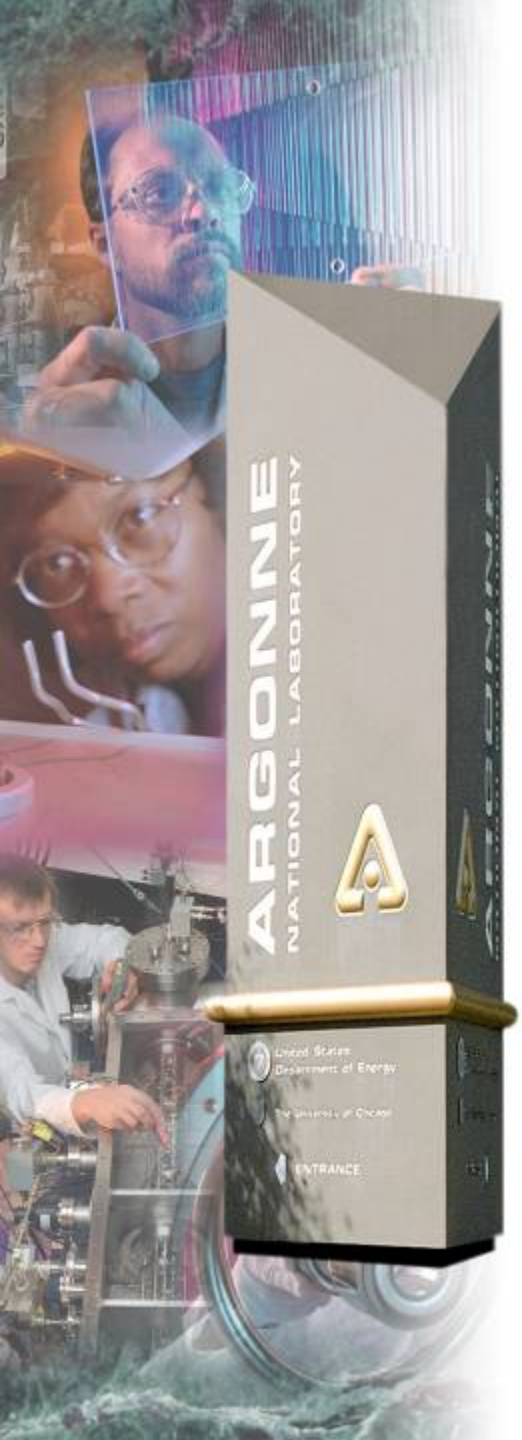

Water and Waste Regulatory Issues & Management Options

a workshop associated with the 11th International Petroleum Environmental Conference
October 13, 2004
Albuquerque, NM, USA

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Argonne National Laboratory

Office of Science
U.S. Department of Energy

A U.S. Department of Energy
Office of Science Laboratory
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Welcome

- Introductions
- Purpose and Goals of Workshop
- Announcements

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Topics for Discussion

- Types of water and waste streams generated
- Overview of major regulatory programs
- Water and waste management options
- Specific regulatory permit requirements

Exploration and Production (E&P) Activities Generate 3 Types of Waters and Wastes

- Drilling wastes
- Produced water
- “Associated” wastes

Drilling Wastes

- Drilling fluids (muds)
  - Used to support the hole, transport cuttings to the surface, control drilling
  - May contain mercury, cadmium arsenic
  - Can be contaminated with formation components
- Drill cuttings
  - Ground up rock fragments from the drill bit
  - Can be coated with muds

Types of Drilling Fluids

- water-based muds (WBMs)
- oil-based muds (OBMs)
- synthetic-based muds (SBMs)

Drilling Mud Main Ingredients

- Base fluid (water, diesel, mineral oil, synthetic fluid)
- Barite ($BaSO_4$)
  - used as weighting material
- Clay (often bentonite)
  - Aids in removing cuttings from well and forming a filter cake on the well bore
- Lignosulfonates and lignites
  - Keep the mud in a fluid state

Types of Mud Additives

- pH control agents
- Bacteriocides
- Scale and corrosion inhibitors
- Defoamers
- Emulsifiers
- Flocculants
- Lost circulation additives
- Lubricants
- Shale control inhibitors

Volume of Drilling Waste Generated

	1985 API Survey *Volume (bbl)*	1995 API Survey *Volume (bbl)*
Liquid Wastes (mud, completion fluid, pit water, formation testing fluid, other liquids)	324 million (90%)	109 million (74%)
Solid Wastes (cuttings, circulated cement, other solids)	38 million (10%)	39 million (26%)

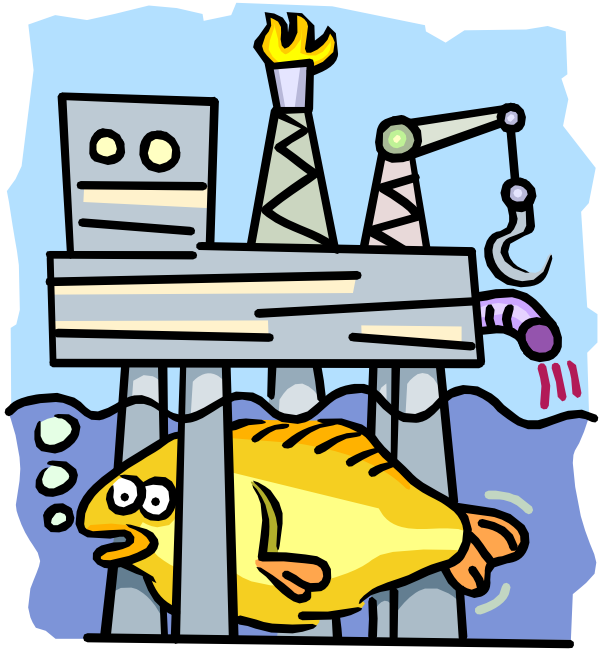
Note: The API surveys did not include most offshore wastes

What is Produced Water?

- Water that comes to the surface with oil and gas
- Contains many chemical constituents
- Concentrations vary widely by:
  - Geographic location
  - Geological formation
  - Type of production
  - Life span of well

What Is In Produced Water?

- Key Constituents
  - Salt content (salinity, total dissolved solids [TDS], electrical conductivity)
  - Oil and grease
    - *Not a single compound but a composite of many hydrocarbons and other organic materials*
  - Toxicity from various natural inorganic and organic compounds or chemical additives
  - NORM
- Final disposition or use of produced water determines which constituents are of greatest concern

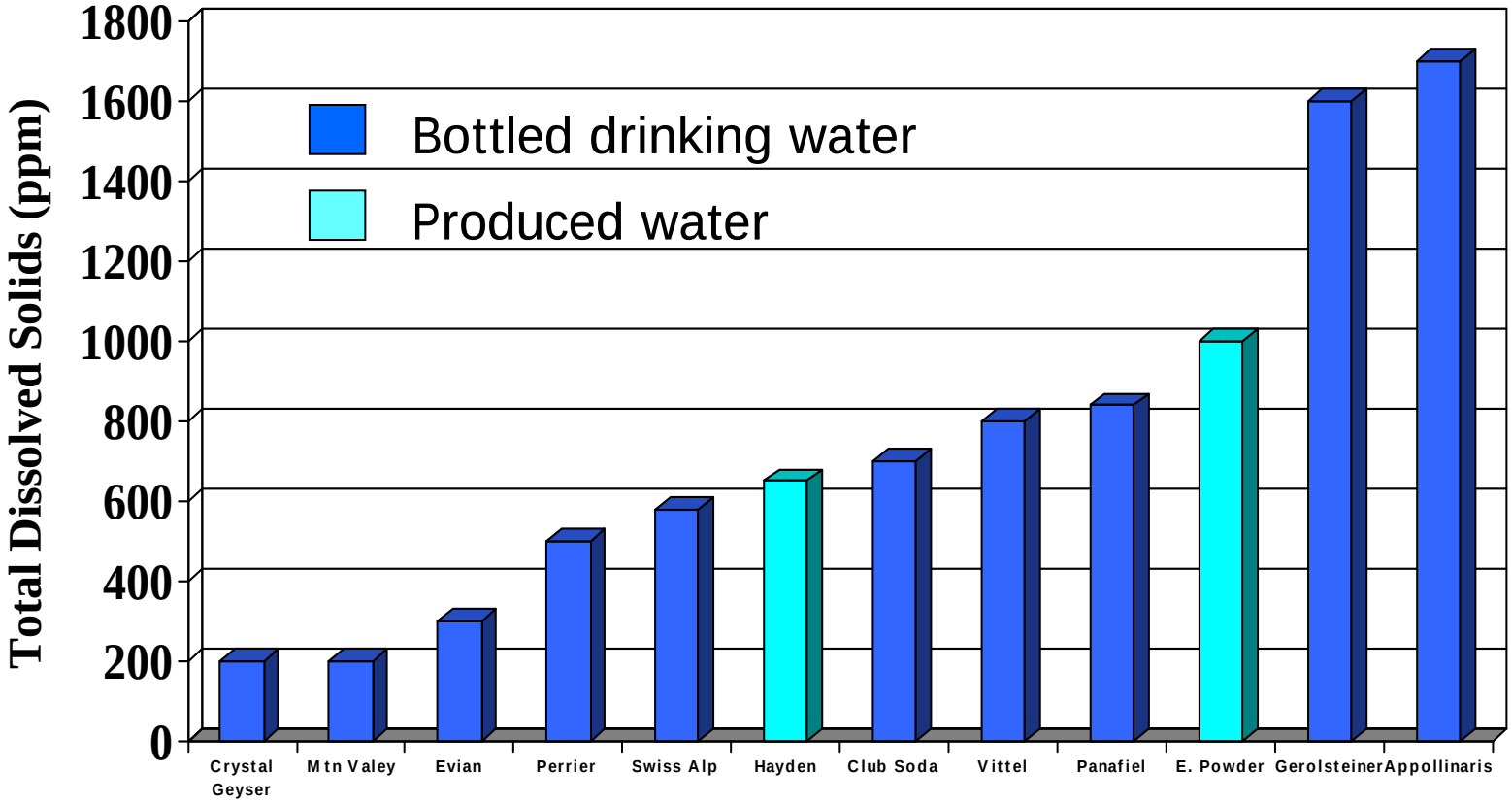


Potential Adverse Impacts of Produced Water

- Can harm aquatic life when discharged at inappropriate locations or at excessive concentrations
  - Different impacts at different locations
- Can harm crops and soils if used for irrigation without proper consideration of salts and sodium
  - Same applies for spills
- Not all impacts are bad – more on beneficial uses later

Produced Water Characteristics

- Usually is salty
  - Chlorides vary from <1 to >200,000 mg/l



Source: S. DeAlbuquerque, ConocoPhillips

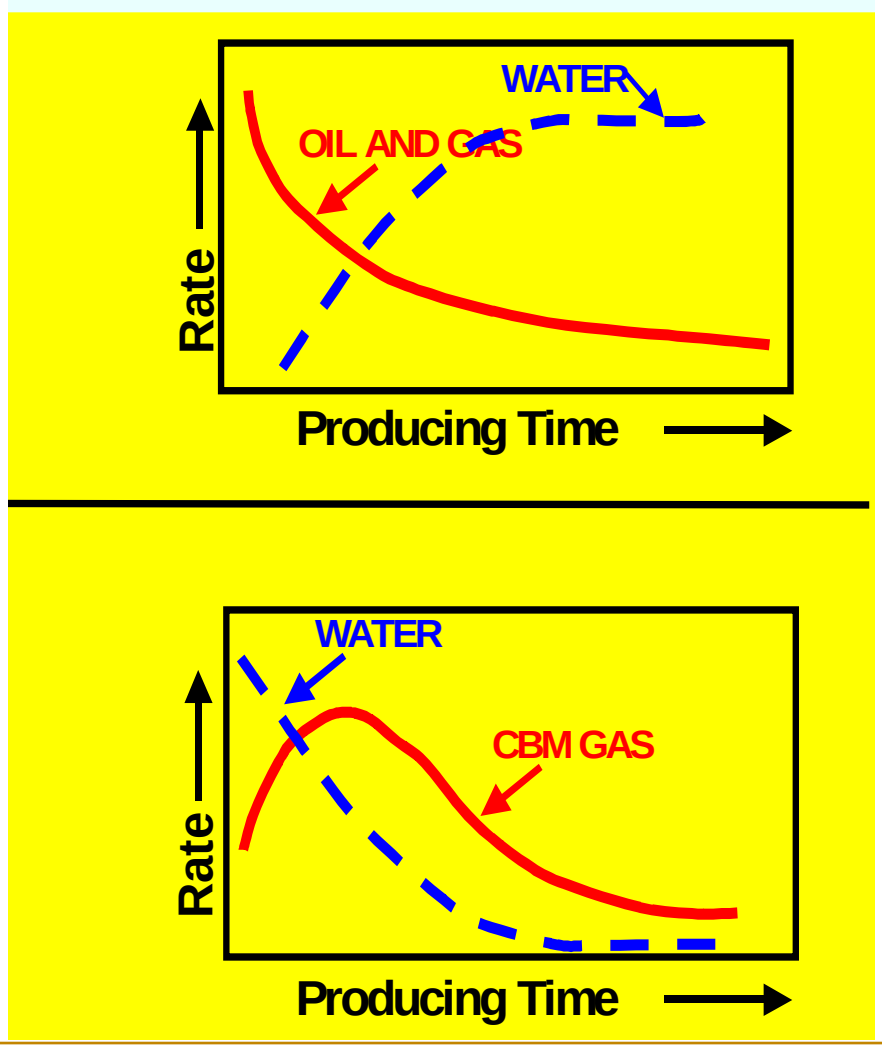
Produced Water Volume

- Largest volume waste stream from oil and gas production
  - Worldwide estimate – 77 billion bbl/year (2003 SPE paper)
  - U.S. offshore – 0.2 to 1.2 billion bbl/year (no good estimates)
  - U.S. onshore (more than 850,000 wells)
    - *18 billion bbl/year (1995 API study)*
    - *14 billion bbl/year (2002 estimate from recent inquiries)*
      - Problems with missing data for many states
      - Estimated by multiplying historical water-to-oil ratio times the crude oil production
      - Does not account for gas and CBM wells

Relative Volumes from Oil, Conventional Natural Gas, and Coal Bed Methane

- Oil has greatest volume
- Conventional natural gas has relatively little
- Coal bed methane starts out high but declines

Produced Water Volume Changes Over Time in a Well and a Field



Conventional oil and gas well

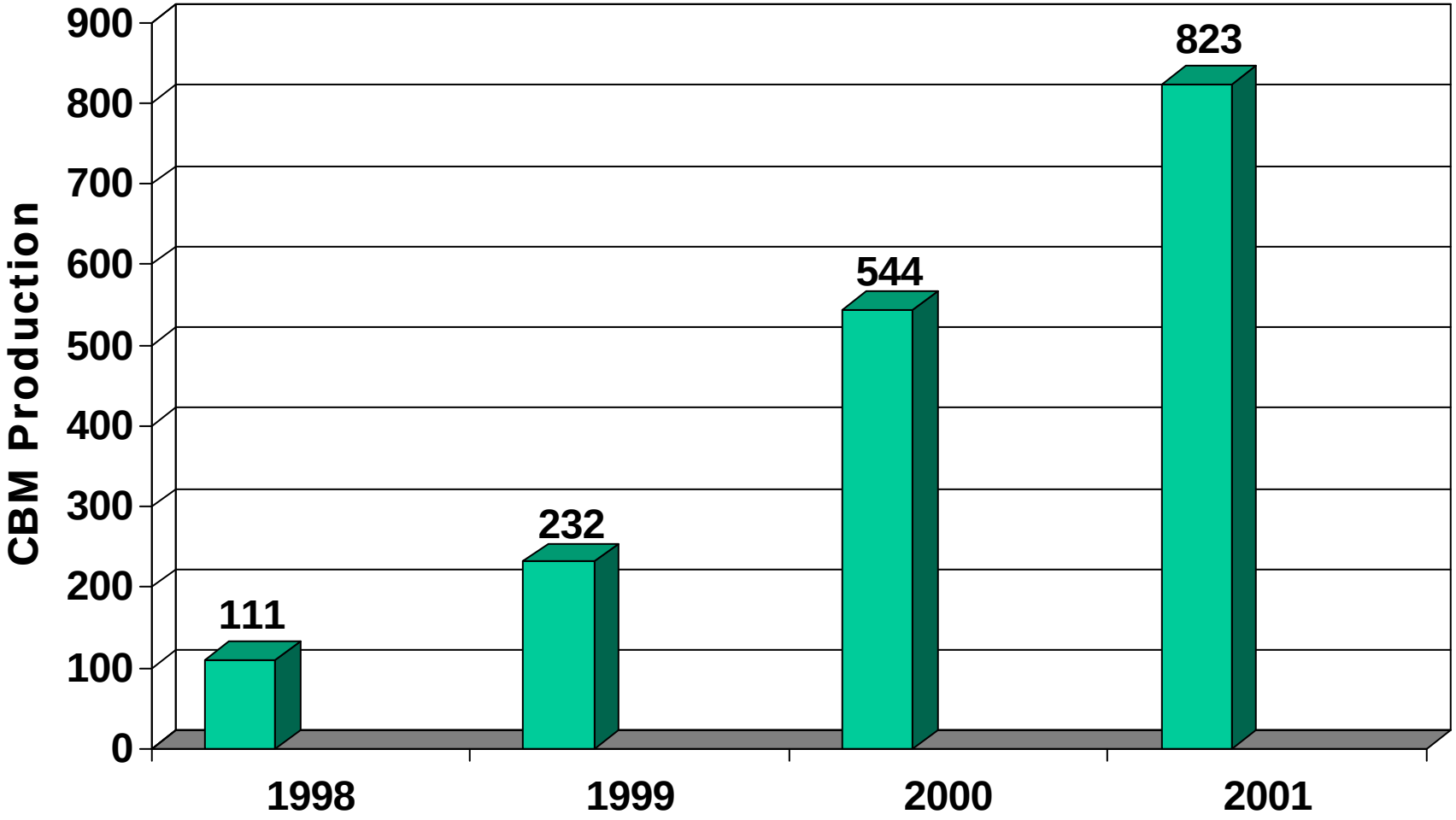
Coal bed methane well

Ratio of Water to Oil

- Worldwide estimate – 2:1 to 3:1
- U.S. estimate – 7:1
- Many older U.S. wells have ratios > 50:1
  - This often determines profitability of well

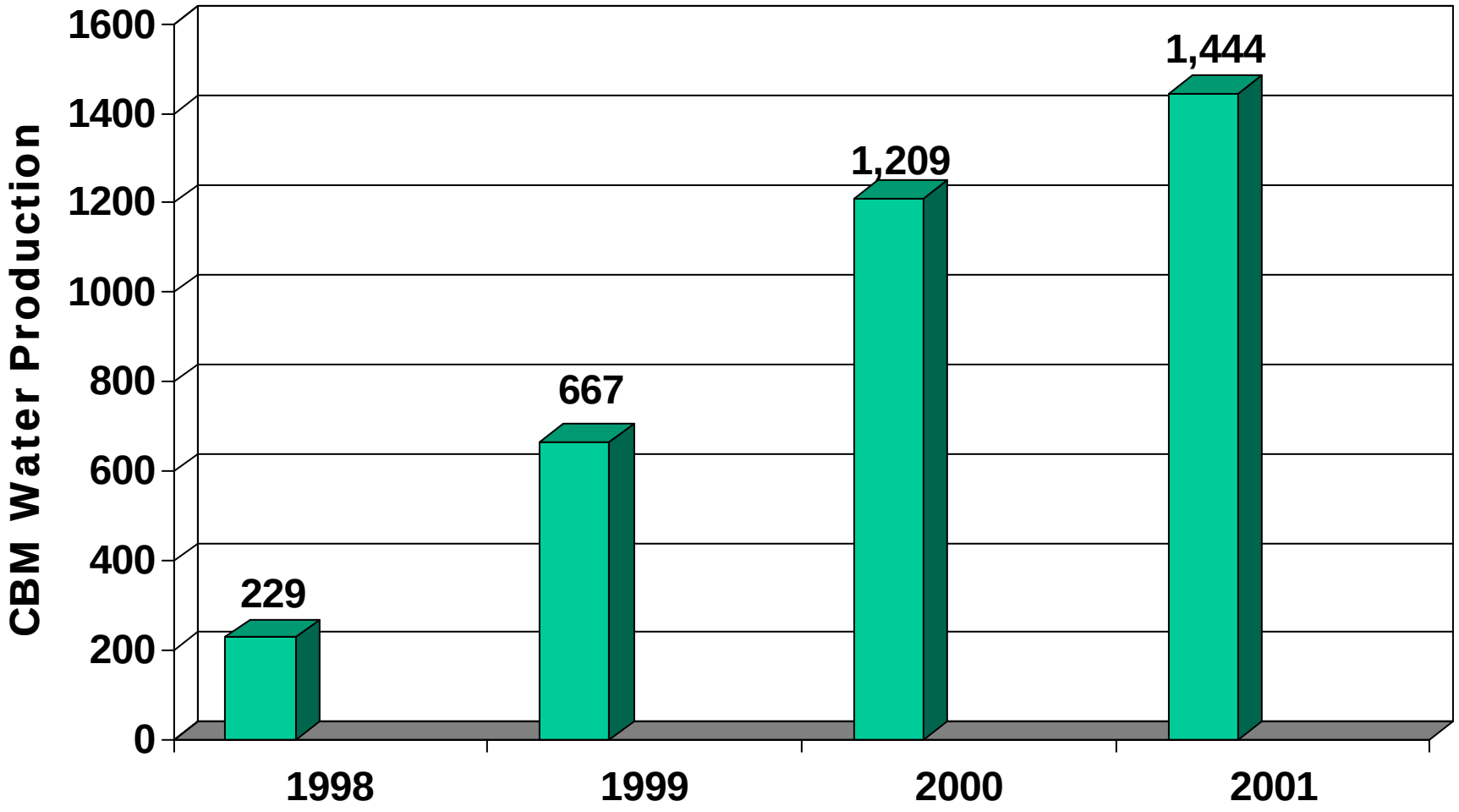
Go to downhole video

CBM Production in Powder River Basin (MMcf/day)



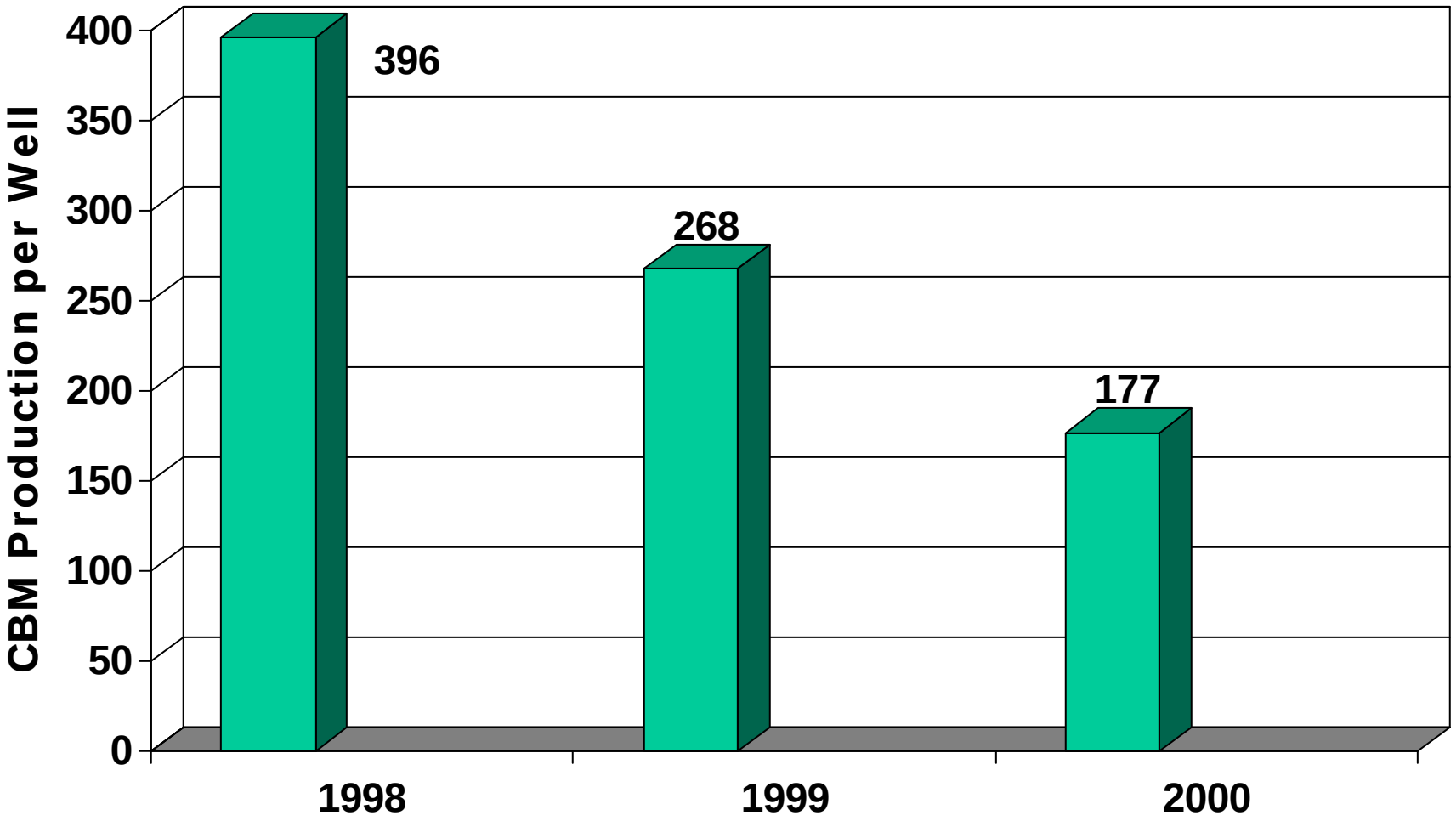
Source: DOE/NETL report 11/02

CBM Water Production in Powder River Basin (thousand bbls/day)



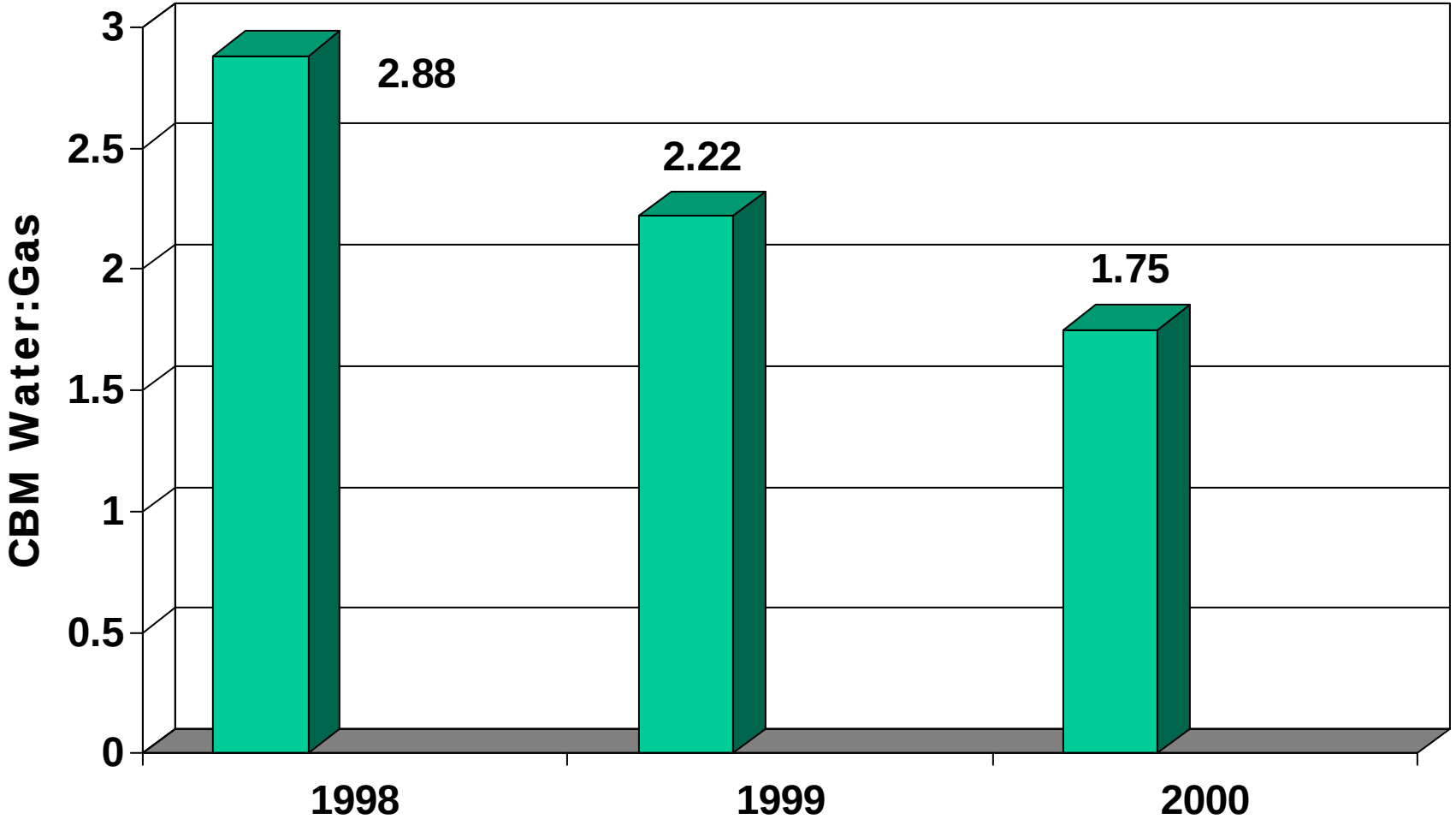
Source: DOE/NETL report 11/02

CBM Water Production per Well in Powder River Basin (bbls/day)



Source: DOE/NETL report 11/02

CBM Water/Gas Ratio (bbls/Mcf)



Source: DOE/NETL report 11/02

Number of U.S. Producing Wells in 2002

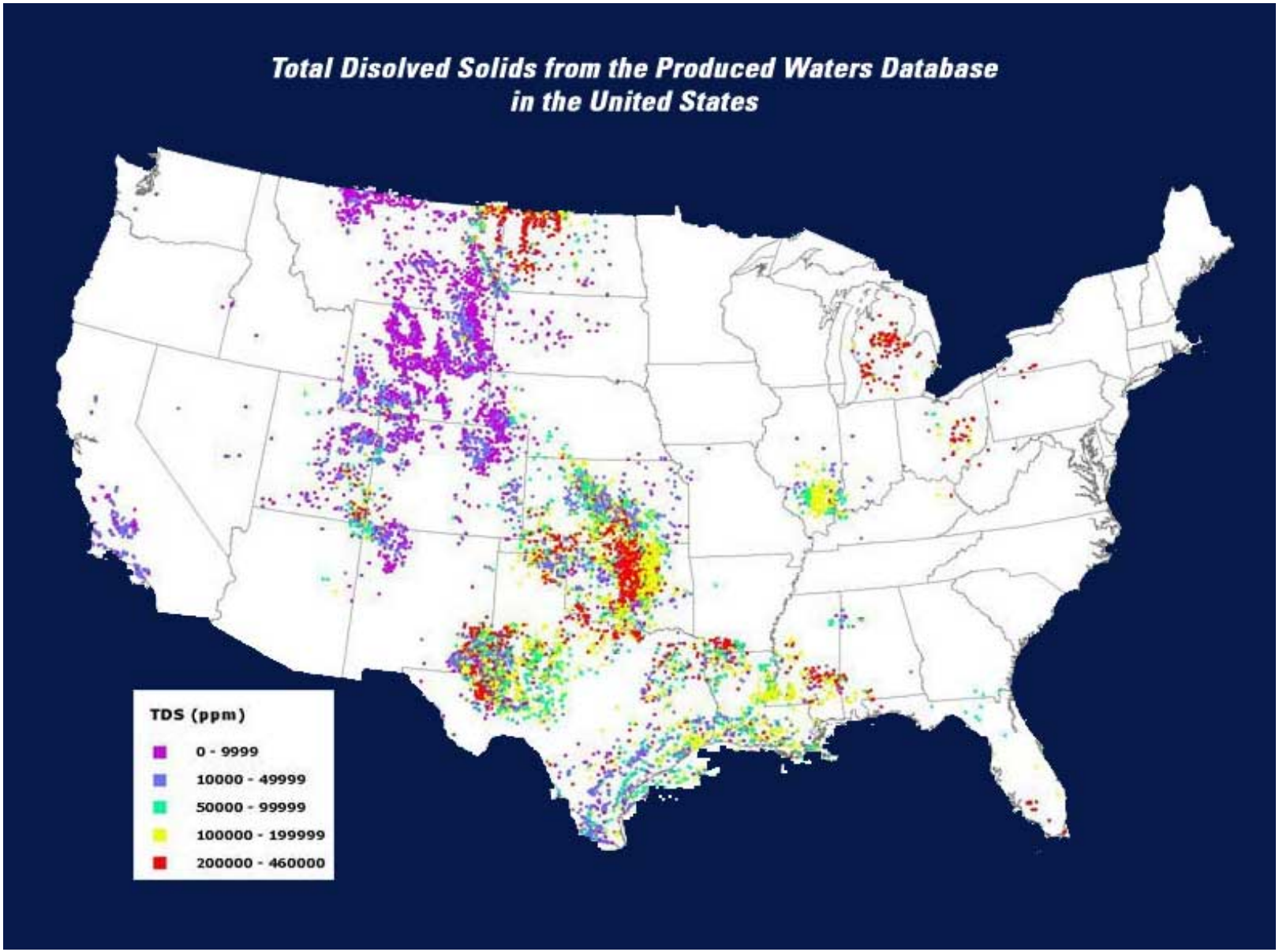
Type of Well	Oil	Gas	Total
Onshore (low production)	402,072	245,961	648,033
Onshore (high production)	113,225	134,794	247,019
Offshore	3,700	3,245	6,948
Total	519,000	383,000	902,000

Source: U.S. Department of Energy, Energy Information Administration and Interstate Oil and Gas Compact Commission

USGS Has Made Available a Produced Water Compositional Database

- Provides geochemical information on produced water across the United States
- Contains more than 50,000 records of location, geologic setting, sample type, and major ion composition
- Originally compiled at the DOE Fossil Energy Research Center in Bartlesville, Oklahoma
- Can be used to
  - Provide information on understanding petroleum reservoirs
  - Determine need for anti-scaling additives
  - Aid in the design of water handling and treatment systems
  - Help identify disposal and beneficial use options

http://energy.cr.usgs.gov/prov/prodwat/intro.htm


Total Disolved Solids from the Produced Waters Database
in the United States
TDS (ppm)
0 - 9999
10000 - 49999
50000 - 99999
100000 - 199999
200000 - 460000

Source: USGS

Associated Wastes

- Well completion, treatment, and workover fluids
- Produced sand
- Tank bottoms
- Contaminated soil
- Naturally Occurring Radioactive Material (NORM) scale and sludges
- Many more

Well Completion, Workover, and Treatment Fluids

- Materials used to prevent damage to the well bore during operations (completion) or to allow safe repair, maintenance, or abandonment (workover)
- Contain corrosion inhibitors, viscosifiers, filtration reducers
- Water- or oil-based

Produced Sand

- Solid particles that come to the surface with other produced fluids
  - Particles used in hydraulic fracturing
  - Sand from the formation
  - Scale
- May contain NORM, other naturally occurring contaminants
- Accumulates in tanks and is removed periodically

What is NORM?

