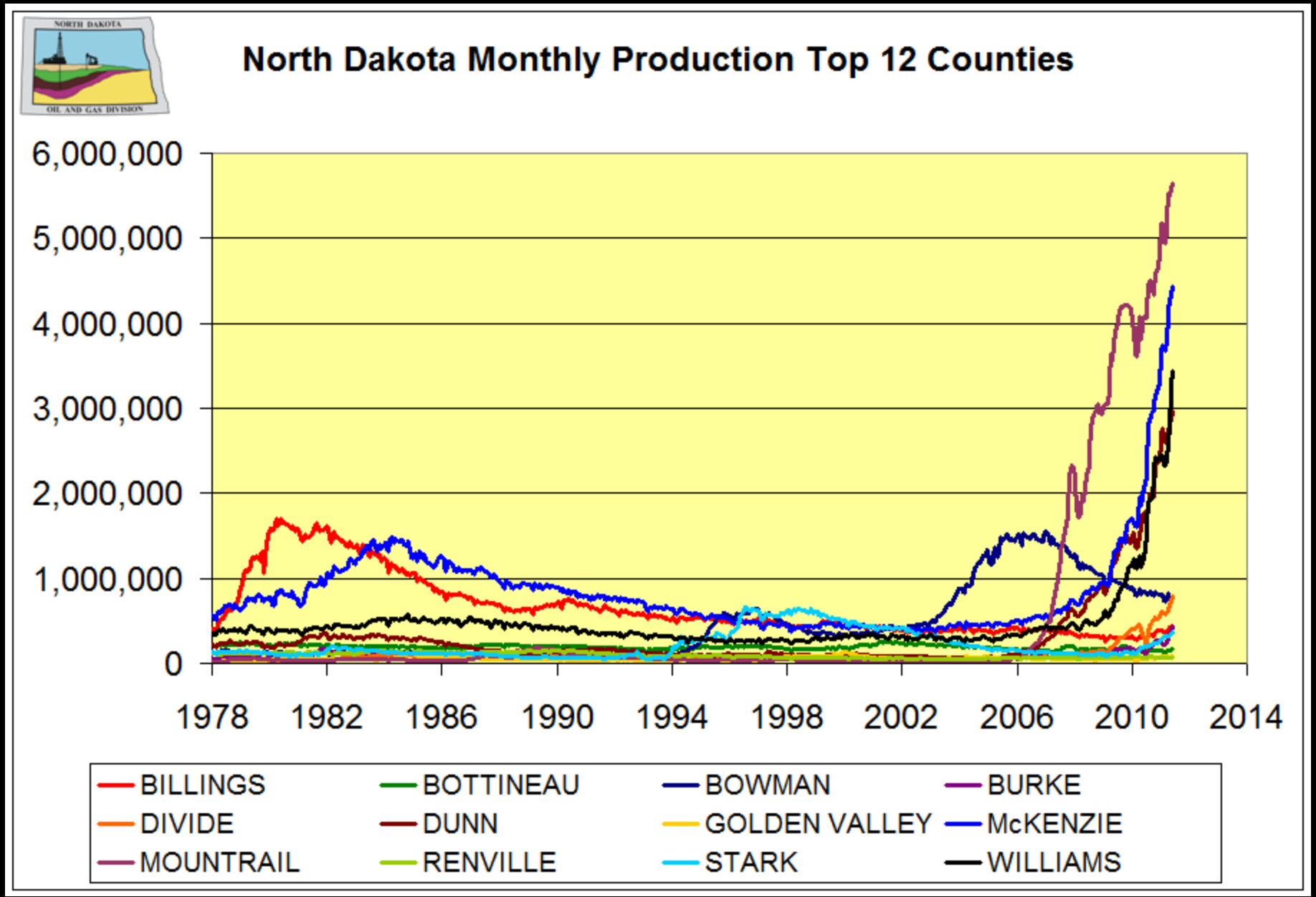

NORTH DAKOTA
OIL AND GAS DIVISION
North Dakota New Well Permits Issued
2500
2000
1500
1000
500
0
1950 1955 1960 1965 1970 1975 1980 1985 1990 1995 2000 2005 2010 2015 2020



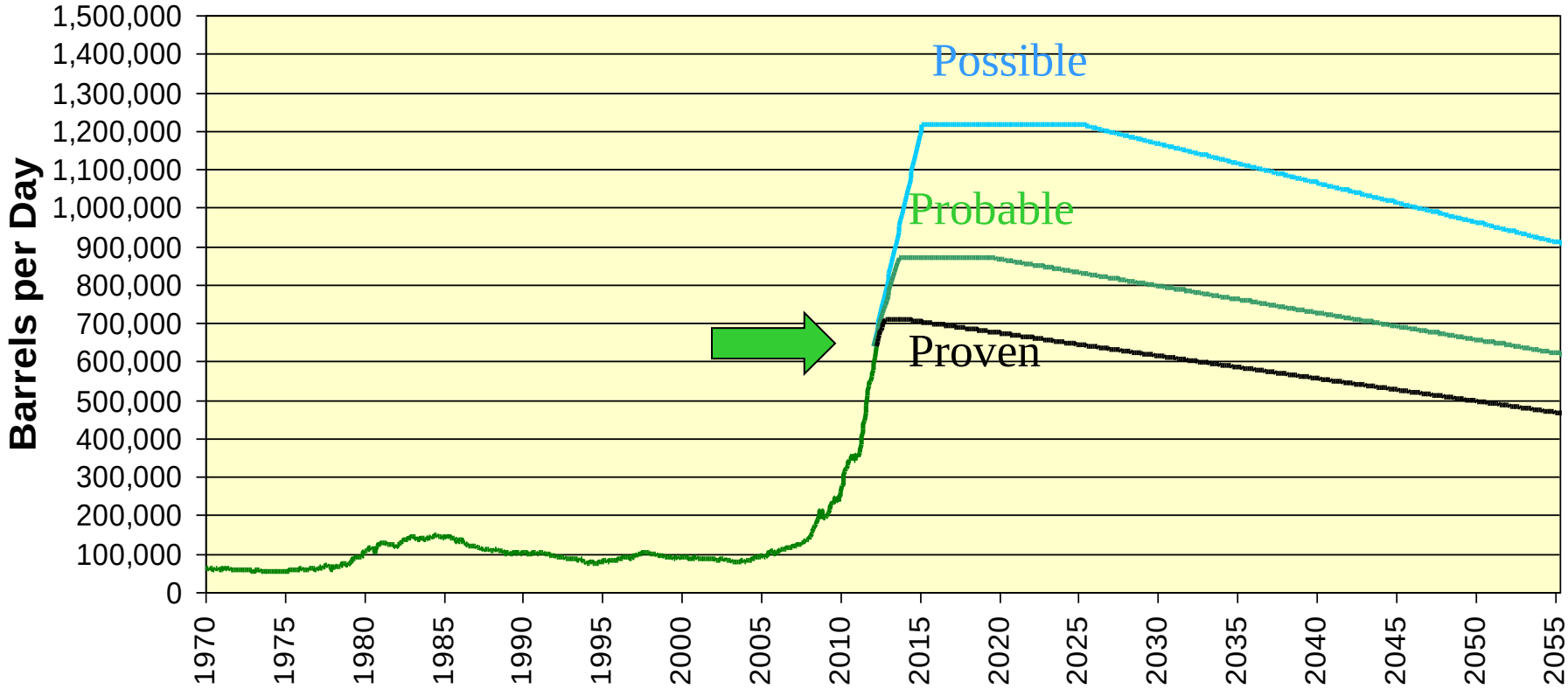
7188 total wells – 3876 Bakken horizontal (53.9%)



Production 639,277 bopd (appr 572,151 from Bakken—89.5%)


North Dakota Monthly Production Top 12 Counties
NORTH DAKOTA
OIL AND GAS DIVISION
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
1978
1982
1986
1990
1994
1998
2002
2006
2010
2014
BILLINGS
BOTTINEAU
BOWMAN
BURKE
DIVIDE
DUNN
GOLDEN VALLEY
McKENZIE
MOUNTRAIL
RENVILLE
STARK
WILLIAMS

North Dakota Oil Production

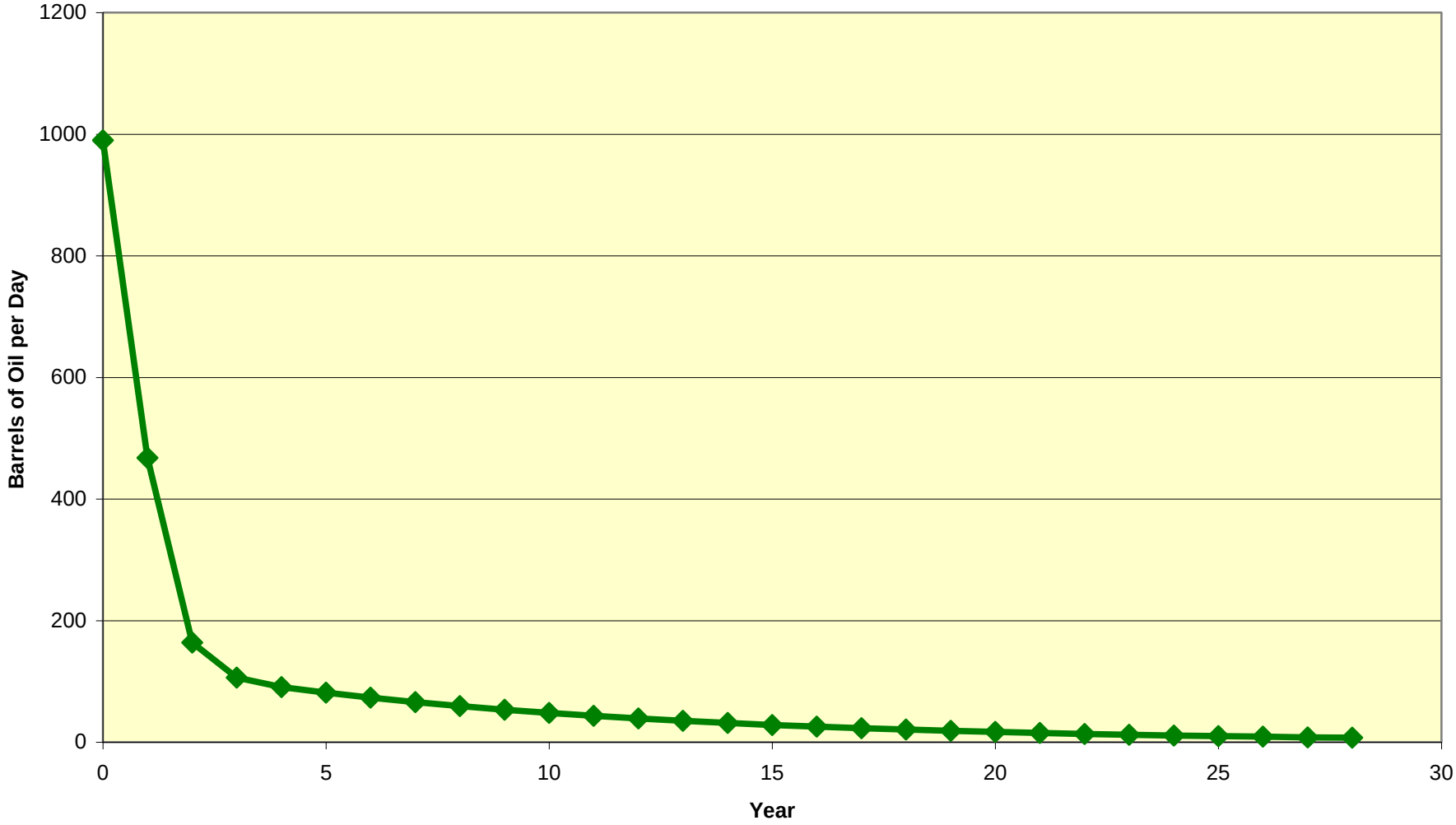


3,876 **Bakken and Three Forks wells drilled and completed**

36,000 **more new wells possible in thermal mature area**

Proven=7 BBO – Probable=10 BBO – Possible=14 BBO (billion barrels of oil)

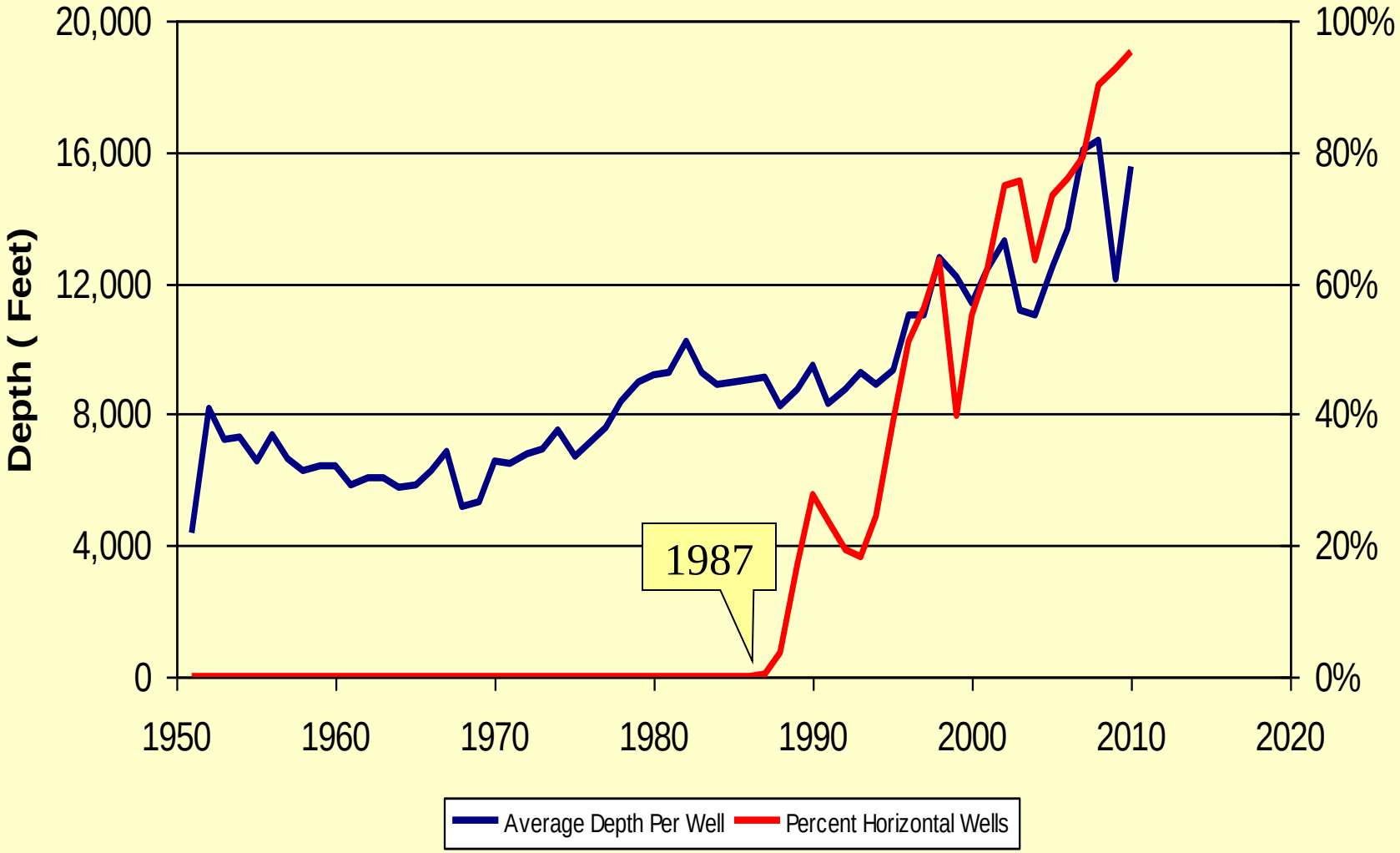
Typical Bakken Well Production

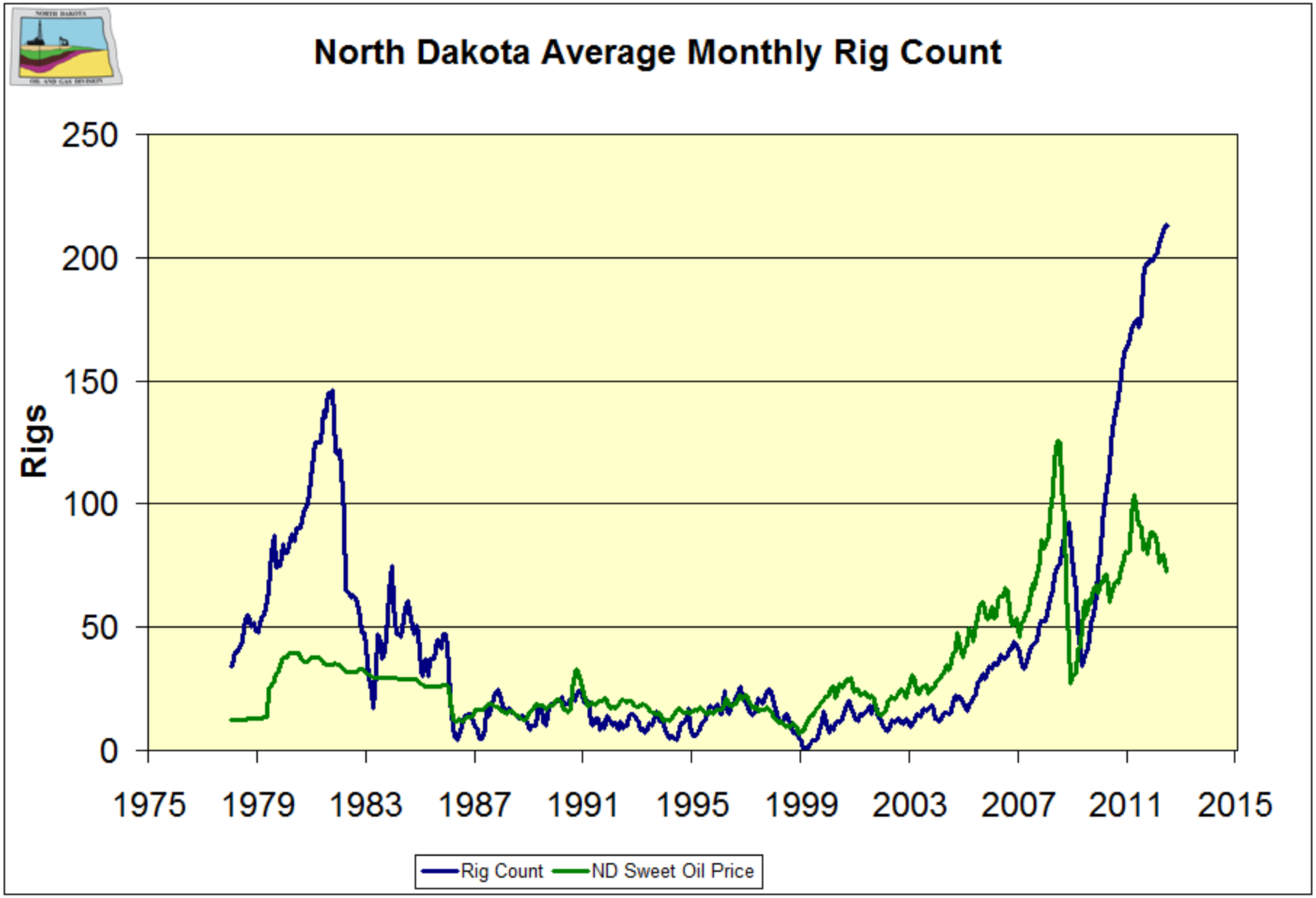


Typical 2012 Bakken well

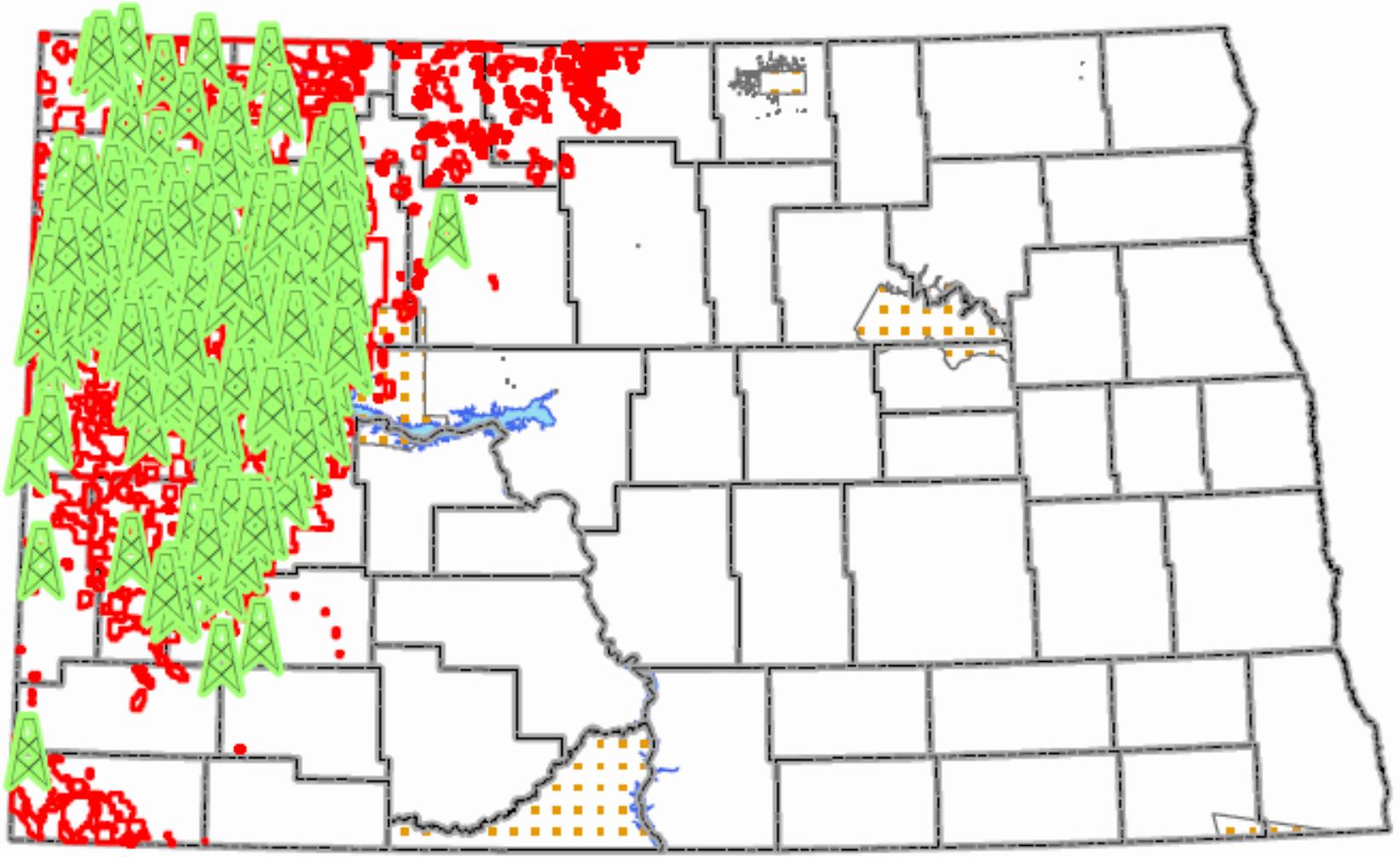
- **45-year well life**
- **615,000 barrels of oil**
- **$9 million to drill and complete**
- **$20 million net profit**
- **$4 million in taxes**
- **$7 million in royalties**
- **$2 million in wages**
- **$2 million in operating expenses**

North Dakota Well Depth and % Horizontal




North Dakota Average Monthly Rig Count
Rigs
250
200
150
100
50
0
1975
1979
1983
1987
1991
1995
1999
2003
2007
2011
2015
Rig Count
ND Sweet Oil Price

NORTH DAKOTA – 208 DRILLING RIGS – Aug 2012



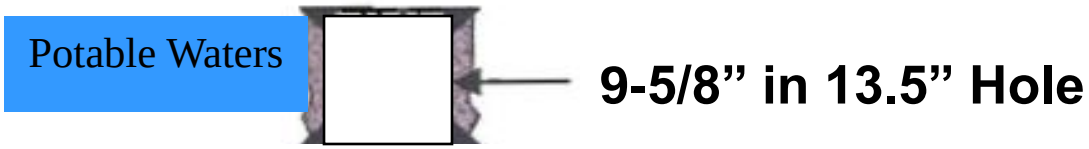
Current drilling activity is focused

in Mountrail, Dunn, McKenzie, and Williams Counties.

