The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future*

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Abstract

April 2011 marks the 100th anniversary of the well that discovered the Belridge giant oil field in the San Joaquin Valley of California. During the 100 years the field has produced 1.6 billion of the approximately 6 billion barrels of the estimated original oil in place. The field covers an area roughly 22 miles long and 2.5 miles wide (35 by 4 km). It has three totally separate and distinctly different producing zones: Pleistocene shallow fluviodeltaic sands producing heavy oil via steamflood; Miocene deepwater diatomite layers producing light oil via hydraulic fractures and with water injection for pressure maintenance; and Oligocene to lower Miocene marine sandstones producing gas and light oil via gas expansion. Each of the vertically stacked zones requires different work models and different completion strategies to sustain production.

Although down from its peak of 160,000 BOE per day in 1986, the field currently produces 80,500 BOE per day which makes it one of the largest onshore fields in the USA. Since discovery via a surface oil seep, over 15,000 wells have been drilled although only 6,000 producers and 2,400 injectors are still active. However, new insights to the reservoirs have resulted in about 600 new wells being drilled and completed in each of the past few years.

In the 1930s the field had the deepest well drilled in North America. In the 1990s the field had the closest well spacing of any field in the world: vertical and horizontal wells drilled as close as 37.5 ft (11.5 m) apart and completed with sand-propped hydraulic fracs. Continuing to successfully develop and produce the reservoirs requires applying conventional technologies and techniques in new and unconventional ways. Fit-for-purpose reservoir characterization studies in 2D and 3D, coupled with standardized workflows for modeling and documentation, build upon past fundamental knowledge using state-of-the-art software and databases to handle the immense quantity of data.
At the start of the 21st century the field is gearing up for many more years of activity with expansion of steam drives in the oil sands and in the diatomite shales, installation of a large microseismic array, distributed temperature sensing to monitor water movement in water injection wells, and regular InSAR surveys to monitor ground movements. Exploration wells are also being drilled for seismic targets that are well below the current producing zones.

Selected References


The Belridge Giant Oil Field
- 100 Years of History and a Look to a Bright Future

Theme V: Reservoir Characterization from Outcrops to Drilling

2011 AAPG International Conference & Exhibition, Milan, Italy

Malcolm Allan and Joseph Lalicata

October 26, 2011

File Name: AAPG-ICE_Belridge-100Years_Milan_Oct-14-11.ppt
Outline of Presentation

Location Map for Belridge Giant Oil Field

Overview of Reservoirs and Production History

Geological Setting and Petroleum Systems

Early Days

Sub-Monterey Pool (North Belridge)

Tulare Pool

Diatomite Pool
  • Diatomite is a Unique, Unconventional Rock Type
  • Type Log and Cross section
  • Data Coverage
  • Hydraulic Fractures are Key
  • 3D Reservoir Models and Reservoir Limits
  • Defining Limits of Pay

New Techniques to Improve Current Operations
  • Horizontal Wells
  • Pressure Surveys
  • InSAR
  • DTS
  • Microseismic

Looking Towards a Bright Future
Geographic Location Map of Belridge Field

- 45 miles (75 km) west of Bakersfield
- 140 miles (225 km) northwest of Los Angeles

Belridge Field is located 45 miles west of Bakersfield and 140 miles northwest of Los Angeles in Kern County, California.
California’s Top Oil Fields

<table>
<thead>
<tr>
<th>Rank</th>
<th>Field Name</th>
<th>State</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Prudhoe Bay</td>
<td>AK</td>
</tr>
<tr>
<td>2</td>
<td>Sprayberry Trend Area</td>
<td>TX</td>
</tr>
<tr>
<td>3</td>
<td>Mars-Ursa (Miss. Canyon)</td>
<td>Offshore Gulf</td>
</tr>
<tr>
<td>4</td>
<td>Thunder Horse (Miss. Canyon)</td>
<td>Offshore Gulf</td>
</tr>
<tr>
<td>5</td>
<td>Belridge South</td>
<td>CA</td>
</tr>
<tr>
<td>6</td>
<td>Kuparuk River</td>
<td>AK</td>
</tr>
<tr>
<td>7</td>
<td>Wasson</td>
<td>TX</td>
</tr>
<tr>
<td>8</td>
<td>Atlantis (Green Canyon)</td>
<td>Offshore Gulf</td>
</tr>
<tr>
<td>9</td>
<td>Midway-Sunset</td>
<td>CA</td>
</tr>
<tr>
<td>10</td>
<td>Elk Hills</td>
<td>CA</td>
</tr>
</tbody>
</table>