- Naturally occurring radioactive material
- Found in:
  - produced water
  - sludge (225,000 tons/yr)
  - scale (25,000 tons/yr)
  - equipment
  - soil contaminated by spills

- NORM wastes have similar chemical characteristics to NOW wastes but also contain radionuclides

In the U.S., Most E&P Wastes Are Nonhazardous Wastes

- Environmental Protection Agency (EPA) decisions in 1988 and 1993
- States have regulatory authority over E&P wastes
- Some generic industrial wastes are hazardous
  - Solvents, paint wastes, etc.

U.S. Regulatory System

Laws

- Clean Water Act
- Safe Drinking Water Act

Water Regulations

- National Pollutant Discharge Elimination System (NPDES) program
- Effluent limitations guidelines (ELGs)
- Underground Injection Control (UIC) program
- Drinking water program

Permits and Guidance

- Environmental Protection Agency (EPA) regions and states issue NPDES and UIC permits

Clean Water Act (CWA)

- Federal Water Pollution Control Act of 1948
  - 1972 amendments brought major overhaul of the law
  - 1977 and 1987 amendments strengthened programs
- No point source discharges allowed to surface waters unless authorized by NPDES permit
- No discharges in toxic amounts
- Discharge limits must meet best available technology and also protect water quality

Safe Drinking Water Act (SDWA)

- First enacted in 1974 as Title XIV of Public Health Service Act, as amended
  - goal is to ensure that drinking water at the tap is clean and safe to drink
- Protects public water supply through:
  - Maximum Contaminant Levels (MCLs) & Maximum Contaminant Level Goals (MCLGs) for more than 75 contaminants
  - Filtration and disinfection
  - Control of water quality at the tap

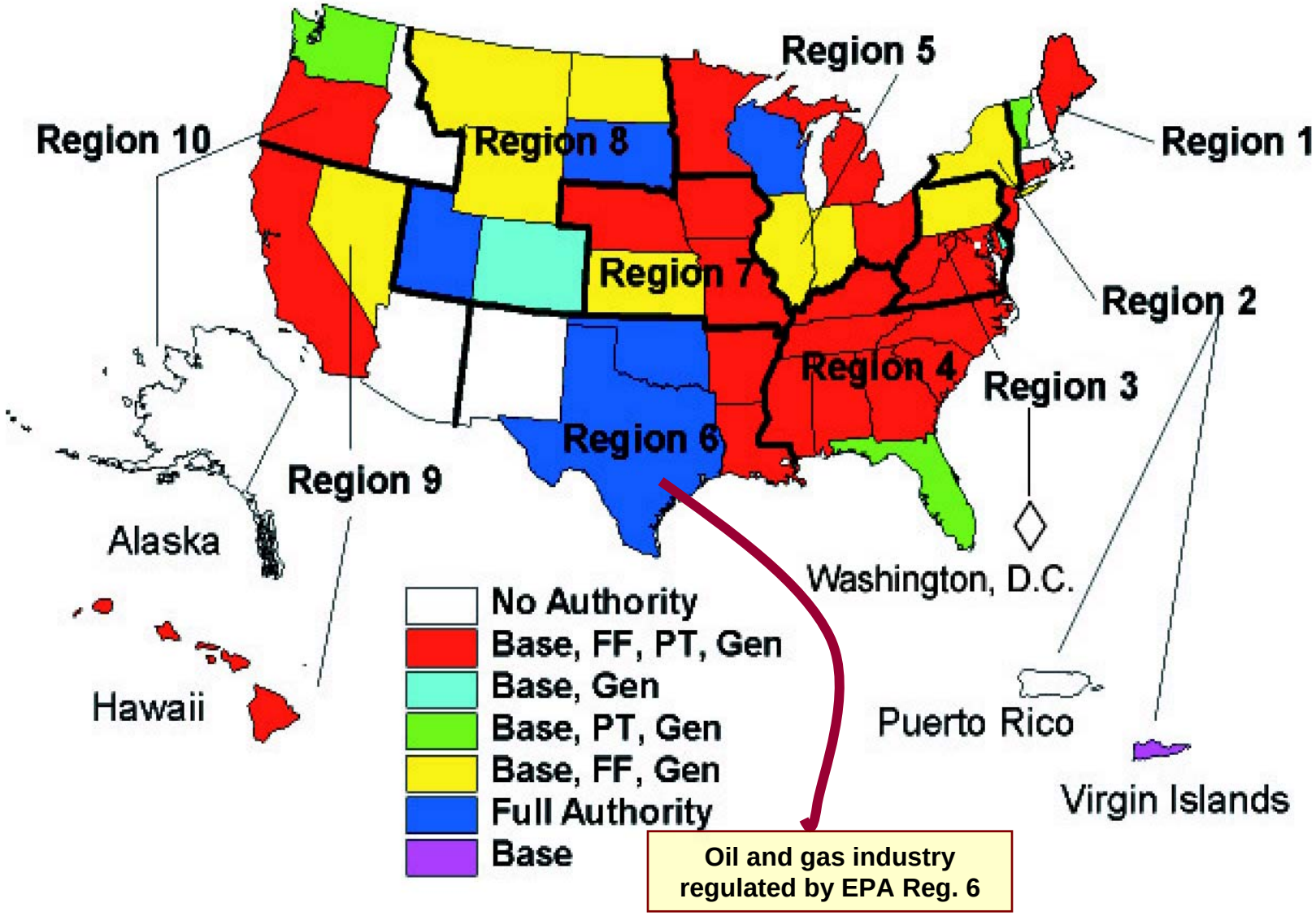
SDWA – Continued

- Regulates subsurface emplacement of waste
  - Underground Injection Control Program (UIC)
- Contains additional ground water protection programs
  - Demonstration program to develop, implement, and assess critical aquifer protection areas (sole source aquifers)
  - Elective state program for protecting wellhead areas around public water system wells
- Envisions protection of drinking water at the source
  - Source Water Protection Programs

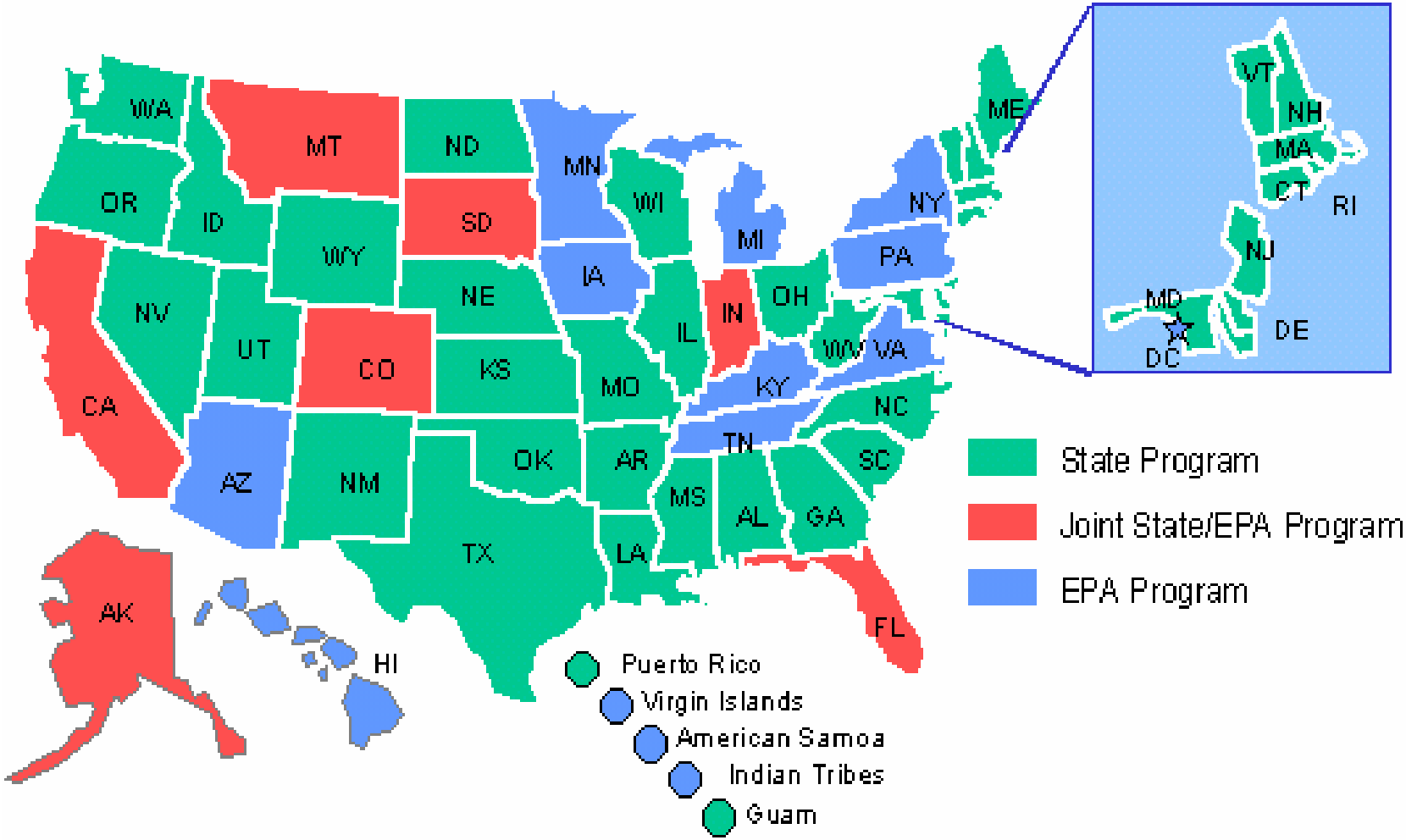
State vs. Federal Authority

- Both CWA and SDWA are administered through regulatory programs
  - Major regulatory programs can be delegated
    - *State can seek approval from the EPA for the day-to-day implementation and enforcement of programs*
    - *Examples: NPDES, UIC*
  - When states do not have delegated authority, programs are administered by EPA regional offices

State NPDES Program Authority



UIC Program Delegation



Major CWA Programs

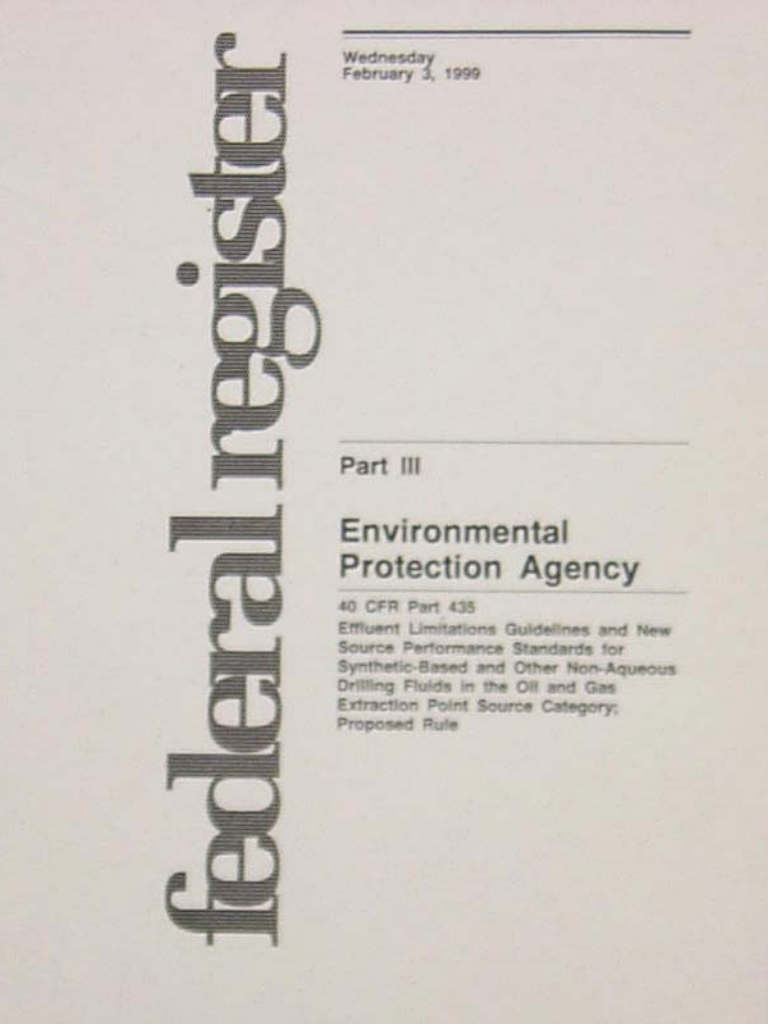
- NPDES permits
- Water quality standards
- Wetlands

NPDES Permits

- **Permits require**
  - Numerical limits
  - Operational measures and controls
  - Reporting and recordkeeping
  - Self-monitoring
- **Numerical limits are based on the more stringent of:**
  - Technology-based limits (BAT, NSPS) or best professional judgment
  - Water quality-based limits (considers dilution and mixing in stream)
- **Permits are issued for 5-year term and must be reissued**

EPA Headquarters Establishes National Effluent Limitations Guidelines (ELGs)

- performance-based controls
- must consider:
  - technologies that are already successfully in use
  - costs and economic impacts
  - non-water quality environmental impacts


federal register

Wednesday
February 3, 1999

Part III

Environmental Protection Agency

40 CFR Part 435
Effluent Limitations Guidelines and New Source Performance Standards for Synthetic-Based and Other Non-Aqueous Drilling Fluids in the Oil and Gas Extraction Point Source Category; Proposed Rule

Effluent Limitations Guidelines (ELGs)

- **Original Standards**
  - Best Practicable Technology Currently Available (BPT) effluent limits are established for conventional, toxic and non-conventional pollutants
- **Current Standards for Existing Facilities**
  - Best Available Technologies Economically Achievable (BAT) effluent limits represent the best existing economically achievable performance of direct discharging plants in the subcategory or category
  - Best Conventional Pollutant Control Technology (BCT) is not an additional limitation but replaces BAT control of conventional pollutants
- **Current Standards for New Facilities**
  - New Source Performance Standards (NSPS) apply to new dischargers and reflect reductions that are achievable demonstrated control technology

Water Quality Standards

- **Water quality standards (WQS) define the goals for a waterbody by designating its uses, setting criteria to protect those uses, and establishing provisions to protect water quality from pollutants**
- **WQS consist of four basic elements:**
  - (1) *designated uses* of the water body (e.g., recreation, water supply, aquatic life, agriculture),
  - (2) *water quality criteria* to protect designated uses (numeric pollutant concentrations and narrative requirements),
  - (3) an *antidegradation policy* to maintain and protect existing uses and high quality waters, and
  - (4) *general policies* addressing implementation issues (e.g., low flows, variances, mixing zones).

Water Quality Standards (cont'd.)

- **Every state must develop state-specific WQS that must be approved by the EPA**
  - The EPA's recommended water quality criteria (WQC) provide technical guidance to states and tribes in adopting WQS
  - WQC are developed for the protection of aquatic life as well as for human health
  - The EPA's list contains 65 compounds and families of compounds; EPA continues to develop new water quality criteria for toxics, nutrients, microorganisms

    http://www.epa.gov/ost/standards/wqcriteria.html
- **WQS are used to establish NPDES permit limits**
- **WQS can serve as cleanup standards under CERCLA and RCRA**

Excerpt from EPA WQ Criteria Table

NATIONAL RECOMMENDED WATER QUALITY CRITERIA FOR PRIORITY TOXIC POLLUTANTS

	Priority Pollutant	CAS Number	Freshwater CMC (µg/L)	Freshwater CCC (µg/L)	Saltwater CMC (µg/L)	Saltwater CCC (µg/L)	Human Health For Consumption of: Water + Organism (µg/L)	Human Health For Consumption of: Organism Only (µg/L)	FR Cite/ Source
1	Antimony	7440360					5.6 B	640 B	65FR66443
2	Arsenic	7440382	340 A,D,K	150 A,D,K	69 A,D,bb	36 A,D,bb	0.018 C,M,S	0.14 C,M,S	65FR31682 57FR60848
3	Beryllium	7440417					Z		65FR31682
4	Cadmium	7440439	2.0 D,E,K,bb	0.25 D,E,K,bb	40 D,bb	8.8 D,bb	Z		EPA-822-R-01-001 65FR31682
5a	Chromium (III)	16065831	570 D,E,K	74 D,E,K			Z Total		EPA820/B-96-001 65FR31682
5b	Chromium (VI)	18540299	16 D,K	11 D,K	1,100 D,bb	50 D,bb	Z Total		65FR31682
6	Copper	7440508	13 D,E,K,ee	9.0 D,E,K,ee	4.8 D,ee,ff	3.1 D,ee,ff	1,300 U		65FR31682
7	Lead	7439921	65 D,E,bb,gg	2.5 D,E,bb,gg	210 D,bb	8.1 D,bb			65FR31682
8a 8b	Mercury Methylmercury	7439976 22967926	1.4 D,K,hh	0.77 D,K,hh	1.8 D,ee,hh	0.94 D,ee,hh		0.3 mg/kg J	62FR42160 EPA823-R-01-001
9	Nickel	7440020	470 D,E,K	52 D,E,K	74 D,bb	8.2 D,bb	610 B	4,600 B	65FR31682
10	Selenium	7782492	L,R,T	5.0 T	290 D,bb,dd	71 D,bb,dd	170 Z	4200	62FR42160 65FR31682 65FR66443

Various Standards for Mercury (ppb)

WQC (CWA)	Freshwater	0.77 avg 1.4 max
	Saltwater	0.94 avg 1.8 max
	Human health	0.05
MCL (SDWA)		2.0
Special Standards for Great Lakes Basin	Aquatic life protection	0.9 avg 1.7 max
	Human health	0.0018
	wildlife	0.0013

Water Quality-Based Limits

- States adopt numerical WQS for many pollutants
- States develop mixing zone policies that allow for dilution
- WQ-based limits are calculated by multiplying the WQS by the allowable dilution
- Permit limits must not cause exceedance of WQS outside of mixing zones

Establishing NPDES Permit Limits and Conditions – Simplified Overview

Step 1 – Develop technology-based limits

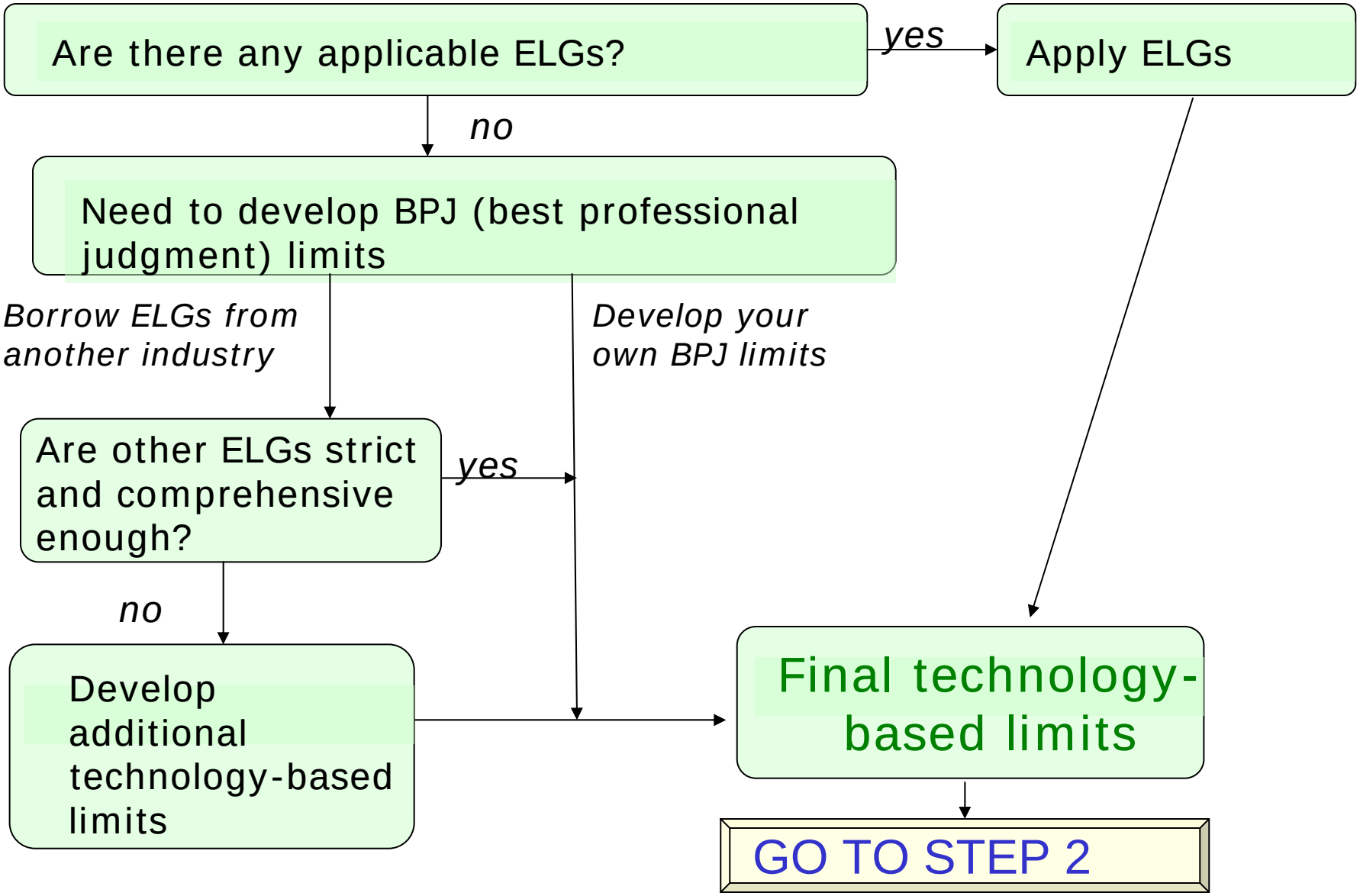
↓

Step 2 – Develop water quality-based limits

↓

Step 3 – Determine other permit conditions

Establishing NPDES Permit Limits and Conditions
Step 1 - Develop Technology-based Limits



Establishing NPDES Permit Limits and Conditions
Step 2 - Develop Water Quality-based Limits

Do technology-based limits developed in step 1 protect water quality?

-determine background concentrations of pollutants and dilution

-compare concentrations to water quality standards

yes

no

Develop water quality-based limits:

-stricter limits for pollutants already covered by technology-based limits

-limits for other pollutants not covered by technology-based limits

May need to do modeling and determine mixing zone

Final water quality-based limits

GO TO STEP 3

Establishing NPDES Permit Limits and Conditions
Step 3 – Determine Other Permit Conditions

Use numerical limits developed in steps 1 and 2 and determine monitoring and reporting methods and frequency

Are other types of controls necessary?

-best management practices plans

-operational requirements

-restrictions on flow or other activities

no

yes

Develop other types of controls and add to permit

Final permit

Example of Permit Limit Calculation

1. **Separately calculate technology-based limits and WQ-based limits.**
2. **Permit limit is the more stringent of the two.**

	lead	benzene
Technology-based limit	***200 ppb***	***1,000 ppb***
WQ-based limit		
WQS	**5.6 ppb**	**700 ppb**
dilution	**20:1**	**20:1**
limit	**112 ppb**	**14,000 ppb**
Permit limit	**?**	**?**

Other NPDES Permit Conditions

- Discharge rate
- Best management practices (BMP) plan
- Toxicity testing
- Ecological testing
- List of chemical additives
- Extra chemical monitoring

Other NPDES Programs

- General permits
- Stormwater permits
- Pretreatment program

General NPDES Permits

- Cover group of similar dischargers in the same geographic area
- EPA regulations direct Regions to issue general permits for offshore oil and gas activities
  - EPA may issue individual permits in areas of biological concern
  - Applicants may request individual permits
  - Used by Regions 4, 6, 9, and 10 for coastal, territorial seas, and Outer Continental Shelf areas

Stormwater Permits

- **Prior to 1987, stormwater runoff was not always regulated**
- **1987 amendments to Clean Water Act (CWA) said that stormwater runoff must be covered under an NPDES permit (usually general permit)**
  - Phase I: large municipal storm sewers, runoff from industrial sites and from construction sites disturbing >5 acres
    - *Rules issued 11/16/90*
  - Phase II: small municipal storm sewers, runoff from construction sites disturbing from 1-5 acres
    - *Rules issued 12/8/99*

Phase I Permits Were Issued in 1998

- Permit technical requirements
  - must provide an ESA consultation
  - must provide information on whether the activities would affect any property on the National Register of Historical Places
    - *where effects occur, must provide written agreement with State or Tribal Historic Preservation Officer*
  - must conduct inspections at least every 14 days and within 24 hours of any rainfall > 0.5“

Phase I Permit Requirements (2)

- must develop a stormwater pollution prevention plan (SWPPP)
  - describe BMPs (does not specify which BMPs must be used but must use one or more as necessary)
  - employ structural practices to divert flows, store flows, and/or control runoff
  - provide the timing and sequence of different BMPs
  - install and maintain any control measures in accordance with manufacturer's specifications
  - sediment traps and ponds must be cleaned out before accumulating more than 50% of their capacity

What About the E&P Sector?

- CWA exempts oil and gas E&P and mining sites from stormwater permits [§402 (l)(2)]
  - "Stormwater Runoff From Oil, Gas, and Mining Operations.--***The Administrator shall not require a permit under this section, nor shall the Administrator directly or indirectly require any State to require a permit, for discharges of stormwater runoff from mining operations or oil and gas exploration, production, processing****, or treatment operations* or transmission facilities, composed entirely of flows which are from conveyances or systems of conveyances (including but not limited to pipes, conduits, ditches, and channels) used for collecting and conveying precipitation runoff and which are not contaminated by contact with, or do not come into contact with, any overburden, raw material, intermediate products, finished product, byproduct, or waste products located on the site of such operations."

EPA's Interpretation

- Once the well is drilled and exploration begins, EPA may not require a permit
- But -- EPA interprets construction of lease roads, drill pads, and other disturbed areas to be outside of the scope of the exemption
- Result: permit required during construction phase but not during operational phase

Jurisdiction

- EPA has delegated NPDES authority to most states
  - States issue their own general permits
- Where states do not take over program, EPA regions issue permits
- Region 6 presents particular problem for industry
  - NM does not have primacy
  - OK and TX have primacy for all categories except for oil and gas
  - Region 6 writes oil and gas stormwater NPDES permits for these 3 heavy producing states

What Was the Concern in the Summer and Fall of 2002?

- When EPA issued its Phase II permit, most new E&P operations would need to get a Phase II permit before starting
  - The huge increase in number of permits, ESA certifications, and historic preservation reviews is likely to cause:
    - *delays in starting to drill (drill rig scheduling problems)*
    - *costs for additional studies and paperwork*
    - *some wells won't get drilled*

Number of U.S. Wells Drilled

Year	Oil	Gas	Dry	Total
2000	7,358	16,455	4,025	27,838
2001	8,060	22,083	3,996	34,139
2002 (Jan-Oct)	4,111	13,271	3,017	20,399

Source: DOE Energy Information Administration website

What Happened during the Fall of 2002?

- EPA received numerous criticisms and contacts from oil and gas industry directly and through political channels
  - Interpretation of exemption
  - Failure to study economic impacts on E&P industry
  - Other issues
- EPA did not issue the draft permit on schedule
- Discussions were elevated to senior management level at agencies

A New Draft Permit!

- New combined Phase I and II permit was issued on December 20, 2002
  - Phase II facilities must meet most of the same conditions in the Phase I permit
- On December 30, EPA published notice that oil and gas E&P sites that disturb from 1-5 acres would have a 2-year extension before having to obtain a stormwater permit

Follow Up Activities

- During the two year-period, EPA will study the oil and gas industry to:
  - Evaluate impact on the industry
  - Determine appropriate BMPs
  - Examine the applicability of the CWA exemption language
- DOE is participating in a discussion group with EPA and states
  - IOGCC provided some state survey information
  - DOE is encouraging industry to provide more data to EPA
  - DOE took EPA HQ staff on oil field tour in Nov. 2003

How Are Wastes Managed?

- Different options for different wastes
- Onshore versus offshore
- Onsite versus offsite
- Different options for different states and countries

Water and Waste Management at Onshore U.S. Wells

- Drilling wastes and other wastes
  - Most use an onsite lined or unlined pit
  - At the end of the drilling job:
    - *Liquid contents of pit are disposed into an injection well*
    - *Solids are buried in place and covered by clean dirt or are land spread*
  - Some wastes must be disposed of at offsite commercial disposal facilities
- Produced water
  - Most of it is injected for either enhanced recovery or disposal

Water and Waste Management at Offshore U.S. Wells

- Drilling wastes
  - Most are discharged if permit allows
  - Others are injected onsite or hauled back to shore
- Produced water
  - Most is discharged
  - Some is injected for enhanced recovery or disposal

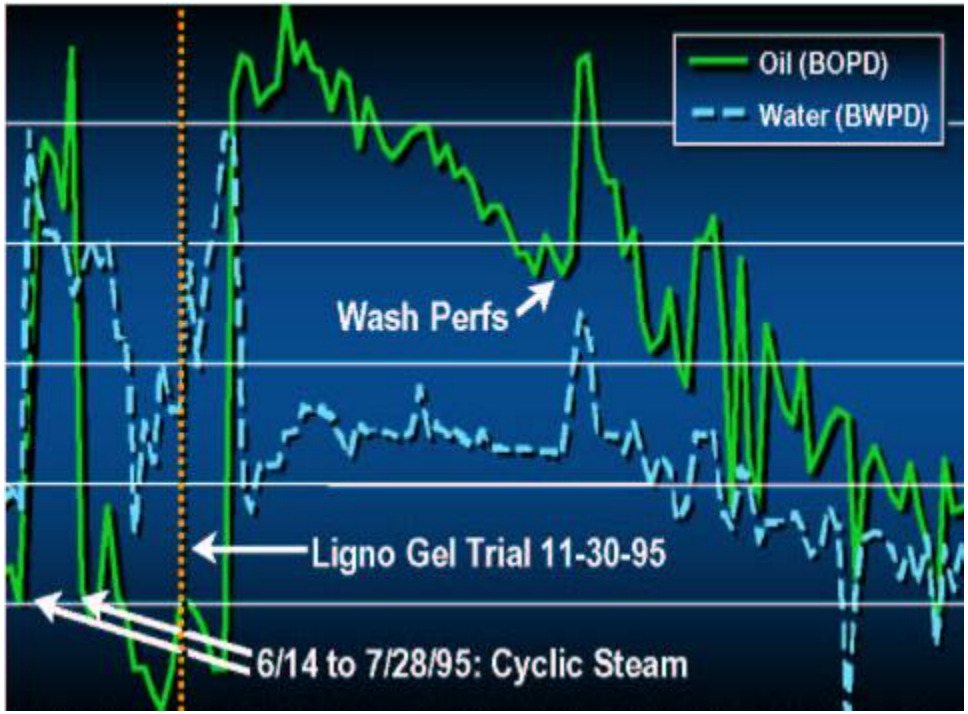
Produced Water Management Options – Follow Waste Management Hierarchy

Try to follow the most environmentally friendly option first. If not practical or economical, then go to next best option.

- Waste minimization
  - Reduce generation of waste
  - Reduce exposure of material to locations where it can cause a problem
- Recycle/reuse
  - Put the material to another use
- Disposal
  - With or without treatment

Waste Minimization

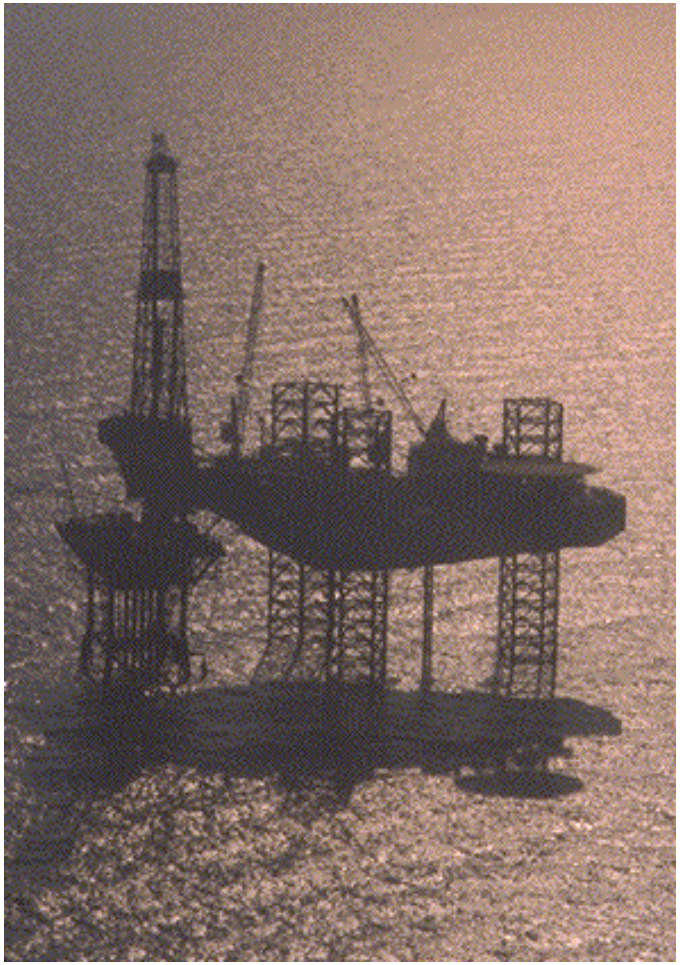
- Reduce produced water production
  - Mechanical blocking devices
    - *Packers*
    - *Plugs*
    - *Cement*
  - Water shut-off chemicals
    - *Polymer gels*
    - *Microbial products*
    - *lignosulfonate*



Source: G. Thakur, ChevronTexaco

Waste Minimization (continued)

- Manage water without bringing it to surface
  - Downhole
  - Sea floor
- Downhole oil/water separators
- Other related technologies

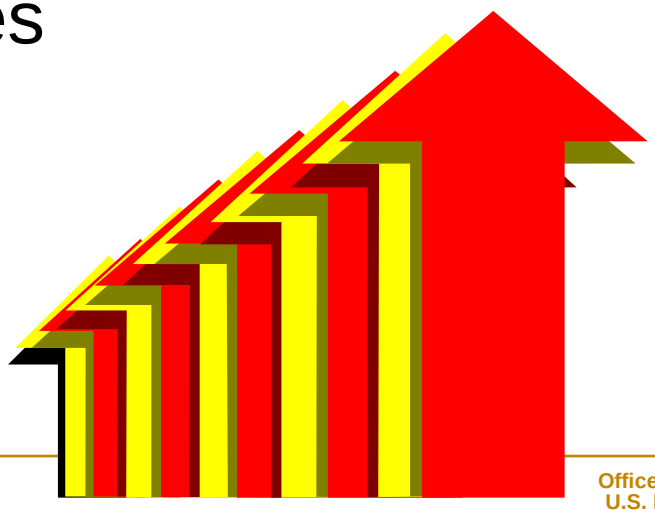


What Is A Downhole Oil/Water Separator (DOWS or DHOWS)?

