Overview

• Intro to PVT: Why? When? What?
  – Reservoir Engineering 101
• Sample Sources
  – Brief overview of Surface vs Subsurface
  – pros/cons for each
  – Detailed look at FT tool sampling
• Blueprint for Fluids Program
  – Phase Behavior basics
  – Production Trends
  – PVT, Flow Assurance
  – Experimental theories, Mathematics
• Value of Fluids Testing
The Big Picture: Optimize Recovery?

- Predict reservoir drive mechanism
  - Depletion, expansion, aquifer support
- Determine reservoir geophysical properties
- Determine rock properties
  - Porosity, perm/relative perms, wetting characteristics, capillary pressures
- Determine fluid properties
  - Viscosity, compressibility, gas solubility, density, shrinkage, flow assurance, chemistry, retrograde behavior
Why Collect Reservoir Fluid Samples?

Formation fluid samples are needed for a variety of reasons. Fluid samples are evaluated in the lab to establish their physical and chemical properties, such as hydrocarbon type and the pressure, volume, temperature (PVT) behavior of the reserves in place. These properties help form the foundation for planning efficient field development. The investment in facilities and processing depends on the amount, types and flow characteristics of fluids in the reservoir.

How large are the reservoirs and what will be the recovery?
What kind of crude will be produced?
Does the crude contain ‘unwanted’ compounds that can inhibit production?
Who gets what, i.e. allocation?

Bottomline: phase behavior, crude quality/price, flow assurances
When?

• Exploration and Appraisal
  – design facilities
  – tune models
  – appraisal well counts
• Development
  – confirmation studies
  – developmental well counts
  – allocation
• Production and Abandonment
  – infill programs
  – facility upgrades
  – EOR
  – allocation
What?

- Phase behavior
- Saturation pressure
- Gas solubility
- Volume of oil at surface per equivalent barrel in reservoir
- Fluid Density
- Fluid viscosity
- Surface recoveries/ratios
- Fluid compressibility
- Compositional analyses
- Atmospheric liquid analyses
- Crude ‘quality’
- Flow Assurance properties
First Things First: Let’s get some samples!

- **Surface Separator:**
  - Large volumes of reservoir fluid are produced
  - Flow rate stability can be monitored, no sense of ‘urgency’
  - Multiple sample sets can be collected
  - Drawdown is the enemy, GOR key
    - Unconventional concerns

- **Surface Wellhead**
  - Likely multi-phase

- **Subsurface (Standard Downhole Samples):**
  - Ideal when GOR not available or not accurate
  - Recommended for solids analyses
Surface Separator Sampling

Sampling Methods

Gas Sampling Points
1. Gas Overhead
2. Meter Run
3. Upstream of BPR
4. Separator Body

Liquid Sampling Points
5. Upstream of Dump Valve
6. Bottom of Sight Gauge
7. Downstream of Dump Valve
Separator Sampling
Separator = Mini Reservoir

Sampling Methods

Phase Behaviour Relationship Between Sep. Gas and Oil
Sample Altering?

Sampling Methods

Temperature Drop – Liquid Dropout

2 Phase Region
Liquid Dropout

$P_{\text{sep}}$

$T_{\text{sep}}$

$T \rightarrow$

$P$

separator gas

separator oil
Sample Altering

Sampling Methods

Pressure Drop – Gas Breakout

$P$  

$P_{\text{sep}}$  

$T_{\text{sep}}$  

$T$  

sep rate gas  

separator oil  

2 Phase Region  

Gas Breakout
Evaluation of Samples

- **Separator Liquid**
  - bubble point determination at separator temp
  - Methane content vs pressure
  - Flash test, ie GOR, composition
  - K-P “Hoffman” plot

- **Separator Gas**
  - Opening pressure
  - Oxygen/nitrogen content

- **GOR?**
  - Extrapolate to time=0 or initial yield?

- **Wellhead**
  - Single phase?

