CWAG ENERGY CONFERENCE

NORTH DAKOTA OIL & GAS UPDATE

Big Sky, Montana – February 16, 2012

OIL & GAS UPDATE

- North Dakota results
  - magnitude of play
- Impact of Development
  - pros and cons
- Planning for the Future
  - best practices

Bruce E. Hicks
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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/*

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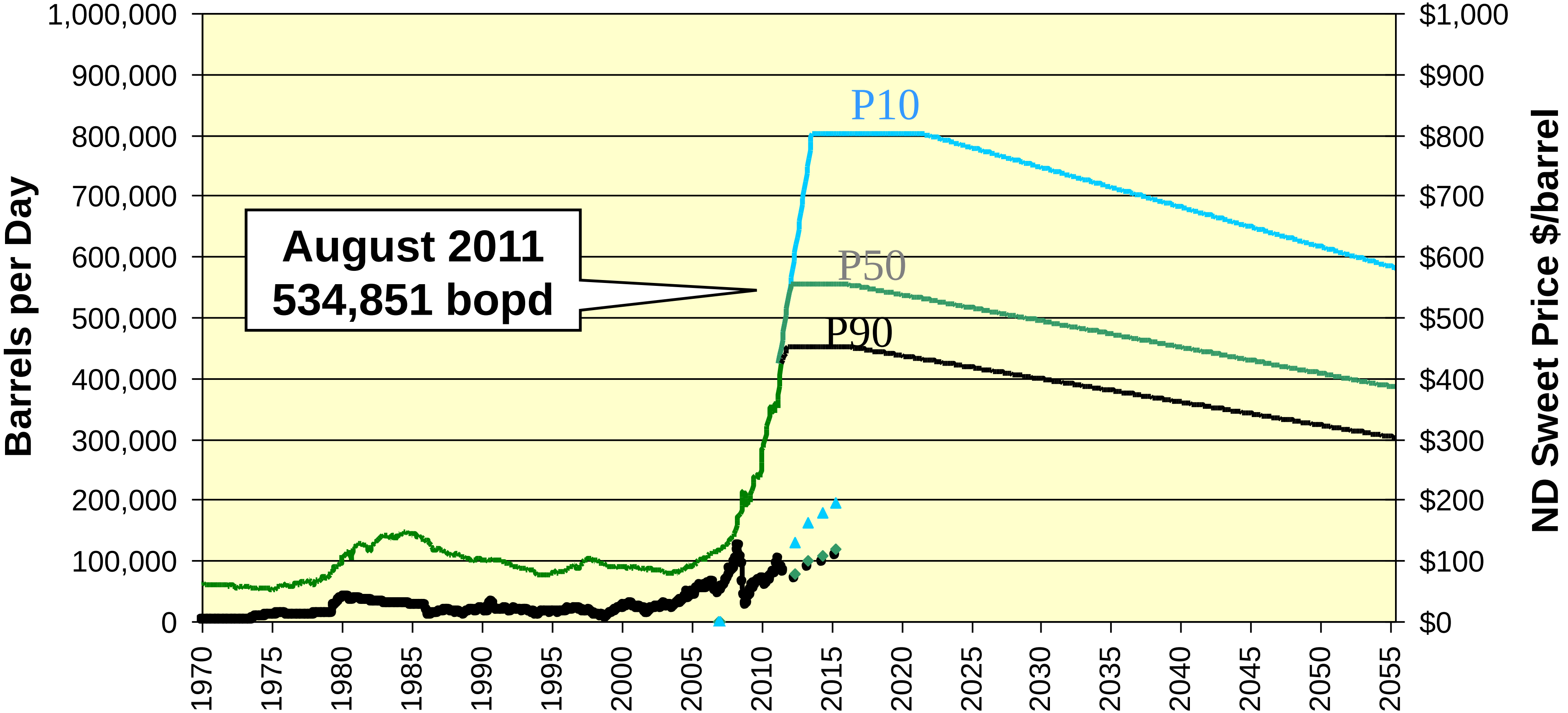
North Dakota Oil Production and Price

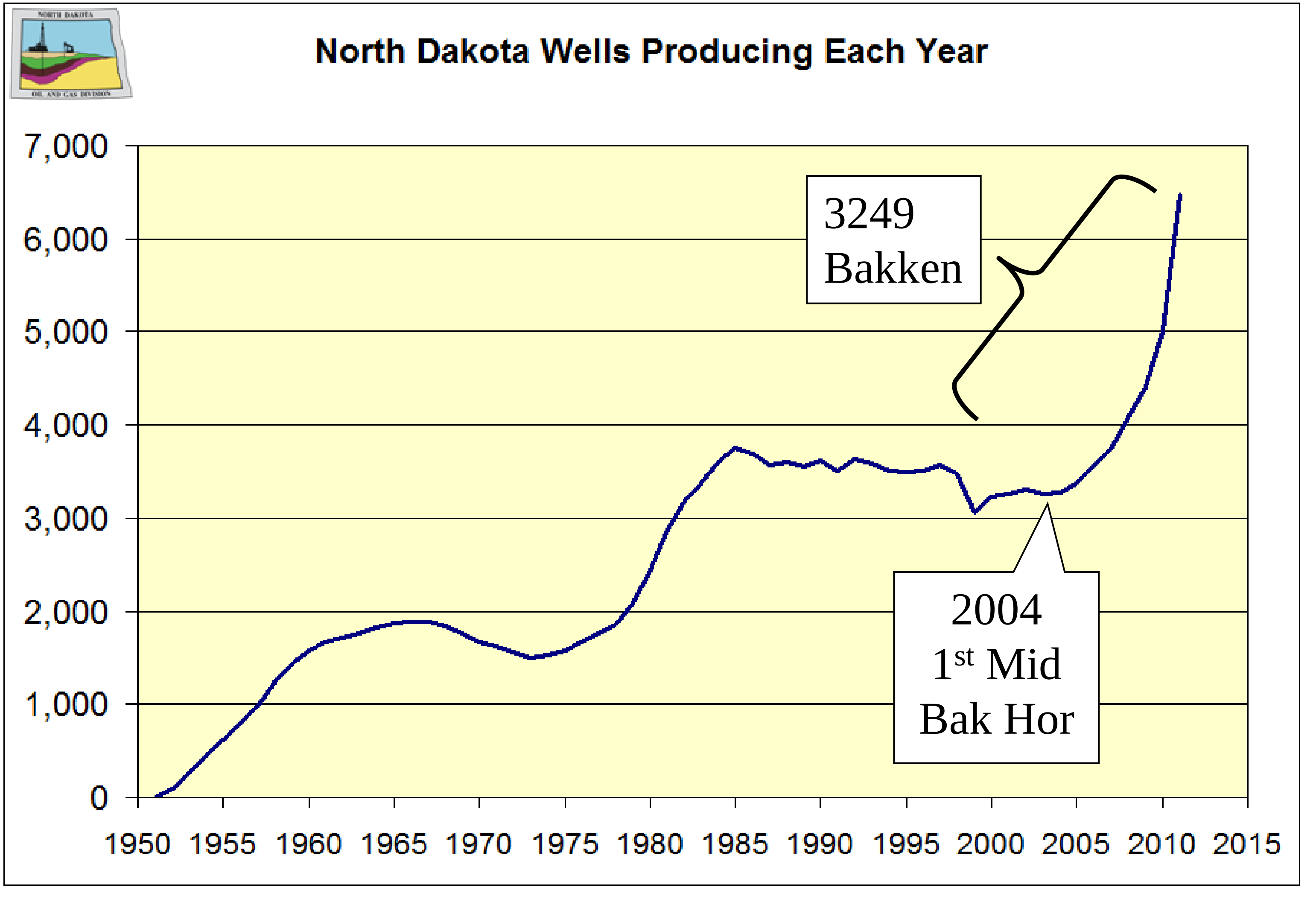


3,249 Bakken and Three Forks wells drilled and completed

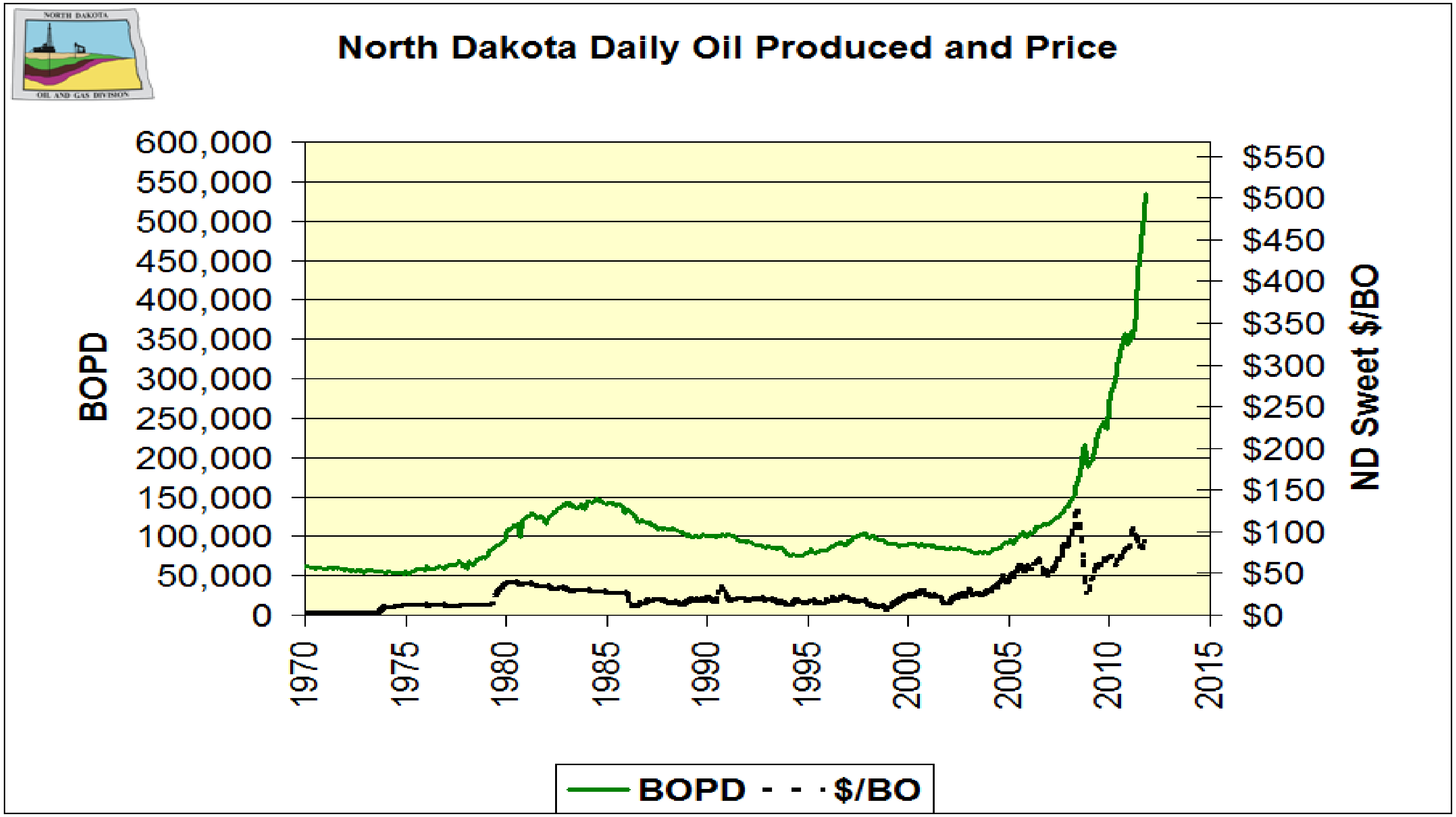
30,000 more new wells possible in thermal mature area

P90=5 BBO – P50=7 BBO – P10=11 BBO (billion barrels of oil)

History
Bakken - Three Forks P10
Bakken - Three Forks P50
Bakken - Three Forks P90
$/Barrel History & DOE-EIA Projected
$/Barrel P50
$/Barrel P10

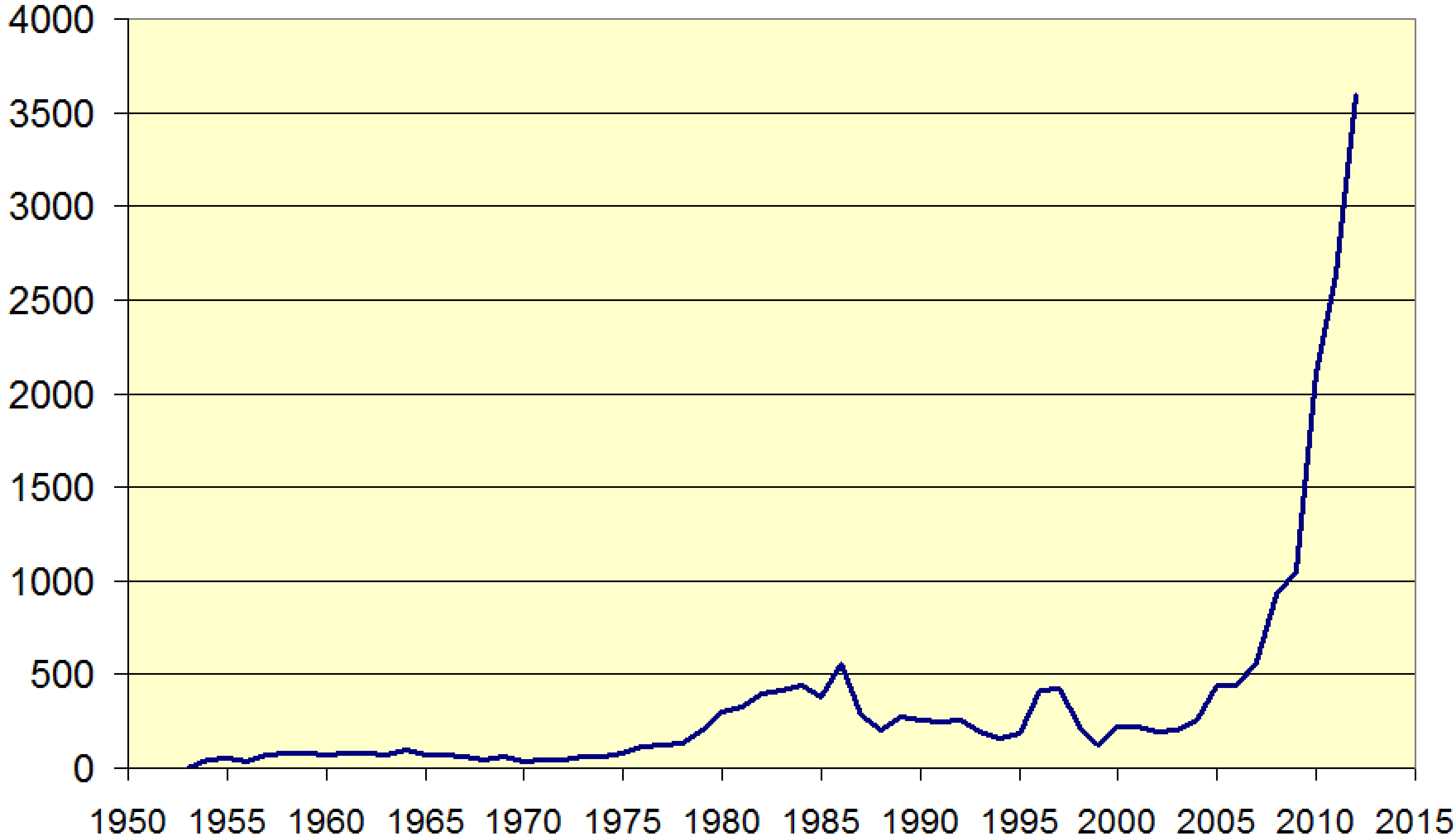


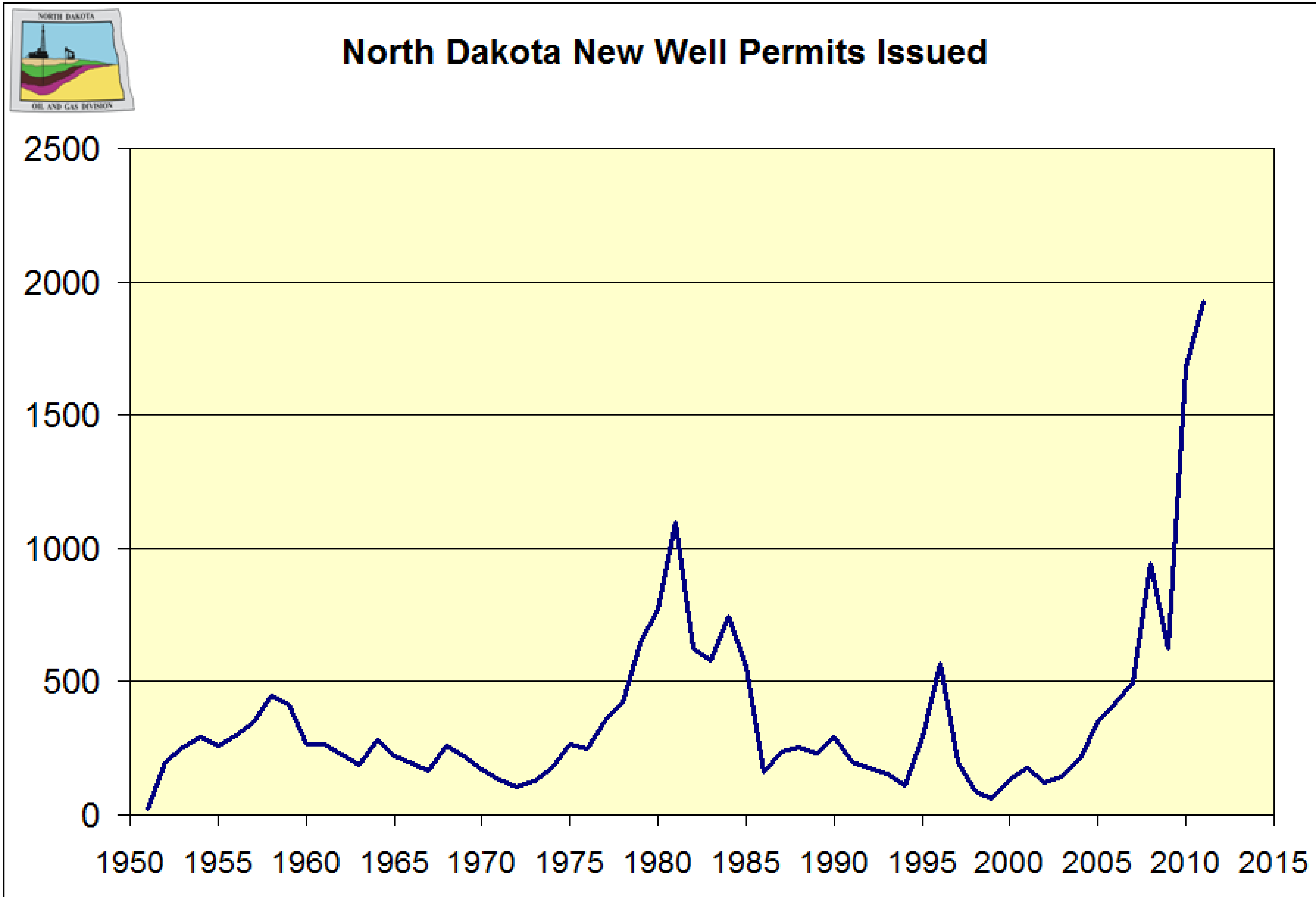
6470 total wells – 3249 Bakken horizontal (50.2%)



Production 534,851 bopd (appr 468,000 from Bakken—87.5%)

North Dakota Industrial Commission Cases Heard




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

NDIC RBDMS - [frmLocWells : Form]

File Edit Forms Reports View Records Admin Window Help

Rigs and "LOC" Wells

Legend: Run Query Sort By

List By ( ) Inspectors (•) Counties

County	LOCs	Rig_A	(L/R)
BILLINGS	44	8	(5.5)
BOTTINEAU	15	1	(15)
BOWMAN	8		
BURKE	64	13	(4.9)
DIVIDE	46	8	(5.8)
DUNN	202	36	(5.6)
GOLDEN VALLEY	2	2	(1)
HETTINGER	3		
MCKENZIE	295	56	(5.3)
MCLEAN	9	2	(4.5)
MOUNTRAIL	172	30	(5.7)
RENVILLE	11	1	(11)
STARK	42	6	(7)
WARD	1		
WILLIAMS	194	39	(5)