- tool that mounts in bottom of well and separates oil from water
- oil is pumped to the surface
- water is pumped to injection zone without coming to surface

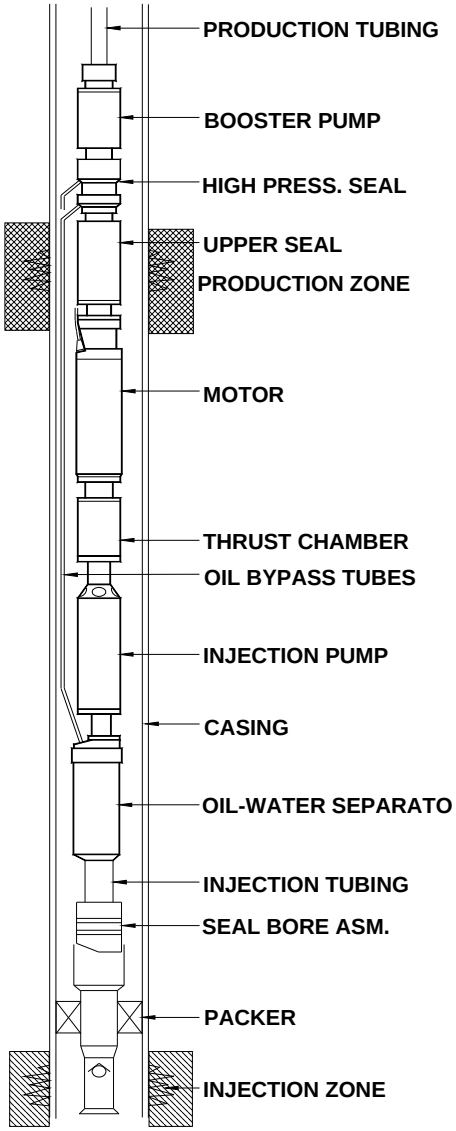
Advantages of DOWS

- reduces produced water handling costs
- may increase oil production from individual wells or from a field
- reduces opportunity for contamination of drinking water supplies



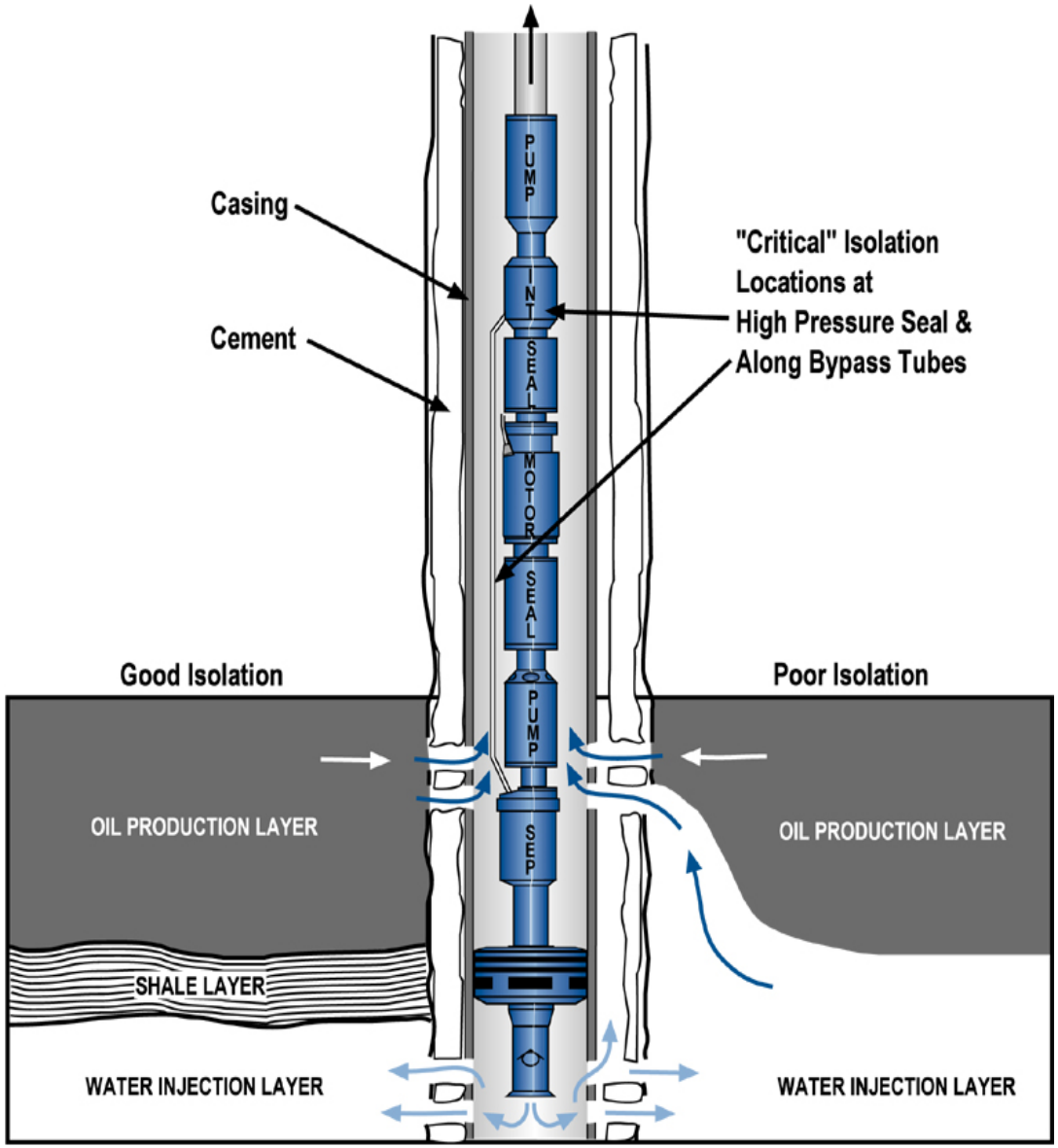
Several Types of DOWS

- Hydrocyclone type
  - electric submersible pump
  - progressing cavity pump
  - rod pump
  - gas lift
- Gravity-separation type
  - rod pump
  - hydraulic pump
- Centrifuge type
  - Currently under development



Source: Centrilift

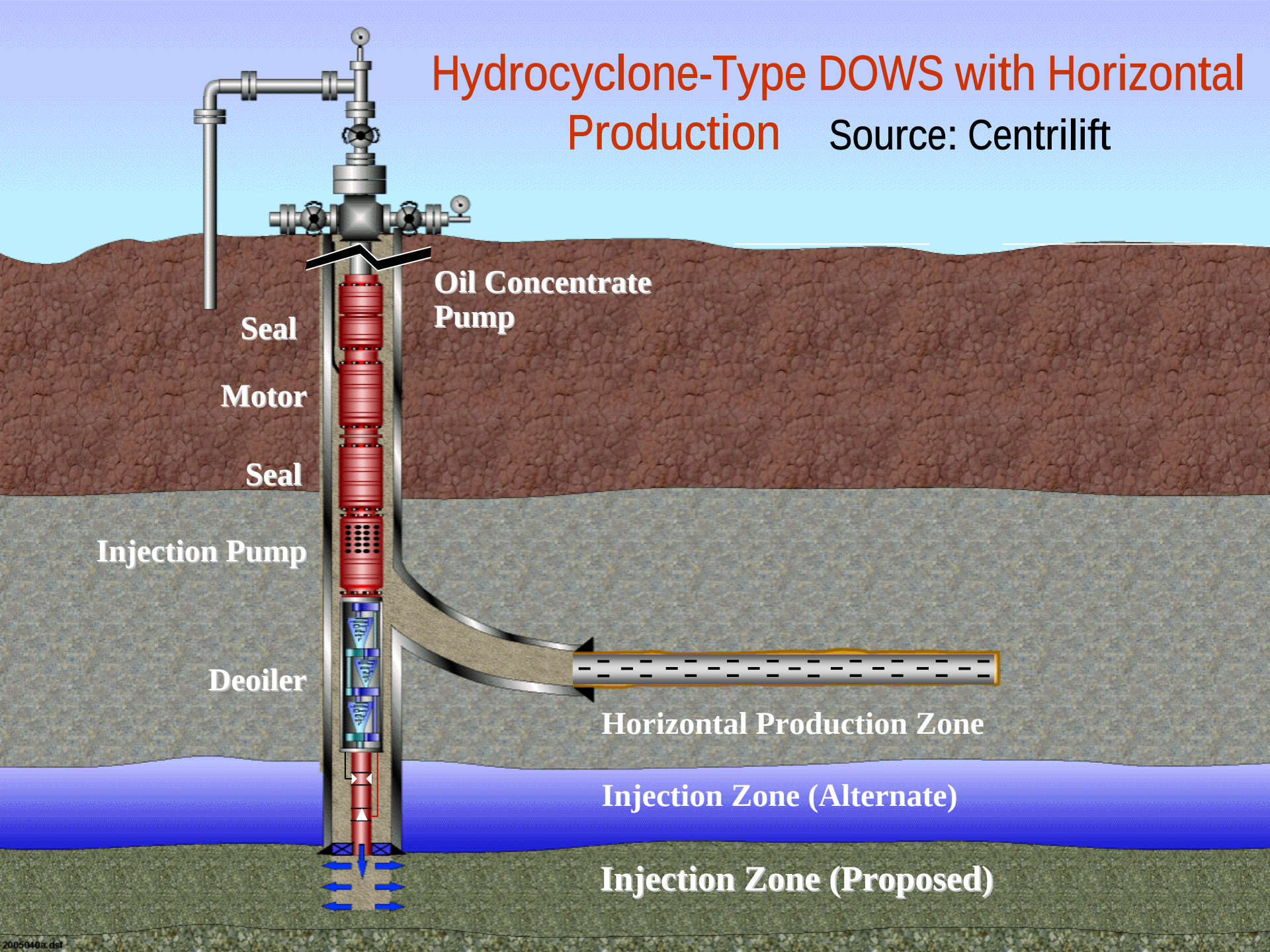
Diagram of Hydrocyclone-Type DOWS



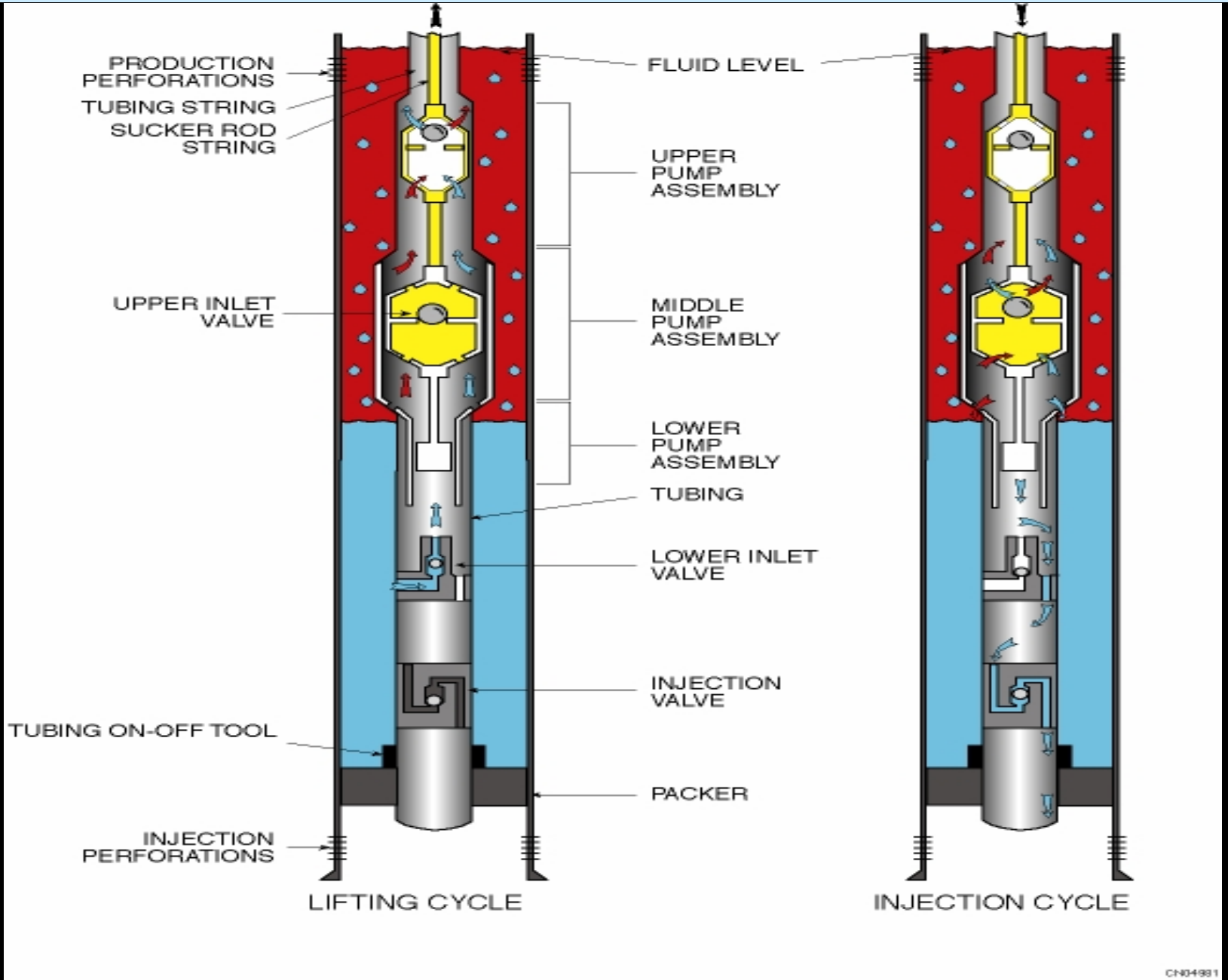
Source: Centrilift

Hydrocyclone-Type DOWS with Horizontal Production

Source: Centrilift

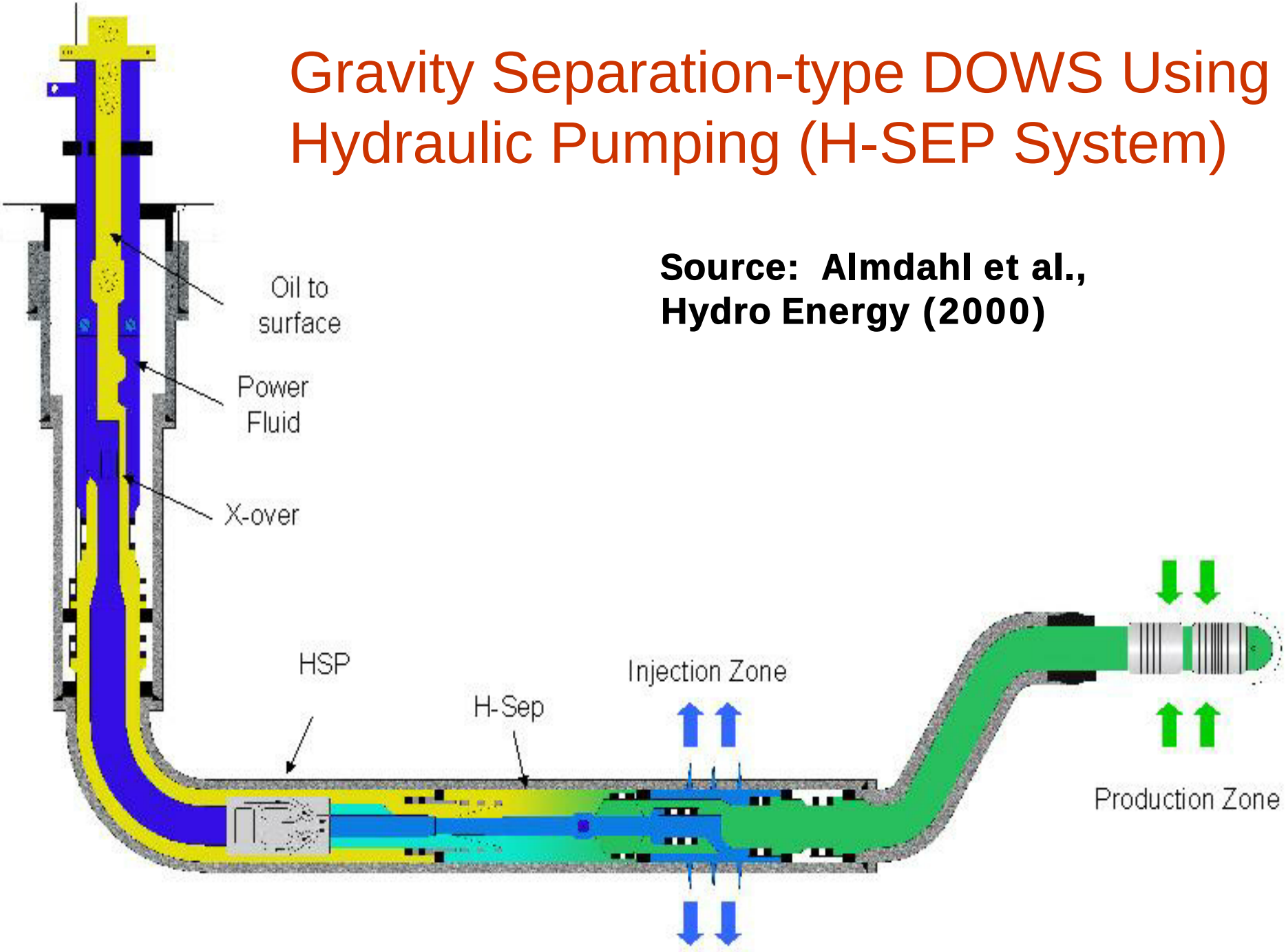


Gravity-Separation DOWS with Rod Pump Source: Texaco



Gravity Separation-type DOWS Using Hydraulic Pumping (H-SEP System)

Source: Almdahl et al., Hydro Energy (2000)



1999 Argonne National Laboratory report funded by U.S. Department of Energy

To download a full copy of the report, go to:

www.ead.anl.gov/project/dsp_topicdetail.cfm?topicid=18

Economics

- costs include cost of tool plus cost of well workover
- hydrocyclone type - $90,000 to >$300,000
- gravity type - $15,000 to >$100,000
- payback period is variable
  - several installations paid back costs in 2 months
  - others never worked right

Summary Statistics - Performance

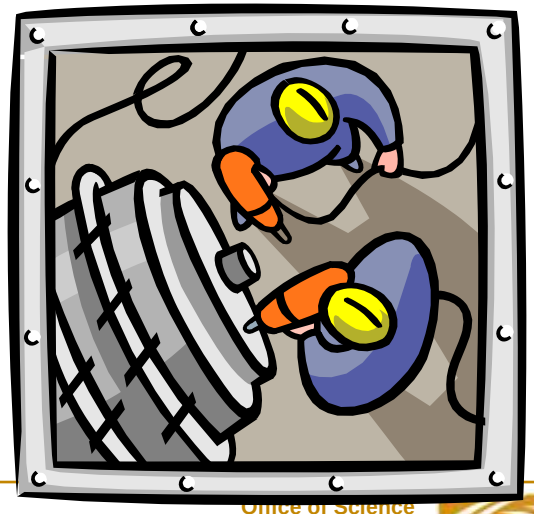
- oil to surface
  - increased in 60% of trials
  - top 3 DOWS increased production from 457% to 1,162%
- water to surface
  - decreased in all trials
  - water reduction ranged from 14% to 97%; most installations had >75% reduction
- Life span of many trials was not good

Why Have DOWS Not Been Used More Often?

- Limited range of application
- Economics
- Performance
- Lack of familiarity with technology

Actions to Improve Future Prospects for DOWS - Manufacturers

- Need to improve dependability
  - **Develop effective devices to control formation plugging with solids**
  - **Improve quality control and reduce human error**
- Cost/benefit to operators must be enhanced
  - **Lower cost of tool**
  - **Raise expected benefits**
    - ***Longer lifetime***
    - ***Greater production***



Actions to Improve Future Prospects for DOWS - Operators

- Try DOWS on wells with a high chance of success
  - Look for locations with both producing and injection zones in carbonate rock
- Evaluate water management more carefully
  - Consider total costs of surface equipment, including offshore platform space
- Consider DOWS as part of reservoir production strategy
  - Venoco
  - Pi-mode strategy

Venoco Project

- Received DOE funds for multi-year project to improve field economics and minimize water disposal offshore of Southern California
- Currently doing reservoir characterization
- DOWS should be installed in 2004

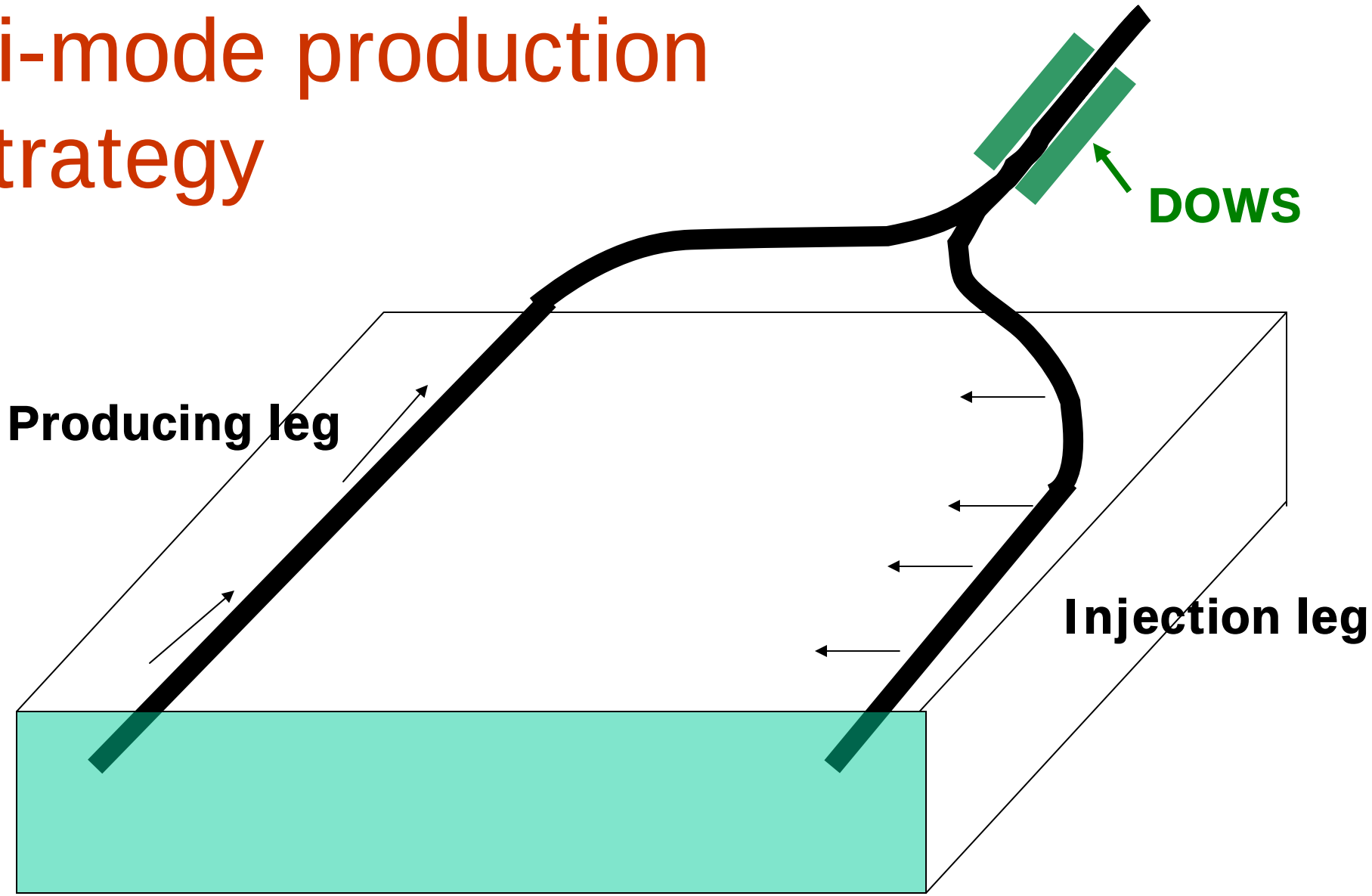
Pi-mode production strategy

- Several articles promote use of DOWS to reinject water into producing formation to:
  - maintain formation pressure
  - produce reserves faster and more effectively

Ehlig-Economides and Economides (2000)

Guerithault and Economides (2001)

Pi-mode production strategy



Based on: Ehlig-Economides and Economides (2000)

Conclusions on DOWS

- DOWS offers substantial potential for reducing costs and increasing oil production
- DOWS technology has worked very well in some but not many installations
- The marketplace appears to be at a stalemate condition presently
  - Developers not strongly marketing
  - Operators not buying and trying

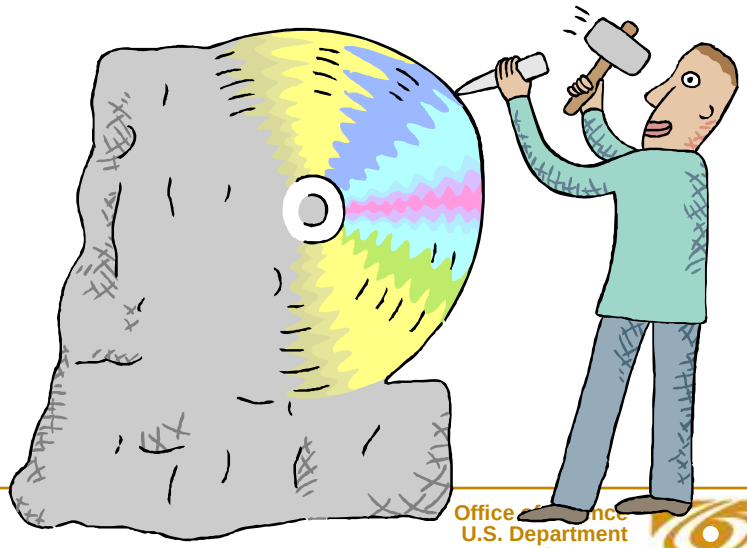
Conclusions - continued

- The technology would benefit from minor improvements and better quality control

- DOWS performance would benefit from more judicious selection of wells in which the devices are installed, including some new wells in targeted formations with a high probability of success

Other Related Technologies

- Downhole Gas/Water Separators
- Downhole Water Sink
- Subsea Separation (SUBSIS)

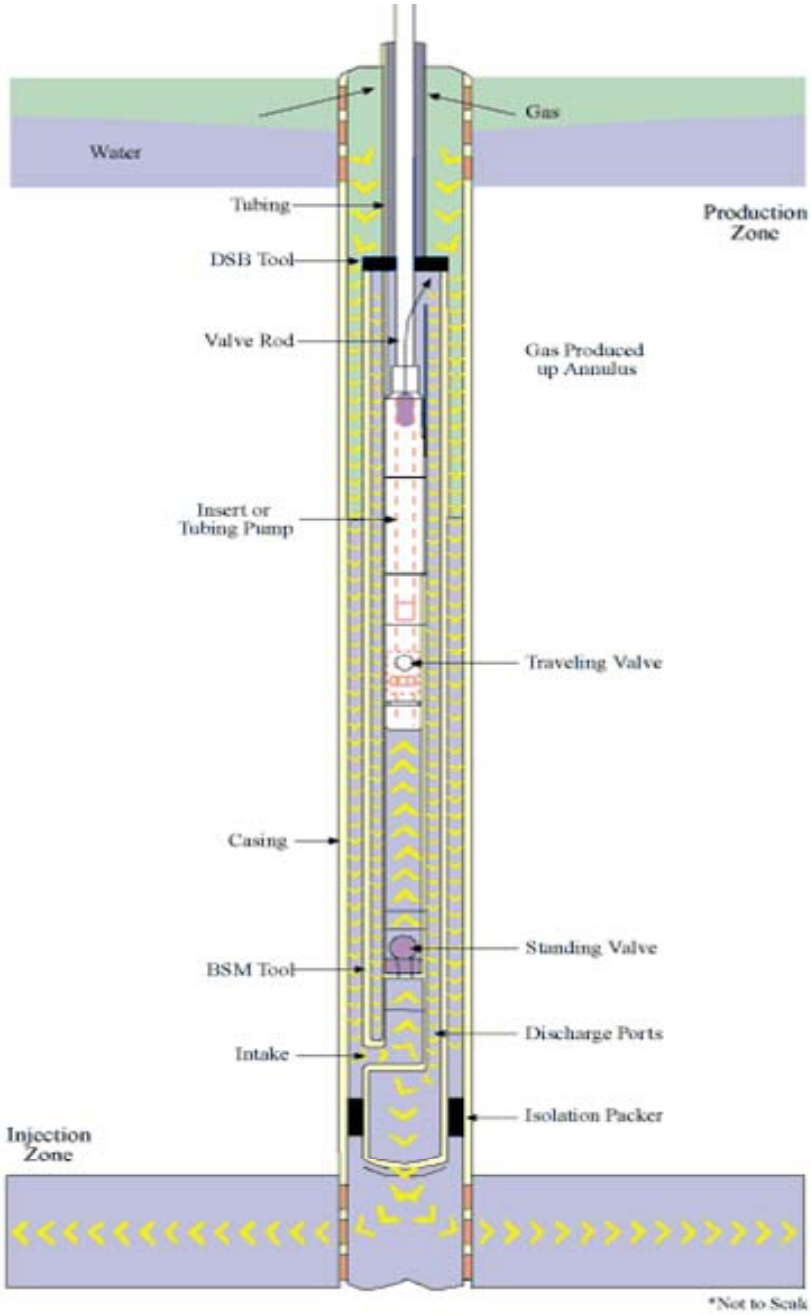


Downhole Gas/Water Separators

- Used more frequently than DOWS
- Described in 1999 study available from Gas Technology Institute

Types of DGWS

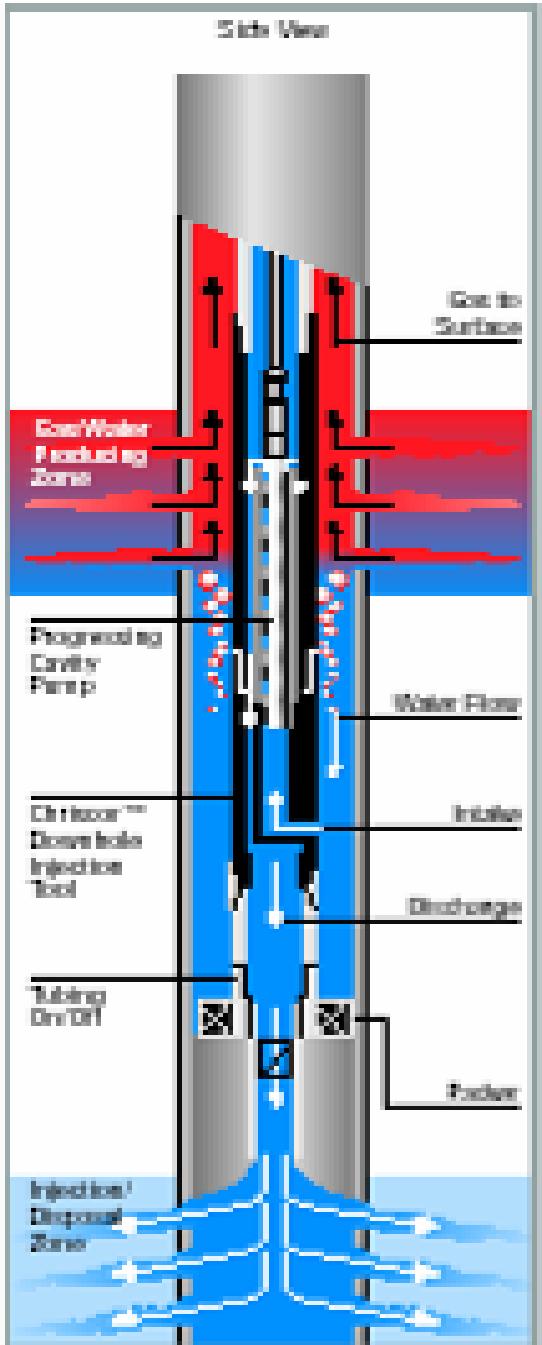
- Bypass tools
  - Lift water into tubing where it accumulates
  - When hydrostatic pressure is high enough, water flows by gravity to injection zone
- Modified plunger rod pump
  - Upstroke creates vacuum, sucking water into pump
  - On downstroke water is injected under pressure



Source: Gas Technology Institute website (www0.gastechnology.org)

Types of DGWS – continued

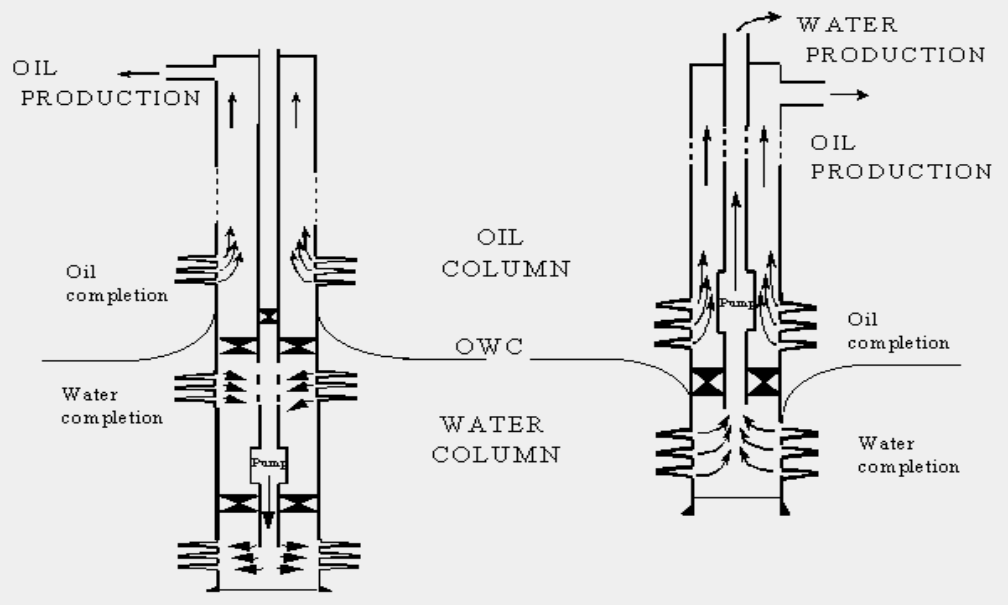
- Electric submersible pump
  - Mounted upside down
  - Pump water to injection zone
- Progressing cavity pump
  - Discharge downward
  - Better at handling solids
- These pumps are often used with a bypass tool



Source: Kudu Pumps website: www.kudupumps.com

Downhole Water Sink

- Uses dual completions
  - One at depth of strong oil production
  - Other at lower depth where water is produced
  - Separated by packer
  - Water collected below packer is injected and kept away from producing zone or is lifted to the surface