Belridge Field
45 miles west of Bakersfield
140 miles northwest of Los Angeles

From list of ‘Top 100 US Oil Fields by 2009 Proved Reserves’
-from EIA, Dept. of Energy

Three are in Kern County
Belridge Field
15 miles long, 2½ mile wide, 8000 acres
(Diatomite Pool = 12 miles long, 3/4 mile wide, 3350 acres)

KEY DATES FOR BELRIDGE FIELD
1911 – Tulare & Diatomite pools discovered
1930s – Discovery & development of underlying sub-Monterey pools
1942 – Development of overlying Tulare Fm heavy oil began
1977 – First successful hydraulic fracture in Diatomite
1979 – Shell purchased assets of Belridge Oil Co. ($3.6 billion)
1997 – Aera Energy LLC formed from Shell & Mobil assets

LEGEND
- LIMITS OF DIATOMITE DEVELOPMENT
- Aera Leasehold
- Operated by Aera
### Belridge Field has a Huge Surface Footprint

<table>
<thead>
<tr>
<th>Pool Name’</th>
<th>Productive Size</th>
<th>Depth</th>
<th>Active Wells (per DOGGR, May/11)</th>
<th>Cum. Prod. (Dec/09) Daily Prod. (May/11)</th>
<th>Production</th>
<th>Production method Drive mechanism</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tulare</td>
<td>10,500 acres</td>
<td>400-1,000 ft</td>
<td>1,710 prod., 501 inj.</td>
<td>1,370 MMBO, 380 BCFG 29,275 BO, 6.6 MMCFG</td>
<td>Heavy Oil (11-15º API)</td>
<td>Slotted liner &amp; gravel-pack Steamflood</td>
</tr>
<tr>
<td>Diatomite</td>
<td>3,500 acres (3,000 Aera)</td>
<td>800-2,000 ft</td>
<td>4,129 prod., 1,343 WI, 380 Steam</td>
<td>270 MMBO, 214 BCFG 49,068 BO, 24.9 MMCFG</td>
<td>Light Oil (25-39º API)</td>
<td>Hydraulic fracture Waterflood, or primary, or steam</td>
</tr>
<tr>
<td>Sub-Monterey</td>
<td>1,600 acres (all Aera)</td>
<td>6-9,400 ft</td>
<td>46 prod., 0 inj.</td>
<td>673 BCFG, 70 MMBO 182 BO, 5.3 MMCFG</td>
<td>Gas &amp; light oil</td>
<td>Slotted liner &amp; shot perfs Primary (gas expansion)</td>
</tr>
</tbody>
</table>

3 active pools + 5 drilling rigs + 15 workover rigs = very crowded infrastructure

©Sara Leen, National Geographic
Belridge Field – Production through Time

1911 - Discovery  TULARE Heavy Oil  Steamflooding post-1979  PEAK 1983-1990  Decline

1911 - Discovery  DIATOMITE Light Oil  Hydraulic fracs post-1978  PEAK 2001-2008

1930 - Discovery  SUB-MONTEREY Oil & Gas  PEAK 1935-1945  Decline

Daily Rates
May/11
29,000 BO
Nov. 2002
49,000 BO
25 MMCFG

1938
Discovery
135 MMCFG 13,950 BO

May/11
180 BO
5.3 MMCFG

Belridge Field, Daily Production and Injection Rates

TULARE HEAVY OIL
DIATOMITE LIGHT OIL
SUB-MONTEREY GAS & OIL
# Petroleum Systems -- Belridge Field

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Sub-Monterey Formations</th>
<th>Diatomite (Reef Ridge Shale &amp; Antelope Shale)</th>
<th>Tulare Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plate Tectonic Setting</td>
<td>Fore-arc setting and probably underlain by oceanic ophiolitic crust. Anticline began in Eocene due to stress fields set up by right lateral strike-slip movement along the San Andreas fault to the west.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reservoir Interval Age</td>
<td>Oligocene to Lwr Miocene</td>
<td>Upper Miocene</td>
<td>Pleistocene</td>
</tr>
<tr>
<td>Depositional Environment</td>
<td>Marginal marine Shelf sands</td>
<td>Inland sea with 600-1000 ft water depth (cf. present-day Sea of Cortez). Seasonally laminated diatomite</td>
<td></td>
</tr>
<tr>
<td>Reservoir Lithology</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Trapping Mechanism</td>
<td>Elongated anticline, fault compartments</td>
<td>Elongated anticline Still not in hydrodynamic equilibrium</td>
<td></td>
</tr>
<tr>
<td>Seals</td>
<td>Overlying shales and lateral sand pinchouts</td>
<td>Layered clay-rich zones at base of diatomite cycles form partial seals</td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon Source</td>
<td>Low sulfur oil &amp; gas from Eocene source rocks</td>
<td>Oil from mature Monterey shales to east that are basinal equivalents of reservoir units.</td>
<td></td>
</tr>
</tbody>
</table>