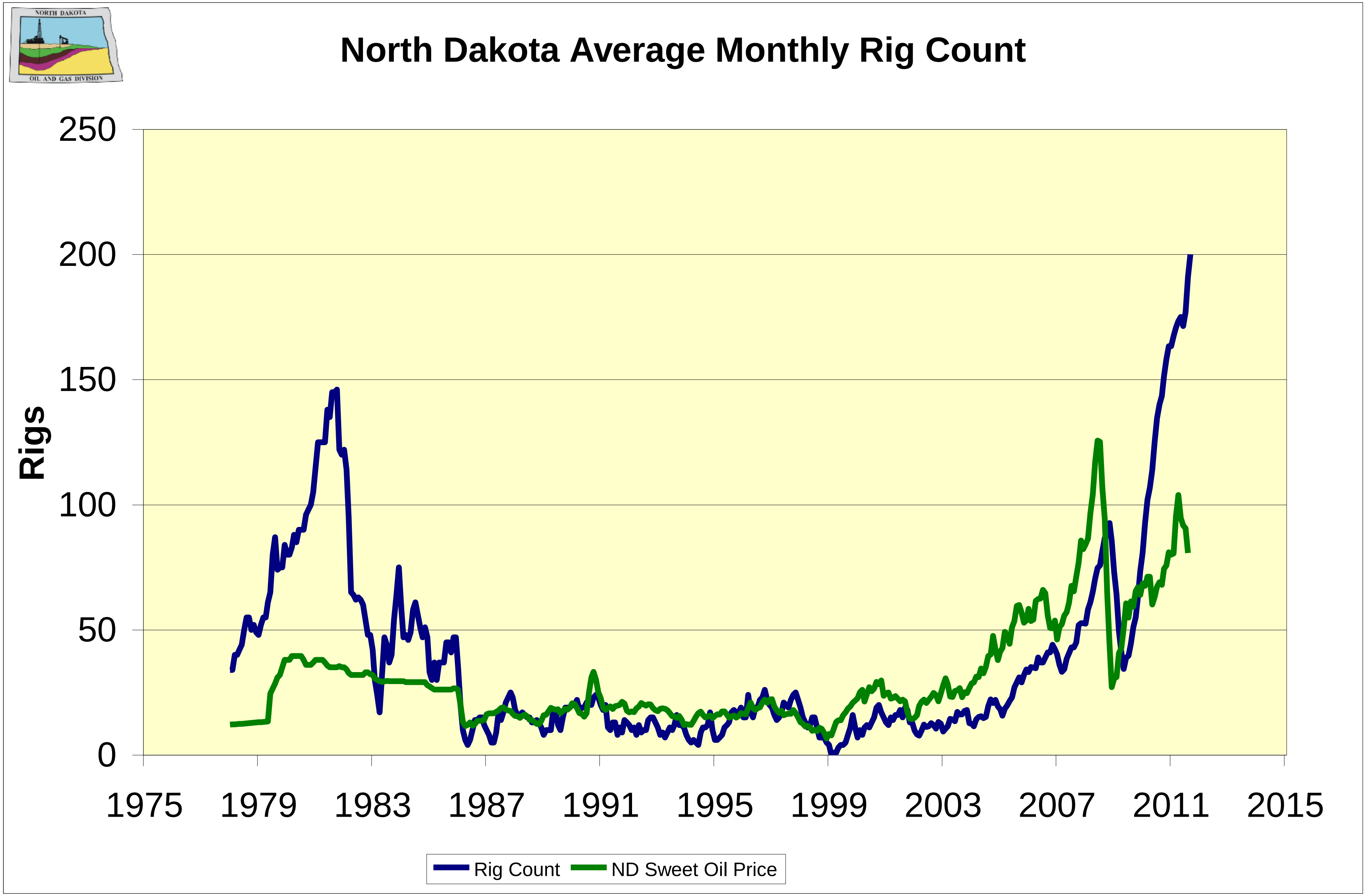
Show ALL Totals 1108 202 (5.5)

* Operator	Bonds	LOCs	RIGs	(L/R)	ePm
ABRAXAS PETROLM CORP.	3	3			
AMERICAN EAGLE	1	1	1	(1)	1
ARSENAL ENERGY USA INC.	2	2			
BALLANTYNE OIL, LLC	3	1			
BALLARD PETROLEUM	2	1	1	(1)	
* BAYTEX ENERGY USA LTD	1	5	2	(2.5)	
BENNET SWD, LLC	2	1			
BRIGHAM OIL & GAS LP	2	48	16	(3)	15
BUCKHORN ENERGY SERVICES	5	2			
* BURLINGTON RES O&G CO	8	48	7	(6.9)	21
CHESAPEAKE OPERATING INC	1	12	2	(6)	2
CHIMNEY SWEEP OIL & GAS CO	2	1			
* CONTINENTAL RESOURCES	12	103	20	(5.2)	47
CORINTHIAN EXPLORATION	1	4			
* CORNERSTONE NAT RES LLC	1	5	1	(5)	3
CRESCENT PT ENERGY US	1	8	3	(2.7)	5
DAKOTA-3 E&P CO	1	29	5	(5.8)	29

*** = Comments Exist for the Operator** 1108 202 (5.5) 426

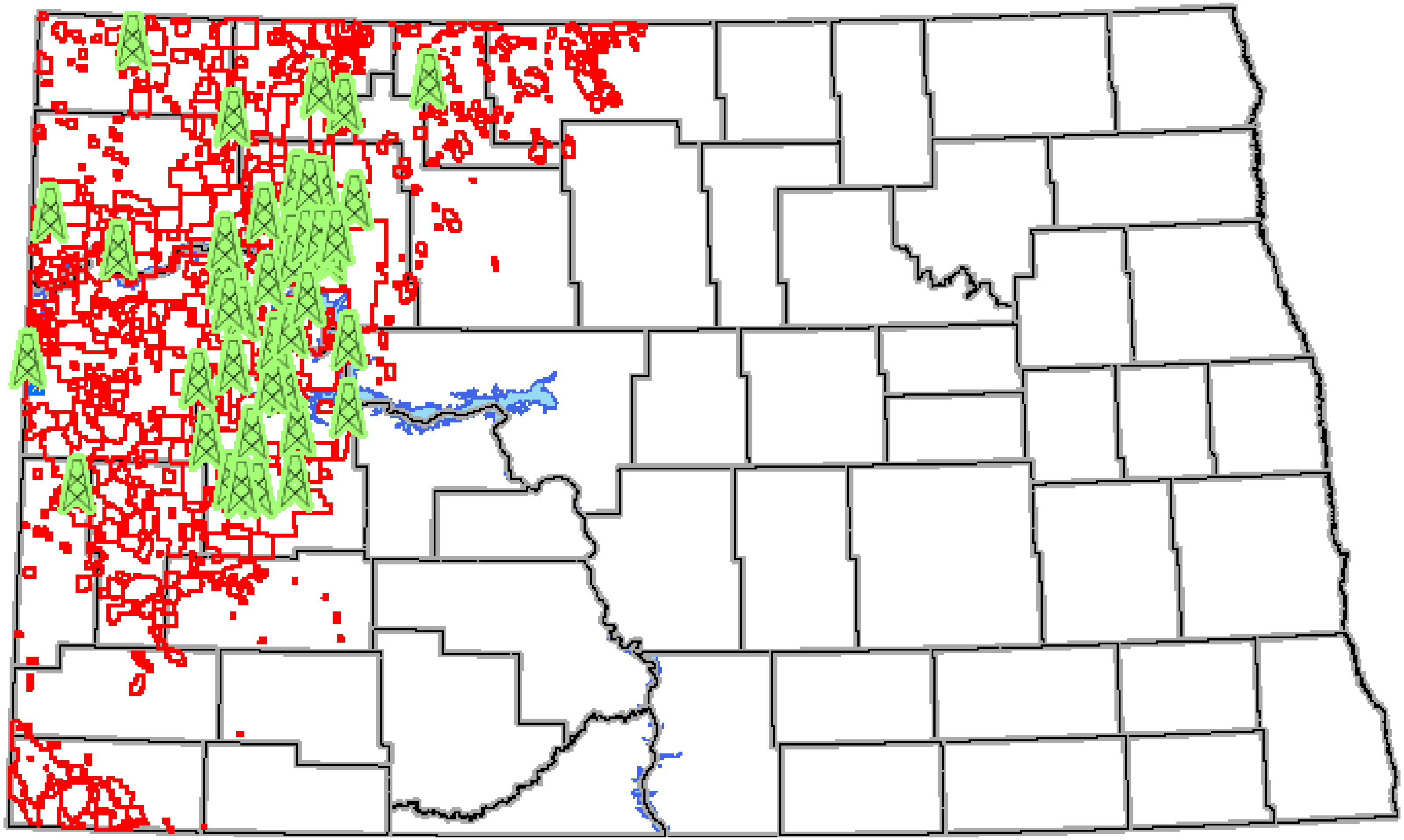
All Rigs / Loc Wells

v v FileNo	Operator	Well_Nm	Field	Cnty	Rig	Stat
9388	SLAWSON EXPL	MOEN 1-35 SWD	TIMBER CREEK	MCK	Y	DRL
11259	PETRO HARVES	OPSETH 29-1	SOUTH COTEAU	BRK	Y	A
12923	WHITING OIL AN	ROXANE 21-16H	PARK	BIL	Y	DRL
16435	WHITING OIL AN	BSMU 3204	BIG STICK	BIL	Y	DRL
18821	XTO ENERGY IN	ROUST 34X-7G	HOFFLUND	WIL	Y	DRL
18939	TRUE OIL LLC	ANDERSON 12-18H	BUFFALO WALLOV	MCK	Y	DRL
18969	PETRO HUNT LL	FORT BERTHOLD 148-95-27A-34-1H	WILDCAT	DUN	Y	DRL
19456	HESS CORPOR/	RS-BALL-157-90- 2227H-1	CLEAR WATER	MTL	Y	DRL
19685	FIDELITY EXPL {	KOSTELECKY 5-8H	HEART RIVER	STK	Y	DRL
19835	HESS CORPOR/	SKJEI MIDWEST TRUST 15-35H	RAINBOW	WIL	Y	DRL
20035	DAKOTA-3 E&P	MAGGIE OLD DOG 19-18H	REUNION BAY	DUN	Y	DRL
20053	SM ENERGY CC	NELSON 15-11H	WILDCAT	MCK	Y	DRL
20065	PETRO HUNT LL	ROSSLAND 157-101-14B-23-1H	WILDCAT	WIL	Y	DRL
20098	XTO ENERGY IN	JOHN 33X-8	GRINNELL	WIL	Y	DRL



NORTH DAKOTA
OIL AND GAS DIVISION
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

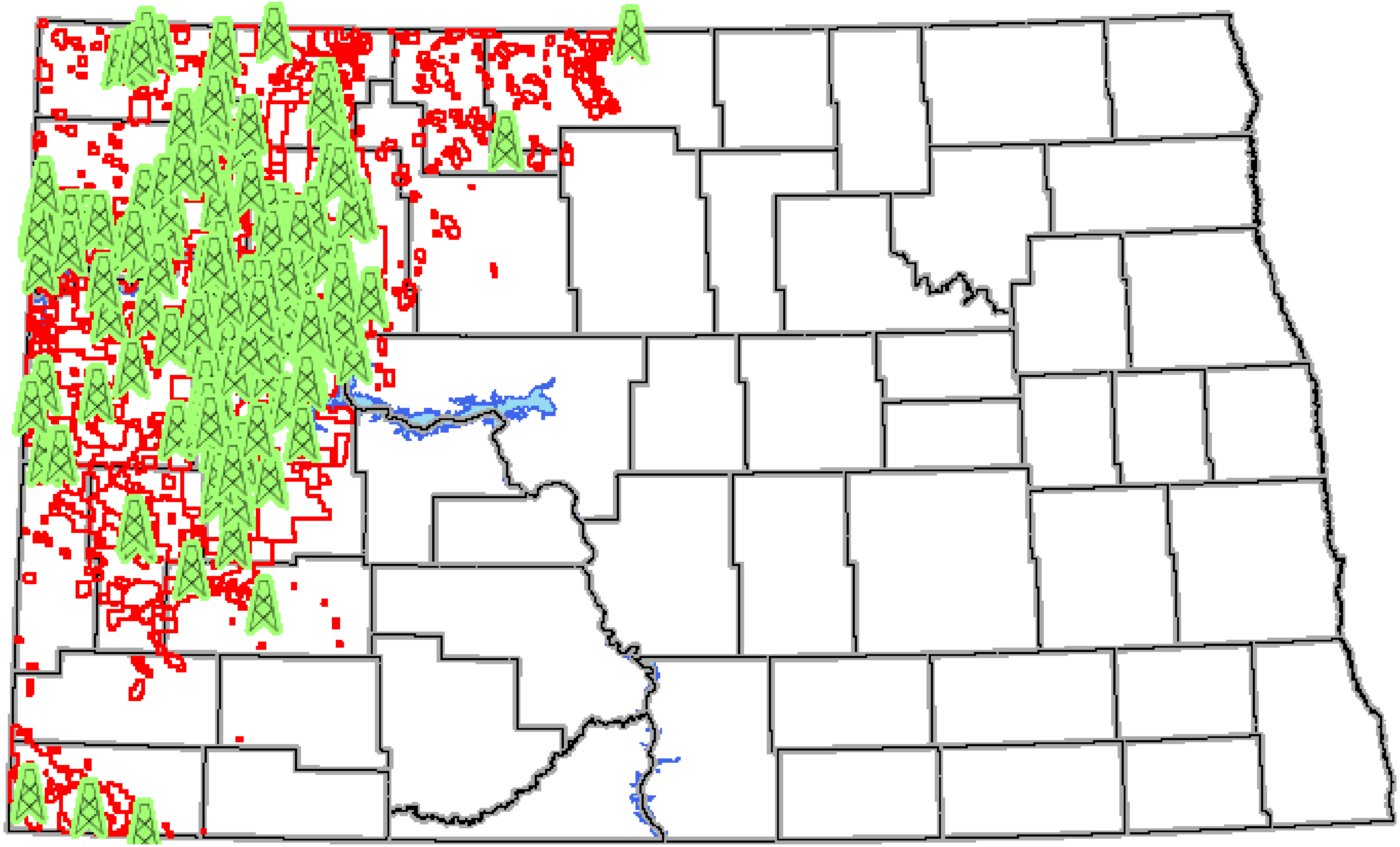
NORTH DAKOTA – 93 DRILLING RIGS – Feb 2010



Two years ago, drilling activity was focused

in Mountrail and Dunn Counties.

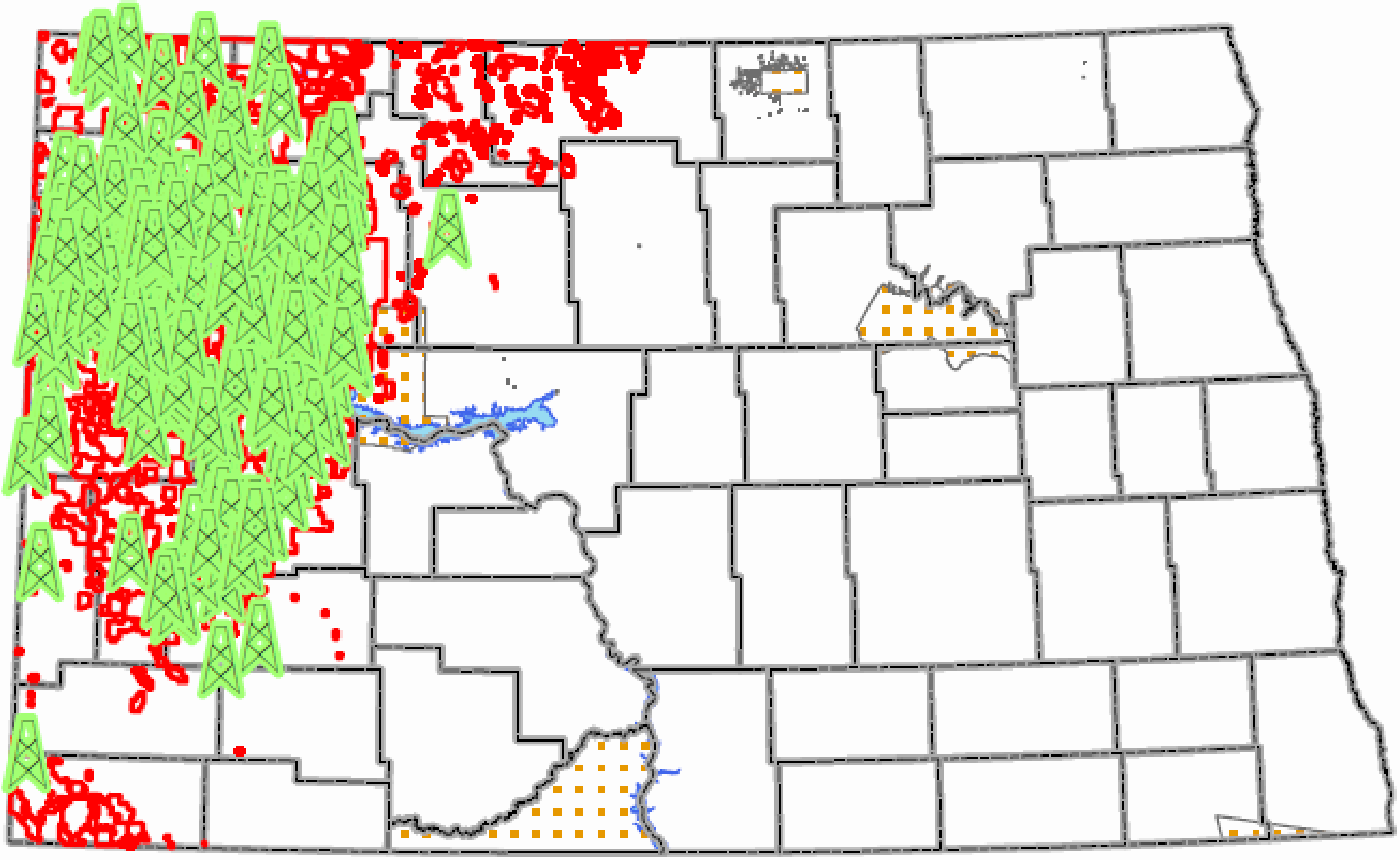
NORTH DAKOTA – 167 DRILLING RIGS – Feb 2011



One year ago, drilling activity was focused

in Mountrail, Dunn, McKenzie, and Williams Counties.

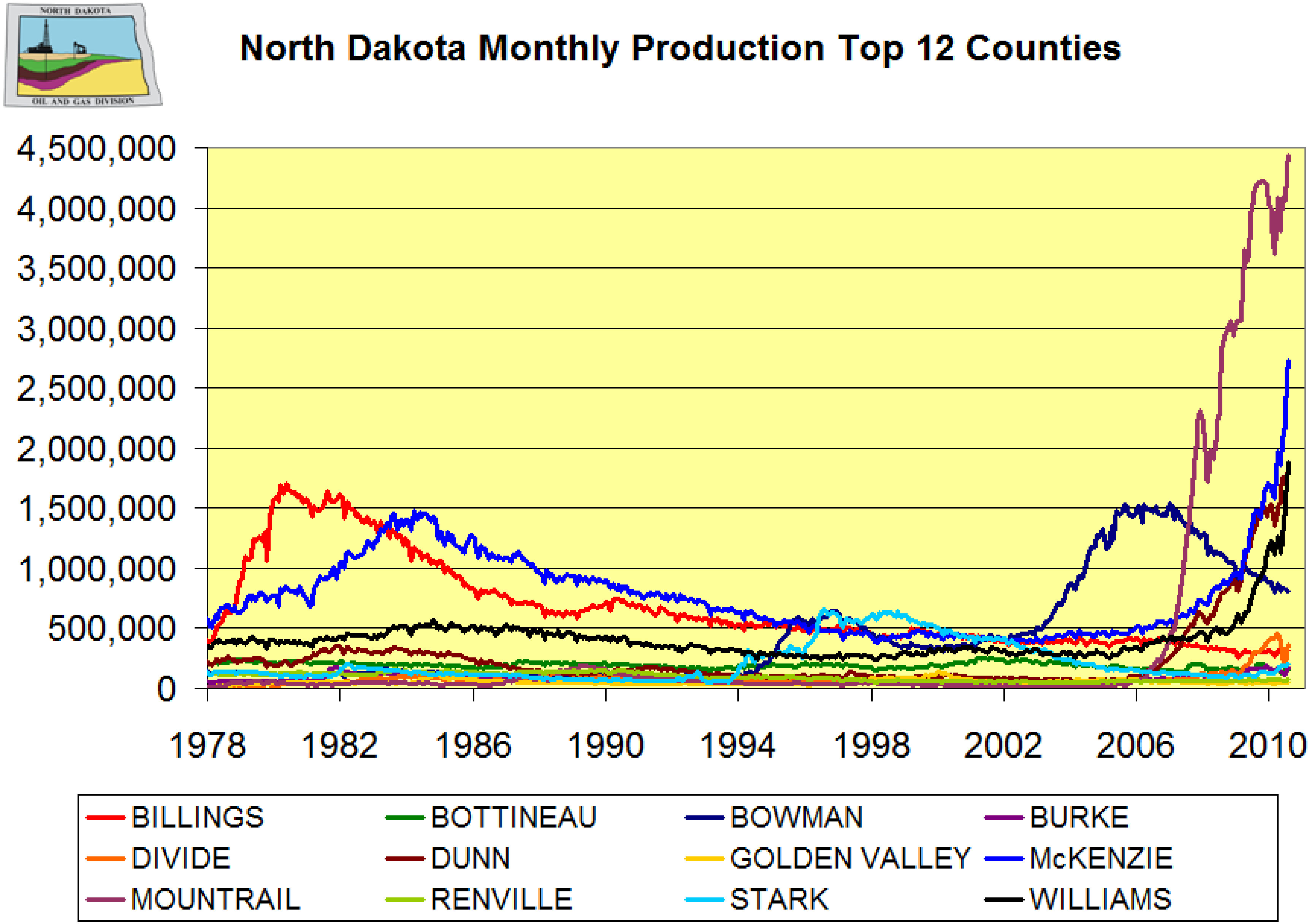
NORTH DAKOTA – 205 DRILLING RIGS – Feb 2012



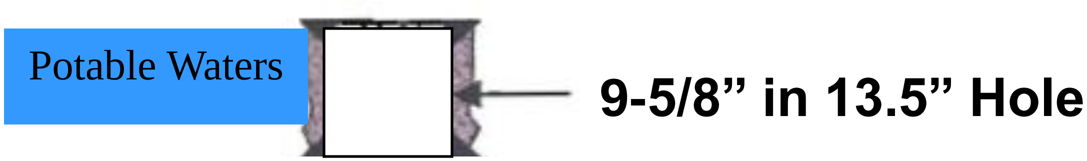
Current drilling activity is focused

in Mountrail, Dunn, McKenzie, and Williams Counties.