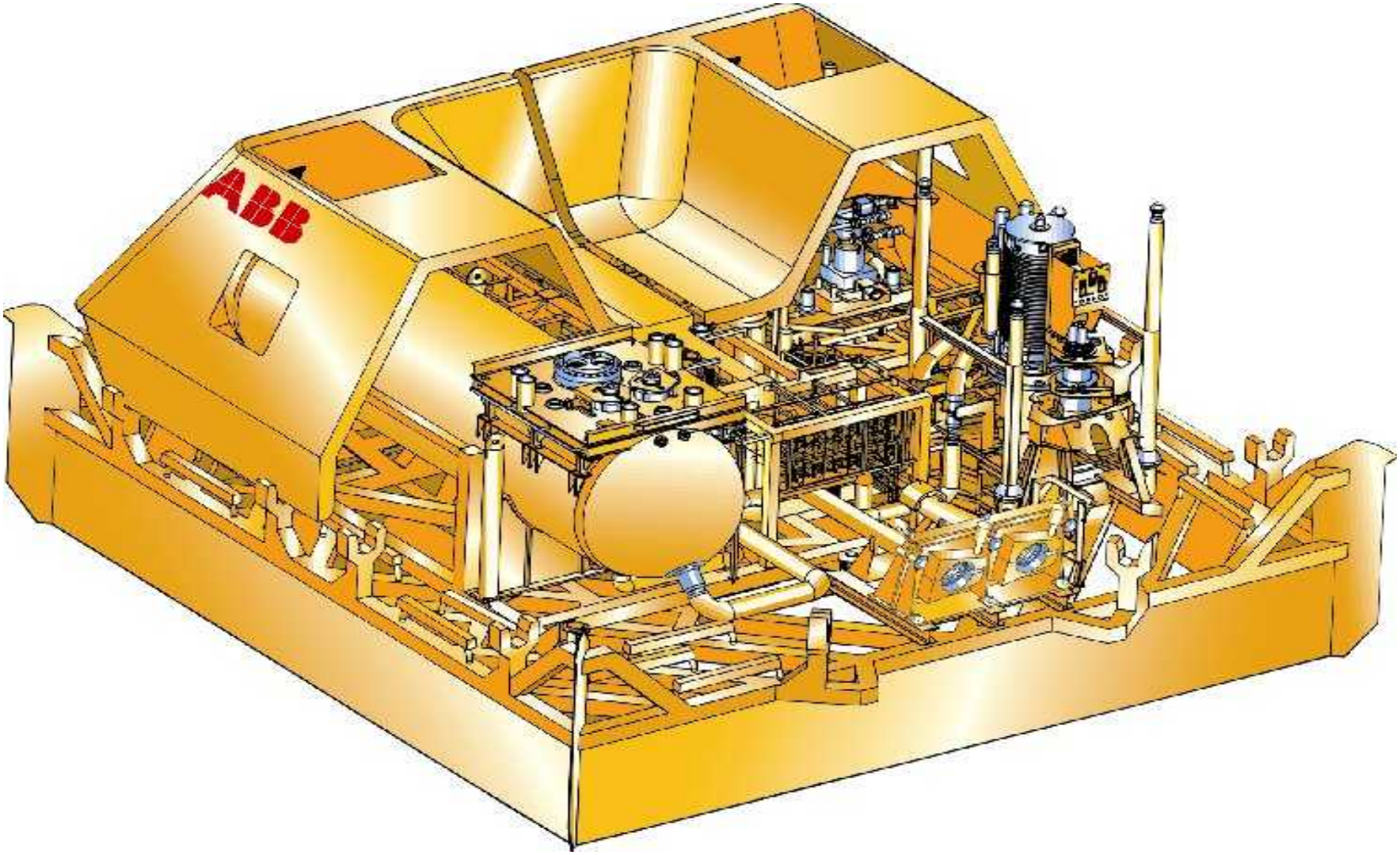
Source: A. Wojtanowicz, Louisiana State University

SUBSIS (Subsea Separation and Injection System)

- Not a DOWS, but separates oil and water at sea floor
- Developed by ABB Offshore Systems
- Very large size (350 tons, 3 m x 10 m)
- Full operation started in August 2001 in 350 m depth off the coast of Norway
  - Water was injected from sea floor to dedicated injection well
  - Flow rate: 20,000 bpd avg. and 60,000 bpd max.
  - Resulted in incremental oil production of 2.5 million bbl

SUBSIS System

Source:ABB Offshore Systems



SUBSIS System

Source: ABB Offshore Systems

Recycle/Reuse

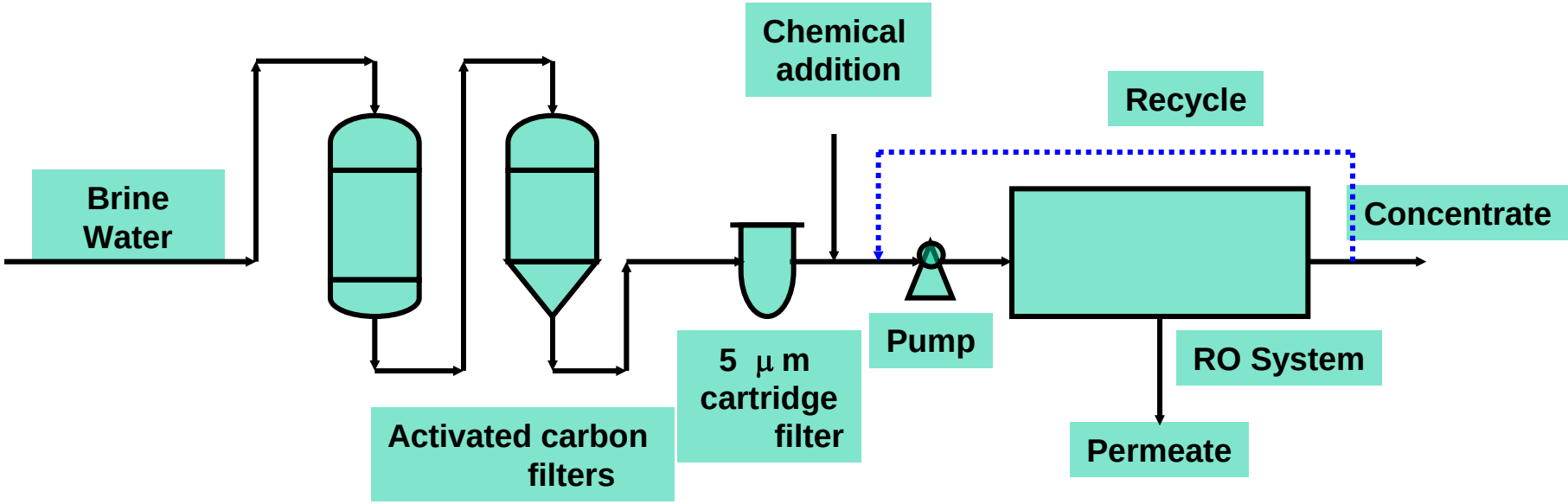
- Injection for enhanced recovery
  - **California**
    - *Nearly 25,000 produced water injection wells*
    - *1.8 billion bbl/year total injection*
      - 900 million bbl/year water flood
      - 560 million bbl/year steam flood
      - 360 million bbl/year injection for disposal
  - **New Mexico**
    - *5,036 wells permitted for enhanced recovery*
      - 350 million bbl/year
    - *903 wells permitted for disposal*
      - 190 million bbl/year

Texas

- 38,540 wells permitted for enhanced recovery
  - 5.3 billion bbl/year
- 11,988 wells permitted for disposal
  - 1.2 billion bbl/year

Recycle/Reuse (Water Supply)

- Aquifer storage and recovery
- Drinking water
  - Program under way at Texas A&M University to treat produced water for water supply
  - Current cost - $0.80/bbl - $1.30/bbl



Source: D. Burnett, Texas A&M University

Recycle/Reuse (Plants and Animals)

- Agriculture/Aquaculture
  - 480,000 bpd used for irrigation of fruit trees in California
  - Several examples of successful irrigation of range land produced much more forage grass
    - *May need to add soil supplements*
  - Tomatoes grown using produced water were smaller than those using drinking water (Wyoming)
  - Tilapia fish raised in produced water grew larger than controls but some died (Wyoming)
- Livestock watering (TDS is critical)
- Wildlife watering and habitat

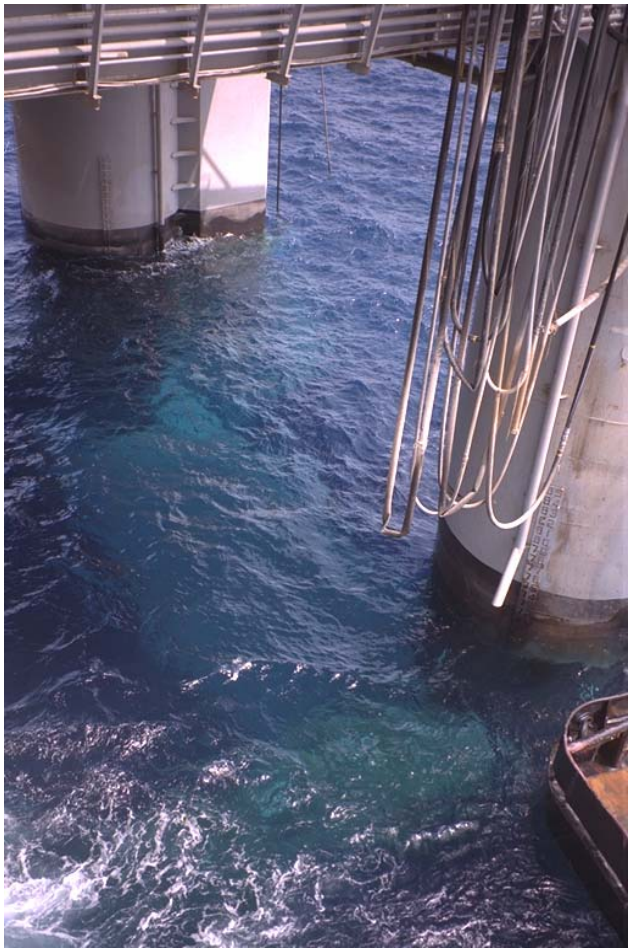
Recycle/Reuse (Industrial Uses)

- Use in oil field
  - Treated and used in drilling operation in New Mexico
  - Saves over 4 million bbl/year of fresh groundwater
- Power Generation
  - 360,000 bpd is further purified and used to make steam at a cogeneration facility in California
  - Recent NETL grant to study use as makeup for cooling towers

- Dust control
- Vehicle washing
- Fire control
- *See July 2003 ALL report for more details on reuse of CBM water*

Disposal

Discharge



Injection

U.S. Regulatory System

Laws

- *Clean Water Act*

Discharge Regulations

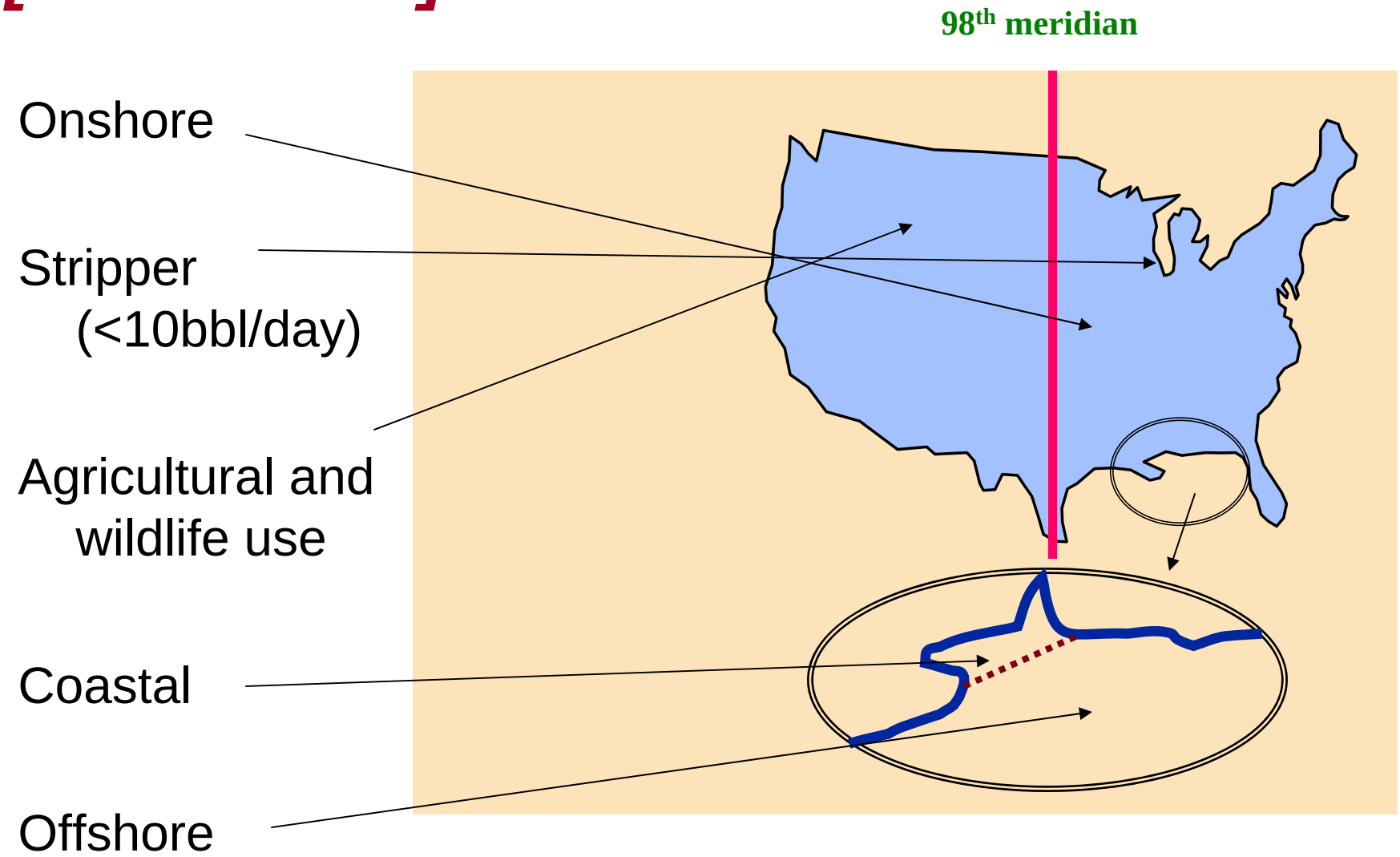
- *National Pollutant Discharge Elimination System (NPDES) program*
- *Effluent limitations guidelines (ELGs) for offshore oil and gas*

State regulations for onshore waste disposal

Permits and Guidance

- *Environmental Protection Agency (EPA) issues NPDES general permits for discharges*
- *Minerals Management Service (MMS) issues guidance and approvals for waste injection*

EPA Oil and Gas Effluent Limitations Guidelines (ELGs) [40 CFR 435]

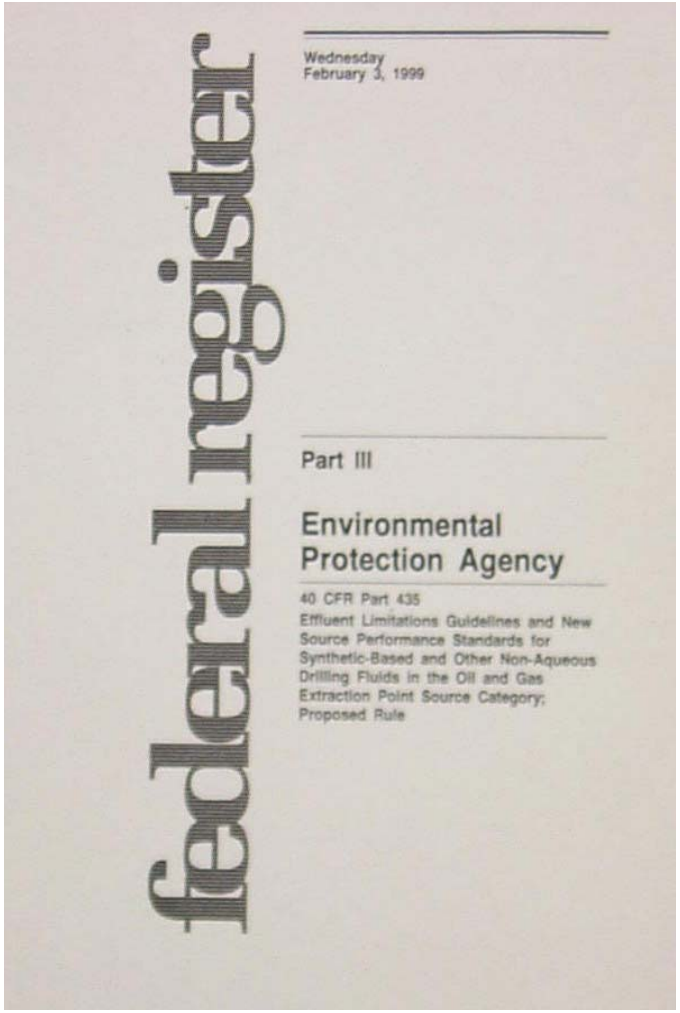


ELGs for Wells Located Onshore

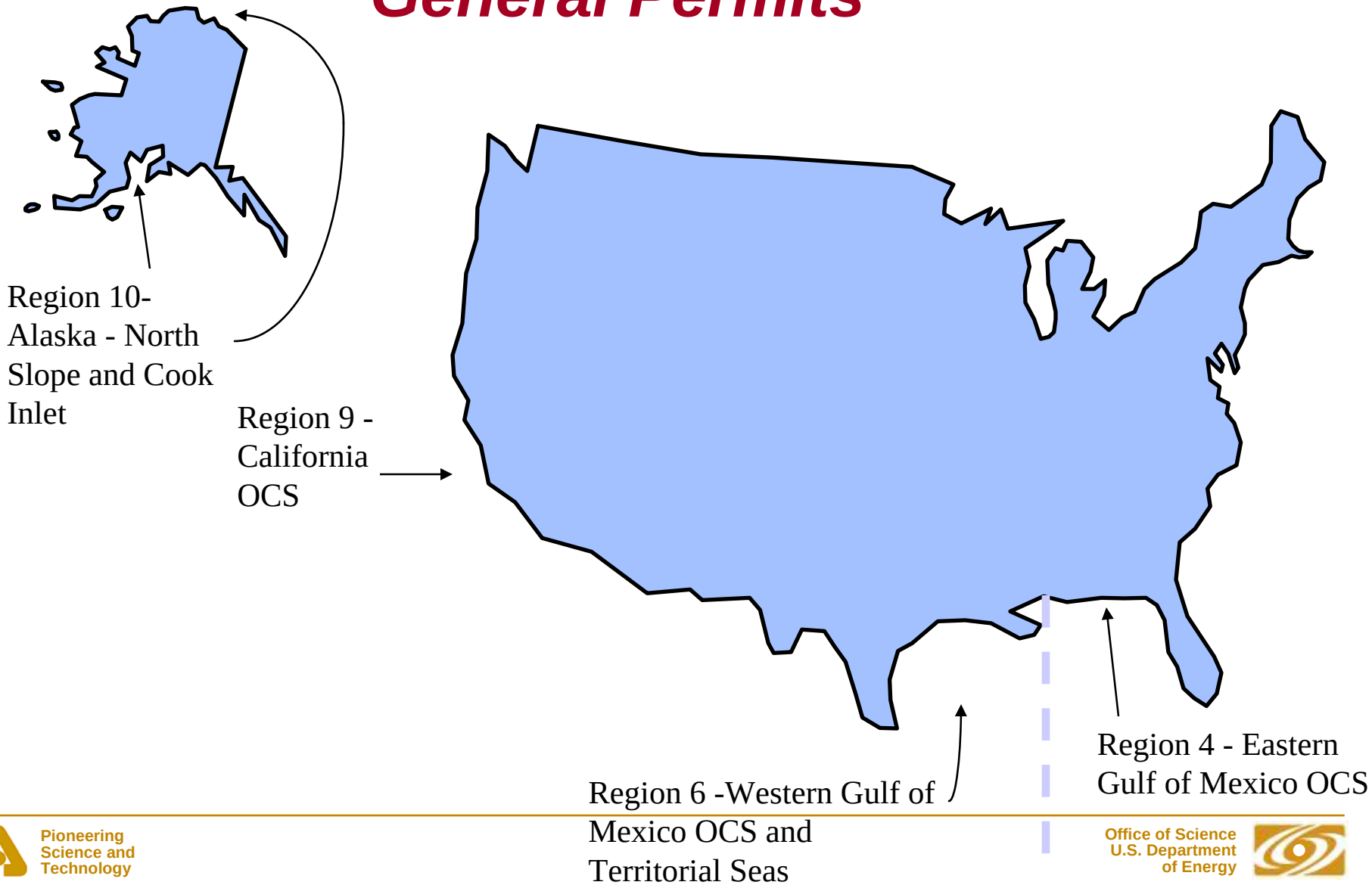
- Onshore subcategory
  - zero discharge
- Stripper subcategory
  - No national requirements
  - Jurisdiction left to state or EPA region
- Agricultural and Wildlife Use subcategory
  - produced water must have a use
    - *Water must be of good enough quality for wildlife, livestock, or other agricultural use*
    - *Produced water must actually be put to that use*
  - Oil and grease limit of 35 mg/l maximum

Offshore and Coastal ELGs

- Best Available Technology (BAT) for offshore produced water:
  - Oil and grease limits before discharge
    - *29 mg/l monthly average*
    - *42 mg/l daily maximum*
- BAT for coastal produced water
  - zero discharge except in Cook Inlet, Alaska
  - Offshore limits are required there

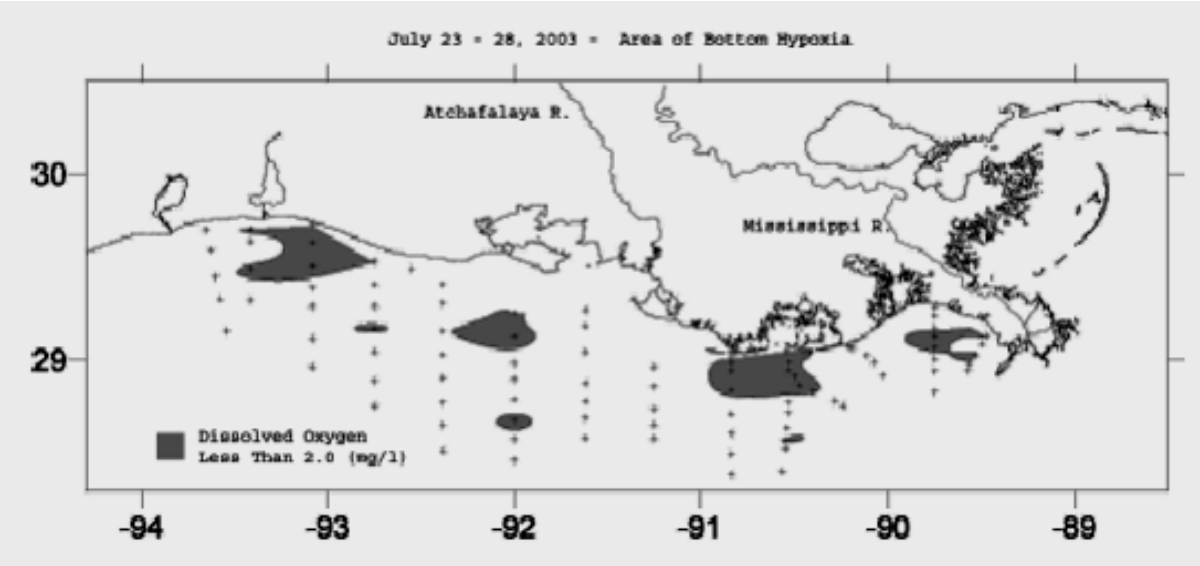


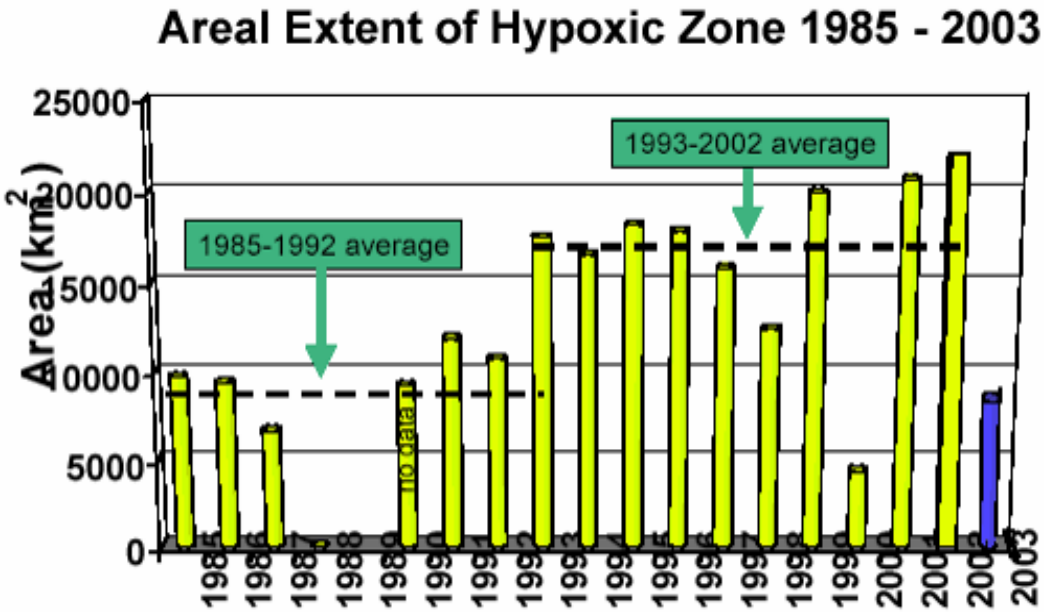
EPA Regions Issuing Offshore General Permits



Impact of Produced Water Discharge on Hypoxic Zone in Western Gulf of Mexico

- Large hypoxic zone in the bottom waters of the Gulf of Mexico near the mouth of the Mississippi River
- Major studies underway to evaluate contribution from produced water





Pioneering Science and Technology

Source: Rabalais, LUMCON

Produced Water Regulatory Requirements Around the World

- No single consistent format
- Several key international agreements

Agreement	Oil in Water Limit	Other
OSPARCOM (North Sea countries)	**40 mg/l now; 30 mg/l by 2006**	**Pre-approval of chemical additives**
Baltic Sea Convention and HELCOM standards	**15 mg/l; 40 mg/l if BAT cannot achieve 15 mg/l**	**Pre-approval of chemical additives**
Kuwait Convention and Protocols (Red Sea region)	**40 mg/l ; 100 mg/l max.**	
Barcelona Convention and Protocols (Mediterranean countries)	**40 mg/l; 100 mg/l max.**	

Requirements for Other Countries

- The following tables are taken from a 2002 paper by Fredrick Jones, Arthur Leuterman, and Ian Still
  - "Discharge Practices and Standards for Offshore Operations around the World," presented at the 7th International Petroleum Environmental Conference, Albuquerque, New Mexico, USA, November 7-10, 2000
  - They are presented as illustrations but may not be up to date

Country	Legal Basis	Oil in Water Limit
Albania	Barcelona Convention[1]	40 mg/L 100 mg/L max
Algeria	Barcelona Convention[1]	40 mg/L 100 mg/L max
Angola		No Standard set
Argentina	Resolution No. 105/92	Case-by-case
Australia (Western)		30 mg/L 50 mg/L max
Azerbaijan		
Bahrain	KUWAIT Convention [2]	40 mg/L 100 mg/L max
Belgium	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Brazil		20 mg/L max.
Canada	Act RSC 1987	40 mg/L avg. 80 mg/L max
China	GB 4914-85	30-50 mg/L avg. 75 mg/L max.
Colombia	SEPC[6]	Removal of 80% of oil
Denmark (North Sea)	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Denmark (Baltic Sea)	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)

Ecuador	SEPC[6]	
Egypt	Decree No. 338/95	15 mg/L max. 40 mg/L max. (Alternative)
Estonia	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
Finland (North Sea)	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Finland (Baltic Sea)	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
France (Mediterranean Sea)	Barcelona Convention[1]	40 mg/L 100 mg/L max
France (North Sea)	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Germany (Baltic Sea)	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
Germany (North Sea)	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Greece	Barcelona Convention[1]	40 mg/L avg. 100 mg/L max
Indonesia	MD KEP 3/91; 42/97	75 mg/L avg.
Iran	KUWAIT Convention [2]	40 mg/L avg. 100 mg/L max
Iraq	KUWAIT Convention [2]	40 mg/L avg. 100 mg/L max
Ireland (North Sea)	Rules and Procedures for Offshore Petroleum Exploration Operations. OSPAR Convention[3]	40 mg/L avg.
Israel	Barcelona Convention[1]	40 mg/L avg. 100 mg/L max
Italy	Dm of 28.7 1994	40 mg/L avg.

Kuwait	KUWAIT Convention[2]	40 mg/L avg. 100 mg/L max
Lebanon	Barcelona Convention[1]	40 mg/L 100 mg/L max
Libya	Barcelona Convention[1]	40 mg/L 100 mg/L max
Lithuania	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
Monaco	Barcelona Convention[1]	40 mg/L 100 mg/L max
Morocco	Barcelona Convention[1]	40 mg/L 100 mg/L max
Netherlands	Mining reg. 1996. Reg. 687/ 1224, 1987; OSPAR Convention[3]	40 mg/L avg. 100 mg/L max.
Nigeria	Act No. 34/68: Regs 1992	40 mg/L avg. 72 mg/L max.
Norway	PARCOM 10/10/1 1988; OSPAR Convention[3]	40 mg/L avg. 100 mg/L max
Poland	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
Portugal	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Qatar	KUWAIT Convention[2]	40 mg/L avg. 100 mg/L max.
Oman	Decree No. 10/82 KUWAIT Convention[2]	40 mg/L avg. 100 mg/L max.
Russia	Water Code 1995/ GOST 1977	0.05 mg/L MPC
Russia (Baltic Sea)	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
Saudi Arabia	KUWAIT Convention[2]	40 mg/L 100 mg/L max

Spain (Mediterranean Sea)	Barcelona Convention[1]	40 mg/L 100 mg/L max
Spain (North Sea)	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Sweden (Baltic Sea)	HELCOM Convention[7]	15 mg/L max. 40 mg/L (Alternative)
Sweden (North Sea)	OSPAR Convention[3]	40 mg/L PARCOM Decision 86/1
Syria	Barcelona Convention[1]	40 mg/L 100 mg/L max
Thailand	NEQA 1992: Gov. Reg. 20/90	100 mg/L max.
Trinidad		40 mg/L max.
Tunisia	Order of 1989	10 mg/L max.
Turkey (Mediterranean Convention)	Barcelona Convention[1]	40 mg/L 100 mg/L max
United Arab Emirates	KUWAIT Convention[2]	40 mg/L avg. 100 mg/L max.
United Kingdom	PARCOM 10/10/1988 OSPAR Convention[3]	40 mg/L avg. 100 mg/L max.
United States	40 CFR 435	29 mg/L 42 mg/L max
Venezuela	Decree No. 833/1995	20 mg/L
Vietnam	Decision No. 333/QB 1990	40 mg/L
Yugoslavia	Barcelona Convention[1]	40 mg/L 100 mg/L max

Basic Separation of Oil, Gas, and Water

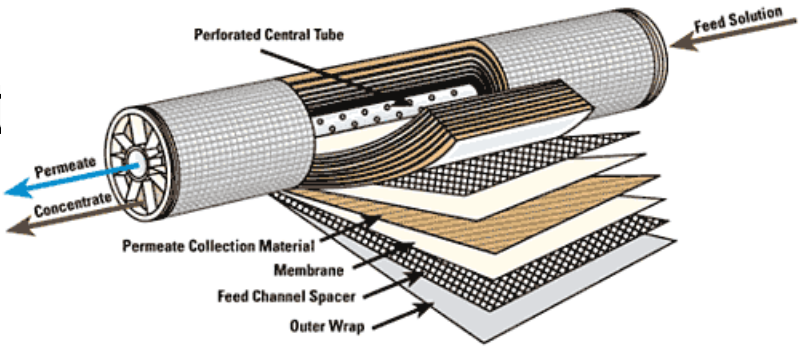
- Free-water knockout tank separates three phases
- Emulsions
  - Heater-treater
  - Demulsifying chemicals
- Onshore – pass through tank battery, then inject
- Offshore – discharge

Treatment before Injection

- Make sure water is compatible with formation
  - Solids
  - Dissolved oil
  - Microbes
  - Corrosion sources
- Typically use various treatment chemicals
- May need filtration

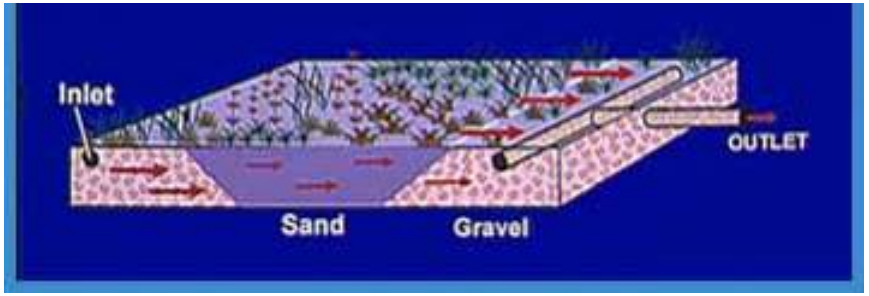
Onshore Discharges

- Often need to remove salt or TDS
  - Reverse osmosis
  - Ion exchange
  - Electrostatic precipitation



Source: Osmonics

- May employ biological treatment
  - Constructed wetlands



Other Onshore Disposal Technologies

- Evaporation via misting towers
- Freeze-Thaw Evaporation
- Evaporation ponds

Source: Western Pump & Dredge

Produced Water Offshore Treatment Technology

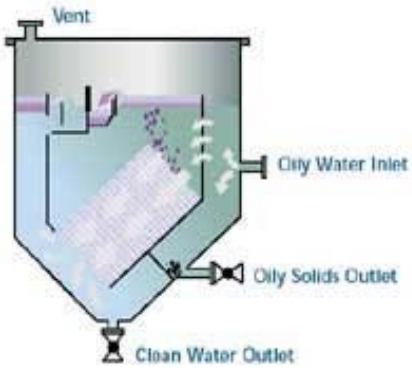
- There are many types of produced water treatment used at offshore facilities
  - Primarily designed to reduce free oil and other dissolved organics in order to meet the oil and grease limit of 29 mg/l average and 42 mg/l maximum
- Oil and grease is a variable parameter
  - Free oil (large droplets, easy to remove)
  - Dispersed oil (small droplets)
  - Dissolved oil (difficult to remove)
    - *ORNL project to evaluate dissolved organics*
- Measurement of oil and grease depends on analytical method

Analytical Issues for Oil and Grease

- Measurement technique for oil and grease has changed due to phase-out of freon
- Newer methods measure different component of oil and grease and may not match up with standards based on older analytical method
- Different methods used in other parts of the world

Source: Turner Designs

Separation Technologies

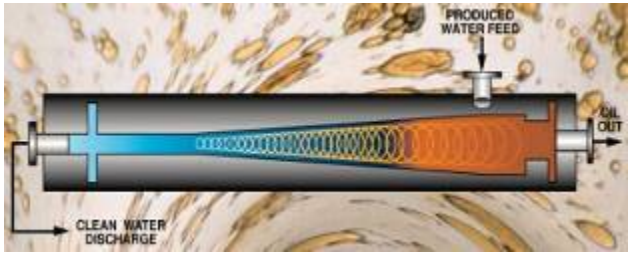


Corrugated plate separator

Source: Natco

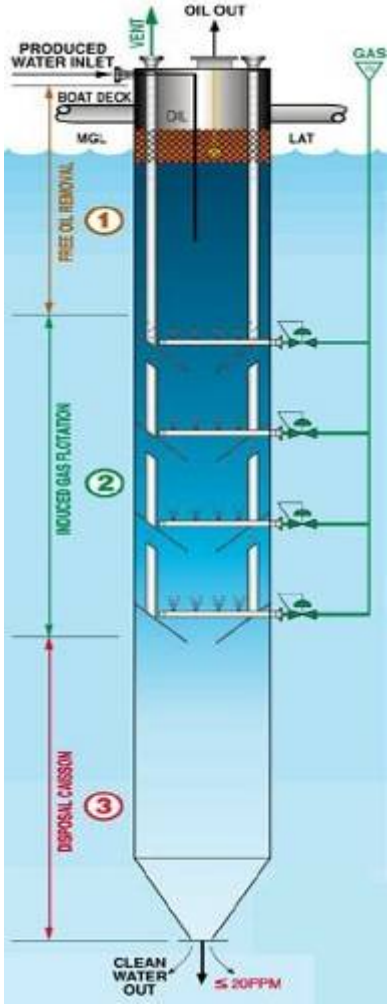
Hydrocyclone

Source: Natco



Hydrocyclone

Source: Engineering Specialties



Flotation pile

Source: Engineering Specialties

Filtration Technologies

Cartridge filter

Source: Twin Filter

Media filter

Source: Natco

Coalescer Technology

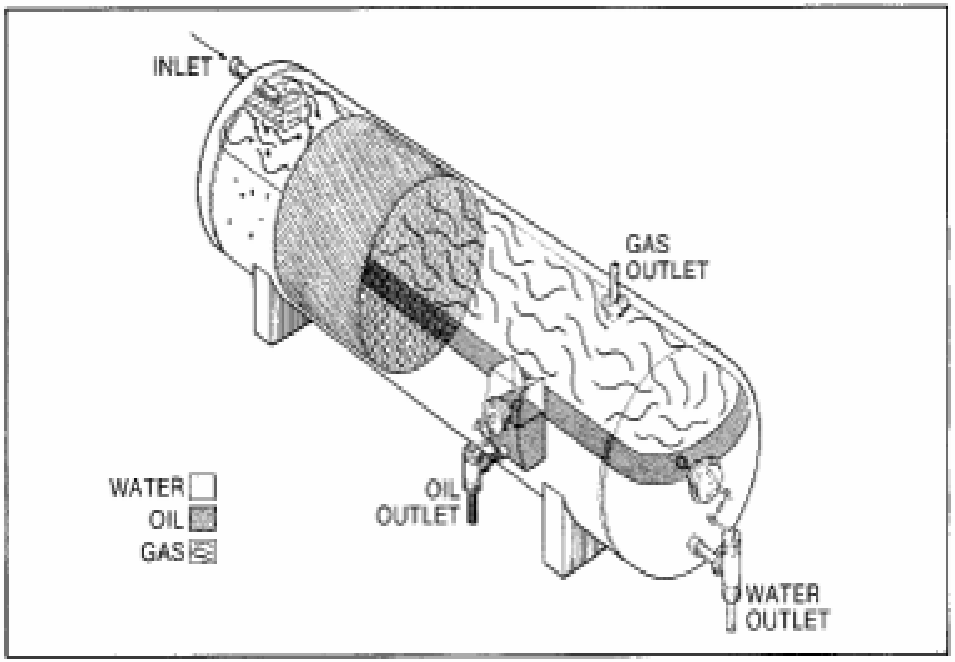
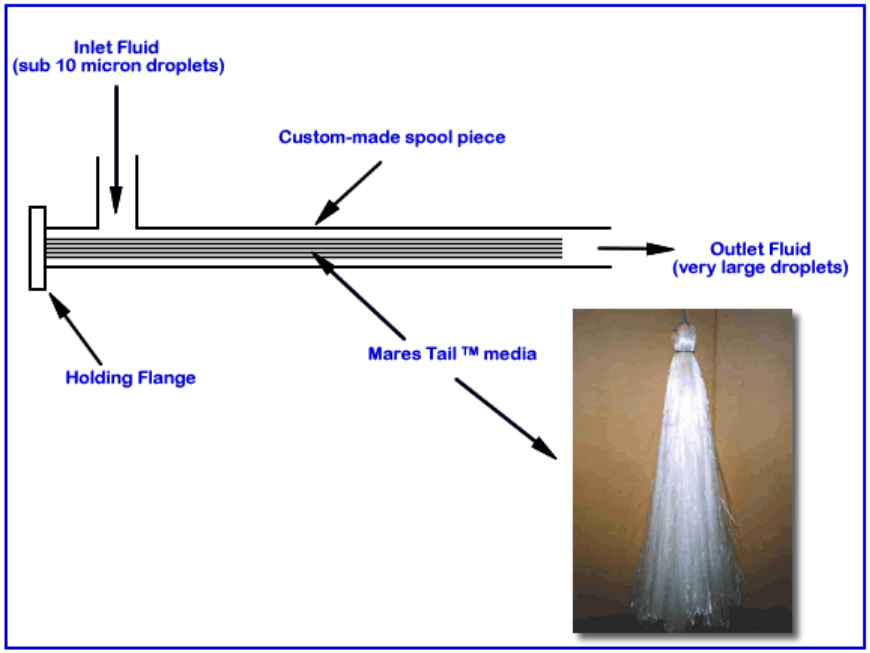


Figure 1. Cutaway view of PERFORMAX Coalescer



Source: Natco

Source: ERT Ltd.

