Table of Contents

List of Tables

List of Figures

List of Data Files on the CD

FINAL_MASTER_ERCB_Presentation.pdf

Performance Plots (Slide Nos. 47-60)	Performance_Plots_Feb29_08.xls
Steam Data (Slide No. 61)	Boiler Data.xls
Produced Water Quality (Slide No. 66)	Produced Water Analysis.pdf
Composition of Produced Gas (Slide Nos. 68-76)	LabCombustionGasAnalyses.xls
Temperature Observation Data (Slide Nos. 78-86)	OB Well Temp Reading_DepthOK.xls
Whitesands Initial Design Basis Memorandum	Formatted DBM Feb27.pdf

1 GEOLOGY AND GEOPHYSICS

1.1 Resource Description

Whitesands currently holds 73 sections of land under oil sands lease agreements in the Conklin area of northeastern Alberta. The site of the planned Project in Section 12, Twp 77, Rge 9, and Section 7, Twp 77, Rge 8, W4M is held under Oil Sands Agreement 7400010012 (Lease 012), which expires in 2015-01-13. The P&NG rights in Section 7 are held by BP Canada. In Section 12, where the Project's producing zone in the McMurray Formation is located, BP Canada holds the natural gas rights in the Clearwater Formation.

The latest March 2007 McDaniel & Associates Ltd. Report commissioned by Whitesands Insitu Ltd. estimated 2.6 billion barrels of gross bitumen-in-place and 799 million barrels of recoverable bitumen resource (High Estimate) based on SAGD technology on the Whitesands lease. McDaniel's reviewed approximately 125 wells situated on and in close proximity to the Whitesands lease (Figure 1). Included in the McDaniel's report were 35 stratigraphic wells that were drilled by the Company between 2003 and 2007 within the Pilot Area or in close proximity to the Pilot Area. Of these 20 are Oil Sands Evaluation wells (OSE wells), and 15 are experimental wells (observation, air injection or water injection). Twenty six Company wells have had detailed core work completed which includes core reports and core photographs. A single well previously drilled on the lease had an accompanying core analysis. Petrophysical evaluation of well logs and the review of available core reports yielded reservoir parameters for determining the exploitable intervals contained within the McMurray Middle and McMurray Lower, including: net bitumen pay, modified gross pay, porosity, water saturation, bitumen content and net to gross ratio. Data collected from each well was used to map the areal extent and spatial distribution of the bitumen.

McDaniel & Associates Consultant Ltd. (March 2007) defines the Best Estimate of an SAGD'able in-situ interval as a subsurface stratigraphic interval containing a minimum thickness of 10 metres of continuous bitumen-saturated sand, net of localized permeability barriers, with porosity and mass bitumen content (ratio of bitumen to water and mineral matter) meeting a minimum of 27 and 8 percent, respectively, with a competent top reservoir seal. High and Low Estimates of SAGD interval employ the same methodology, with the exception that minimum thickness of 8 and 12 metres, respectively, were used. The determination of the percentage of exploitable OBIP is a geometric reduction of the total SAGD'able original bitumen in place (OBIP) to account for areal and vertical inefficiencies in placement of the SAGD well pairs during development. The ultimate recovery percentage of bitumen from within the calculated exploitable bitumen volume represents an estimate of the ultimate recovery percentage (recovery factor) of the bitumen from within the exploitable volume of each well-pair; with the unexploited reservoir volume outside the steam chamber already having been accounted for in the exploitable percentage calculations. Recovery factors were determined by examining a number of analogous SAGD projects presently under production and comparing the reservoir and fluid characteristics with those encountered at the Whitesands Lease.

In 2003 and 2006 Whitesands conducted 2 3-D seismic programs of an approximate 39 km^2 area on the Whitesands Lease. One 3-D survey encompassed the Project site (see Figure 1 and Figure 11). The objectives of the 3D programs were to evaluate bitumen resource to identify a Project location with acceptable reservoir characteristics that was a suitable development site within reasonable proximity to existing infrastructure.

1.2 Regional Geology

The bitumen resource target for the Project is the McMurray Formation, the basal unit of the Lower Cretaceous Mannville Group. The McMurray Formation contains significant bitumen reserves which constitute the Athabasca oil sands deposit of northeastern Alberta.

The Mannville Group is composed of very weakly consolidated to unconsolidated clastic sedimentary rocks that rest unconformably on the carbonates of the Devonian Beaverhill Lake Group (see Figure 2). In northeastern Alberta, the Mannville Group is divided into three formations (from oldest to youngest): the McMurray, the Clearwater, and the Grand Rapids. The Mannville Group is overlain by Cretaceous Colorado Shale that is truncated by Quaternary glacial deposits. (see Figure 2).

1.2.1 Geology of the McMurray Formation – Production Zone

The Whitesands Lease is situated in the south-eastern corner of the Athabasca Oil Sands Area. On the lease, bitumen accumulations are found within clastic sediments of the McMurray Formation of the Lower Cretaceous Mannville Group. The Whitesands Lease is located directly west of the main channel system of the Lower-Middle McMurray. Two main channels within the McMurray succession are present on the lease and it is within these channels that THAI™ reservoir is confined. Outside of these two channels, much of the lease hosts non-reservoir estuarine embayment sediments. Future delineation drilling and interpretation may reveal further local channel development with THAI™ potential. Throughout the lease and surrounding area, the McMurray has been subdivided into lower, middle and upper units, consistent with McMurray interpretation elsewhere in north-eastern Alberta.

There are very few preserved occurrences of the Lower McMurray in the lease area. Where present, the Lower McMurray consists of thin and often wet, fine- to coarse-grained subarkosic sands, typically with interbedded shales. These sediments were deposited unconformably on eroded argillaceous carbonates and calcareous shales of the Waterways Formation of the Devonian Beaverhill Lake Group. Limited exploitable reservoir is noted within this unit. During Lower McMurray time, base level in the lease area was mostly above that of the main channeling taking place to the east. The result of this was a paucity of Lower McMurray fluvial channel development or Lower McMurray deposition in the area.

The Middle McMurray hosts the richest accumulations of bitumen within the McMurray succession on the Whitesands lease. Middle McMurray time was marked by development of two main estuarine channels that cut across the lease, with one directed southwest-northeast and the other southeast-northwest. These channels are of variable width, but generally average more than 1.6 km in cross-sectional area. Within these channels, the Middle McMurray is dominated by estuarine channel deposits consisting of highly permeable subarkosic sands with good vertical, and more limited lateral continuity, interbedded with sandy and muddy lateral accretion beds, mudstone clast material and cross-bedded tidal flat deposits. Good sediment supply and a lower base level during Middle McMurray time permitted multiple channeling events, channel stacking, and reworking of older deposits, resulting in reservoir units tens of metres in thickness.

Often within the upper portion of the Middle McMurray, and within the regional sequences outside of the channel areas, estuarine bayfill deposits, generally sourced from migrating distributary channels within a prograding delta are found. These deposits consist of very fine- to medium-grained sands, with both muddy and silty drapes and interbeds, demonstrating a strong tidal influence. On well logs, these deposits have a coarsening-upwards character. Clean sand intervals within these embayment sediments are generally thin, limiting development potential to instances where they are in direct communication with estuarine channel deposits of the Middle McMurray unit.

The upper McMurray is typically separated from the Middle McMurray by a thin regional shale horizon—McMurray A Shale. The Upper McMurray is dominated by estuarine bayfill deposits. These are characterized by very fine- to medium-grained, often cross-bedded sands, with both muddy and silty drapes and interbeds. On well logs, these sequences have a coursing-upwards character and closely resemble similar sequences within the Middle McMurray, previously described.

1.2.2 Clearwater Formation

The Clearwater Formation is made up of two sand-shale sequences in the Project area, described below:

1.2.2.1 Wabiskaw C Sand

The lowermost part of the Clearwater Formation is made up of the Wabiskaw C Sand, which directly and sharply overlies the McMurray Formation. This interval, typically around 3m thick, consists of marine silty sands. The contact between Wabiskaw C Sand and upper McMurray is usually sharp due to the lithology and fluid difference within these units.

1.2.2.2 Lower Clearwater Shale

Overlying the Wabiskaw C Sand is a shale sequence that is about 20 m thick forming the major cap rock between the Clearwater Sandstone Member above and the Wabiskaw–McMurray below. It includes the five-metre thick Wabiskaw Marker, a regionally correlatable bentonite bed. Over a five-metre interval, this shale sequence quickly grades into the overlying Clearwater Sandstone.

1.2.2.3 Clearwater Sandstone

The Clearwater Sandstone is a very uniform, 30 to 40 m thick marine shoreface complex that hosts a significant, structurally-controlled gas but now essentially depleted accumulation, which extends into the northeastern-most part of the Whitesands lease holdings.

1.2.2.4 Upper Clearwater Shale

The Clearwater Sandstone is sharply overlain by a series of interbedded shales and cleaning-upward sandy siltstone packages that total 22 to 36 m in thicknesses. This is the seal for the Clearwater Sandstone gas pool.

The top of the Clearwater Formation has a short, transitional contact with the base of the Grand Rapids Formation.

1.2.3 Grand Rapids Formation

The Grand Rapids Formation can be divided into an upper and lower member:

The Lower Grand Rapids Member is a 30 to 40 m thick upward-coarsening sandstone, which is water wet throughout the area.

The Upper Grand Rapids member consists of 38 to 60 m of up to four stacked coarsening-upwards sand cycles separated by impermeable, thin marine shales. Minor gas is sometimes trapped in combined structural-stratigraphic traps in the upper cycles in the regional study area.

1.2.4 Colorado Group

Tight marine shales of the Cretaceous Colorado Group overlie the Grand Rapids Formation. The Colorado Group is truncated at the unconformable contact with the unconsolidated Quaternary glacial drift. Preserved Colorado Group thickness varies from as little as 3 m to more than 80 m in the study area. In the vicinity of the proposed Project, 40 to 60 m of Colorado section is expected. The Colorado Group Shale forms an effective seal between the brackish water- and hydrocarbon-charged Cretaceous sediments below and the freshwater-bearing glacial sediments above.

1.2.5 Quaternary – Water Source Horizon

The surficial glacial drift is made up of gravel, sand, silt and mud. It is the freshwater aquifers of the Quaternary glacial drift that are used as fresh water source for the Project.

1.3 Project Site Geology

The Project site is in Section 12 Twp 77 Rge 9W4M (see Figure 1). In sections, there are 3 horizontal wells and 19 vertical wells which have penetrated the McMurray Formation. Among them, 9 wells were cored. All the 19 vertical wells are accompanied by standard open hole logs, 7 of which with HMI (High Resolution Micro Imager) logs.

1.3.1 Typical Composite Well Log and Cross Section

The OB7 well logs show the common stratigraphic units in the project site area (see Figure 3 and Figure 4). From the bottom to the top, these units are Devonian limestone, McMurray C (Lower McMurray), McMurray B (Middle McMurray), McMurray A (Upper McMurray), Wabiskaw C Sand, and Lower Clearwater Shale including the Wabiskaw Marker. The contacts between each unit are distinctive. The top of the Devonian limestone shows a significant increase on the density porosity log. The contact between McMurray C and McMurray B can be identified from the Gamma Ray log or Density Porosity log due to the sudden lithological change from McMurray C Shale to McMurray B basal sand. A 2~3 meter water zone at the bottom of McMurray B can be identified from the resistivity logs with the help of the Gamma Ray log. The top of McMurray B is identified by the regional correlation marker—McMurray A Shale, which shows a distinctive high Gamma API value. A thin gas zone (<1 m) is interpreted from the Neutron-Density log crossover. The boundary between McMurray A and Wabiskaw C sand is picked at the step shown on both Gamma Ray and Resistivity logs. The top of Wabiskaw C Sand is identified from both Gamma Ray and Resistivity logs due to the sudden lithological change from Wabiskaw C Sand to the Lower Clearwater Shale. The Lower Clearwater Shale is a regional stratigraphic marker due to its significant thickness, distinctive log characteristics, and widely areal distribution.

The stratigraphic units shown on the OB7 well logs are generally correlatable in the project site area (See Figure 5 and Figure 3). The McMurray C varies in thickness depending on the topography of the Devonian unconformity and the McMurray B channel scouring. Where the McMurray B channel cuts deeper (See OB3 in Figure 5), the McMurray C is relatively thinner. Correspondingly, the McMurray B is thicker with relatively thicker bottom water zone. Internally, the McMurray B shows a typical channel characteristic becoming shalier upwards. It's characterized by a sand-dominated interval at the base, a sand-shale interbedded interval in the middle, and a shale-dominated interval at the top. The McMurray A is uniform in thickness and lithology with a total thickness of about 8m including the 2 meters McMurray A Shale at the bottom and 6 meters sand on the top. A very thin gas zone is present locally. Overlying the McMurray A, the Wabiskaw C Sand is about 3m in thickness uniformly. The Lower Clearwater Shale, which is a regional cap rock for the Wabiskaw C and McMurray Formation, is about 20m in thickness in the entire project area.

1.3.2 Isopach Maps of the Zones of Interest

For the THAI^{TM} process, the zones of interest include the McMurray B, McMurray A, Wabiskaw C Sand, and the Lower Clearwater Shale as the cap rock. As the thicknesses and lithology of McMurray A, Wabiskaw C Sand, and the Lower Clearwater Shale are very uniform in this area, it's unnecessary to generate isopach maps for them. As a result, only the following isopach maps are generated: McMurray B total thickness, McMurray B total net bitumen sand, McMurray B basal bitumen sand, McMurray B bottom water sand, and gas pay in the McMurray A or Wabiskaw C Sand.

McMurray B thickness ranges between 32m and 39m in the project area (See Figure 6). The general NW-SE contour trend is interpreted to be consistent with the regional main channel direction. Areas with relatively thick McMurray B correspond to the channel thalweg. For example, on the cross section in Figure 5, the OB3 well is interpreted to intersect the channel thalweg while the OB1 well is relatively closer to the southwestern channel edge.

McMurray B net bitumen is defined by using a 27% porosity cutoff and 20 Ωm.m resistivity cutoff in the McMurray B succession without requiring the continuity of the bitumen. Therefore, the bitumen in both the interbedded sand-shale interval and basal sand interval is included. The net pay ranges between 13m and 20m in the area (See Figure 7).

As recovery of bitumen in the interbedded sand-shale interval will be strongly affected by the shale layers, distribution of the bitumen in the basal clean sand is considered to be a key factor to determine the horizontal well locations. From the Isopach map (See Figure 8), relatively thick basal bitumen sand is expected in the northwest and east of the existing horizontal wells.

Bottom water is another factor which has effect on the THAI™ process. In this area, bottom water zone is up to 4m in thickness (See Figure 8).

A very thin gas zone is locally present in the McMurray A or Wabiskaw C Sand. The gas zone is usually less than 1 meter in thickness (See Figure 10).

1.3.3 Reserve Estimate

Based on the definitions and guidelines prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society), McDaniel & Associates Consultants Ltd. has assigned about 58 MMbbls of probable reserves (2P) to the section 12-077-09W4M and about 135 MMbbls of possible reserves (3P) to the sections 12-077-09W4M and 07-077-08W4M. In this estimate, 27% porosity and 8% mass bitumen content cutoffs are used. The average porosity is 34% and average bitumen saturation is 80%.