- **Subsurface**: transfer, flash test, bubble point
Wireline Formation Test Tools

‘Big’ Chambers vs ‘Small’ Chambers

• ‘Big’ Chambers
  – 1 gallon, 2 ¾ gallon
  – Non-DOT
  – Onsite evaluations
  – Onsite transfers
  – Minimal restoration
  – Time is money$$$

• ‘Small’ Chambers
  – 400-1000 cc
  – DOT approved, mobile
  – onsite/lab evaluations
  – Unlimited restoration
  – Analysis preference
Answer 3 Questions:

• What is the fluid behavior in the range of expected operating pressures and temperatures

• What is the market price of the discovered hydrocarbons and how can they be accommodated in export systems, ie, sample quality

• Does the fluid have the potential for hydrate, wax or asphaltene precipitation, ie, flow assurance
Reservoir Fluid Behavior

P-T Phase Diagram

Reservoir Conditions

critical

path to surface

path in reservoir
Black Oil Reservoirs

- **Behavior**
  - Heavy oil = lean gas
  - Viscosity discrepancy
  - Simple black oil models

- **Production Trends**
  - Consistent above bubble point
  - Preferential gas flow, GORs increase
  - Pressure trends

- **Lab/operational issues**
  - Emulsions, temp control, GC errors, hi viscosity errors
  - Well conditioning, slugging, metering
  - hi viscosity, hi impurities, par/asph, gas lift
  - Sampling inconsistent
Gas-Condensate Behavior

- Very light system
- Life is great… above the dew point
- Depletion below dew point:
  - Condensation begins
  - Liquid production drops, yields drop
  - Near wellbore condensate “banking”
  - Perm barriers
  - Inconsistent flow = inconsistent sampling

Fig. 1—Phase diagram of gas-condensate system: \( g = \) gas and \( c = \) condensate.
So...what the hell is happening?

- Flowing bottomhole pressure drops below dew point in near-wellbore area
  - Condensation begins
- Drawdown extends radially through reservoir
  - Condensate banking leaches out into reservoir
  - High condensate saturation reduces perm of gas
  - High perm vs low perm reservoirs?
Condensate ‘Banking’

- Condensate
- Gas
- Dew Point
- Distance from wellbore

Graph showing the relationship between pressure and distance from wellbore, with condensate and gas phases indicated.
“During early production, a ring of condensate rapidly formed around the wellbore when near-wellbore pressures decreased below dew point. The saturation of this condensate ring was considerably higher than measured from PVT studies due to relative permeability effects. This high condensate saturation reduced the effective permeability to gas, thereby reducing gas productivity.”

“After pressure throughout the reservoir decreased below the dew point, condensate formed throughout the reservoir, thus the gas flowing into the ring became leaner causing the condensate ring to decrease. This increased the effective permeability of the gas. This caused the gas productivity to increase as was observed in the field.”

SPE 59773 ‘Investigation of Well Productivity in G-C Reservoirs’
Gas Relative Perm Changes?

Fig. 8 - Reservoir gas relative permeability
Gas-Condensate Production Trends

• Pressure Trends:
  – No discontinuity

• Gas Production
  – Pressure driven
  – Decrease due to condensation & condensate induced reduction in perm
  – Eventual increase due to increased gas perm

• Pressure Trends:
  – no discontinuity

• Liquid (ie condensate) Production:
  – > Psat = consistent
  – < Psat = decline
  – ∴ Yields decline
Summary: What can go wrong with my models?

- Improper well conditioning
  - sample too late in life, significant drawdown
  - Productivity testing vs. PVT testing

- Sample quality
  - ‘unsteady state’ sampling, gas carryover

- Inaccurate PVT analysis
  - Lean gases, small retrograde liquid volumes

- Gas reservoir testing procedures
  - Drawdown is the enemy
  - Tapered strings? Non-Darcy flow?
  - Unrepresentative gas production

- Light oil, heavy gas
- Full range of components
  - Solution gas and oil comps similar
- Heavy gas
  - Large condensate contribution
  - Physical properties similar
  - Large evolution of gas/liquid upon pressure drop
- Light oil
  - Low density, low viscosity, high mobility
- Handled by compositional model, accounting for both phases, compositional gradients
Near Critical Production

- Composition: heavies, lights and mid-range
- Light liquid – heavy gas
- Large initial shrinkage and gas liberation
- Gas/liquid comps similar
  - Gas volumes increase SLIGHTLY
  - ‘oil’ volumes decrease SLIGHTLY
- Volatile Oils:
  - gas/oil viscosity increases, less preferential flow
  - Separator liquid = 1 part oil + 3 parts condensate
PVT Experiments:
Simulation of Reservoir Depletion

- **Black Oils:**
  - Differential liberation, viscosity, separator flash tests
  - Black oil behavior
  - models