Flotation Technologies

Induced gas flotation
Source: Natco

Dissolved gas flotation

Source: Separator Specialists

Flotation cell

Extraction of Dissolved Organics

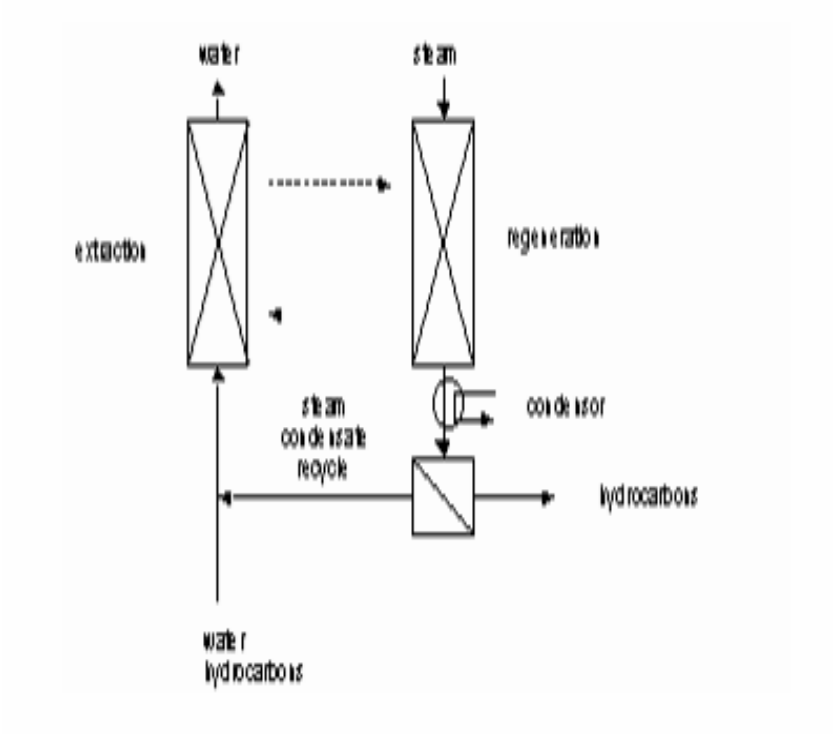
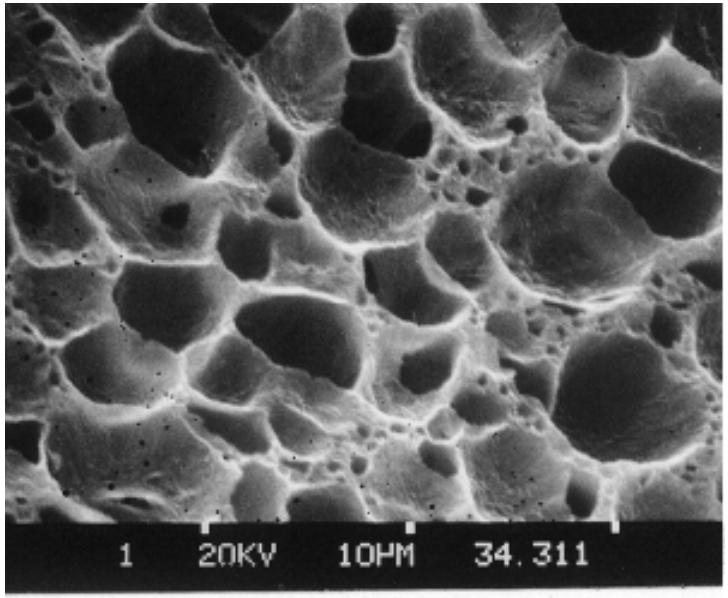


Figure 2: Schematic Overview of Macro Porous Polymer Extraction Process



Source: Akzo Nobel

ELGs for Drilling Wastes

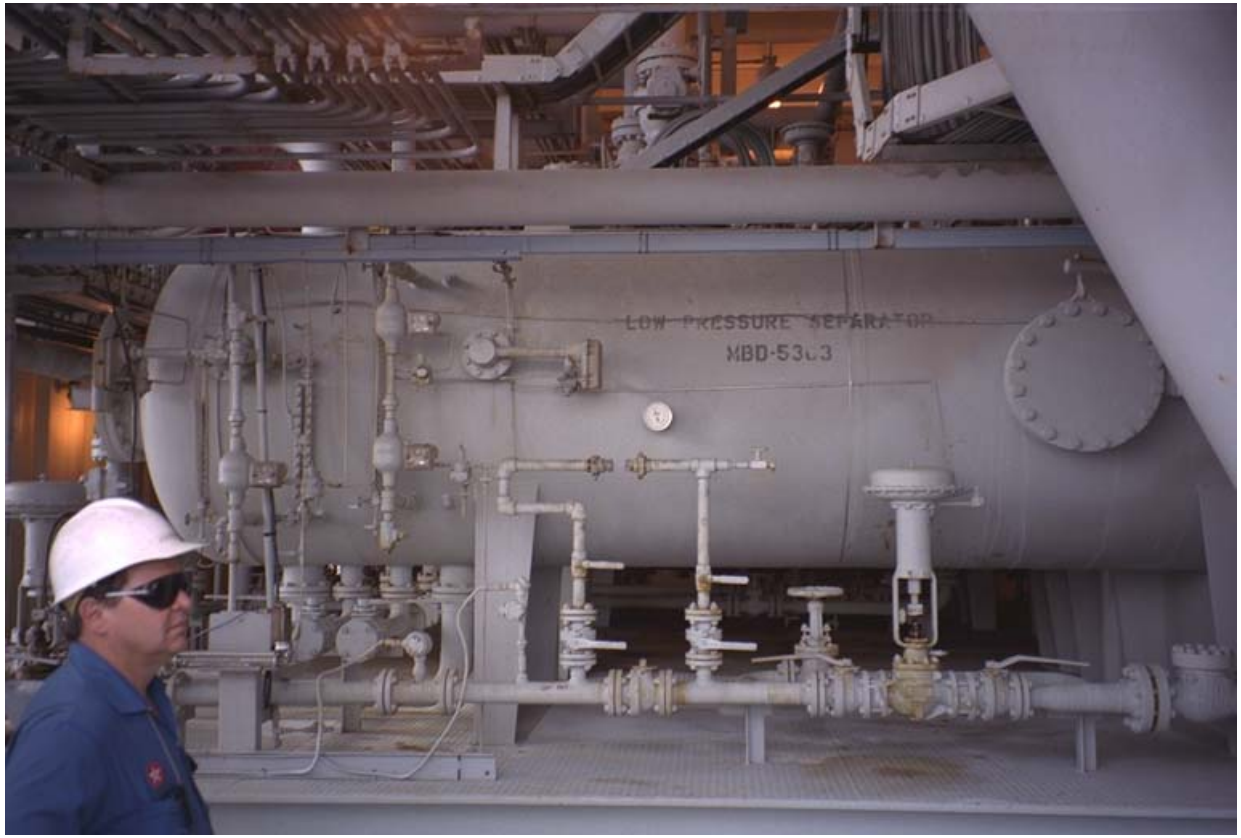
- no discharge allowed from 0-3 miles from shore (except for Alaska)
- >3 miles from shore
  - limits are placed on drilling fluid toxicity, and mercury and cadmium in barite
  - no discharge of free oil or diesel allowed (no discharge of oil-based muds and cuttings)
  - additional limits on PAHs, sediment toxicity, biodegradation rate, and fluid retained on cuttings for synthetic-based muds

ELGs for Produced Water and Treatment, Workover, and Completion (TWC) Fluids

- limits placed on oil and grease

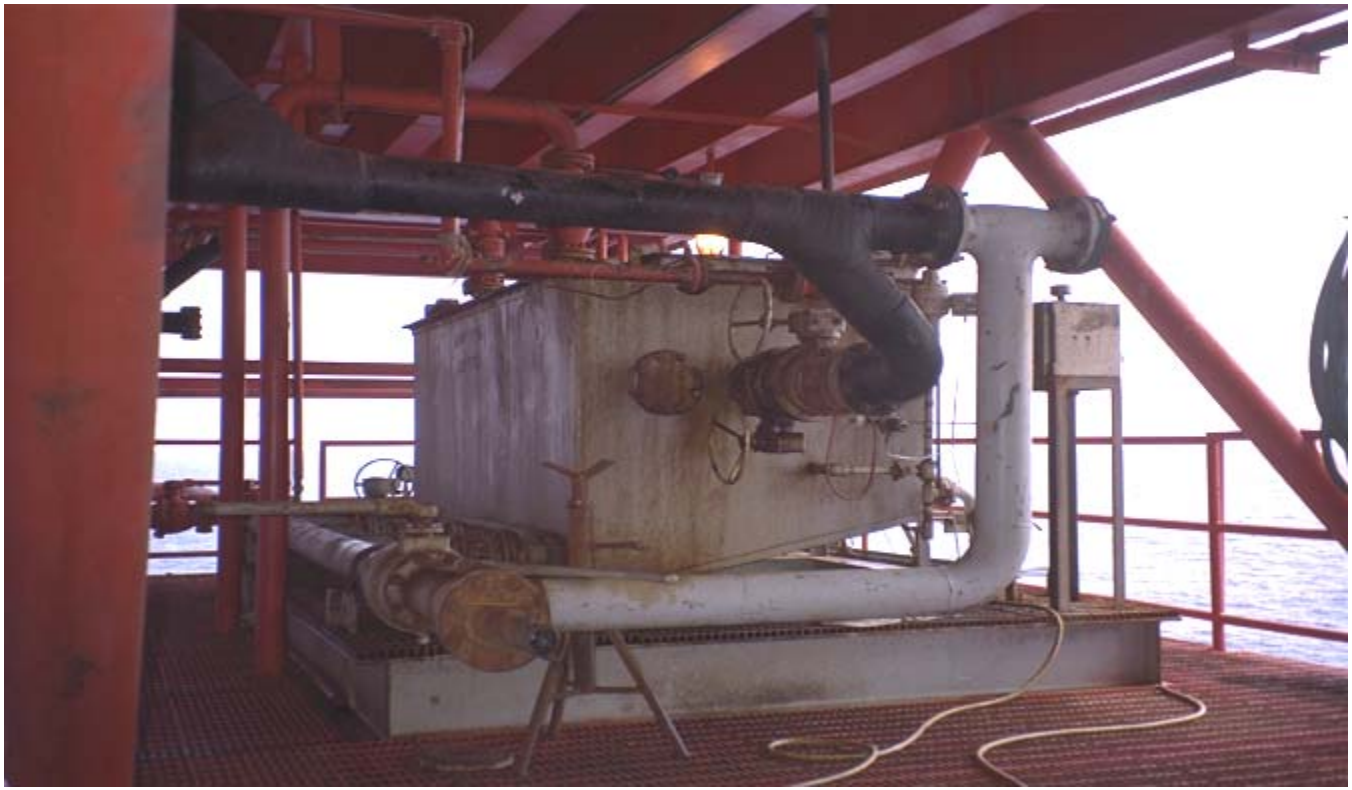
ELGs for Produced Sand

- zero discharge



ELGs for Deck Drainage

- no free oil discharge allowed



ELGs for Domestic Waste

- no discharge of floating solids or foam
- no discharge of garbage or plastics (food waste only beyond 12 miles)
  - food waste must be ground up before discharge

ELGs for Sanitary Waste

- facilities with 10 or more persons - minimum chlorine limit
- facilities with <10 persons - no discharge of floating solids

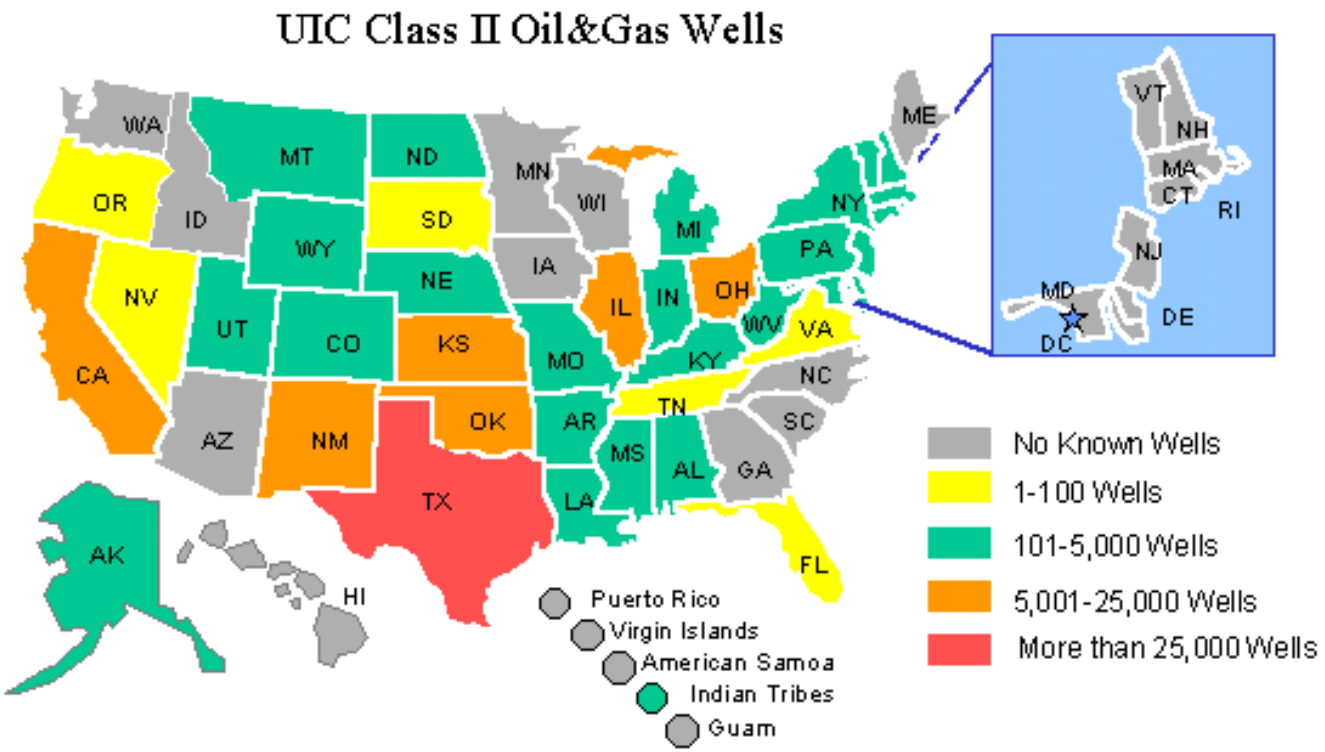
Injection Operations—General Information

- When oil and gas are extracted, large amounts of saline formation water (brine) brought to the surface

- When states started to implement rules that prevented the disposal of brine to surface water bodies and soils, injection of waste fluid became the prevalent form of disposal (over 2 billion gallons of brine per day)

Injection Operations—Numbers of Class II Wells

- Approximately 167,000 oil and gas injection wells in the United States (TX: 53,000; CA: 25,000; OK: 22,000; and KS: 15,000)



Injection Operations—Two Class II Well Types

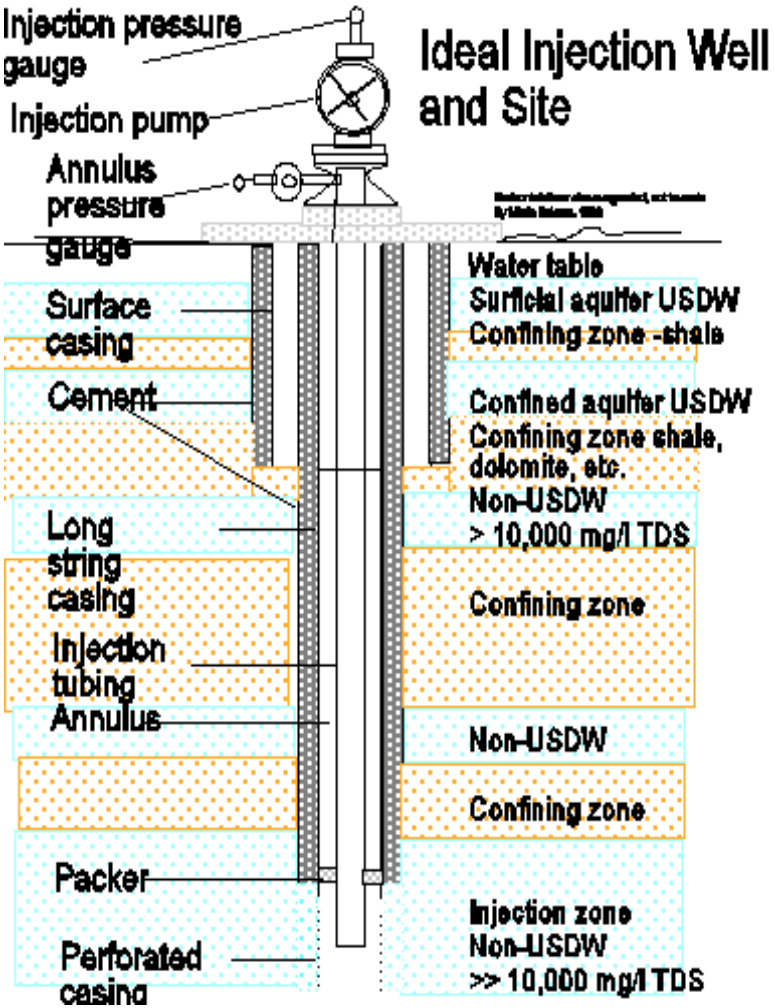
- Wells Used for Secondary Recovery of Oil
  - Water is pumped into the formation that contains some residual hydrocarbons
  - A portion of the hydrocarbons are recovered, along with the injected water, by extraction or production wells
  - In a common configuration, one injection well is surrounded by 4 or more extraction wells
  - The recovered fluid is treated to remove most of the hydrocarbons in a device called a separator
- Wells Used for Disposal
  - Excess fluids from production and some other activities directly related to the production process are injected solely for the purpose of disposal

Injection Operations—EPA's UIC Regulations under the SDWA

- 40 CFR Part 146
  - Provides the technical criteria and standards for the UIC program
  - General Provisions
    - *Area of Review*
    - *Corrective Action*
    - *Mechanical Integrity*
    - *Plugging and Abandoning*
  - Criteria and Standards Applicable to Class II Wells
    - *Construction Requirements*
    - *Operating, Monitoring, and Reporting Requirements*
- 40 CFR Part 124
  - Describes the procedures the EPA will use for issuing permits

Injection Operations—Siting, Design, and Construction of Class II Wells

- Siting
  - Enough confining zones between the injection zone and the lowermost USDW
  - No reasonable possibility of contamination
- Design and Construction
  - Does not allow any fluid to escape the injection string or any fluid to migrate in the bore-hole to a USDW
  - The tubing should be set on a packer, the packer should be isolated and monitored for leaks, and the casing should be properly cemented on the outside



Injection Operations—Federal/State Interface

- 40 CFR Part 145
  - Describes the elements of an approvable state program and the procedures for EPA approval of state participation in the permit programs
- Alternative Route
  - In 1980 Congress added Section 1425 to the SDWA relieving Class II well programs in the states from having to meet the technical requirements in the UIC regulations
  - Instead, a demonstration can be made that the state has an *"…effective program (including adequate record-keeping and reporting) to prevent underground injection which endangers drinking water sources"*
  - EPA Guidance #19

Injection Operations—Federal/State Interface

- General
  - State programs must be at least as stringent as federal blueprint
  - States free to impose stricter requirements
- EPA Region 3
  - West Virginia: Primacy State
    - *West Virginia Department of Environmental Protection*
  - Pennsylvania: Direct Implementation State
    - *Pennsylvania Bureau of Oil and Gas Management with Own Separate Program*
  - Differences: permitting agencies, regulatory definitions and technical standards

Injection Operations—Examples of State Programs: Texas

- Overview
  - Railroad Commission of Texas with long regulatory history (authority derives from TX Natural Resources Code and Texas Water Code)
  - On April 23, 1982, the Commission's UIC Class II program was approved by the EPA under Section 1425 of the SDWA
  - Largest oil and gas injection well program
- State Wide Rules in Title 16 (Economic Regulation), Part 1 (Railroad Commission of Texas), Chapter 3 (Oil and Gas Division) of the Texas Administrative Code
  - Rule §3.9 – Salt Water Disposal Wells
  - Rule §3.46 – Fluid Injection into Productive Reservoirs

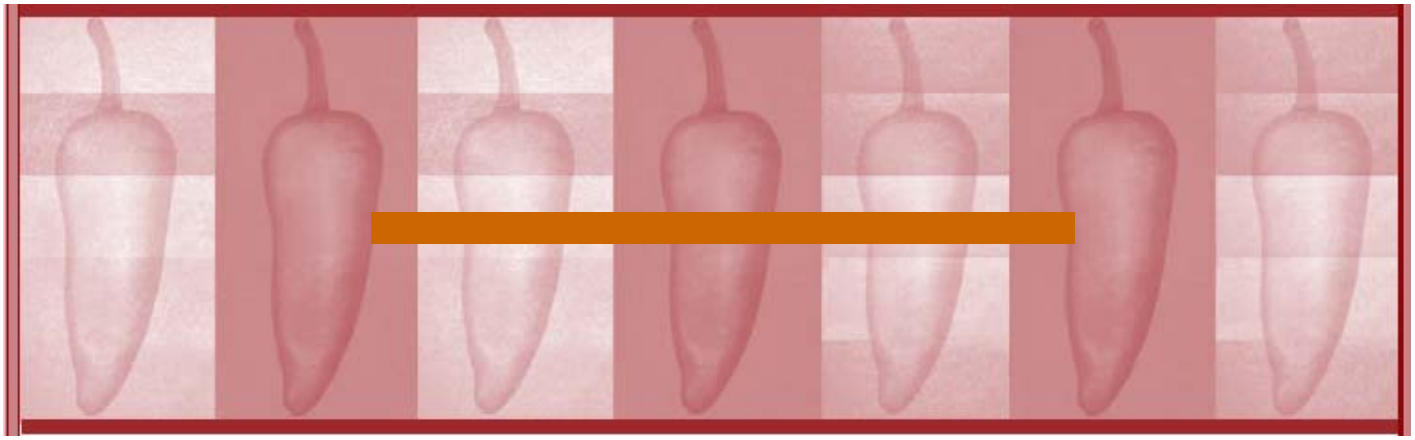
Injection Operations—Examples of State Programs: California

- Overview
  - In California, all Class II injection wells are regulated by the Department of Conservation, Division of Oil, Gas, and Geothermal Resources (authority derives from Public Resources Code)
  - In 1983, the Division received EPA primary authority, *primacy,* to regulate Class II wells.
  - Second largest well oil and gas injection well program
  - Some 60% of California's oil production is a result of Class II injection wells

Injection Operations—Examples of State Programs: California

- Rules in Title 14 (Natural Resources), Division 2 (Department of Conservation), Chapter 4 (Development, Regulation, Conservation of Oil and Gas Resources) of the California Code of Regulations
  - Subchapter 1 (Onshore Well Regulations), Article 3 (Requirements)
    - *Section 1724.6 – Approval of Underground Injection and Disposal Projects*
    - *Section 1724.10 – Filing, Notification, and Testing Requirements for Underground Injection Projects*
  - Subchapter 1.1 (Offshore Well Regulations), Article 3 (Regulations)
    - *Section 1748 – Waste Disposal and Injection Projects*
  - Subchapter 2 (Environmental Protection), Article 3 (Requirements)
    - *Section 1775 – Oilfield Wastes and Refuse*

SDWA UIC Case Study: Hydraulic Fracturing Litigation



- Background on Hydraulic Fracturing & Coalbed Methane (CBM) Recovery
- Statutory & Regulatory Framework
- Serial Litigation & Administrative Responses
- Perspectives

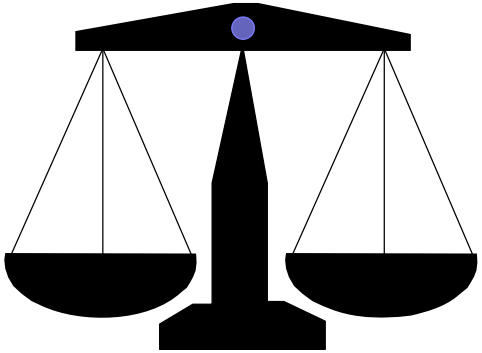
Background on Frac'

- Mechanics of Hydraulic Fracturing
  - Definition
  - Applications
- CBM Recovery Operations
  - Production and Reserves
  - Universe of Wells and Fracturing Jobs

Statutory & Regulatory Framework

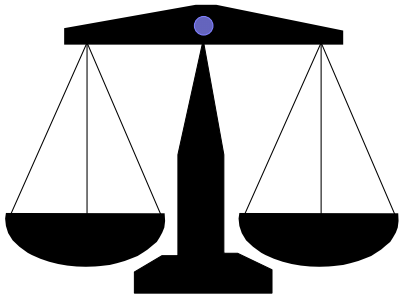
- Safe Drinking Water Act (SDWA)
  - Implemented by U.S. Environmental Protection Agency (EPA)
- Underground Injection Control Program
  - Protection of Underground Sources of Drinking Water (USDWs)
  - Definition of Well
  - Five Classes of Wells
- Authorization of State Programs
  - Program Approval Routes

Serial Litigation & Administrative Responses



LEAF I Case

- Filed by Legal Environmental Assistance Foundation against EPA (Oct. 95)
  - Challenging EPA's Denial of Petition to Withdraw Alabama's Program
- 11th Circuit Court of Appeals (Aug. 97)
  - Outcome: LEAF Wins this Round
- Writ of *Mandamus* Granted (Feb. 99)
  - Definition and Content

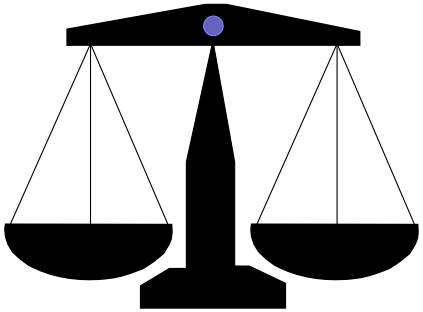


State Program Withdrawal Proceedings by EPA

- General Mechanics
  - Cause to Believe, Process Components, Outcomes
- Here
  - Alabama Submits Revised Program (Oct. 99)
  - EPA Approves Program Revision (Jan. 00)

LEAF II Case

- Filed by LEAF against EPA (Jan. 00)
  - Challenging Program Approval Order
- 11th Circuit Court of Appeals (Dec. 01)
  - Outcome: Favorable to EPA
- Other Proceedings and Filings
  - Supreme Court Denies Review (Oct. 02)
  - LEAF Files Petition for Writ of *Mandamus* With 11th Circuit (Feb. 04)



Final Determination by EPA

- Final Rule Published in Federal Register (July 04)
- Response to LEAF II Decision and Public Comments
- Alabama's UIC Program Complies with the SDWA's Approval Criteria

Perspectives

- Legislative “Fixes”
- EPA’s National Hydraulic Fracturing Study
- Other Techniques
- End of the Saga?

Legislative Fixes

- Several Offered
- But Never Passed into Law
- Example Language

EPA's National Hydraulic Fracturing Study

- Methodology
  - Literature Reviews
  - Communications with State/Local Regulators & Concerned Citizens
  - Search for Confirmed "Damage Cases"
- Conclusions (June 04)
  - Practice Poses Little or No Threat to USDWs
  - Additional study Not Justified at this Time

Other CBM Production Enhancement Techniques

- Horizontal Technology
  - "Z Pinnate™ Horizontal Drilling and Completion System" (CDX, Dallas, TX)

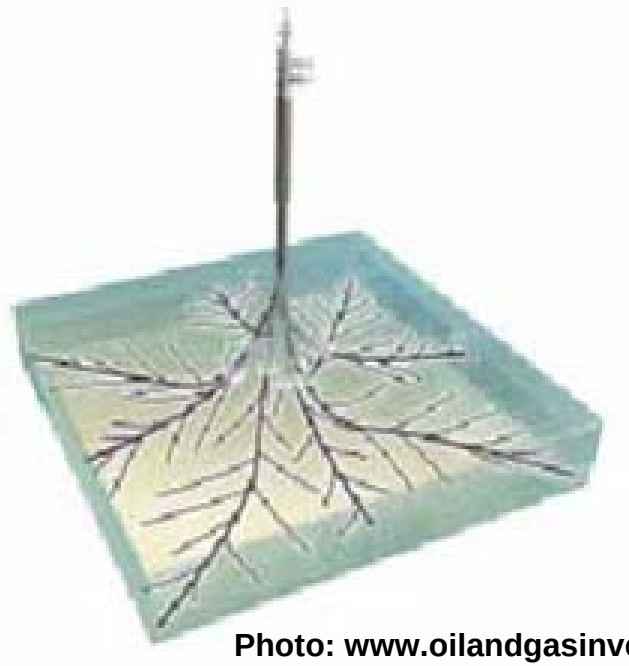


Photo: www.oilandgasinvestor.com/pdf/Coalbed_Methane.pdf

End of the Saga?

- Closure in Alabama
- Future Litigation in Other States?

MMS Requirements for Offshore Waste Injection

- wastes must be E&P wastes and originate in the offshore
- operators must receive case-by-case approval for injection
- wastes can be encapsulated in well bore or injected into formation
- MMS approval required for storage of NORM offshore

Bureau of Land Management (BLM) Regulations

- Exercises Jurisdiction over Onshore Leasing, Exploration, Development, and Production of Oil and Gas on Federal Lands
- Approves and Supervises Most Oil and Gas Operations on American Indian Lands
- Regulations, Orders and Notices
  - 43 CFR Part 3160 (Onshore Oil and Gas Operations)
  - Onshore Oil and Gas Orders (OOGOs) implement and supplement regulations
  - Notice-to-Lessees (NTLs) implement and supplement OOGOs and regulations

Produced Water Cost

- Costs range from <1¢ /bbl to several dollars/bbl
- Many factors contribute to cost

Components of Produced Water Cost

- Site preparation
- Pumping
- Electricity
- Treatment equipment
- Storage equipment
- Management of residuals removed or generated during treatment
- Piping
- Maintenance
- Chemicals
- In-house personnel and outside consultants
- Permitting
- Injection
- Monitoring and reporting
- Transportation
- Down time due to component failure or repair
- Clean up of spills
- Other long-term liability.