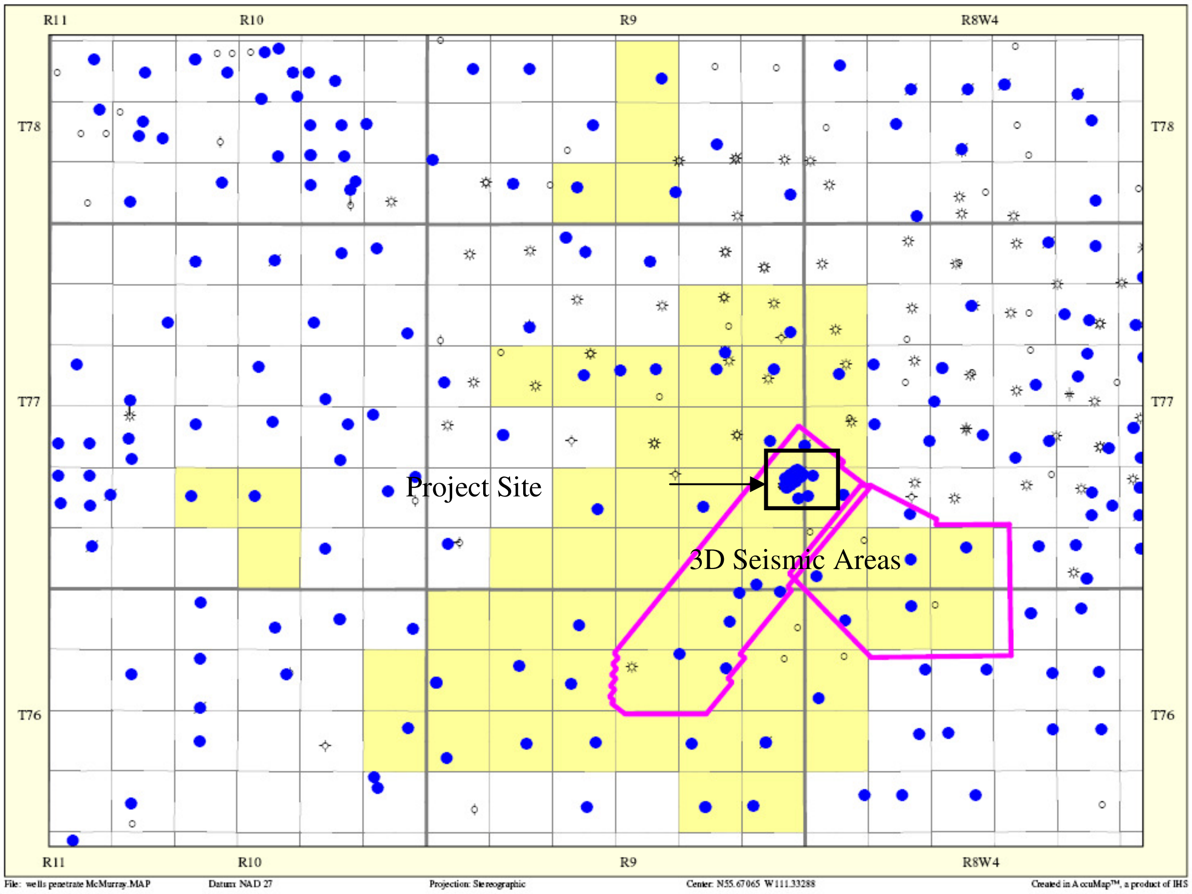
1.3.4 Water Disposal Zones

Whitesands proposes to dispose of water produced from the Project into the bottom water sandstone of the McMurray Formation or the deep zones including the Keg River and Granite Wash formations of the Devonian Elk Point Group.

The water sand of the McMurray Formation is up to 4m intersected by the well AA/12-07-077-08W4 in this area. The permeability of the sand is 6,610 mD. The porosity is 34% and water saturation is 93.4%.

The other water disposal option is the deep zones. Water is currently being disposed into the Keg River dolomite by BP Canada Energy Company using a well at 02/15-23-077-09W4M about 3.5 km from the proposed Project site. Water injection started in 1980 with continuous injection since 1992. The average monthly injection rate is about 3,500 m^3 from 1994 to 2006. The injection rate is over 5,000 m^3/month from 1996 to 1998.

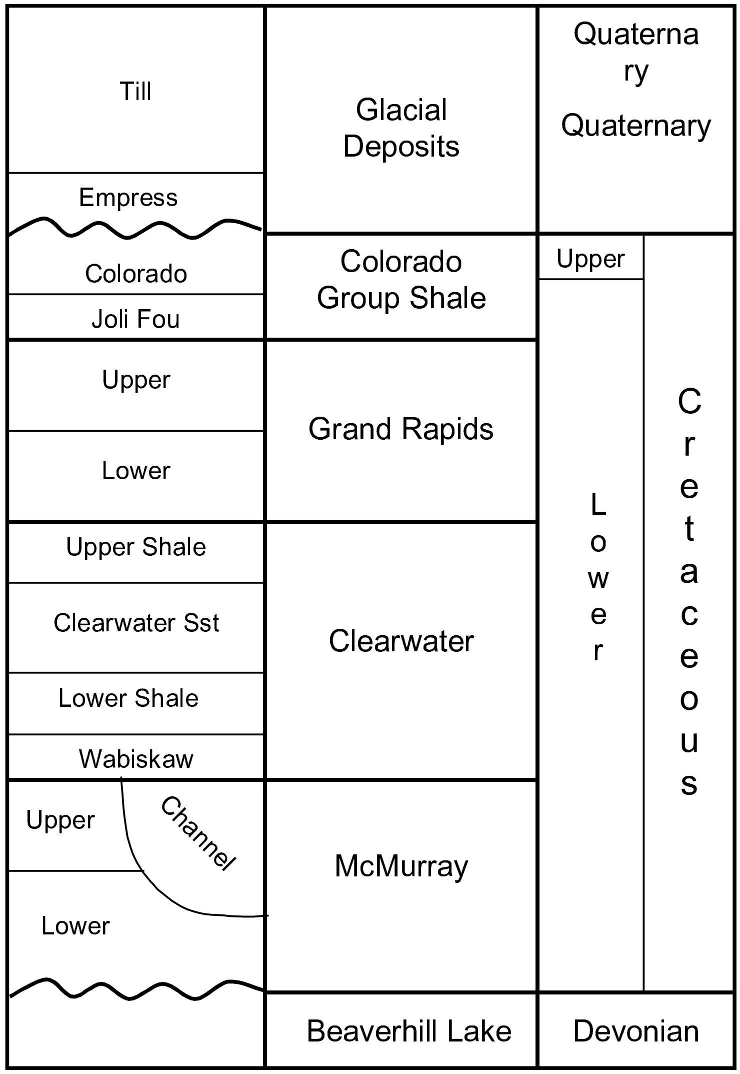
Figure 1 Well Control and 3D Seismic Areas