**Paleogeography in late Miocene (± 5-1 Ma) e.g. Diatomite time by Ron Blakey at U. of N. Arizona**

USGS open-file report, Magoon/Lillis/Peters, 2008
Discovery Well Drilled in April 1911

Driller’s Log and Lithology Log for Well 101, Section 33

Well was spudded on an outcrop of oil-stained sand along the Chico-Martinez Creek as it crosses the slight surface expression of the Belridge anticline.

IP = 100 bbl/day of 23.4° API oil
Belridge Field has Expanded over the Years

<table>
<thead>
<tr>
<th>Area</th>
<th>Total Wells</th>
<th>Active Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Bel.</td>
<td>More than 25,000</td>
<td>1,012 (Dec/10)</td>
</tr>
<tr>
<td>South Bel.</td>
<td>8,846 (Dec/10)</td>
<td></td>
</tr>
</tbody>
</table>

- Tulare & Diatomite Discovery Well - 1911
- Tulare & Diatomite Discovery Well - 1912
- Sub-Monterey Discoveries – 1930s

- 1950 about ??? wells
- 1920 & 1930 about 30 wells
- 2010
- 1930 about 170 wells
- 1920 about 100 wells

About 100 wells
About 170 wells
About ??? wells
1920s and 1930s

By the late-1920s, steel derricks and diesel engines replaced wooden derricks powered by steam because of the increased safety, efficiency, and ability to handle longer casing strings.

In June 1934, General Petroleum drilled Berry 1-30 to TD at 11,377 ft (3468 m)
– deepest well in world at the time
– mud log and driller’s log only
  (before electric logs in California)

Also in the 1930s, the deeper sub-Monterey reservoirs were discovered at 6,000 to 8,000 ft (1800-2450 m) in North Belridge and became important petroleum resources for WW2.

Valuation Report in October, 1919

– “… it is estimated that within ten years both pools will be commercially exhausted.”
– “Southern Belridge Field is entirely drilled up”
– “Future production… is estimated to be about 1,800,000 barrels”

Quotes from Valuation Report of the Belridge Oil Company’s holdings
KEY DATES FOR SUB-MONTEREY POOL
1930: Discovery year for Temblor Sand in Monterey Formation
1932: Discovery well for 64 Zone, well 64-27N, in sub-Monterey formations
1938: Peak production of 135 MMCFG/day and 13,950 BO/day
1930-1948 Total of 148 wells (8 dry holes) drilled in the sub-Monterey pools
1941: Discovery well for Y Sand; well 47-27N
1966: Discovery year for Carneros Sand
1979: Shell purchased assets of Belridge Oil Co. ($3.6 billion)
2001: Program for recompletions / add-pays began
2011: Currently 46 active wells

Pool Limits

Pool Name Sub-Monterey

Productive Size
(Aera only) 1,600 acres
(all Aera)

Reservoir Depth 6,000 – 9,400 ft

Active Wells
(per DOGGR, May/11) 49 prod., 0 inj.

Aera Wells 46 prod. (100%) 0 inj.

Cum. Prod. 673 BCFG, 70 MMBO

Daily Production
All Aera 5.3 MMCFG, 182 BO

Production Gas & light oil

Completion Method Slotted liner & shot perfs

Drive Mechanism Primary (gas expansion)
**Tulare Pool, Belridge Field**

**KEY DATES FOR TULARE POOL**
1911:
- Jan.: Belridge Oil Co. formed, purchases 30,800 acres from Mrs Hopkins for $1 million
- April: Well 101-33 TD’d at 782 ft, completed in Tulare and Diatomite, IP = 100 BOPD
1912: Discovery well for North Belridge
1956-59: In-situ combustion pilot (12 companies)
1963: Cyclic steaming begins
1963-1968: In-situ combustion project (Mobil)
1979 – Shell purchased assets of Belridge Oil Co. ($3.6 billion)
1986: Peak production of 172,700 BO/day, 114.4 MMCFG/day
1987-2007: Aquifer Lift project on east flank to reduce aquifer inflow
1993: First horizontal wells in Tulare