North Dakota Monthly Production Top 12 Counties

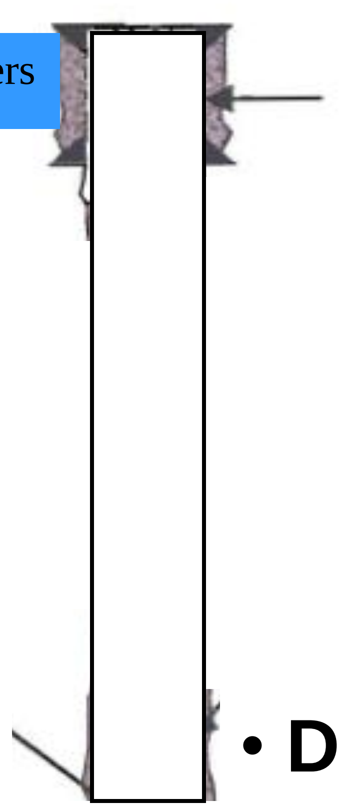


TYPICAL HORIZONTAL OIL WELL



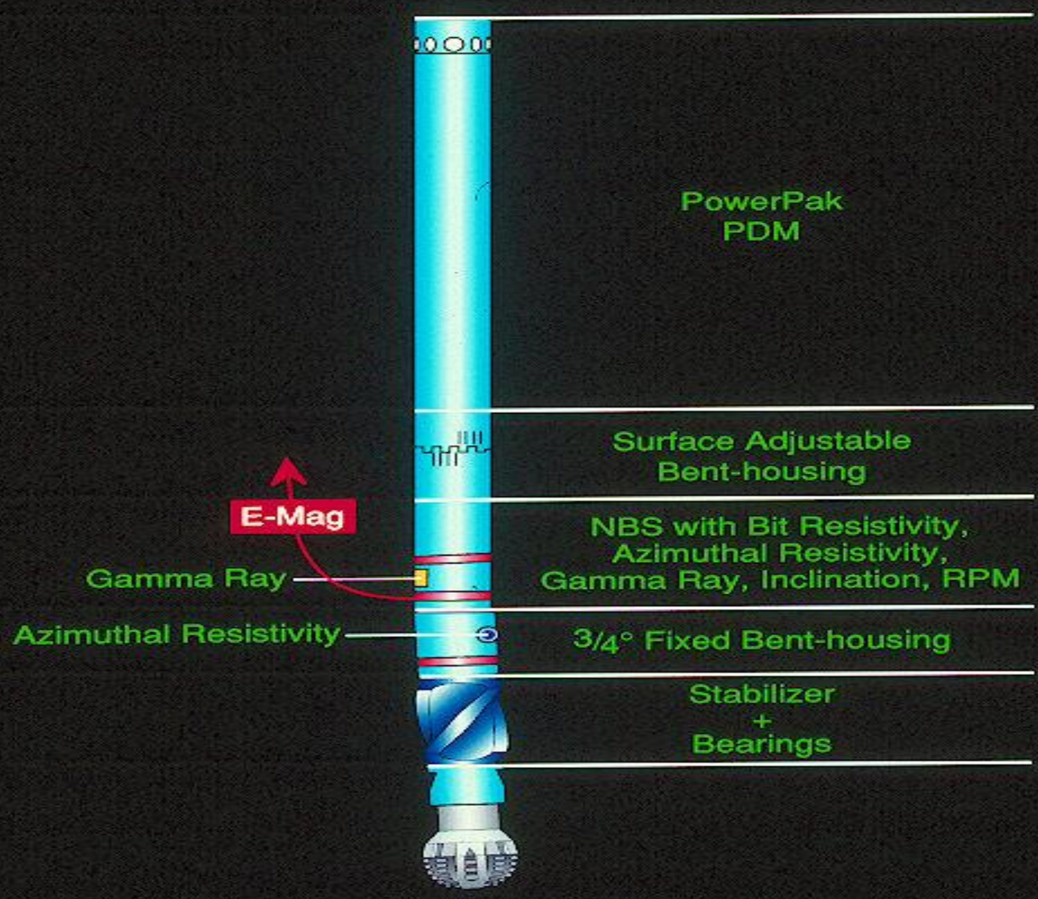
- Drill with fresh water
- Total depth below lowest potable water
- Run in hole with surface casing
    - 1st layer of surface water protection
- Cement casing back to surface of ground
    - 2nd layer of surface water protection

TYPICAL HORIZONTAL OIL WELL

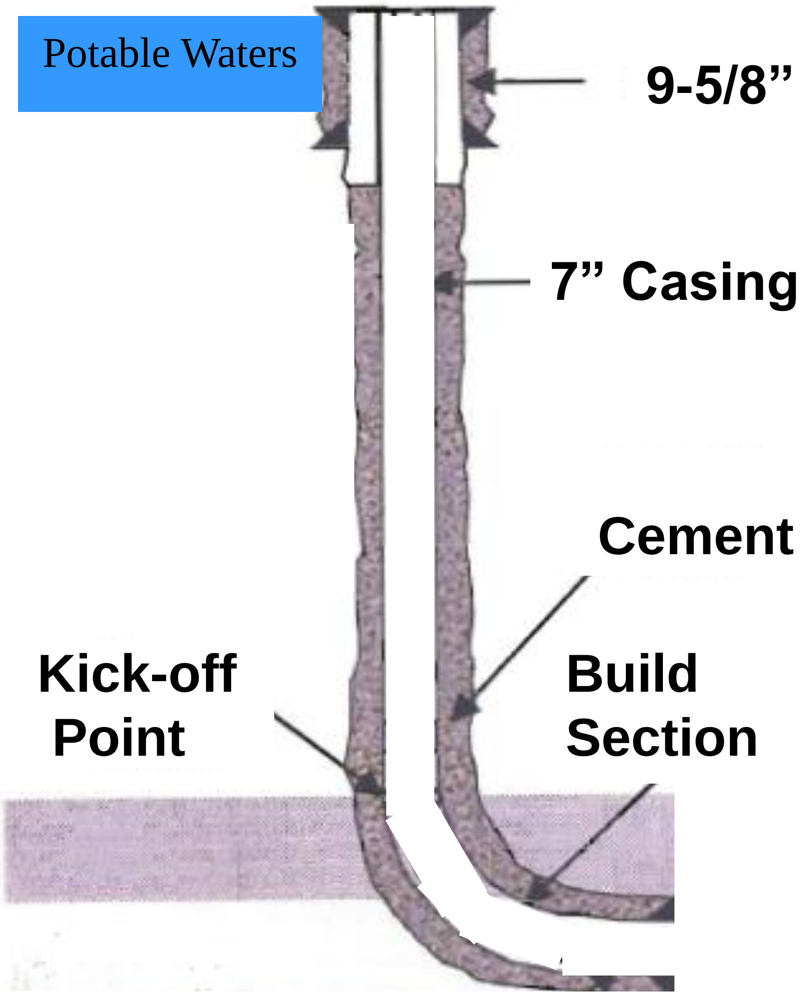


- Drill vertically to kick-off point
- Run in hole with bent assembly
- Downhole mud motor

GeoSteering Tool

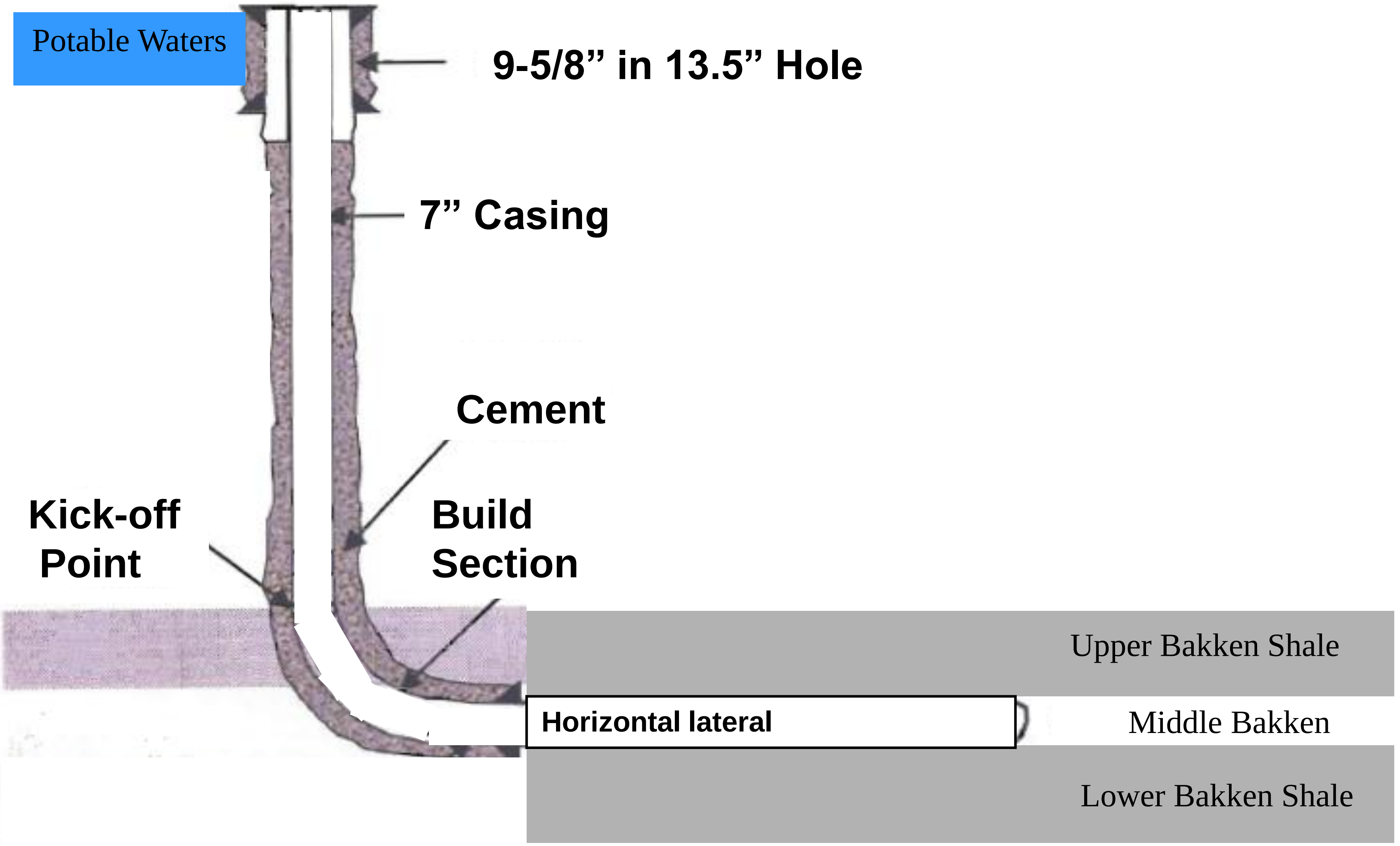


TYPICAL HORIZONTAL OIL WELL

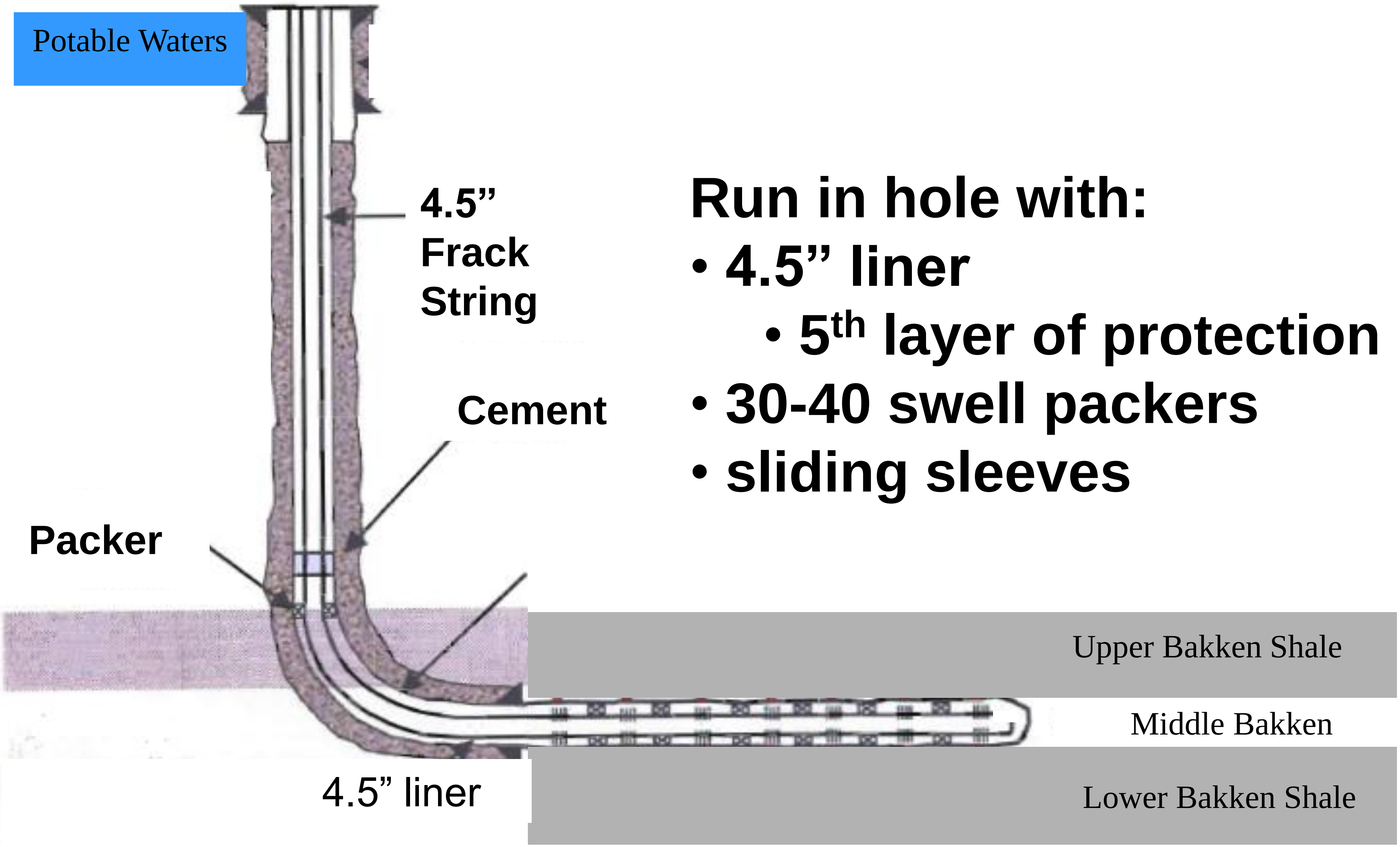


- Drill 8-3/4” hole to pay
- Run in hole with 7” casing
  - 3rd layer of protection
- Cement 7” casing
  - 4th layer of protection

TYPICAL HORIZONTAL OIL WELL



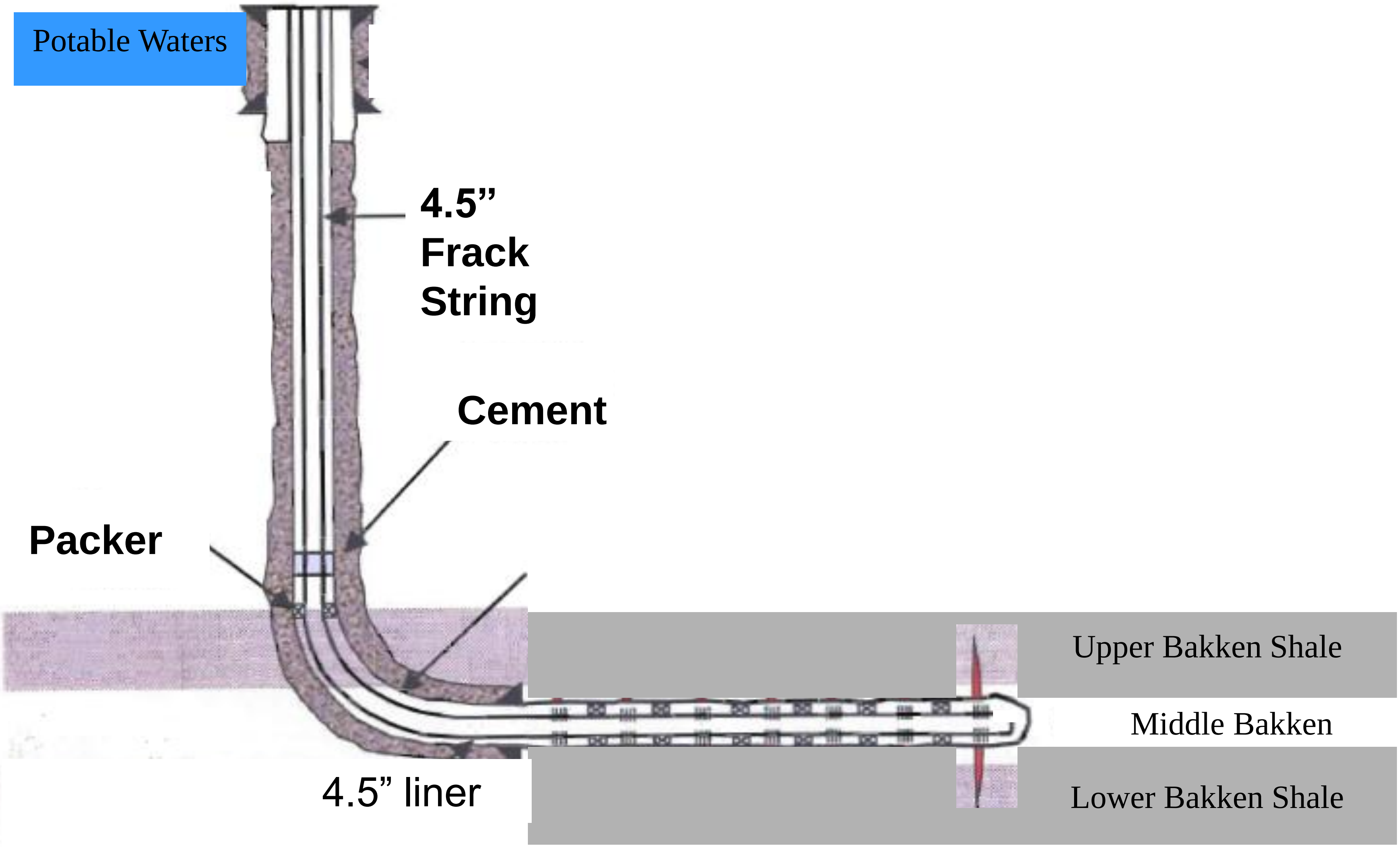
TYPICAL HORIZONTAL OIL WELL



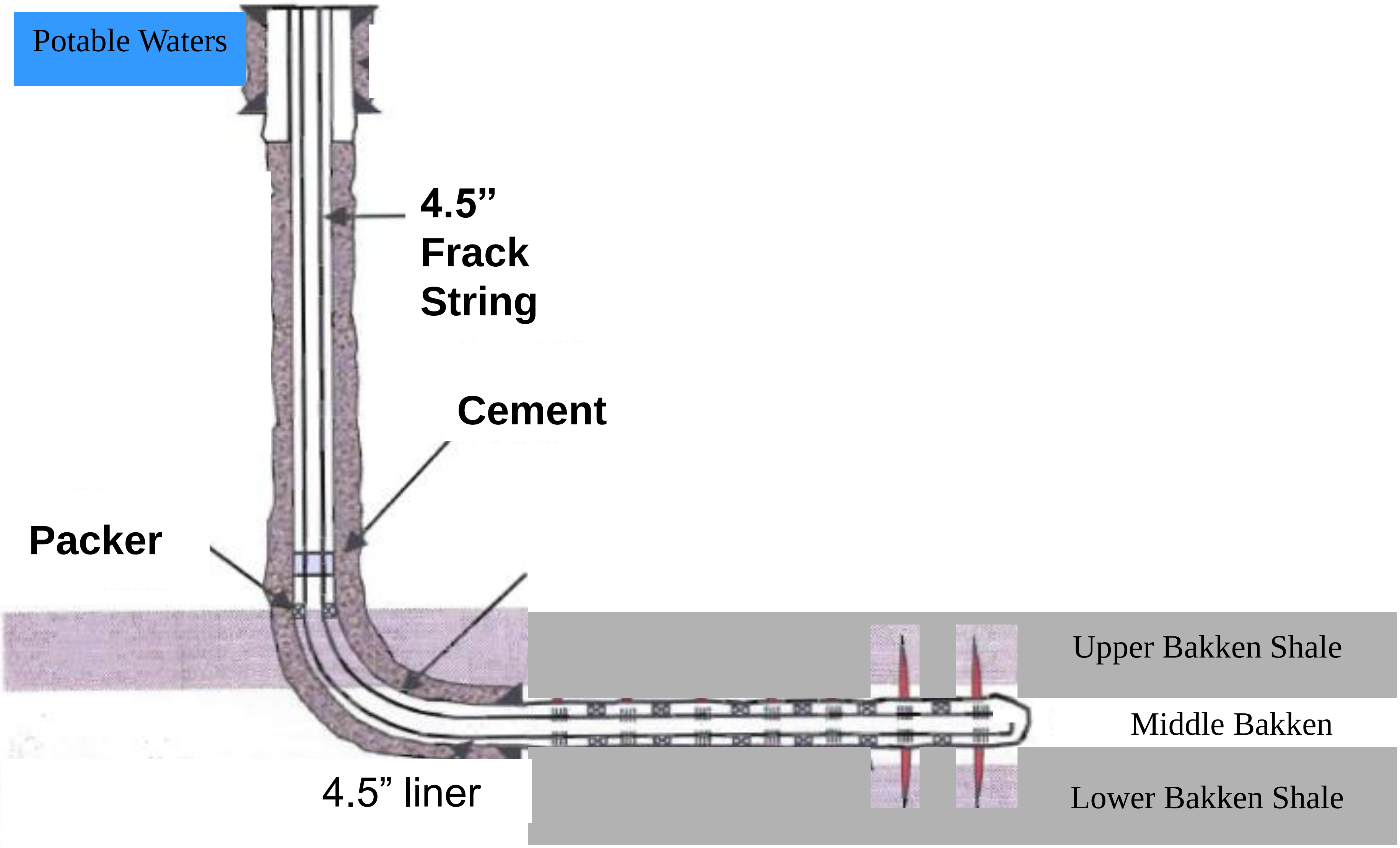
Run in hole with:

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

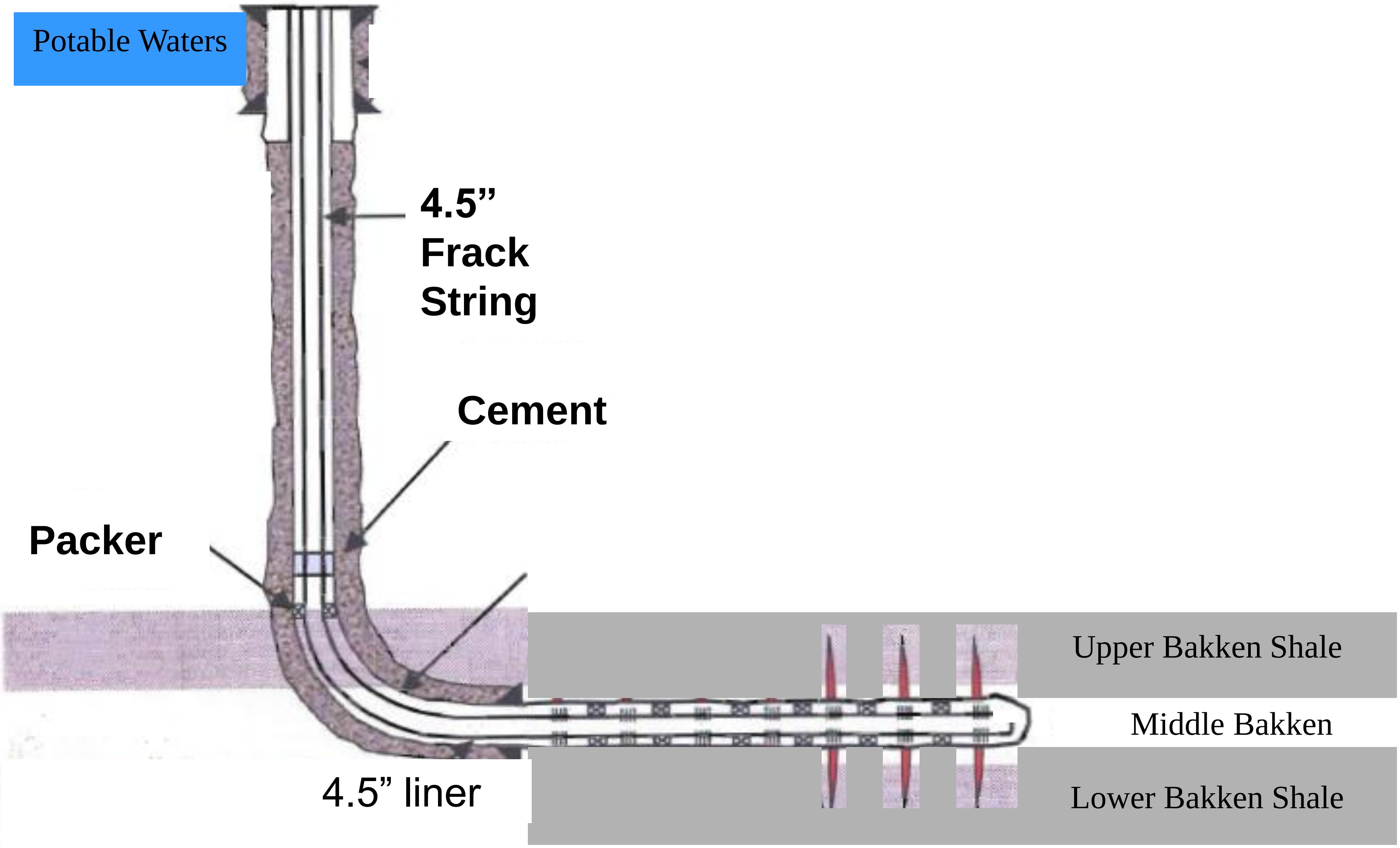
TYPICAL HORIZONTAL OIL WELL



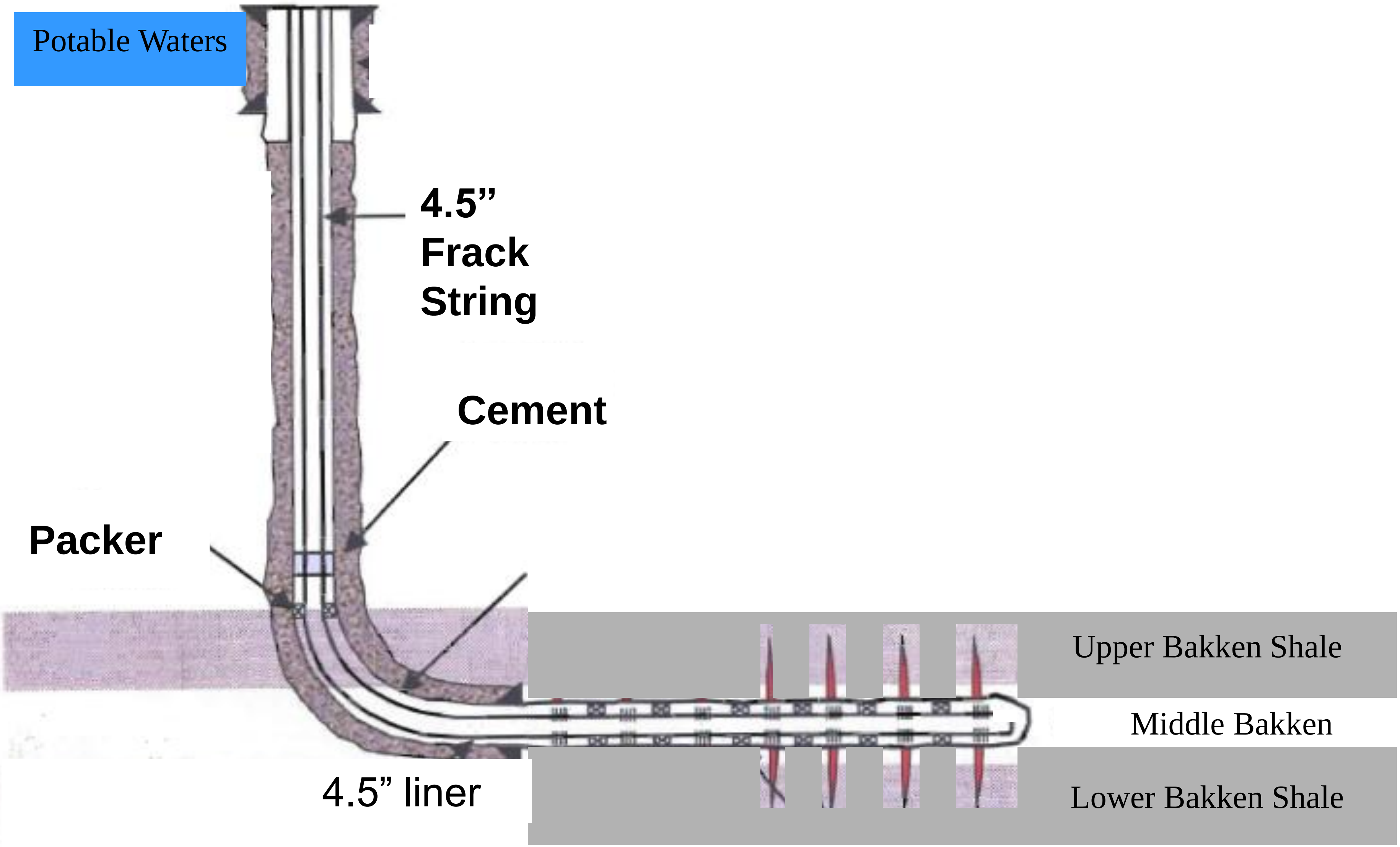
TYPICAL HORIZONTAL OIL WELL



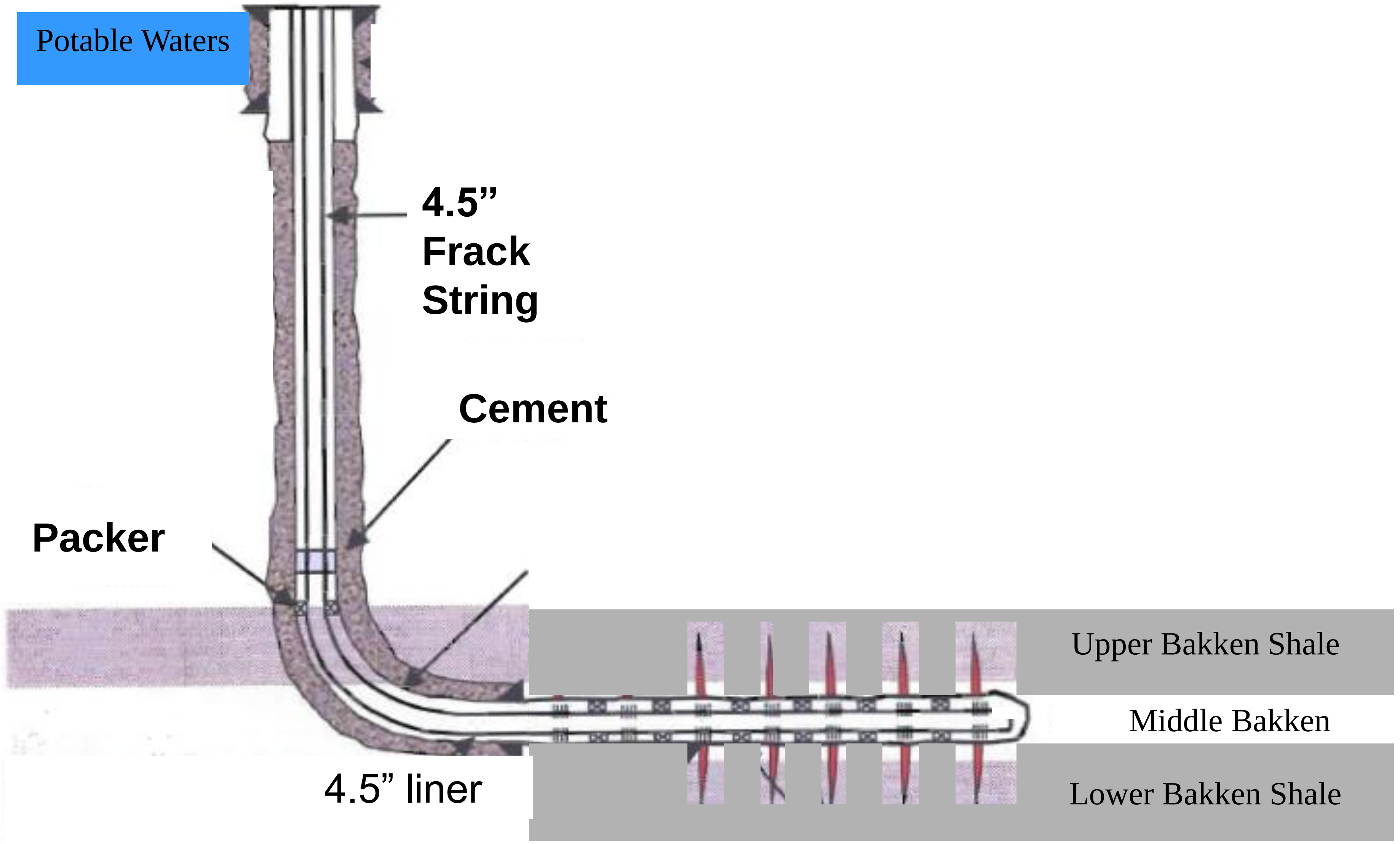
TYPICAL HORIZONTAL OIL WELL



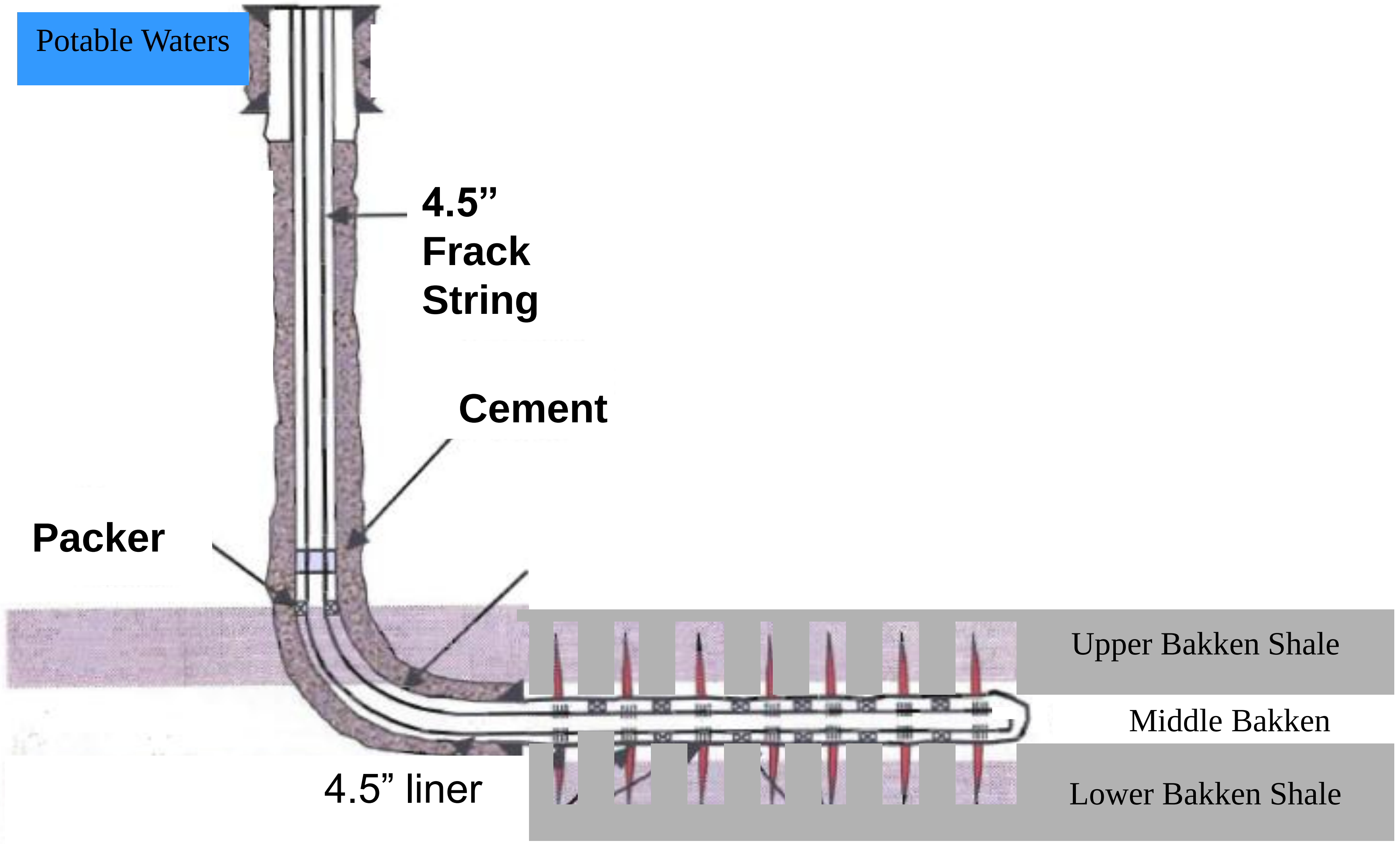
TYPICAL HORIZONTAL OIL WELL



TYPICAL HORIZONTAL OIL WELL



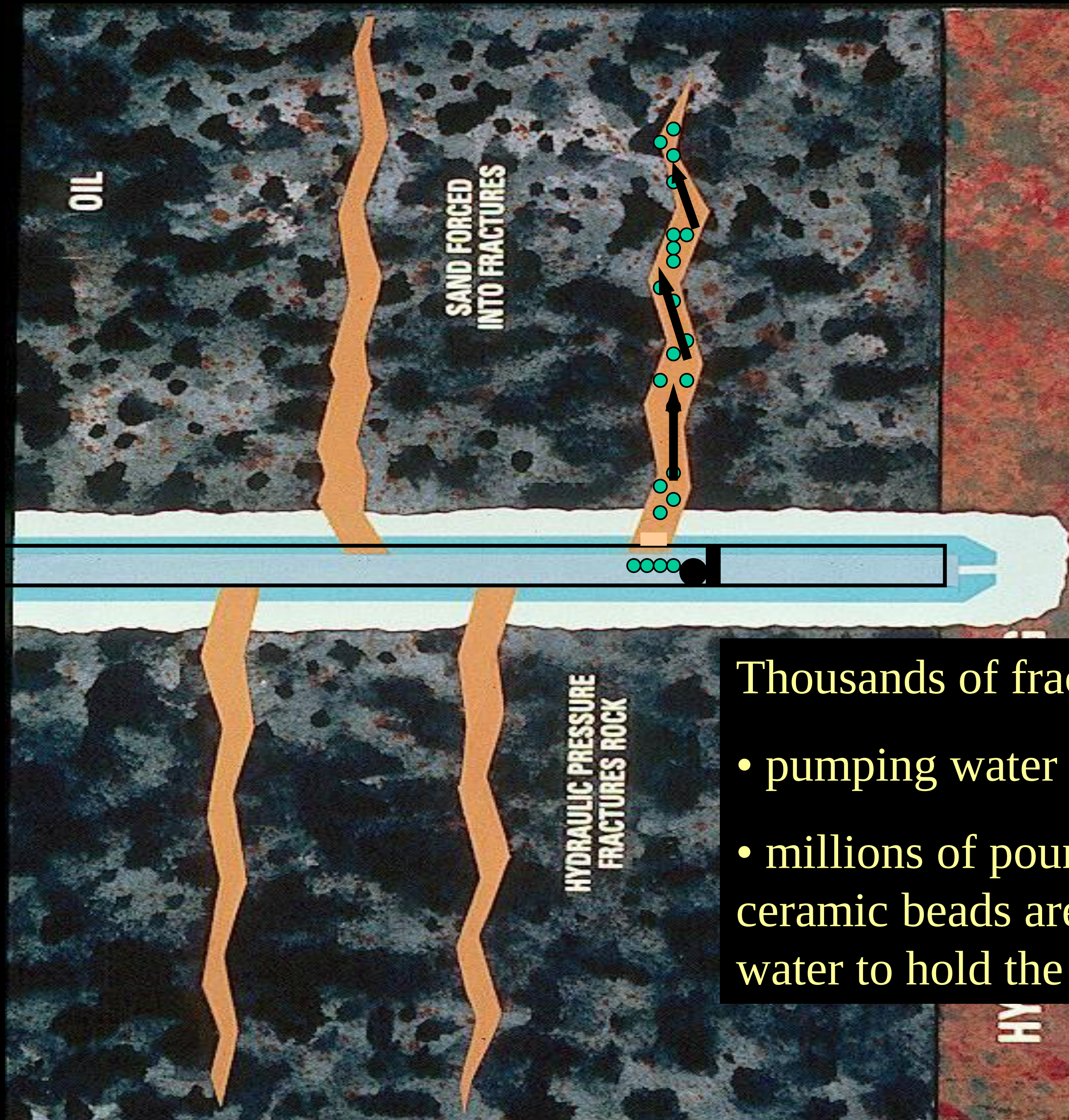
TYPICAL HORIZONTAL OIL WELL



WHY FRACK THE ROCK?