RIGS

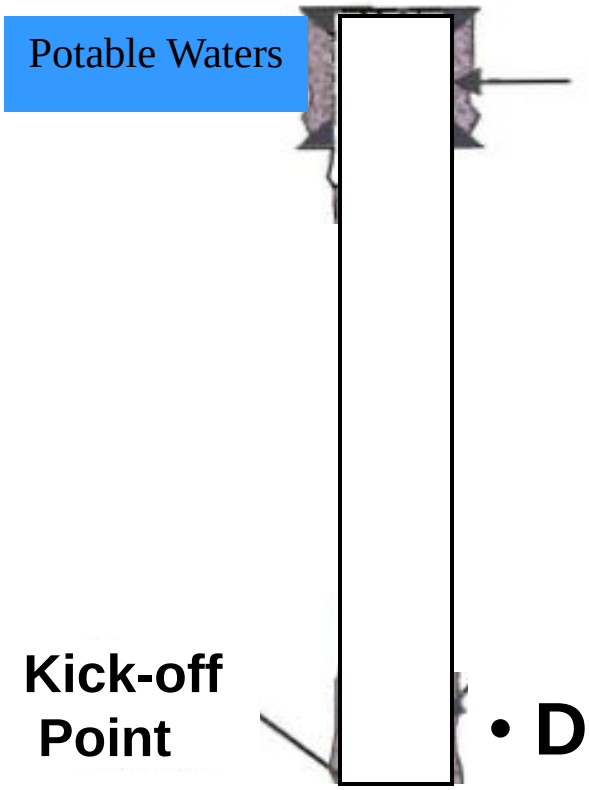
- 208 rigs currently
- 225 rigs - 2 years to secure leases
- 225 rigs – another 16 years f/5H/SU
- Declining rig count?
  - walking rigs replace inefficiencies
  - drilling more wells w/less rigs

TYPICAL HORIZONTAL OIL WELL



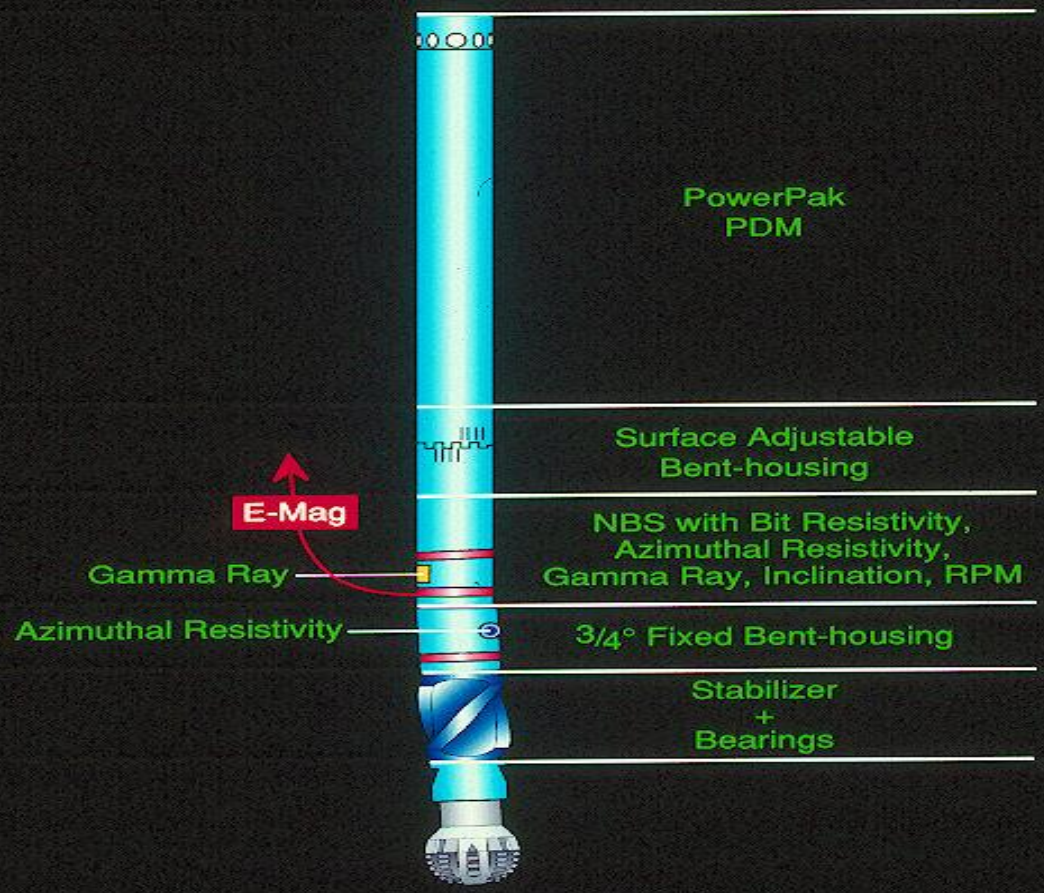
- Drill with fresh water
- Total depth below lowest potable water
- Run in hole with surface casing
  - 1st layer of surface water protection
- Cement casing back to surface of ground
  - 2nd layer of surface water protection

TYPICAL HORIZONTAL OIL WELL

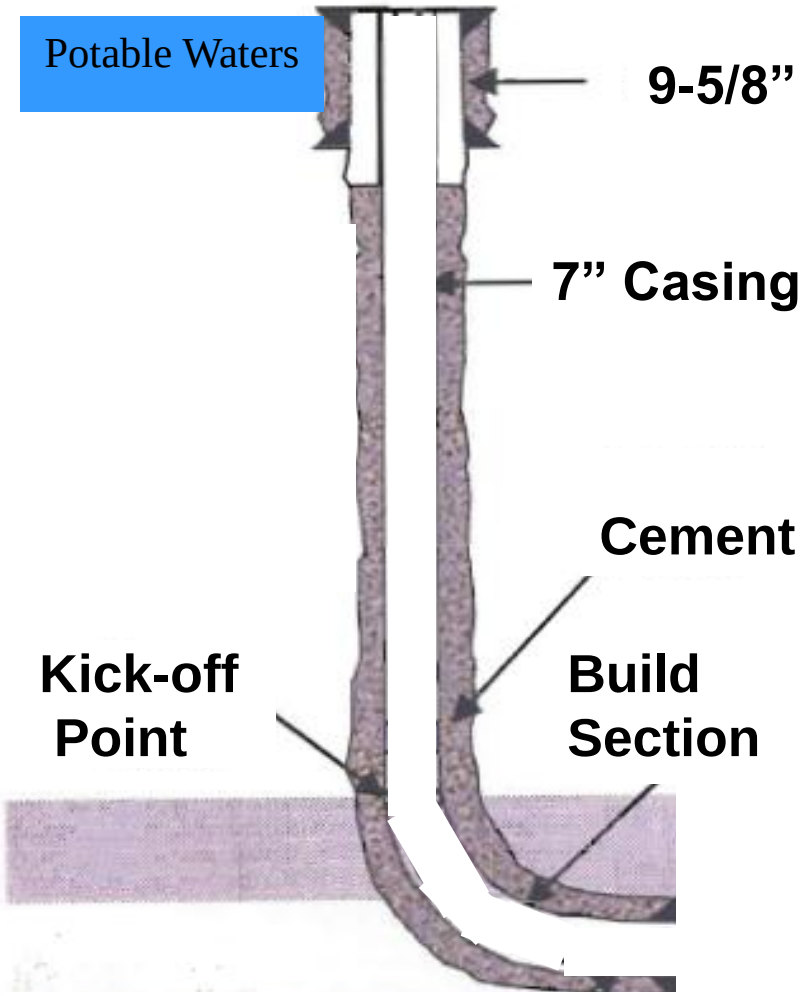


- Drill vertically to kick-off point
- Run in hole with bent assembly
- Downhole mud motor

GeoSteering Tool

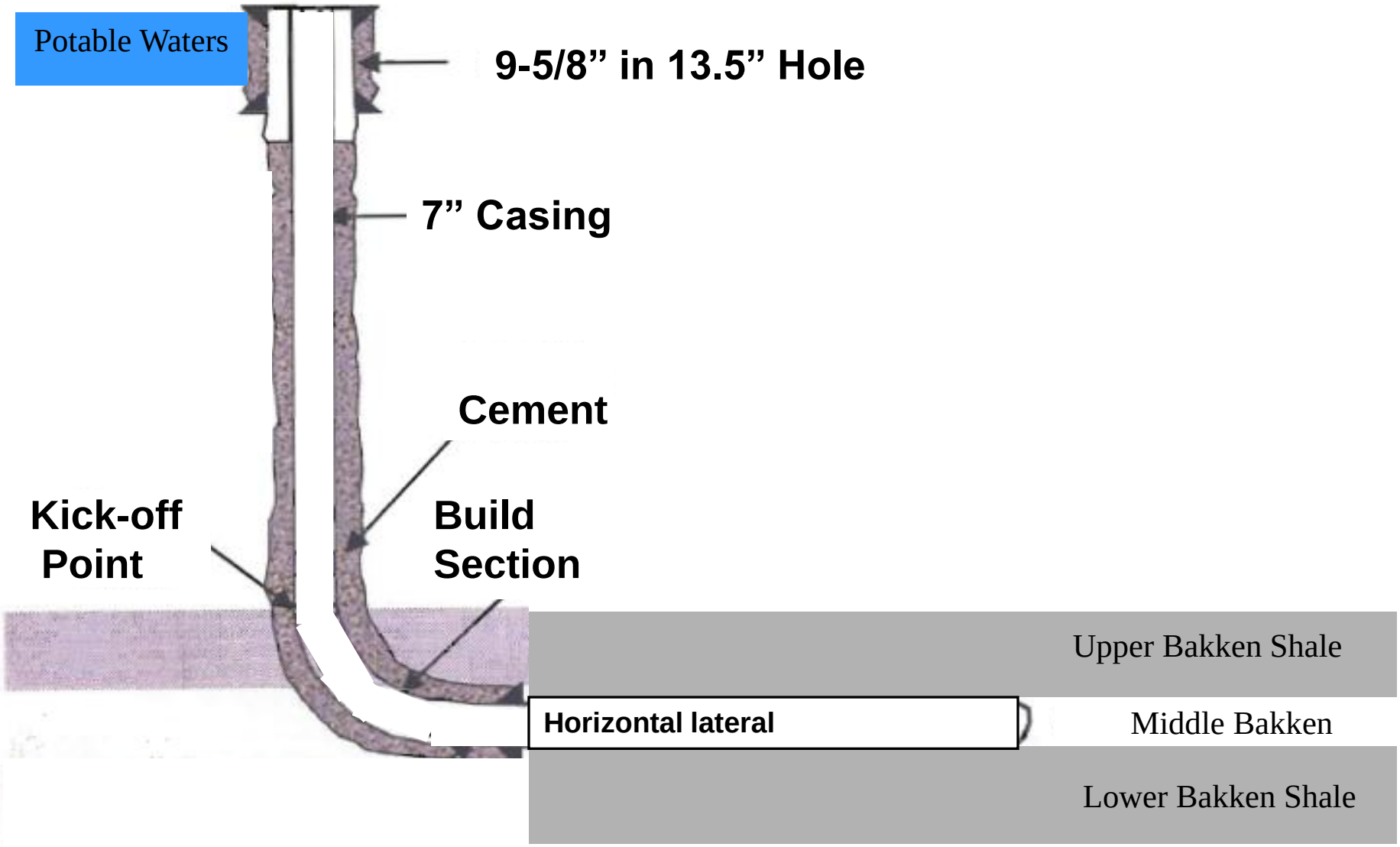


TYPICAL HORIZONTAL OIL WELL

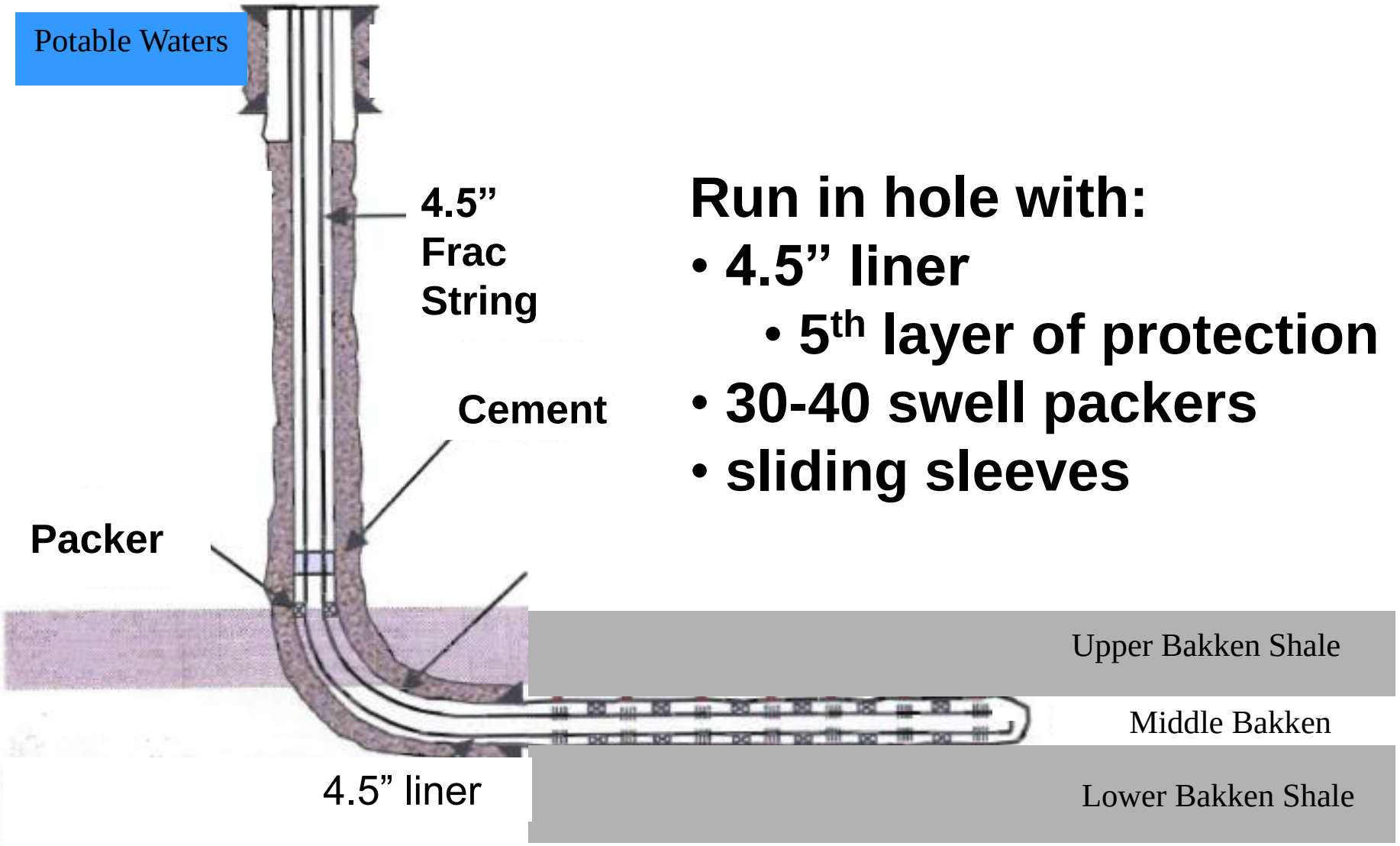


- Drill 8-3/4” hole to pay
- Run in hole with 7” casing
  - 3rd layer of protection
- Cement 7” casing
  - 4th layer of protection

TYPICAL HORIZONTAL OIL WELL



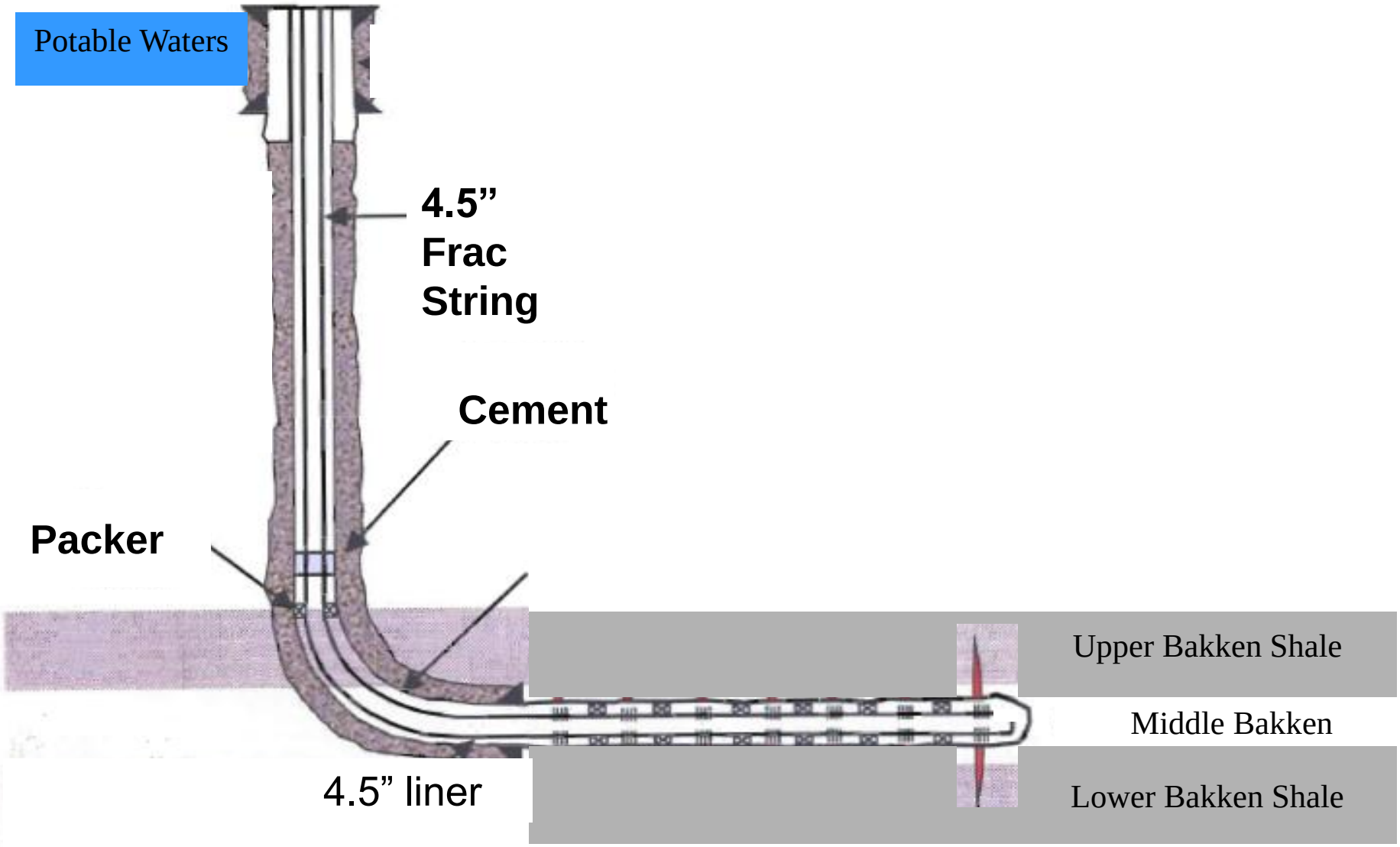
TYPICAL HORIZONTAL OIL WELL



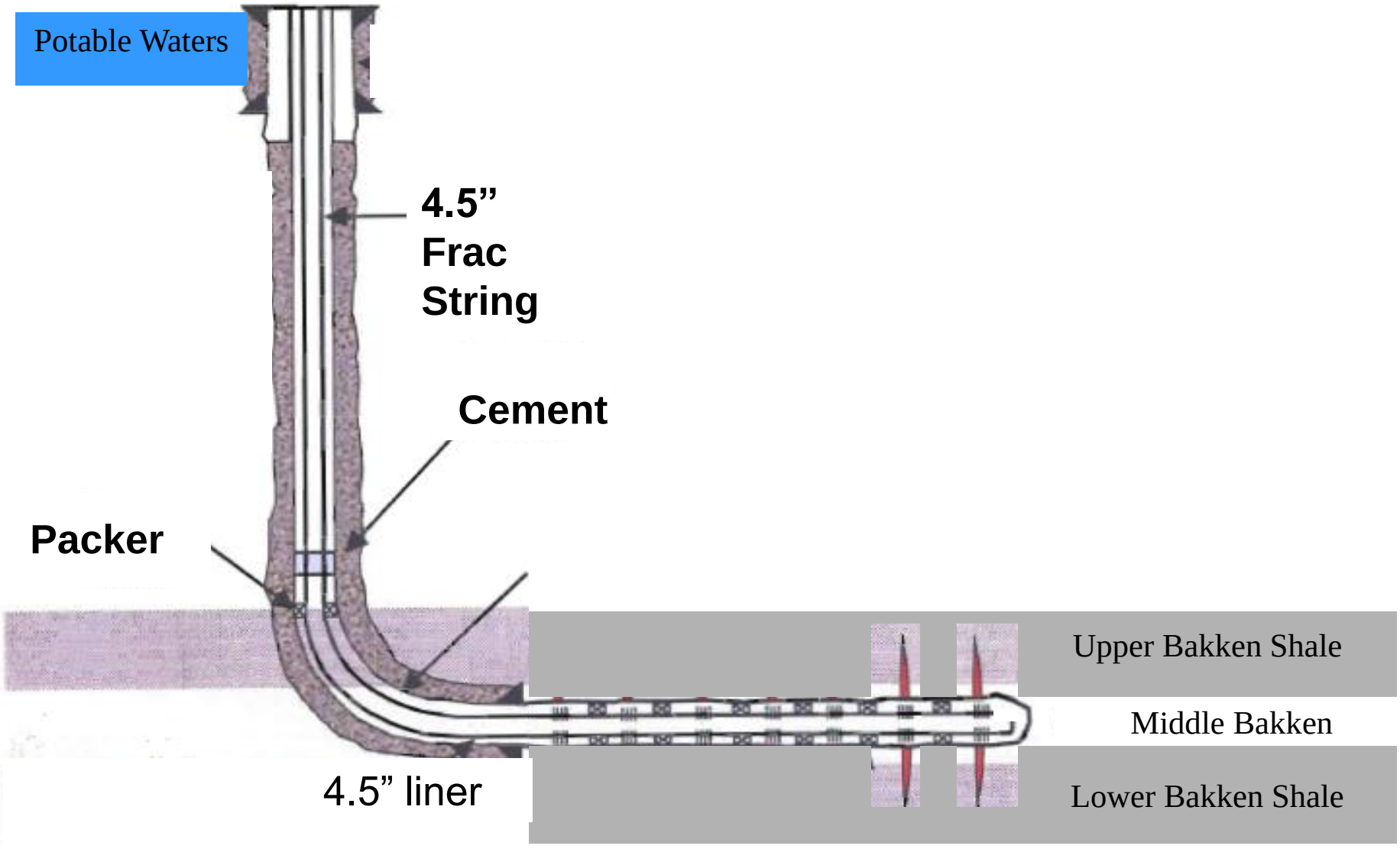
Run in hole with:

- **4.5” liner**
  - **5th layer of protection**
- **30-40 swell packers**
- **sliding sleeves**