**BELRIDGE FIELD, Tulare Pool**
12 miles long, 3 mile wide, 10,500 acres
(18 by 5 km, 4300 ha)

**Pool Name**

<table>
<thead>
<tr>
<th><strong>Tulare</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Productive Size (Aera only)</td>
</tr>
<tr>
<td>Reservoir Depth</td>
</tr>
<tr>
<td>Active Wells (per DOGGR, May/11)</td>
</tr>
<tr>
<td>Aera Wells (% of total)</td>
</tr>
<tr>
<td>Cum. Prod.</td>
</tr>
<tr>
<td>Daily Production (Aera only)</td>
</tr>
<tr>
<td>Production</td>
</tr>
<tr>
<td>Completion Method</td>
</tr>
<tr>
<td>Drive Mechanism</td>
</tr>
</tbody>
</table>
Reservoir Monitoring via Time-Lapse Logging, Tulare Formation

Original liquid oil saturations (green) are being replaced over time by gas (red) as the steam chest develops from the top of each sand interval.

Neutron and temperature surveys are run in cased-hole observation wells every 2 years to provide time-lapse monitoring.

Drilled 9-5/8" hole to TD at 1196 ft, logged, cemented 7" casing to TD, completed as observation well.
**Diatomite Pool, Belridge Field**

**Pool Name**: Diatomite

**Productive Size**
- (Aera only): 3,500 acres (3,000 Aera)

**Reservoir Depth**: 800-2,000 ft

**Active Wells**
- (per DOGGR, May/11): 4,129 prod., 1,343 WI, 380 Steam

**Aera Wells**
- (% of total): 3,950 prod (96%), 1,162 water inj. (87%), 380 steam inj. (100%)

**Cum. Prod.**: 270 MMBO, 214 BCFG

**Daily Production**
- (Aera only): 49,068 BO, 25.0 MMCFG (45,686 BO, 20.6 MMCFG)

**Production Light Oil**: 25-39º API

**Completion Method**: Hydraulic fracture

**Drive Mechanism**: Waterflood, or primary, or steam

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**KEY DATES FOR DIATOMITE POOL**

- **1911**: Belridge Oil Co. formed, purchases 30,800 acres from Mrs Hopkins for $1 million
- **April**: Well 101-33 TD’d at 782 ft, completed in Tulare and Diatomite, IP = 100 BOPD
- **1912**: Discovery well for North Belridge
- **To 1970s**: Upper few tens of feet in Diatomite often completed with overlying Tulare oil sands so that light oil from Diatomite would ‘dilute’ heavy oil enough to allow economic production of heavy oil
- **1977**: First successful hydraulic fracture in Diatomite
- **1979**: Shell purchased assets of Belridge Oil Co. ($3.6 billion)
- **1986**: Water injection began to mitigate subsidence
- **1997**: Aera Energy LLC formed from Shell & Mobil assets
- **2002**: Peak production of 76,100 BO/day, 52.9 MMCFG/day (Aera = 94%)

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**BELRIDGE FIELD, Diatomite Pool**

- 12 miles long, 1 mile wide, 3,500 acres (20 by 2 km, 1400 ha)

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Diatomite is composed of pelagic diatoms deposited onto a mid-bathyal seafloor and then buried.
SEM Photo of Diatomite

Clay-rich Zone of Opal A, 848 ft in well 511S1-1N, North Belridge

- 40% Opal A (mainly broken and whole diatoms) and minor organics
- 40% detrital quartz & feldspar, and minor pyrite
- 20% mixed layer illite-smectite clays (with 30-40% expandable layers)
Unique Rock Properties Control
Diatomite Productivity

Diatomite is an unconventional shale . . . .