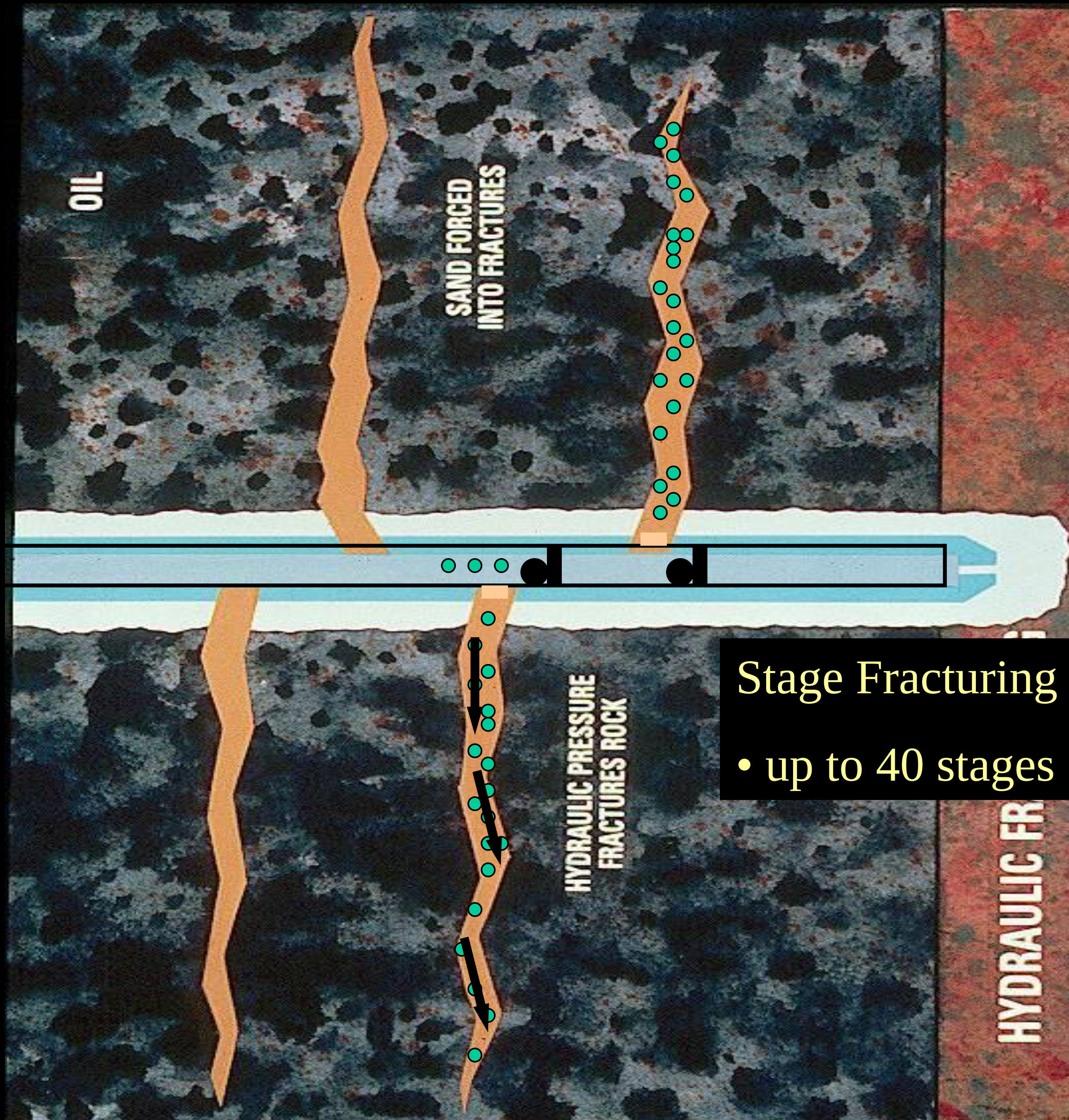
- already developed easy oil
    - oil flows easily without fracking

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



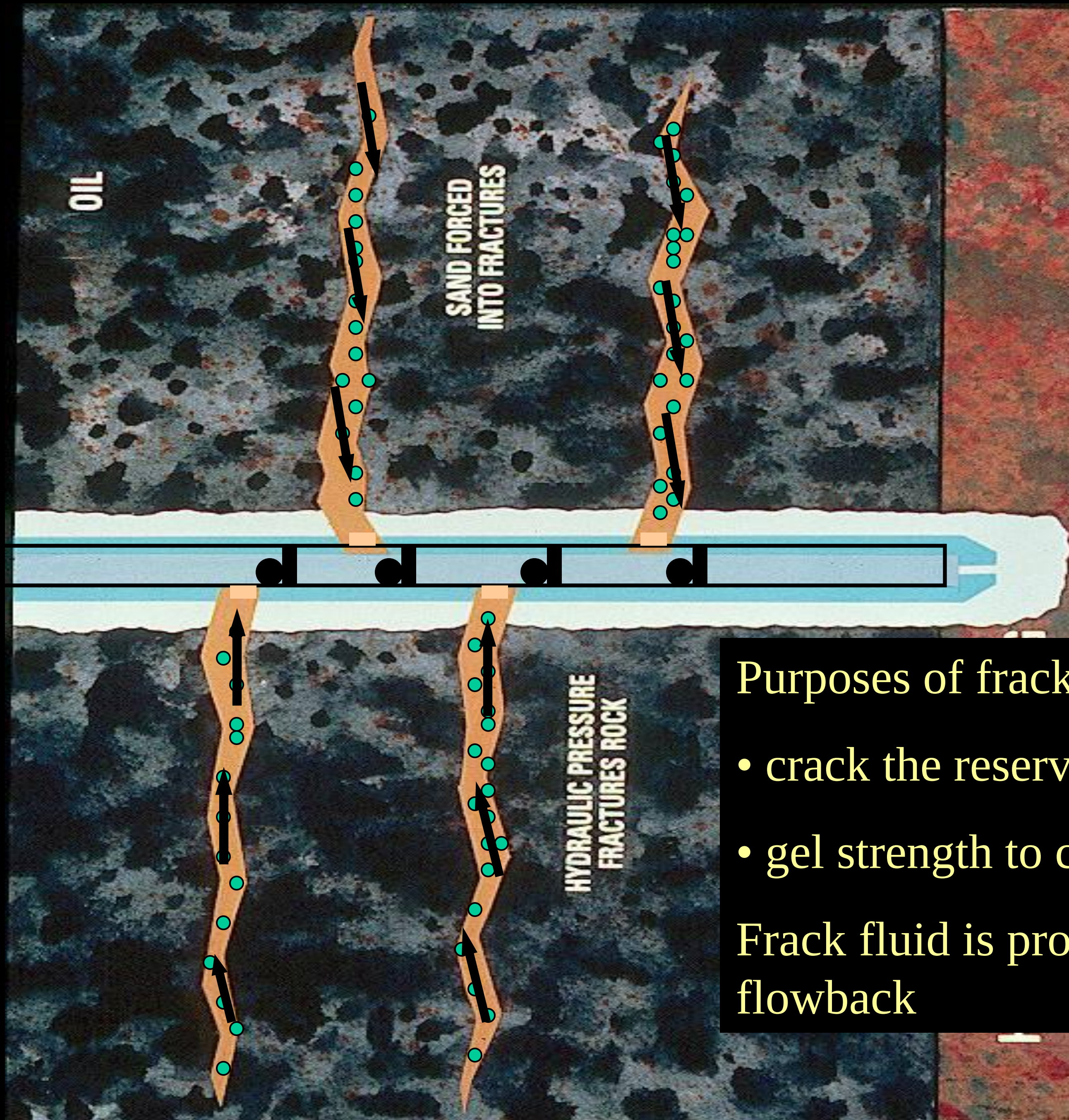
Thousands of fractures are created

- 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.



Stage Fracturing

- up to 40 stages

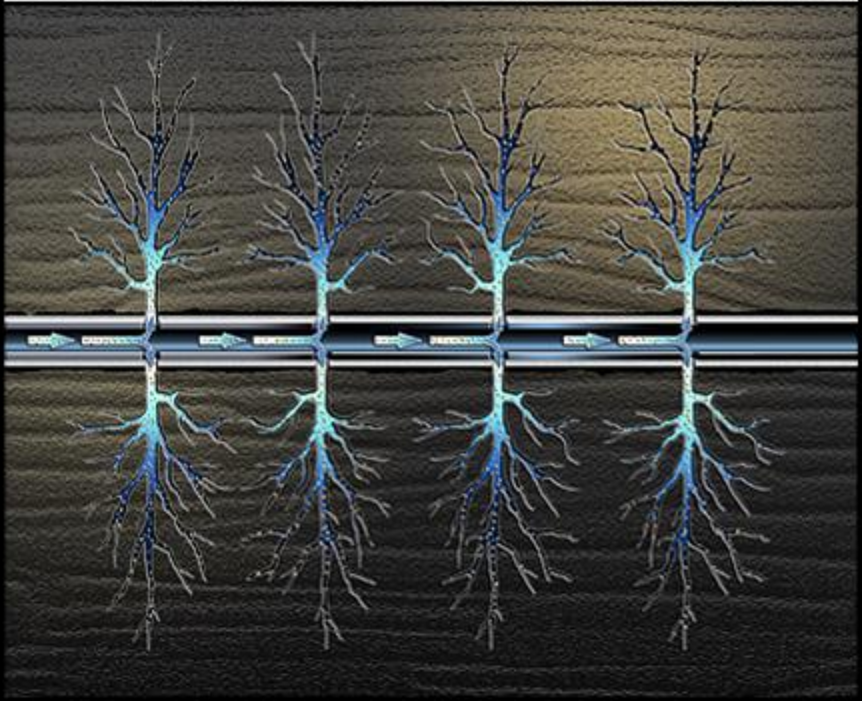


Purposes of frack fluid

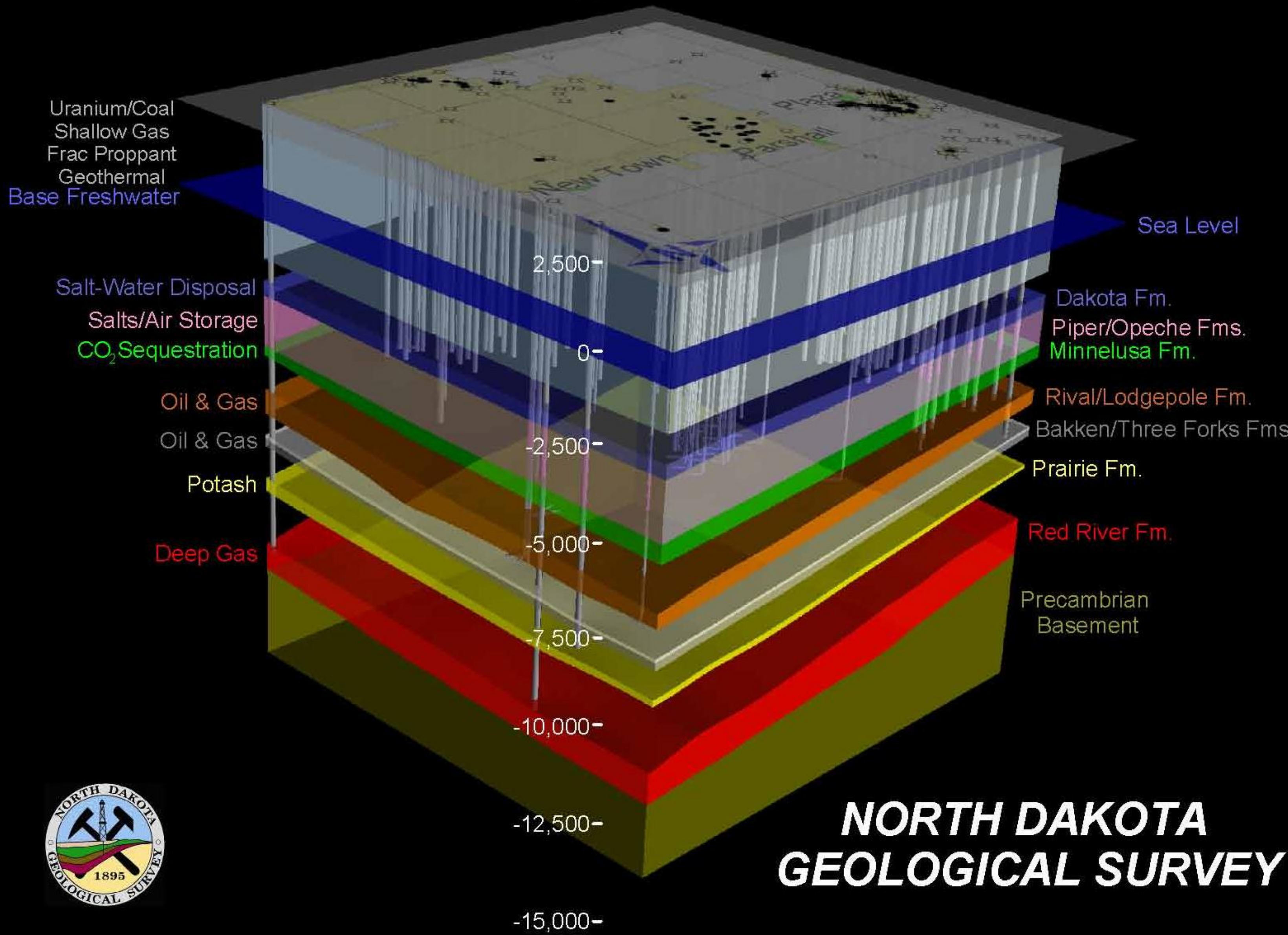
- crack the reservoir
- gel strength to carry sand

Frack fluid is produced back as flowback

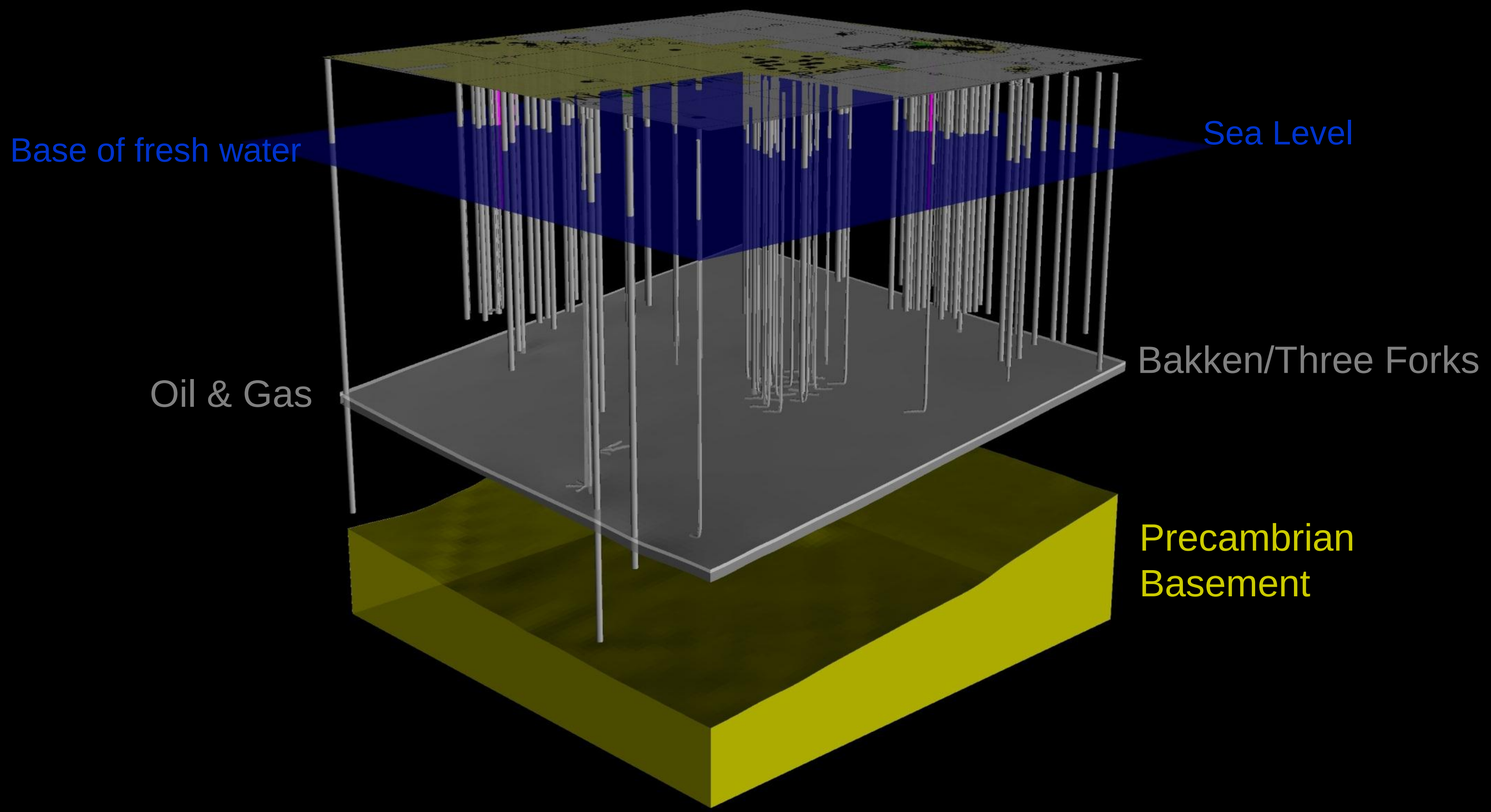
Hydraulic Fracturing: Mixture of water, sand and chemicals pressurized and pumped into the well to form microscopic fractures in shale.



Three-Dimensional Geologic Model of the Parshall Area



NORTH DAKOTA
GEOLOGICAL SURVEY



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

BOOM IMPACT ON LOCAL ECONOMY

- Housing: increased rent, insufficient
- Workforce: retail, grocery, restaurants
- Energy needs: electricity, fuel
- Population: increase load on services
- Medical: increase load on services
- Law enforcement
- Revenue increase: property & sales tax

HEALTH ISSUES

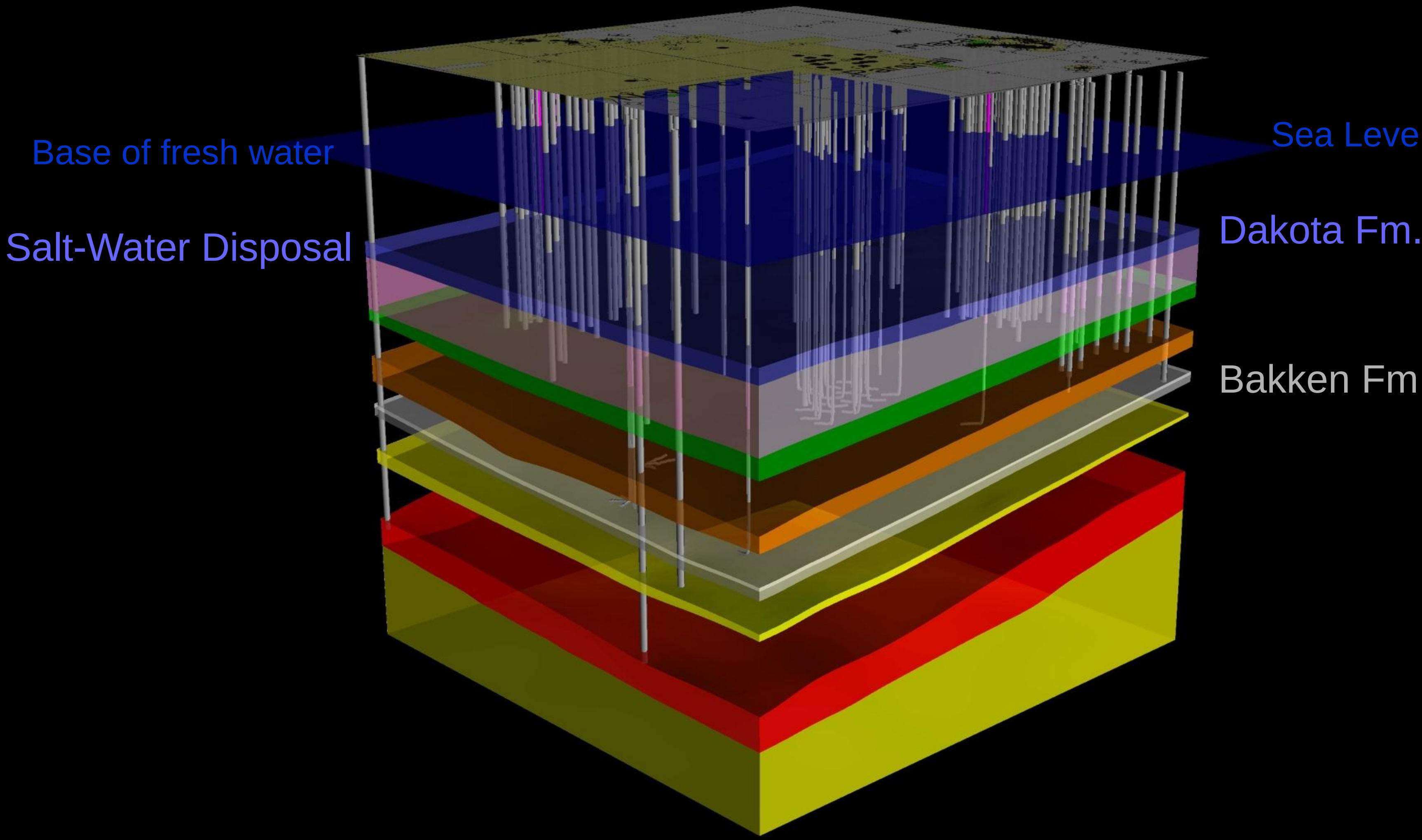
- Dust
  - NDSU study thru Agriculture Dept
  - Magnesium chloride
  - Calcium chloride

HEALTH ISSUES

- Threat of Contamination
  - ~~hydraulic stimulation~~
  - mechanical well failure
  - spills on surface

Industrial Commission Regulation

- Water flowback after frack
  - Storage in open pits prohibited
  - 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

BOOM RELATED HEALTH ISSUES

- **Medical Shortages**
  - **clinics**
  - **hospitals**

BOOM RELATED SAFETY ISSUES

- ~~**Hydraulic stimulation**~~
- **Mechanical failure**
- **Traffic-congestion/speeders**
- **Crime**

BOOM RELATED WELFARE ISSUES

- **Fortune**
  - **mineral owner lease/royalties**
  - **surface owner lease on surface**

What Does Every New Bakken Well Mean to North Dakota

A typical 2011 North Dakota Bakken well will produce for 28 years

If economic, enhanced oil recovery efforts can extend the life of the well

In those 28 years the average Bakken well:

Produces approximately 550,000 barrels of oil

Generates over $20 million net profit

Pays approximately $4,360,000 in taxes
- $2,100,000 gross production taxes
- $1,900,000 extraction tax
- $360,000 sales tax