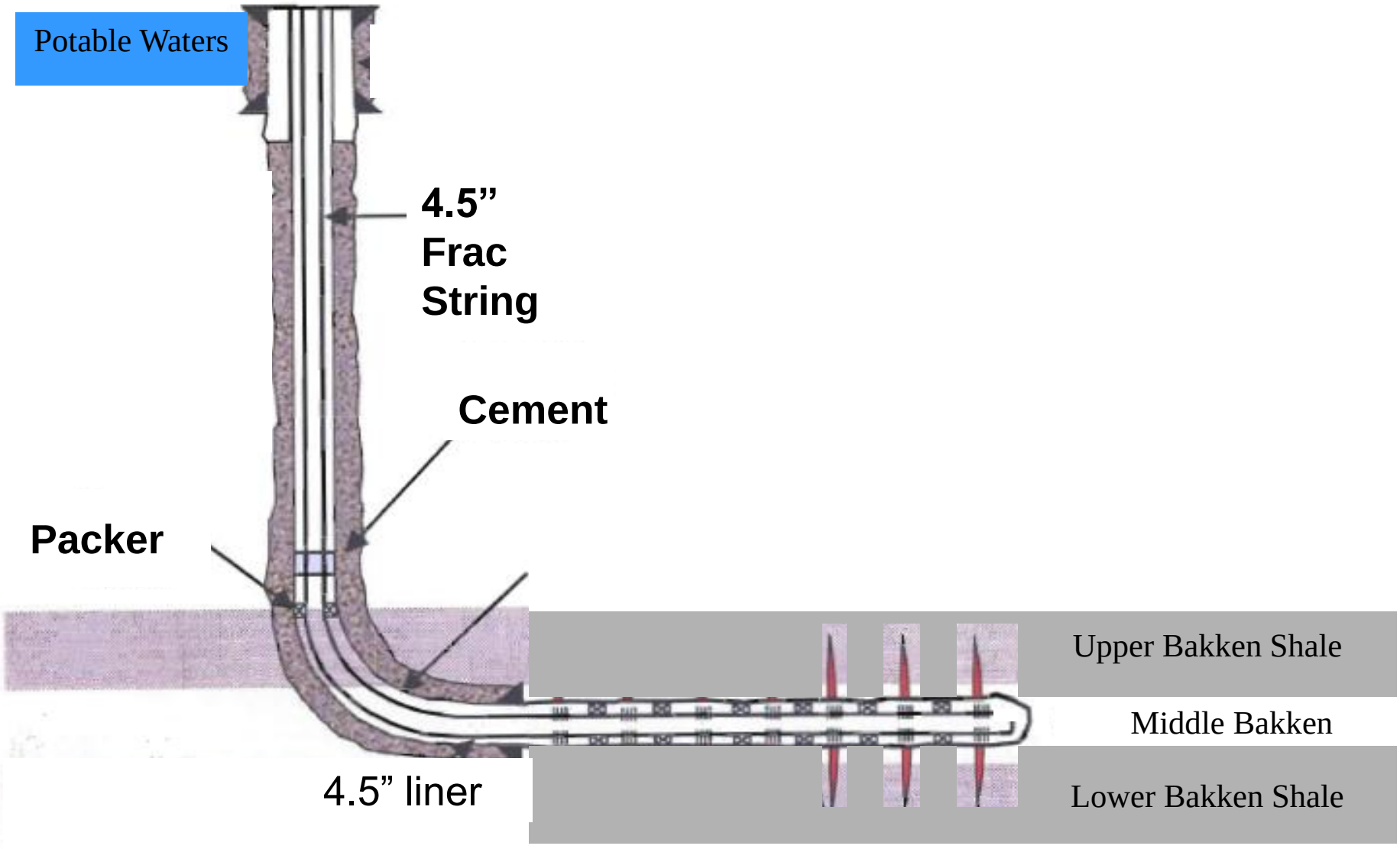
TYPICAL HORIZONTAL OIL WELL



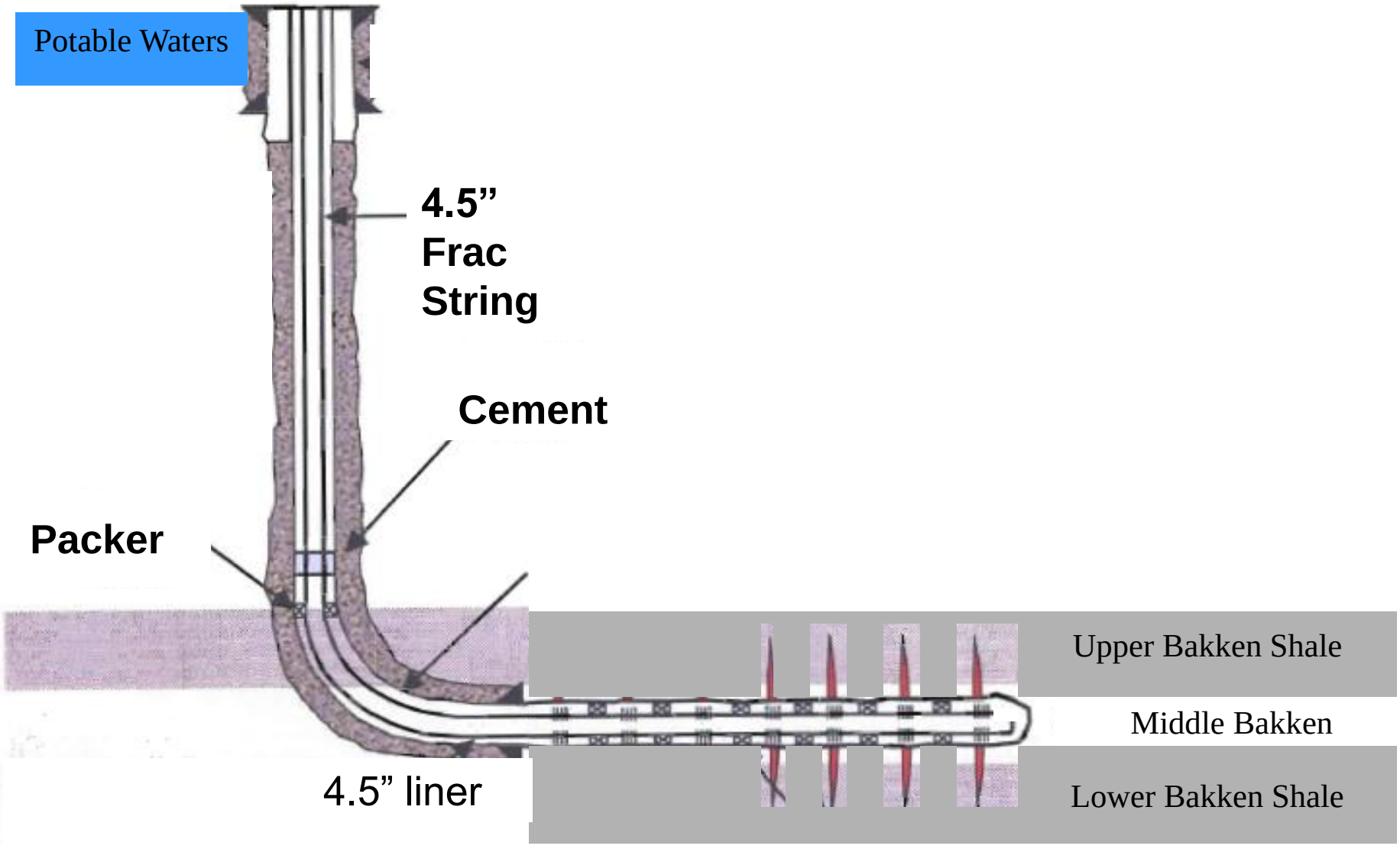
TYPICAL HORIZONTAL OIL WELL



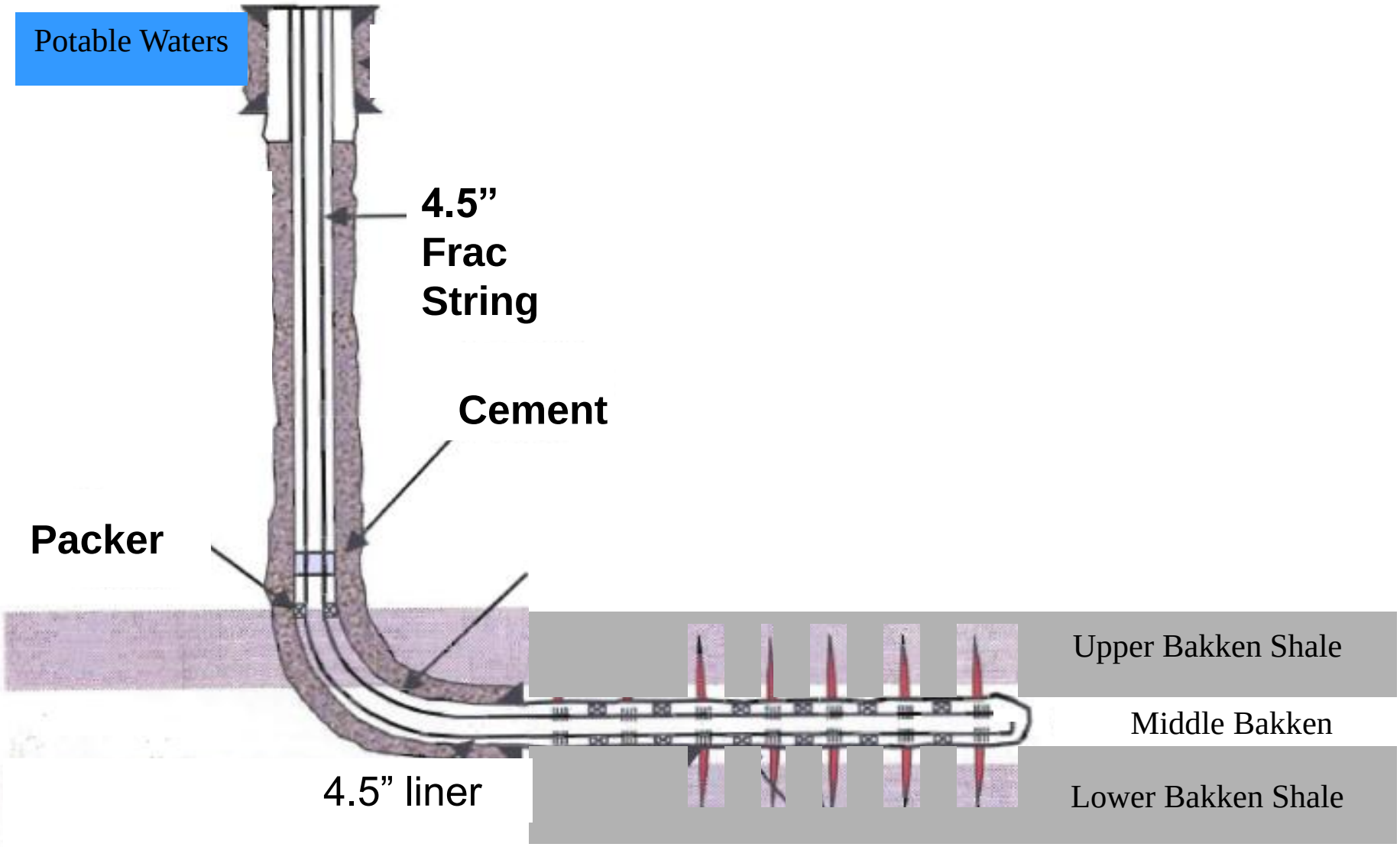
TYPICAL HORIZONTAL OIL WELL



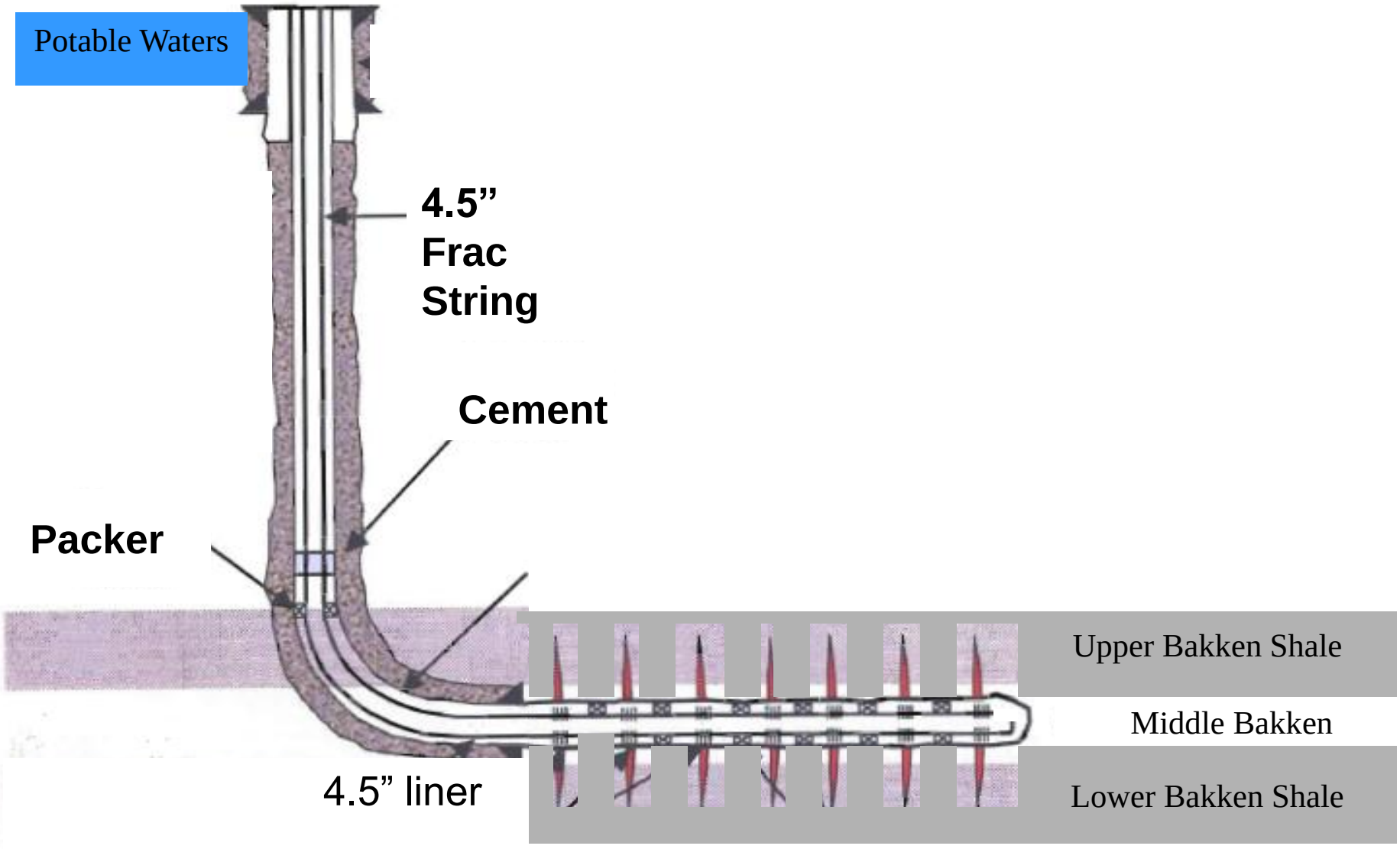
TYPICAL HORIZONTAL OIL WELL

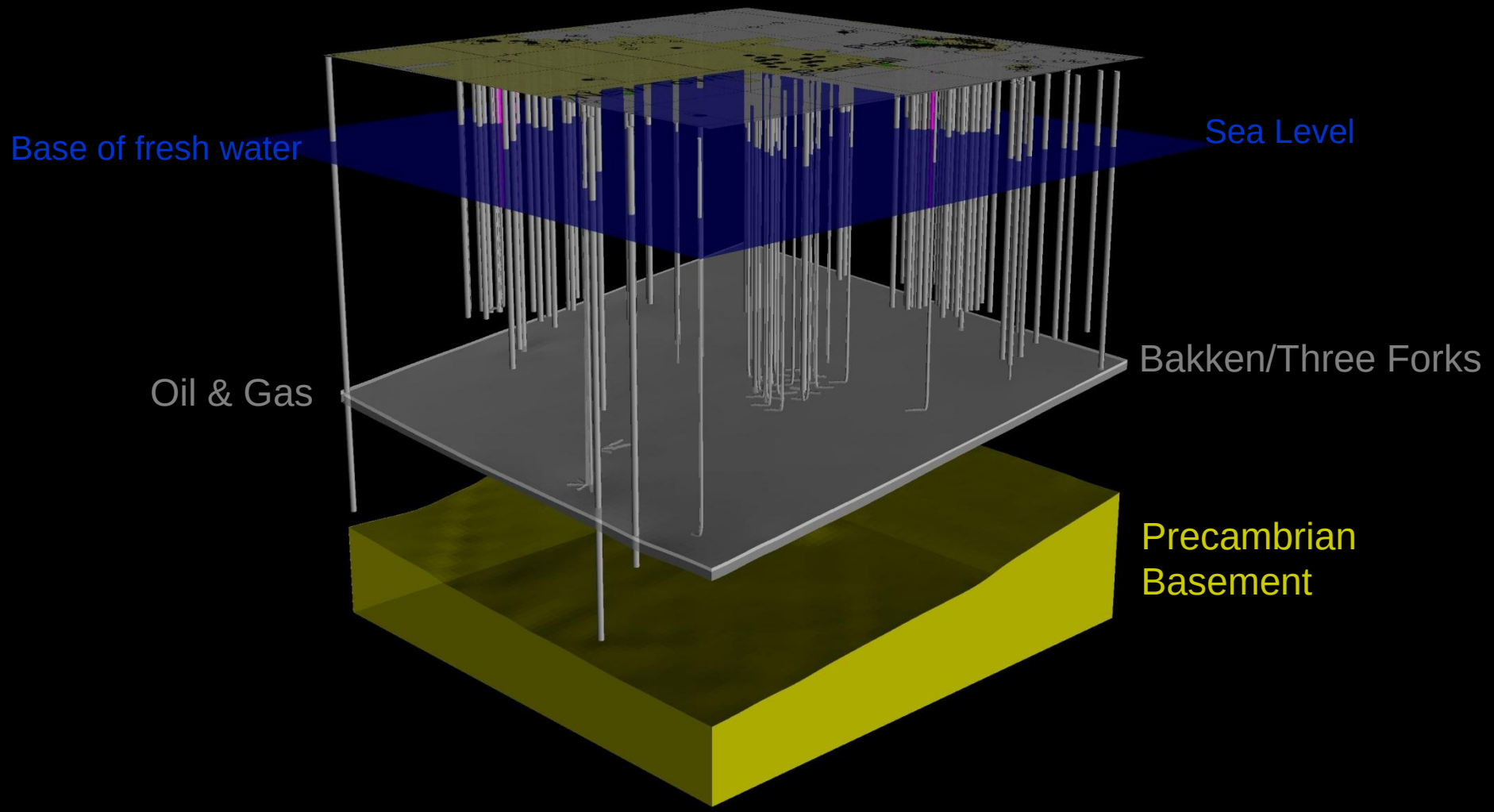


TYPICAL HORIZONTAL OIL WELL



TYPICAL HORIZONTAL OIL WELL



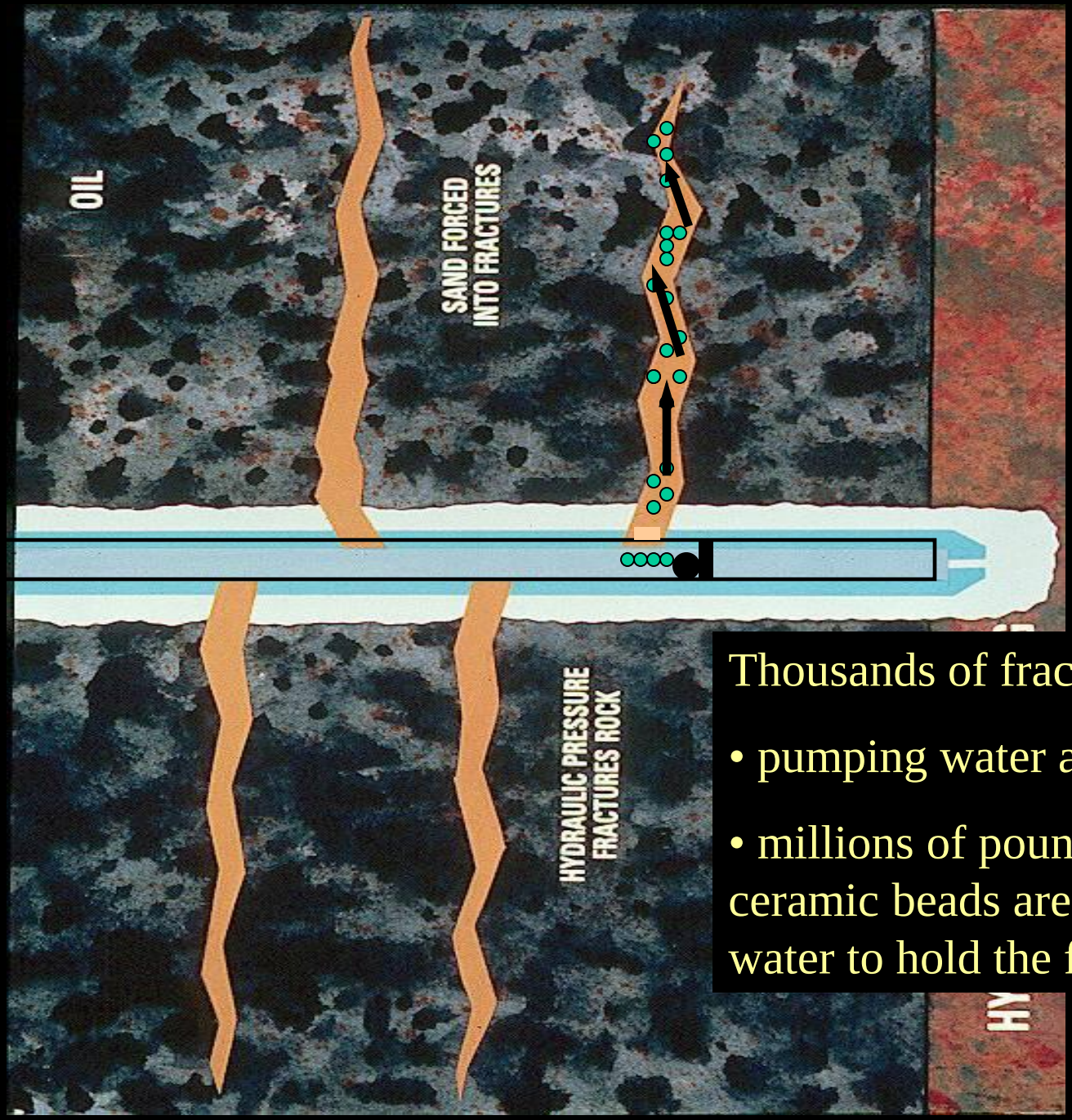


Oil & Gas zone is 1-1/2 miles below fresh water zone

WHY FRAC THE ROCK?

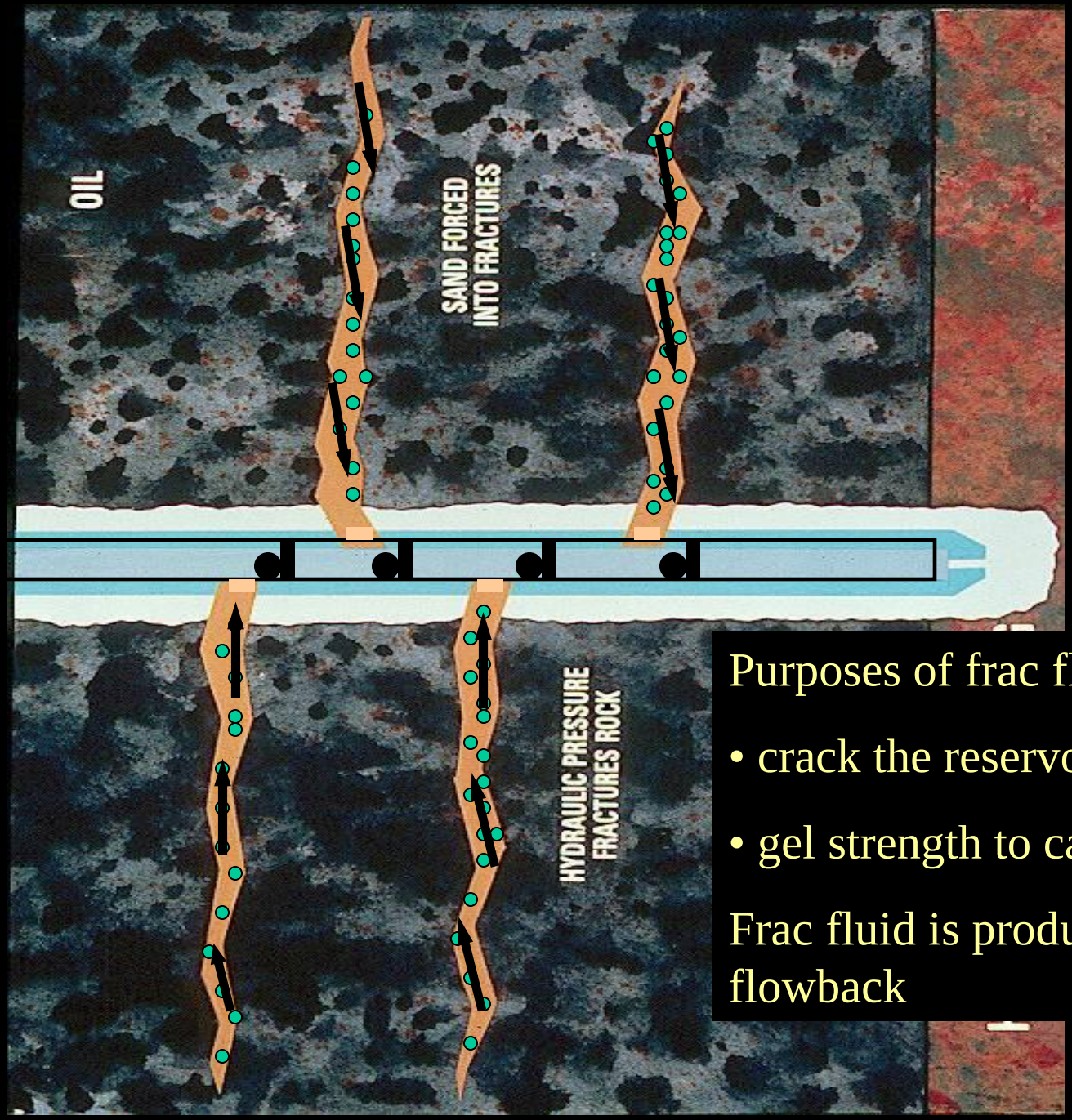
- already developed easy oil
  - oil flows easily without fracking

- Unconventional Reserves
  - reservoirs are tight
  - uneconomic to produce w/o fracking
  - must create a path for oil to flow



Thousands of fractures are created

- pumping water at 6,000-9,000 psi
- millions of pounds of sand and ceramic beads are pumped with the water to hold the fractures open.

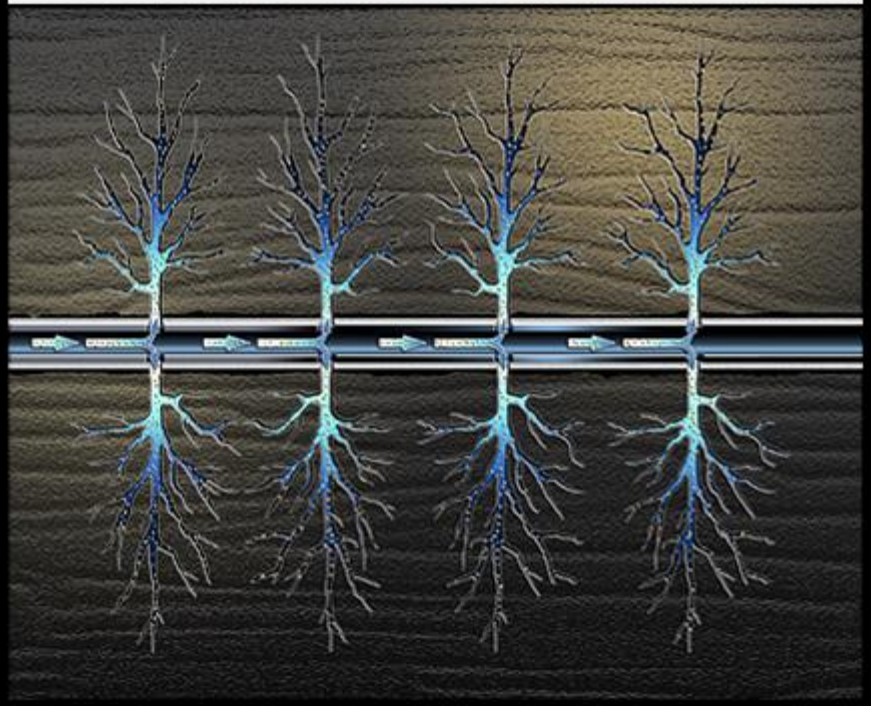


Purposes of frac fluid

- crack the reservoir
- gel strength to carry sand

Frac fluid is produced back as flowback

Hydraulic Fracturing: Mixture of water, sand and chemicals pressurized and pumped into the well to form microscopic fractures in shale.