Exceptional Vertical Thickness of Pay
- Thickness of pay can be 1000-1200 ft (300-400 m)
- Along the crest the pay zones can be stacked with few non-pay intervals

Very High Porosity
- Opal A has 55-65% Ø and mostly fluid-supported, with little grain support
- Opal CT has 35-50% Ø and is grain-supported due to crystallization

Extremely Tight
- Very small pore throats and pore spaces often filled with skeletal fragments
- Opal A & Opal CT have matrix permeabilities ranging from 0.1 to 1 mD

Large Surface Area
- One ft$^3$ of rock has 15 million ft$^2$ (340 acres, 140 ha) of surface area
- Water-wet and has high interstitial water saturation ($S_{wi}$) above 50%

Highly Compressible
- Opal A compressibility (Cr) 100-300 microsips, Opal CT ± 10-30 microsips
- Decrease in pore pressure results in compaction in the reservoir
  (especially in the shallower Opal A) which causes subsidence of the overburden and lateral movement at or near the unconformity with the overlying Tulare Formation

Reservoir Fluids move very Slowly
- Fluids move at Diffusion Speed of only 1-3 ft (0.3-1.0 m) per year
- Fluids move by linear flow through micro-fractures towards the large planes of the induced hydraulic fractures
Type Log, Diatomite Reservoir

Lithostratigraphy = Chronostratigraphy

Note the ‘cleaning upward’ funnel patterns on the GR and RHOB / Porosity curves.

Each major cycle starts with a layered clay base and gets cleaner upwards until it is almost pure diatomite. It is then overlain by the clay-rich base of the overlying cycle.

Each of the 9 production intervals (between DIAT & M2 markers) used for volumetrics and injection conformance has one or more major depositional cycles.

Cyclic Diatomite

Brown Shale Opal CT

Opal A shown as gray in depth track
The “clay rich” zones A-E (shown in brown) in the upper Opal A exist in North Belridge and along the flanks. These zones are preserved by down-faulting north of the MB-13 fault, and removed by erosion along the crest of the anticline south of Section 12.

Transition between the Opal A and the diagenetically altered Opal CT:
• around the H & I marker in North Belridge, off the flanks, and on the southeast nose.
• around the M2 marker on the crest in Middle & South Belridge

The Etchegoin and San Joaquin Formations are eroded along the crest but are preserved on the Del Sur (SE) nose and on the flanks.
Data Coverage for Diatomite Reservoir

All geologic, petrophysical, and completion data for the diatomite & deeper units over the entire Belridge Field and surrounding area are stored in a single unified database (Landmark’s OpenWorks®).

Data for new wells and directional surveys updated nightly for all wells from enterprise database.

Statistics as of Sept. 2011

14,530 wells in database, (75% are in South Belridge), 700 more each year

6390 wells have sufficient logs to pick markers (typically GR, Rdeep, RHOB)

4660 wells have oil saturation calculations (need Rdeep & RHOB)

500 wells with pressure surveys (RFTs)

NOTE:
All wells without markers picked from logs have markers back-interpolated from structure grids

All wells without logs have petrophysical summation data back-interpolated from grids

All planned wells have back-interpolated porosity & saturation curves so that the completion intervals can be pre-planned & scheduled prior to drilling

*Same database used by all Diatomite geoscientists*
Excellent areal coverage of modern log data is essential for the creation of 3D structure and property models.

These models are used to predict porosity (RHOB) and oil saturation for an undrilled well, and generate pseudo-logs (synthetic logs) for it.

The pseudo-logs are used to pre-plan and schedule completion intervals.

If the well is logged and we get real log data, there is a final review, but predictions are normally very accurate.
Hydraulic Fractures are Key to Diatomite Productivity, Pattern Geometry, and Well Spacing

Until the first successful hydraulic fracture in 1977 by Mobil, the only part of the Diatomite that was completed was the uppermost few tens of feet that were commingled with the overlying heavy oil zones of the Tulare Formation as a way to lower oil viscosity so it could be pumped out.

After 1977, sand-propped hydraulic fractures became the completion style for diatomite production wells.

With increased awareness of the importance of fracture azimuth and the ability to measure the geometry of induced fractures, patterns became increasingly complex.

As the diatomite became more understood, development strategies evolved:

1. Primary development
2. Compaction management
3. Infill drilling
4. Waterflood optimization

However, the pattern geometry of either line drive or pattern flood set up by the original operators still controls the current patterns.
Defining Reservoir Limits is Still Challenging

The flanks and nose areas of the field are the most difficult.