Pays royalties of $7,600,000 to mineral owners

Pays salaries and wages of $1,600,000

Pays operating expenses of $2,300,000

Costs $7,300,000 to drill and complete

BOOM RELATED WELFARE ISSUES

- Prosperity
  - commercial property increases
  - home property increases

Job Opportunities

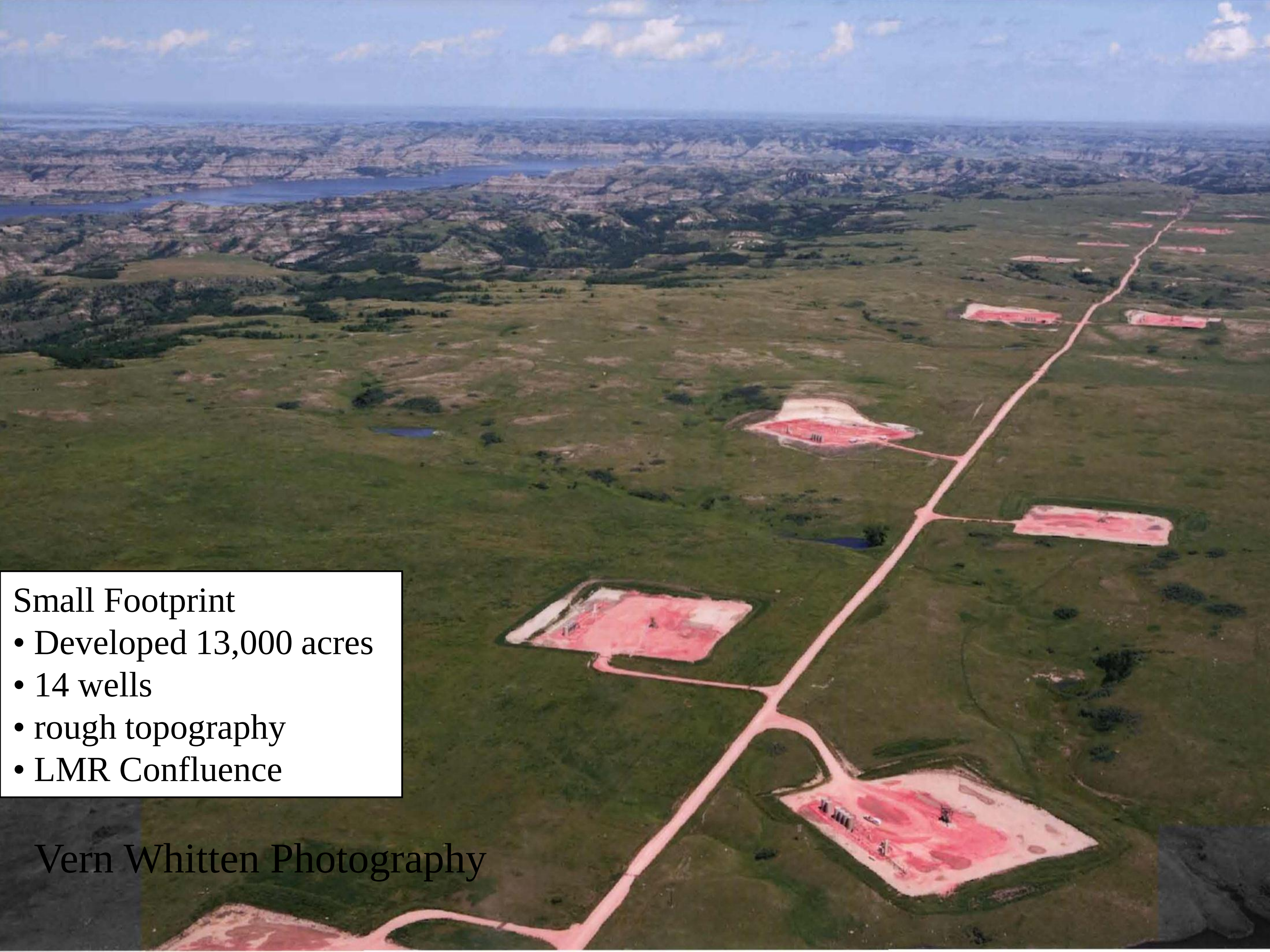
- 170 – 225 rigs
  - 20,000 jobs in drilling
- 15 – 25 years
  - 28,000 additional wells
  - 28,000 long term jobs

PLANNING FOR THE FUTURE

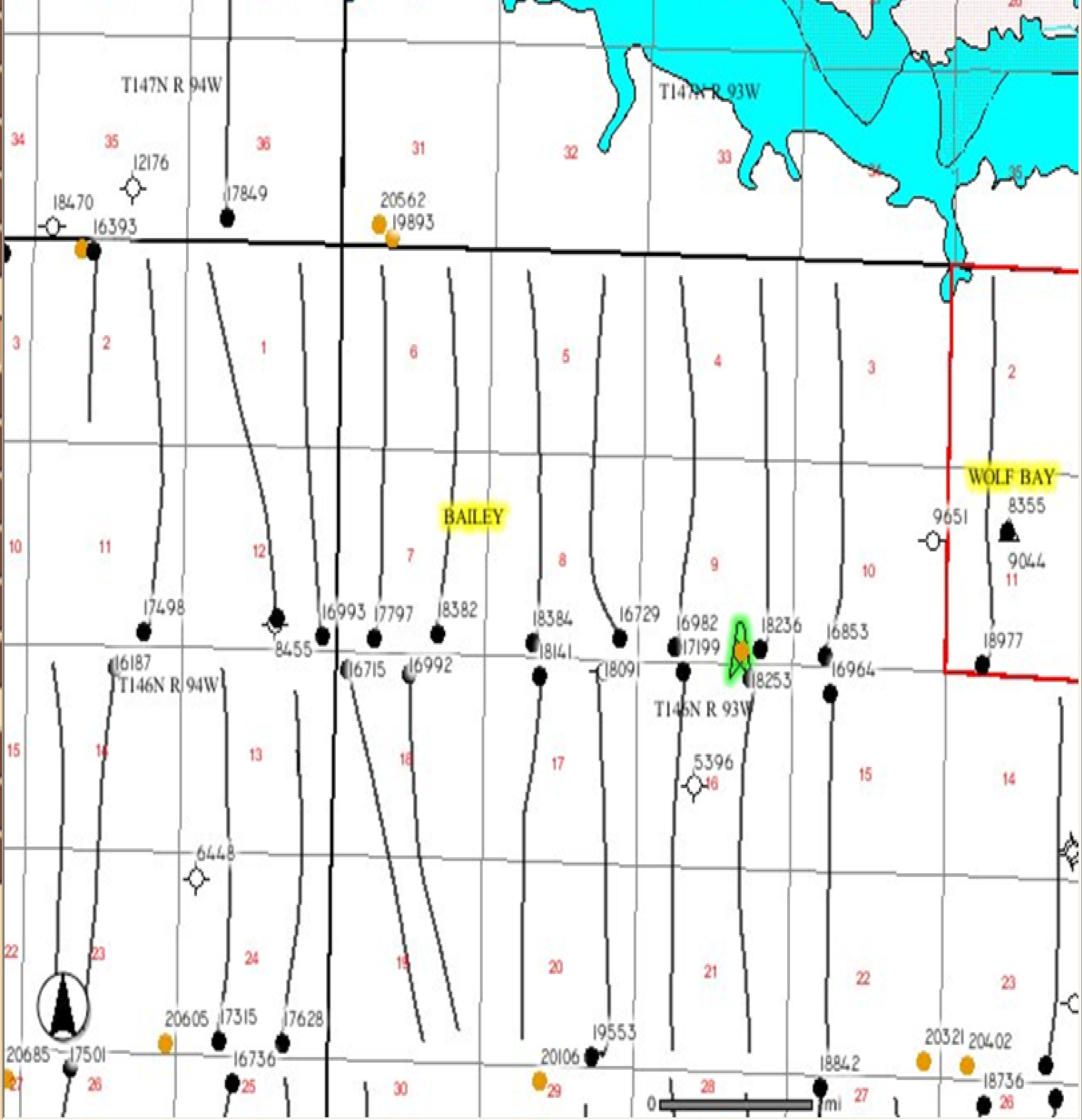
- Housing
- Lagoons
- Workforce
- Energy needs
- Population
- Medical
- Law enforcement
- Revenue increase

PLANNING FOR THE FUTURE
BEST PRACTICES

- **Corridors**


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

w Entire State
revious View
ear Selection
Search
enerate PDF
Zoom In
Zoom Out
Pan
Rect Identify
elect Object
Buffer
Distance
Find Well
nd Field/Unit
Find Section



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.

w Entire State
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Search
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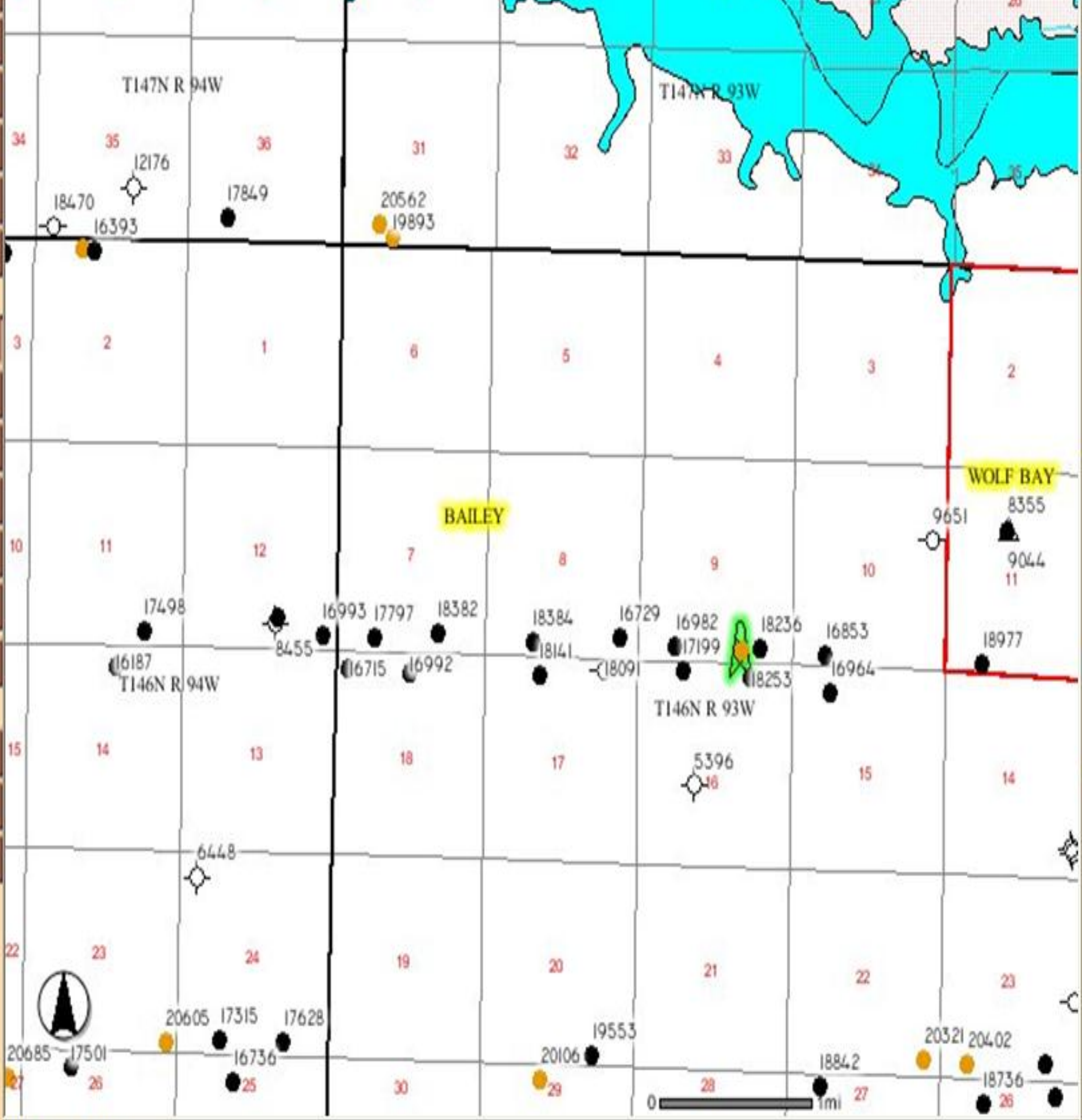
Zoom In
Zoom Out
Pan
Rect Identify
elect Object
Buffer
Distance

Find Well
nd Field/Unit
Find Section



Major Rivers
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Wells
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NAIP 2009

Refresh Map

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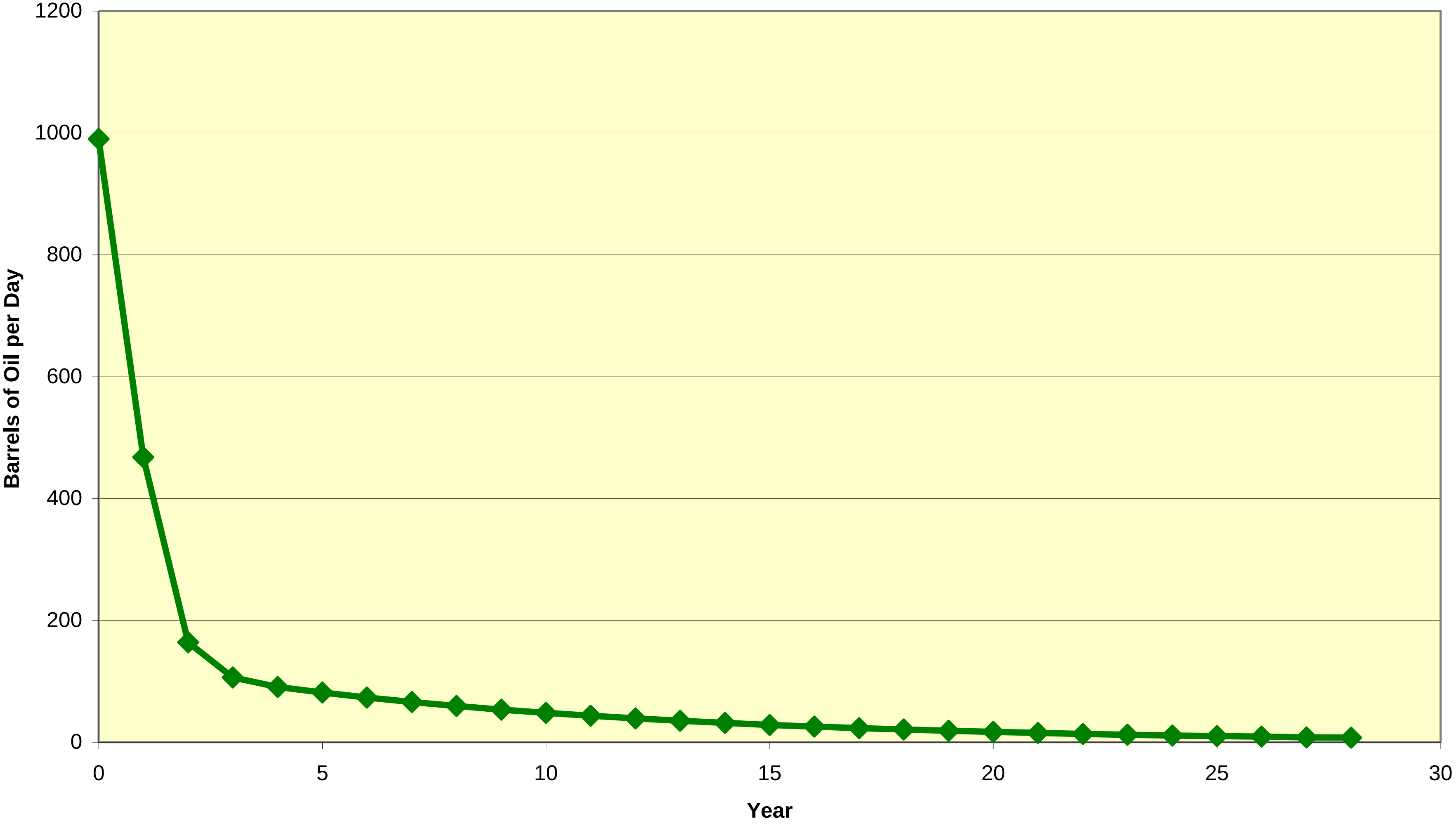
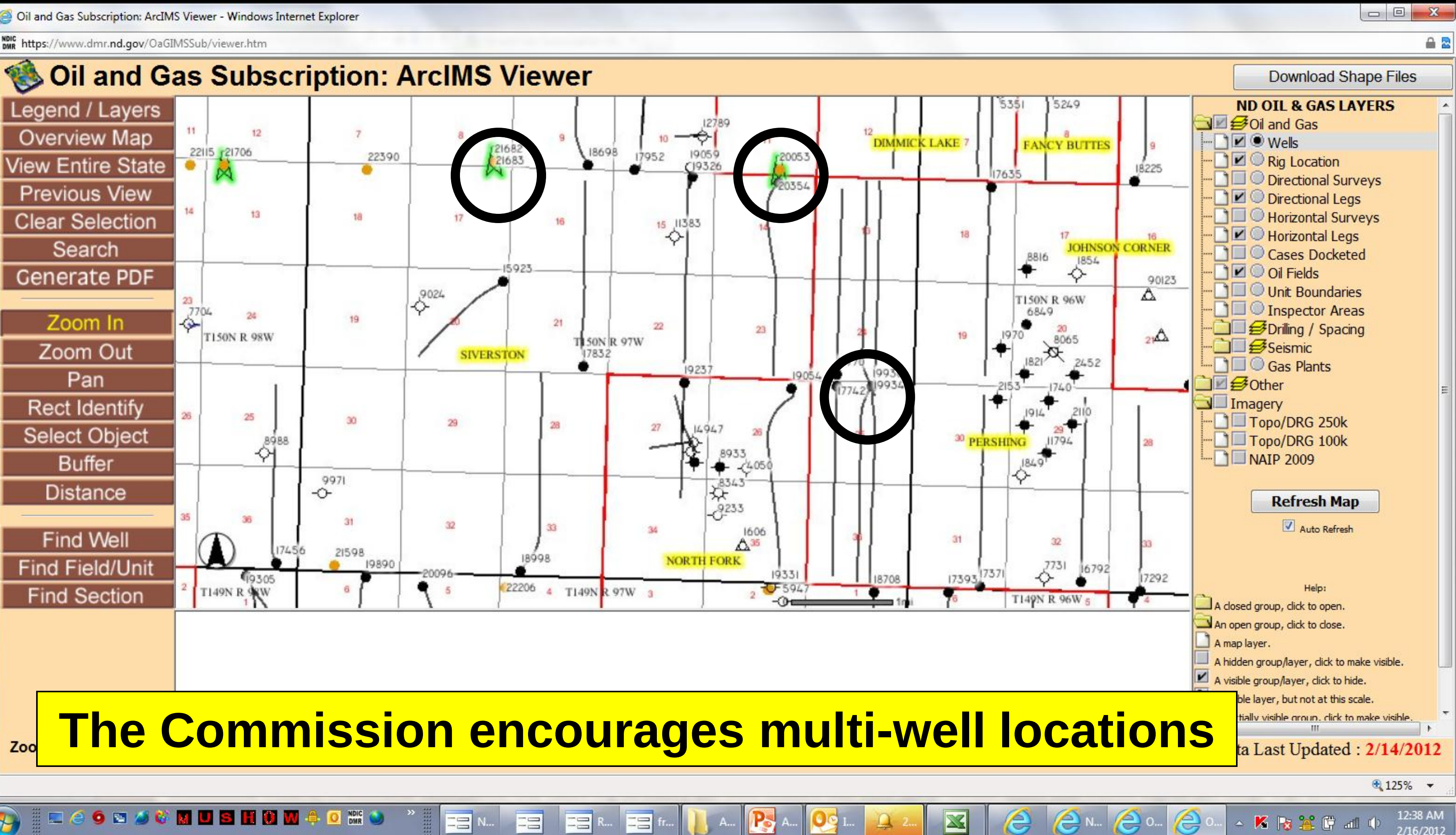
Help:
A closed group, click to open.
An open group, click to close.
A map layer.
A hidden group/layer, click to make visible.