Costs for Offsite Commercial Disposal Facilities

State	Number of Facilities Using This Process	Type of Disposal Process	Cost[a]
CA	1	Evaporation/injection	$0.01-$0.09/bbl
KY	1	Injection	$1/bbl
LA	23	Injection	$0.20-$4.50/bbl
NM	4	Evaporation	$0.25-$0.81/bbl
NM	1	Evaporation/injection	$0.69/bbl
NM	1	Injection	$0.69/bbl
OK	Eola Muds	Injection	$0.30/bbl
PA	3	Treat/discharge	$1-$2.10/bbl
PA	1	Treat/POTW	$1.25-$1.80/bbl
PA	1	POTW/road spread	$1.30-$4.20/bbl
TX	9	Injection	$0.23-$4.50/bbl
UT	5	Evaporation	$0.50-$0.75/bbl
WY	10	Evaporation	$0.50- $2.50/bbl
WY	1	Treat/injection or discharge	$0.96/bbl
WY	3	Injection	$0.60-$8.00/bbl

Source: Veil (1997)

Rocky Mountain Region Produced Water Management Costs

Management Option	Estimated Cost ($/bbl)
Surface discharge	0.01-0.80
Secondary recovery	0.05-1.25
Shallow reinjection	0.10-1.33
Evaporation pits	0.01-0.80
Commercial water hauling	1.00-5.50
Disposal wells	0.05-2.65
Freeze-thaw evaporation	2.65-5.00
Evaporation pits and flow lines	1.00-1.75
Constructed wetlands	0.001-2.00
Electrodialysis	0.02-0.64
Induced air flotation for deoiling	0.05
Anoxic/aerobic granular activated carbon	0.083

Source: Jackson and Myers (2002, 2003)

Final Thoughts on Water Management

- Many alternatives are available for managing produced water
- Companies must consider:
  - Volume of water generated
  - Chemical and physical characteristics
  - Regulatory requirements
  - Costs
  - Long-term liability of chosen options
- In a water-limited world, produced water can be a resource

Waste Management

- Waste streams that normally are considered to be wastes can be considered wastewater streams at offshore facilities
  - Ex. drilling muds and cuttings
  - NORM
- The same waste management hierarchy described for water can be used for wastes/wastewaters

Examples of Drilling Waste Management Approaches

I - Waste Minimization Approaches

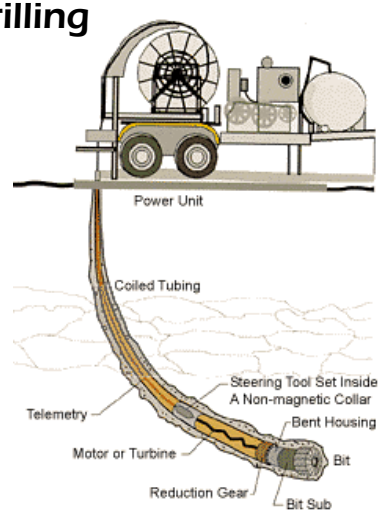
synthetic-based and oil-based muds generate less cuttings than water-based muds

coiled tubing drilling

directional/horizontal drilling

use of less toxic components and additives for muds

air drilling



II - Recycle or Reuse Approaches

road spreading when roads benefit from application of waste

reuse synthetic-based and oil-based muds

use cleaned cuttings for fill or cover material

restoration of wetlands with clean cuttings

use cuttings as aggregate for concrete or bricks

thermal treatment with fluid recovery

III - Disposal Approaches

land spreading or land farming

road spreading

burial in onsite pit or offsite landfill

discharge to ocean

salt cavern disposal

underground injection

thermal treatment

biotreatment (e.g., composting, vermiculture)

What Are the Onshore Disposal Options for Offshore Drilling Waste?

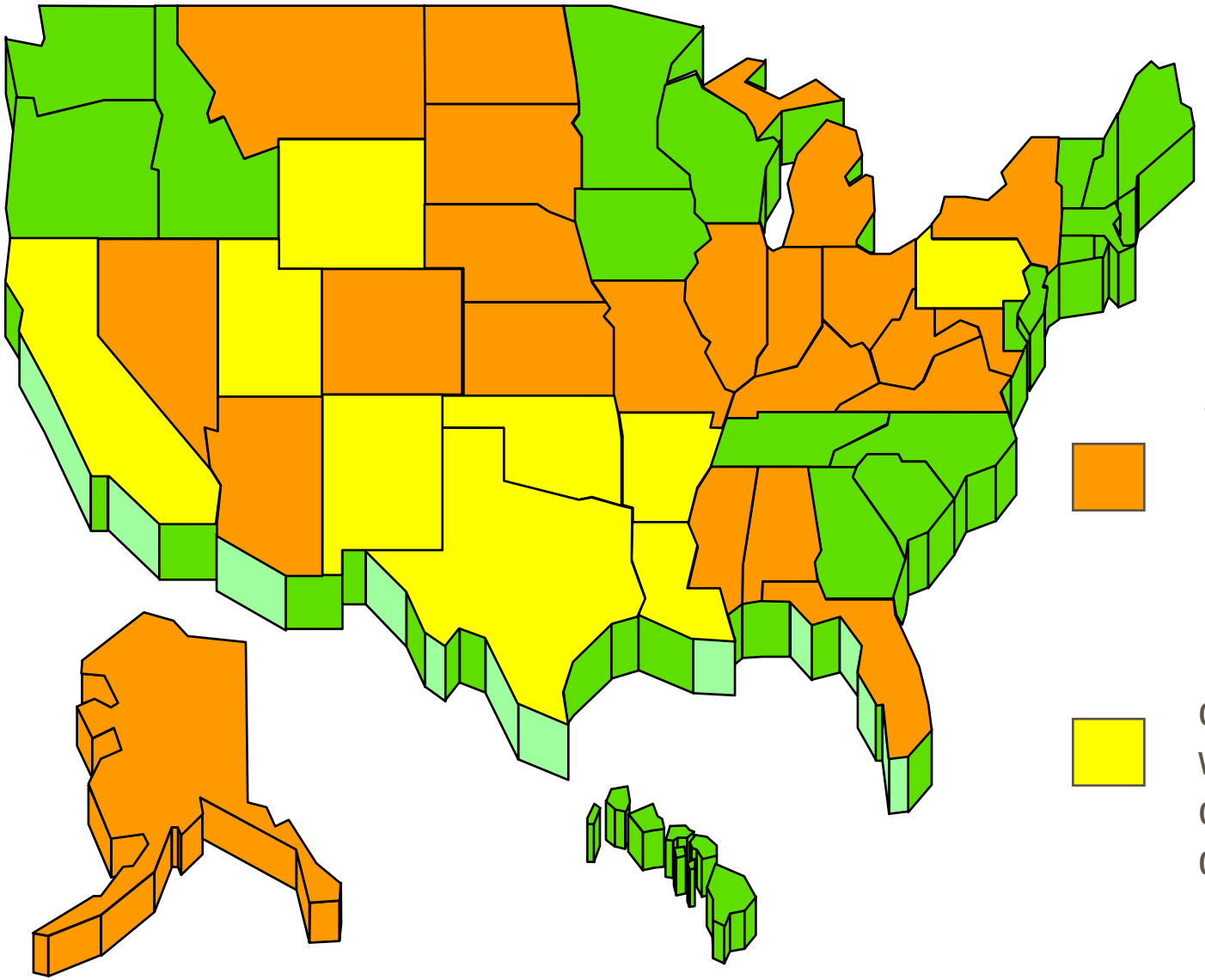
- Nearly all offshore waste currently goes to two major waste disposal companies
  - waste collected at series of transfer stations on Intracoastal Waterway in LA
  - hauled to eastern Texas for unloading to trucks
  - trucked to one facility for slurrying and injection and another competing facility for disposal in salt caverns
- Some waste sent to a land treatment facility in LA

Offsite Commercial Disposal of Oil Field Wastes

- For onshore U.S., most oil field wastes are disposed onsite but large volumes of oil field wastes are disposed offsite

Type of Waste	% Disposed Offsite	Vol. Disposed Offsite
drilling wastes	28%	102 million bbl
produced water	<2%	<400 million bbl
associated wastes	52%	6 million bbl
NORM	>90%	> 250,000 tons

Survey of Offsite Disposal Practices



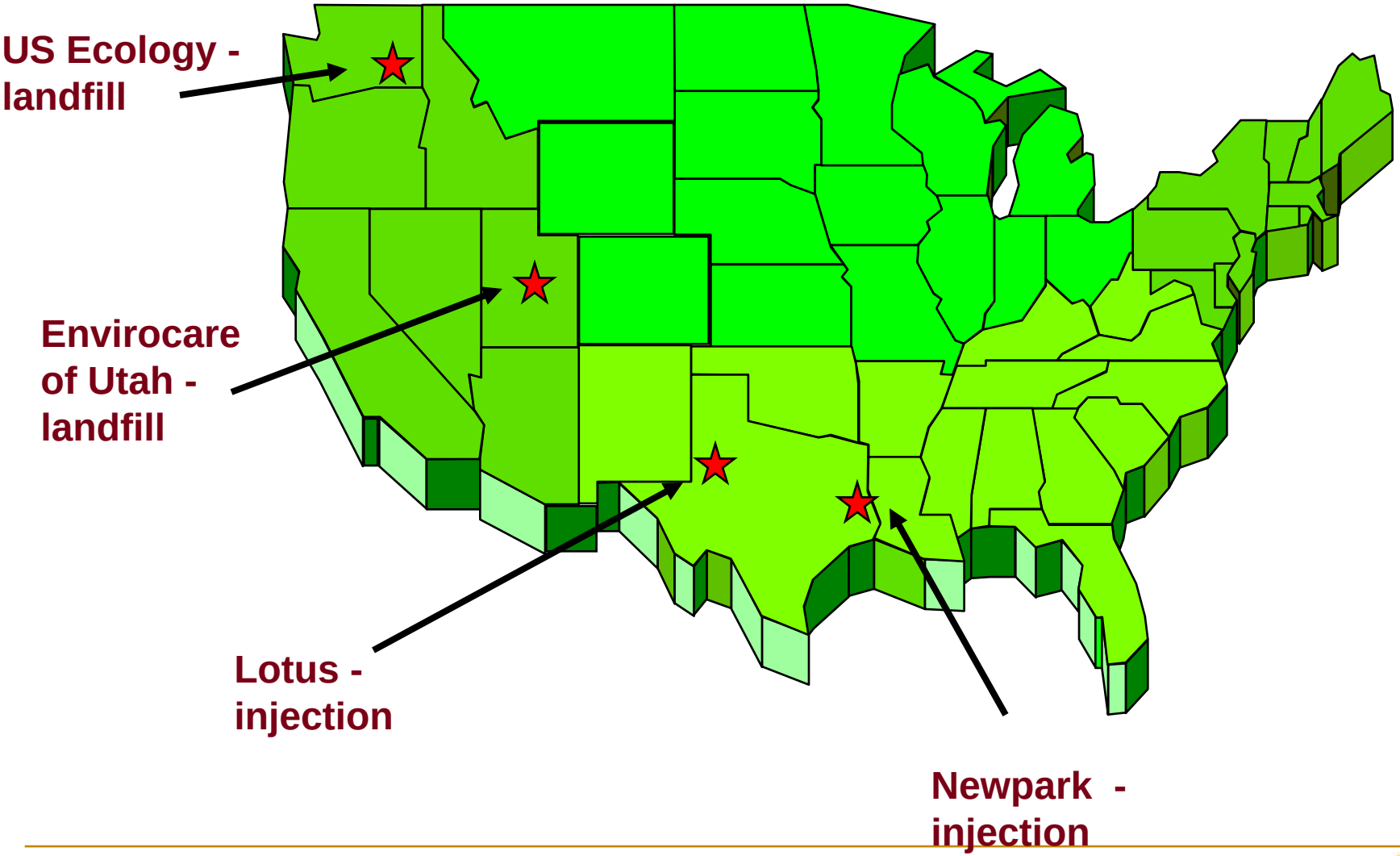
oil and gas states with few or no commercial disposal companies

oil and gas states with a network of commercial disposal companies

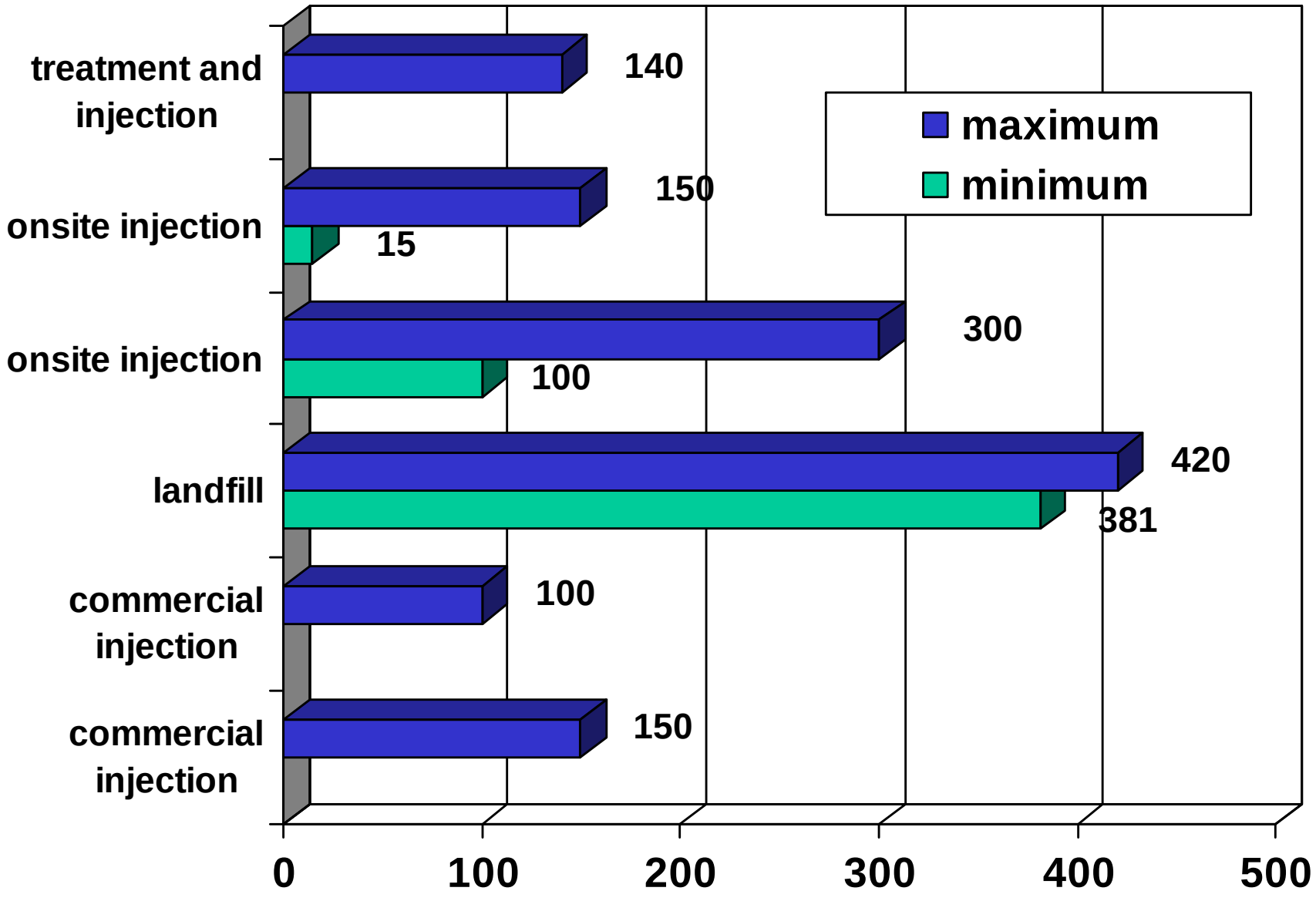
1997 Disposal Costs for Oily and Solid Wastes (does not include transportation costs)

Method	$/bbl	$/yd^3
landspread	5.50-57	14-40
landfill/pit	0.50-36	6.50-37.50
evaporation	2.50-2.75	4.20-18.90
treat/reuse	0-12	12.50-28.50
incineration	10.50-38	--
injection	8.50-11.50	--
salt cavern	1.95-6.50	--

Location of Commercial NORM Disposal Companies



1998 NORM Disposal Costs - ($/bbl)



International Perspective

- Some developing countries do not have well-established E&P waste requirements or infrastructure
- U.S. companies operating there may face limited and costly disposal options
- DOE/PERF efforts to develop a risk-based framework for waste management

Example of an Innovative Pollution-Preventing Technology:

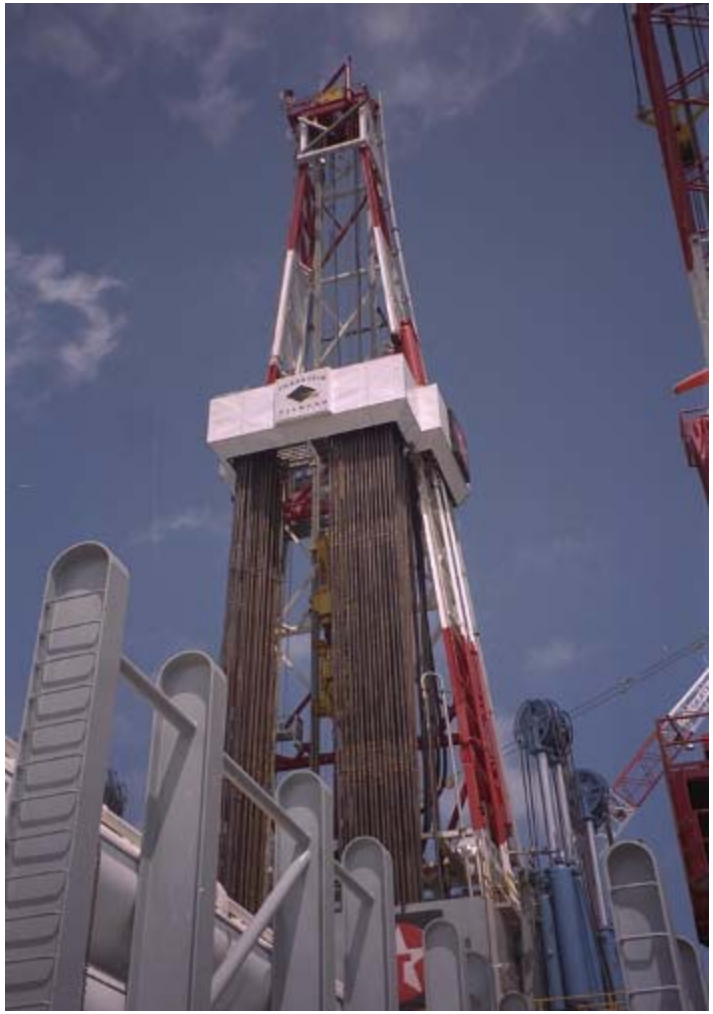
Synthetic-Based Muds Offer Strong Drilling Performance and Low Environmental Impacts

Types of Drilling Fluids

- water-based muds (WBMs)
- oil-based muds (OBMs)
- synthetic-based muds (SBMs)

Advantages of WBMs

- commonly used offshore
- used to drill shallow section of many wells
- inexpensive
- low toxicity
- muds and cuttings can be discharged onsite
  - offshore Gulf of Mexico and California >3 miles from shore
  - offshore Alaska
  - Cook Inlet Alaska



Disadvantages of WBMs

- poor performance in difficult drilling situations
  - deep wells
  - horizontal or extended reach wells
- stuck pipe
- drilling delays

Advantages of OBMs

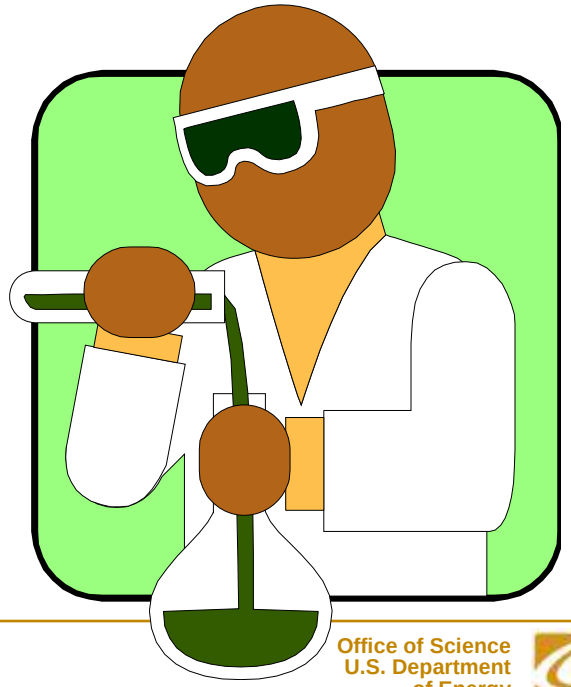
- improved performance in difficult drilling situations
  - Horizontal sections
  - Deep sections
- minimizes slumping
- muds are generally recycled

Disadvantages of OBMs

- cannot discharge cuttings or muds onsite
  - haul to shore
  - injection
- potential health and safety problems

Types of SBMs

- EPA definition: "*…produced by reaction of purified chemical stock (not fractionation, distillation, cracking, or hydroprocessing…)*"
- Internal olefins (IOs)
- Esters
- Linear alpha-olefins (LAOs)
- Poly-alpha-olefins (PAOs)
- Linear paraffins
- Others



Advantages of SBMs

- performance comparable to or better than OBMs
- low toxicity
- muds are recycled
- some deepwater wells cannot be drilled without SBMs

Example of SBM Performance from Gulf of Mexico

	WBMs	SBMs
# wells	5	3
Average depth drilled	116 feet/day	336 feet/day
Total cost/well	$9.6-14.7 million	$4.4-6.5 million
Average days to completion	197	61

Disadvantages of SBMs

- High cost
- Until 2001, no formal U.S. regulatory approval to discharge cuttings

Innovative Process for Developing SBM Rules

- During the early and mid 1990s, when ELGs and EPA permits were issued, SBMs were not commonly available
  - no mention of SBMs in ELGs or general permits
- This regulatory barrier impeded wider use of this innovative and pollution-preventing technology
- Industry and government worked cooperatively
  - Developed new rule in half the usual time
  - Began to build trust to overcome previous adversarial relationship

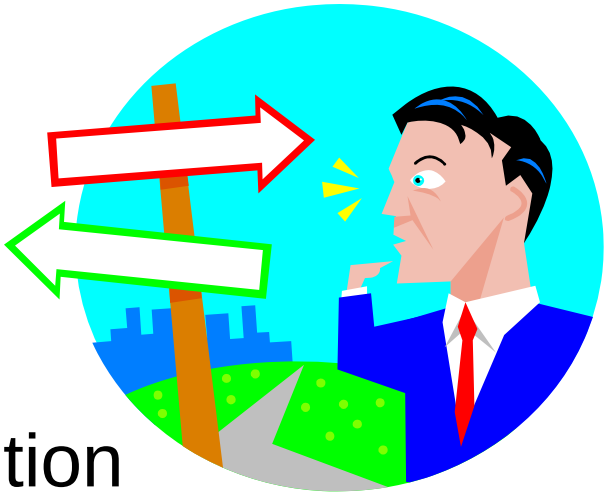
Efforts to Resolve the Regulatory Barrier

- 1995 - DOE funded study to identify and clarify the problem
- DOE established informal synthetic fluids discussion group
  - government
  - industry
- EPA used the group to present information needs for modifying ELGs

EPA's Decision to Modify Offshore ELGs for SBMs

- Normally need 4-6 years to develop ELGs
- EPA recognized environmental benefits from SBMs
- decided to use "expedited rulemaking" approach
  - proposed rule in 1 year
  - final rule in 3 years
- industry provided data to EPA iteratively
- EPA and other stakeholders met throughout the process to discuss progress and exchange information and comments

Options and Outcome



- EPA evaluated both a discharge option and a zero-discharge option
- Final rule adopted January 2001 allowed discharge of SBM cuttings as long as limits were met
  - Zero-discharge would have resulted in excessive fuel usage and air emissions
  - EPA weighed those impacts against the water quality impacts of the discharge option

Summary

- SBMs represent an innovative, cost-effective, and environmentally friendly technology
- EPA used expedited rulemaking process to develop new regulations for SBM cuttings discharges

This is a win/win/win situation

Wetlands Restoration Using Treated Drilling Waste – A Beneficial Reuse of a Waste Product

Wetlands Loss

- greatest environmental problem facing coastal Louisiana is the loss of wetlands

- oil and gas industry has contributed to the loss

What Can Be Done?

- restore damaged wetlands
- use solid waste product from oil and gas exploration (treated drill cuttings) as a substrate for restoring wetlands

Background

- DOE funded Greenhill Petroleum to conduct studies on using treated drill cuttings to restore wetlands
  1) laboratory mesocosm studies to assess growth success
     - *Southeastern Louisiana University (SLU)*
  2) field pilot study near Venice, LA
     - *create berm out of dredged material*
     - *fill inside of berm with treated cuttings*
     - *plant with wetlands vegetation*

Potential Economic and Environmental Benefits

- >300 wells/year are drilled in coastal Louisiana marshes
  - if all cuttings from these wells were used for wetlands restoration, could create 450 acres/year of wetlands and avoid land disposal of 4.5 million barrels of cuttings
- no cost savings to operators have been estimated
- current cost to restore wetlands using conventional approaches is $10,000/acre

SLU Mesocosm Studies

- **144 200-liter growth vessels**
- **4 3,000-liter water supply reservoirs**
- **3 hydrological regimes**
- **four substrates**
- **6 types of wetlands plants**
- **2 replicates of each set of conditions**

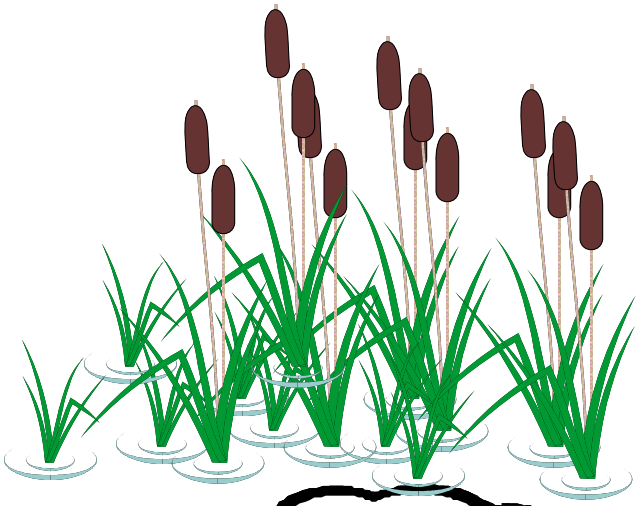
Features of Hydrological Control System

Water supply reservoir

Piping in growth chamber showing how to control water level

Results of Freshwater Mesocosm Studies

- cuttings treated by process A (cuttings separated from drilling fluids)
  - low toxicity
  - supported plant growth comparable to dredged material



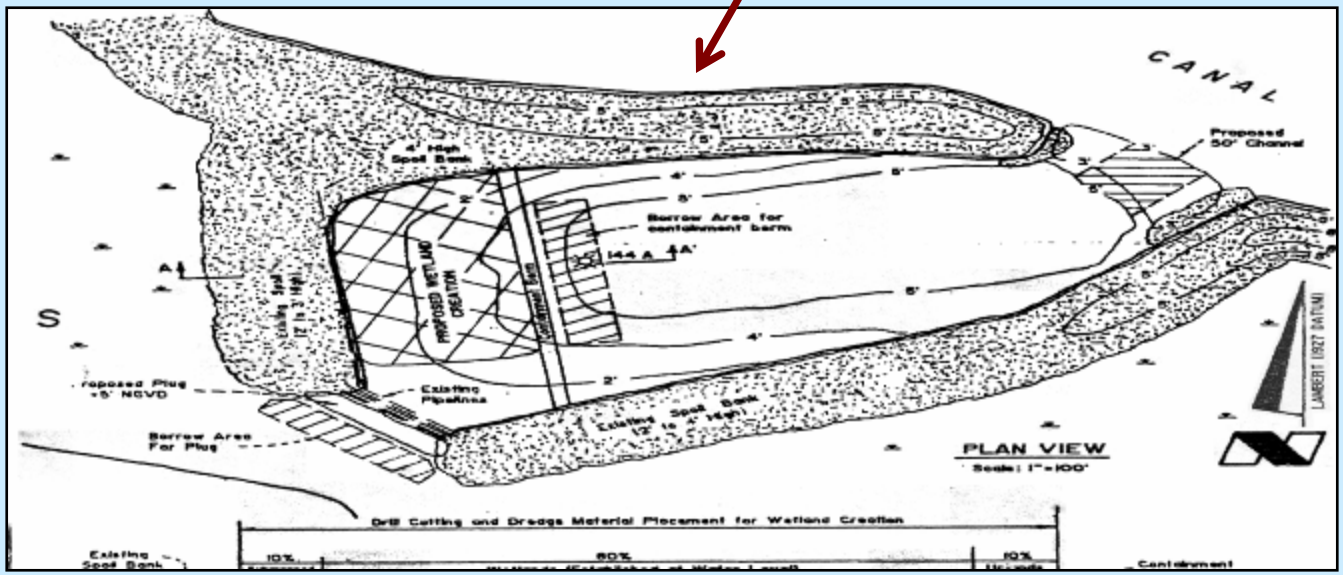
- cuttings treated by process B (cuttings separated and stabilized in a silica matrix)
  - poor plant growth
  - suspected problem was high pH

Results of Saltwater Mesocosm Studies

- cuttings treated by process A
  - low toxicity
  - supported plant growth comparable to dredged material
- cuttings treated by process B
  - much better plant growth than in fresh water study
  - high pH was apparently buffered by seawater
- barium was taken up by plants and converted to an insoluble form
  - leaching of metals does not appear to be a problem

Site Location

Site Plan



Problems with Permits for Field Pilot Study

- Greenhill applied for a wetlands permit
- EPA wetlands office generally agreed, but EPA discharge permit office objected
  - disposal of drill cuttings is subject to NPDES permit
  - NPDES general permit prohibits discharge of drill cuttings to coastal waters

Argonne Asked to Get Involved

- formed project team
  - DOE
  - Argonne
  - university
  - SWACO (service company)
  - XPLOR Energy (oil company)

- looked for other regulatory mechanisms that would lead to a permit

Approval for Field Trial?

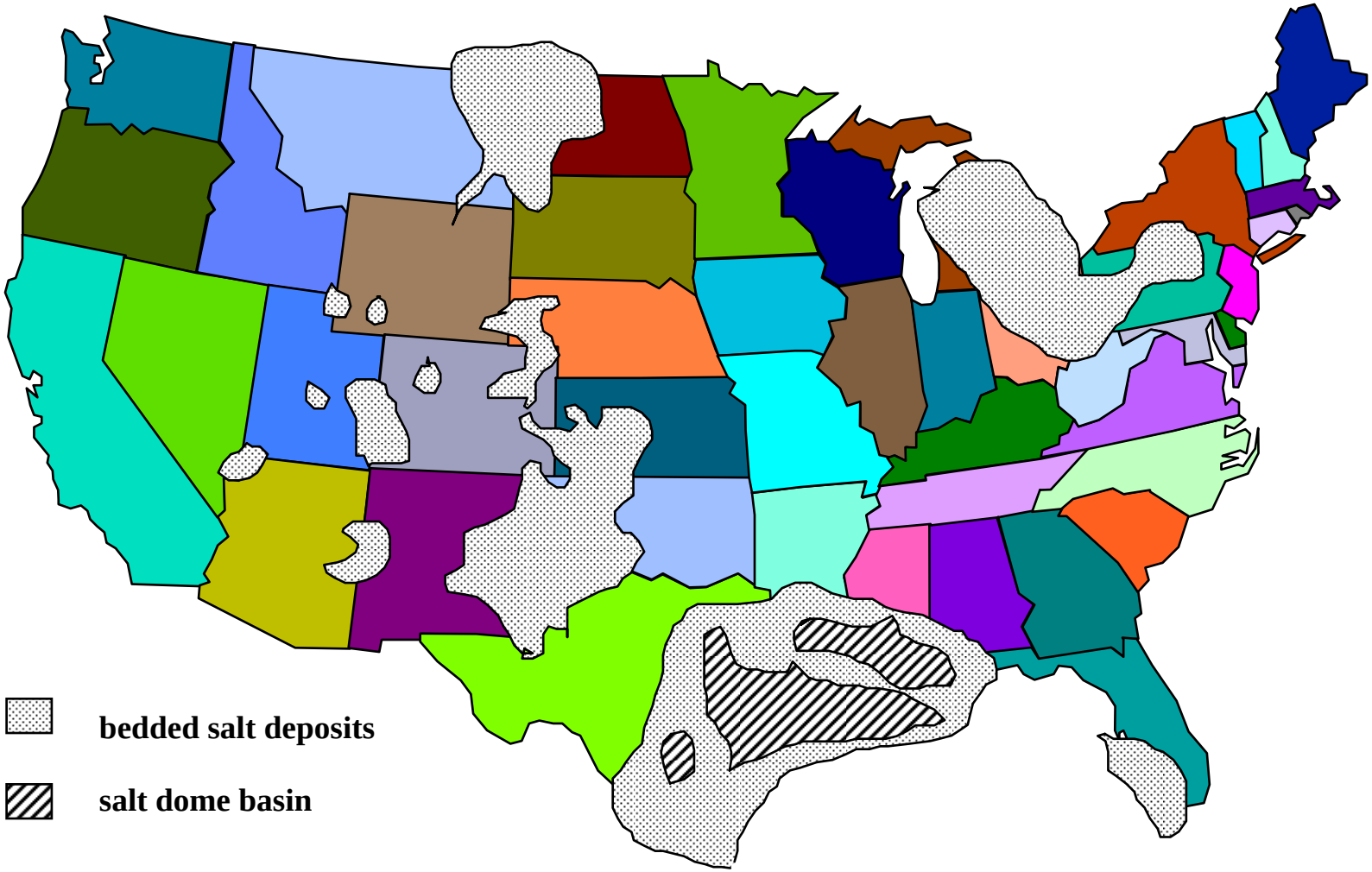
- Argonne met with EPA
- EPA was not willing to follow traditional regulatory programs to approve a field trial
- EPA suggested a program called Project XL
  - allows circumvention of existing environmental rules when applicant can show superior environmental benefits from project
- Argonne could not get an oil company to serve as project sponsor
  - No approval or permit was granted

Conclusions

- the concept of using treated drill cuttings for wetlands restoration is sound
- properly treated cuttings can support good growth
- the process reuses a waste product for a beneficial purpose
- there is a substantial lack of trust between regulatory agencies and industry
  - additional work is needed to get regulators comfortable with the concept

Salt Caverns Represent a Cost-Effective and Safe Alternative for Disposal of Oil Field Wastes

Major U.S. Salt Deposits



How Caverns Are Formed

- ***Caverns are formed through solution mining***

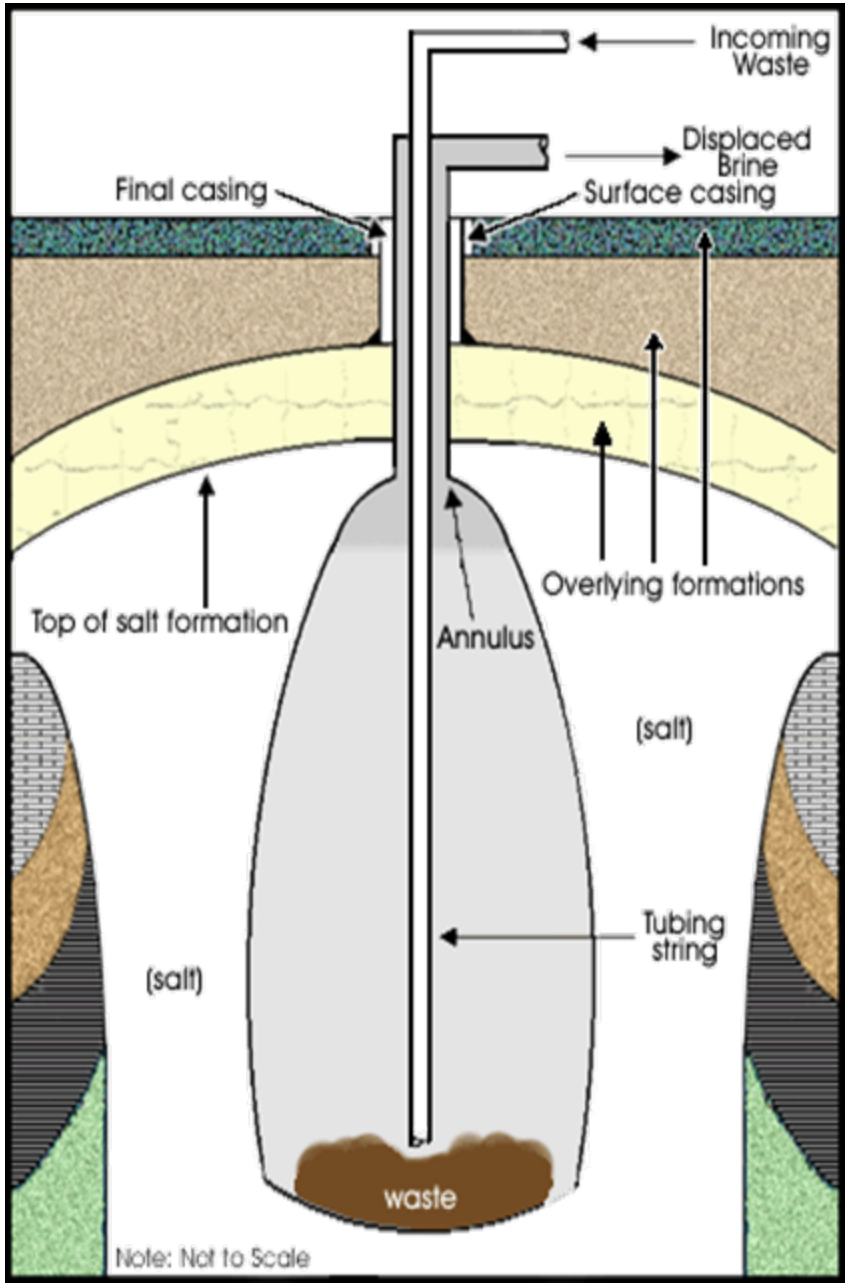
  -water that is not fully saturated with salt is injected into a formation where it dissolves salt