- **Gas-Condensates:**
  - Constant volume depletion
  - Gas-condensate behavior

- **Near-Critical, Volatile Oils**
  - CVD study, viscosity
  - Oil properties, gas-phase properties
  - Volatile oil behavior, models
### Oil Properties

<table>
<thead>
<tr>
<th>Pressure (psia)</th>
<th>Oil Density (g/cm³)</th>
<th>Oil Compress. (V/V/psi) x 10⁶</th>
<th>Oil Viscosity (cP)</th>
<th>Liberated GOR, Rl (scf/bbl)</th>
<th>Solution GOR, Rs (scf/bbl)</th>
<th>Oil FVF, Bo (vol/resid. vol)</th>
<th>Solution GOR, Rs (vol/ST vol)</th>
<th>Sep. Adj. FVF, Bo (vol/ST vol)</th>
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<td>168</td>
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<td>15 at 60 °F</td>
<td>0.899</td>
<td>API = 25.7</td>
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</table>

### Vapor Properties

<table>
<thead>
<tr>
<th>Pressure (psia)</th>
<th>Gas Density (g/cm³)</th>
<th>Gas Z Factor (vol/vol at std)</th>
<th>Incr. Gas Gravity (Air = 1.00)</th>
<th>Cum. Gas Gravity (Air = 1.00)</th>
<th>Gas FVF, Bg (res bbl/mmscf)</th>
<th>Gas FVF, Bg (res cu ft/scf)</th>
<th>Total FVF, Bt (vol/resid. vol)</th>
<th>Calc. Gas Viscosity (cP)</th>
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<tr>
<td>3250</td>
<td>0.179</td>
<td>0.901</td>
<td>0.708</td>
<td>0.708</td>
<td>882</td>
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<tr>
<td>1500</td>
<td>0.077</td>
<td>0.906</td>
<td>0.664</td>
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<td>1921</td>
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<td>750</td>
<td>0.038</td>
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<td>0.681</td>
<td>0.684</td>
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<td>0.0222</td>
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<td>150</td>
<td>0.009</td>
<td>0.985</td>
<td>0.786</td>
<td>0.717</td>
<td>20882</td>
<td>0.1172</td>
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<td>15,025</td>
<td>0.002</td>
<td>1.000</td>
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<td>212088</td>
<td>1.1908</td>
<td>154.308</td>
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**Notes:**
- Compressibility is calculated using the indicated and previous pressures.
- Bg = Oil Volume at P,T / Stock Tank Volume
- Bod = Oil Volume at P,T / Residual Oil Volume at 60 °F
- Sep. Adjusted Data using Muhammad A. Al-Marhoun method
- Gas MW = Vapor Gravity x Molecular Weight Air
- Standard Condition: 15,025 psia at 60 °F
- Lab conditions: 60 °F and 1.000 API
- Oil Viscosity measured using electro magnetic viscometer.
- Gas FVF, Bg = Total Liberated Vapor, Rl x Bg x 10^-6
- Gas Viscosity calculated with Lee-Gonzales Correlation
- Sep. Adjusted: Separated Adjusted
So..how good is that oil study?

<table>
<thead>
<tr>
<th>Procedure</th>
<th>GOR (SCF/STB)</th>
<th>FVF ($P_{\text{sat}}$ bbl/STB)</th>
<th>Gas Gravity</th>
<th>API at 60 °F</th>
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<tr>
<td>Reservoir Oil</td>
<td>816</td>
<td>1.339</td>
<td>0.672</td>
<td>21.9</td>
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<td>Single-Stage Flash</td>
<td></td>
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<td>Differential Liberation @ Res. Temp</td>
<td>795</td>
<td>1.329</td>
<td>0.652</td>
<td>22.1</td>
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<td>Multi-Stage</td>
<td>771</td>
<td>1.311</td>
<td>0.623</td>
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<tr>
<td>Separator Test</td>
<td></td>
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</table>
What is the longest continuously running science experiment in the world?

Pitch Drop Experiment, started 1927 by Dr Thomas Parnell

Viscosity = 100-300 billion centipoise
Simulation of Reservoir Depletion

- **Black Oils:**
  - Differential liberation, viscosity
  - Black oil behavior
  - models

- **Gas-Condensates:**
  - Constant volume depletion
  - Gas-condensate behavior

- **Near-Critical, Volatile Oils**
  - CVD study, viscosity
  - Oil properties, gas-phase properties
  - Volatile oil behavior, models
### How Good is that Gas study?