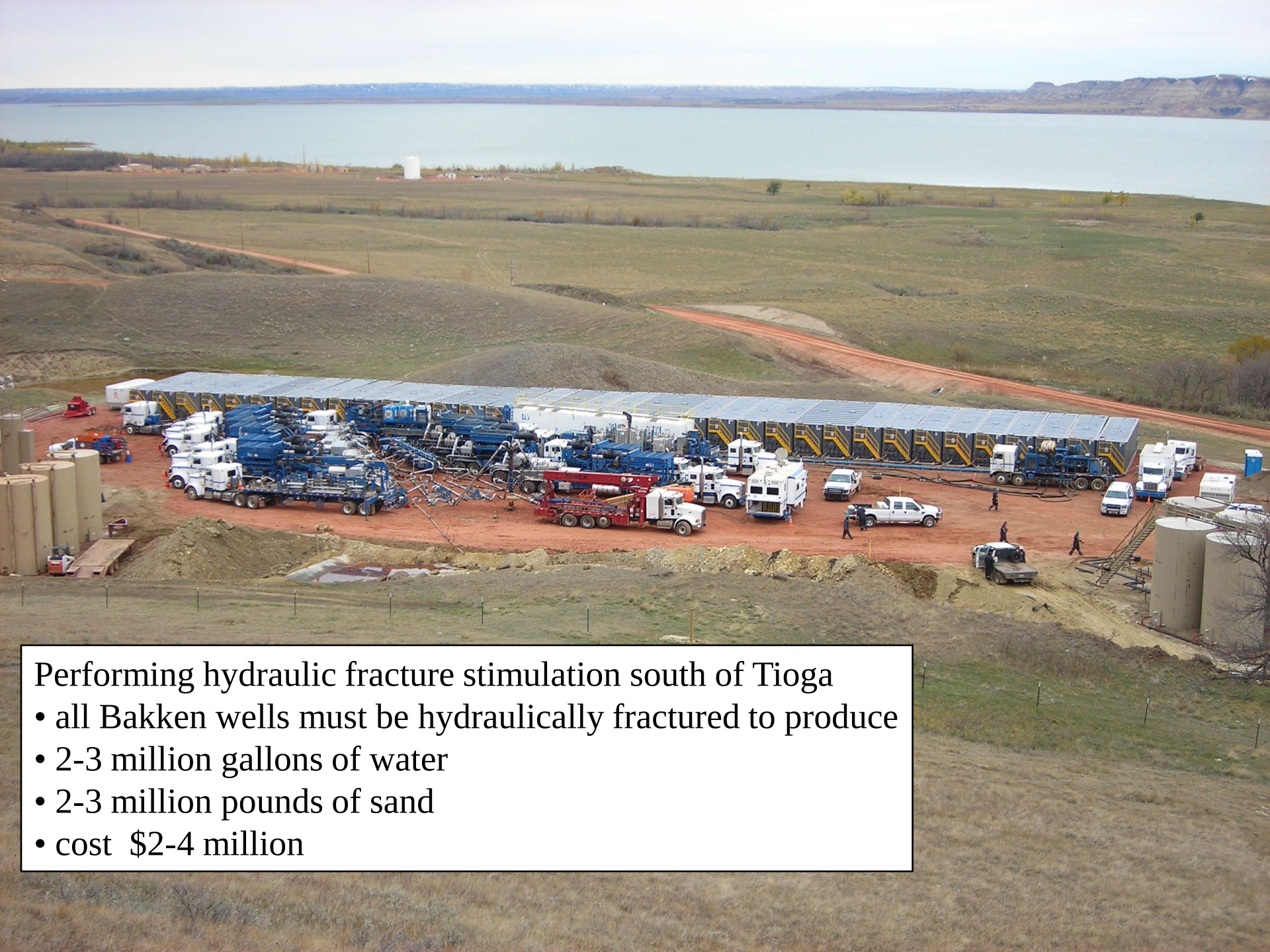


Thirsty Horizontal Wells

- 2,500 wells / year
- 15 - 25 years duration
- 20 - 30 million gallons water / day

Commission supports surface water use

- Lake Sakakawea best water resource
  - one inch contains 10 billion gal water
    - 5000 wells @ 2mil gal wtr/well
    - 2-year supply



Performing hydraulic fracture stimulation south of Tioga

- all Bakken wells must be hydraulically fractured to produce
- 2-3 million gallons of water
- 2-3 million pounds of sand
- cost $2-4 million

PLANNING FOR THE FUTURE

- New Commission Rules
  - Fresh wtr ponds for frac wtr allowed
    - eliminates 100s of truck trips

EPA Guidance for HF using Diesel Fuel

- Draft guidance presented 5-10-2012
  - Comment by 7-9-2012
    - Extended to 8-23-2012
- NDIC commented on 6-25-2012

EPA Guidance for HF using Diesel Fuel

- States have effective HF regulations
- UIC permit not appropriate
- Definition of diesel too broad
- Allows biodiesel w/same chemicals
- EPA: N/A to Primacy States
  - Guidance appears to require it

BLM Proposed HF Rules

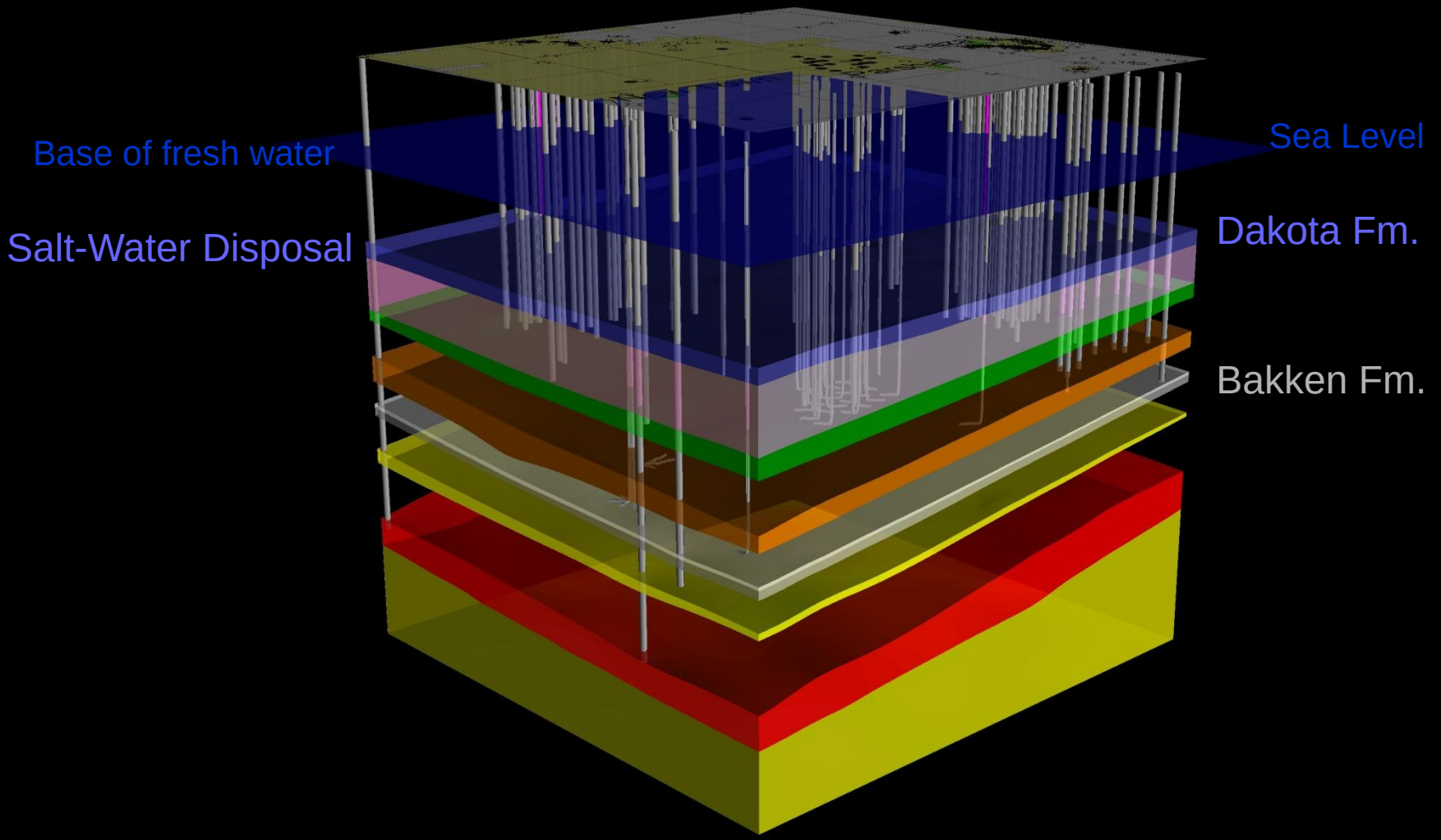
- Draft rules presented 5-11-2012
  - Comment by 7-10-2012
    - Extended to 9-10-2012
- NDIC commented on 6-25-2012

BLM Proposed HF Rules

- Rules eff on federal and Indian lands
- States have effective HF regulations
- Defines simple acid job as HF
- Duplication of North Dakota regs
- BLM short-staffed: Permit > 180 days

Industrial Commission Regulation

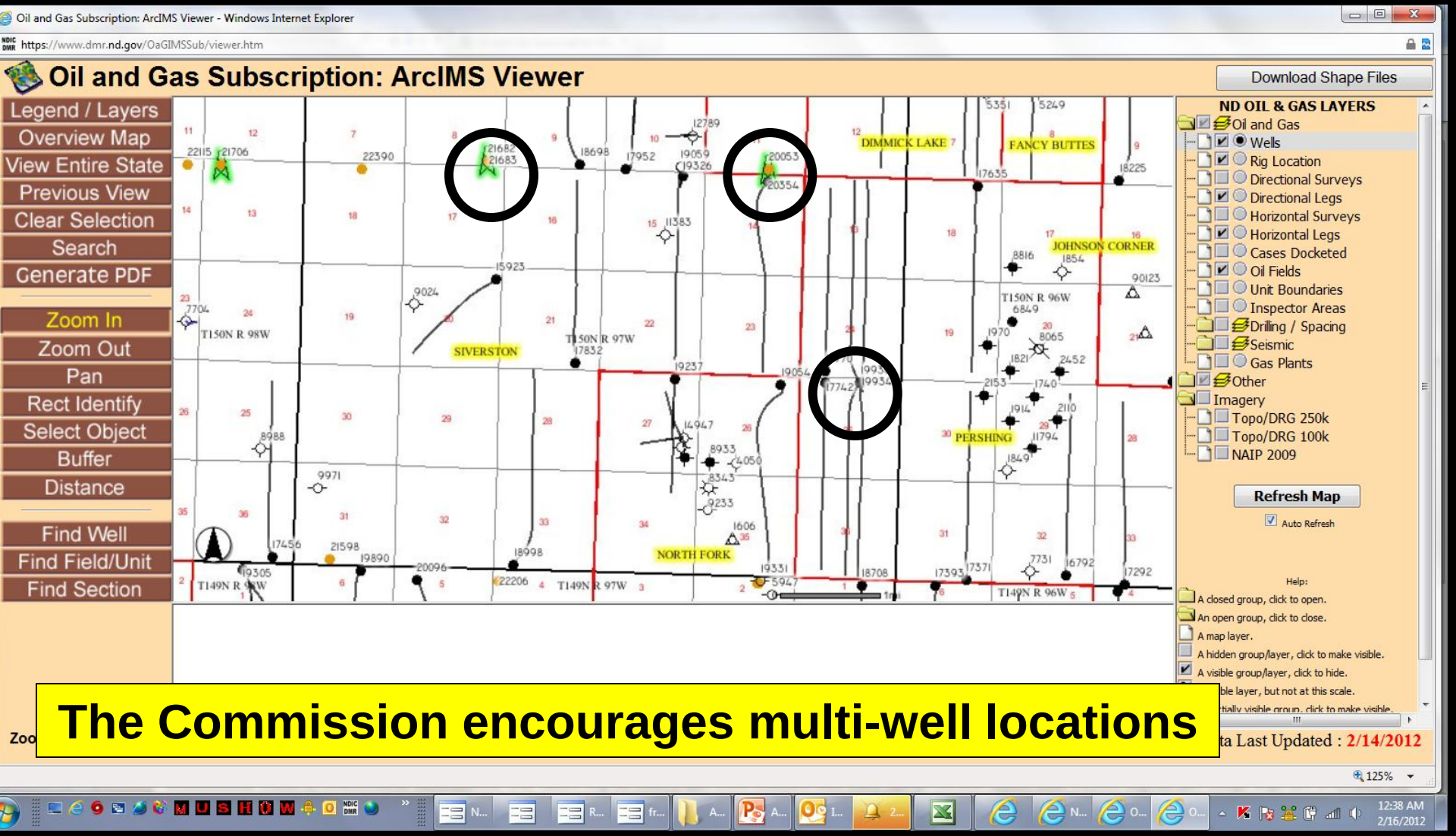
- Water flowback after frac
  - Flowback in lined pit allowed
  - Disposal wells permitted through Underground Injection Program
  - Disposal zone is 2,500 feet below potable waters



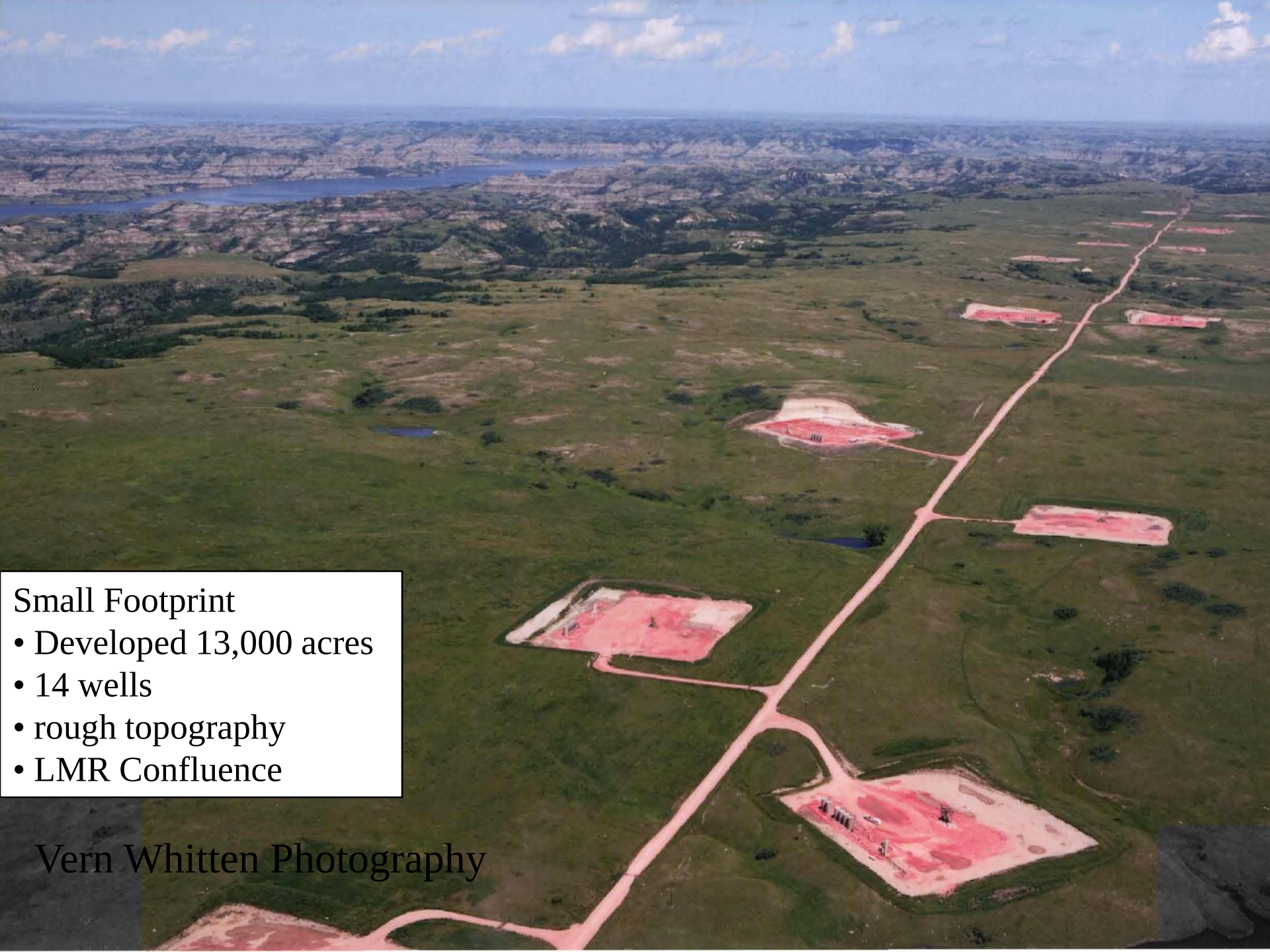
Disposal zone is 1/2 mile below fresh water zone

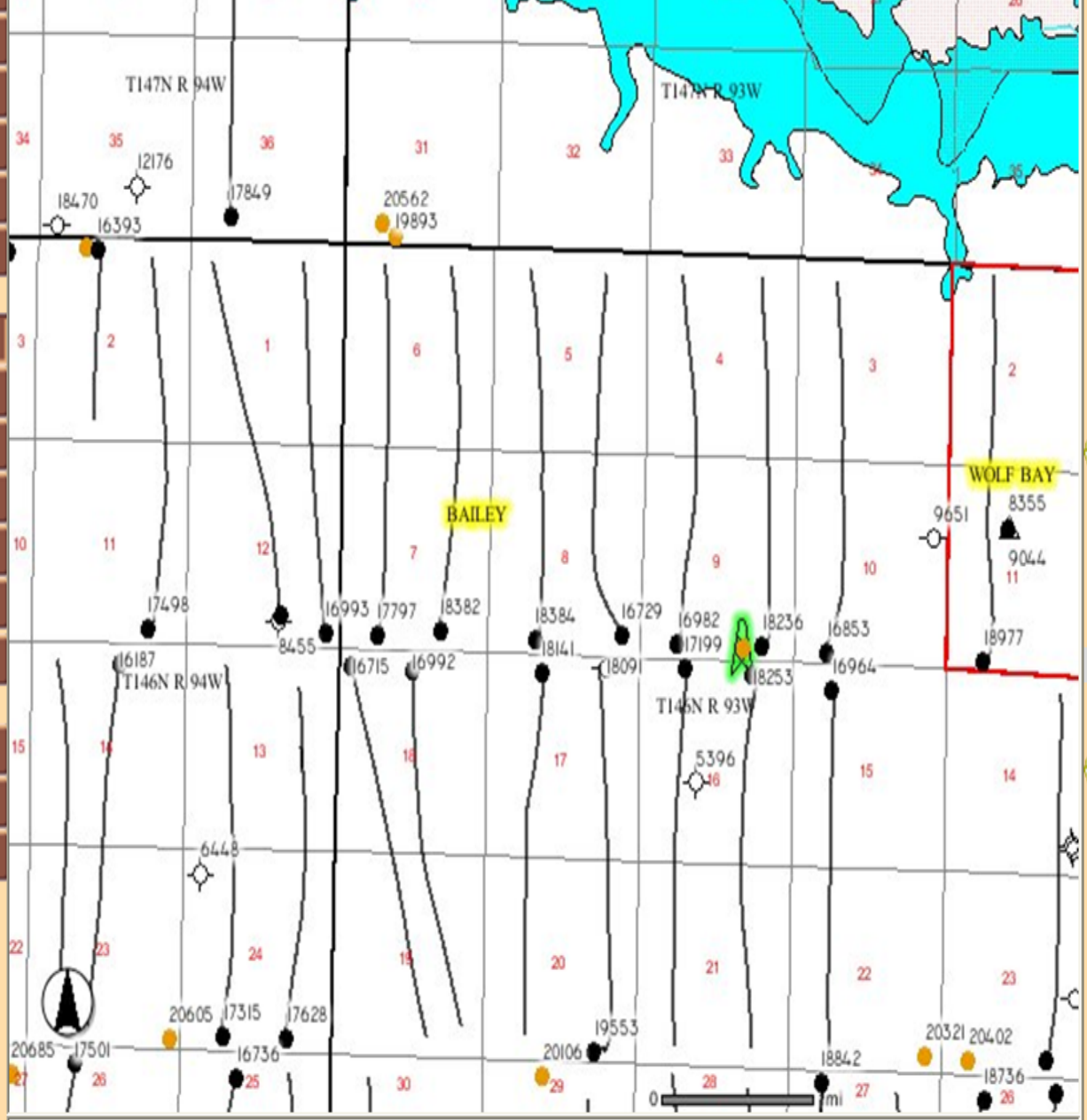
PLANNING FOR THE FUTURE

- Corridors for development
- Educate local and County officials



The Commission encourages multi-well locations


Small Footprint
• Developed 13,000 acres
• 14 wells
• rough topography
• LMR Confluence
Vern Whitten Photography



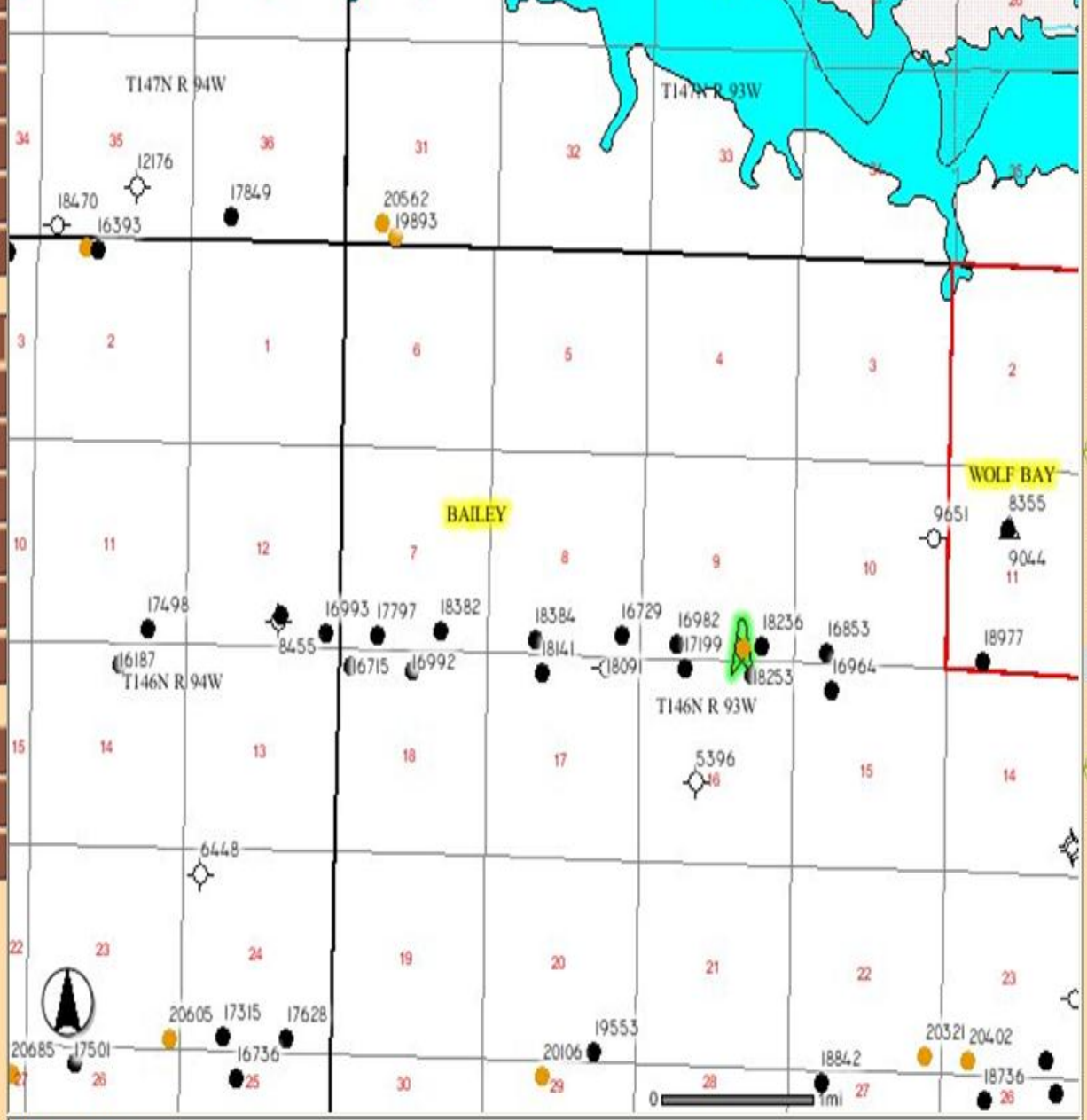
Major Rivers
Selection cleared.

- Wells
- Rig Location
- Directional Surveys
- Directional Legs
- Horizontal Surveys
- Horizontal Legs
- Cases Docketed
- Oil Fields
- Unit Boundaries
- Inspector Areas
- Drilling / Spacing
- Seismic
- Gas Plants
- Other
  - Reservations
  - Corporate Boundaries
  - Rivers and Roads
    - County Roads
    - Major Roads
    - Major Rivers
    - Missouri River
  - Land Ownership
- Imagery
  - Topo/DRG 250k
  - Topo/DRG 100k
  - NAIP 2009

Refresh Map

Auto Refresh

Help:
A closed group, click to open.
An open group, click to close.
A map layer.
A hidden group/layer, click to make visible.



Major Rivers
Selection cleared.

- Entire State
- Previous View
- Clear Selection
- Search
- Generate PDF
- Zoom In
- Zoom Out
- Pan
- Rect Identify
- Select Object
- Buffer
- Distance
- Find Well
- Find Field/Unit
- Find Section

- Rig Location
- Directional Surveys
- Directional Legs
- Horizontal Surveys
- Horizontal Legs
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Refresh Map