  -the resulting brine solution is then removed leaving a void space

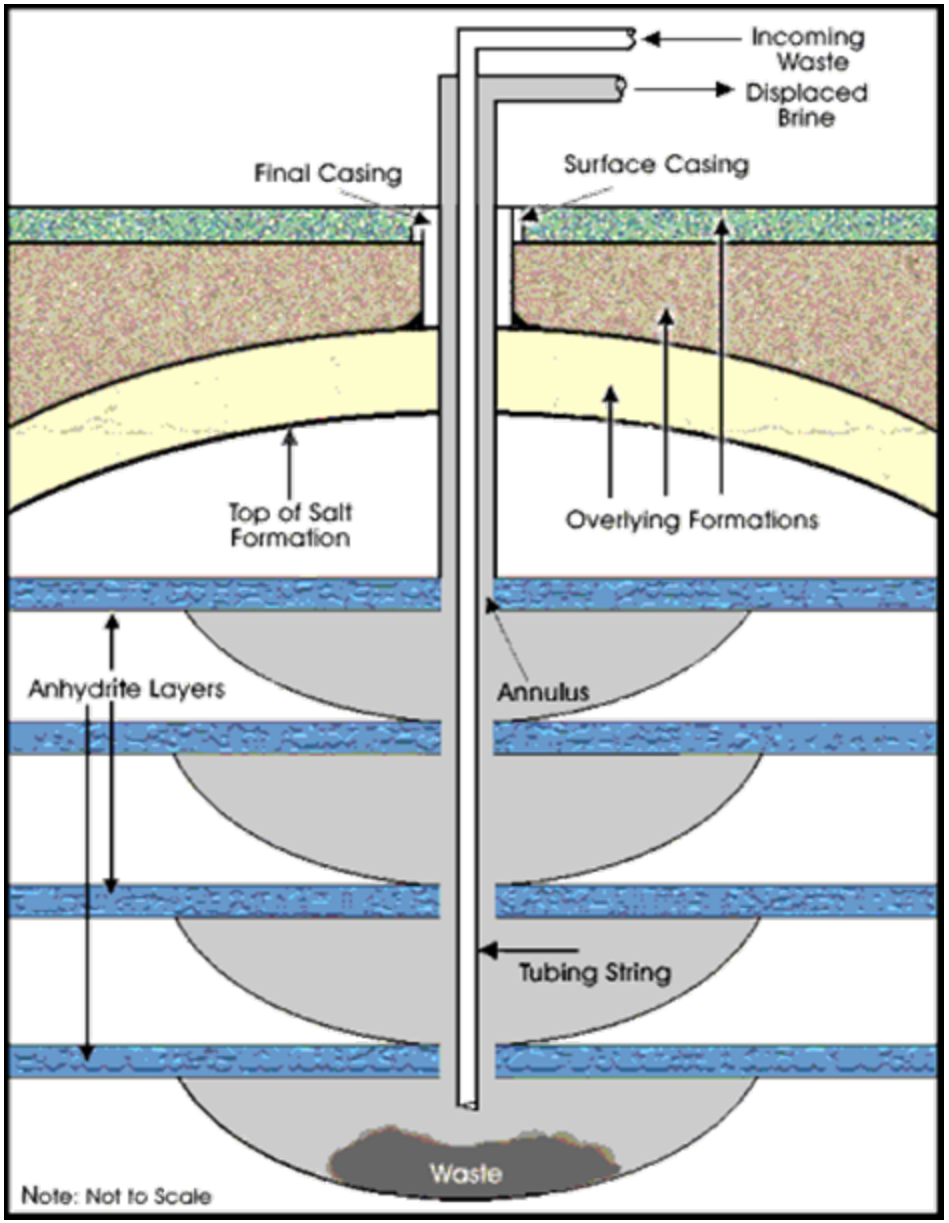
Size and Shape of Caverns

- Caverns can be formed in domal salt or bedded salt
- Salt mining has produced irregularly shaped caverns as well as caverns that are nearly cylindrical
- Caverns presently in use have a wide range of sizes
  - caverns in the Strategic Petroleum Reserve are very large and have an average volume of 420 million gallons
  - disposal caverns in Texas are much smaller (18 million gallons)

Schematic Drawing of a Cavern in Domal Salt



Schematic Drawing of a Cavern in Bedded Salt



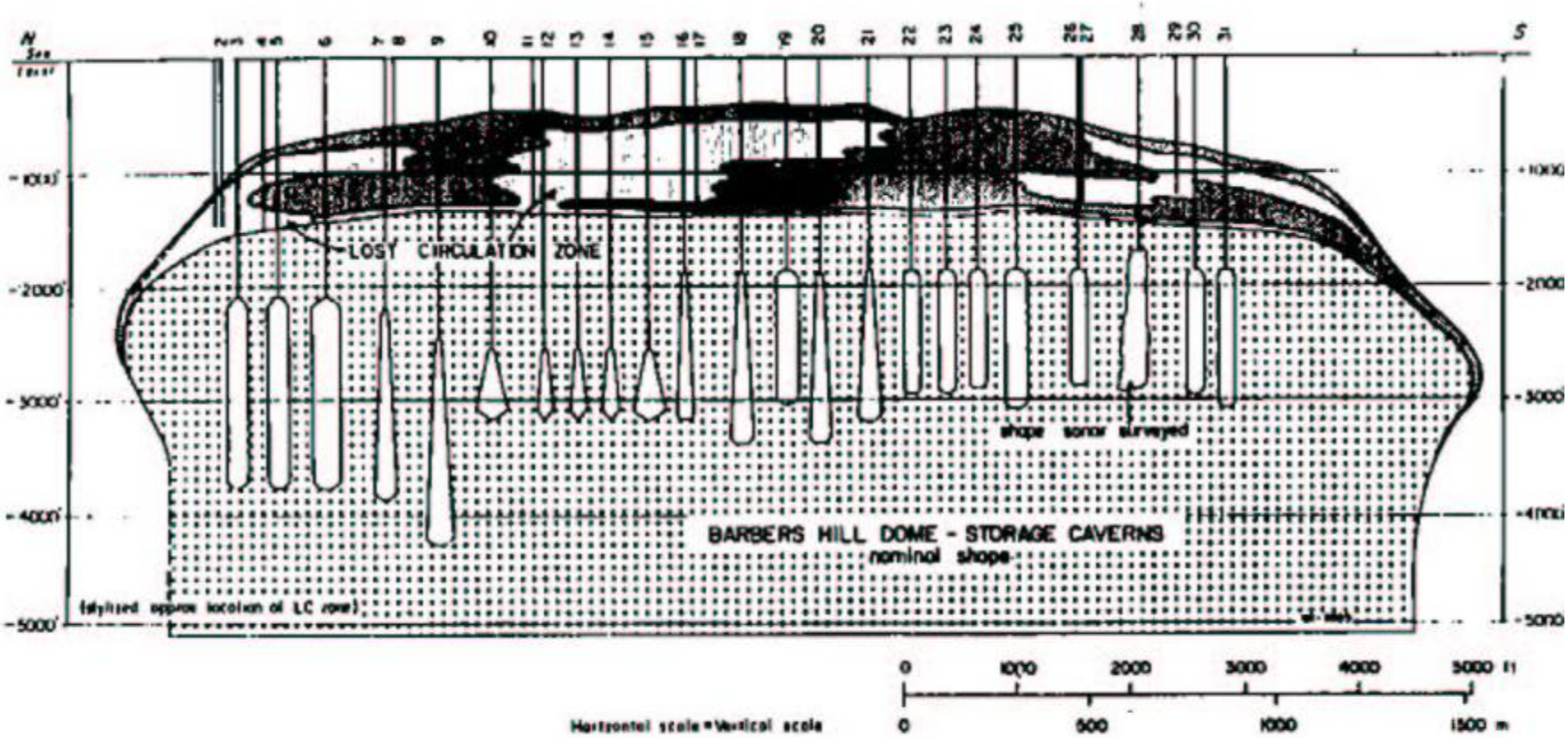
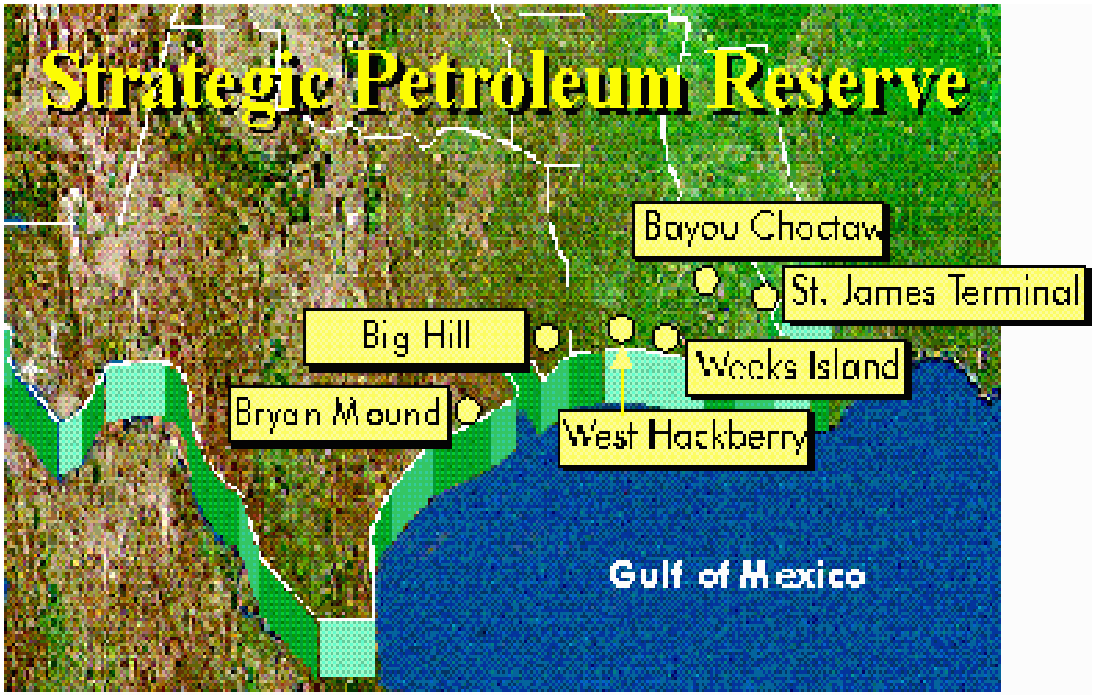


Figure 6. Cross section of Barbers Hill Salt Dome (north-south) showing nominal geometry of storage caverns and lost-circulation zones in cap rock.

from Seni (1988)

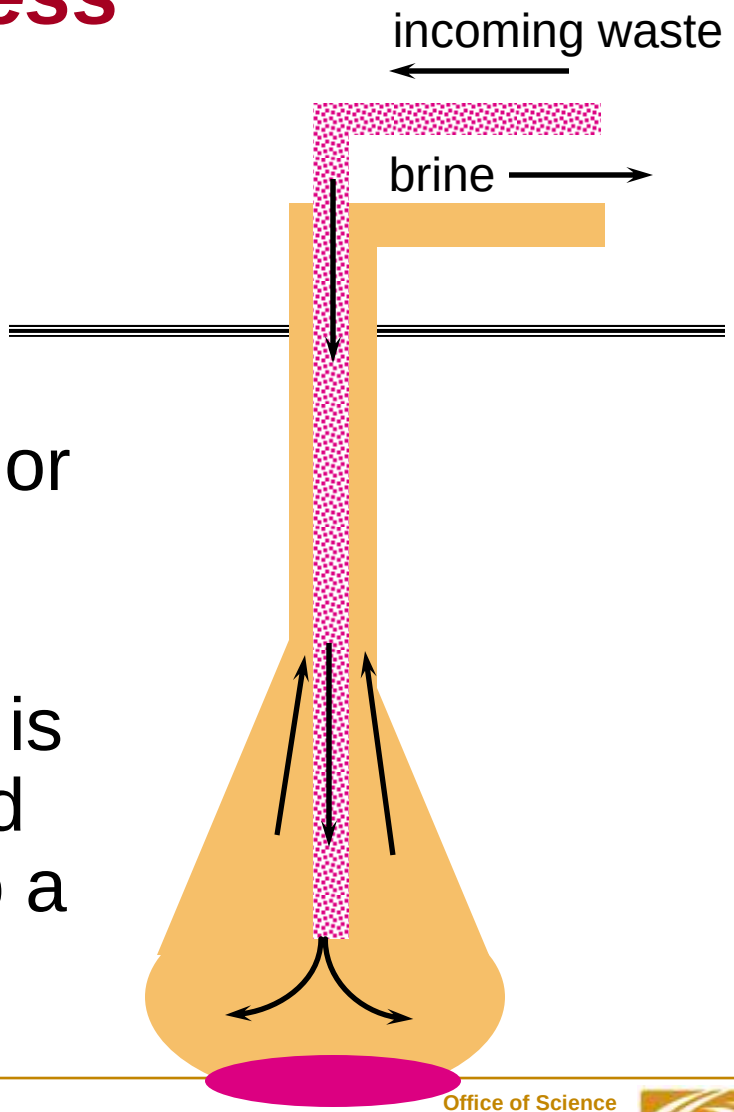
Strategic Petroleum Reserve (SPR)

- SPR now has a capacity of about 563 million barrels of crude oil stored in 5 solution-mined caverns in Texas and Louisiana
- Serves as an emergency supply of oil for the United States



The Waste Disposal Process

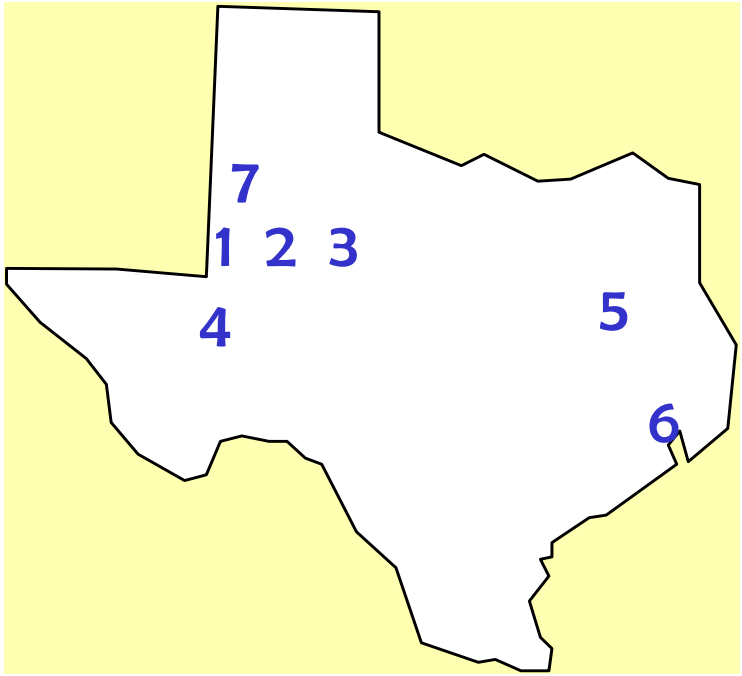
- salt caverns are initially filled with brine
- wastes are injected as a slurry of waste and water or brine
- the incoming waste displaces the brine which is brought to the surface and either sold or injected into a disposal well



Caverns Act Like Giant Oil/Water/Solids Separators

- solids sink to the bottom and oil floats to the top
- as wastes fill the cavern, the end of the tubing is raised so that filling can continue.

Location of Permitted NOW and NORM Disposal Caverns in Texas (as of 2002)



1. Lotus, LLC; Andrews County; horizontal caverns; accepts NOW and NORM
2. NES Permian Basin- Permian Brine-Grimmett Bros., Andrews County; accepts NOW
3. NES Permian Basin - Big Springs; Howard County; 3 caverns; accepts NOW and NORM
4. NES Permian Basin - Fort Stockton; Pecos County; accepts NOW and NORM
5. Taylor Disposal Operating, Inc.; Freestone County; 2 caverns; accepts NOW
6. Trinity Storage Services, Inc.; Liberty County; 2 caverns; accepts NOW
7. Wasson Solid Waste Disposal LLC; Yoakum County; accepts NOW

Cavern Closure

- Once a cavern has been filled with waste, the cavern would be sealed and the borehole plugged with cement
- Plugs would be placed above and below water-bearing zones to isolate those zones permanently
- Once sealed, the cavern would be subject to a number of post-closure processes

Cavern Failure Is Most Likely to Occur after Closure

- creeping action of salt
- geothermal heat
- modeling of liquid-filled caverns indicates:
  - elevated pressures
  - low likelihood of leaks and failures
- solids-filled caverns will be equally or less likely to fail

Estimated Cancer and Noncancer Risks - Results of Risk Analysis

- cancer risk [goal: excess cancer risk 10^{-4} - 10^{-6}]

	Chemical Risk	Radiological Risk
- 100% release	10^{-7} - 10^{-16}	10^{-13} - 10^{-22}

- noncancer risk [goal: hazard index <1.0]

	Chemical Risk	Radiological Risk
- 100% release	10^{-3} - 10^{-7}	NA

- Cavern disposal poses very low human health risks, even if all caverns leak or fail
- The radiological risks are many orders of magnitude smaller than the chemical risks

Disposal Caverns Are Safe for E&P and NORM Waste Disposal

- even when all caverns leak, the modeled risks are within or below the acceptable risk ranges

- human health risks from cavern disposal of oil field wastes are very low

Conclusions

- cavern disposal of E&P and NORM waste is technically feasible
- Cavern disposal poses very low human health risks, even if all caverns leak or fail
- The radiological risks are many orders of magnitude smaller than the chemical risks

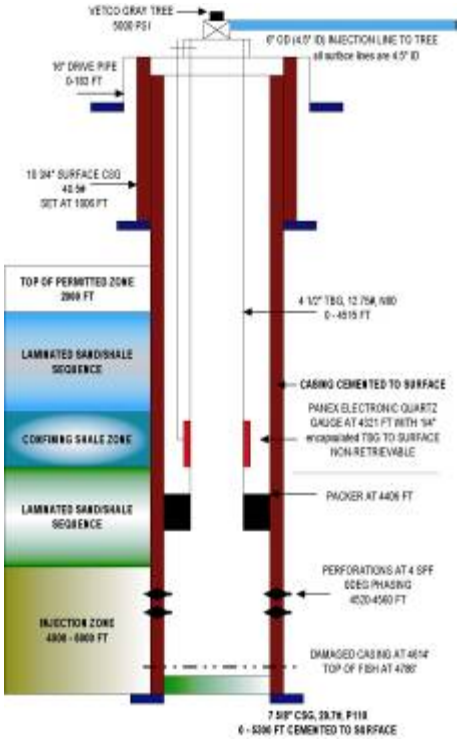
For more information, visit:

www.npto.doe.gov/saltcaverns

Slurry Injection Can be a Cost-Effective and Safe Alternative for Disposal of Drilling Wastes

What Is Slurry Injection?

- Solid material is ground into small particles
- Pumped into a formation at high pressure



Source: Richard Keck – SPE Cuttings Injection School (1999)

- Formation fractures allowing slurry to move into rock

Types of Underground Injection of Solid or Semisolid Wastes

- Salt caverns
- Subfracture injection (below fracture pressure)
- Slurry injection
  - Annular injection
  - Dedicated injection well with tubing and packer

Slurry Injection Below Fracture Pressure – Cap Rock Above Salt Dome

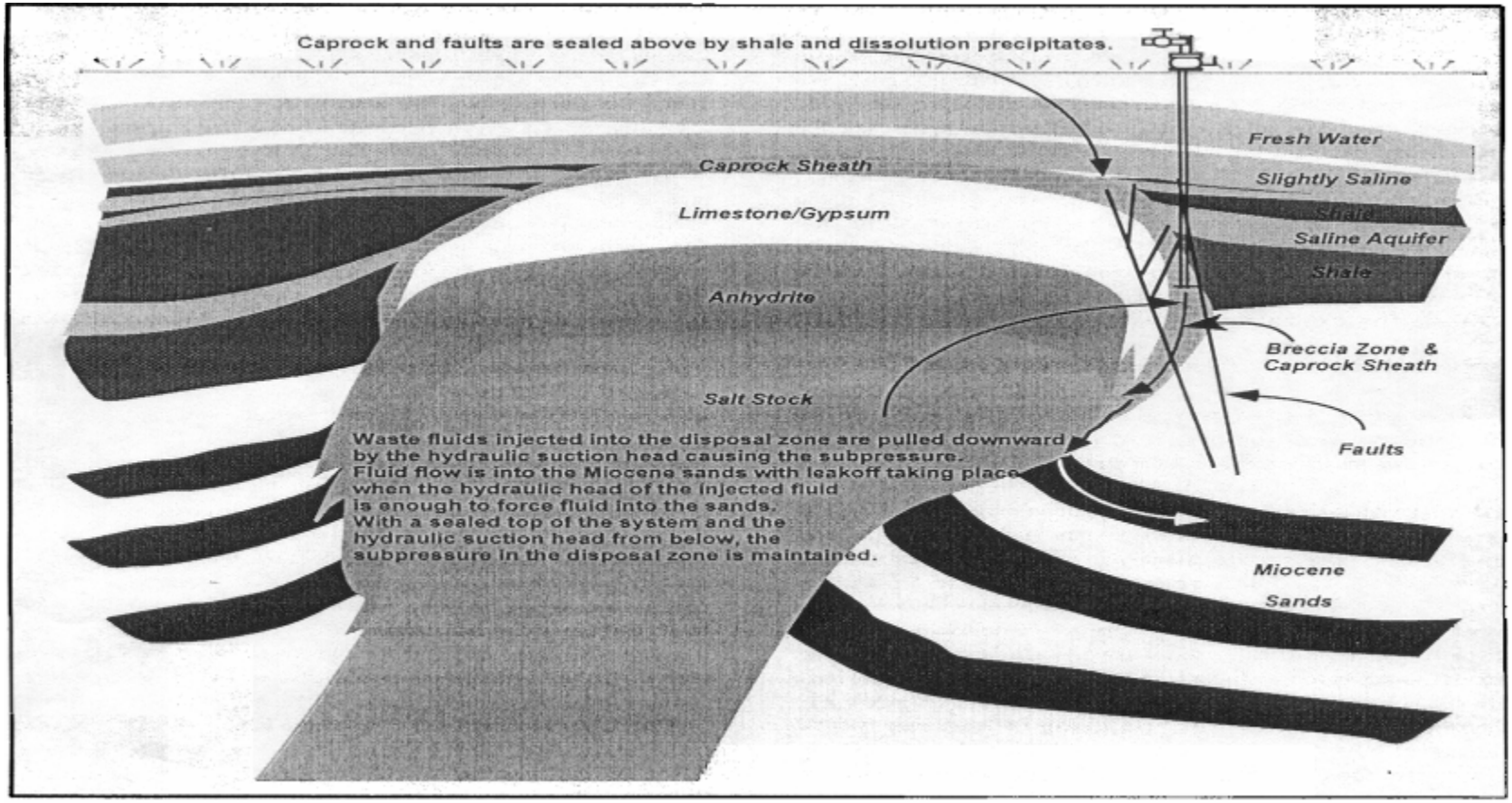


FIGURE 1: Subpressured disposal zone geology and hydraulics.

Source: Richard Keck – SPE Cuttings Injection School (1999)

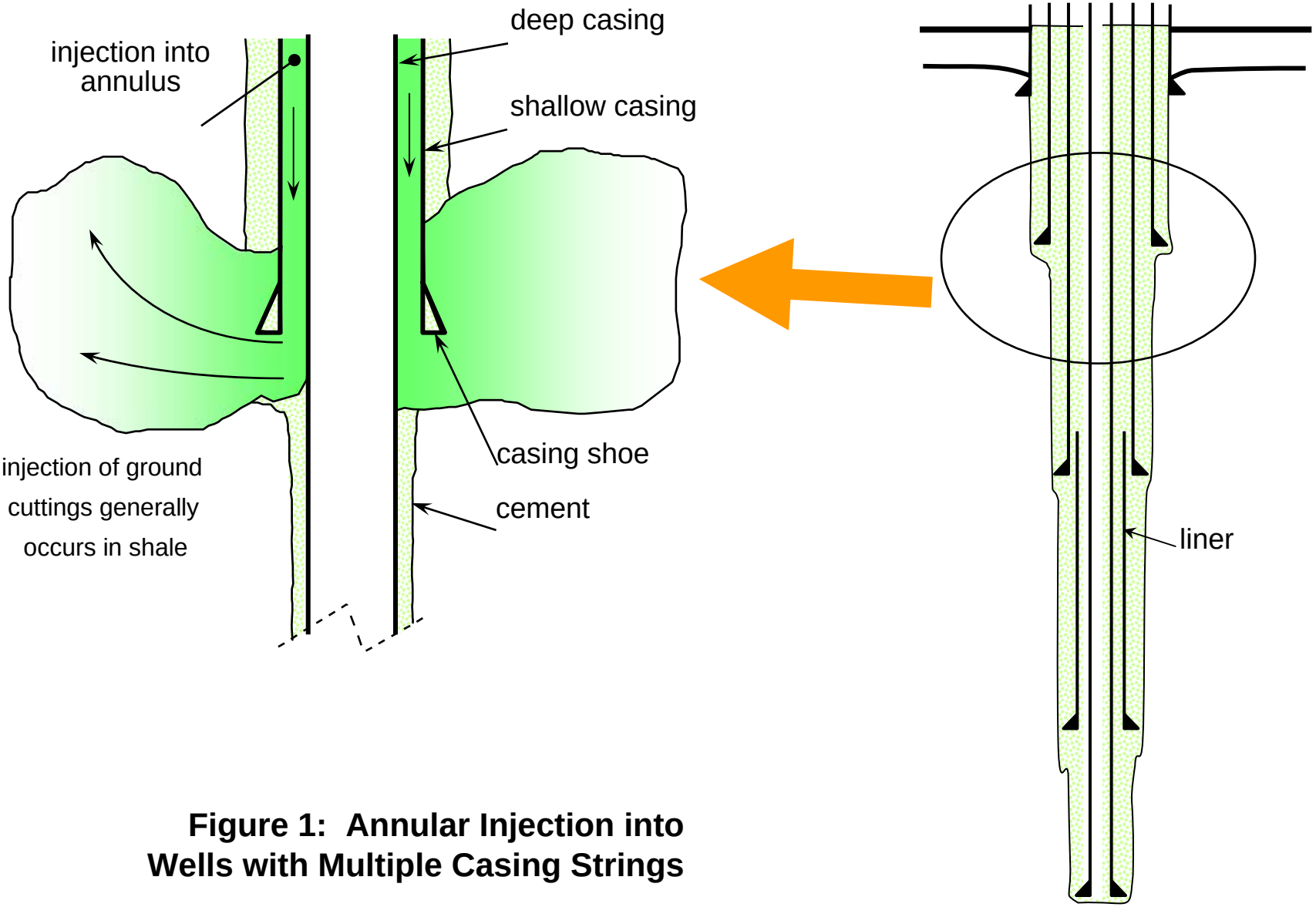


Figure 1: Annular Injection into Wells with Multiple Casing Strings

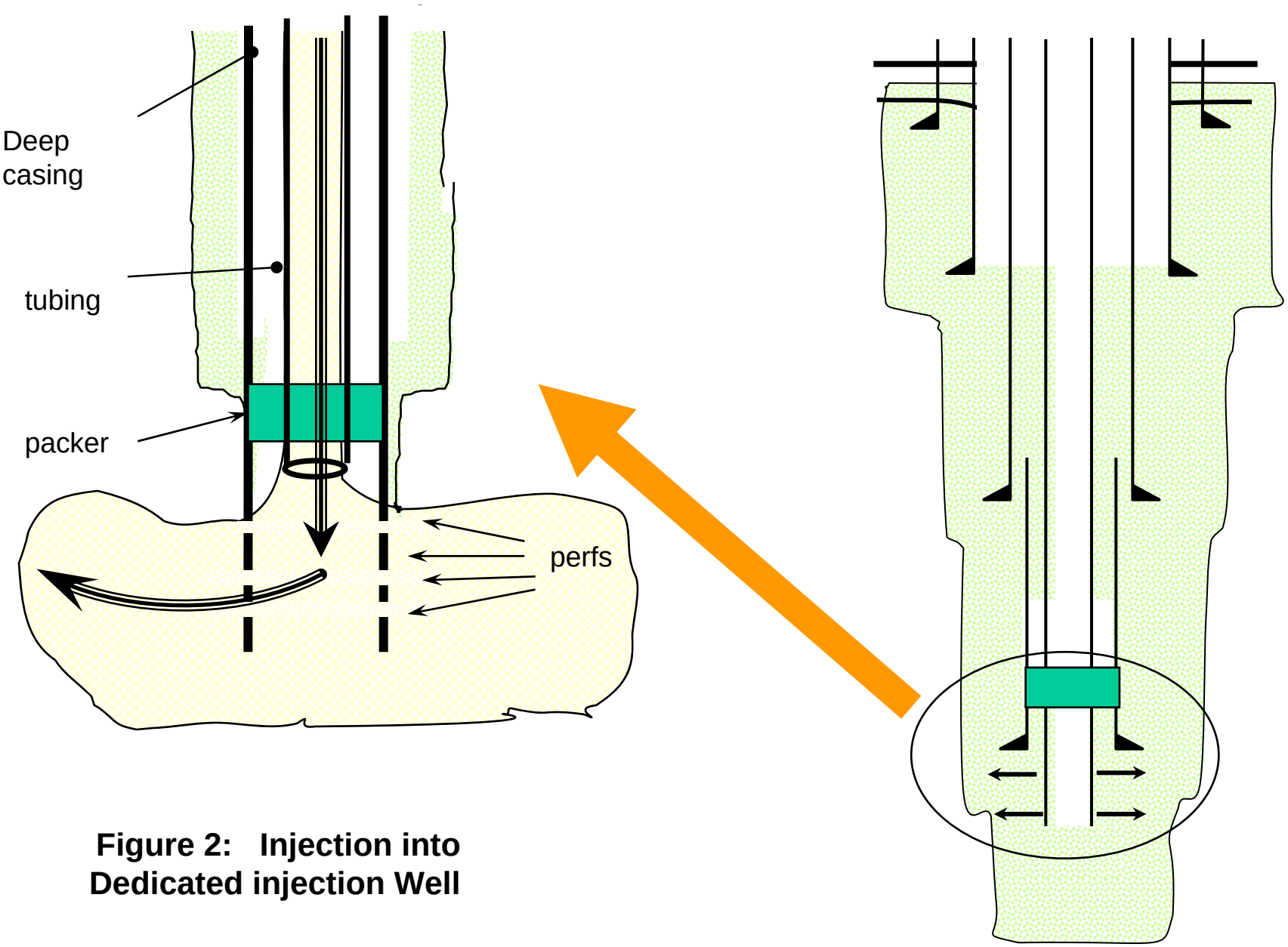
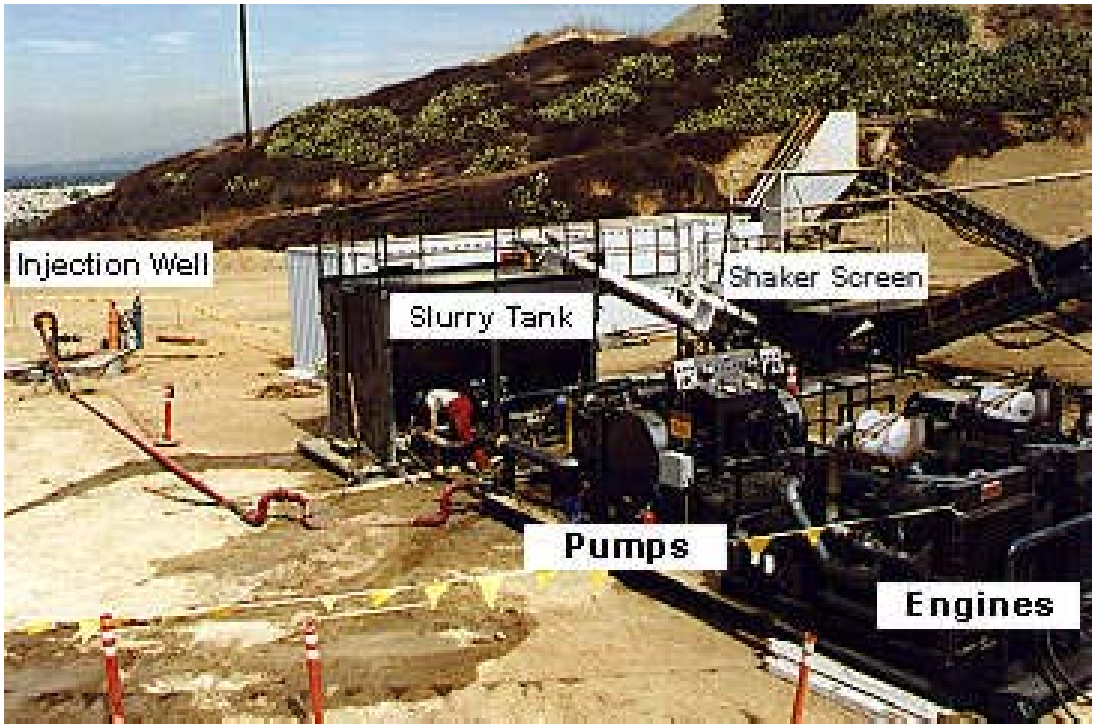


Figure 2: Injection into Dedicated injection Well

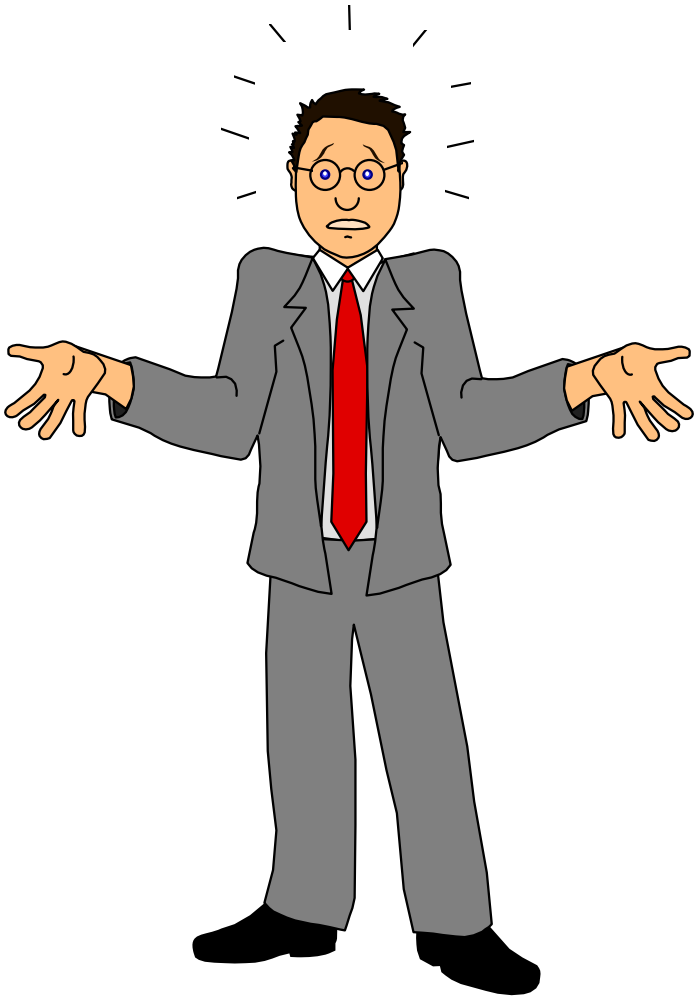


Layout of Equipment

Photos courtesy of Terralog Technologies

Many Names for the Slurry Injection Process

- SFI (trademarked)
- FSI
- DCI
- Cuttings reinjection
- Grind and inject
- Others?