Note: 1. Whitesands lease in yellow

2. Wells in solid blue penetrated McMurrayFormation

Figure 2 Generalized Stratigraphic Section



Generalized Stratigraphic Chart of the Project Area

Figure 3 Project Well Layout and Well Spacing

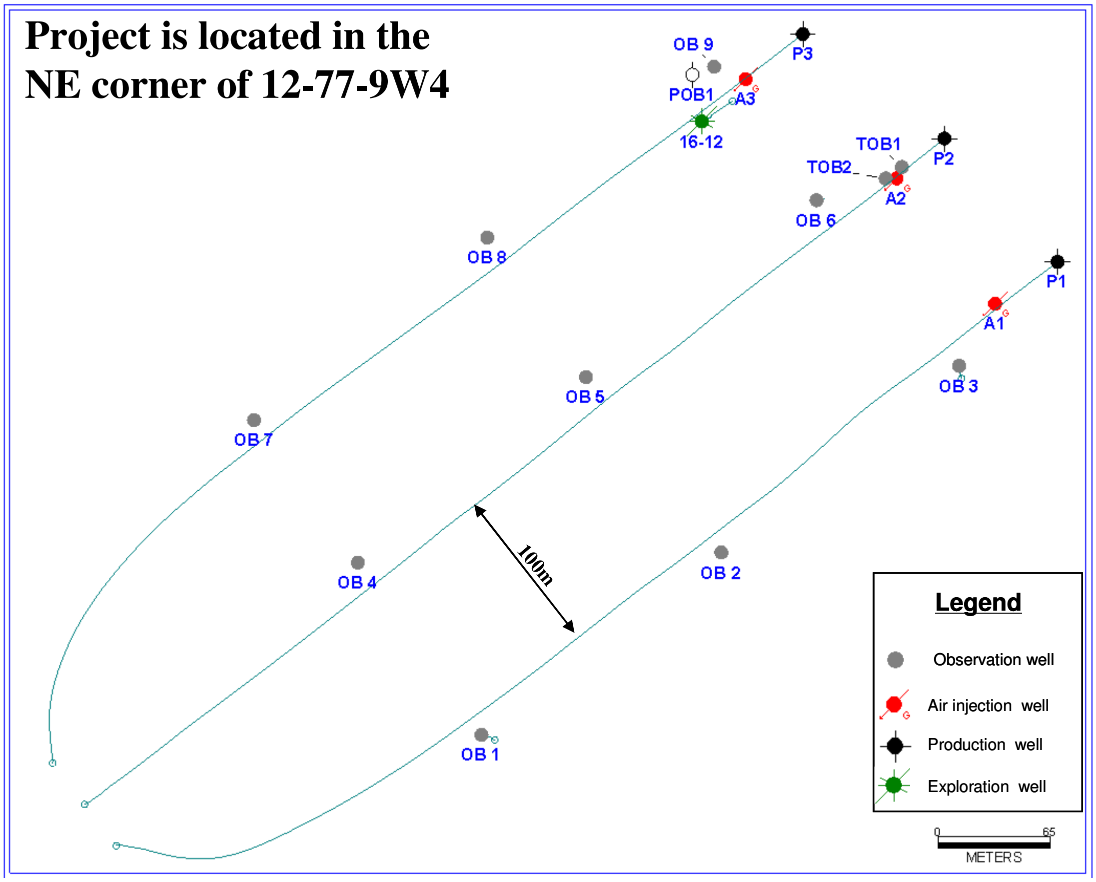


Figure 4 Typical Composite Log at the Project Site

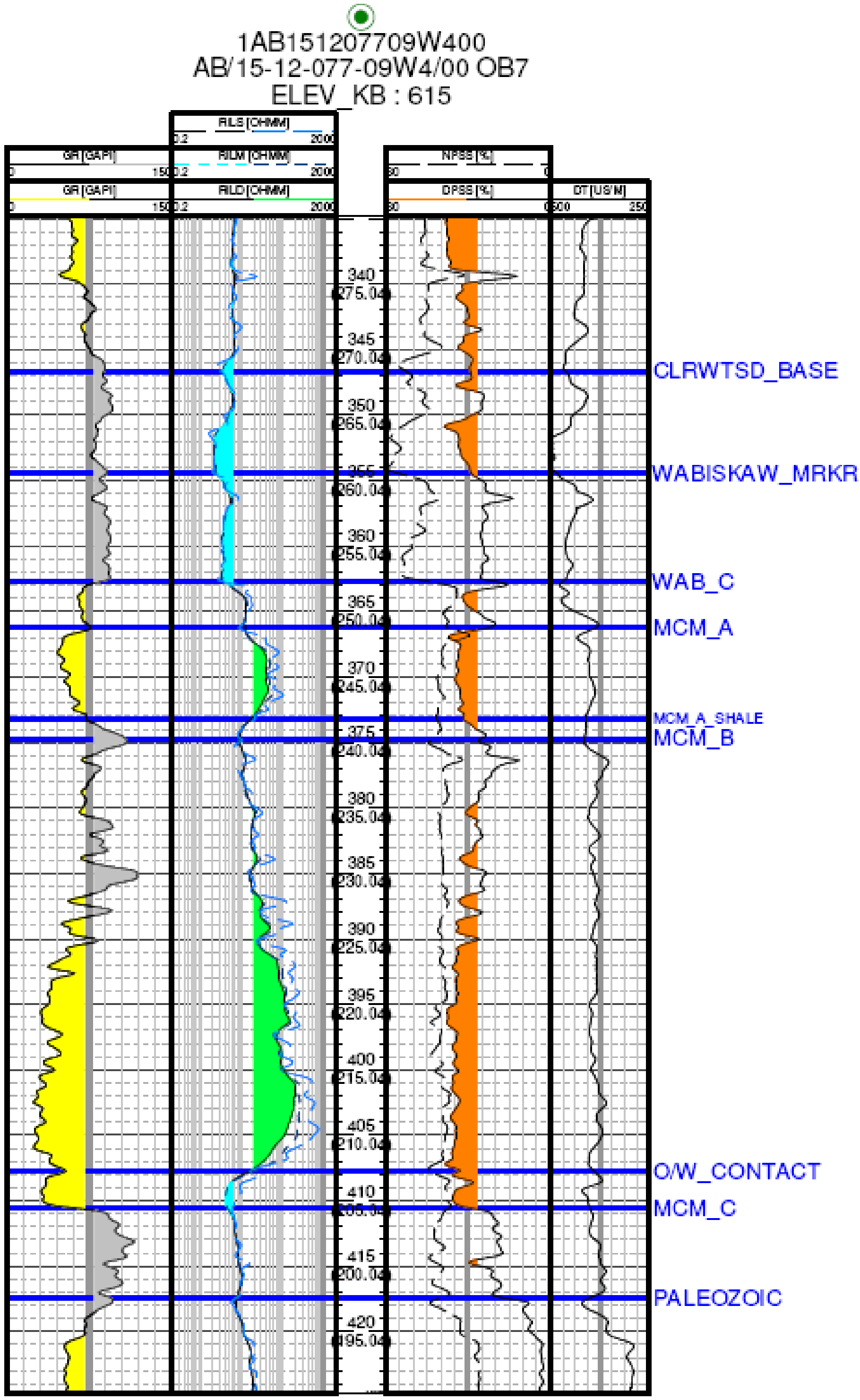


Figure 5 Representative Stratigraphic Cross Section at the Project Site

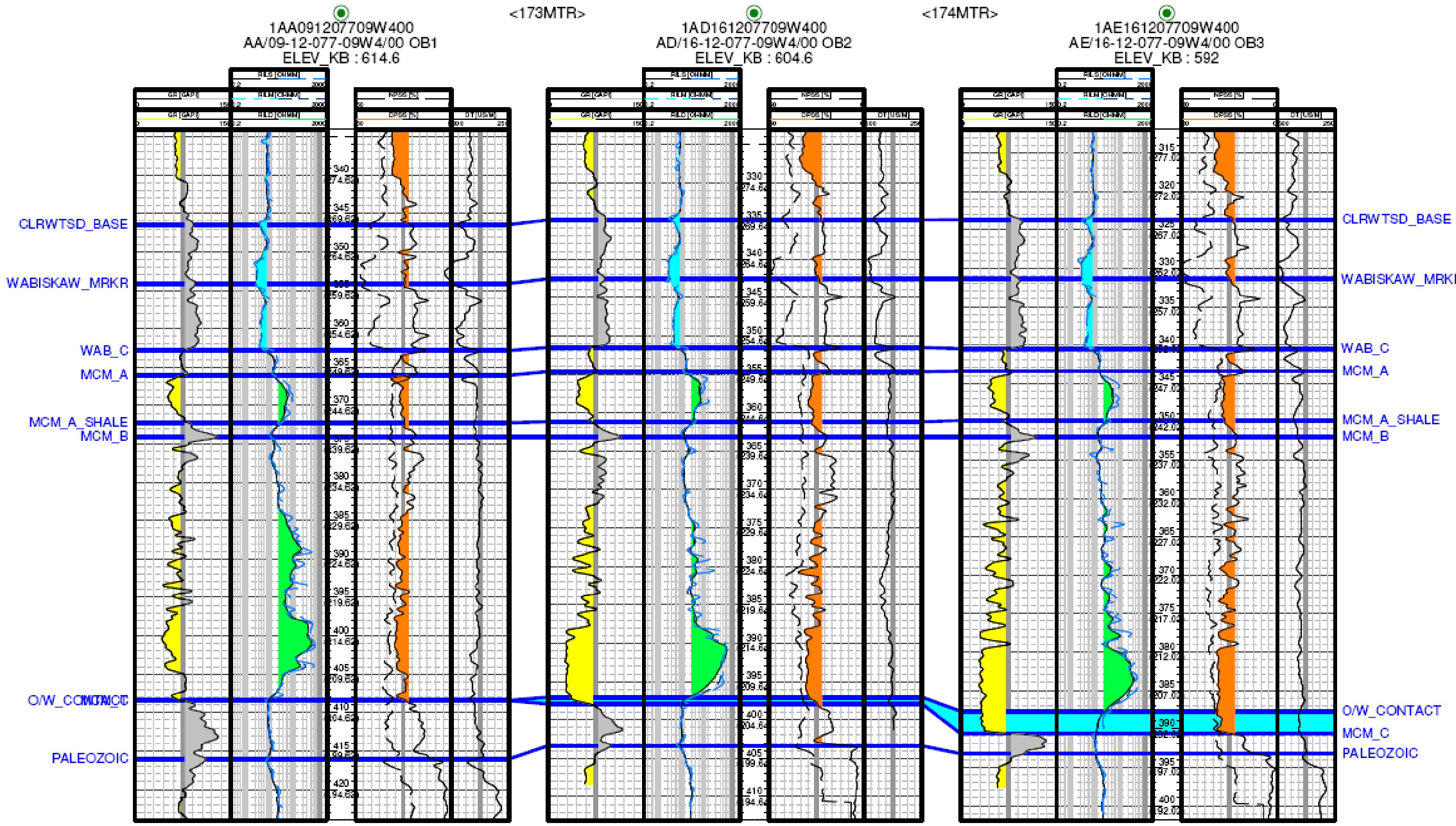


Figure 6 McMurray B Isopach Map

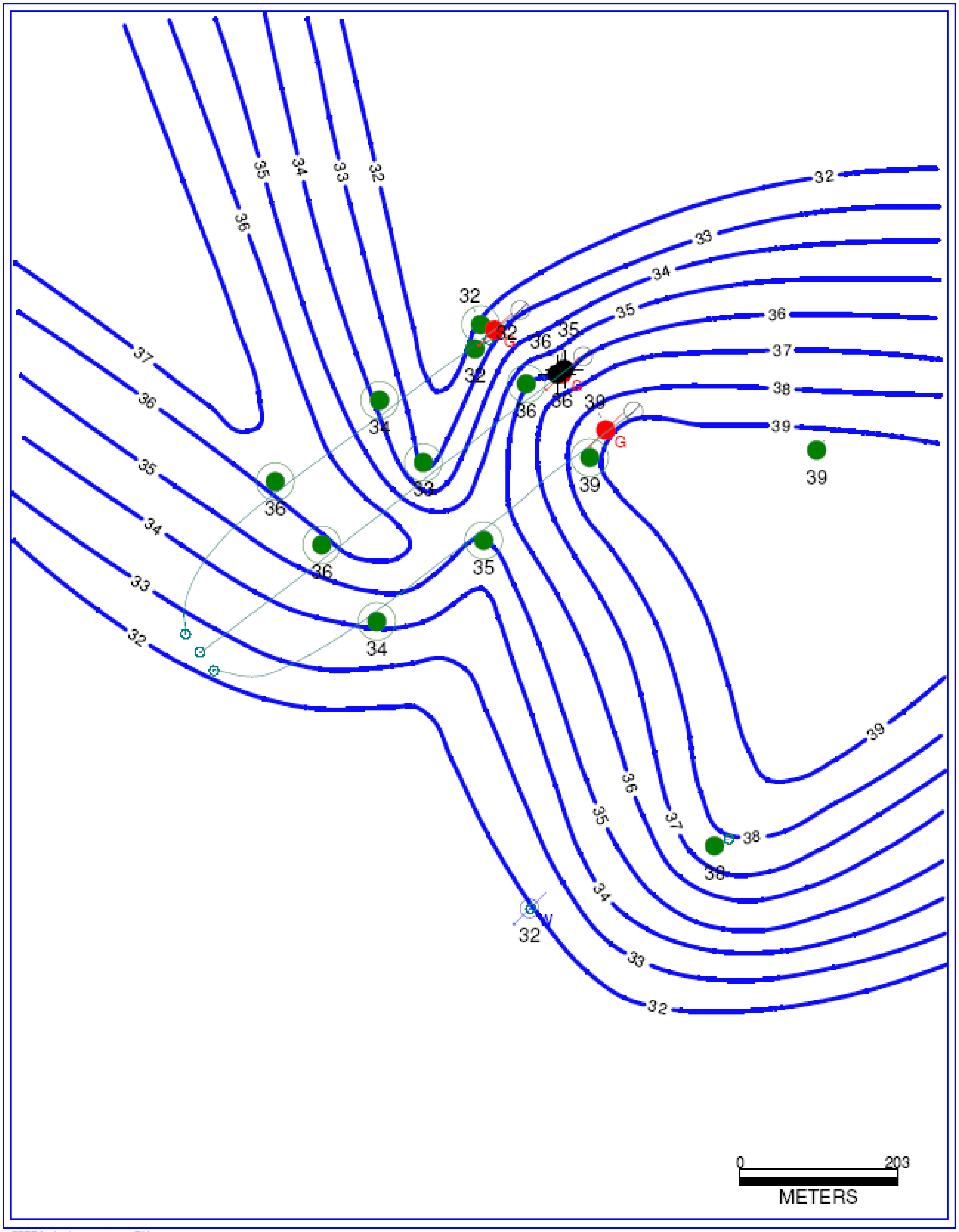


Figure 7 McMurray B Net Bitumen Isopach Map

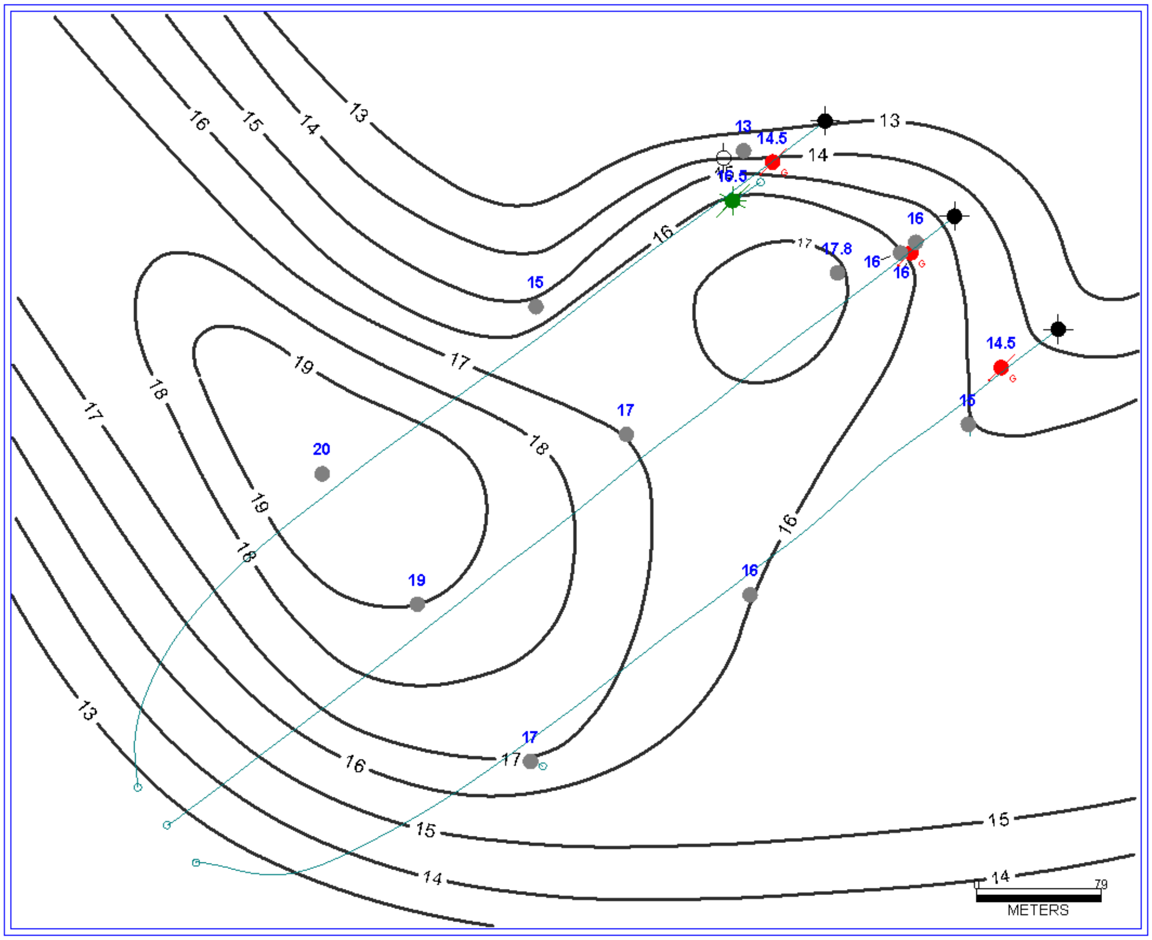


Figure 8 McMurray B Basal Sand Net Pay Isopach Map

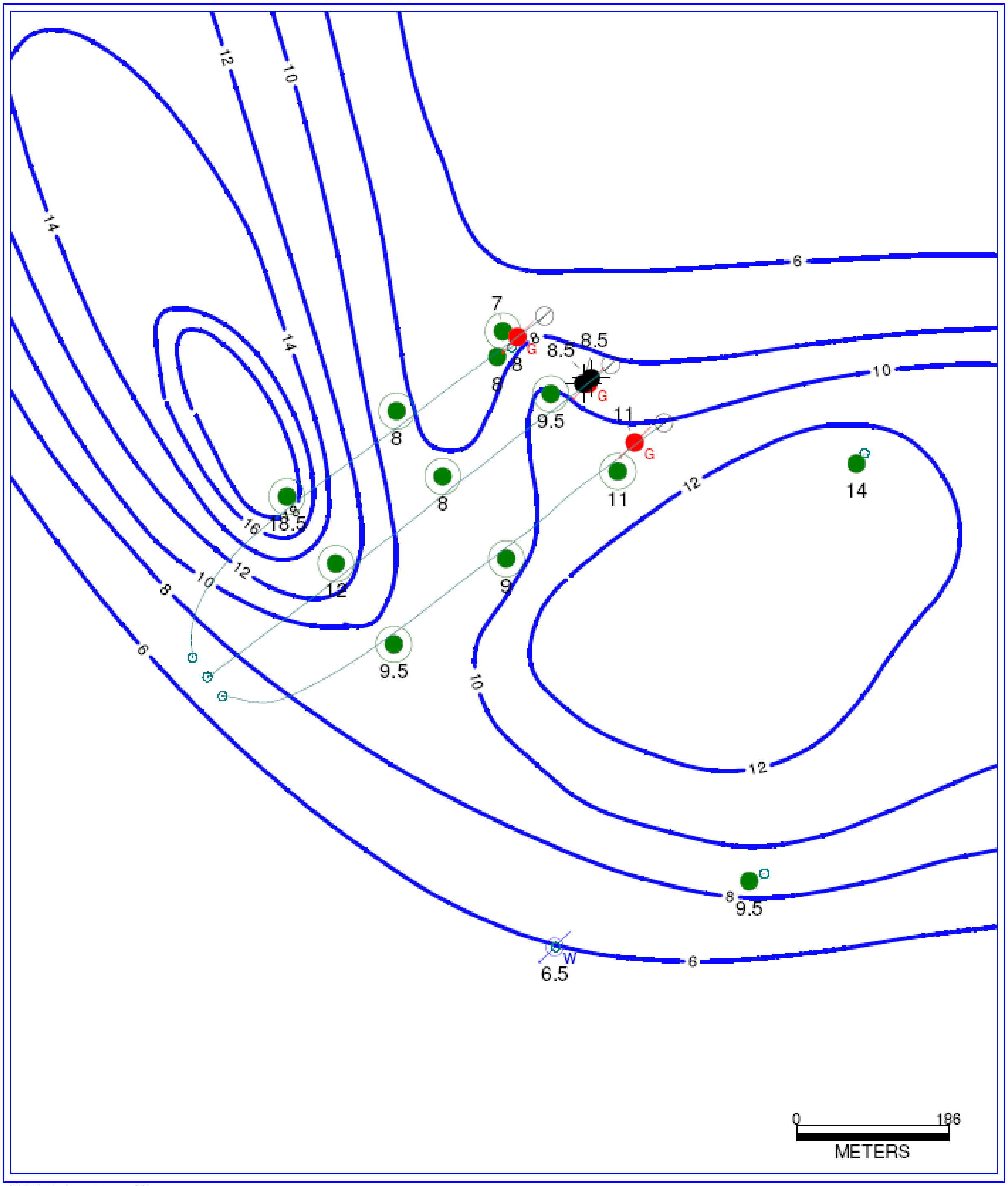


Figure 9 McMurray B Bottom Water Isopach Map

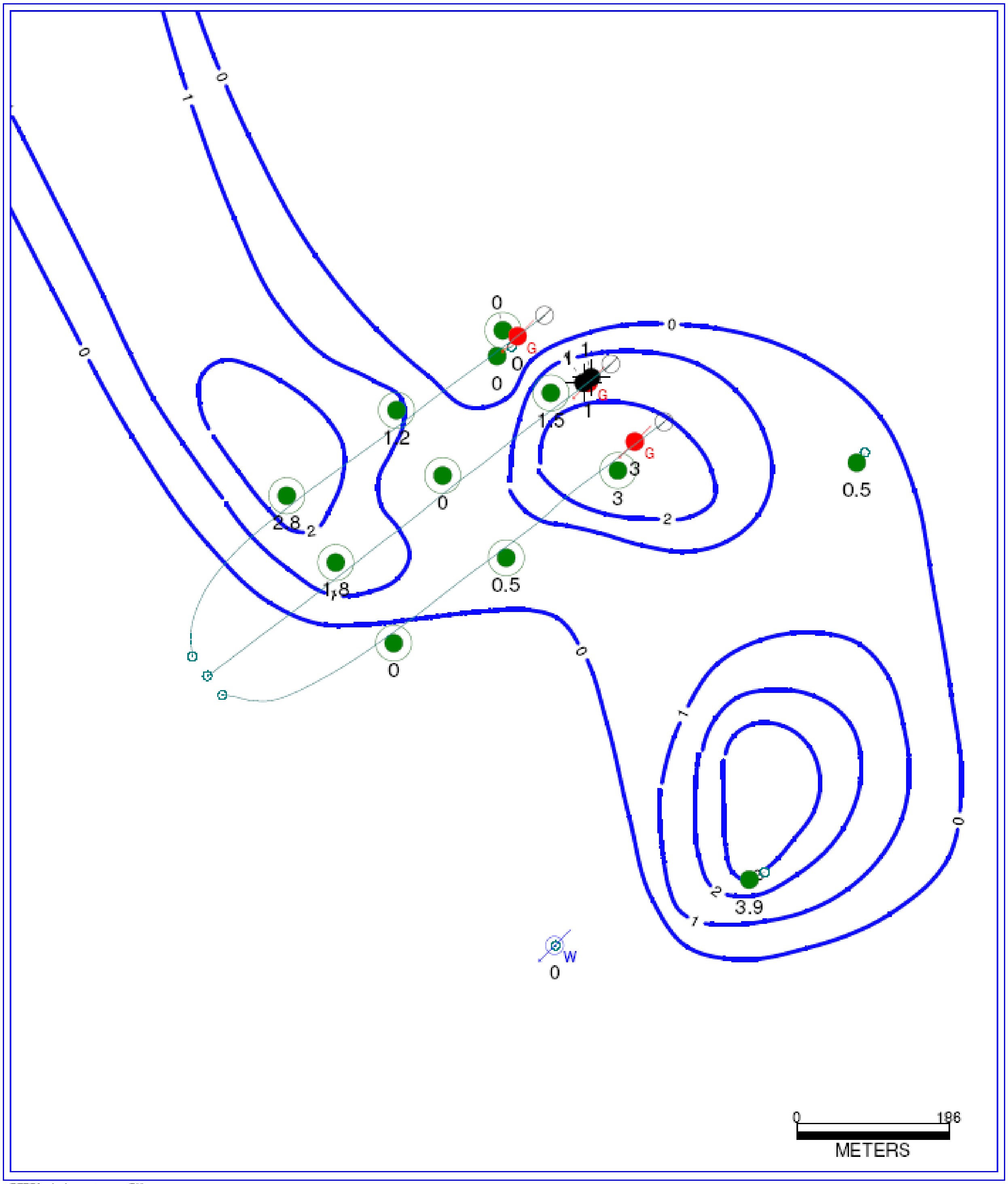


Figure 10 Top Gas Isopach Map

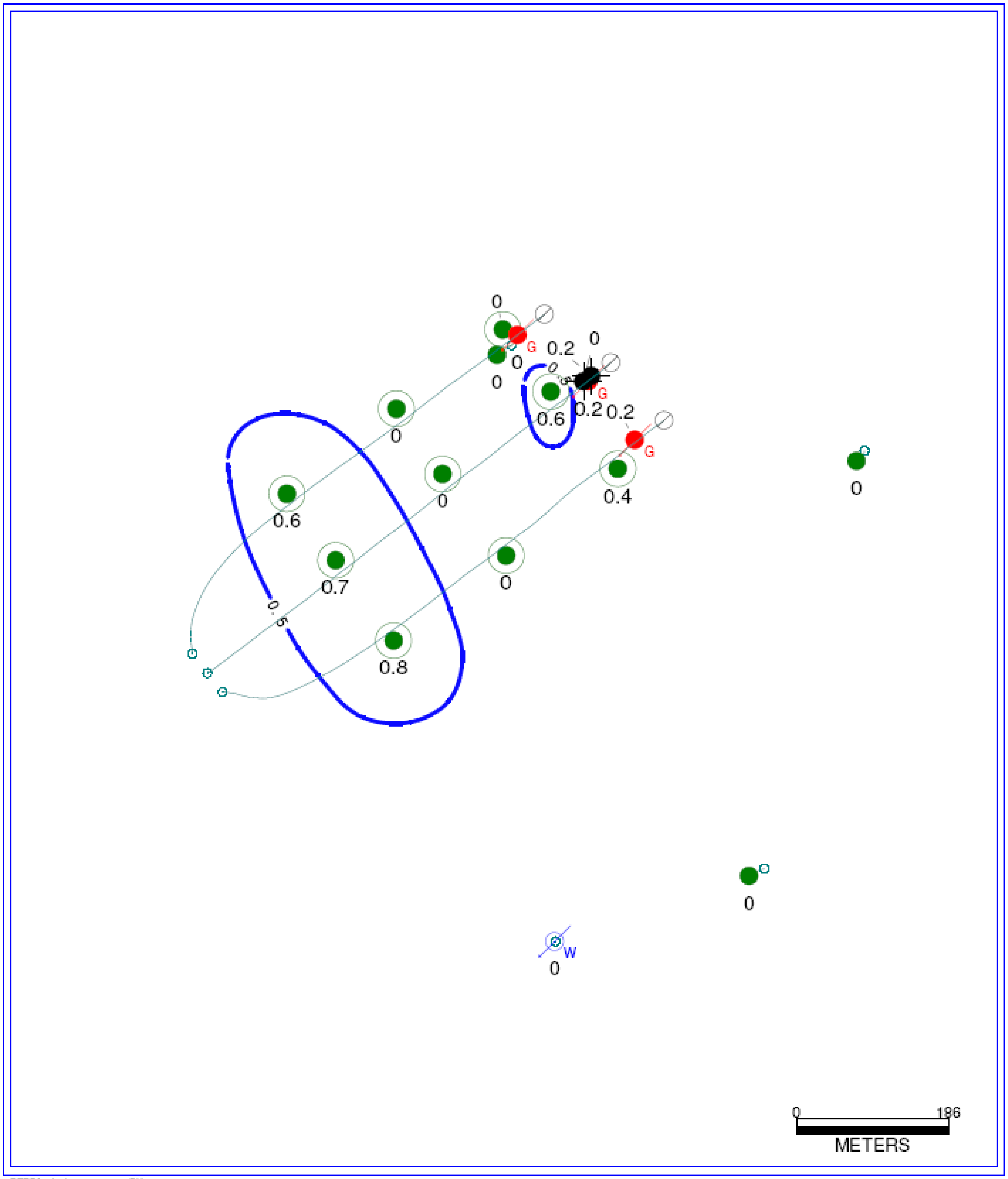
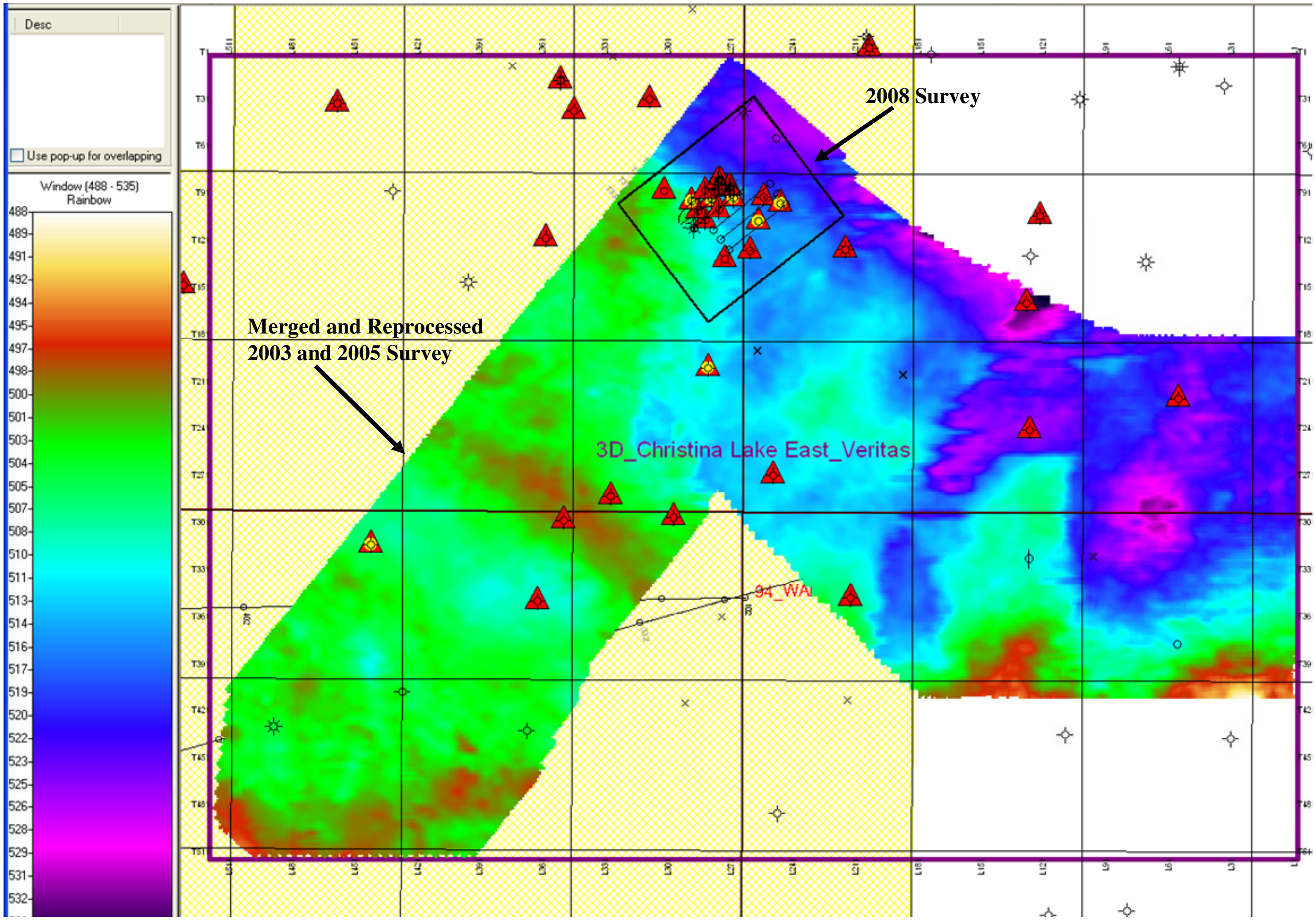


Figure 11 Seizmic Surveys



2 WELLS

The well spacing and pattern are depicted in Figure 12. Their relationship to the facilities is shown in Figure 13.

The project consists of three well pairs, each consisting of a vertical injection well and a horizontal production well. The project has a water source well, water disposal wells, several temperature observation wells and a pressure observation well for zones above the production zone, the Wabasca formation and the Clearwater.

Prior to drilling the three well-pairs observation wells labelled OB-1 to OB-9 were drilled and cased. These wells were equipped with sensors to aid in drilling the horizontal wells, then once the horizontal wells were done, thermocouples were placed and the wells were filled with cement.