Auto Refresh

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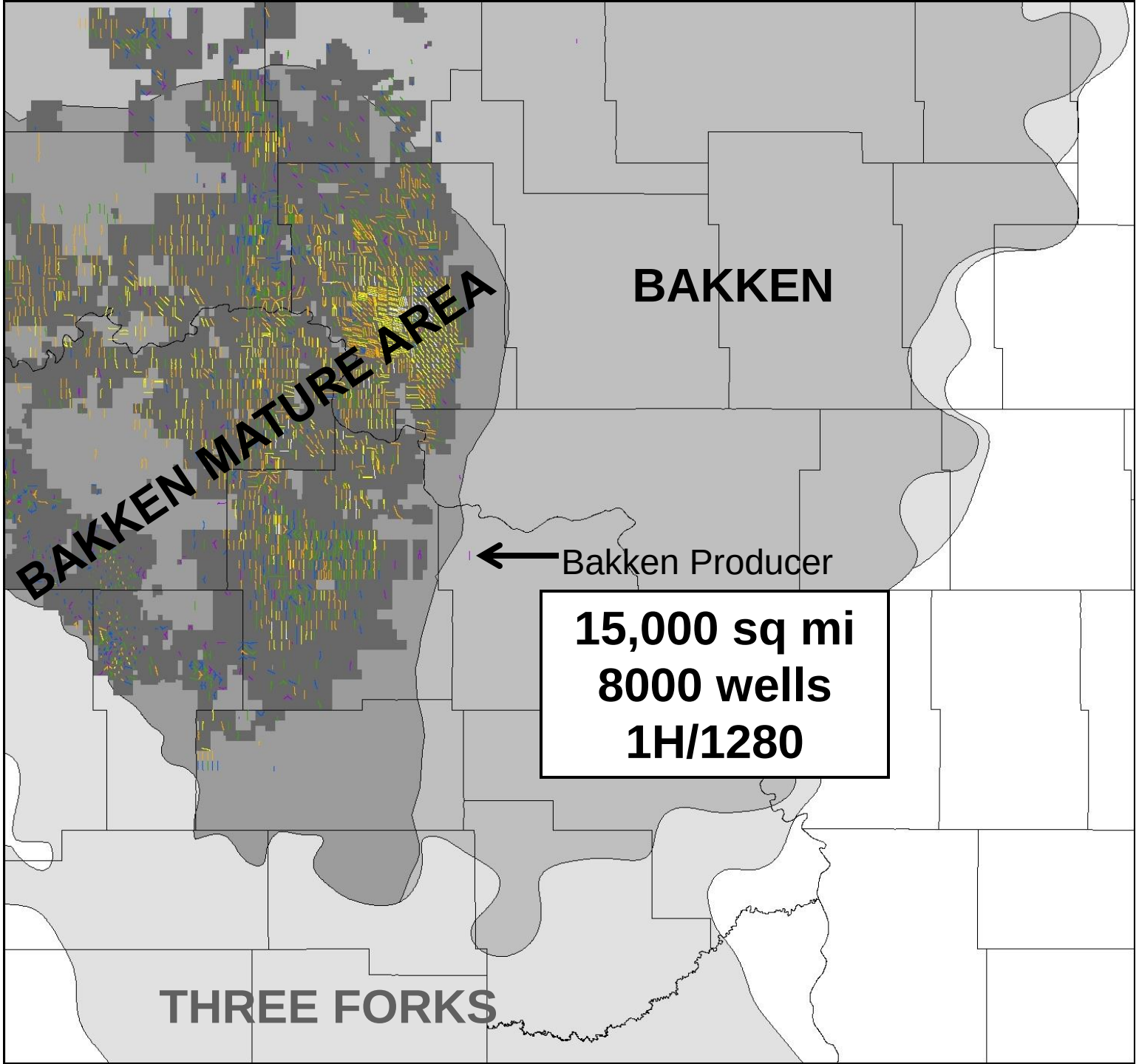
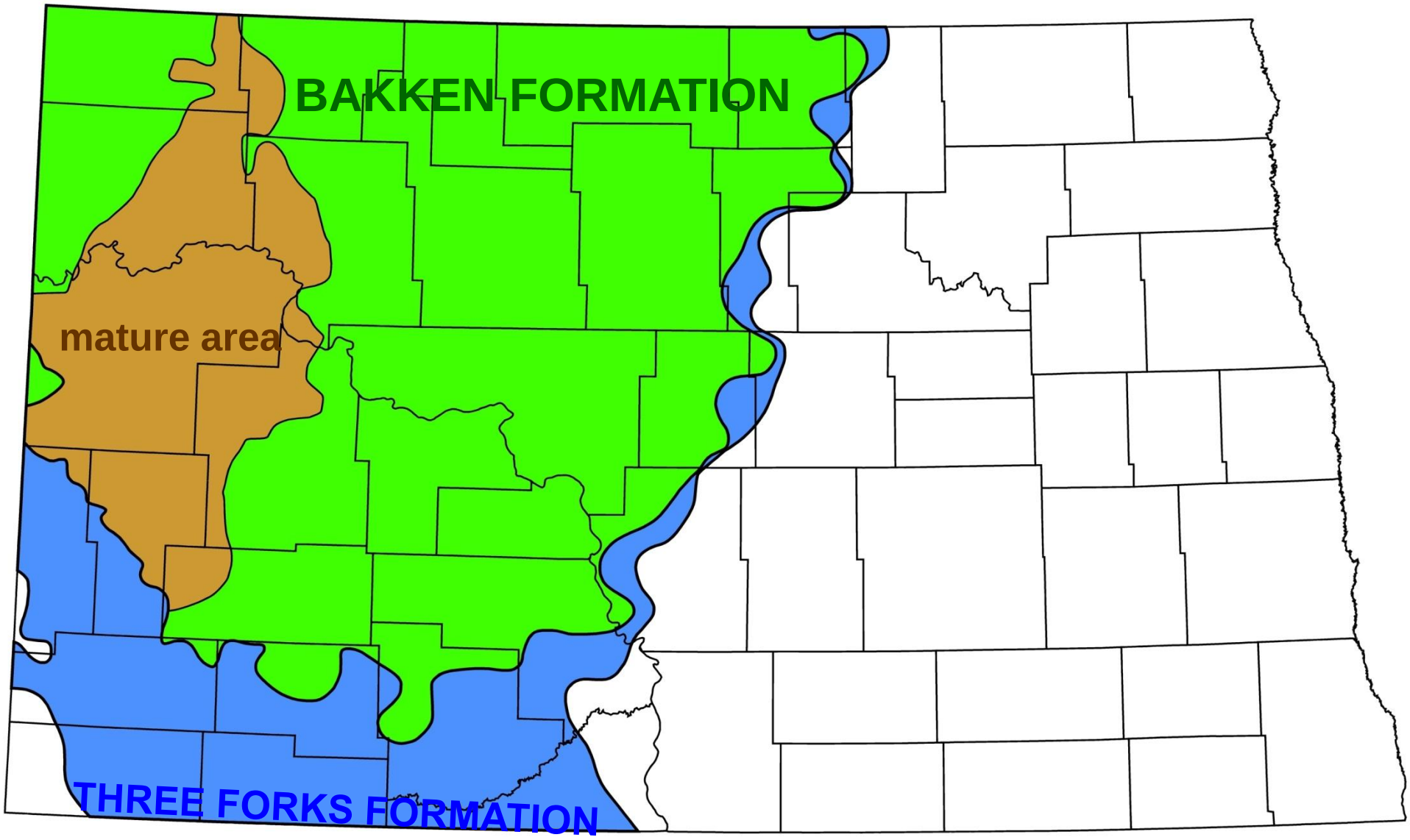
Six Wells on a Single Pad


BAKKEN
BAKKEN MATURE AREA
Bakken Producer
15,000 sq mi
8000 wells
1H/1280
THREE FORKS

ESTIMATED MATURE AREA OF THE BAKKEN FORMATION



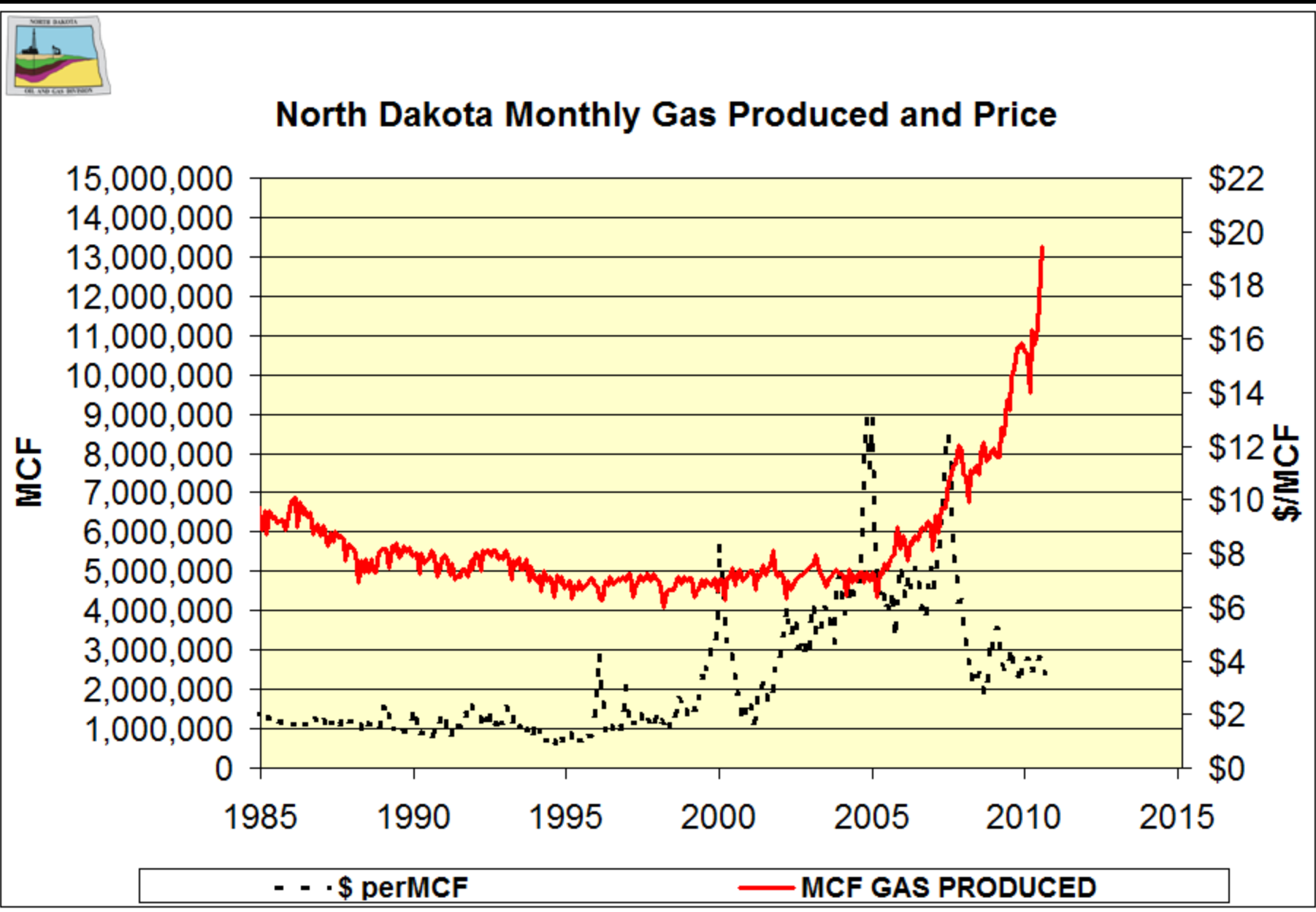
(Nordeng, 2010)

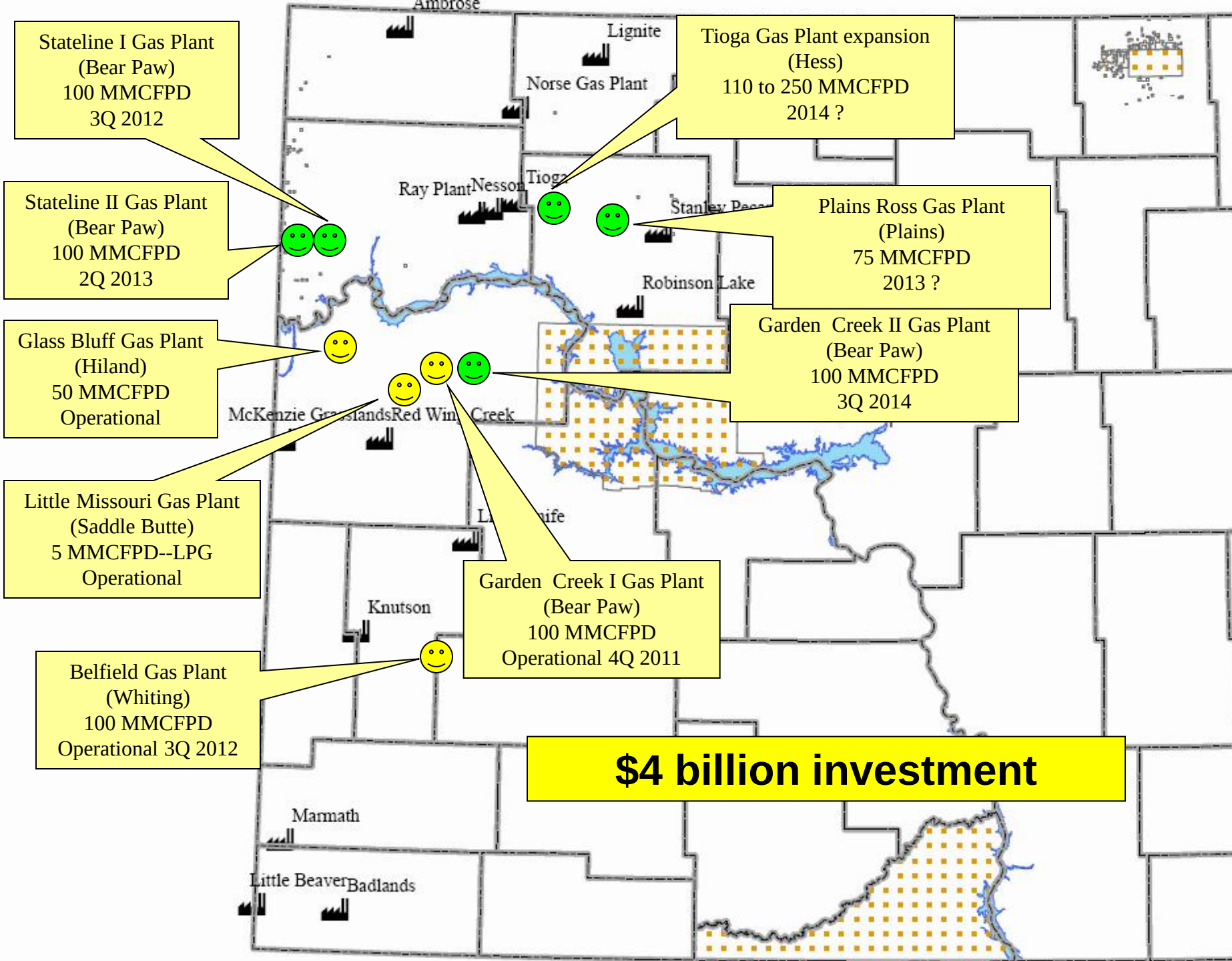
WELLS

- 7,188 wells currently producing
  - 3,876 Bakken
  - 4,000 more to secure leases
- 40,000 additional development wells
  - 225 rigs – another 16 years
  - 100 rigs – another 30 years
- Bakken Pool – 4 targets

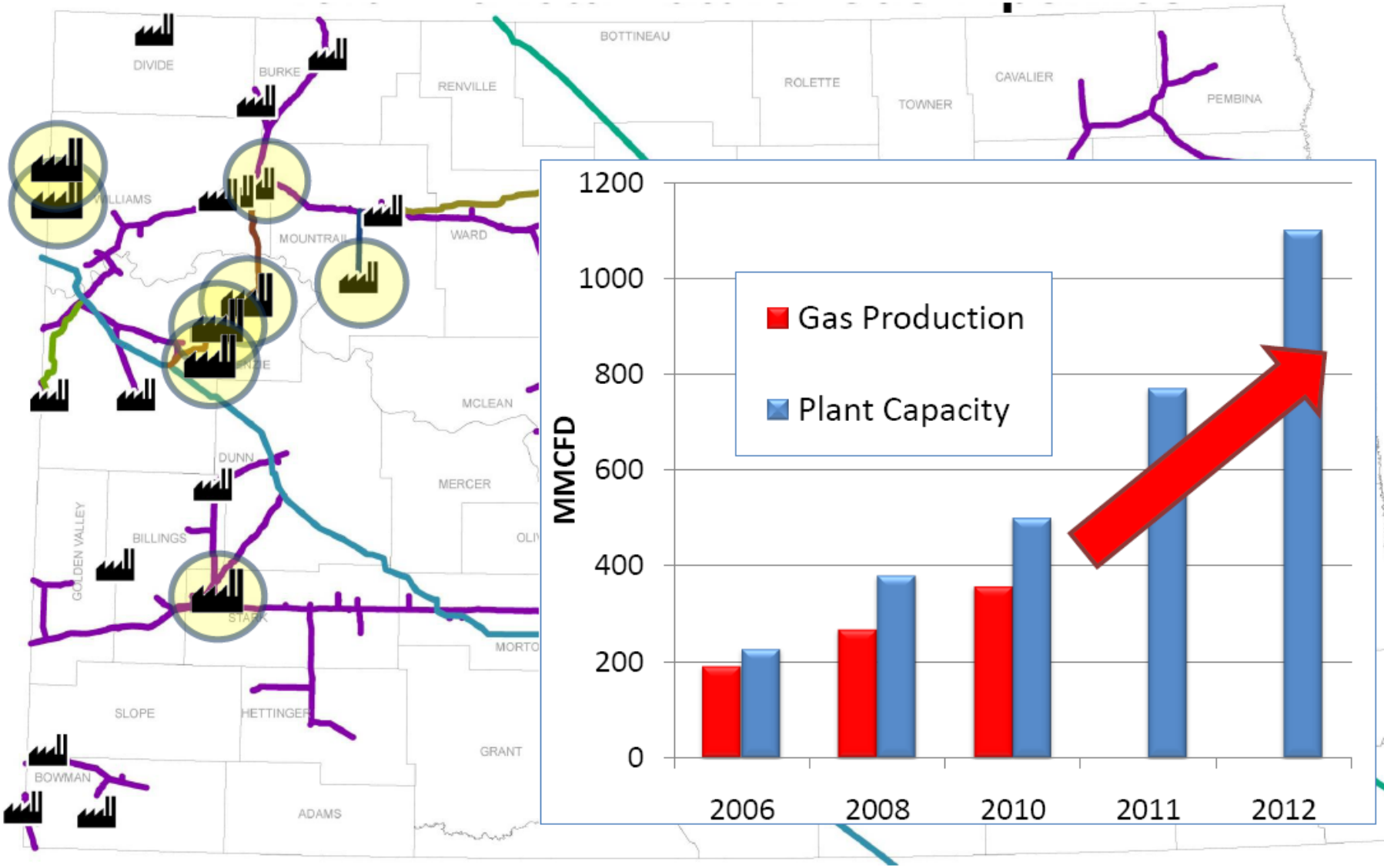
ASSOCIATED GAS

- Current gas plant cap exceeds prod
  - no infrastructure
  - infrastructure bottlenecks
- $4 billion investment in gas
  - must justify expendatures
  - 4 new plants recently online
  - 4 new + one expansion planned
  - compressor upgrades

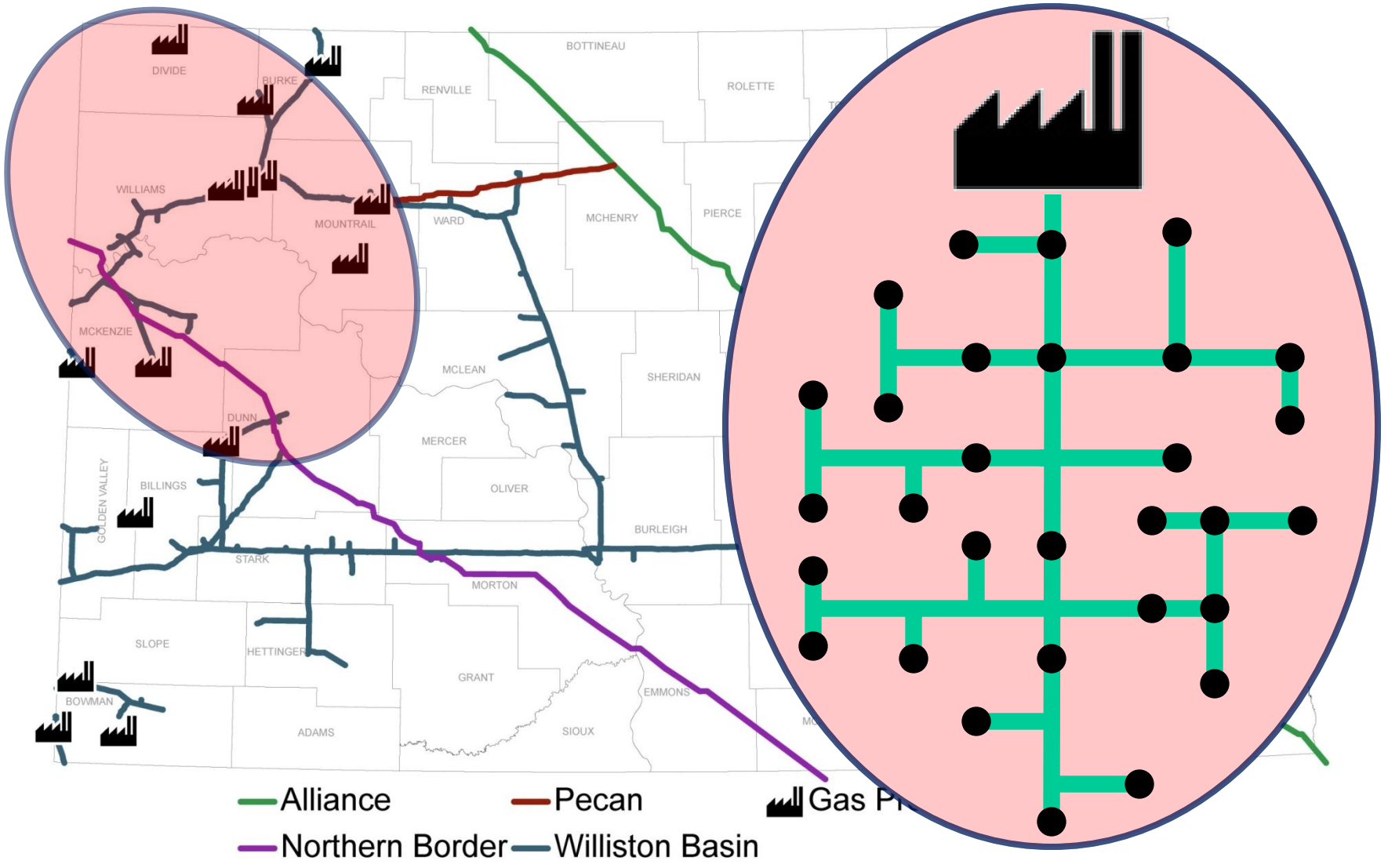

North Dakota Monthly Gas Produced and Price
MCF
$/MCF
15,000,000
14,000,000
13,000,000
12,000,000
11,000,000
10,000,000
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
$22
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
1985
1990
1995
2000
2005
2010
2015
$ perMCF
MCF GAS PRODUCED

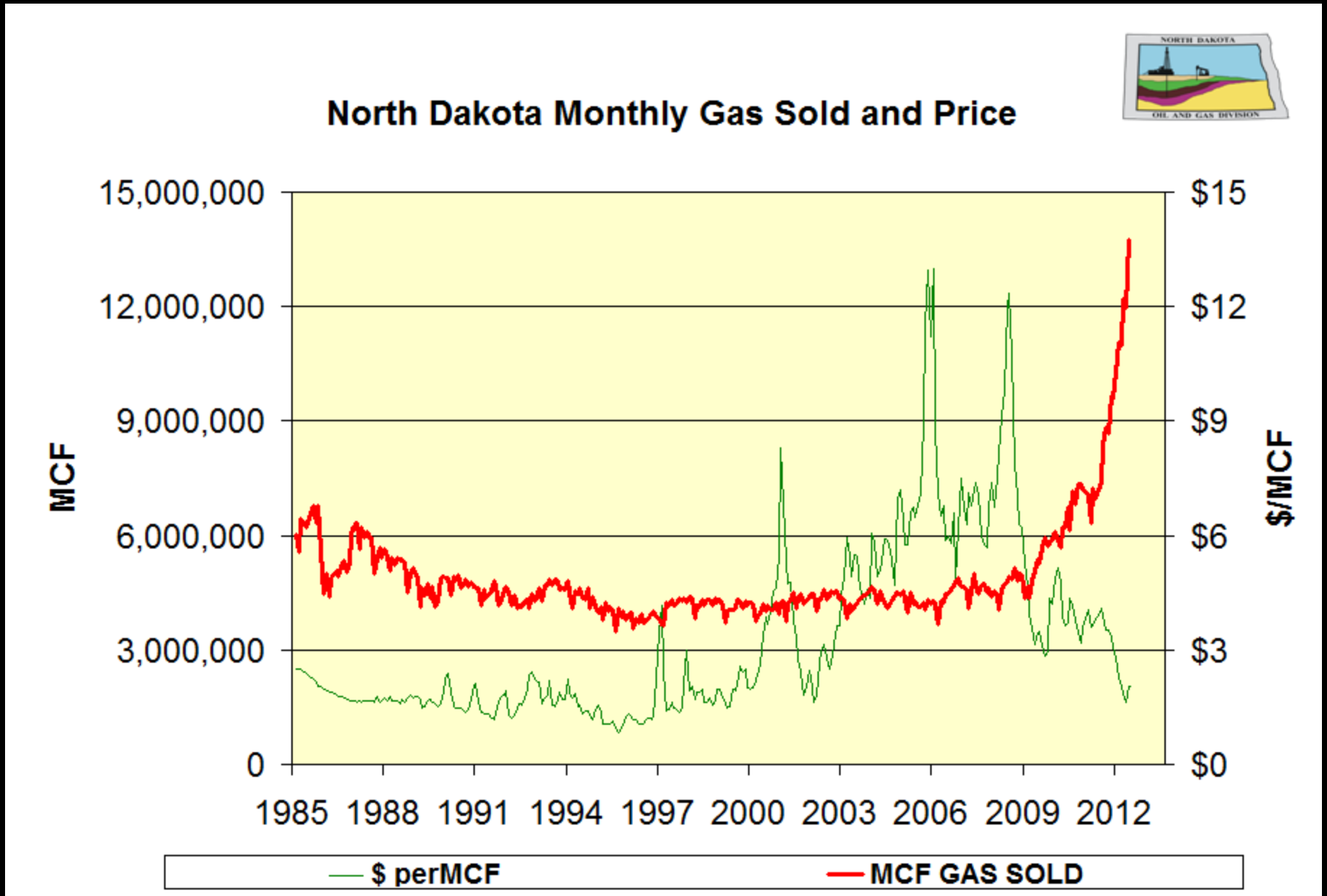

Stateline I Gas Plant
(Bear Paw)
100 MMCFPD
3Q 2012
Stateline II Gas Plant
(Bear Paw)
100 MMCFPD
2Q 2013
Glass Bluff Gas Plant
(Hiland)
50 MMCFPD
Operational
Little Missouri Gas Plant
(Saddle Butte)
5 MMCFPD--LPG
Operational
Belfield Gas Plant
(Whiting)
100 MMCFPD
Operational 3Q 2012
Tioga Gas Plant expansion
(Hess)
110 to 250 MMCFPD
2014 ?
Plains Ross Gas Plant
(Plains)
75 MMCFPD
2013 ?
Garden Creek II Gas Plant
(Bear Paw)
100 MMCFPD
3Q 2014
Garden Creek I Gas Plant
(Bear Paw)
100 MMCFPD
Operational 4Q 2011
$4 billion investment
Ambrose
Lignite
Norse Gas Plant
Ray Plant
Nesson
Tioga
Robinson Lake
McKenzie Grasslands
Red Wing Creek
Knutson
Marmath
Little Beaver
Badlands