Western North Dakota

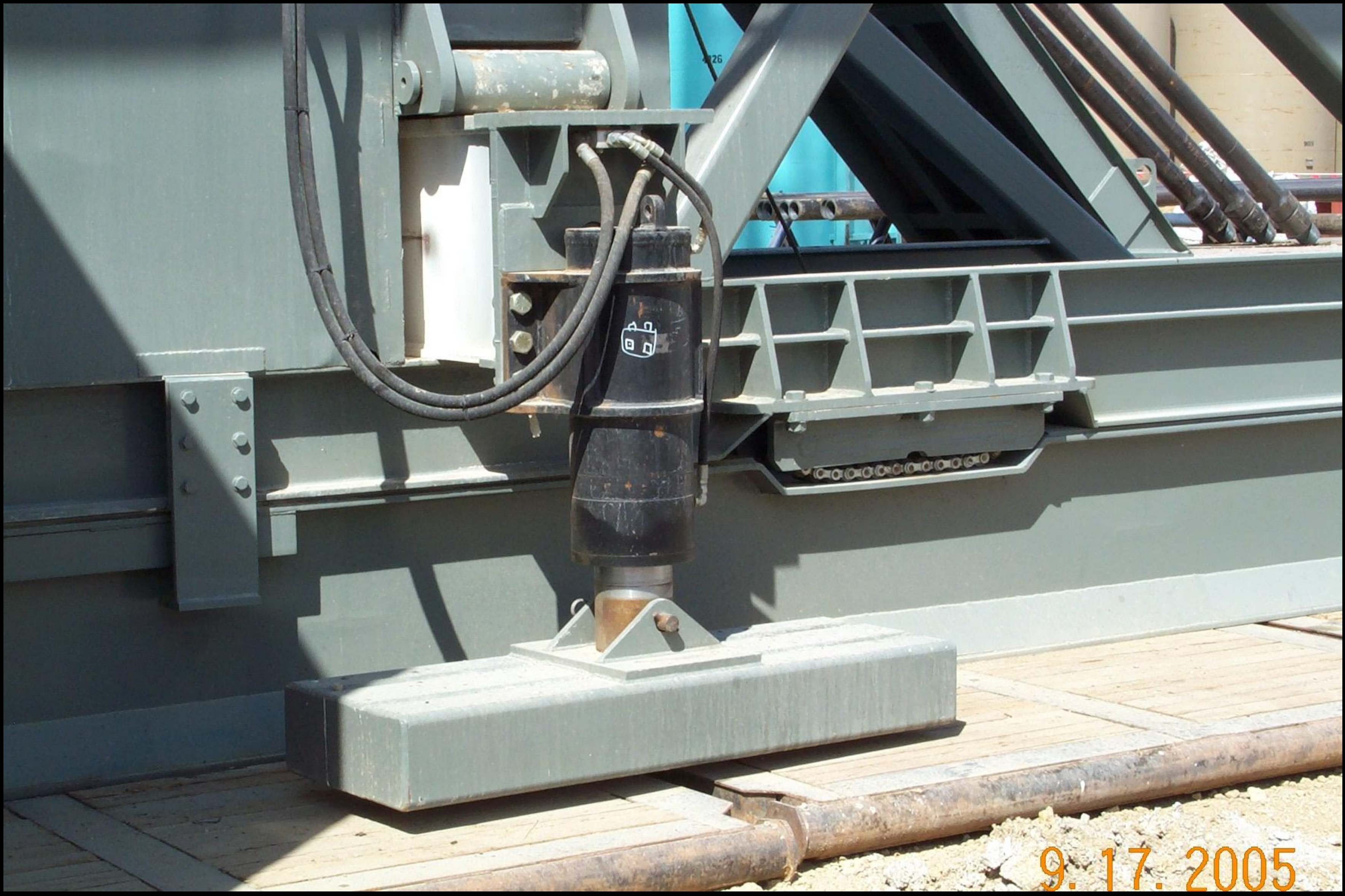
- 1,100 to 2,700 wells/year = 2,000 expected
  - 100-225 rigs = 12,000 – 27,000 jobs = 20,000 expected
  - 225 rigs can drill the 5,000 wells needed to secure leases in 2.5 years
  - 225 rigs can drill the 28,000 wells needed to develop spacing units in 14 years
  - 33,000 new wells = thousands of long term jobs

Typical Bakken Well Production



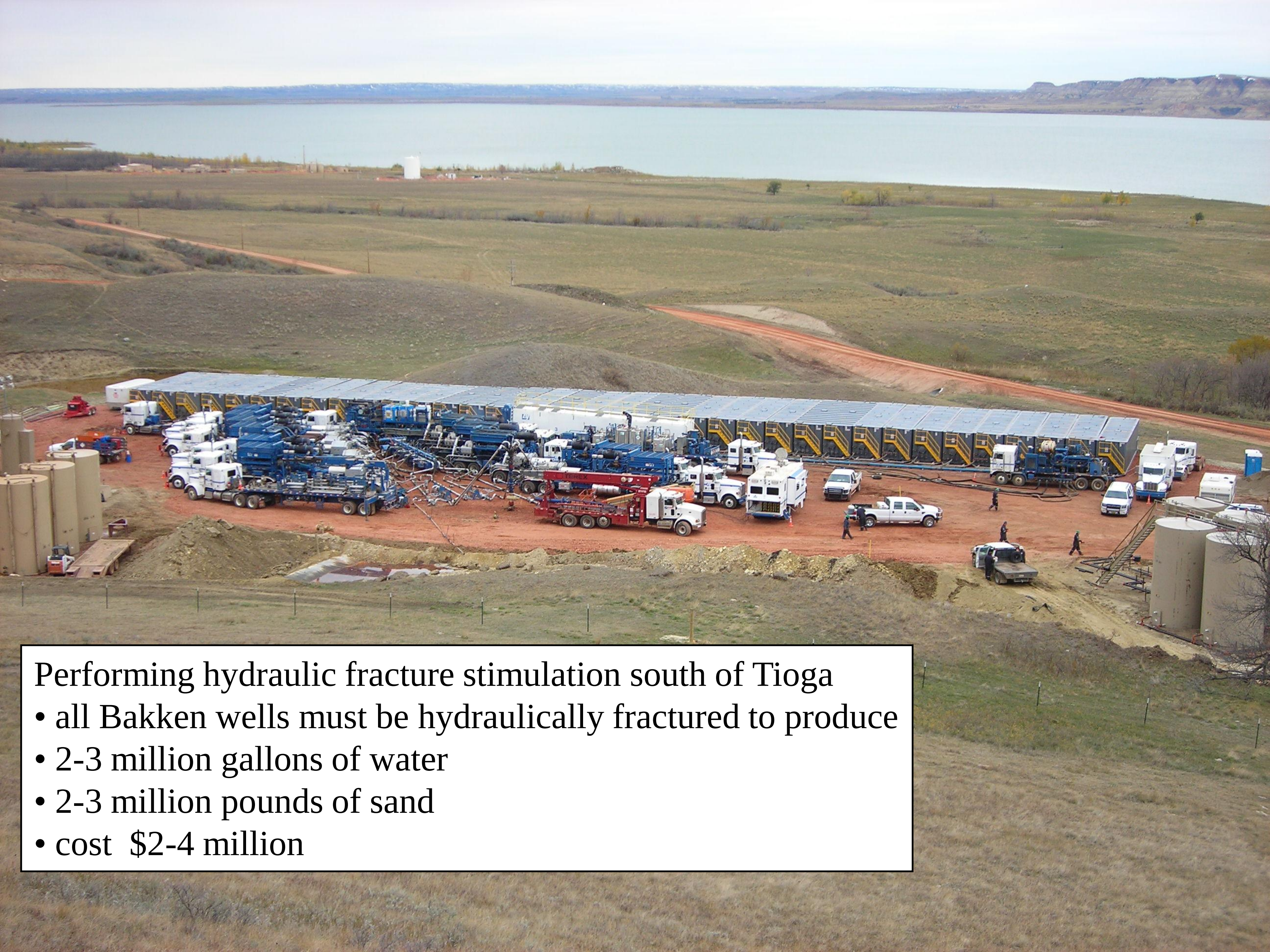


The Commission encourages multi-well locations


9. 17. 2005

PLANNING FOR THE FUTURE
BEST PRACTICES

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

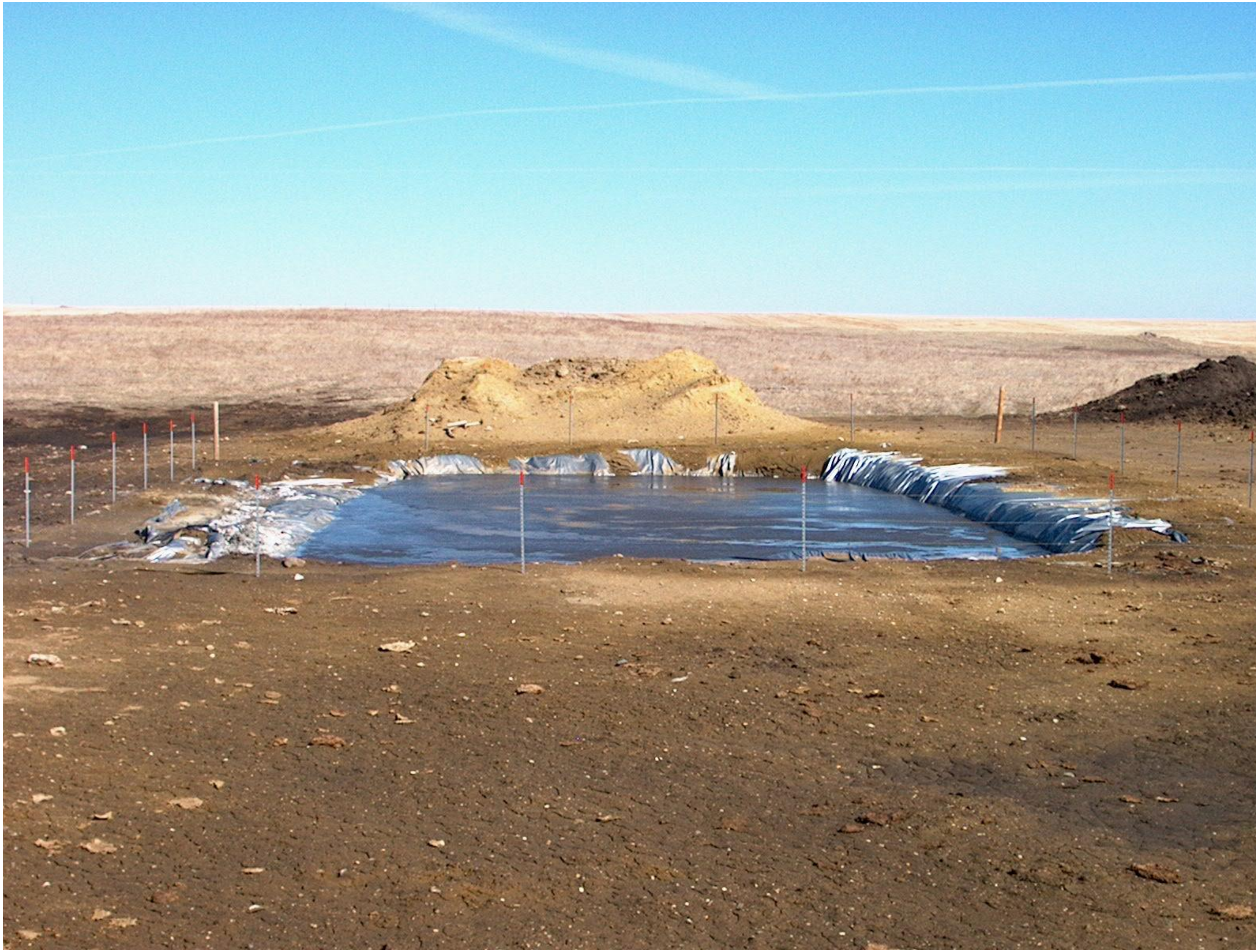


Performing hydraulic fracture stimulation south of Tioga

- 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
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

Thirsty Horizontal Wells

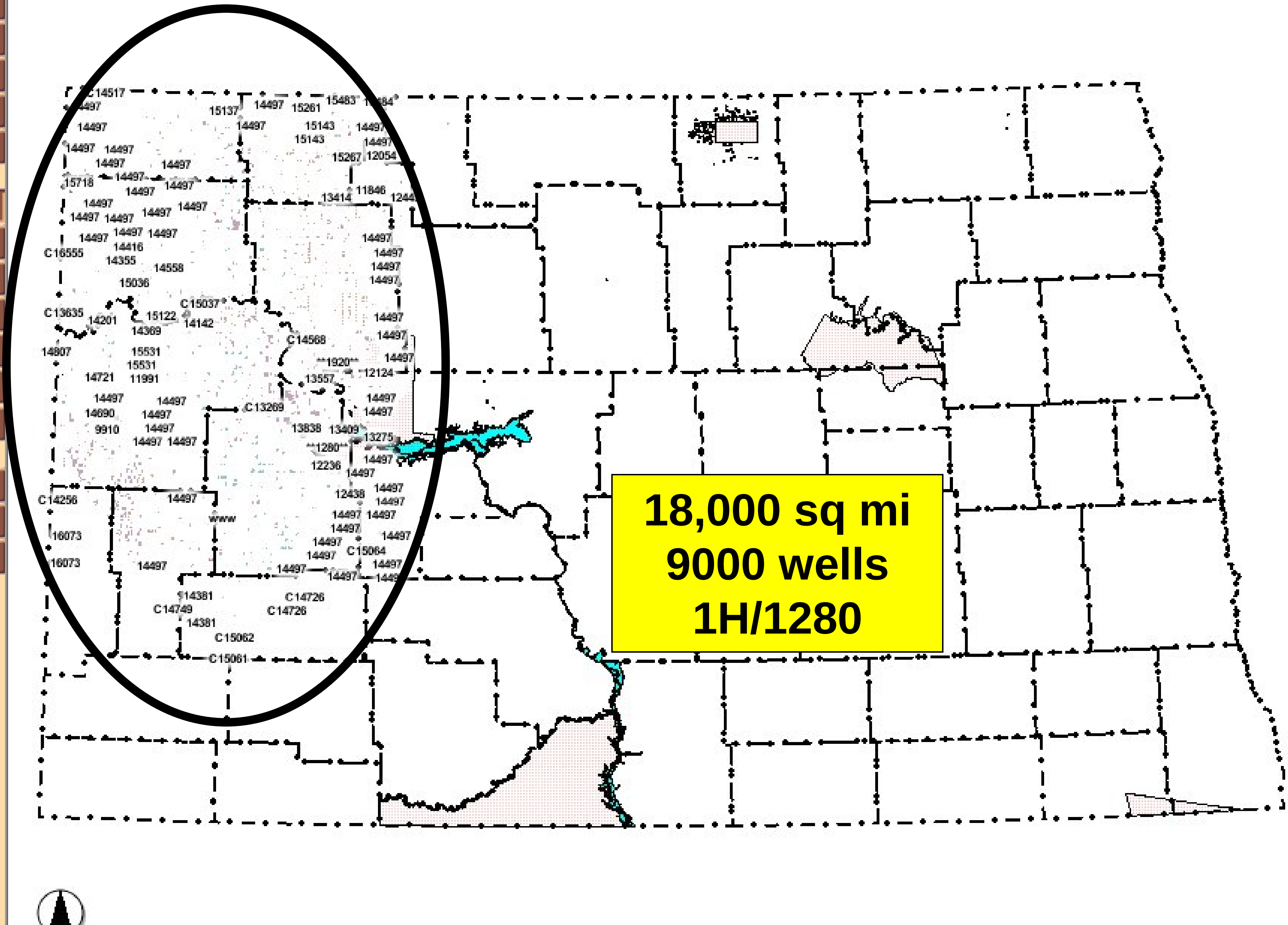
- 2,500 wells / year
- 15-25 years duration
- 20 million gallons water / day