Two additional wells were drilled at the toe of producer P-2 on alternate sides of injector A-2 after P-2 and A-2 were drilled. These wells were not cased. They were cemented with thermocouples in place.

The wells which make up the project are listed in Table 1.

Figure 12 Well Layout

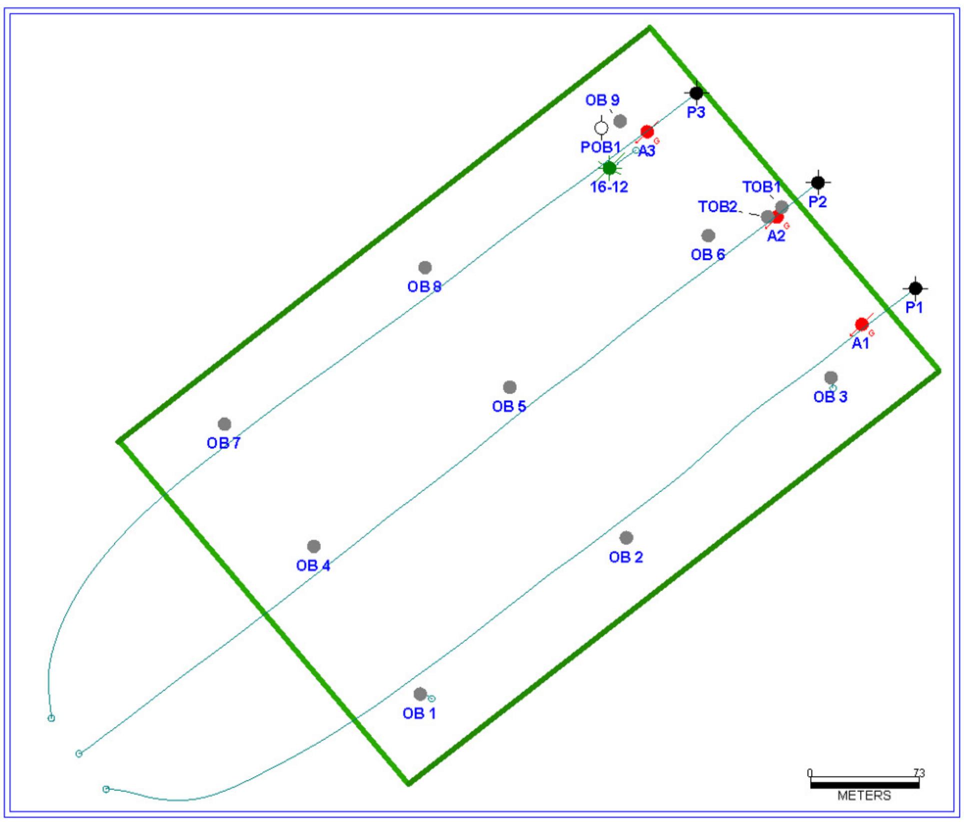


Figure 13 Site Map

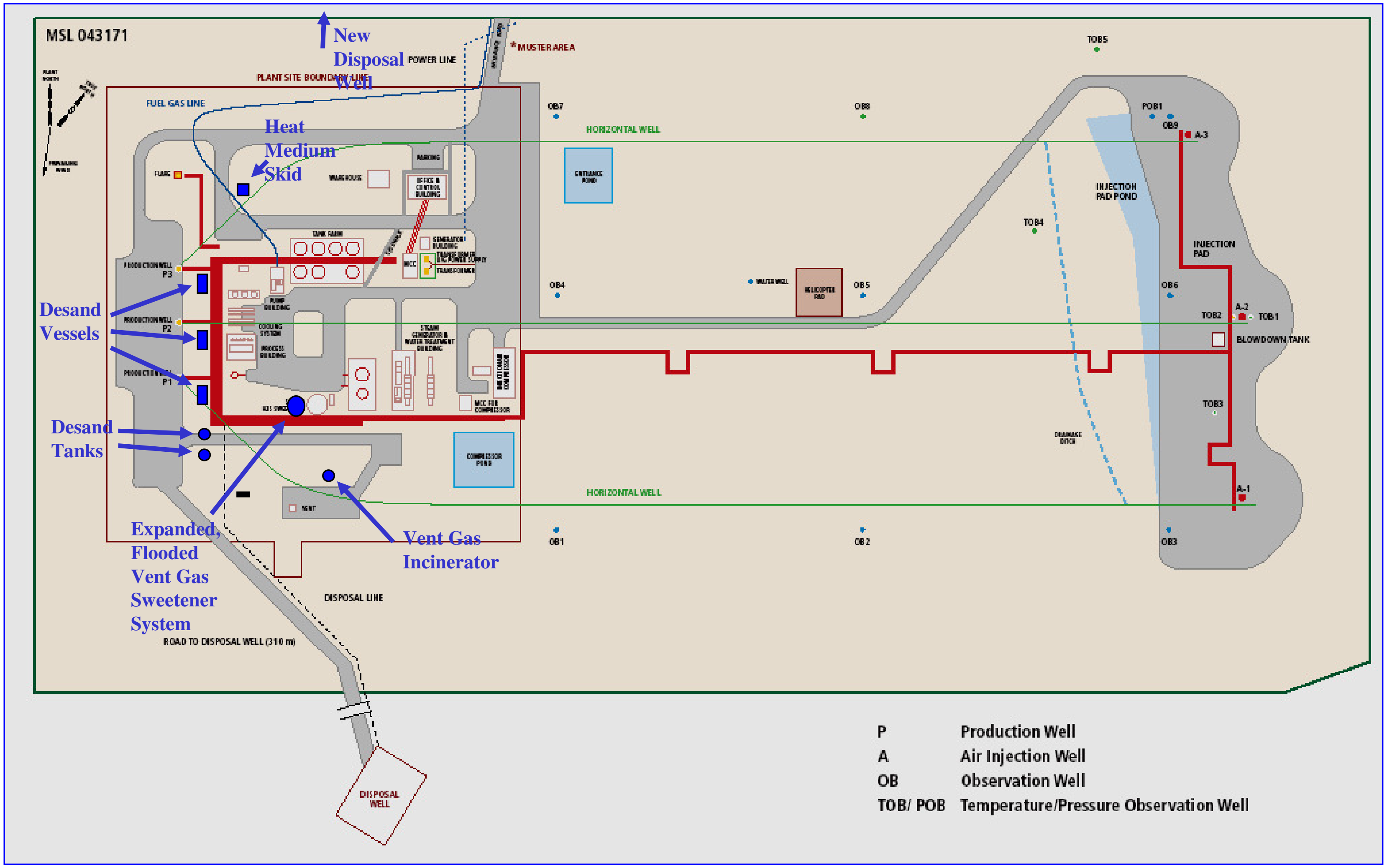


Table 1 Well List

Well	UWI	Status at End of 2007
Injection wells		
A1	AR/16-12-077-09W4M	On injection
A2	AP/16-12-077-09W4/0	On injection
A3	AQ/16-12-077-09W4/0	On injection
Production Wells		
P1	AH/16-12-077-09W4/0	On production
P2	AJ/16-12-077-09W4/0	On production
P3	AK/16-12-077-09W4/0	On production
Water Disposal		
WD1	00/08-12-077-09W4/0	On disposal
WD2	00/15-12-077-09W4/3	Standing
Water Source		
Source	F2/10-12-077-09W4/0	On production
Monitor	F3/10-12-077-09W4/0	Standing
Observation		
OB1	AA/09-12-077-09W4/0	Cemented full length
OB2	AD/16-12-077-09W4/0	Cemented full length
OB3	AE/16-12-077-09W4/0	Cemented full length
OB4	AA/15-12-077-09W4/0	Cemented full length
OB5	AB/16-12-077-09W4/0	Cemented full length
OB6	AC/16-12-077-09W4/0	Cemented full length
OB7	AB/15-12-077-09W4/0	Cemented full length
OB8	AF/16-12-077-09W4/0	Cemented full length
OB9	AG/16-12-077-09W4/0	Cemented full length
POB1	AU/15-12-077-09W4/0	Standing
TOB1	AN/16-12-077-09W4/0	Cemented full length
TOB2	AT/16-12-077-09W4/0	Cemented full length

2.1 Spacing and Pattern

The basic pattern for THAI is horizontal production wells with injection wells at the toes. The horizontal producers at the Whitesands Pilot Project are spaced 100 metres apart as is typical in SAGD operations.