New or Expanding Gas Plants

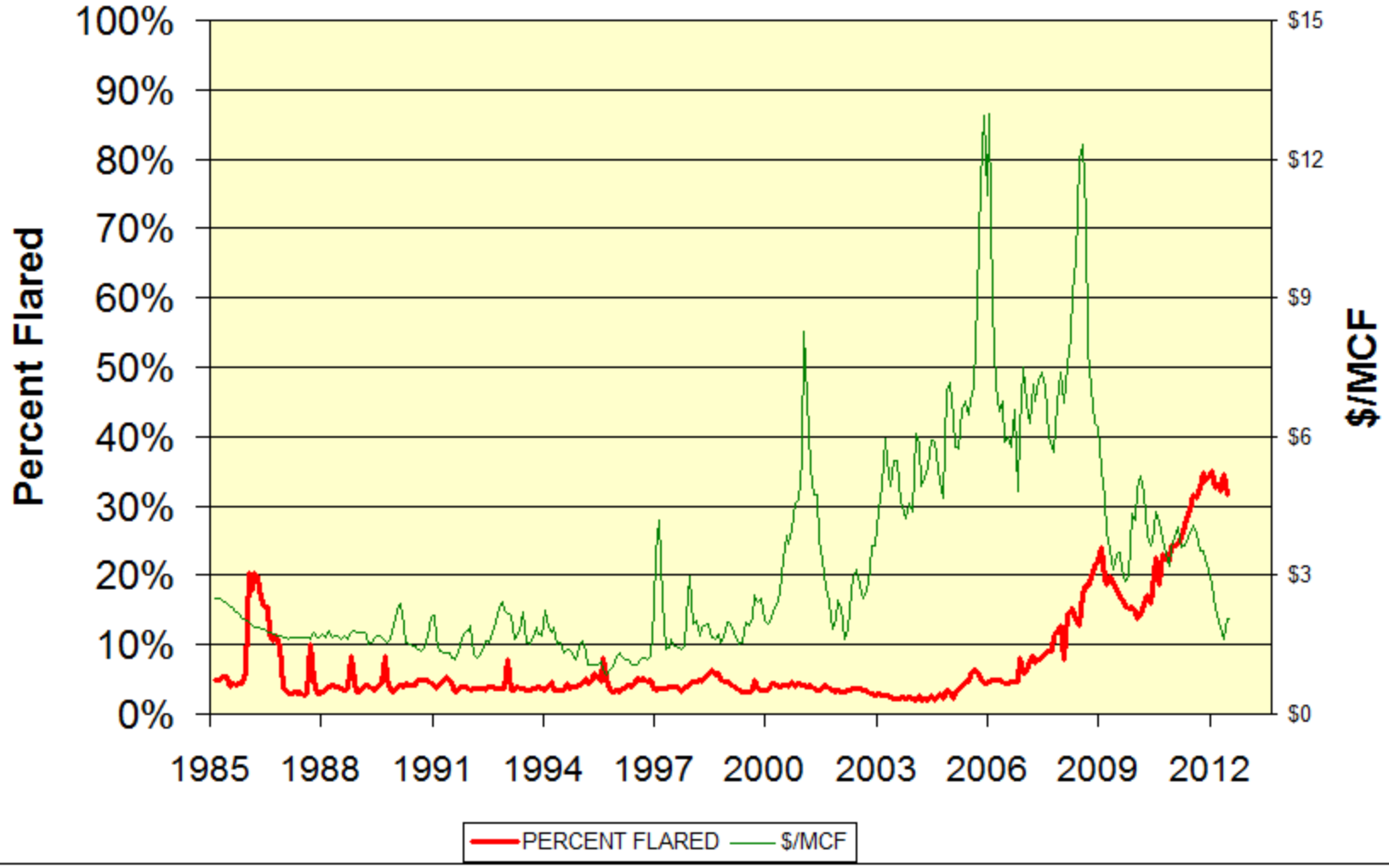


Natural Gas Challenges

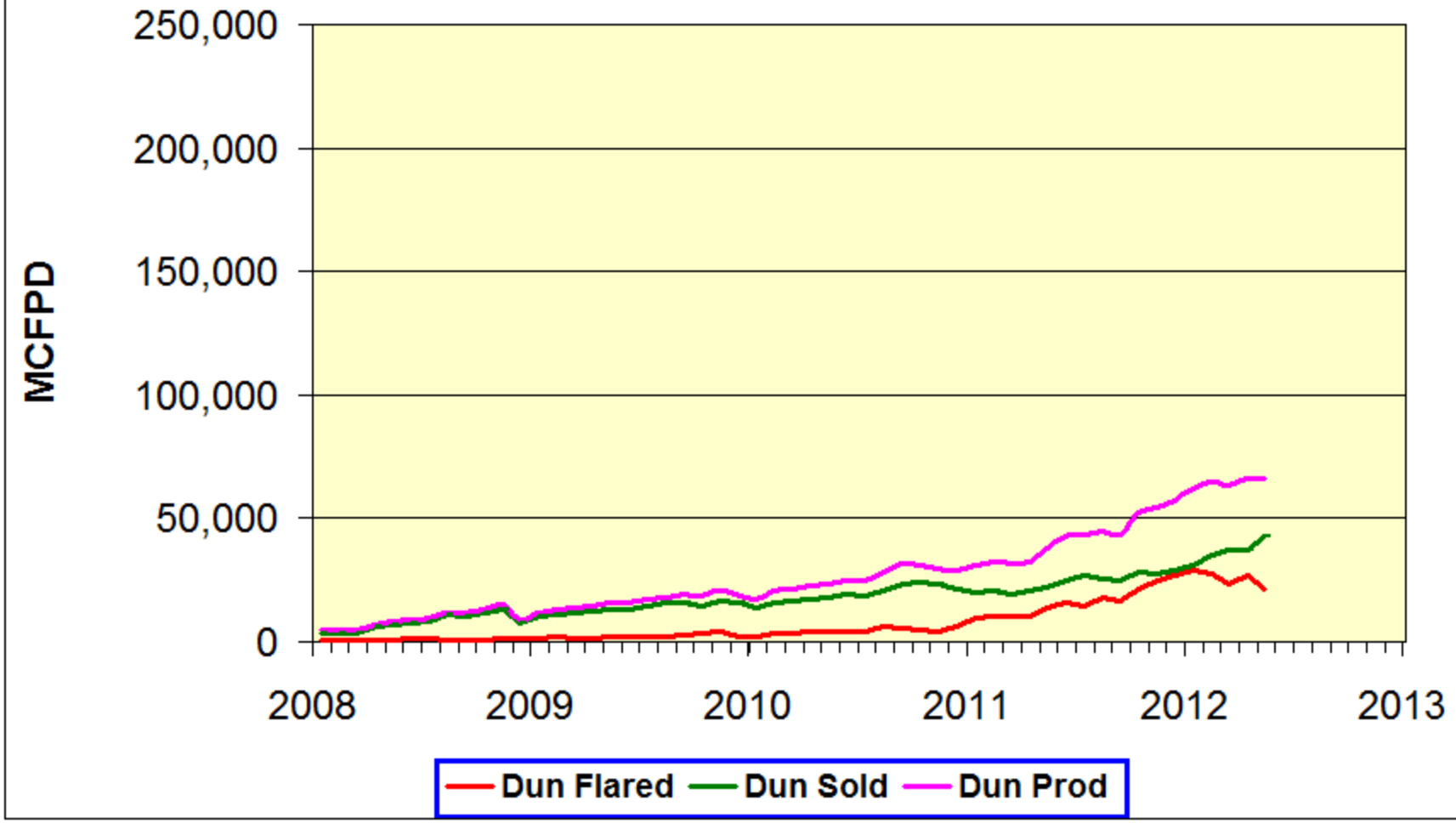



North Dakota Monthly Gas Sold and Price
NORTH DAKOTA
OIL AND GAS DIVISION
MCF
$/MCF
15,000,000
12,000,000
9,000,000
6,000,000
3,000,000
0
$15
$12
$9
$6
$3
$0
1985 1988 1991 1994 1997 2000 2003 2006 2009 2012
$ perMCF
MCF GAS SOLD

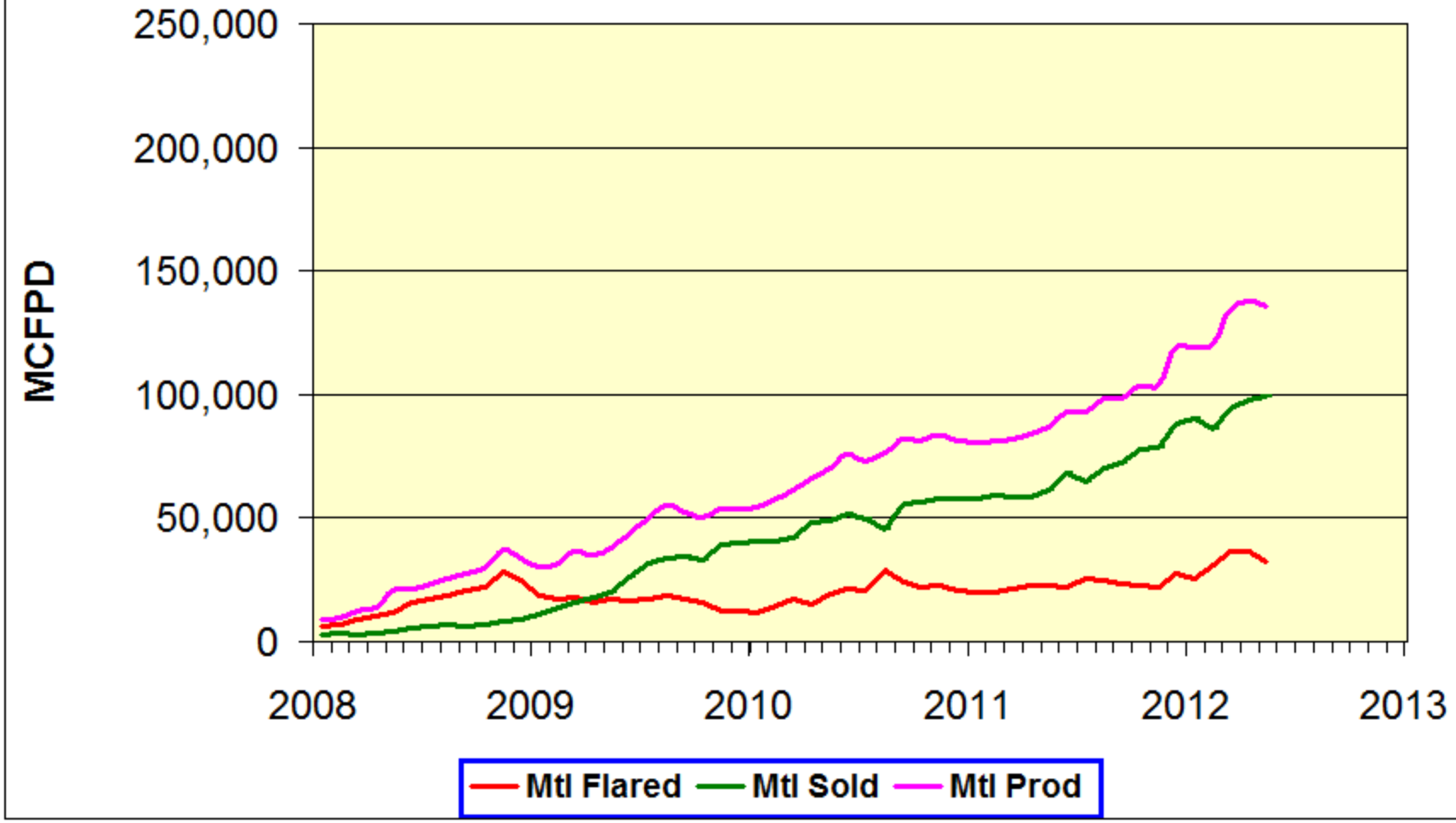
North Dakota Monthly Gas Flared



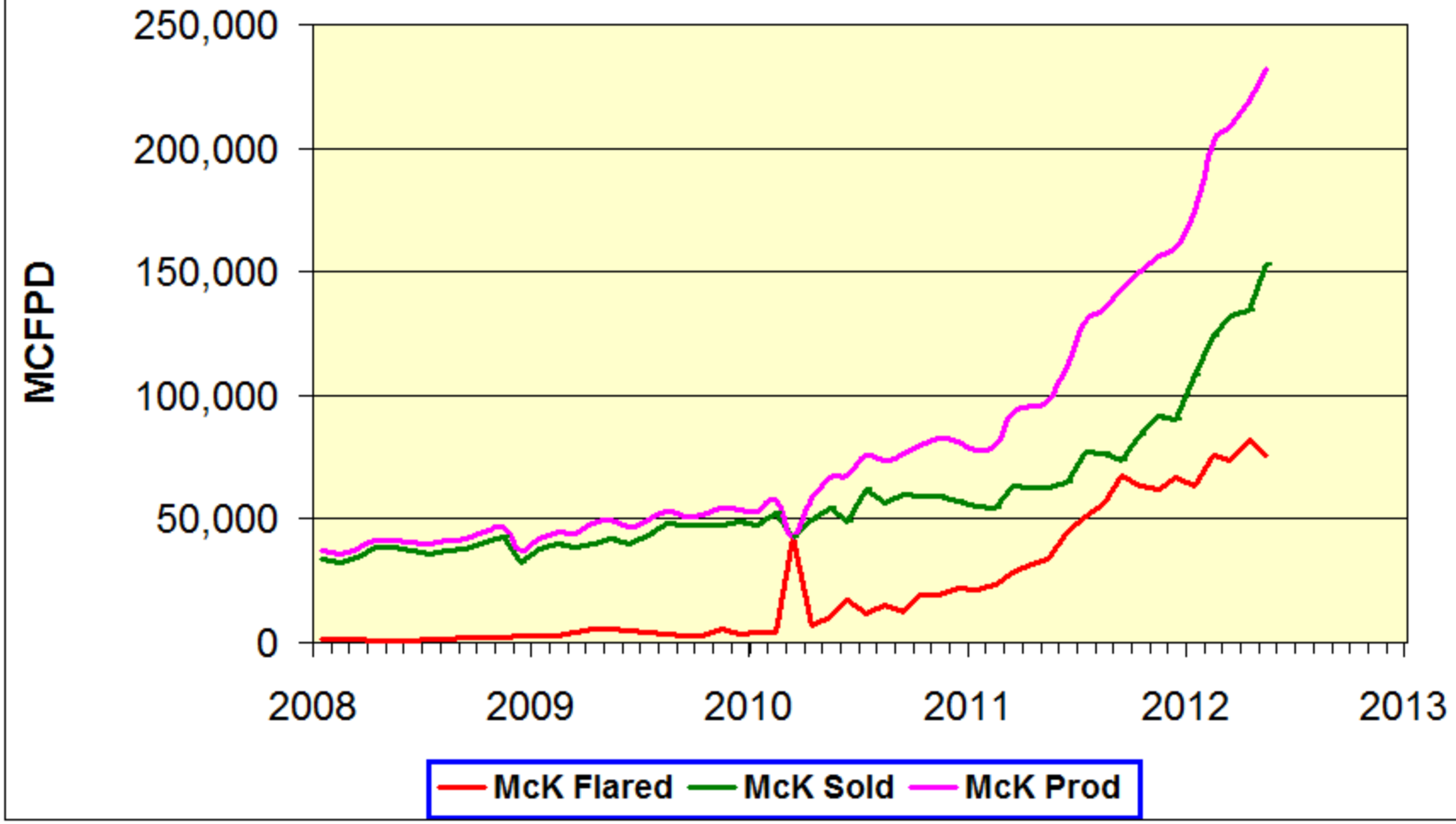
Dunn County Daily Gas Volumes

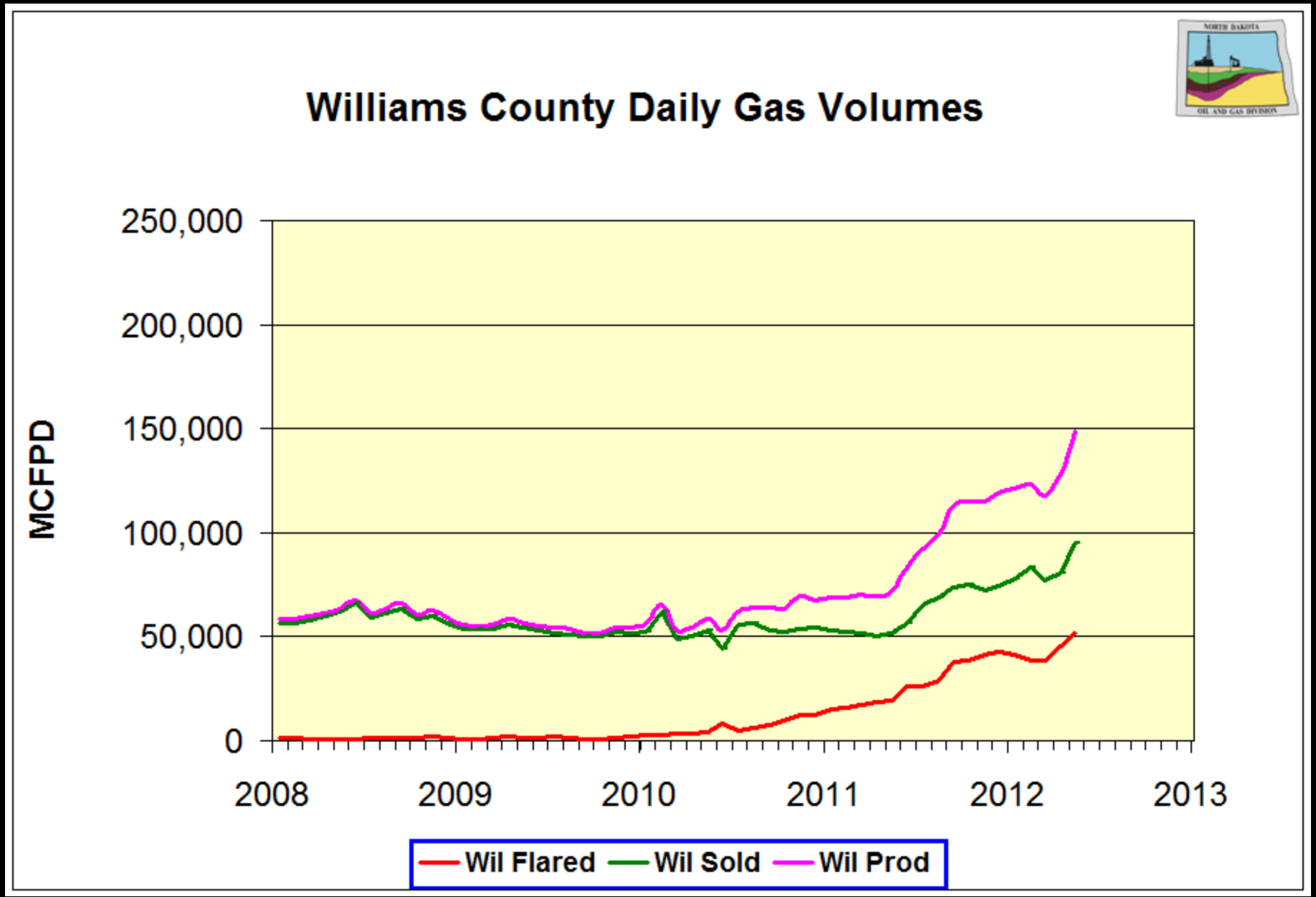


Mountrail County Daily Gas Volumes



McKenzie County Daily Gas Volumes



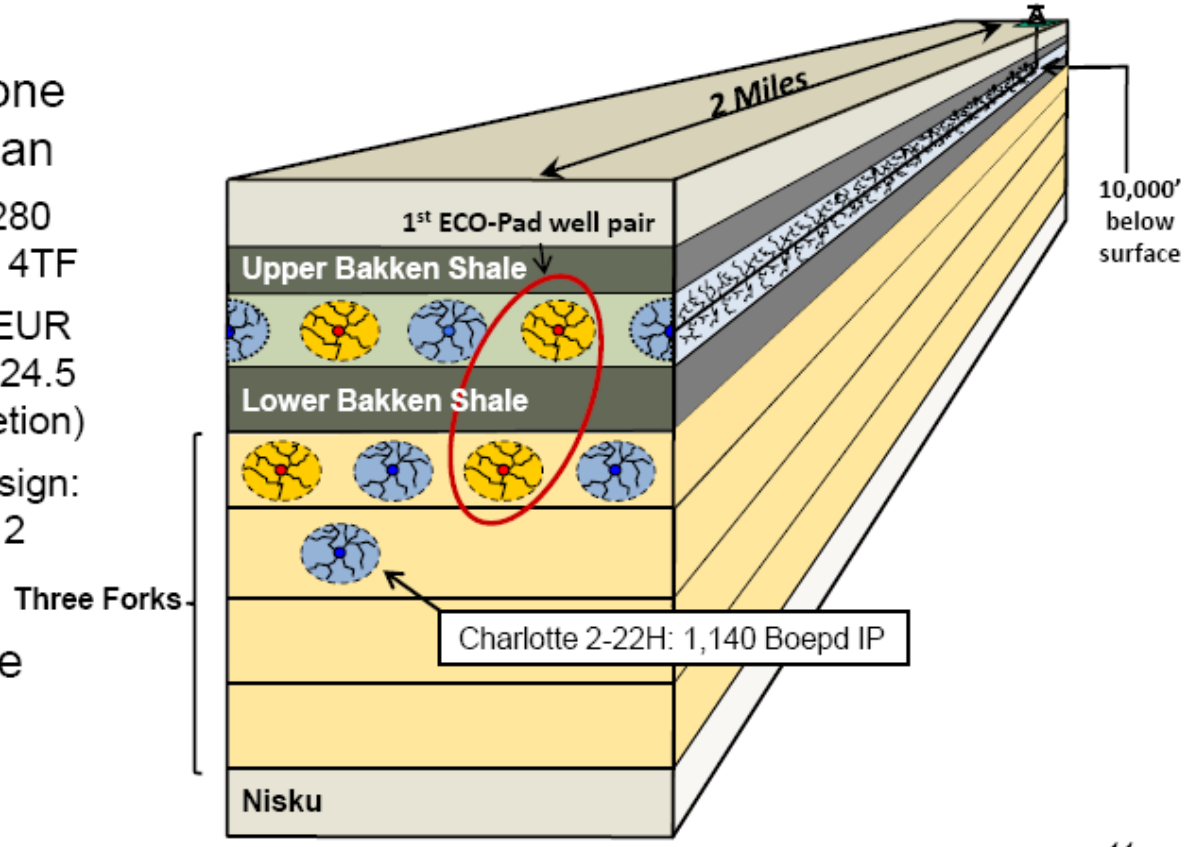

Williams County Daily Gas Volumes
MCFPD
250,000
200,000
150,000
100,000
50,000
0
2008
2009
2010
2011
2012
2013
Wil Flared
Wil Sold
Wil Prod

PLANNING FOR THE FUTURE

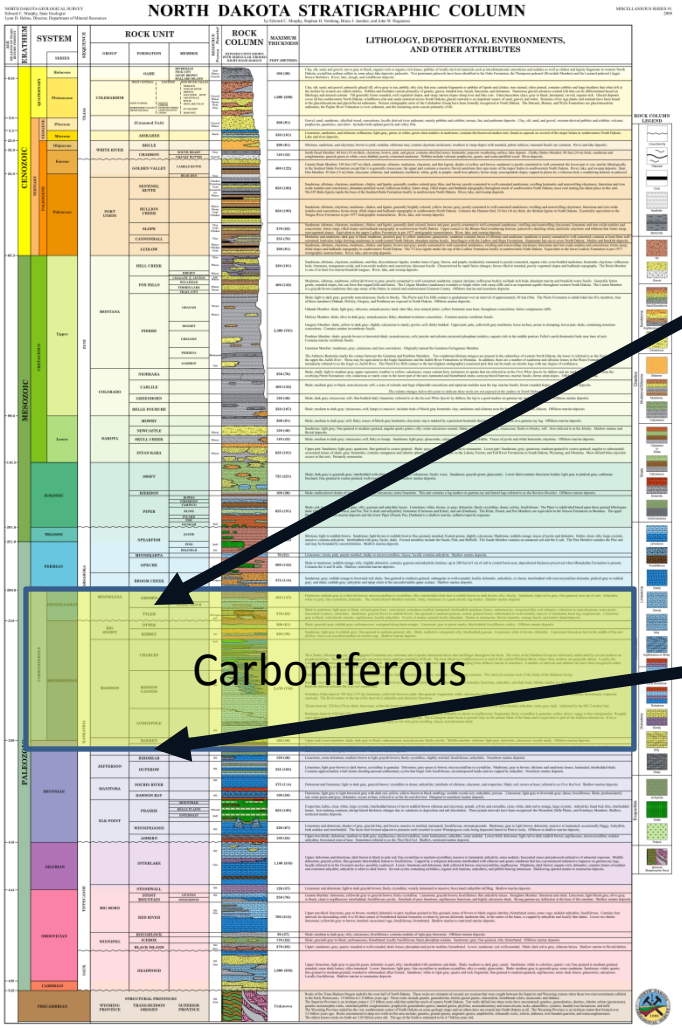
- Evaluate potential new plays

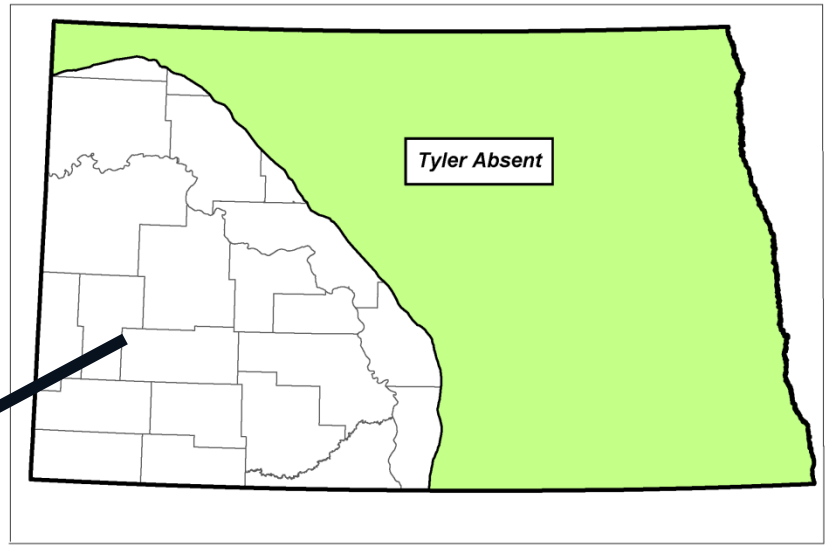
Bakken Development Plan

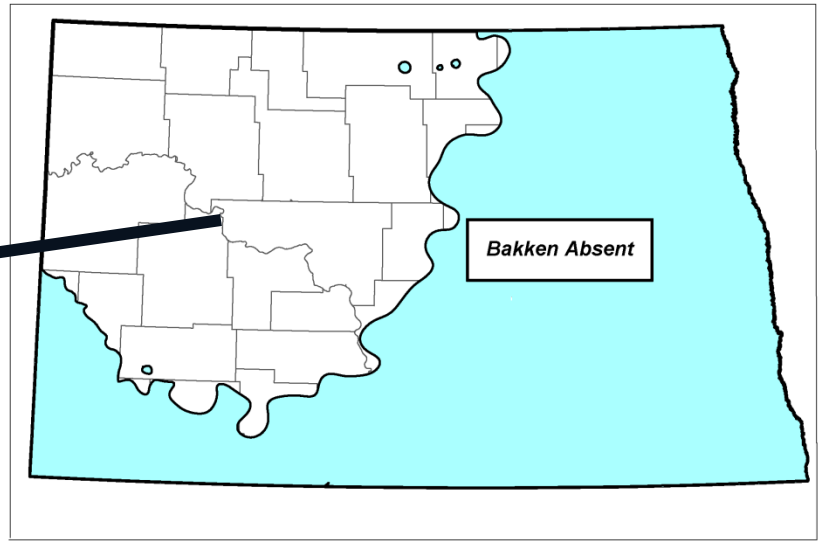
- Original dual-zone development plan
  - 8 wells per 1,280 acres – 4 MB, 4TF
  - 603,000 Boe EUR per well (avg. 24.5 stages/completion)
  - ECO-Pad® design: 2 wells south, 2 wells north
- Additional Three Forks potential