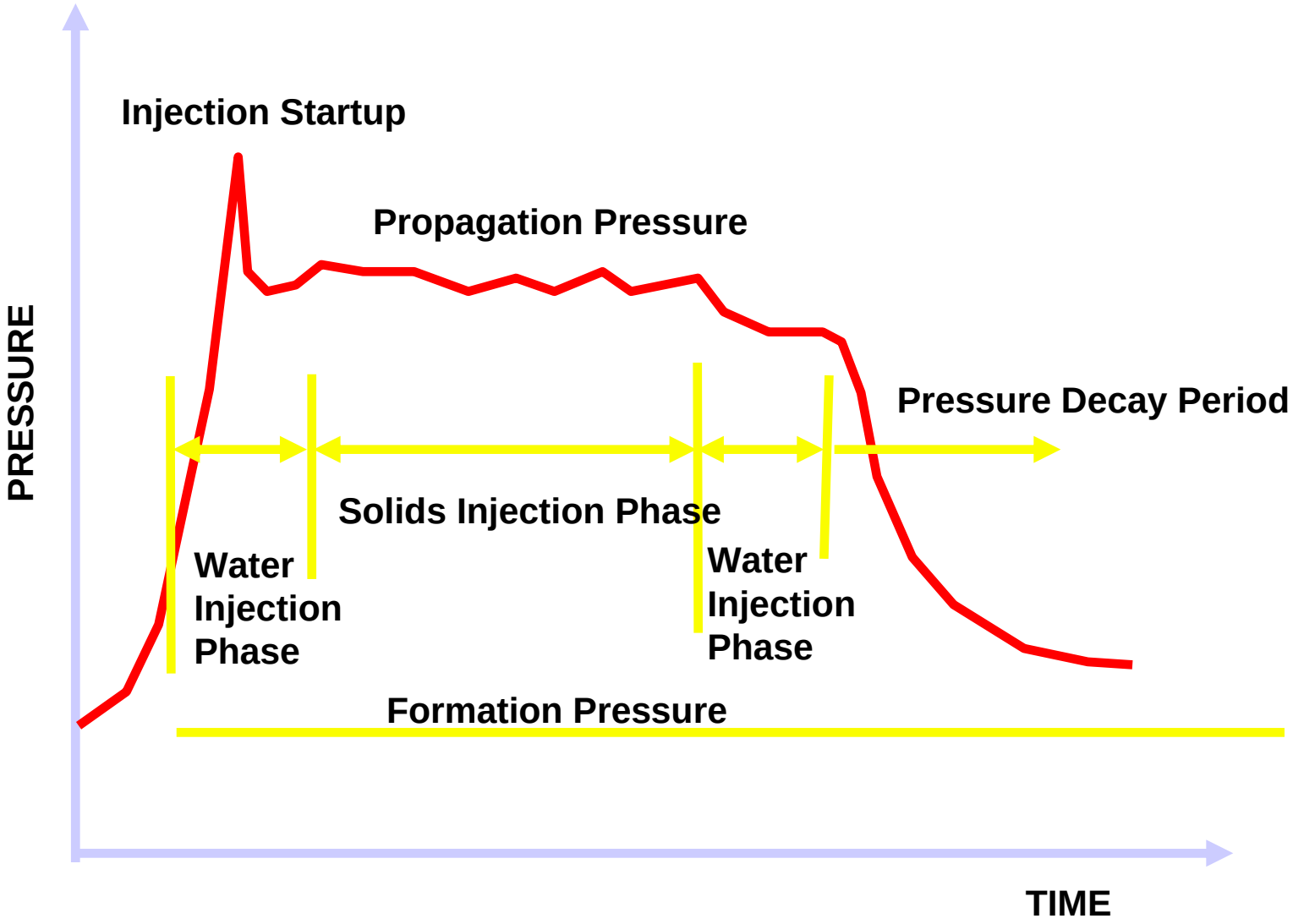


Examples of Slurry Injection

Photo courtesy of Terralog Technologies

- Single-well annular injection
  - Several offshore Gulf of Mexico contractors
  - Occasional onshore wells
- Large scale injection projects
  - Alaska – ARCO, BP, and Phillips
  - Louisiana – Chevron
  - California - Terralog

Example of Injection Cycle



Source: Mike Bruno, ***Presentation to 2000 Chevron Upstream Waste Workshop***

Daily Pressure Response Over Time

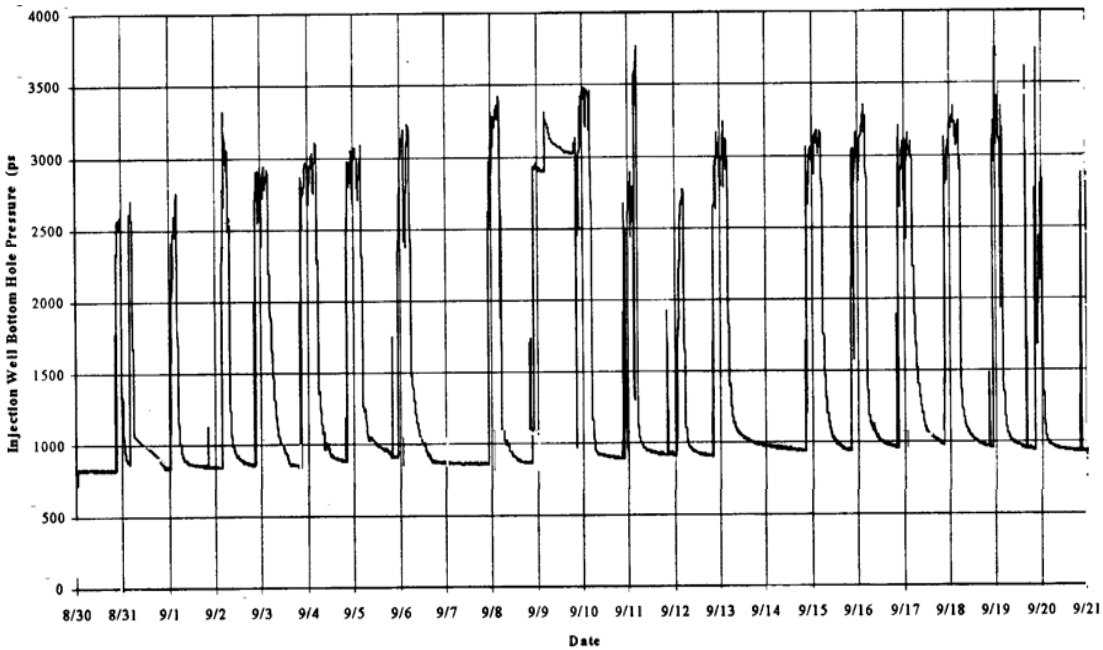


Fig. 6--Daily pressure response

Volume:
2000 – 4000 BPD

Depth: 4100 feet

Source: Richard Keck – SPE Cuttings Injection School (1999)

Description of Study Effort

- Argonne has no financial stake in slurry injection and can offer unbiased evaluation
- Split project into three components
  - Regulatory compendium
  - Technical report
    - *Technology description*
    - ***Database of actual field use of slurry injection***
  - Brochure written for nontechnical audience

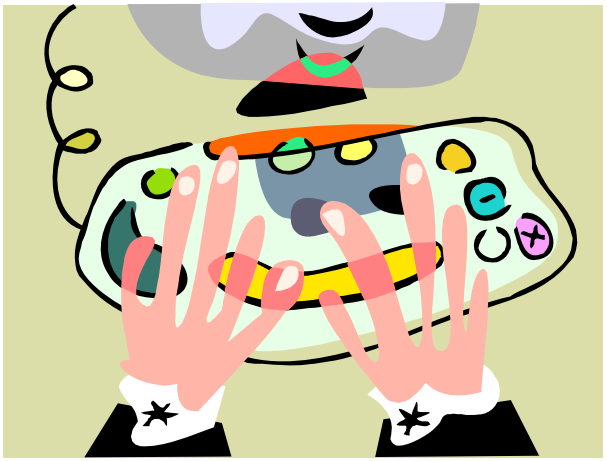
Technical Report

- Describes slurry injection vs. other types of solid injection
- Detailed description of how slurry injection is conducted
  - Injection mechanism
  - Continuous vs. intermittent
  - Longevity

Technical Report - continued

- Step-by-step description of slurry preparation, pre-injection, injection, and post-injection practices
- Discussion of geology suitable for slurry injection
- Overview of fracturing theory
- Monitoring methods
- Economics of slurry injection
- Extensive list of references on slurry injection

Database of Slurry Injection Trials



- Data compiled from:
  - Literature (primarily SPE papers)
  - Information from service companies and operators
- Currently have data on 334 trials
  - Data are not fully complete for all injection jobs
  - Data were collected by operators and we had no way to verify accuracy
  - Nevertheless, the database is most thorough publicly-available source of information on slurry injection

Summary of Database - Locations of Slurry Injection Jobs

Location	Number of Records in Database
Alaska	136 (North Slope 129, other 7)
Gulf of Mexico	66
California	18
Other U.S. onshore	28 (Louisiana – 20, Texas - 6, Oklahoma - 1, North Carolina - 1)
North Sea	35
Canada	9 (Alberta - 4, Saskatchewan - 3, Nova Scotia offshore - 2)
Latin America	4 (Argentina - 1, Mexico - 2, Venezuela - 1)
Asia	20 (India - 17, Indonesia - 1, Russia/Sakhalin - 1, Thailand - 1)
Africa	17 (Tunisia - 14, Egypt - 2, Chad - 1)
U.K. onshore	1
Total	334

Summary of Database – Who Does It and What Do They Do?

- Mostly done by major oil and gas companies
- Several international service companies work with operators
- Type of injection
  - 296 jobs are annular injection
    - *Typically inject into shale layers*
  - 36 are into dedicated disposal wells
    - *Typically inject into sandy layers*

Summary of Database – Depth of Injection

Depth Range (ft)	*Number of Records in Database*
< 2,500	14
2,501 - 5,000	36
5,001 - 7,500	8
7,501 - 10,000	2
>10,000	3

Summary of Database – Rate and Duration

- Injection rate
  - Typically < 5 bbl/minute
  - Range: 0.3 – 44 bbl/minute
- Duration of injection
  - Some jobs (often annular) lasted for a few days
  - Handled wastes from one or a few wells
  - Other dedicated disposal wells have been in service for months or years

Summary of Database – Injection Pressure and Materials Injected

- Injection pressure
  - Typically 1,200 – 2,500 psi
  - Range: 50 – 5,431 psi
- Type of material injected
  - Drill cuttings
  - Drilling muds
  - Produced sands
  - Tank bottoms
  - Scale and sludge with NORM
  - Others

Summary of Database – Volume of Slurry Injected

Total Reported Slurry Volume (bbl)	Number of Jobs
<10,000	87
10,000 - 50,000	206
50,001 - 100,000	9
100,001 - 500,000	13
500,001 - 1,000,000	5
>1,000,000	12
Total	332

Problems with Slurry Injection

- Operational
  - Slurries had wrong viscosity
  - Injection rate was too slow
  - Well bore needed to be flushed with clean water
  - Power failures
- Environmental
  - Fracture moved to improperly cemented well and slurry returned to surface or to sea floor

Economics

- **Depends on**:
  - Volume of material to be disposed
  - Regulatory requirements
  - Availability of low-cost onshore disposal infrastructure
- **Database includes 12 examples of comparative cost for drilling waste management at offshore platforms**
  - Use oil-based muds and inject
  - Use synthetic-based muds and discharge
  - Haul waste back to shore
- **Each option was the most cost-effective in at least one location**
  - Points out the need for site-specific evaluation

Conclusions

- Slurry injection has been used successfully in many locations around the world
- Although some injection jobs have not worked well, the reasons for these problems are understood and can be overcome by proper siting, design, and operation
- The costs for slurry injection can be competitive or more attractive than costs for other disposal methods

Conclusions - continued

- When slurry injection is conducted at locations with suitable geological conditions and the injection process is properly monitored, slurry injection can be a very safe disposal method
  - Because wastes are injected deep into the earth below drinking water zones, properly managed slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods

Availability of Reports

- Regulatory compendium, technical report (including full database), and brochure can be downloaded from Argonne website at:

http://www.ead.anl.gov/project/dsp_topicdetail.cfm?topicid=18

Final Thoughts on Waste Management

- There are many technologies or approaches for managing E&P waste and produced water
- Not every approach is the best in all cases
- Site-specific evaluation of options is the best approach

How Do Companies Choose a Water or Waste Management Option?

- Look at available options that comply with regulations
- Consider costs:
  - capital
  - O&M
  - transportation
  - potential future liability costs
- Is the option technically practicable?
  - Availability of disposal infrastructure
  - climate

DWMIS Home Page

Drilling Waste Management Information System

The information resource for better management of drilling wastes

Search :: GO

The Drilling Waste Management Information System is an online resource for technical and regulatory information on practices for managing drilling muds and cuttings, including current practices, state and federal regulations, guidelines for optimal management practices, and case studies for successful applications.

Visitors can use these resources to:

- learn about industry standard practices;
- determine which regulatory requirements must be met;
- select optimal management strategies for their location and circumstances;
- learn about successful applications of drilling waste management practices.

:: Technology Descriptions ::

Basic information about practices that are currently employed to manage drilling wastes.

:: Federal and State Regulations ::

Existing state and federal regulations that form the regulatory context for drilling waste management practices.

:: Technology Identification ::

An interactive tool to determine optimal management practices for a given geographical or environmental setting.

:: Case Studies ::

Summaries of successful applications of waste management practices.

The Drilling Waste Management Information System was developed by Argonne National Laboratory and industry partners, ChevronTexaco and Marathon, under the U.S. Department of Energy's (DOE's) Natural Gas & Oil Technology Partnership program. Funding for the project was provided through DOE's National Energy Technology Laboratory.

Contact Us :: Privacy/Security

http://web.ead.anl.gov/dwm

Opening Screen of the Technology Identification Module

Drilling Waste Management Information System

The information resource for better management of drilling wastes

Search :: GO

- Technology Descriptions
- Federal & State Regulations
- Technology Identification
- Case Studies
- Internet Resources
- References
- Acronyms/Glossary

Drilling Waste Management Technology Identification Module

The **Technology Identification Module** is an interactive tool for identifying appropriate drilling waste management strategies for a given well location and circumstances.

The Technology Identification Module follows the philosophy of a waste management hierarchy. Waste management options with the lowest environmental impacts are encouraged ahead of those with more significant environmental impacts. The Technology Identification Module helps identify waste management options, but users should also consider their own site-specific costs and waste volumes.

How it Works

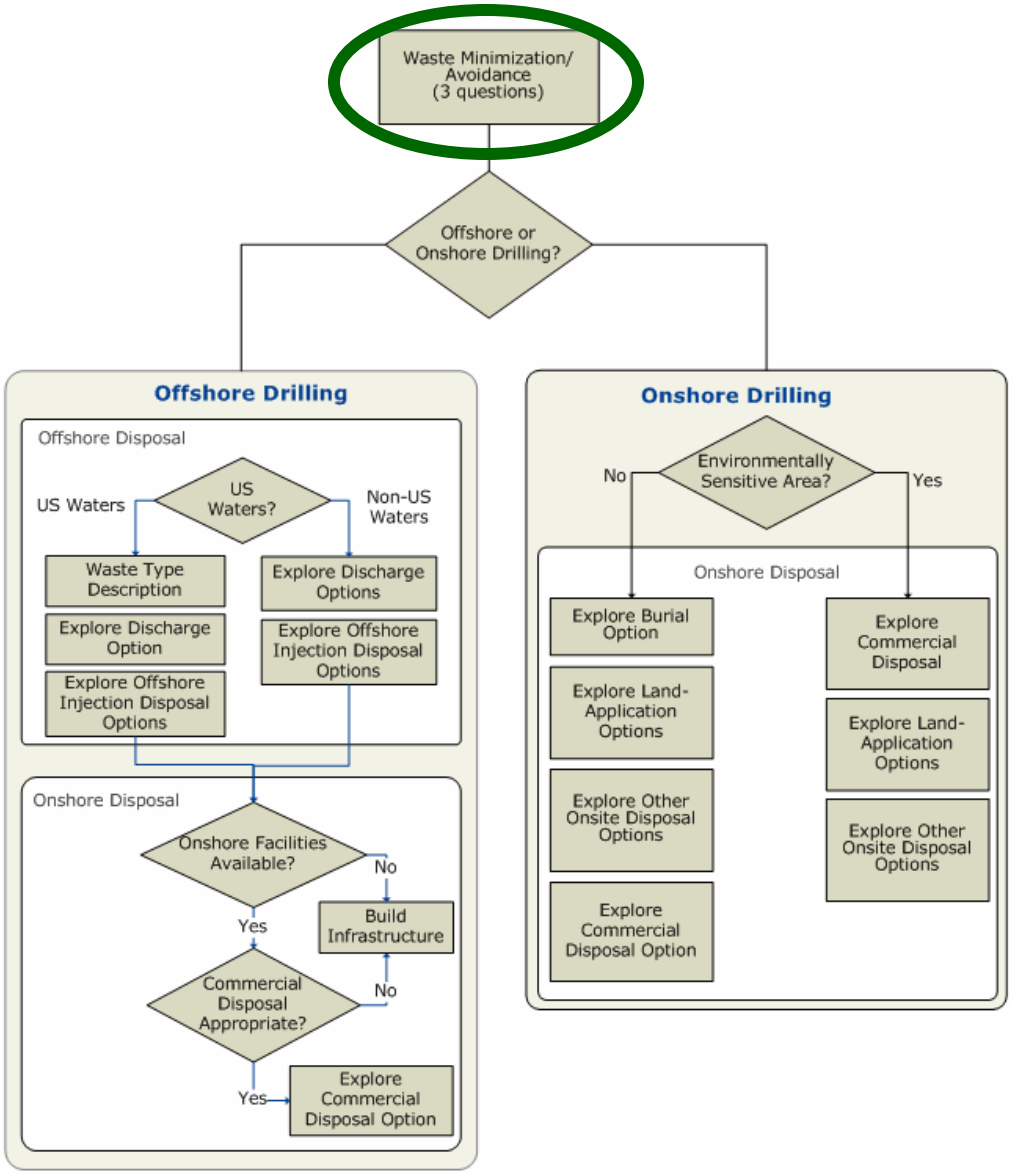
Users will be asked to answer a series of questions about the location of the well site, physical features of the site that may allow or inhibit the use of various options, whether the regulatory agency with jurisdiction allows or prohibits particular options, and whether cost or the user's company policy would preclude any options. Nearly all questions are set up for only "yes" or "no" responses. Depending on how the initial questions are answered, users will face from 15 to 35 total questions. Some of these can be answered immediately, while others may require some additional investigation of other portions of this web site or external information. Suitable options will be identified as users complete the questions, and users will be able to print out a summary of suitable options when the process is completed.

Click here to begin

First-time users are encouraged to run quickly through the list of questions and provide sample answers to see the types of information that are needed to complete the questions. Then they can return to answer questions more carefully and to explore multiple options.

Overview of Flow Diagram

Drilling Waste Management - Technology Identification Module - Process



Questions on Waste Minimization and Reuse

Drilling Practices

Consider drilling practices that reduce waste volume, lower environmental impacts and recycle wastes.

Show Full Diagram

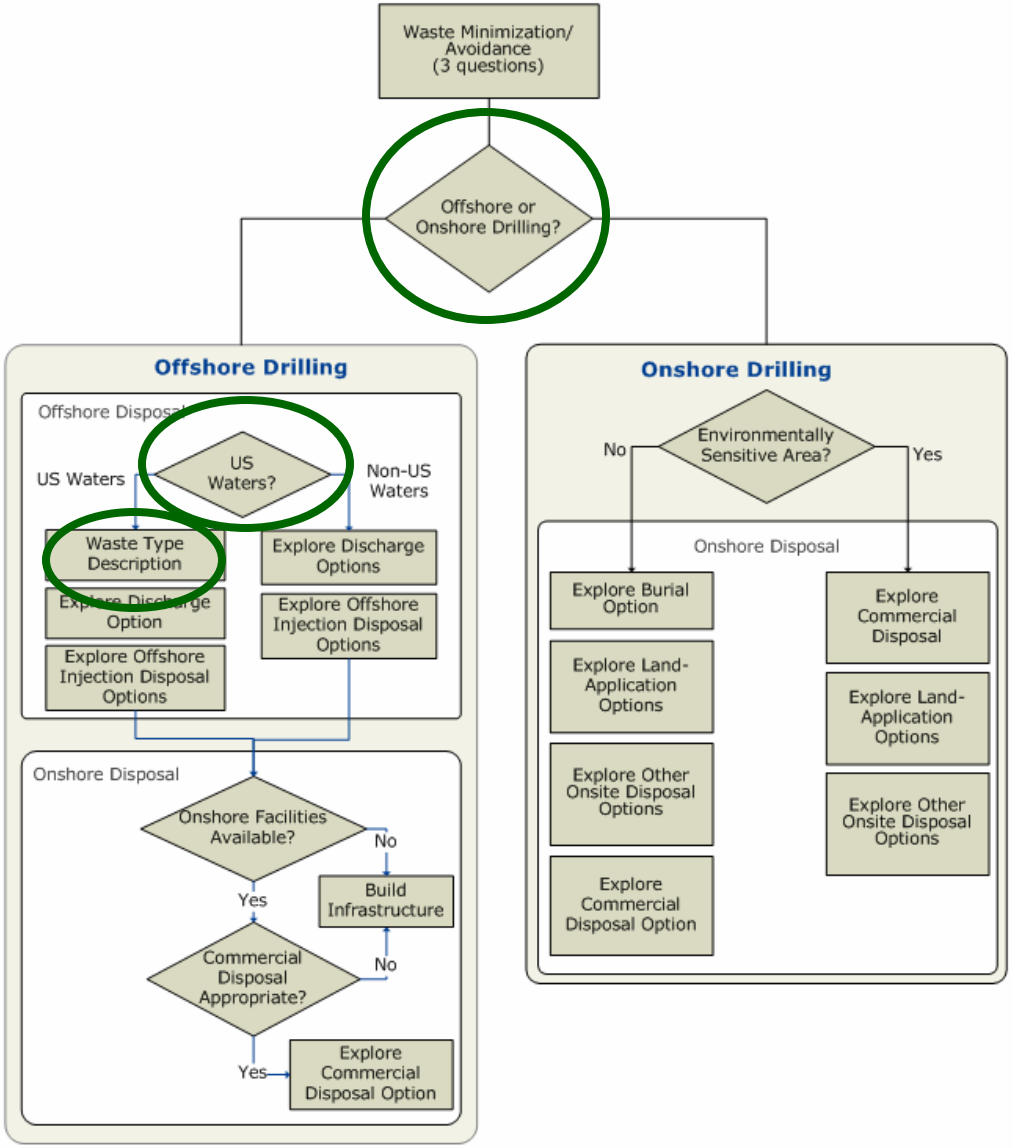
	Yes	No
Considering costs and feasibility and regulatory acceptability, are you able to drill using a technology that reduces the volume of waste generated? (Examples include coiled tubing drilling, multiple laterals off of a main well bore, and air drilling, or other technologies).	○	○

Although this website is devoted to drilling waste management, technologies or management practices that reduce other environmental impacts, such as lower air emissions, or that minimize the total environmental impact over all media should also be considered.

	Yes	No
Considering costs and feasibility and regulatory acceptability, are you able to drill using a drilling fluid and additive package that has lower environmental impacts than conventional fluids?	○	○
Considering costs and feasibility and regulatory acceptability, are there opportunities to recycle or reuse your drilling wastes? (Examples: recycle or reclaim muds, reuse cleaned cuttings as fill materials, soil supplement, aggregate, etc.)	○	○

<< Start Over | < Back | Next > | Finish | Close

Overview of Flow Diagram



Drilling Description

Describe drilling location and drilling wastes to manage.

Where are you drilling?

- ○ Onshore
- ◉ Offshore US waters
- ○ Offshore non-US waters

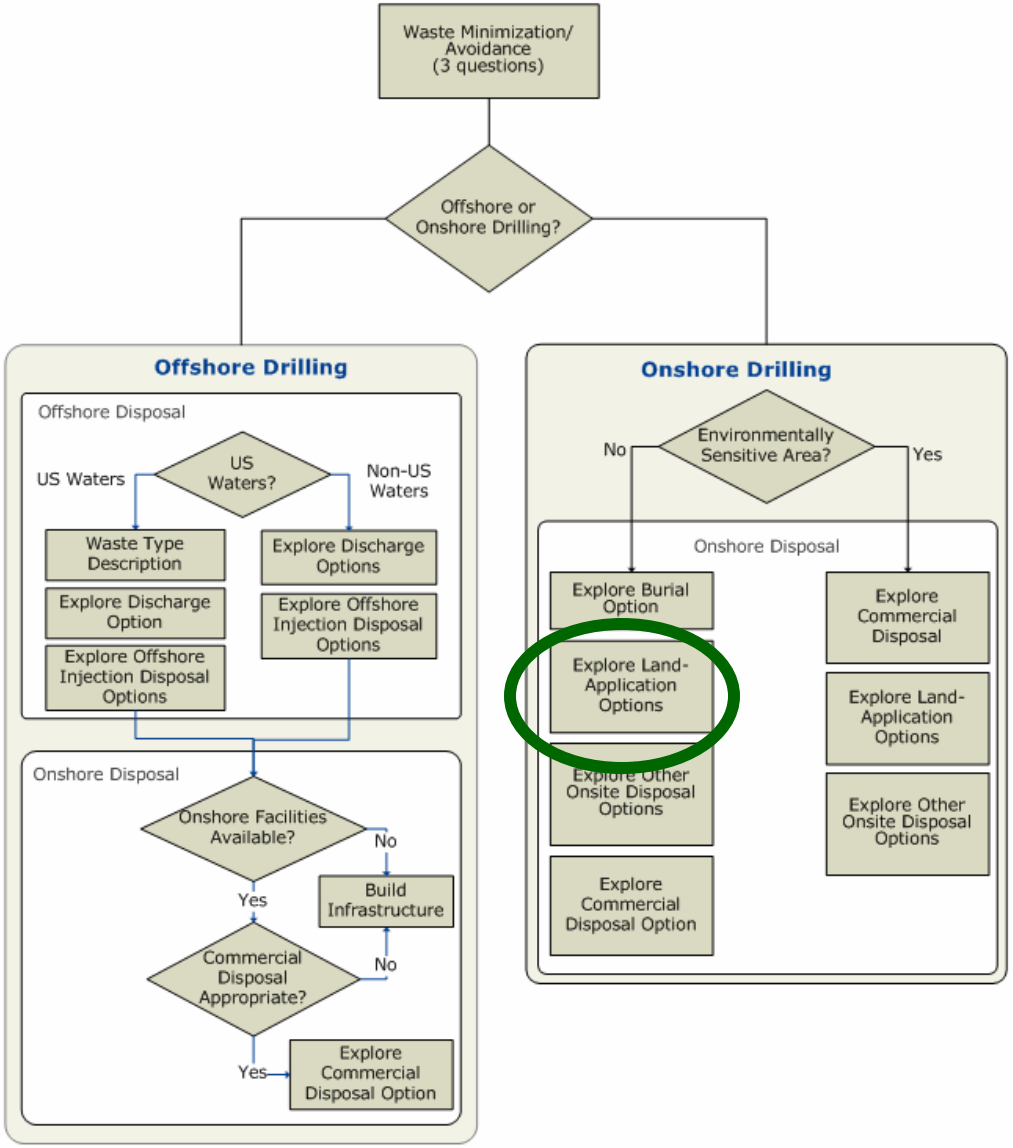
What types of drilling wastes do you manage?

- ○ Water-based muds and cuttings
- ○ Oil-based muds and cuttings
- ○ Synthetic-based muds and cuttings

Show Full Diagram

<< Start Over | < Back | Next > | Finish | Close

Overview of Flow Diagram



Sample Screen from an Interactive Online Questionnaire

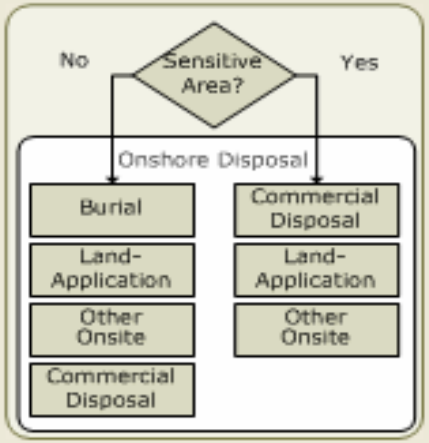
Onshore Land Applications

Consider land applications for reuse of waste.

Landspreading: Some types of drilling fluids will biodegrade better than others and can be preferentially selected if land application is planned as the waste management option. To the extent that land spreading improves the properties of previously poor soils, this activity can be considered a beneficial resuse of the drilling waste.

	Yes	No
Does your regulatory agency allow landspreading of your type of drilling wastes?	○	○
Do you have land available to you (i.e., landowner approval) at or near the drilling site that has sufficient surface area, a low or modest slope, is outside of a floodplain, and allows for buffer zones around buildings, roads and streams?	○	○
Does your company have any policies against land spreading drilling waste onsite, or would the risk and liability associated with landspreading there be unacceptable for your company?	○	○
Can you cost-effectively meet the requirements imposed by your regulatory agency?	○	○

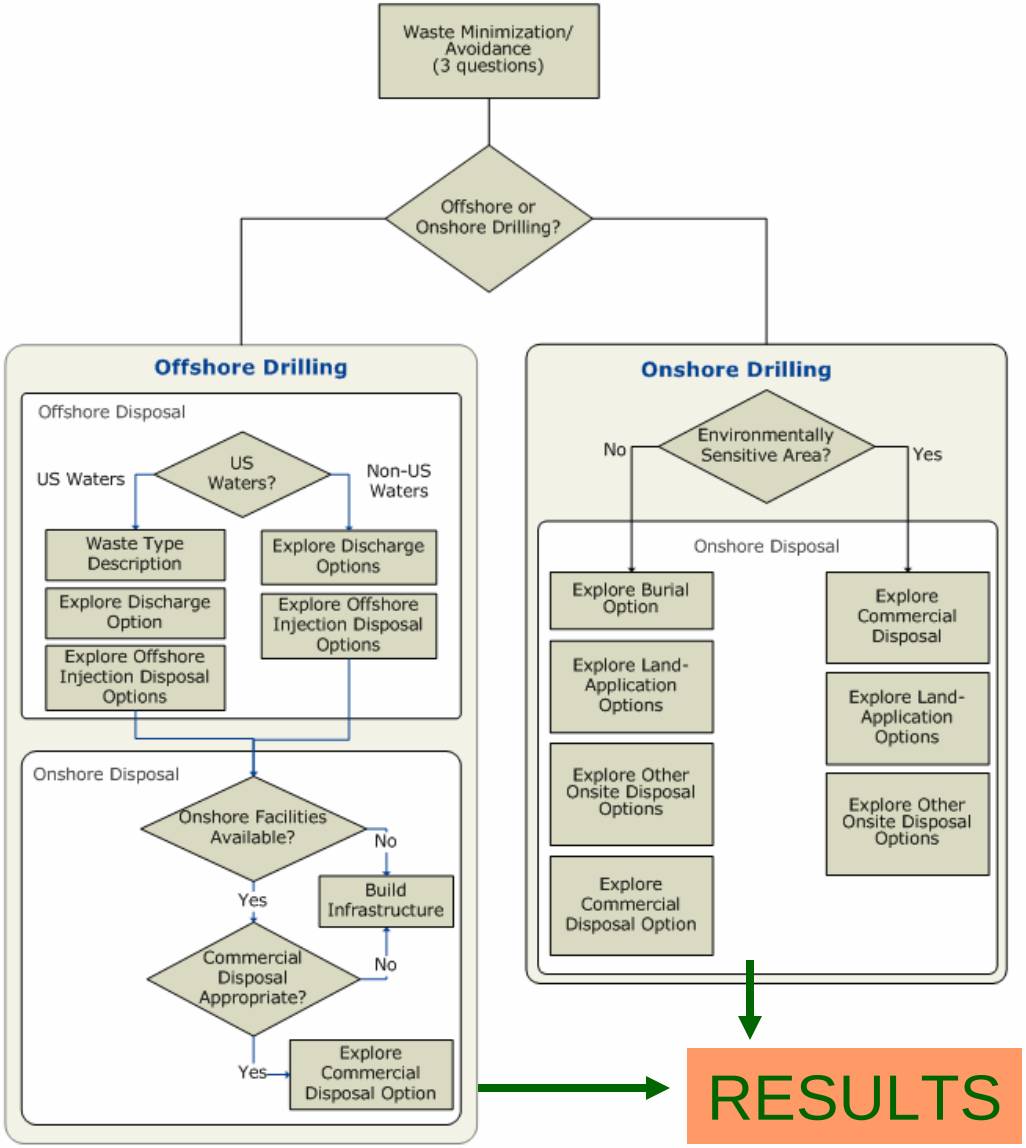
Onshore Drilling



Show Full Diagram

<< Start Over | Cancel | < Back | Next > | Finish

Overview of Flow Diagram



Results Screen – Based on Answers to Questions

Technology Identification Module Results

Summary of Drilling Waste Management Options

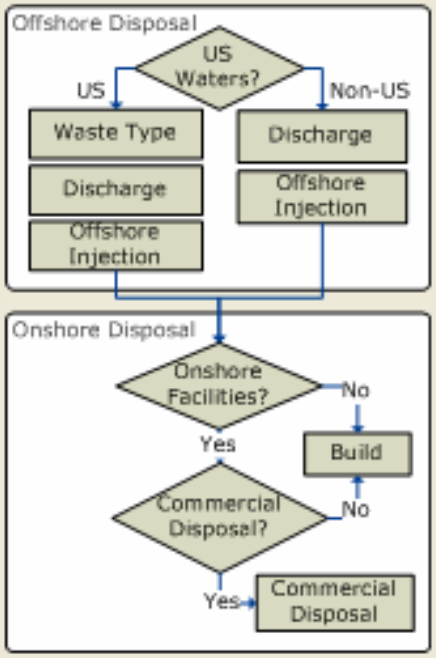
Drilling Location	Offshore U.S. waters greater than 3 miles.
Waste Type	Water-based muds and cuttings

Waste Treatment and Disposal Options

- Discharge to the ocean. Discharge of water-based muds and cuttings may be allowed.
- Inject waste through slurry injection at the present platform.
- Dispose of waste at the offsite commercial disposal company that best meets your company's needs (cost, risk, convenience, etc.)

Print this Page | Show Summary with Questions

Offshore Drilling



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Other Issues or Questions?