The observation wells OB-1 through -9 were drilled before the horizontal wells to prove up reserves and provide instrumented guide points to help steer the horizontals. The vertical injection wells were drilled after the horizontal wells in case they had to be moved if the horizontals came up short or were too far off the planned trajectory. Afterward, thermocouple strings with 16 thermocouples spanning the McMurray formation and two above were cemented in place.

Two additional observation wells were drilled about 5 metres from the injection well A-2 to provide early results of the development of the combustion zone. TOB1 was offset in the toe direction of P-2 and TOB-2 was offset in the heal direction. These were not cased like the OB wells but the thermocouple spacing was the same.

A pressure observation well designated POB-1 was placed beside OB-9. It has pressure gauges landed in the Wabasca and Clearwater formations which are above the McMurray formation.

The spacing and pattern for the wells is shown in Figure 12.

2.2 Well Bore Completions

2.2.1 Production Wells

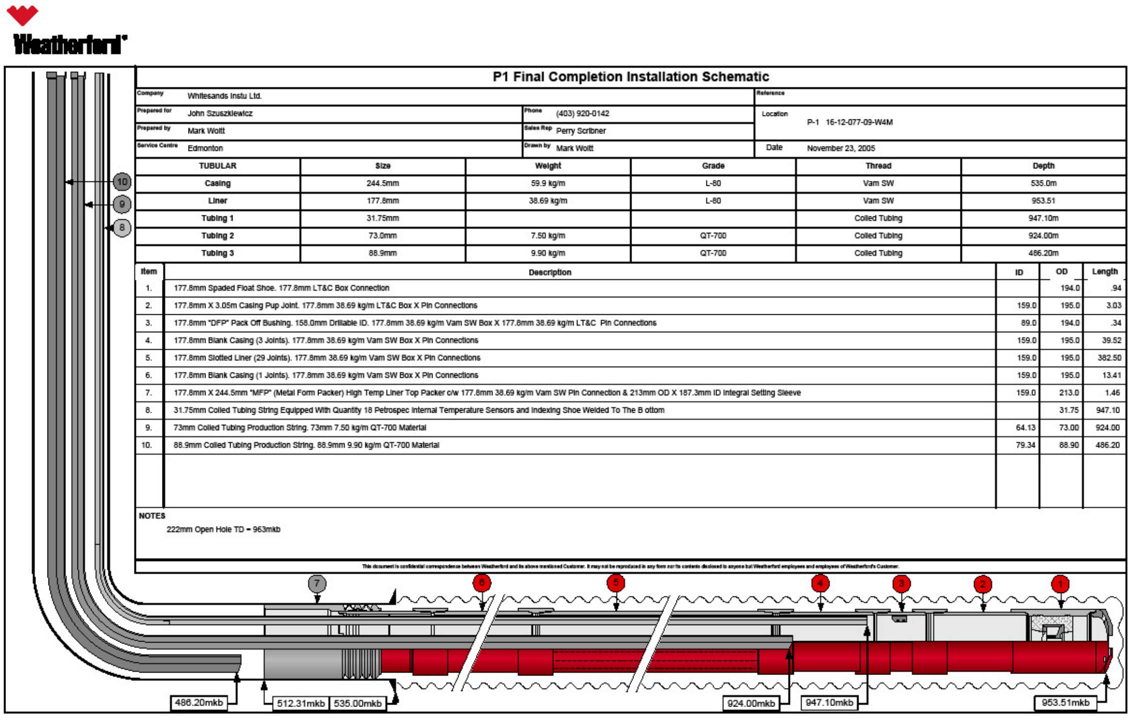
Production wells P-1, P-2 and P-3 are all designed as shown in Figure 14. Features of the production wells are:

- 244.5 mm intermediate casing from surface to horizontal at bottom of zone.
- 144.5 mm slotted liner from heal to about 30 metres from the toe of the well.
- 144.5 mm blank liner for the last 30 metres at the toe of the well.
- 88.9 mm production tubing landed at the heel just above the liner top.
- 73.0 mm injection tubing to the toe of the well.
- 31.8 mm coiled tubing string to the toe of the well with 18 thermocouples spanning the horizontal interval.

The three tubings were run side by side. The injection string was used to heat the formation around the well prior to air injection. Also, until there was sufficient heat in the surrounding formation steam injection was necessary to keep the bitumen hot and flowing. It was also a means of introducing heat to maintain lift on steam.

The main operating problem with the horizontal wells has been sand production which has created erosion and handling problems at surface. The slots in the P wells were formed by cutting 0.559 mm slots and rolling them to create a surface lip of only 0.457 mm. We plan to use a smaller slot size on future wells.

Figure 14 Production Well - Typical



P1 Final Completion Installation Schematic

Company	Whitesands Instu Ltd.	Reference	
Prepared for	John Szuszkiewicz	Phone	(403) 920-0142
Prepared by	Mark Woitt	Sales Rep	Perry Scribner
Service Centre	Edmonton	Drawn by	Mark Woitt
Location	P-1 16-12-077-09-W4M	Date	November 23, 2005

TUBULAR	Size	Weight	Grade	Thread	Depth
Casing	244.5mm	59.9 kg/m	L-80	Vam SW	535.0m
Liner	177.8mm	38.69 kg/m	L-80	Vam SW	953.51
Tubing 1	31.75mm			Coiled Tubing	947.10m
Tubing 2	73.0mm	7.50 kg/m	QT-700	Coiled Tubing	924.00m
Tubing 3	88.9mm	9.90 kg/m	QT-700	Coiled Tubing	486.20m

Item	Description	ID	OD	Length
1.	177.8mm Spaded Float Shoe. 177.8mm LT&C Box Connection		194.0	.94
2.	177.8mm X 3.05m Casing Pup Joint. 177.8mm 38.69 kg/m LT&C Box X Pin Connections	159.0	195.0	3.03
3.	177.8mm "DFP" Pack Off Bushing. 158.0mm Drillable ID. 177.8mm 38.69 kg/m Vam SW Box X 177.8mm 38.69 kg/m LT&C Pin Connections	89.0	194.0	.34
4.	177.8mm Blank Casing (3 Joints). 177.8mm 38.69 kg/m Vam SW Box X Pin Connections	159.0	195.0	39.52
5.	177.8mm Slotted Liner (29 Joints). 177.8mm 38.69 kg/m Vam SW Box X Pin Connections	159.0	195.0	382.50
6.	177.8mm Blank Casing (1 Joints). 177.8mm 38.69 kg/m Vam SW Box X Pin Connections	159.0	195.0	13.41
7.	177.8mm X 244.5mm "MFP" (Metal Form Packer) High Temp Liner Top Packer c/w 177.8mm 38.69 kg/m Vam SW Pin Connection & 213mm OD X 187.3mm ID Integral Setting Sleeve	159.0	213.0	1.46
8.	31.75mm Coiled Tubing String Equipped With Quantity 18 Petrospec Internal Temperature Sensors and Indexing Shoe Welded To The B ottom		31.75	947.10
9.	73mm Coiled Tubing Production String. 73mm 7.50 kg/m QT-700 Material	64.13	73.00	924.00
10.	88.9mm Coiled Tubing Production String. 88.9mm 9.90 kg/m QT-700 Material	79.34	88.90	486.20

NOTES

222mm Open Hole TD = 963mkb

2.2.2 Injection Wells

Injection wells A-1, A-2 and A-3 are all designed as shown in . Features of the injection wells are:

- 177.8 mm casing into the top of the McMurray formation.
- 114.3 mm liner with a wire wrap screen straddling the top of the basal McMurray and the IHS and another at the base of the McMurray on depth with the horizontal production well.
- 60.3 mm inner tubing from surface to a pack-off at the top of the lower screen.
- 114.3 mm tubing to the top of the liner and packed off from the casing.

This arrangement allowed steam to be injected at the base of the well to develop communication through the cold bitumen to the horizontal well and allowed steam or air to be injected to the upper screen.

We have experienced loss of isolation between the outer tubing string and the casing annulus on A-2 and A-3. A workover on A-3 found a collapsed tubing. The well has been recompleted with only the upper string. We no longer have to steam the lower part to establish bitumen mobility and air injectivity is not impaired, so the tubing string to the lower screen is no longer required. The annulus has been fully displaced to nitrogen so that if we ever do use steam again pressure build-up in the annulus will be minimal.

At this time we do not intend to change the injector well design but would ensure that the casing annulus has been displaced to nitrogen and not left with a column of water.

2.2.3 Temperature Observation Wells

Prior to drilling the three well-pairs observation wells labelled OB-1 to OB-9 were drilled and cased. Each of these wells had a sensor suspended in place to aide with steering the horizontal well as it was drilled past. Then thermocouple strings consisting of 16 thermocouples spanning the McMurray and two above the McMurray were placed and the wells were filled with cement.

Two additional wells were drilled at the toe of producer P-2 on alternate sides of injector A-2 after P-2 and A-2 were drilled. These wells were not cased. They were just cemented with the thermocouples in place.

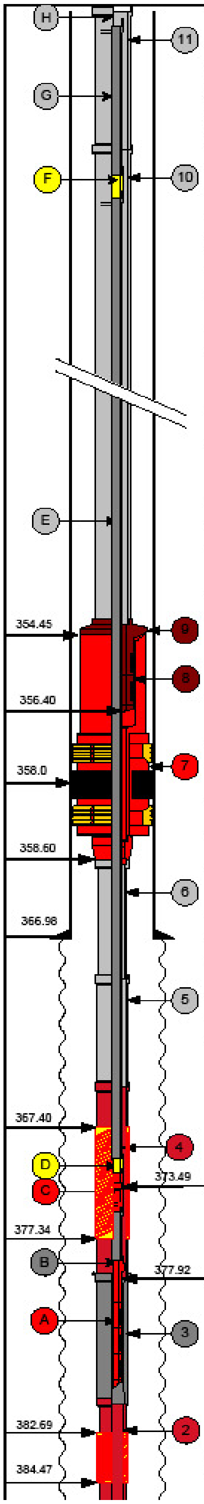
The thermocouples are read by a solar powered converter and transmitted by an RTU to the data acquisition system.

2.2.4 Pressure Observation Well

The pressure observation well was drilled through the Wabasca and cased. It has 0.33 metres of perforations in the Wabasca, a formation on top of the McMurray A formation and another set in the Clearwater formation above that. The two zones are isolated by a packer and pressure sensors are landed at perforation depth in the two zones. The pressure sensors are read by converters and the data is sent via the RTU at OB-9 to the data acquisition system.

There have been a couple of periods of spurious readings from these pressure sensors. However, early problems were corrected by troubleshooting the instrument system. A later problem was corrected by replacing the batteries on the solar power system.

Figure 15 Injection Well-Typical



Whitesands THAI A1 Injector Final Installation Report

Company	Whitesands Insitu LTD	Reference	69766
Prepared for	John Szuszklewicz	Phone	(403) 920-0142
Prepared by	Mark Woltt	Sales Rep	Perry Scribner
Service Centre	Edmonton	Drawn by	Laren Cruise
Location	Petrobank A1 Liesmer 16-12-77-9-W4	Date	Sept 19, 2006

TUBULAR	Size	Weight	Grade	Thread	Depth
Casing	177.8mm	38.68kg/m	L-80	Premium	366.98mKb
Liner	114.3mm	17.26kg/m	L-80	Vam Top	385.3mKb
Tubing 1	114.3mm	18.75kg/m	NKAC-80M	New NK3SB	
Tubing 2	60.3mm	6.84kg/m	L-80	Old NK3SB	

ITEM	DESCRIPTION	I.D.	O.D.	Length
	114.3mm Liner & Liner Packer			
1.	114.3mm Guide Shoe. 114.3mm 17.26 kg/m Vam Top Box		124.5	.25
2.	114.3mm X 2.0m DuraGrip Wire Wrap Screen With .006" Gauge. 114.3mm 17.26kg/m Vam Top Box X Pin, c/w Bottom .63m Blank Section and 1.42m Top Blank Section, L-80 Base Pipe Material, 825 Rib and Guage Wire	101.6	127.0	3.83
3.	68.27mm X 3.0m Polish Bore Receptacle. 114.3mm 17.26 kg/m Vam Top Pin X Pin c/w Coupling Connection, L-80 Material	68.27	124.5	3.35
4.	114.3mm X 10.0m DuraGrip Wire Wrap Screen With .006" Gauge. 114.3mm 17.26kg/m Vam Top Box X Pin, Bottom .58m Blank Section and 1.42m Top Blank Section, L-80 Base Pipe Material, 825 Rib and Guage Wire	101.6	127.0	11.94
5.	114.3 x 6.17m Pup Joint. 114.3mm 17.26 kg/m Vam Top Box X Pin	101.6	124.5	6.17
6.	114.3 x 1.21m Pup Joint. 114.3mm 17.26 kg/m Vam Top Box X Pin	101.6	124.5	1.21
7.	177.8mm UltraPak Permanent Packer c/w 120.6mm X 3.0m Upper Seal Bore & 101.6mm Lower Bore, PIPacker Thermal Element, 114.3mm 17.26kg/m Vam Top Pin Down, L-80 Material	101.6	148.7	4.15
	114.3mm Injection Tubing			
8.	120.6mm Single Piece (Integral) Seal Assembly w/ 3 Sets Thermal Optivee Seals, **2.71m Effective Stroke**, 114.3mm 17.26 kg/m Vam Top Pin Up Connection, L-80 Material	95.25	120.6	3.59
9.	120.6mm Seal Assembly Locator Sub. 114.3mm 17.26 kg/m Vam Top Box X 114.3mm 18.75kg/m New NK3SB Box, L-80 Material	100.3	143.5	.33
10.	36 Joints of 114.3 Tubing To Surface. 114.3mm 18.75 kg/m New NK3SB Box X Pin NKAC-80M Material	100.53	132.0	346.72
11.	114.3 X .51m Pup Joint. 114.3mm 18.75 kg/m New NK3SB Box X Pin L-80 Material	100.53	132.0	.51
	60.3mm Injection Tubing			
A.	68.27mm X 3.0m Single Piece Locator Seal Assembly c/w 3 Sets Thermal Optivee Seals & 60.3mm 6.84kg/m Old NK3SB Box Up X Half Mule Shoe Down. **2.68m Effective Stroke**, L-80 Material	47.63	79.50	3.30
B.	60.3mm X 2.46m Pup Joint, 60.3mm 6.84 kg/m Old NK3SB Box X Pin Connections. L-80 Material	49.40	73	2.46
C.	60.3mm "NCN" Landing Nipple c/w 47.63mm "XN" Profile & 45.49mm No-Go. 60.3mm 6.84 kg/m Old NK3SB Box X Pin. L-80 Material	45.49	77.70	.35
D.	60.3mm 6.84kg/m NK3SB Pin x 60.3mm 6.84kg/m NS-CT Box Crossover Sub, L-80 Material	49.00	73.0	.61
E.	39 Joints of 60.3mm 6.84kg/m NS-CT Tubing, L-80 Material	49.00	73.0	364.44
F.	60.3mm 6.84kg/m NS-CT Pin to 60.3mm 6.84kg/m Old NK3SB Box Crossover, L-80 Material	49.00	73.0	.44
G.	60.3mm X 2.48m Pup Joint, 60.3mm 6.84kg/m Old NK3SB Box X Pin Connections, L-80 Material	49.00	73.0	2.48
H.	60.3mm X 114.3mm Old NK3SB Tubing Hanger	49.00	120.0	.27

NOTES

The 114.3mm tubing string was landed with the seal assembly 1.60m from shouldering out on the packer to accommodate tubing length change

2.2.5 CAPRI™ Well Design

In May 2008 we were ready to drill a replacement to the P-3 well in order to install a CAPRI™ liner with smaller slots. This would allow us to test the in-situ catalyst concept. Replacing P-3 provided a much quicker regulatory approval than waiting for approval of a new well outside of the original, approved scheme area.