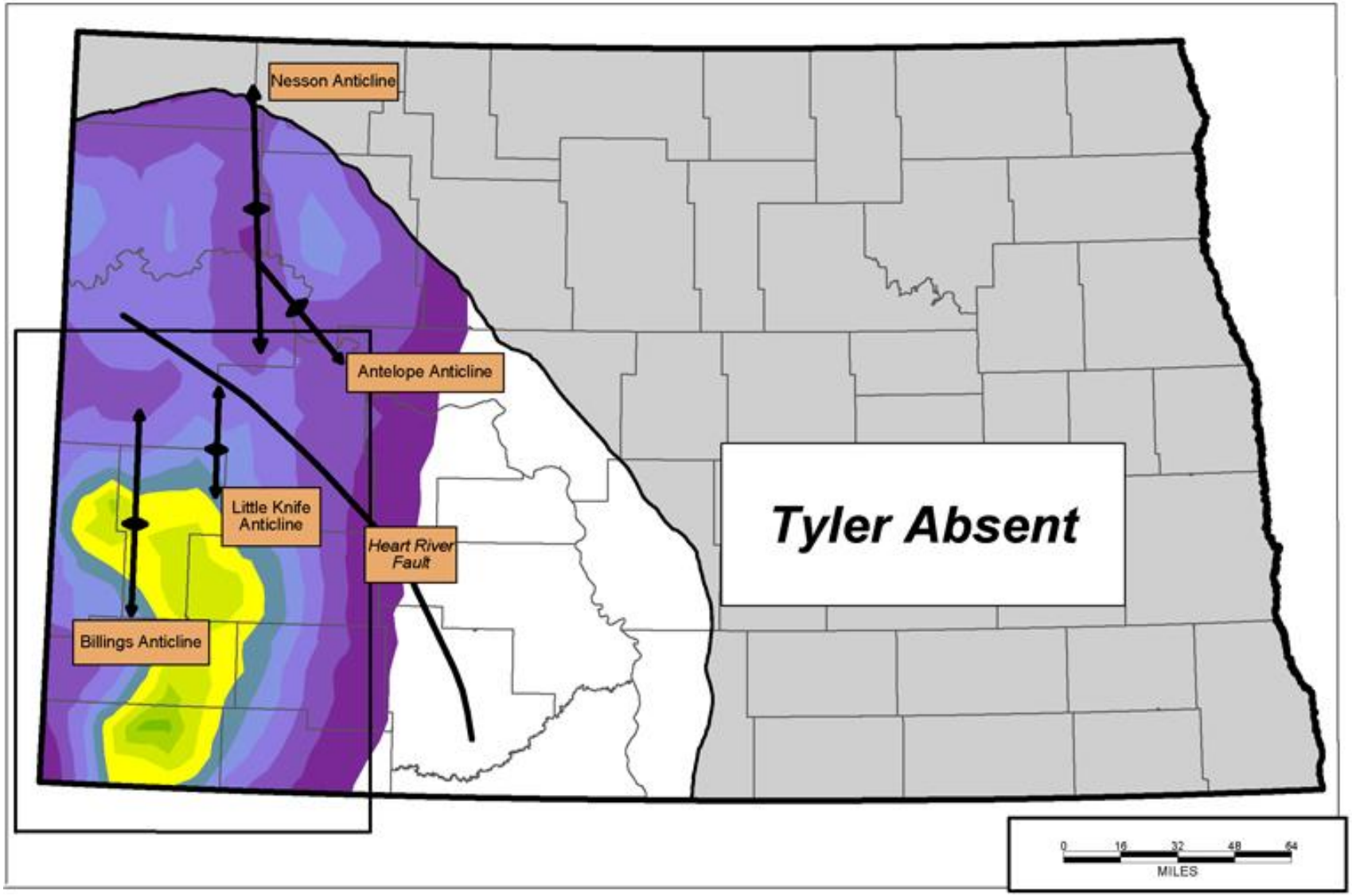


Regional Extent Tyler and Bakken








Nesson Anticline
Antelope Anticline
Little Knife Anticline
Heart River Fault
Billings Anticline
Tyler Absent
0
16
32
48
64
MILES

North Dakota Geological Survey
Geologic Investigations No. 127

RESOURCE POTENTIAL OF THE TYLER FORMATION

Stephan H. Nordeng and Timothy O. Nesheim

Edward C. Murphy, State Geologist
Lynn D. Helms, Director Dept. of Mineral Reources
2010

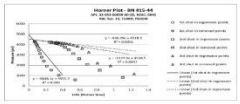


Figure 1. Horner plot of pressures measured during the shut-in periods of an open hole drill stem test (DST) of the Tyler Formation (8180-8282 ft. M.D.) in Pennzoil Co. & Depco's BNH15-44 (Figure 5, #6848). The extrapolated shut in pressures (Horner, 1951) from the 2nd and 3rd shut in periods of the DST indicate that the Tyler formation fluid pressure is ~4525 psi at a depth of 8230 ft., which yields a pressure gradient (0.55 psi/ft.) above the expected hydrostatic pressure range (0.43-0.46 psi/ft.). The 1st shut-in period did not reach "steady-state" conditions and therefore does not yield a reliable extrapolated formation pressure. The fluid recovered in this test was 354' of gas cut mud. This well was spudded on February 2nd, 1979 (DST run on March 18th, 1979) in the Flat Top Butte field, where only one well produced just 446 bbls of oil from the Tyler-Heath Formation over a four month period in 1960 (Texaco Inc.'s Mary Pace #1; API: 33-053-00461-00-00; NDIC: 2667; Sec. 14, T146W, R101W). There is no record of injection within the Flat Top Butte field.

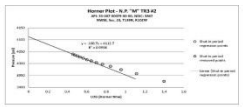


Figure 2. Horner plot of pressures measured during the shut-in period of an open hole drill stem test (DST) of the Tyler Formation (7743-7776 ft. M.D.) in Amerada Petroleum Corp.'s N.P. "M" TRH #2, shown on Figure 5 by #3867. Both the maximum pressure recorded (4039 psi = 0.52 psi/ft.) and the extrapolated formation pressure (4112.7 psi = 0.53 psi/ft.) are above the hydrostatic pressure range expected for the depth tested (3300-3560 psi = 0.43-0.46 psi/ft.). The DST fluid recovery was 2.5 BBLS oil, reversed out 69.54 BBLS oil. Cumulative production for this well was 1,440,113 BBLS of oil. This well was spudded on May 2nd, 1965 (DST run on May 15th, 1965) in the Medora field, where Initial production began in June, 1964 and initial injection in February, 1970.

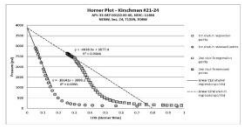


Figure 3. Horner plot of pressures measured during the shut in periods of a conventional bottom hole drill stem test (DST) on the Tyler Formation (7540-7556 ft. M.D.) in Milestone Petroleum's Kirschman #21-24, shown on Figure 5 by #11484. The calculated fluid pressure of the Tyler formation (the average of the extrapolated pressures from the two DST shut in periods) is ~3883 psi at a depth of 7545 ft., which yields a pressure gradient (0.51 psi/ft.) above the hydrostatic pressure expected for this depth (0.43-0.46 psi/ft.). The DST fluid recovered was 0.03 bbls of oil and 0.48 bbls of water. Kirschman #21-24 was a wildcat well drilled outside areas of production and injection for the Tyler Formation.

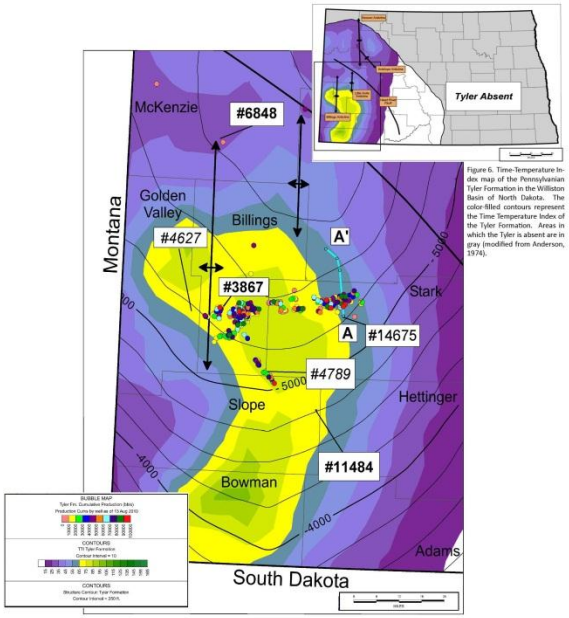


Figure 5. Detail map showing the distribution of Tyler production (Total Bbls) in North Dakota together with Time-Temperature contours and the location of wells from which pressure gradients (#6848, #3867, #11484) and Rock Eval data (#4627, #4789) were obtained. The color-filled contours represent the Time-Temperature Index of the Tyler Formation and are keyed to the color bar located in the lower left corner. Shades of yellow and green (>65) represent the TTIs that correspond with the oil window. TTIs less than 65 and above 15 are in shades of blue and purple and represent conditions that could generate oil. This map lies within the black outline on Figure 6. Cumulative production from the Tyler Formation (barrels oil) is represented by the color of the circles centered on the wells that have and/or are producing oil from the Tyler Formation. The solid contour lines on the detail map represent the mean sea level elevation of the top of the Tyler formation.

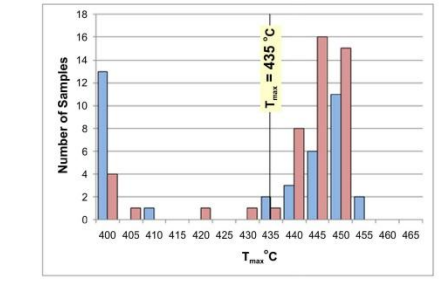


Figure 7. A frequency diagram showing that most of the samples of the Tyler Formation collected from the Government Taylor A-1 (#4627) in red, and the State of North Dakota #41-36 (#4789) in blue, have been thermally matured beyond the threshold that marks the onset of oil generation (Tmax ~435oC).

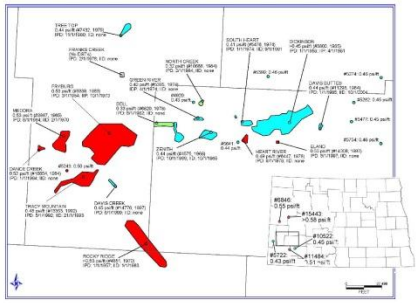


Figure 8. Field map showing the producing Tyler Fields in southern Billings, Slope, and Stark counties. For each field the Initial Pressure Gradient (IPG), Initial Production Date (IPD), and Initial Injection Date (IID) are given. Fields with evidence of initial fluid overpressure in the Tyler are colored in red, fields that were initially at hydrostatic pressure are colored in blue, and fields that were underpressured prior to production are colored green. Most of the western Tyler fields all contain evidence of overpressuring prior to injection with the exception of Davis Creek. The eastern Tyler fields were at or below hydrostatic pressure, with the exception of the Heart River and Eland fields. Field boundaries are approximate. In the bottom right corner is an index map of North Dakota showing the Tyler DST's of interest with their NDIC well numbers that are located outside the main area of Tyler production. DST results indicate that the Tyler Formation is over-pressured in three wells and at hydrostatic pressure within two wells outside the area of main production.

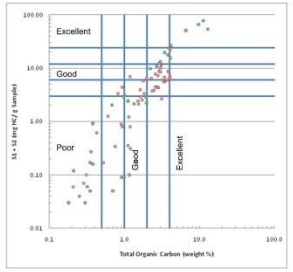


Figure 9. A kerogen quality diagram (Dembicki, 2009) constructed from the Total Organic Carbon (TOC) versus the mass of existing (S1) and potential (S2) hydrocarbons contained in samples of the Tyler Formation. The samples are from the Government Taylor A-1 (green circles) and the State of North Dakota #41-36 (red squares).

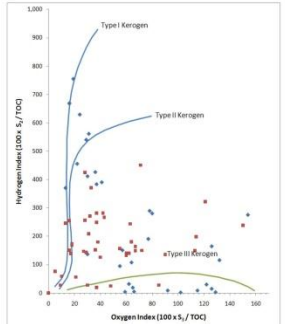


Figure 10. A modified van Krevelen diagram that classifies kerogen on the basis of the Hydrogen Index (HI) and Oxygen index (OI) derived from Rock Eval pyrolysis data. The blue diamonds represent the data from the Government Taylor A-1 (NDIC # 4627, SESE, Sec. 9, T139N, R103W) and the red squares refer to data from the State of North Dakota #41-36 (NDIC #: 4789, NE NE, Sec. 36, T137N, R100W). The data suggest that kerogen within the Tyler Formation includes oil prone Type I and Type II, gas prone Type III as well as mixtures of both oil and gas prone kerogen.

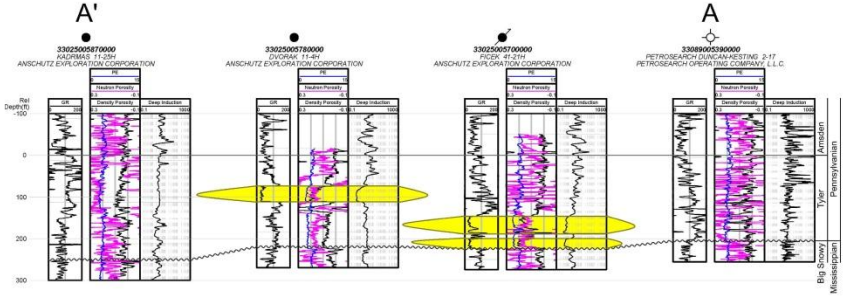


Figure 4. Cross-section extending from A to A' along the light blue line in Figure 5. The Kesting 2-17 (#14675 on Figure 5) corresponds to the point labeled A. Conventional sandstone reservoirs are shown in yellow. The section illustrates the discontinuous nature of the conventional sandstone reservoirs of the Tyler Formation.

Discussion

The purpose of this study is to examine the pressures within the Pennsylvanian aged Tyler Formation with the intent of determining whether or not the formation exhibits pressure-depth relationships consistent with a source system that is hydraulically isolated from the over and underlying formations. Hydraulic isolation is one of the key elements that Schmoker (1996) used to define a basin-centered petroleum accumulation. Meissner (1978) recognized several of these elements in the Bakken Formation in the Williston basin. In these accumulations, the source rock and reservoir rock are either one and the same or lie in very close proximity to one another. This occurs because the rocks that encase the source beds lack sufficient permeability to allow petroleum generated within the source beds to escape and migrate away. As a result, pressures within the source beds and associated reservoir rocks typically exhibit abnormally high or low formation fluid pressures relative to the pressure expected in a reservoir that is in hydraulic communication with the overlying rocks. The "expected" pressure in this study assumes hydrostatic conditions so that the expected pressure would be consistent with a hydrostatic gradient of between 0.43 and 0.49 psi/ft. Therefore, abnormally low or high pressure would yield hydraulic gradients (pressure/depth) that lie outside the range of gradients that correspond with fresh water (0.43 psi/ft) or saltwater (0.49 psi/ft).

The Tyler Formation is a regionally extensive, organically-rich, Pennsylvanian unit deposited during the earliest stages of the Absaroka Sequence. Terrestrial sediments derived from source areas south of the Williston basin are interbedded with nearshore, marine limestone and shale (Gerhard and Anderson, 1988). The Tyler Formation is bounded below by an erosional surface developed on Mississippian aged rocks formed during tectonic uplift in the Late Mississippian and Early Pennsylvanian. A variety of lithologies consistent with progradation of sediments into the basin overly the Tyler except along the eastern margin of the basin where these rocks have been truncated by the erosional surface that marks the Absaroka – Zuni sequence boundary (Anderson, 1972; Gerhard and Anderson, 1988).

Pressure gradients were obtained from pressure build up curves and pressure recorder depths used during drill stem tests of the Tyler Formation. Estimates of formation pressures are obtained by constructing Horner plots in which formation pressures are plotted against the logarithm of Horner time (Horner Time = [total Flow Time + Δshut-in time]/Δshut-in time). The formation pressure is determined from the Horner plot by finding the y-intercept of the best-fit line that passes through the pressures recorded during the last part of the shut-in periods (See Figures 1-3).

The range of initial pressure gradients present in the Tyler Formation suggest that the formation is frequently over-pressured and in a few cases under-pressured. Several fields were initially over-pressured and prior to injection: Dance Creek, Eland, Flat Top Butte, Fryburg, Heart River, Medora, Rocky Ridge, and Round Top Butte (Figure 8). Most of these over-pressured fields are located on the western side of the producing Tyler fields. Two fields may have been under-pressured prior to production, Bell and North Creek, which are located in the central area of most of the producing Tyler Fields (Figure 8). These results lead to the conclusion that the Tyler Formation is not always in hydraulic communication with the units above or below it and thus suggests that the Tyler may be sufficiently isolated so as prevent the petroleum generated within the Tyler Formation to escape.

The Time-Temperature Index (TTI) map of the Tyler Formation, constructed from modern geothermal heat flow measurements (SMU Geothermal Lab, 2010) and stratigraphic interval thickness data shows that oil production from the Tyler Formation is from rocks that are mature enough to generate oil. RockEval data also indicates that at least some of the organic-rich rocks within the Tyler are good to excellent source rocks even though there is probably more than one type of kerogen present. The available Rock Eval data also confirms the presence of thermally mature shales in vicinity of current Tyler production (Figures 5 & 7).

The limited data available today suggest the Tyler Formation is a regionally extensive unit that may contain good to excellent quantities of oil prone kerogen (Figures 9 & 10) that is sufficiently mature (Figure 7) to generate oil within a hydraulically compartmentalized environment (Figure 8). If so, then the Tyler Formation possesses the elements needed to qualify as a basin centered petroleum accumulation.

References

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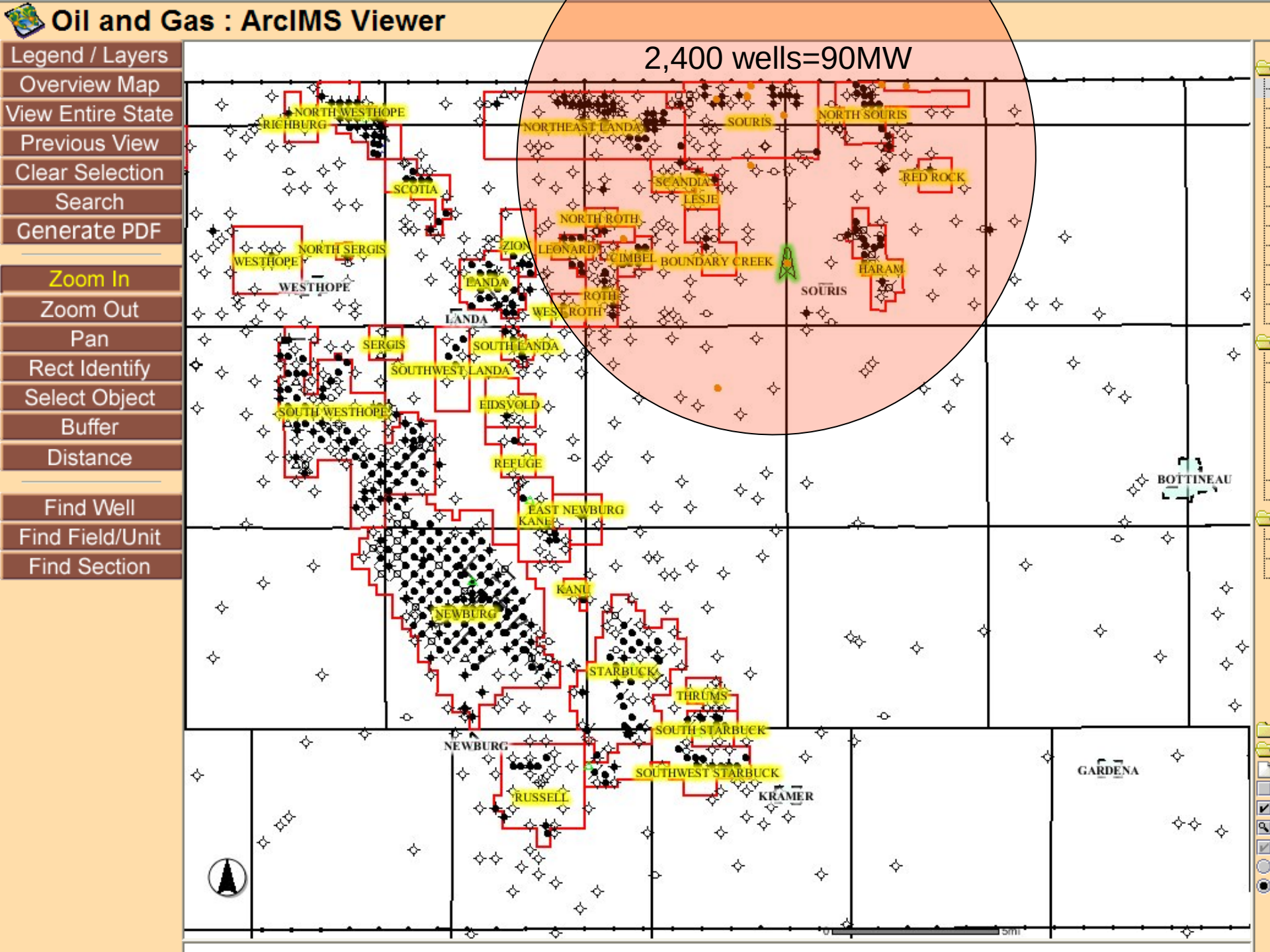
Oil and Gas : ArcIMS Viewer
2,400 wells=90MW
Legend / Layers
Overview Map
View Entire State
Previous View
Clear Selection
Search
Generate PDF
Zoom In
Zoom Out
Pan
Rect Identify
Select Object
Buffer
Distance
Find Well
Find Field/Unit
Find Section
NORTH WESTHOPE
RICHBURG
SCOTIA
NORTH SERGIS
WESTHOPE
WESTHOPE
LANDA
SERGIS
SOUTH LANDA
SOUTHWEST LANDA
SOUTH WESTHOPE
EIDSVOLD
REFUGE
EAST NEWBURG
KANE
KANU
NEWBURG
NEWBURG
RUSSELL
STARBUCK
THRUMS
SOUTH STARBUCK
SOUTHWEST STARBUCK
KRAMER
GARDENA
BOTTINEAU
NORTHEAST LANDA
SOURIS
NORTH SOURIS
SCANDIA
LESJE
RED ROCK
NORTH ROTH
ZION
LEONARD
CIMBEL
BOUNDARY CREEK
HARAM
SOURIS
ROTH
WEST ROTH

File No. 15092
Armstrong #1-5 Hanson
Sec 5-T155N-R102W
Williams County, ND

Western North Dakota

- 1,100 to 2,700 wells/year = 2,000 expected
  - 100-225 rigs = 12,000 – 27,000 jobs
  - Another 10,000-15,000 jobs building infrastructure
  - 225 rigs can drill the wells needed to secure leases in 2 years
  - 225 rigs can drill the wells needed to develop spacing units in 16 years
  - 35,000-40,000 new wells = 45,000-50,000 long term jobs

FRAC WATER ADDITIVES

- 99.5% water and sand
  - 80.5% water
  - 19.0% proppant
  - 0.5% chemicals
    - most are found in every household

- **Compound**
  - **Purpose**
    - **Common application**

- Fresh **Water** – 80.5%
- Proppant – 19.0%
  - Allows the fractures to remain open so the oil and gas can escape
    - Drinking water filtration, **play ground sand**
- Acids - 0.12%
  - Help dissolve minerals and initiate fractures in rock (pre-fracture)
    - **Swimming pool cleaner**
- Petroleum distillates – 0.088%
  - Dissolve polymers and minimize friction
    - **Make-up remover**, laxatives, and candy
- Isopropanol – 0.081%
  - Increases the viscosity of the fracture fluid
    - **Glass cleaner**, antiperspirant, and hair color
- Potassium chloride – 0.06%
  - Creates a brine carrier fluid
    - Low-sodium **table salt substitute**
- Guar gum – 0.056%
  - Thickens the water to suspend the sand
    - **Thickener used in cosmetics**, baked goods, ice cream, toothpaste, sauces, and salad dressing
- Ethylene glycol – 0.043%
  - Prevents scale deposits in the pipe
    - Automotive **antifreeze**, household cleansers, deicing, and caulk

- Sodium or potassium carbonate – 0.011%
  - Improves the effectiveness of other components, such as cross-linkers
    - Washing soda, detergents, **soap**, water softeners, glass and ceramics
- Sodium Chloride – 0.01%
  - Delays break down of the gel polymer chains
    - **Table Salt**
- Polyacrylamide – 0.009%
  - Minimizes friction between fluid and pipe
    - **Water treatment**, soil conditioner
- Ammonium bisulfite – 0.008%
  - Removes oxygen from the water to protect the pipe from corrosion
    - Cosmetics, **food and beverage processing**, water treatment
- Borate salts – 0.007%
  - Maintain fluid viscosity as temperature increases
    - Used in laundry **detergents**, hand soaps and cosmetics
- Citric Acid – 0.004%
  - Prevents precipitation of metal oxides
    - **Food additive**; food and beverages; lemon juice
- N, n-Dimethyl formamide – 0.002%
  - Prevents the corrosion of the pipe
    - Used in **pharmaceuticals**, acrylic fibers and plastics
- Glutaraldehyde – 0.001%
  - Eliminates bacteria in the water
    - **Disinfectant**; Sterilizer for medical and dental equipment

Hydraulic Fracturing Stimulation is Safe

- IOGCC survey—no contamination
- EPA survey – no contamination
- GWPC study verifies State's regs
- GWPC - IOGCC FracFocus Chemical Registry

PLANNING FOR THE FUTURE
BEST PRACTICES

- Rules require posting HF
  - must post on FracFocus

Find a Well

Back To Search

Next Page

Page 1 of 5 Go

	API No.	Job Date	State	County	Operator	WellName	Well Type	Latitude	Longitude	Datum
	33-025-01132	4/13/2011	North Dakota	Dunn	XTO Energy/ExxonMobil	Alwin Federal 12X-19	Oil	47.627564	-102.967017	NAD83
	33-105-01913	4/18/2011	North Dakota	Williams	XTO Energy/ExxonMobil	Lonnie 31X-3	Oil	48.196639	-102.880264	NAD83
	33-105-01824	5/14/2011	North Dakota	Williams	XTO Energy/ExxonMobil	Allen 21X-17	Oil	48.254792	-103.058819	NAD83
	33-105-01825	4/28/2011	North Dakota	Williams	XTO Energy/ExxonMobil	Woodrow 34X-32	Oil	48.198603	-103.053617	NAD83
	33-053-03113	3/22/2011	North Dakota	Mc Kenzie	XTO Energy/ExxonMobil	101 Federal 21X-24	Oil	47.546178	-104.000694	NAD83
	33-105-01948	2/26/2011	North Dakota	Williams	XTO Energy/ExxonMobil	Normark 24X-31	Oil	48.460233	-103.008811	NAD83
	33-105-01899	2/17/2011	North Dakota	Williams	XTO Energy/ExxonMobil	Michael State 31X-16	Oil	48.167464	-103.031950	NAD83
	33-025-01165	5/9/2011	North Dakota	Dunn	Marathon Oil	Lucky Fleckenstien #34-20H	Oil	47.264306	-102.330608	NAD83
	33-025-01173	5/3/2011	North Dakota	Dunn	Marathon Oil	Wardner #24-35H	Oil	47.245872	-102.445641	NAD83