**Constant Volume Depletion Fluid Compositions**

<table>
<thead>
<tr>
<th>Component</th>
<th>Saturation Pressure (mole %)</th>
<th>6000 psia (mole %)</th>
<th>5000 psia (mole %)</th>
<th>4000 psia (mole %)</th>
<th>3000 psia (mole %)</th>
<th>2000 psia (mole %)</th>
<th>Liquid at 2000 psia (mole %)</th>
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<tr>
<td>Nitrogen</td>
<td>0.197</td>
<td>0.236</td>
<td>0.228</td>
<td>0.209</td>
<td>0.184</td>
<td>0.166</td>
<td>0.350</td>
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<tr>
<td>Carbon Dioxide</td>
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<td>0.225</td>
<td>0.233</td>
<td>0.229</td>
<td>0.220</td>
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<td>Hydrogen Sulfide</td>
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<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
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<td>Methane</td>
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<td>93.057</td>
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<td>1.529</td>
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<td>Iso-Butane</td>
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<td>0.377</td>
<td>0.366</td>
<td>0.353</td>
<td>0.345</td>
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<td>N-Butane</td>
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<td>N-Pentane</td>
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<td>0.222</td>
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<td>Hexanes</td>
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<td>Heptanes</td>
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<td>Octanes</td>
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<td>100.00</td>
<td>100.00</td>
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<td>100.00</td>
<td>100.00</td>
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<td>C10+ MW</td>
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<td>178.2</td>
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<td>161.0</td>
<td>155.6</td>
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<td>Gravity (Air = 1.0)</td>
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<td>Z Factor (@ P &amp; T)</td>
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<td>0.936</td>
<td>0.926</td>
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## Calculated Surface Gas and Liquid Recovery

### Experimental and Equation of State Predictions

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<thead>
<tr>
<th>Fraction Vapor Liberated / Step</th>
<th>Initial</th>
<th>7232</th>
<th>6000</th>
<th>5000</th>
<th>4000</th>
<th>3000</th>
<th>2000</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0.066</td>
<td>0.070</td>
<td>0.090</td>
<td>0.107</td>
<td>0.107</td>
<td>0.130</td>
<td></td>
</tr>
</tbody>
</table>

| EOS Predicted Liquid Fractions | 1st Stage: 1015 psia, 96°F | (mole fraction) | 0.061 | 0.056 | 0.048 | 0.036 | 0.024 | 0.024 | 0.015 |
|                               | 2nd Stage: 515 psia, 72°F  | (mole fraction) | 0.861 | 0.858 | 0.856 | 0.854 | 0.854 | 0.852 | 0.851 |
|                               | 3rd Stage: 105 psia, 104°F | (mole fraction) | 0.829 | 0.826 | 0.825 | 0.823 | 0.823 | 0.823 | 0.822 |
| Stock Tank, 15 psia, 60°F     | (mole fraction)            | 0.950 | 0.949 | 0.948 | 0.947 | 0.947 | 0.946 |      |

<table>
<thead>
<tr>
<th>Predicted Liquid Molar Volume</th>
<th>Initial</th>
<th>7232</th>
<th>6000</th>
<th>5000</th>
<th>4000</th>
<th>3000</th>
<th>2000</th>
</tr>
</thead>
<tbody>
<tr>
<td>184.0</td>
<td>175.9</td>
<td>167.2</td>
<td>158.4</td>
<td>150.9</td>
<td>145.3</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Calculated Surface Recovery