Figure 16 shows the liner concept. It consists of concentric slotted liners with catalyst trapped between. Sections of the liner are screwed together to span the length of the open horizontal section.

The inner and outer liner pipes are both slotted at 0.254 mm. This is about half the slot width on the existing P wells which should prevent the sand production problem experienced there.

In order to accommodate the liners, catalyst and the tubings that are to be run inside, a larger diameter outer liner, 244.5 mm, is required. The tubing arrangement has also been changed. As before the production tubing will be landed at the heel of the well, but a smaller diameter injection tubing and the instrument string will be run concentrically to the toe. This arrangement is shown in Figure 17.

Having the instrument string inside the long string simplifies the wellhead and, if necessary, well workovers.

Figure 16 CAPRI Liner

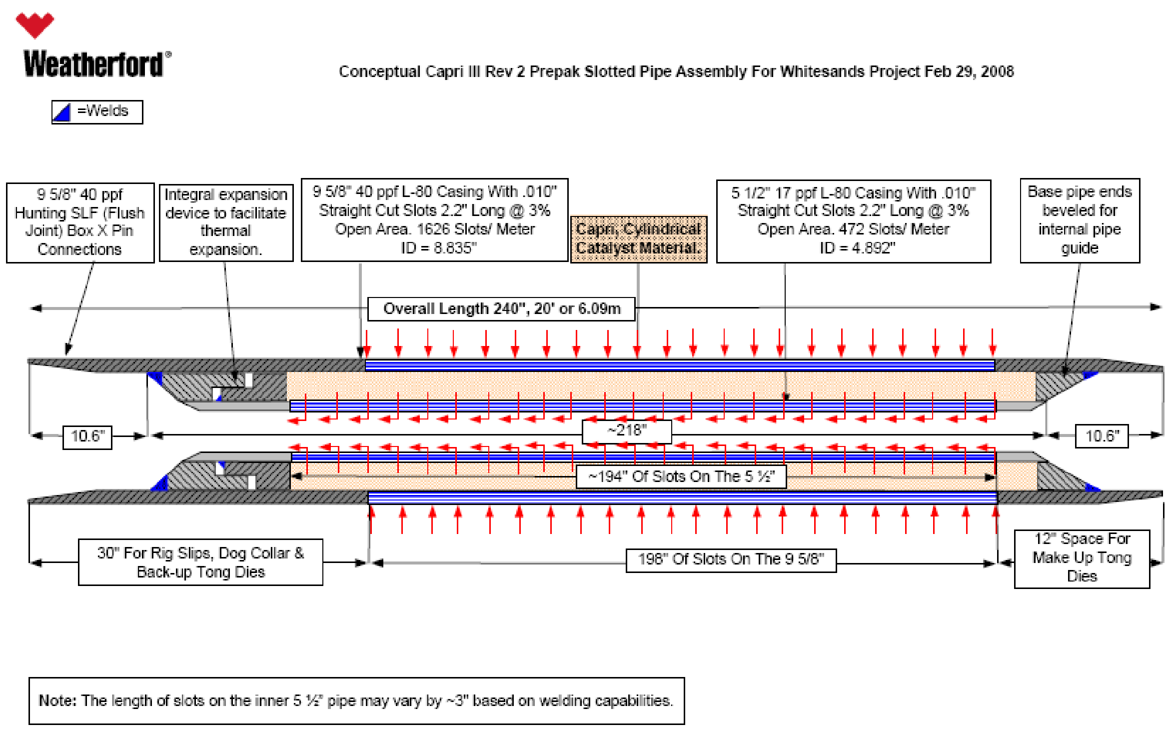
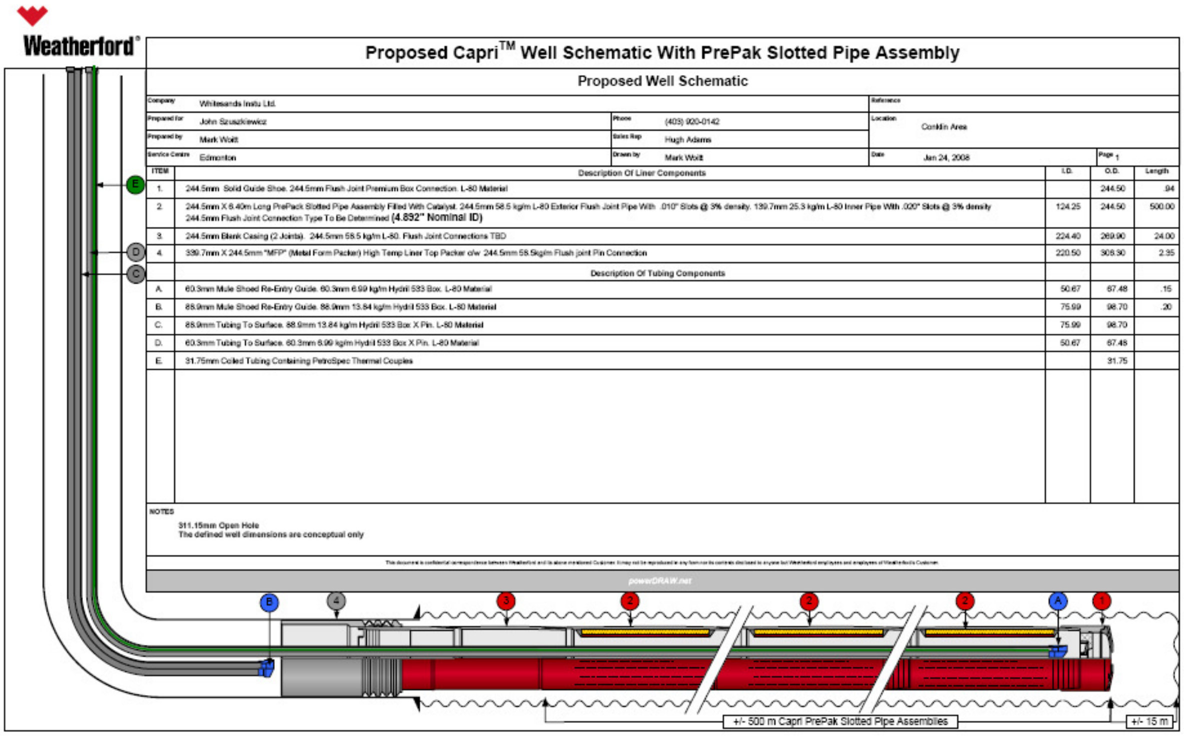


Figure 17 CAPRI Well Design



3 PILOT ECONOMICS TO DATE

Table 2 Annual Report - Pilot Economics

Innovative Energy Technologies Regulation - Project Approval No. 01-019
Annual Report - Pilot Economics for the Year Ended December 31, 2007

(Thousands of dollars)

Revenues		2007		Cumulative
Bitumen Sales	$	1,613	$	1,713

Crown Royalties		2007		Cumulative
Conventional & OSRR'97	$	16	$	21

Capital and Operating Costs		2007		Cumulative
Environmental				
Surface Hydrology & Groundwater Environmental	$	-	$	136
Utilities, Communications & Data Acquisition				
Electricity Consumer Distribution Contribution		-		208
Natural Gas Supply		53		524
SCADA & Wireless Equipment at Plant Site		127		535
		180		1,267
Engineering and Detailed Design		20		5,346
Drilling & Completion				
Stratigraphic/Observation Wells		3		3,207
Observation Wells		(34)		1,384
Water Source Wells		-		220
Disposal Wells		525		1,274
Air Injectors		138		2,591
Horizontal Producers		30		7,861
		662		16,537
Plant & Civil		1		21,150
Operating				
Electricity Expense		1,012		1,461
Labour, including R&D Monitoring		3,377		6,462
Services and Site Maintenance		13,443		16,407
Steam Rental		316		596
		18,148		24,946
Labour Benefits		285		471
	$	19,296	$	69,853

Cash Flow		2007
Loss from Operations	$	(21,467)
Capital Assets		(26,667)
Technology Partnerships Canada Financing (Note 1)		1,200
Taxes		-
After Tax Cash Flow	$	(46,934)

Note 1 Technology Partnerships Canada has committed to invest up to $9.0 million towards the development and field demonstration of the Company's THAI™ technology at the Whitesands project. Under this funding, $6.9 million was received in 2006 and $1.2 million was received in 2007 bringing the total cash received to $8.1 million as of December 31, 2007.

Table 3 Installed Equipment, Plant and Civil Costs

Innovative Energy Technologies Regulation - Project Approval No. 01-019
Annual Report - Pilot Economics for the Year Ended December 31, 2007
Installed Equipment and Plant & Civil Costs - Detail by General Ledger Account

Plant & Civil

Project#	Project Name	GL Acct#	GL Account Name	2007	Cumulative
1037000	WHITESANDS CORPORATE G&A	29040008	COMPUTER HARDWARE		67,802
9040276F	WHITESANDS 9-12-77-09W4 FACILITY	23020104	LOCATION PREPARATION/RESTORATION		5,125
		23020189	CONSULTING ENGINEERING SERVICES		8,783
		25620102	SITE PREPARATION		13,686
		25620104	SERVICE RIG		16,317
		25620180	SUPERVISION & TRAVEL		6,625
		25620189	CONSULTING ENGINEERING		2,587
		25620321	ROAD, CREEK, RAIL AND P/L CROSSINGS		10,329
9058011E	COMPUTER MODELING GROUP(CMG) STARS MODEL	22520006	CONSULTING (R&D/Process Modeling Software)		95,030
9058013F	CHRISTINA LK/LEISMER/WHITESANDS PILOT-S1	23020189	CONSULTING ENGINEERING SERVICES		3,110
		25620102	SITE PREPARATION		351,279
		25620103	LICENCES, PERMITS, SURVEY		15,784
		25620182	TRANSPORTATION		523
		25620186	SITE AND R/W RESTORATION		26,465
		25620189	CONSULTING ENGINEERING		91,328
		25620321	ROAD, CREEK, RAIL AND P/L CROSSINGS		536,788
		25630502	PUMPS AND ACCESSORIES		27,679
9058014F	CHRISTINA LK 16-12-077-09W4 FACILTY	22520006	CONSULTING (R&D/Process Modeling Software)		39,834
		25620102	SITE PREPARATION		729,685
		25620103	LICENCES, PERMITS, SURVEY		134,880
		25620180	SUPERVISION & TRAVEL		75,843
		25620181	EQUIPMENT RENTAL		1,151,618
		25620182	TRANSPORTATION		1,183,253
		25620185	MISCELLANEOUS		21,857
		25620186	SITE AND R/W RESTORATION		889
		25620189	CONSULTING ENGINEERING		35,949
		25620191	CHEMICALS		6,381
		25620192	LINEPIPE INSTALLATION		3,954
		25620193	XRAY INSPECTION & TESTING		309,198
		25620194	COATING & INSULATION		570,257
		25620303	CONTRACT LABOUR/WELDING		1,217,399
		25620305	INSTRUMENTATION AND AUTOMATION		174,847
		25620321	ROAD, CREEK, RAIL AND P/L CROSSINGS		1,333
		25620325	ELECTRICAL EQUIPMENT INSTALLATION		3,382,218
		25620326	CONCRETE WORK, PILES		88,840
		25620500	BUILDINGS		10,141
		25620502	PUMPS AND DRIVERS		9,080
		25620503	PRESSURE VESSELS		147,810
		25620505	TANKS		26,500
		25620507	PIPE, VALVES AND FITTINGS	28,673	68,093
		25620604	FOUNDATIONS		2,140
		25630401	TUBING AND PACKERS		2,607
		25630404	ELECTRICAL EQUIPMENT		1,149,352
		25630500	BUILDINGS		1,044,922
		25630502	PUMPS AND ACCESSORIES		201,142
		25630503	SEPARATORS, TREATERS		1,261,960
		25630505	TANKS		996,514
		25630506	FLARE AND VENT SYSTEMS		70,939
		25630507	PIPE, VALVES AND FITTINGS	-8,876	2,539,964
		25630560	STRUCTURAL STEEL		1,581,580
		25630600	H2S REMOVAL EQUIPMENT		160,141
		25630601	INTRUMENTATION, METERS	-18,772	925,614
		25630603	STEAM GENERATOR PACKAGE		24,730
		25630607	HEATERS, HEAT EXCHANGERS		302,734
9058046F	OPERATIONS EQUIPMENT 16-12-077-09W4	25620180	SUPERVISION & TRAVEL		7,149
		25620191	CHEMICALS		166,267
		25630403	OTHER TANGIBLE COSTS		36,636
		25630507	PIPE, VALVES AND FITTINGS		6,763
		25630510	START-UP FLUIDS		5,932
				1,025	21,150,278

4 SURFACE FACILITIES

The following provides a description of the original facility and modifications. Operational issues have consisted of sand production, H_2S production, treating and water disposal and are discussed below. For clarity, simplified flow diagrams are shown below. For plant layout see Figure 13.

4.1 Original Facility Design

The original plant was based on the following design criteria:

- Up to 100 m3/d bitumen production per well.
- Up to 85,000 standard m3/d gas production per well.
- Vent gas sweetener based on 250 ppm H2S.
- Up to 340 ºC production wellhead temperature.
- Up to 6400 kPa production pressure.
- Up to 85,000 standard m3/d air injection per well.
- Up to 8000 kPa injection pressure.
- Up to 26.4 GJ/hr steam injection.

To accommodate this throughput the facility was equipped as follows:

A production train per production well consisting of:

- Primary separator, gas cooler and secondary separator,
- Liquids meter and sampler on each separator,
- Gas meter of each secondary separator.
- Oil cooler and treater.
- Tanks.
  - 4 x 320 m3 for dilbit (a mixture of diluent and bitumen).
  - 2 x 320 m3 for produced water.
  - 1 x 120 m3 for diluent.
- Provision to recycle fluids off tanks.
- Pressure and temperature monitoring at wellheads and throughout the plant.
- Provisions for chemical injection and corrosion monitoring throughout the plant.
- Automated data collection from plant systems and observation wells.

Figure 18 shows a simplified drawing of the original facility excluding utilities. For clarity only one injection well and one production train is shown.

Production from each of the three horizontal wells went to its own hot, high pressure primary separator in which hot emulsion was separated from the produced gas. These hot liquids went to a mass flow meter, then were combined with that of the other inlet separators to go to an emulsion cooler and treater. The produced gas for each well went to its own gas cooler and cold, lower pressure separator. The condensed liquids were metered, sampled and combined with those of the primary separators before the treater. The remaining gas from each secondary separator was metered, sampled and combined before the vent gas system. Oil cut was by manual sampling and gas samples were taken daily and analysed on a gas chromatograph at site.

This system provided continuous monitoring of each well and, except for the addition of desand vessels, is used today.

For injection, a 7.9 GJ/hour steam generator was tied in as a permanent steam supply. This steam was to provide both the initial heat required to kick off the process and a source of steam that could be used for either gas lift or for temperature control in the production wells. It appeared that this should be sufficient steam as long as the well pairs were started one at a time. However, the facility was designed for a 26.3 GJ/hour steam generator and a temporary steam generator of 19 GJ/hour capacity was used to accelerate heating and later removed. Because the steam could have condensed water in it the quality of the steam reaching the wellheads was not precisely known, so the steam injection measured by independent wellhead meters was used to prorate the water used at the steam generator which can be accurately measured.

Air injection was directed to the injection wells only and metered by individual well meters.