Find a Well

Map Search | Standard Search

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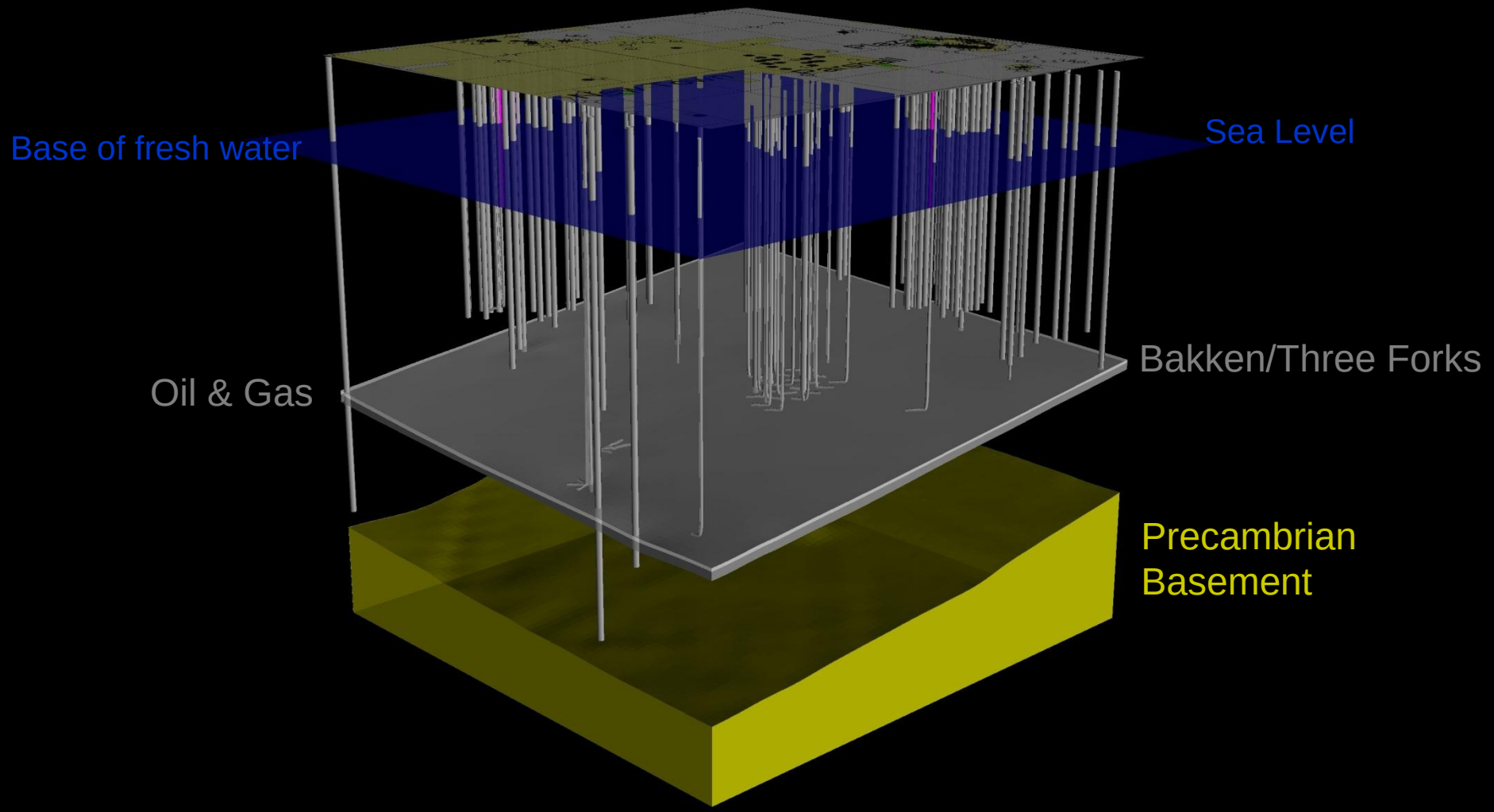
API No.	Job Date	State	County	Operator	WellName	Well Type	Latitude	Longitude	Datum
33-105-02499	5/30/2012	North Dakota	Williams	XTO Energy/ExxonMobil	Odegaard State 21X-16B	Oil	48.429725	-102.963286	NAD83
33-105-02356	6/1/2012	North Dakota	Williams	Liberty Resources LLC	Cornabean 156-101-25-3...	Oil	48.286012	-103.612185	NAD83
33-105-02478	5/14/2012	North Dakota	Williams	Liberty Resources LLC	Sylte 156-101-10-3 1H	Oil	48.341817	-103.661435	NAD83
33-105-02479	5/12/2012	North Dakota	Williams	Liberty Resources LLC	Sylte 156-101-15-22 1H	Oil	48.341817	-103.661558	NAD83
33-105-01866	5/20/2012	North Dakota	Williams	Zavanna, LLC	MARLIN 27-34 1H	Oil	48.139041	-103.405815	NAD83
33-105-02553	6/3/2012	North Dakota	Williams	XTO Energy/ExxonMobil	Thaxton 24X-35B	Oil	48.198333	-103.123097	NAD83
33-105-02504	5/11/2012	North Dakota	Williams	Samson	Longhorn 9-4-158-99H	Oil	48.518656	-103.482061	NAD83
33-105-02076	6/29/2012	North Dakota	Williams	XTO Energy/ExxonMobil	Wagner 24X-23B	Oil	48.402347	-103.051058	NAD83


Base of fresh water
Sea Level
Oil & Gas
Bakken/Three Forks
Precambrian
Basement

Cap and trade proposals in congress could reduce activity an estimated 35-40%

Current administration budget contains tax rule changes that could reduce activity an estimated 35-50%

Oil price below $50 WTI could reduce activity an estimated 25-30%

The future looks promising for sustained Bakken/Three Forks development

EPA regulation of hydraulic fracturing could halt drilling activity for 18-24 months production decline of 25-30%

Federal minor source air permits require 6 -12 months for approval

FRAC WATER ADDITIVES

- 99.5% water and sand
  - 80.5% water
  - 19.0% proppant
  - 0.5% chemicals
    - most are found in every household

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	5/30/2012
State:	North Dakota
County:	Williams
API Number:	33-105-02499
Operator Name:	XTO Energy, Inc.
Well Name and Number:	Odegaard State 21X-16B
Longitude:	-102.963286
Latitude:	48.429725
Long/Lat Projection:	NAD83
Production Type:	Oil
True Vertical Depth (TVD):	9,680
Total Water Volume (gal)*:	2,453,808

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Water			Water	7732-18-5	100.00%	87.29658%	
Sand	Schlumberger	Proppant	Crystalline Silica	14808-60-7	100.00%	11.65037%	
B306	Schlumberger	Gel					
			Hydrocarbon hydrocarbon	Proprietary	60.00%	0.23269%	Pending Disclosure by Supplier
			Guar gum	9000-30-0	60.00%	0.23269%	
J583	Schlumberger	Clay Stabilizer (w/Surfactant)					
			Tetramethylammonium chloride	75-57-0	40.00%	0.09883%	
			Decyl-dimethyl amine oxide	2605-79-0	10.00%	0.02471%	
			Proprietary Component	Proprietary	50.00%	0.12354%	Pending Disclosure by Supplier
W054	Schlumberger	Non-Emulsifying Surfactant					
			Methanol	67-56-1	70.00%	0.09987%	
			Oxyalkylated alkyl alcohol (1)	Proprietary	10.00%	0.01427%	Pending Disclosure by Supplier
			Oxyalkylated alcohol (2)	Proprietary	10.00%	0.01427%	Pending Disclosure by Supplier
			Quaternary ammonium compound	Proprietary	5.00%	0.00713%	Pending Disclosure by Supplier
			Heavy aromatic naphtha	64742-94-5	5.00%	0.00713%	
			Oxyalkylated alcohol (1)	Proprietary	5.00%	0.00713%	Pending Disclosure by Supplier
J610	Schlumberger	Crosslinker					
			Aliphatic polyol	Proprietary	30.00%	0.04211%	Pending Disclosure by Supplier
			Potassium hydroxide	1310-58-3	15.00%	0.02105%	
			Proprietary Component	Proprietary	55.00%	0.07720%	Pending Disclosure by Supplier
Gyptron T-475	Champion Technologies	Antiscale					
			Ethylene Glycol	67-56-1	30.00%	0.02357%	
			Methanol	67-56-1	10.00%	0.00786%	
			Amine phosphonate 5	Proprietary	5.00%	0.00393%	Pending Disclosure by Supplier

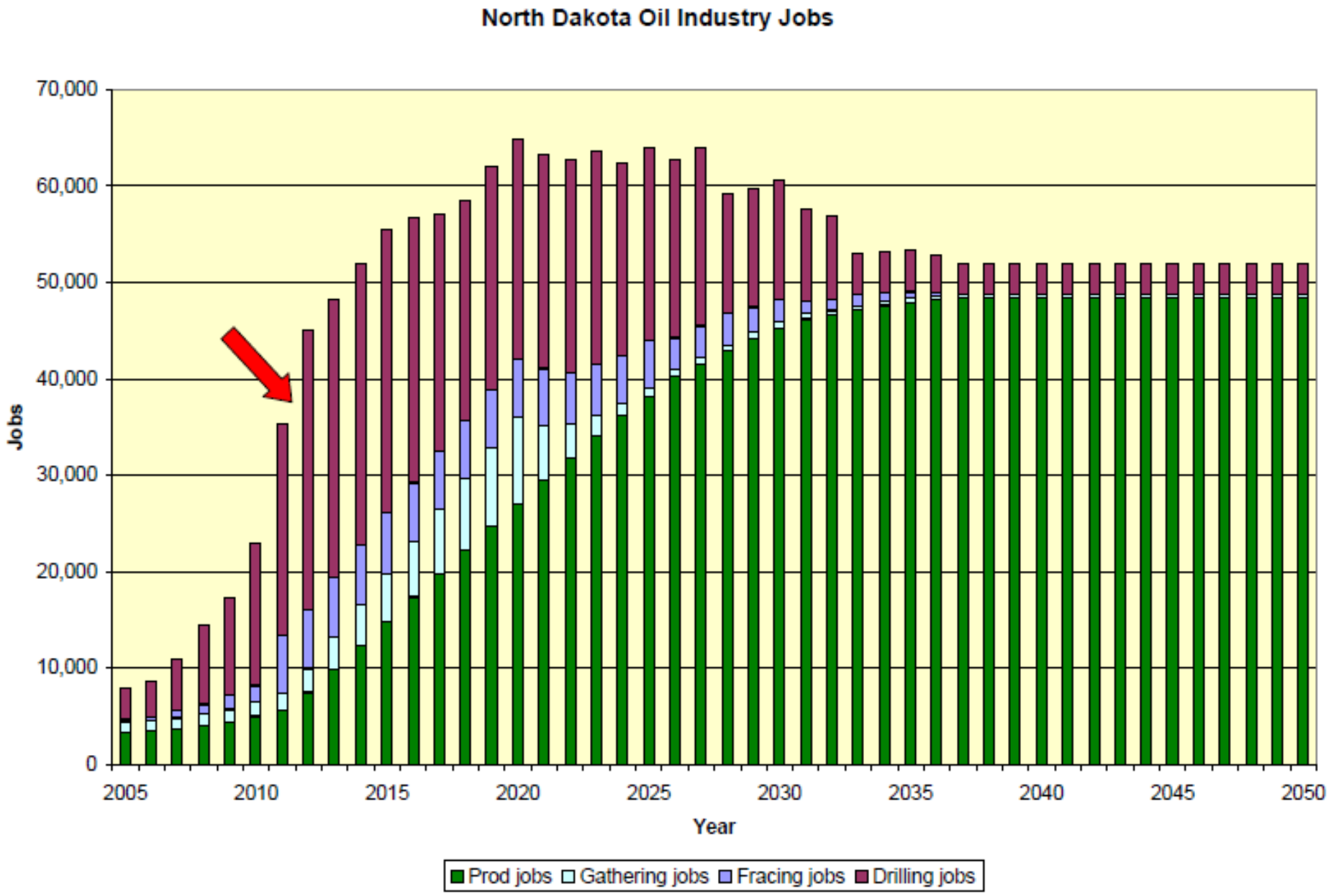
PLANNING FOR THE FUTURE
BEST PRACTICES

- New Commission Rules
  - Eliminates 95% of reserve pits
    - smaller footprint
    - reclaim in 30 days

Recent Commission Orders

- recycle water flowback
- drill cuttings for road base
- recycle drilling mud

Expected Case



WESTERN NORTH DAKOTA ROADS, WATER, & HOUSING

Status of 2011-13 Biennium Expenditures and Allocations

as of April 30, 2012

(in millions)

INFRASTRUCTURE

Oil & Gas Tax Distributions to Cities & Counties
$95.7 mm distributed out of $247.2 mm total

Energy Impact Grant Expenditures
$78.2 mm committed out of $135 mm total

Regular DOT Road Program
$150.6 mm expended out of $295.1 mm total

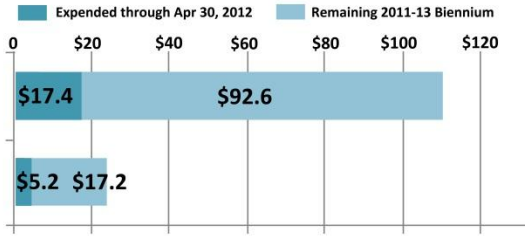
Special State Highway Maintenance Program
$71.1 mm expended out of $228.6 mm total

County & Township Road Reconstruction Program
$69.1 mm expended out of $142.0 mm total

WATER

Western Area Water Supply Program
$17.4 mm expended out of $110 mm total

Southwest Water Pipeline Project
$5.2 mm expended out of $22.4 mm total



$132.4mm

HOUSING

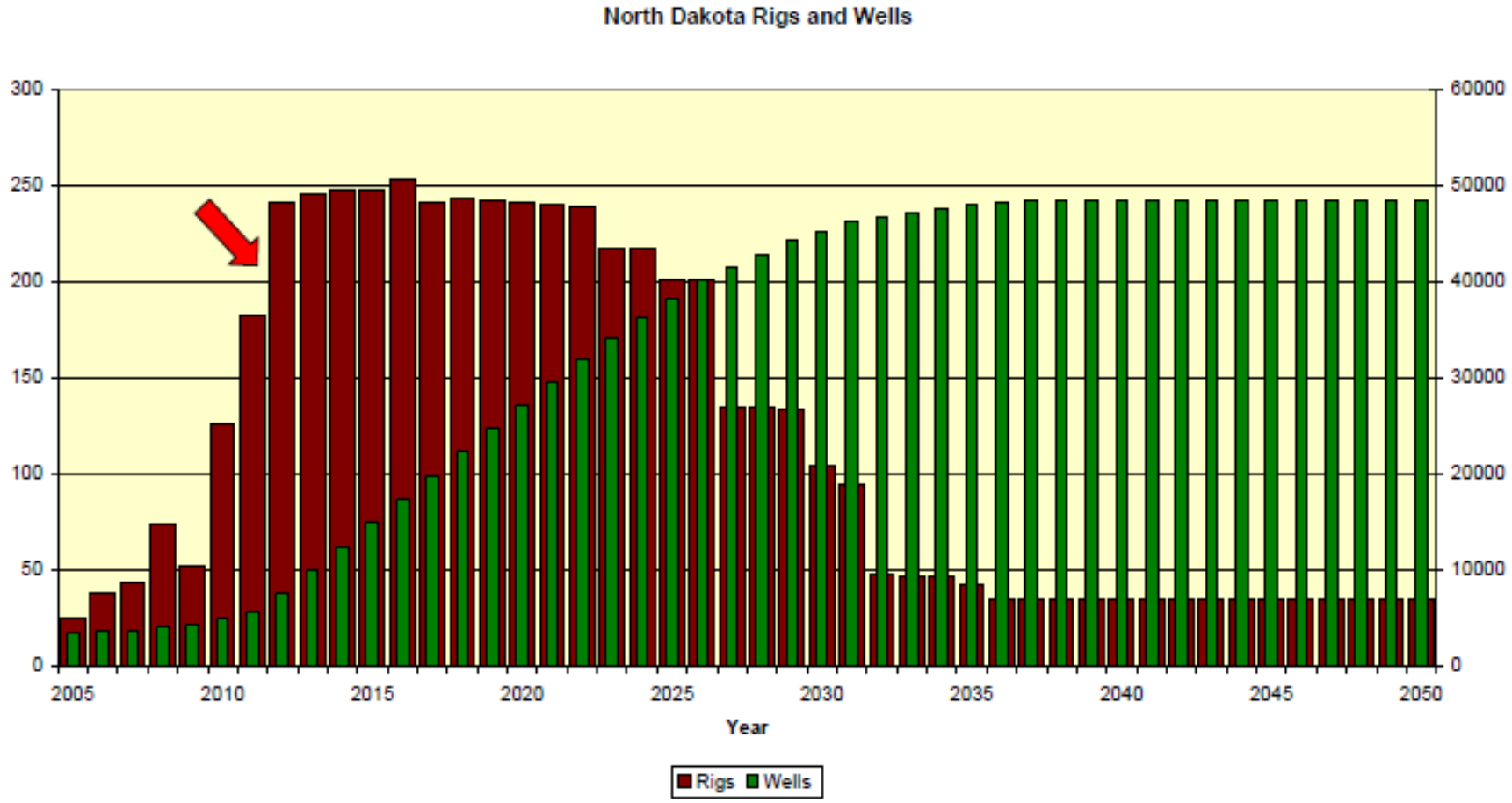
Housing Incentive Fund
$3.9 mm allocated out of $13.5 mm total

Federal Low-Income Housing Tax Credits
$3.9 mm allocated out of $3.9mm total

$17.4mm

TOTAL

Total 2011-13 Biennium Expenditures & Allocations
$495.1 mm expended out of $1,197.7mm total


North Dakota Rigs and Wells
300
250
200
150
100
50
0
60000
50000
40000
30000
20000
10000
0
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
Year
Rigs
Wells

WESTERN NORTH DAKOTA ROADS, WATER, & HOUSING

Status of 2011-13 Biennium Expenditures and Allocations

as of April 30, 2012

(in millions)

INFRASTRUCTURE

Oil & Gas Tax Distributions to Cities & Counties
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$1.048b

WATER

Western Area Water Supply Program
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Southwest Water Pipeline Project
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HOUSING

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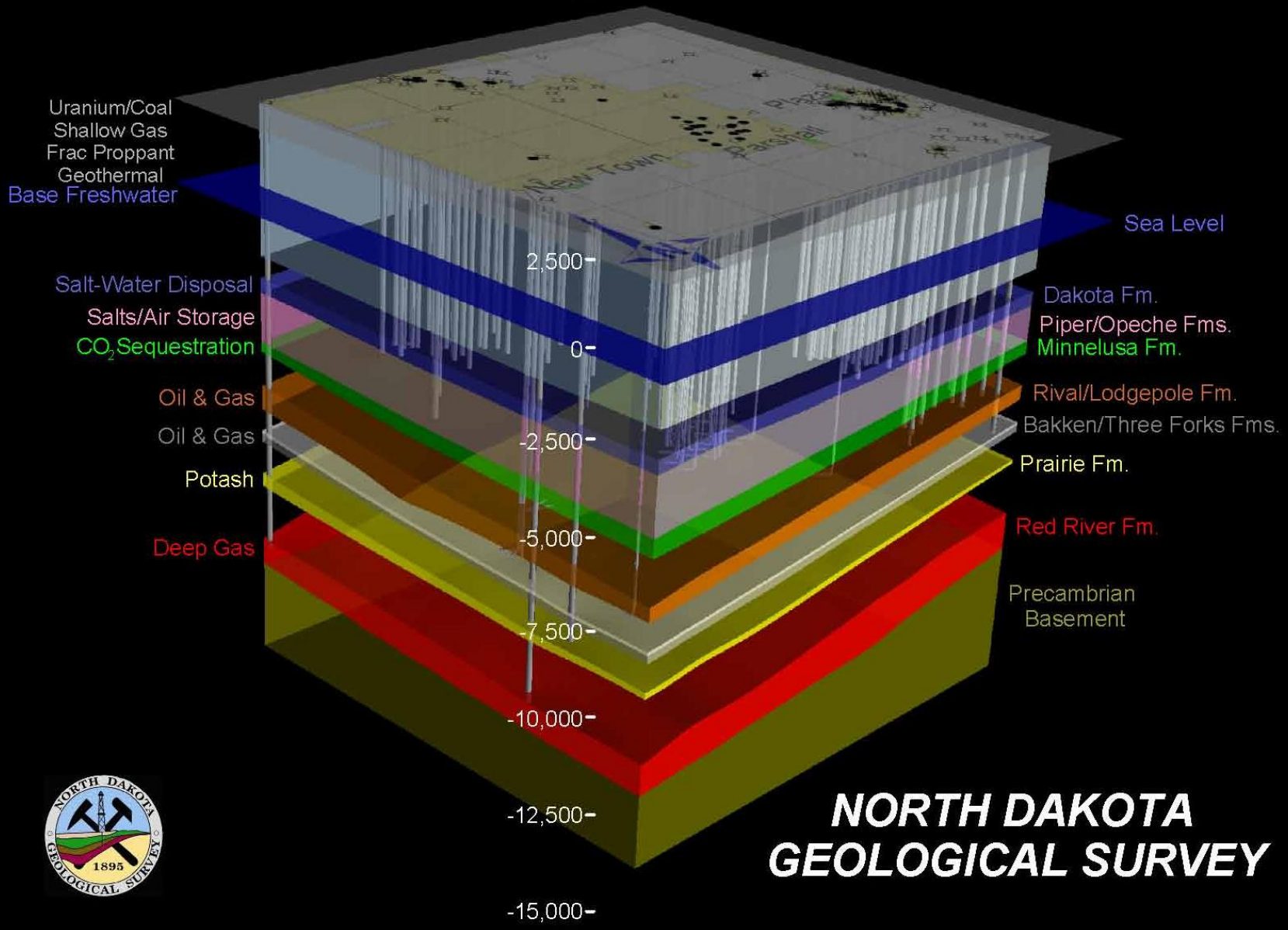
Federal Low-Income Housing Tax Credits
$3.9 mm allocated out of $3.9mm total

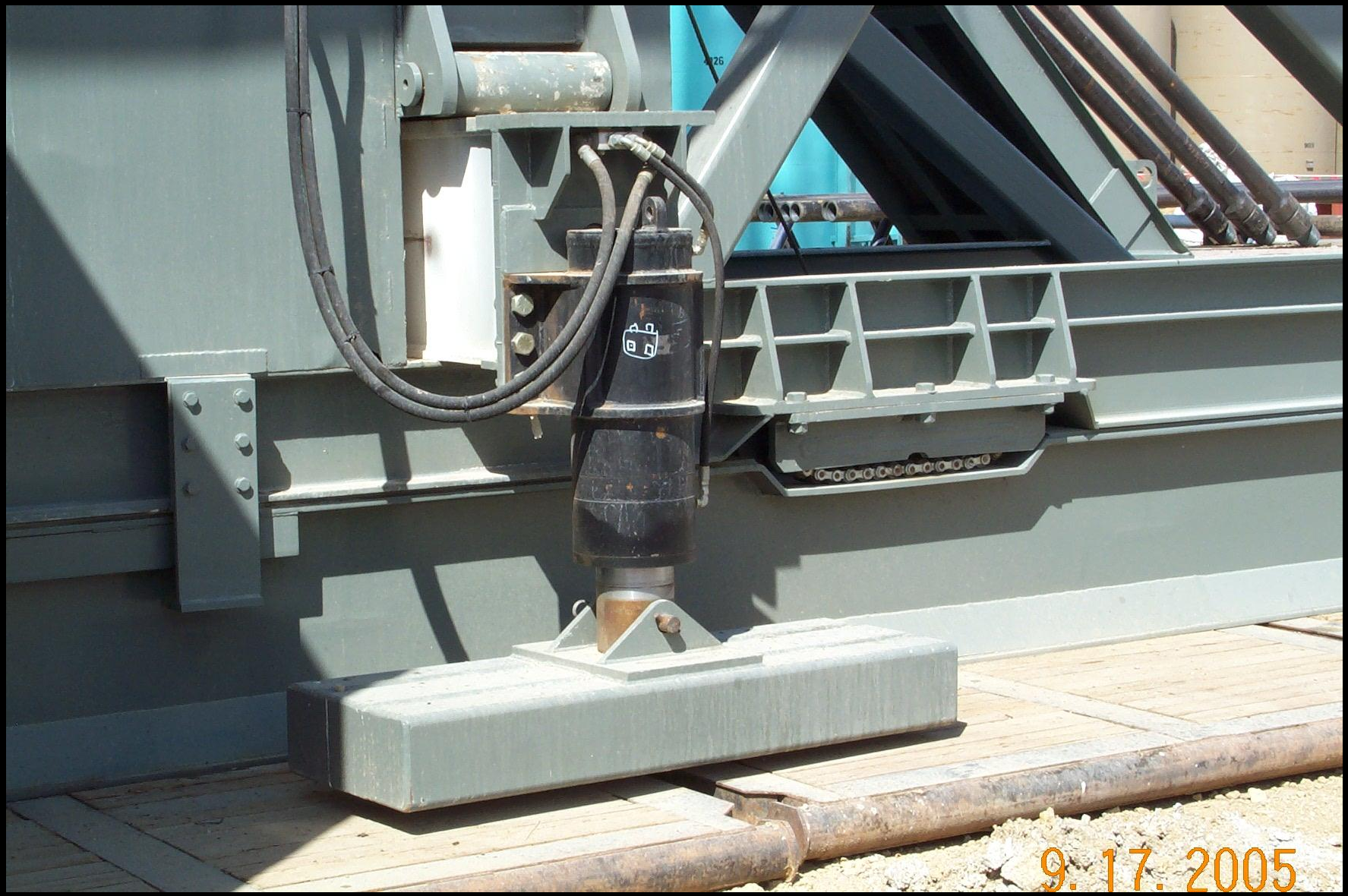
TOTAL

Total 2011-13 Biennium Expenditures & Allocations
$495.1 mm expended out of $1,197.7mm total

Three-Dimensional Geologic Model of the Parshall Area



NORTH DAKOTA GEOLOGICAL SURVEY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