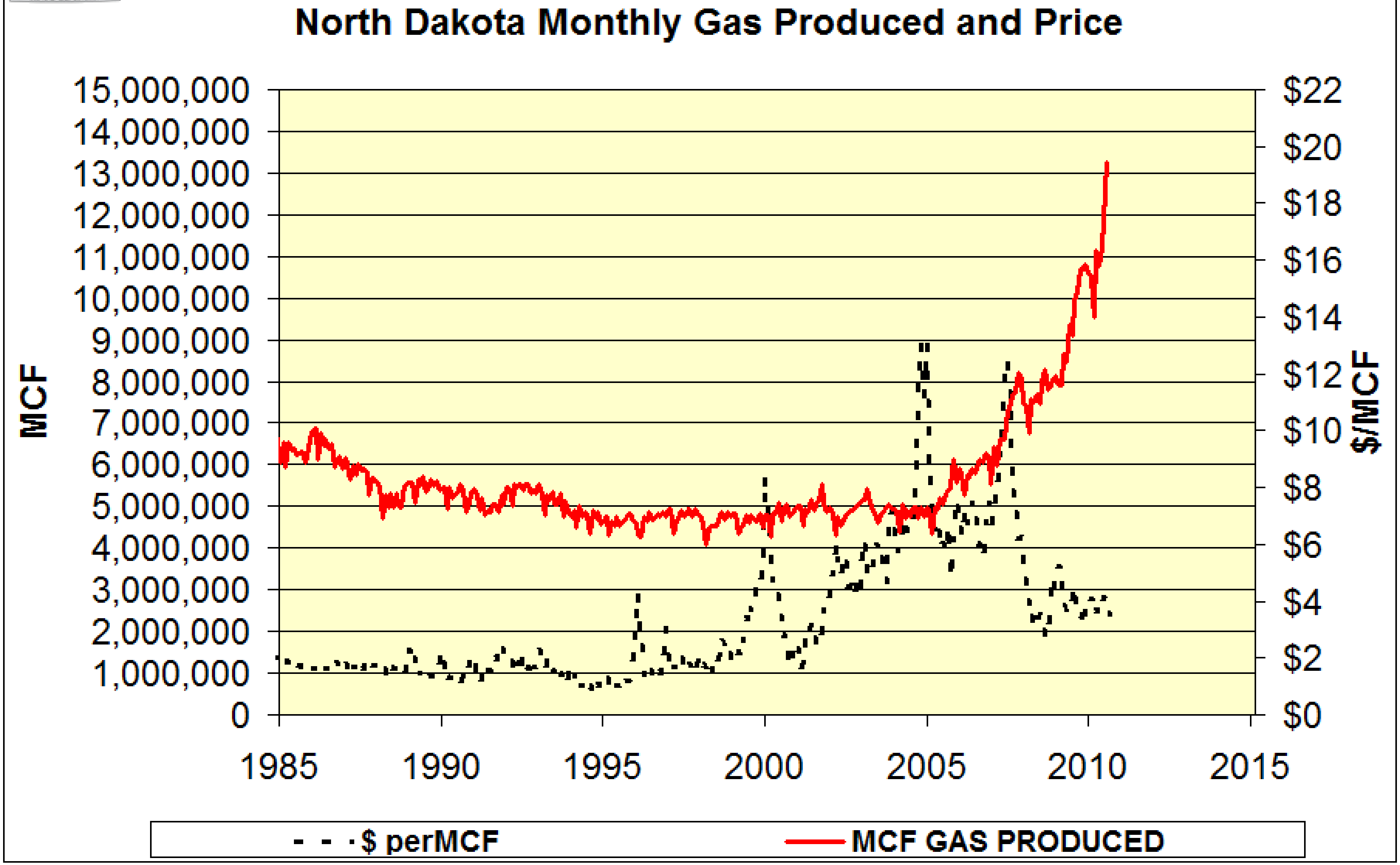
Commission supports surface water use

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

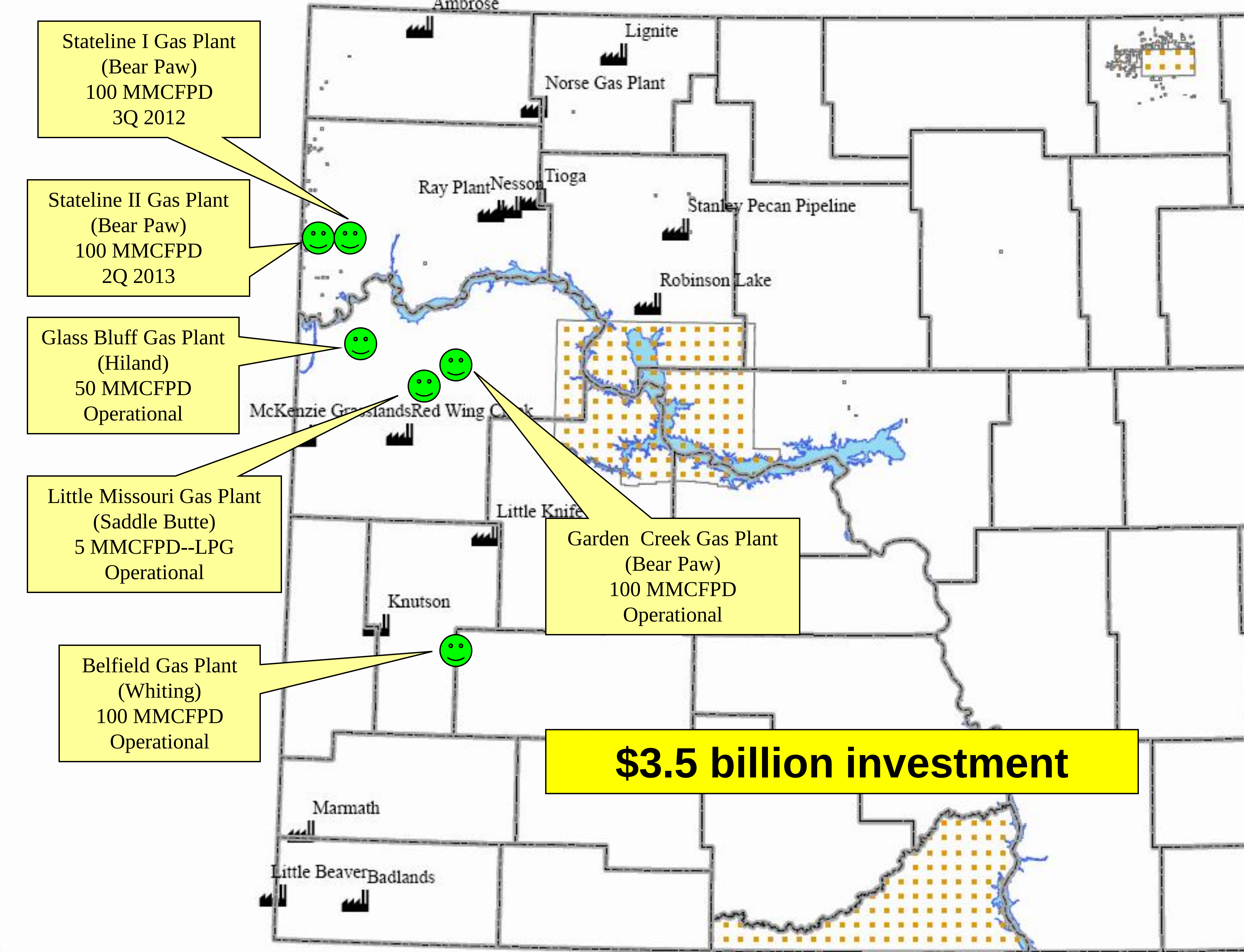
PLANNING FOR THE FUTURE
BEST PRACTICES

- **Infrastructure**

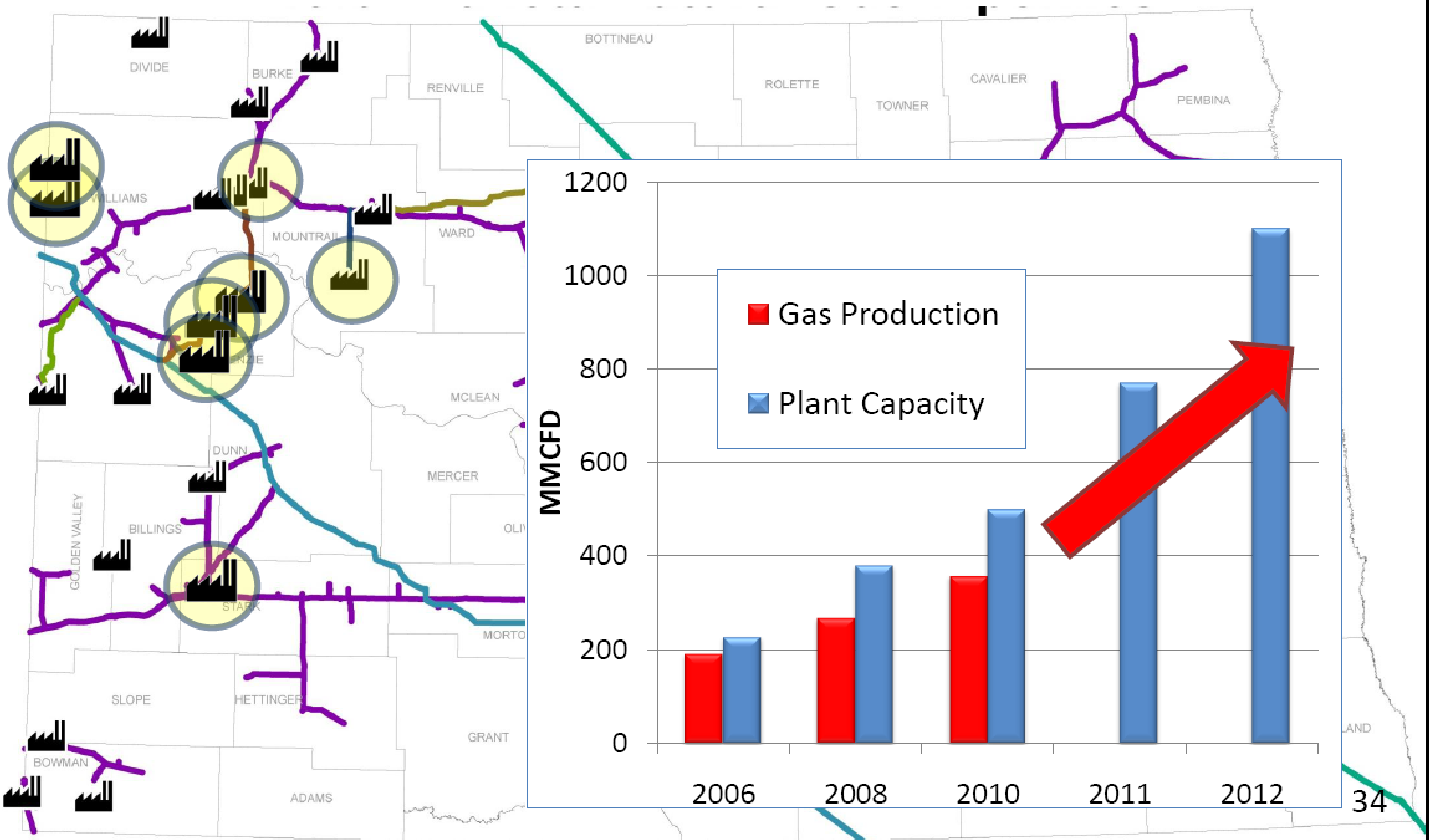

18,000 sq mi
9000 wells
1H/1280



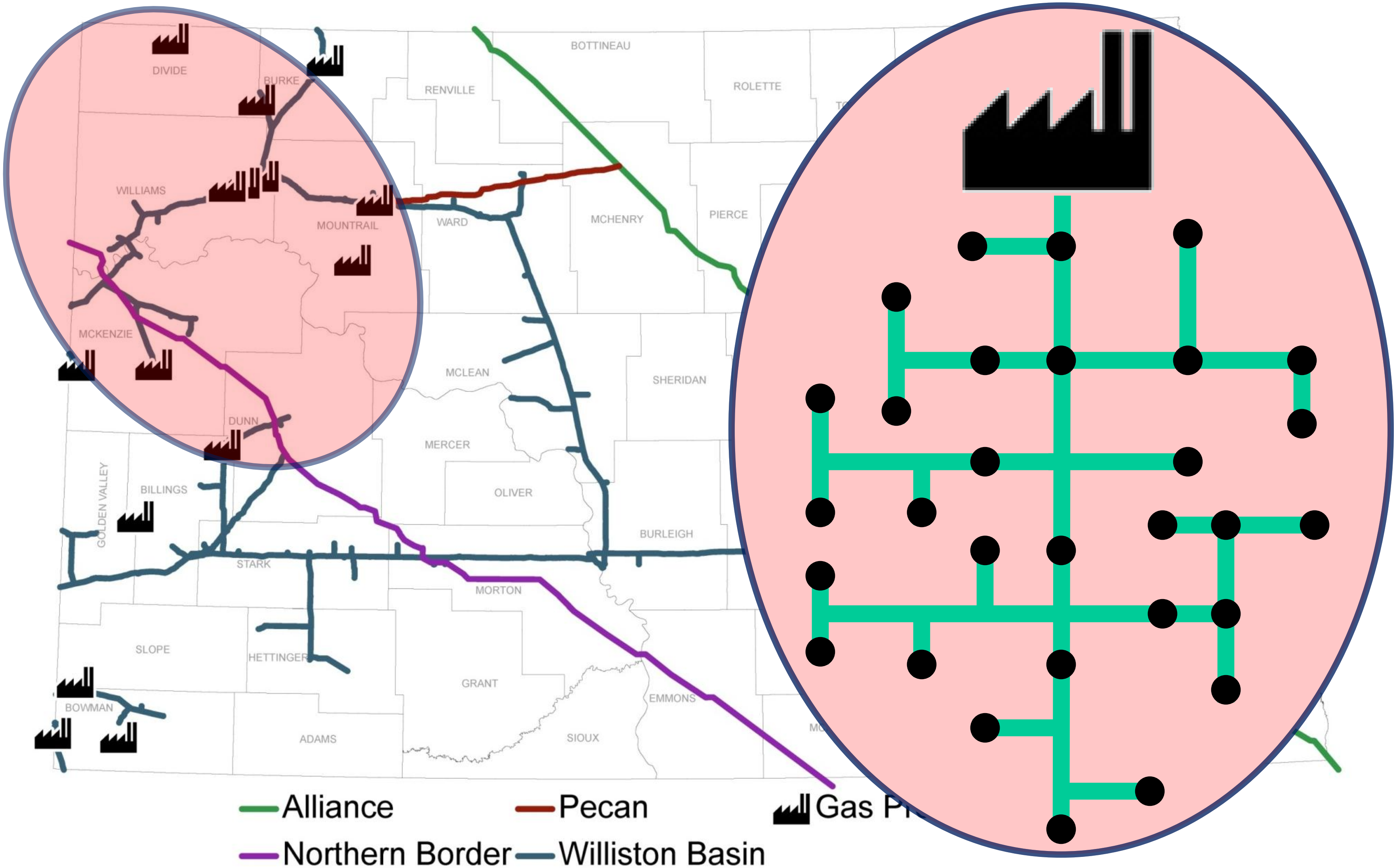
North Dakota Monthly Gas Produced and Price
MCF
$/MCF
15,000,000
14,000,000
13,000,000
12,000,000
11,000,000
10,000,000
9,000,000
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
$22
$20
$18
$16
$14
$12
$10
$8
$6
$4
$2
$0
1985
1990
1995
2000
2005
2010
2015
$ perMCF
MCF 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
Garden Creek Gas Plant
(Bear Paw)
100 MMCFPD
Operational
Ambrose
Lignite
Norse Gas Plant
Ray Plant
Nesson
Tioga
Stanley Pecan Pipeline
Robinson Lake
McKenzie Grasslands
Red Wing Creek
Little Knife
Knutson
Marmath
Little Beaver
Badlands
$3.5 billion investment

New or Expanding Gas Plants



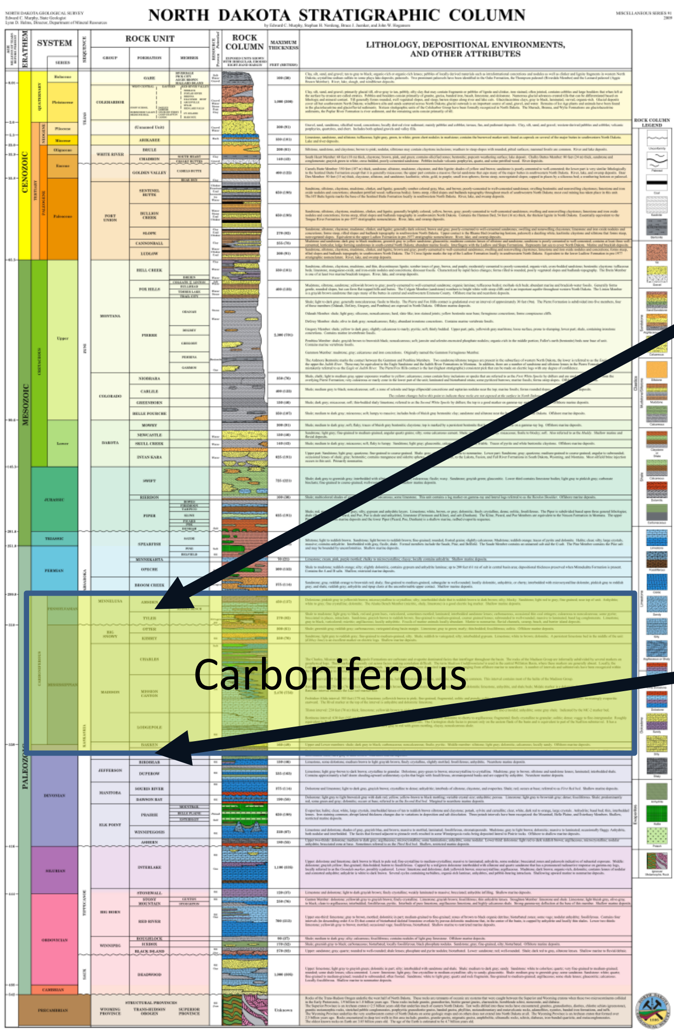
Natural Gas Challenges

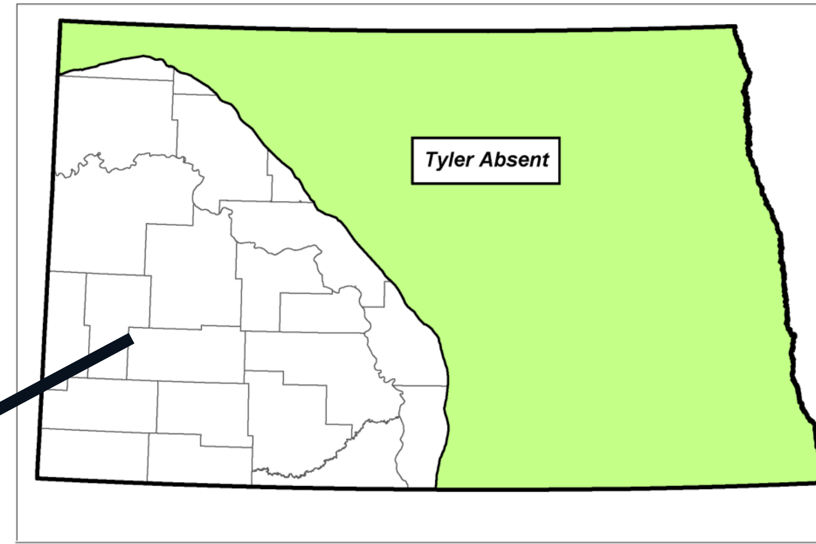


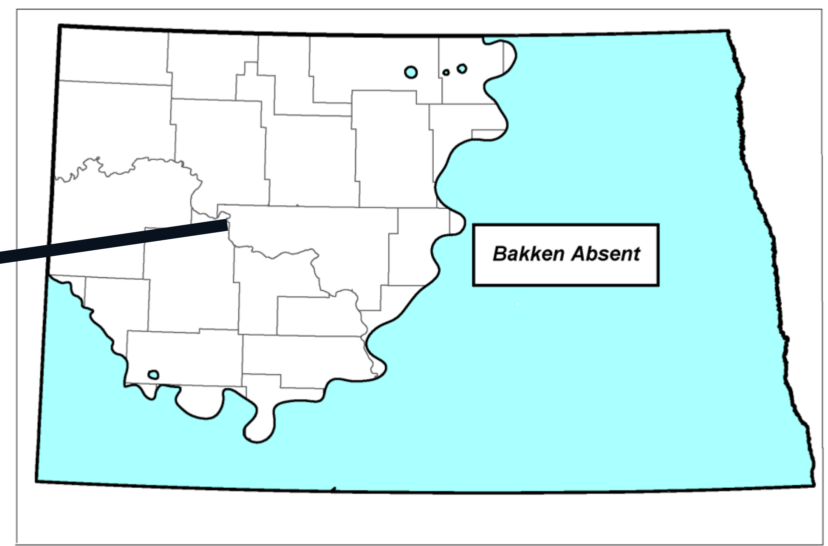
PLANNING FOR THE FUTURE
BEST PRACTICES

- Evaluate potential new plays

Regional Extent Tyler and Bakken







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 Resources
2010

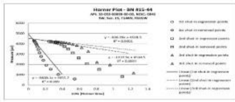


Figure 1. Horner plot of pressures measured during the shut-in periods of an open hole drill stem test (DST) of the Tyler Formation (8180-8282 ft. M.D.) in Pennzoil Co. & Depco's BN#15-44 (Figure 5, #6848). The extrapolated shut in pressures (Horner, 1951) from the 2nd and 3rd shut in periods of the 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.

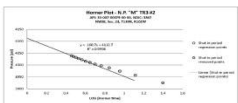


Figure 2. Horner plot of pressures measured during the shut-in period of an open hole drill stem test (DST) of the Tyler Formation (7743-7776 ft. M.D.) in Amerada Petroleum Corp.'s N.P. "M" TR# #2, shown on Figure 5 by #3867. Both the maximum pressure recorded (4039 psi = 0.52 psi/ft.) and the extrapolated 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.

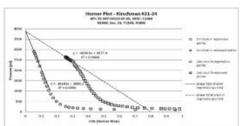


Figure 3. Horner plot of pressures measured during the shut in periods of a conventional bottom hole drill stem test (DST) on the Tyler Formation (7540-7556 ft. M.D.) in Milestone Petroleum's Kirschman #21-24, shown on Figure 5 by #11484. The calculated fluid pressure of the Tyler formation (the average 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.

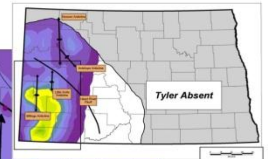


Figure 6. Time-Temperature Index map of the Pennsylvanian Tyler Formation in the Williston Basin of North Dakota. The color-filled contours represent the Time Temperature Index of the Tyler Formation. Areas in which the Tyler is absent are in gray (modified from Anderson, 1974).

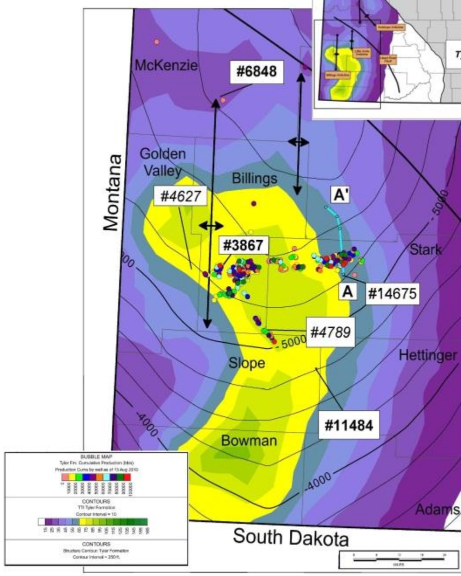


Figure 5. Detail map showing the distribution of Tyler production (Total Bbls) in North Dakota together with Time-Temperature contours and the location of wells from which pressure gradients (#6848, #3867, #11484) and Rock Eval data (#4627, #4789) were obtained. The color-filled contours represent the 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.

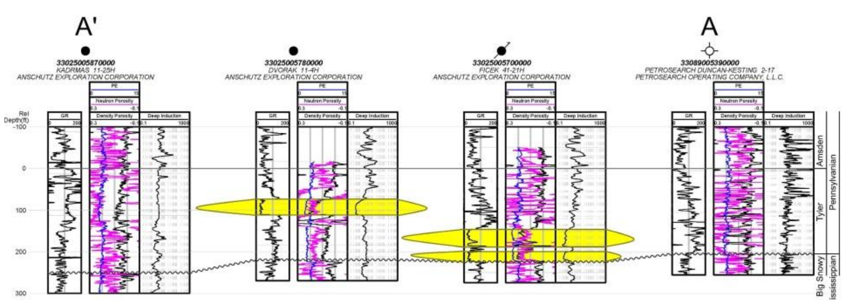


Figure 4. Cross-section extending from A to A' along the light blue line in Figure 5. The Kesting 2-17 (#14675 on Figure 5) corresponds to the point labeled A. Conventional sandstone reservoirs are shown in yellow. The section illustrates the discontinuous nature of the conventional sandstone reservoirs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

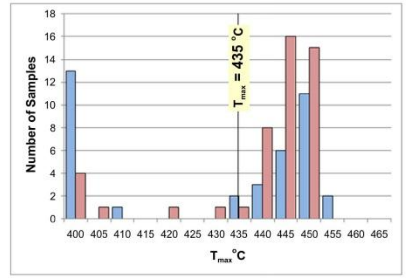


Figure 7. A frequency diagram showing that most of the samples of the Tyler Formation collected from the Government Taylor A-1 (#4627) in red, and the State of North Dakota #41-36 (#4789) in blue, have been thermally matured beyond the threshold that marks the onset of oil generation (Tmax ~435oC).

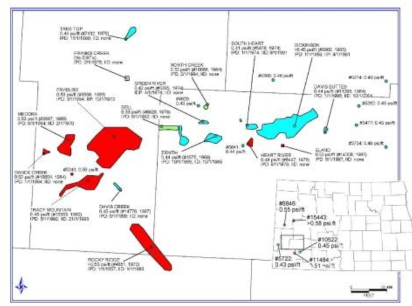


Figure 8. Field map showing the producing Tyler Fields in southern Billings, Slope, and Stark counties. For each field the Initial Pressure Gradient (IPG), Initial Production Date (IPD), and Initial Injection Date (IID) are given. Fields with evidence of initial fluid overpressure in the Tyler are colored 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.

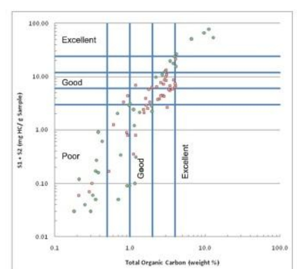


Figure 9. A kerogen quality diagram (Dembicki, 2009) constructed from the Total Organic Carbon (TOC) versus the mass of existing (S1) and potential (S2) hydrocarbons contained in samples of the Tyler Formation. The samples are from the Government Taylor A-1 (green circles) and the State of North Dakota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

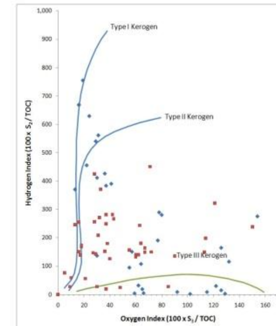


Figure 10. A modified van Krevelen diagram that classifies kerogen on the basis of the Hydrogen Index (HI) and Oxygen index (OI) derived from Rock Eval pyrolysis data. The blue diamonds represent the data from the Government Taylor A-1 (NDIC # 4627, SESE, Sec. 9, T139N, R103W) and the red squares refer 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.

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.

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PLANNING FOR THE FUTURE
BEST PRACTICES

- **Agency Coordination**

Permit Watch List

- Military installations - USAF
- Well head protection areas - NDDH
- Sensitive aquifer areas - NDWC
- Endangered species - USFWL
- Fort Berthold communities – TAT

Currently working with NDDOT, NDGF, NDPR to define critical areas

PLANNING FOR THE FUTURE
BEST PRACTICES

- Rules require shut-in equip
  - protect public health and safety


2011 had record MT snowpack

2011 had record ND snowfall

2011 had record ND flooding

PLANNING FOR THE FUTURE
BEST PRACTICES

- Rules require posting HF
  - must post on FracFocus

Find a Well

Back To Search

Next Page

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


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