The battery was equipped with diluent injection and fluid recycle each of which could go either ahead of the emulsion cooler. Either skimmed oil from the water tanks or water from the dilbit tanks could be brought back to the treater.

Basically, steam, air, diluent and recycle systems continue to be used as described above.

One disposal well for produced water was tied in. Since steam requirements for the pilot are small, water is sourced from a fresh water well and there is no provision in the facility for using the produced water for steam.

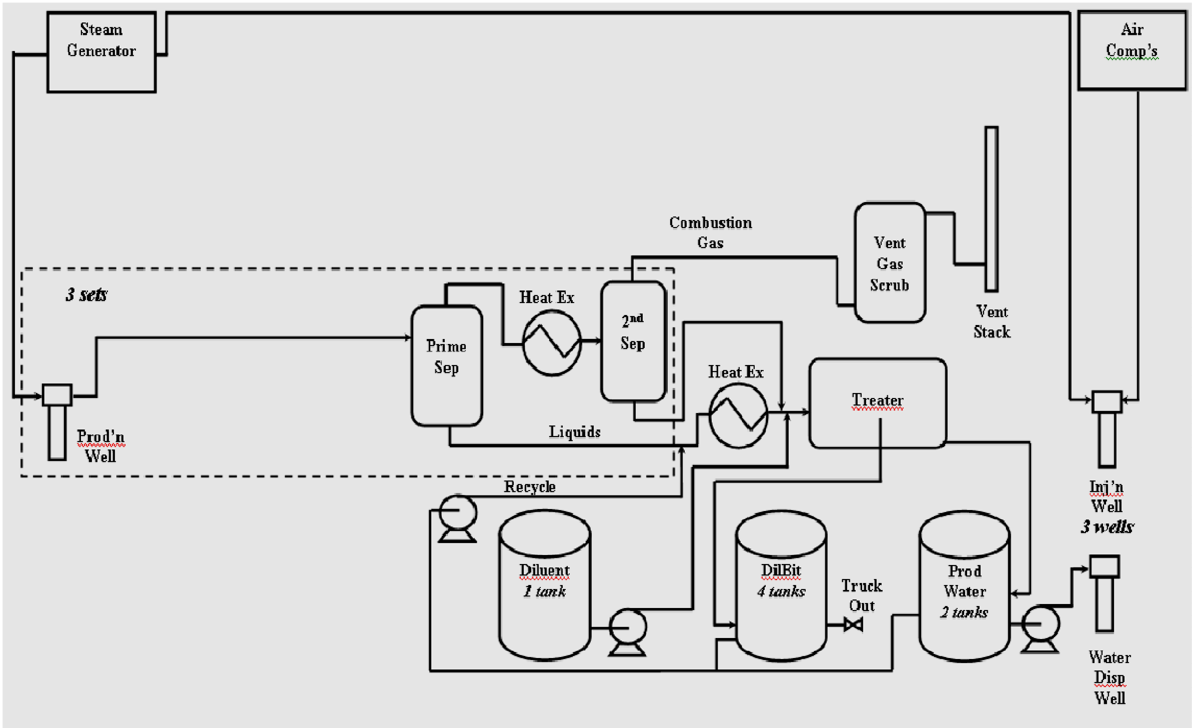
Dilbit is trucked out. Final bitumen production is from truck tickets less the diluent used.

We anticipated that diluent would be required for early production stimulated by steam heating to initiate the THAI™ operation since no upgrading would be occuring. It was not clear that ongoing diluent injection would be required long term. In fact, as upgrading by THAI™ has developed, we have been able to discontinue diluent injection for treating. Diluent is added at the truck-load sales point for pipelining, but that is outside of the plant metering.

The produced gas was directed to a Vent Gas Scrubber that held chemical that would bind up sulphur from H_2S. The gases were then vented to atmosphere since it is non-combustible. This system has been modified as described later.

Utilities consist of electricity, fuel gas and fresh water. The tanks and treater were gas blanketed with fuel gas. Gas off the tanks and treater is directed to a fired flare rather than to the produced gas vent.

Figure 18 Original Battery and Injection Facility



4.2 Facility Modifications

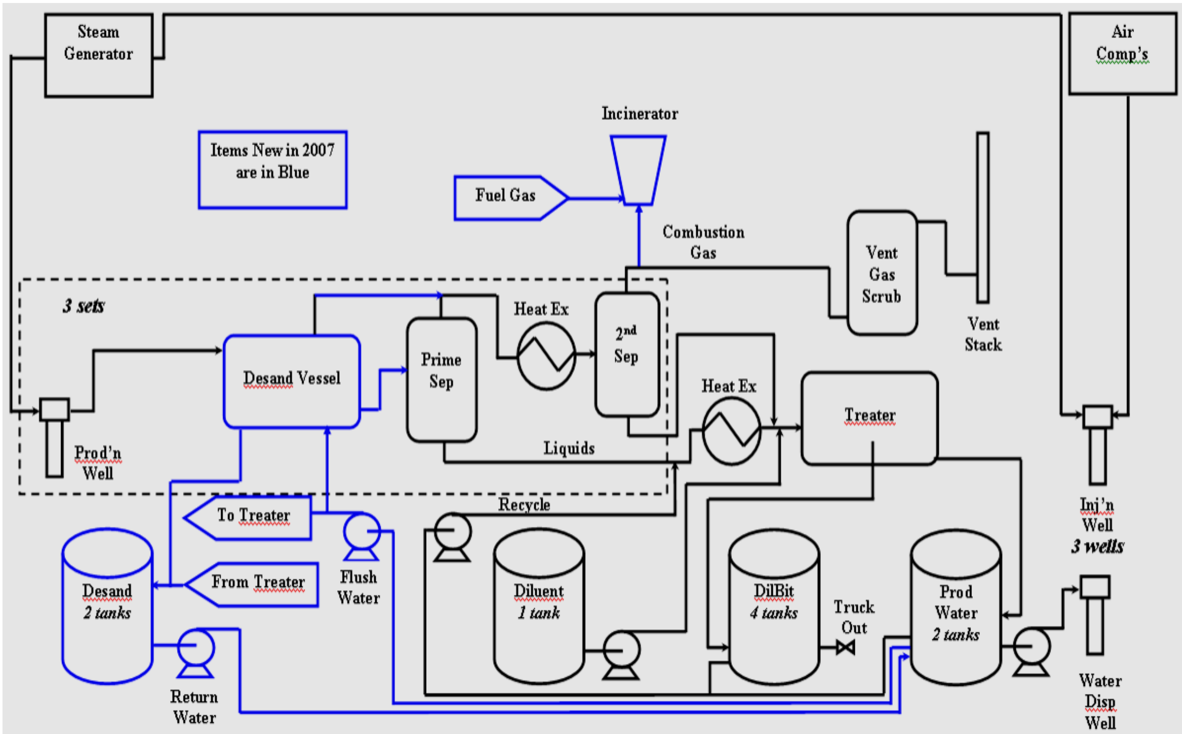
Since the completion of the original facility a number of changes have been made to deal with operational issues. These changes are shown in Figure 19. Two major problems have been addressed. One is sand production from the wells. The other is high chemical usage for H_2S removal. As well we have added a heat medium system to aid treating and another disposal well.

4.2.1 Sand Removal

The production wells have experienced high sand production which may be due to oversized slots for the formation sand. To that end we set up a desand vessel between P-2 and its separator and the treater was equipped with a desand system. Produced water was used to flush sand from this vessel to a pair of settling tanks. This water was returned to the produced water tank. Meters were included to measure the flush water used.

The above provided a proof of concept for removing the sand and all three wells have since been equipped with horizontal desand vessels. The treater and three vessels are flushed to the desand tanks and the flush water is returned to the produced water tanks.

Figure 19 Battery Modifications to End of 2007



4.2.2 H_2S Removal

The original plant design was based on estimated H_2S concentrations of only 100 to 150 ppm. Therefore a H_2S Scrubber sized to handle up to 142,000 standard m^3/d of vent gas as a static scrubber vessel, and up to 255,000 standard m^3/d of vent gas if converted to a flooded system was set up ahead of the vent stack. The H_2S concentration proved to be in the 3000 to 6000 ppm range with occasional excursions outside the range. Consequently the chemical consumption proved expensive and frequent shutdowns to change out the chemical were required.

Two modifications were made to the plant. First, a rental flooded tower system which was promptly available was obtained and piped in between the secondary separators and the vent gas scrubber. The second was an incinerator for the vent gas.

The flooded system allowed us to use the original scrubber as a polishing vessel to remove any residual H_2S and to regulate the flooded system to fully spend the chemical. Since this was a temporary system it is not shown in Figure 19. It did not reduce the chemical requirement but did allow us to operate continuously. We have since replace the temporary system with a permanent, higher capacity system.

Early in 2008 we installed a vent gas incinerator which would convert H_2S in the vent gas to SO_2. Throughput of the incinerator must be limited to less than 1 tonne of sulphur per day, but per unit of H_2S handled the fuel gas cost is lower than the chemical cost. The flooded system remains for use if the incinerator goes off line or if the sulphur emission reached the daily limit.

We are also investigating sulphur recovery systems that could efficiently and economically operate at the maximum anticipated rate of H_2S production with the addition of a three well expansion to the pilot.

4.2.3 Heat Medium system

One other operating issue has been treater operation. When we first designed the facility we assumed that all of the production would be hot and that we would only need cooling. We anticipated that on a start or restart the cold facility would promptly be heated back up by produced fluids.

However, wellhead temperatures have been less than anticipated, recycled fluid volumes have been greater and diluent, when required, is cold from the tank. These conditions have been aggravated by the frequency of shutdowns to deal with sand, by cycling colder flush water through the desand vessels and by the probable production of bottom water upstream of the firefront in the wells.

To help maintain heat in the treater a heat medium skid was installed and the dilbit and produced water tanks were retrofitted with heating coils. Now the recycle fluids and flush water used in the plant is hot, we maintain a higher treater temperature and we can achieve a clean oil cut.

4.2.4 Disposal Well Addition

By the end of 2007 we had also experienced a limited capacity on our disposal well. A new well was drilled to the north of the pilot project but was not yet in service.

The original disposal well was drilled into a McMurray water sand that appeared to be a separate zone of unknown extension below the tar sand layer and separated by a shale. Over time this zone appeared to pressure up and limit how much water could be injected.

In November, 2007 we drilled a well to test the Granite Wash, the Contact Rapids and the Keg River zones for water disposal. All proved unsuitable and the well was completed in the base of the McMurray. This zone is part of the formation being produced at the pilot but a water leg appears to develop and extend north of the pilot wells. This zone appeared to be the only suitable disposal zone in the area. Regulatory approval to use the new well was still pending at the end of 2007.

4.3 Future Changes

Planned facility changes will address the following:

- Tie in P-3B well which includes the CAPRI™ catalyst.
- Further modifications to the sand handling and removal systems to improve reliability.
- Upgrade plant metering and instrumentation as needed.
- Construction of facilites to accommodate three additional THAI™ /CAPRI™ wells:
- Install 5 tonne/day sulphur recovery unit.
- Install up to 85,000 m3/d additional air injection capacity.
- Add 3-phase separators for the new wells.

5 ENVIRONMENT/REGULATORY COMPLIANCE

Table 4 lists the principle regulatory approvals for the Whitesands pilot and their compliance status.

Whitesands has in-place several environmental monitoring and protection programs. These include:

- A 4 station passive sulphur monitoring program surrounding the plant site
- Daily monitoring of vent gas SO_2 and H_2S concentrations
- Annual plant surveys for fugitive emissions
- Plant site surface water runoff and containment system
- 12 shallow groundwater monitoring wells on the plant site
- Dedicated Empress aquifer groundwater temperature, quality and level monitoring
- Ongoing site revegetation, weed control and erosion control program
- Surface disturbance reclamation and reforestation program
- All oil field and domestic waste is disposed of at approved sites for example, CCS Janvier and Newalta Elkpoint

Whitesands has in-place a health and safety program as well as an emergency response plan. A full time health and safety staff member administers the program.

When the decision is made to discontinue operation and abandon the pilot a decommissioning plan will be developed as required by Section 5.2 of EPEA Approval 201967-00-01. At that time all equipment will be removed, any contamination issues remediated and the site reclaimed using the stored topsoil and subsoil.

Table 4 Regulatory Approvals Compliance List

Issuing Agency/Authority	Document	Compliance Status
EUB	EUB Approval 9770B for Pilot Project	Non compliance issues around housekeeping and production reporting have been resolved. Outstanding issues around approval amendment are being resolved. Application submitted to expand pilot by three wells.
	EUB Approval 10553 for Class II Water Disposal Scheme	In compliance
	EUB Interim Base of Groundwater Protection Request Form	n/a
	EUB F35859 Facility Licence	In compliance
	EUB Pipeline Approval 46996	In compliance
AENV	AENV Approval 201967-00-03 for Pilot Project and Letter of Non-	In compliance. Application submitted to expand pilot by

Issuing Agency/Authority	Document	Compliance Status
	objection to Final Development Plan, Industrial Runoff Control System and Conservation and Reclamation Plan	three wells
	AENV Licence 00227258-00-00 for Diverting Water and Operating Works (Plant Water)	In compliance
	AENV Licence 00225572-00-00 for Temporary Diverting Water and Operating Works (Drilling Water)	In compliance
	AENV Approval 201967-00-00 Authorization to Operate Temporary Steam Generator	18 MM btu steam generator removed from site Sept 2007
	AENV Letter of Consent to Add and Operate a Glycol Reboiler as per AENV Project APP 201967-00-00	In compliance
ASRD	ASRD OSE 030001 Letter of Authority – Leismer 2003/04 Core Hole Program	In compliance. Annual monitoring for vegetation establishment and weed control
	ASRD OSE 050005 Letter of Authority – Whitesands Phase II 2005/06 Exploration Program	In compliance. Requested closure
	ASRD OSE 050057 Letter of Authority – Leismer 2005/06 Core Hole Program	In compliance. Annual monitoring for vegetation establishment and weed control
	ASRD OSE 060010 Letter of Authority – Leismer 2006/07 Core Hole Program	In compliance. Annual monitoring for vegetation establishment and weed control
	ASRD OSE 060084 Letter of Authority – Whitesands Phase III 2006/07 Core Hole Program	In compliance. Annual monitoring for vegetation establishment and weed control
	ASRD Industrial Wildfire Control Plan 2007 Wildfire Information Bulletin – March 13, 2007	In compliance
	Letter of Authority OSE 070042 Leismer 2007/2008	In compliance. Annual monitoring for vegetation establishment and weed control
	Letter of Authority OSE 070054 Glover 2007/2008	In compliance. Annual monitoring for vegetation establishment and weed control

Issuing Agency/Authority	Document	Compliance Status
Misc. (miscellaneous agencies)	RMWB Permit No. 2004-0604 Development Approval – Oil Sands Plant	In compliance
	RMWB Permit No. 05/R/02 Boulevard Crossing Approval – Whitesands Access Road Approach	In compliance.
	DFO Letter of Authority ED-03-2788 – Culvert installation on unnamed creek (SW 13-77-9 W4M)	In compliance.
	ACD Historical Resources Act Clearance – Whitesands Experimental Pilot Project	In compliance.
	Project Approval Order No. OSR085 (Oil Sands Royalty Approval for Whitesands Project) (Expires March 31, 2009)	In compliance.