<table>
<thead>
<tr>
<th>Initial Reservoir Fluid in Place</th>
<th>Initial</th>
<th>1000</th>
<th>1000</th>
</tr>
</thead>
<tbody>
<tr>
<td>Vapor Produced / Step</td>
<td>mscf</td>
<td>0.0</td>
<td>86.1</td>
</tr>
<tr>
<td>Cumulative Vapor Produced</td>
<td>mscf</td>
<td>0.0</td>
<td>86.1</td>
</tr>
<tr>
<td>Predicted Surface Liquids</td>
<td>stb</td>
<td>0.0</td>
<td>4.3</td>
</tr>
<tr>
<td>Cumulative Surface Liquids</td>
<td>stb</td>
<td>0.0</td>
<td>4.3</td>
</tr>
<tr>
<td>Predicted Surface Vapor</td>
<td>mscf</td>
<td>0.0</td>
<td>82.8</td>
</tr>
<tr>
<td>Cumulative Surface Gas</td>
<td>mscf</td>
<td>0.0</td>
<td>82.8</td>
</tr>
<tr>
<td>Instantaneous Yield</td>
<td>stb/mmscf</td>
<td>59.3</td>
<td>51.9</td>
</tr>
<tr>
<td>Average Yield</td>
<td>stb/mmscf</td>
<td>59.3</td>
<td>51.9</td>
</tr>
<tr>
<td>Instantaneous GCR</td>
<td>scf/stb</td>
<td>16859</td>
<td>19282</td>
</tr>
<tr>
<td>Average GCR</td>
<td>scf/stb</td>
<td>16859</td>
<td>19282</td>
</tr>
<tr>
<td>Gas Recovery Factor</td>
<td>%</td>
<td>0.0</td>
<td>8.3</td>
</tr>
<tr>
<td>Liquid Recovery Factor</td>
<td>%</td>
<td>0.0</td>
<td>9.6</td>
</tr>
</tbody>
</table>

### Notes:

- Yield (BPMN)
- Pressure (psia)

### Calculated Surface Yields

- Instantaneous Yield
- Average Yield

---
Simulation of Reservoir Depletion

- **Black Oils:**
  - Differential liberation, viscosity
  - Black oil behavior
  - models

- **Gas-Condensates:**
  - Constant volume depletion
  - Gas-condensate behavior

- **Near-Critical, Volatile Oils**
  - CVD study, viscosity
  - Oil properties, gas-phase properties
  - Volatile oil behavior, models
Enhanced oil recovery studies are used to define volumetric and compositional changes in a reservoir fluid during secondary and tertiary recovery processes. The data is most often used to define the operating parameters and track fluid changes during an enhanced oil recovery project.

- Miscible Displacement Studies
- Multi-Contact Studies
- Solubility / Swelling Studies
- Gas Injection Revaporization
• Models, EOS, Simulators
  – reservoir dynamics, phase behavior
• Measured data used as input to ‘tune’ models
  – chemical properties altered to ‘force’ predictions to match behavior
• Multiple scenario, feasibility studies
  – tuned models used to explore other possible environments
Answer 3 Questions:

• What is the fluid behavior in the range of expected operating pressures and temperatures
• What is the market price of the discovered hydrocarbons and how can they be accommodated in export systems, i.e., sample quality
• Does the fluid have the potential for hydrate, wax or asphaltene precipitation
Reservoir Fluid Composition

- Flash of reservoir fluid to 0 psig
- GC analysis of flash/separator products
  - C10+, C20+, C30+, C50+ analyses
  - Internal standard method, distillation method
- Mathematical recombination of flash/separator products to measured GOR from flash (or meter)
Dead Oil (Stock Tank) Analyses
‘Pipeline Package’

- Paraffin, Asphaltene, Sulfur Weight %
- Pour Point, Cloud Point
- SARA analysis
- Viscosity (multi-temp)
- Acid Number, Vapor Pressure, BSW
- Fingerprint Analysis, Geochemical Analysis
- Solids Screening
Paraffins/Waxes

- Long straight hydrocarbon chain molecule (Normal Paraffin)
- With decrease in temperature Wax molecules begin to crystallize (Freeze)
- The onset of Wax Crystals is referred to as Cloud Point
- Reversible behavior
- **Problem Avoidance:** Sample handling at temperatures > 130°F, production heaters
Asphaltenes

- Defined as pentane or heptane insoluble
- Heaviest and largest molecules in the hydrocarbon mixture (ex: C_{79}H_{92}N_{2}S_{2}O, MWT > 750)
- Characteristic black color
- Become unstable with significant changes in density, usually due to changes in pressure, temperature
- Can be stabilized by similar typed ‘resins’
- Problems can also occur due to commingling

**Problem Avoidance:** Pressure maintenance in reservoir, chemical treatments. Pressure/density maintenance during sample handling. Avoid volume changes.
Pressurized Fluid Imaging (PFI) System
Blueprint for Fluids Program

- Proper sampling
- Chemistry
- Physical properties
  - fluid flow assurance, viscosity etc, dead oil analyses
- Reservoir depletion simulation
  - CME, Diff Lib, CVD
- Surface recovery simulation
  - separator tests
- Mathematics
Thanks for not falling asleep!
Questions?