Examples for South Belridge

West flank & SE nose have thin pay but good productivity, especially from horizontal wells

East flank has thick pay but poor productivity due to lower gravity (more viscous) oil

- Thin pay (< 400 ft pay, only 1 frac stage) is uneconomic for a vertical well
- Horizontal wells (with up to 10 frac stages) are being used very successfully to develop thin pay zones
- West flank and SE nose are main areas for horizontal wells

- Few downdip wells with log data to define limits of oil saturation
- Computed extrapolation of data are invalid so edge-lines and dummy data points have to be added manually into 3D & 2D models

A demo cyclic steam project is evaluating heavy oil (15-20º) on the east flank that would otherwise be uneconomic
Current Operations and New Techniques

Area of Dense Horizontal Wells (Longitudinal Fracs)

Crest Area Continuous Steam Project

7th Standard Road

NORTH BELRIDGE

SOUTH BELRIDGE

MIDDLE BELRIDGE

Process Improvements (entire company, field & office)

InSAR satellite surveys (surface of field every 24 days)

DTS Pilot (50 wells scattered in field)

RFT Program (500 wells throughout field)

Heavy Oil Area (East Flank) Cyclic Steam Demo Project

Microseismic Project
Horizontal Wells Drain Thin Pay Zones

Example showing how borehole is ‘toe-up’ and intersects thin but high quality pay (equivalent to 1200 ft of continuous pay in a vertical well)

NOTE:

Thin vertical pay zones (< 400 ft) become long horizontal pay zones (> 1,000 ft) in a horizontal well

The first horizontal wells in the Diatomites at Belridge were drilled by Mobil in the nose of the Del Sur area and aligned NW/SE, parallel to the anticline axis. They have transverse hydraulic fractures.

However, the area has limited productivity and nearly all the later horizontal wells have been ‘longitudinal’ and drilled along the flanks. Especially in Sections 33 and 3.

See SPE Paper 133511
We are now using formation pressure data from open-hole RFTs to decide the completion intervals of new or replacement multi-string water injection wells.

Advantages of Multi-String Injectors:
-- able to control and measure where injection water goes
-- used along axis of field where pay is thickest (3-5 frac stages)
-- used when need for injection conformance is greatest

Current injection support is excellent as formation pressure is at hydrostatic
Offset injector well is already adequately supporting this zone
Additional injection support needed as formation pressure is below hydrostatic

See SPE Paper 144128
InSAR measures Surface Subsidence

The diatomite reservoir is very weak and will compact without adequate pressure support. This compaction causes subsidence of the ground surface and also ‘dog-legs’ and eventually shearing of the well bores.

InSAR (Interferometric Synthetic Aperture Radar) is used to monitor surface subsidence caused by reservoir compaction.

Satellites gather data every 24 days and comparisons of surface elevation with previous months are used to monitor conformance of injection and production across the field.

From Patsek, EIA Workshop, 2000
DTS Used to Measure Water Injection Profile

Well 548LR2-34

Inject

Stop Injection

Warm-Back
(shall in to generate tracer of hot water)

Resume Injection

Constant Injection Rate

Interpretation of DTS Profile

Interpretation by Drawing Tangent on the Leading Isotherm

DTS vs. RAT Profile

See SPE Paper 144116
Active Reservoir Monitoring

Constrained cluster
Caused by cyclic steam injection
(dilation and closure)

Unconstrained cluster
Perhaps caused by activation of pre-existing fracture(s)

Microseismic is being used to monitor fracture growth and location during steaming cycles.

Cross-well Tomography
Electromagnetic and acoustic methods can be used in the future to monitor dynamic changes in reservoir fluid content.
The Belridge giant field still has many hundreds of millions of barrels available for recovery. Although production from the sub-Monterey in North Belridge and the Tulare oil sands is declining, the diatomite reservoirs will sustain the field for many more decades.

There is also the upside of exploration success in deeper zones throughout the field.
Steam Production with Low Environmental Impact

As the nation moves to a lower carbon use economy, there is a need to change the methods of heating the heavy oil reservoirs in the Tulare Formation and in the Diatomite on the east flank.

CURRENT TECHNOLOGY: Steam created by gas-fired generators

If steam is used, it needs to be made at a cost that is competitive with current technology that uses natural gas . . .

POSSIBLE FUTURE: GlassPoint’s solar panels for steam production

POSSIBLE FUTURE: GreenSteam Biomass Plant (using agricultural waste)
Minimizing Surface Impact

The surface of the field is the most crowded oil field in the world.

Tight well spacing (down to less than 30 ft [9 m]) in many areas coupled with surface piping (flow lines, etc.) and overhead electric lines cause many problems.

Possible solutions include horizontal wells that are spudded away from the field, wells with multiple laterals, and pad drilling.
The Distant Future for the Belridge Field

**Final stage (in 2111..):**
Recovery of heat from steamed reservoirs via low temperature geothermal projects

**Challenges until then:**
How to apply modern technology to a giant onshore field with stripper production rates per well but huge remaining oil volumes.
Summary for Belridge Field

Tulare Formation (Pleistocene)
• Trap: updip pinchout, downdip structure
• Fluvio-deltaic & lacustrine sands
• Heavy oil that needs to be steamed
• Slotted liner & gravel packs
• May/11 = 29,275 BOPD (Aera = 24,470)

Diatomite (Miocene Monterey)
• Trap: long narrow anticline
• Cyclic layers of diatomite
• Light oil via primary, waterflood & steam
• Sand-propped hydraulic fractures
• May/11 = 49,068 BOPD, 25.0 MMCFGD
  (Aera = 45,686 BOPD, 20.6 MMCFGD)

Sub-Monterey Formations (Miocene to Eocene)
• Trap: anticline
• Marine shelf sands
• Gas and light oil, still on primary
• Shot and jet perforations
• May/11 = 5.3 MMCFGD, 182 BOPD
  (all Aera)

THANK YOU

Any questions?
THUMBNAILS OF SLIDES PRESENTED

END OF PRESENTATION
Abstract and Biographies

The Belridge Giant Oil Field - 100 Years of History and a Look to a Bright Future

Allan, Malcolm E.¹; Lalicata, Joseph J.¹

(1) Aera Energy LLC, Bakersfield, CA.

April 2011 marks the 100th anniversary of the well that discovered the Belridge giant oil field in the San Joaquin Valley of California. During the 100 years the field has produced 1.6 billion of the approximately 6 billion barrels of the estimated original oil in place. The field covers an area roughly 22 miles long and 2.5 miles wide (35 by 4 km). It has three totally separate and distinctly different producing zones: Pleistocene shallow fluviodeltaic sands producing heavy oil via steamflood; Miocene deepwater diatomite layers producing light oil via hydraulic fractures and with water injection for pressure maintenance; and Oligocene to lower Miocene marine sandstones producing gas and light oil via gas expansion. Each of the vertically stacked zones requires different work models and different completion strategies to sustain production.

Although down from its peak of 160,000 BOE per day in 1986, the field currently produces 80,500 BOE per day which makes it one of the largest onshore fields in the USA. Since discovery via a surface oil seep, over 25,000 wells have been drilled although only 6,000 producers and 2,400 injectors are still active. However, new insights to the reservoirs have resulted in about 600 new wells being drilled and completed in each of the past few years.

In the 1930s the field had the deepest well drilled in North America. In the 1990s the field had the closest well spacing of any field in the world: vertical and horizontal wells drilled as close as 30 ft (9 m) apart and completed with sand-propped hydraulic fracs. Continuing to successfully develop and produce the reservoirs requires applying conventional technologies and techniques in new and unconventional ways. Fit-for-purpose reservoir characterization studies in 2D and 3D, coupled with standardized workflows for modeling and documentation, build upon past fundamental knowledge using state-of-the-art software and databases to handle the immense quantity of data.

At the start of the 21st century the field is gearing up for many more years of activity with expansion of steam drives in the oil sands and in the diatomite shales, installation of a large microseismic array, distributed temperature sensing to monitor water movement in water injection wells, and regular InSAR surveys to monitor ground movements. Exploration wells are also being drilled for seismic targets that are well below the current producing zones.

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Malcolm E. Allan

is a reservoir management geologist with Aera Energy LLC. He began his career working internationally in Africa and the North Sea for Texaco before joining Occidental Petroleum to work in South America (Peru, Colombia), Middle East, and North Africa. After a few years with a small Canadian company in Egypt, Colombia, and Ecuador, he returned to California. Since then Malcolm has worked mainly on two of the giant oil fields in California: Belridge and Elk Hills. He is currently working for Aera Energy LLC on the diatomite reservoirs at the Belridge Field, doing reservoir characterization and field studies. He holds a B.Sc. degree in Geology and an M.Sc. in Petroleum Geology from Imperial College, University of London. He is a California state-registered geologist and a member of the AAPG, SPE, and SPWLA.

Joseph J. Lalicata

is a geologist with Aera Energy LLC. He is involved in reservoir characterization studies, geocellular modeling, and reservoir development for the siliceous shale reservoirs at Belridge and Lost Hills fields, California. Prior to working at Aera, he worked on field studies of the turbidite reservoirs of the Wilmington Field (Los Angeles, California). He holds a B.Sc. in Geology from Binghamton University, New York and an M.Sc. in Geology from University of California, Santa Barbara. He is a member of the AAPG, SPE, and SPWLA.
**North Sea Chalk - A Close Analog for Diatomite**

**Comparison Table**

<table>
<thead>
<tr>
<th>Reservoir</th>
<th>Ekofisk Chalk (CaCO₃)</th>
<th>Belridge Diatomite (SiO₂)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Pay Thickness</strong></td>
<td>200 to 900 ft (175-275 m) Net : Gross Ratio = 0.7</td>
<td>200 in flanks to 1200 ft on crest (175-400 m) Net : Gross Ratio = 0.7 to 1.0</td>
</tr>
<tr>
<td><strong>Porosity</strong></td>
<td>25 to 45% Porosity preserved due to deposition on structural highs, overpressuring of the reservoir, and early migration of hydrocarbons into the structure.</td>
<td>55-65% in Opal A (mostly fluid-supported, with little grain support). 35-50% in deeper Opal CT (grain-supported due to crystallization).</td>
</tr>
<tr>
<td><strong>Permeability</strong></td>
<td>Matrix permeabilities range from 1 to 10 mD. Reservoir permeabilities range from 1 to 100 mD due to high intensity of natural fractures plus fractures caused by compaction and shear.</td>
<td>Matrix permeabilities range from 0.1 to 1.0 mD. Reservoir permeabilities range from 1 to 10 mD due to natural fracturing.</td>
</tr>
<tr>
<td><strong>Compressibility</strong></td>
<td>Average of 100 microsips.</td>
<td>± 100-300 microsips in Opal A, ± 10-30 microsips in Opal CT</td>
</tr>
<tr>
<td><strong>Compaction</strong></td>
<td>North Sea chalk reservoirs compacted due to dissolution / reprecipitation when flooding with cold seawater started, and due to pore pressure decreases caused by net fluid withdrawal. Result is subsidence at the sea bed unless reservoir pressure is maintained.</td>
<td>Decrease in pore pressure results in compaction in the reservoir – especially in the shallower and weaker Opal – due to fragmentation/collapse of the diatoms. Compaction causes surface subsidence unless reservoir pressure is maintained.</td>
</tr>
<tr>
<td><strong>Remedies</strong></td>
<td>Platforms were raised 20 ft (6 m) in August, 1987.</td>
<td>Waterflooding and conformance monitoring.</td>
</tr>
</tbody>
</table>
California Shales compared to other US Shales

Map from ‘Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays’ by US EAI (July/11)

Table data from various sources

<table>
<thead>
<tr>
<th>Name of Shale Play</th>
<th>Monterey / Santos / Temblor</th>
<th>Bakken Shale</th>
<th>Eagle Ford Shale</th>
<th>Marcellus Shale</th>
<th>Barnett Shale</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (ft)</td>
<td>3,500 to 16,000’</td>
<td>4,500 to 8,000’</td>
<td>7,000 to 14,000’</td>
<td>4,000 to 9,000’</td>
<td>5,000 to 8,000’</td>
</tr>
<tr>
<td>Thickness (ft)</td>
<td>500 to 3,500’</td>
<td>20 to 100’</td>
<td>75 to 300’</td>
<td>&lt;10 to 300’</td>
<td>100 to 500’</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>5 to 30%</td>
<td>3 to 12%</td>
<td>3 to 15%</td>
<td>2 to 9%</td>
<td>1 to 9%</td>
</tr>
<tr>
<td>Permeability (mD)</td>
<td>&lt;0.0001 to 2</td>
<td>0.05 to 0.5</td>
<td>&lt;0.0001 to 0.003</td>
<td>0.00001 to 0.01</td>
<td>0.000009 to 0.001</td>
</tr>
<tr>
<td>TOC (%)</td>
<td>0.1 to 12%</td>
<td>2 to 18%</td>
<td>0.6 to 7%</td>
<td>0.1 to 13%</td>
<td>4 to 8%</td>
</tr>
<tr>
<td>Technically Recoverable Resource</td>
<td>15.4 billion BO</td>
<td>3.6 billion BO</td>
<td>3.4 billion BO 21 TCF Gas</td>
<td>410 TCF Gas</td>
<td>3.6 billion BO 434 TCF Gas</td>
</tr>
</tbody>
</table>