ABBREVIATIONS:

ACD – Alberta Community Development is now ABTPR

AENV – Alberta Environment

DFO – Department of Fisheries and Oceans

ERCB –Alberta Energy and Resources Conservation Board

HRA – Historical Resources Act

OSE – Oil Sands Exploration Program

RMWB – Rural Municipality of Wood Buffalo

6 LABORATORY STUDIES: LABORATORY THAI™ EXPERIMENT USING DEER CREEK OIL

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Laboratory THAI™ Experiment using Deer Creek Oil

Ahmed Shahin, Ph.D., Laboratory Supervisor and Conrad Ayasse, Ph.D., V.P. Technology, May 6, 2008

6.1 Abstract

A THAI™ in situ combustion test was conducted in Archon Technology's Calgary Research Centre using Deer Creek oil to evaluate the ease of combustion ignition, combustion stability, shape of the combustion front, composition of combustion gases, oil recovery factor and degree of oil upgrading. The test was entirely successful, with ignition at 300 ºC, high combustion temperature maximum of 650 ºC., stable combustion front movement with a quasi- vertical burning front, normal combustion gas composition with CO_2/CO ratio of >4, 70 % oil recovery, average oil viscosity of 48 cP and average API Gravity of 18.8 degrees. Asphaltene content was reduced by 77% and saturates were increased by 10%. Vanadium and nickel were reduced by 86% and sulphur 13%. Simulated distillation residue was reduced from 64.9% to 11.1%, adding substantially to the value of the bitumen.

6.2 Purpose

The purpose was to assess the suitability of Deer Creek oil for use in the THAI™ in situ combustion process based on the facility of ignition, stability of the burning front, front shape, sand temperatures, produced-oil properties such as viscosity, API gravity, SARA composition, sulfur content and the composition of produced gases.

6.3 Introduction

Until 2005, the only THAI™ 3-D combustion test cell was housed at the University of Bath in the U.K. Over 70 runs were conducted with that equipment by Dr. Malcolm Greaves and his IOR Research Group. A number of Papers emanating from the research are referenced in the Bibliography. Following Dr. Greaves retirement the equipment was dismantled. In 2007, Archon Technologies set up its own research Facilities in Calgary to continue the THAI™ and CAPRI™ research and to test a variety of oils for applicability to THAI™.

6.4 Procedures

6.4.1 Materials used

Artificial oil sand was prepared by making the homogeneous mixture given in Table 5. The sand and clay were placed in a cement mixer, the water added and then the oil. Homogeneity was assured by manually breaking up any lumps that formed while churning the mixture.

6.4.2 Cell completion and packing

A thick-walled 316 stainless steel 3-D Cell having dimensions 0.59 cm long x 0.46 cm wide x 0.19 cm high was fitted with a 1/4 inch inner lining of high-temperature ceramic insulation. The Cell had 72 thermocouple ports on the top surface. A production well consisting of a ¼ tubing perforated tubing having an 80-mesh screen wrapped around it to keep out sand was placed at the center base of the Cell. The last 4-centimeters of the tubing were not perforated to provide an offset of the first perforations from the points of air injection. Two 1/8 inch perforated air injection tubings penetrated the Cell at the upper corners. The Cell was packed with artificial oil sand by slow additions followed by tamping with a heavy steel rod having a plate at the end. The production tubing was passed through the gasketed end plate and the bolts were secured. Using a lab crane, the packed Cell was placed inside a large steel box under a fume shroud. Thermocouples were inserted in 9-rows of 8-each and reached to 3-levels inside the oil sand. A picture of the Cell is shown in Figure 20.

6.4.3 Experimental set-up

Figure 21 shows the experimental set-up. An air compressor provided air to the 3-D Cell at up to 689 kPa (100 psia). Nitrogen was available for Cell pre-heating at whatever pressure was required. Typically, the injection pressure was 517 kPa (75 psia) at start-up. Both the air and nitrogen were flow-controlled. Gas pre-heating, if desired, was provided by heating the 1/8 inch feed line with DC current from a DC inverted Arc welder. Cell surface temperatures were measured with thermocouples and controlled with band heaters. The produced fluids entered a hot separator, where high-boiling oil was recovered. The gas and low-boiling materials were cooled to separate water and oil from the gas phase and these liquids were combined with product from the hot separator. The cooled gas was passed through Drierite (anhydrous calcium sulfate), though CO_2 and O_2 continuous analyzers and finally through a gas chromatograph equipped with a thermal conductivity detector. A back-pressure control valve was placed on the gas stream after the cold separator to maintain Cell back-pressure at 172-207 kPa (25-30 psia).

6.5 Results And Observations

Hot nitrogen was introduced at the air inlets until the first thermocouples reached 300 ºC, then the feed gas was switched to air. A stable combustion was achieved after 3.5 hours, and the temperature profile was recorded every 10-seconds. During the test, the air rate was varied between 10 and 15 liters per minute, and the produced gas backpressure was controlled between 96 and 138 kPa (14-20 psia). Liquid samples of oil and water were collected every hour from the high-temperature and low-temperature separators and re-combined. The dried gas stream passed through a dual O_2/CO_2 continuous analyzer to monitor O_2 for safe operation and CO_2 to assess the efficiency of combustion. Calculated gas phase parameters measuring the efficiency of the burn are given in Table 6. Gas samples were analyzed hourly by gas chromatography and the average is shown in Table 7. The high CO_2/CO ratio is indicative of high-temperature oxidation. As a consequence of the high degree of bitumen cracking and upgreding, the H2S concentration in the produced gas was 1.1%.

The overall oil recovery was 69.6 % OOIP. Figure 22 shows the water and oil production rates, Most of the water was produced in the first half of the test, indicating that mobile water was flowing ahead of the combustion front. Figure 23 shows the cumulative liquid production. The end effect was apparent in the decline in liquid production over the last 4-hours of the test.

Table 8shows physical and chemical properties if the crude Deer Creek oil and average THAI™ oil from the test. Very substantial oil upgrading was indicated by a 10-degree increase in API gravity for THAI™ oil, a reduction in viscosity from > 300,000 cP to 48 cP , a decrease in asphaltenes from 16.92% to 3.85% and a 61% decrease in the oil average molecular weight. The increase of saturates increases the volume of motor fuels obtainable from the THAI™ oil. The increase in Bromine number is indicative of extensive cracking reactions and is close to the pipeline specification limit. The pH of produced water, shown in Figure 26, is between 1.6 and 3.0 in this test: however, in a reservoir the pH is expected to be naturally buffered to around neutral. The viscosity of each oil sample was measured at 3-temperatures and the result extrapolated to 20 ºC: results are shown in Figure 27. The viscosity of the oil composite sample was 48 cP. Simulated distillation data are listed in Table 10 and are plotted in Figure 28. Remarkably, only 11.1% of residue is left at 525 ºC., compared with 64.9% for the Deer Creek crude oil.

As indicated in Table 9, Deer Creek THAI™ oil has 86% less vanadium and nickel, although silicon and iron are increased: overall, the metal content is reduced 58%.

6.6 Conclusions

The 3-D Cell THAI™ test of Deer Creek crude oil indicated that it is an excellent candidate oil for the THAI™ oil recovery process. Coke deposition supplied ample fuel to achieve a stable high-temperature burn with 70 % oil recovery. The oil was substantially upgraded with regard to API Gravity, viscosity, SARA composition, metals content and distillation residue.

Table 5 Experimental parameters of 3-D cell

Cell Size	0.59m x 0.46m x 0.19m
Clean Sand	97% Sand + 3% Kaolin
Sand Porosity	26%
Combustion Mode	Dry
Pre-ignition	
Pre-ignition gas	Hot nitrogen
Rate of hot nitrogen gas, l/min	15
Maximum pre-ignition temp.	300ºC
Ignition	
Air injection rate, l/min	10 – 15
Air flux, m^3/m^2 hr	6 - 10
Back pressure, psig	14 - 20
Oil sand composition, kg	
Sand + 3% Kaolin	109.0
Oil	12.0
Water	5.0

Table 6 Calculated gas phase parameters

H/C ratio (Based on injection flux)	0.53
$CO/(CO+CO_2)$	0.18
O_2 Utilization, %	87.37
O_2/fuel ratio, m^3(ST)/kg	2.25
Air/fuel ratio, (m^3(ST)/kg	10.71
Air/oil ratio, m^3/m^3	2694
Oil recovery, (%OOIP)	69.6

Table 7 Produced gas composition

	mole% (average)
Hydrogen	0.28
Oxygen	2.38
Nitrogen	78.6
Carbon monoxide	3.06
Methane	0.87
Carbon dioxide	14.25
Ethylene	0.10
Ethane	0.25
Propylene	0.03
Propane	0.14
i-butane	0.00
n-butane	0.02
i-pentane	0.00
n-pentane	0.01
H_2S, ppm	11096

Table 8 Physical properties of crude oil and produced oil (average)

ANALYSIS	Crude Oil	THAI(tm) oil (average)
API gravity @ 15.6ºC	8.5	18.5
True density @ 15ºC	1.010	0.943
Viscosity @ 20Cº	309058	48
Acid number, mg KOH/gm	2.71	2.74
Bromine number, g/100g	2.22	10.71
Molecular weight, g/mol	673.8	264.2

SARA Analysis:

Asphaltene, %	16.92	3.85
Resin, %	28.31	11.41
Aromatics, %	30.75	26.65
Saturates, %	13.83	15.24
Volatile. %< 260 ºC	10.19	42.85

Table 9 Metal and sulphur analyses

Analysis	Crude Oil	THAI™ Oil
Metal content, mg/kg		
Tin	0.2	0
Lead	0.2	0
Copper	0	0
Aluminum	2	8
Silicon	5	13.1
Iron	8	49
Chromium	0.2	0
Silver	0	0
Zinc	3	1.2
Magnesium	0	0
Nickel	63	8.9
Barium	0	0
Sodium	2	0.4
Calcium	5	3.1
Vanadium	171	24
Phosphorous	0.7	1.2
Molybdenum	8	1.4
Boron	4	1.2
Manganese	0	0
Sulphur (Wt. %)	3.92	3.42

Table 10: Simulated Distillation Data

Crude Oil		THAI™ Oil	
% off	Temp. ºC	% off	Temp. ºC
0.5	204	0.5	117
5	295	5	187
10	344	10	224
15	384	15	250
20	422	20	271
25	457	25	289
30	494	30	306
35	536	35	322
		40	337
		45	351
		50	365
		55	380
		60	395
		65	410
		70	427
		75	445
		80	467
		85	497
		88	524
Percent Residue	**64.9**		**11.1**

Figure 20 Picture of 3-D Cell

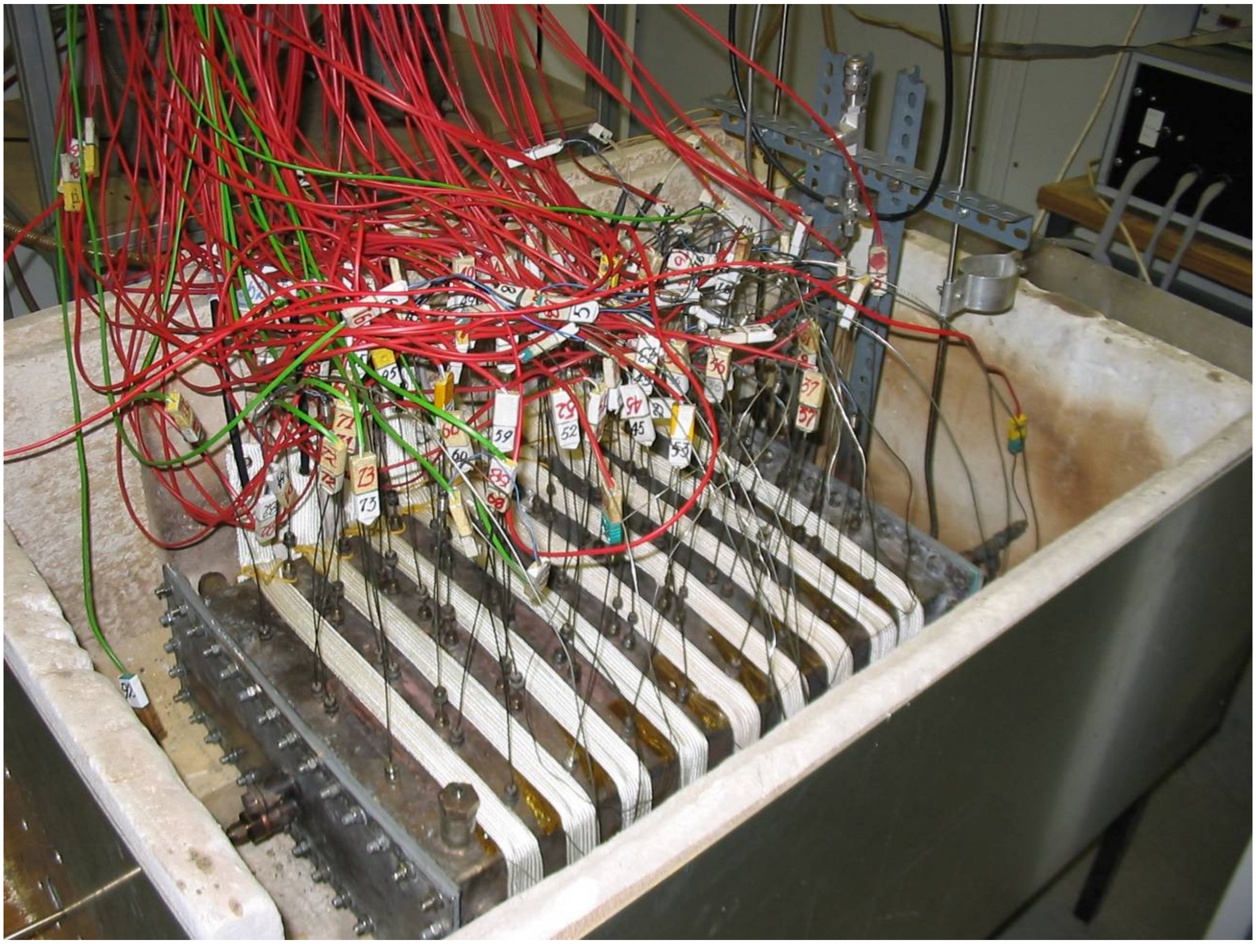


Figure 21 Schematic of the THAI™ 3-D Cell Process

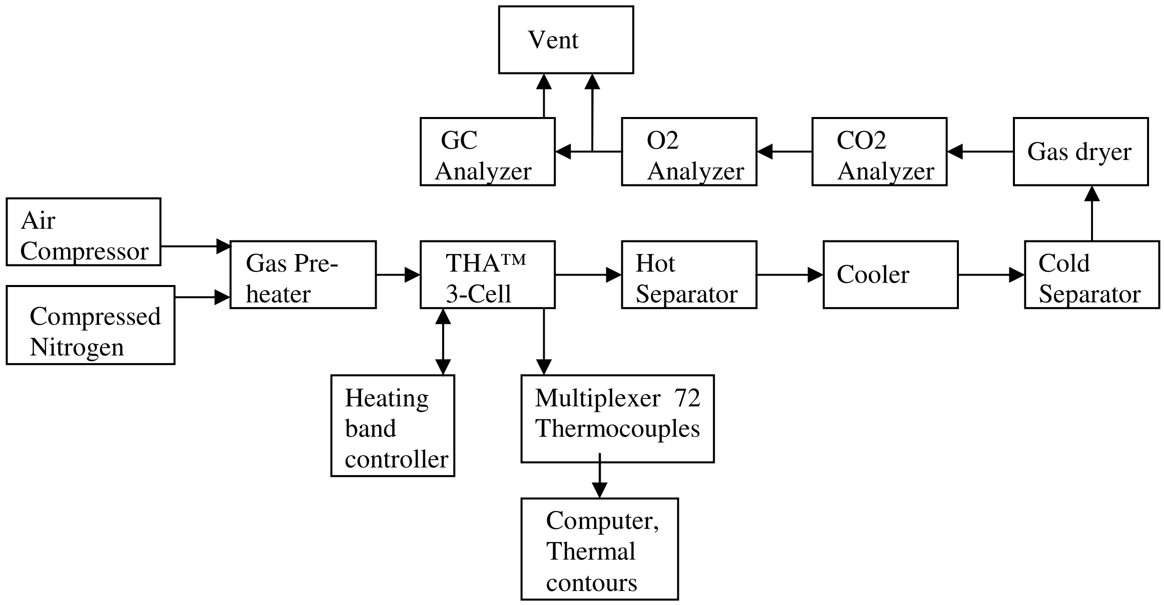


Figure 22 Water and Oil Production Rate, 3-D Cell

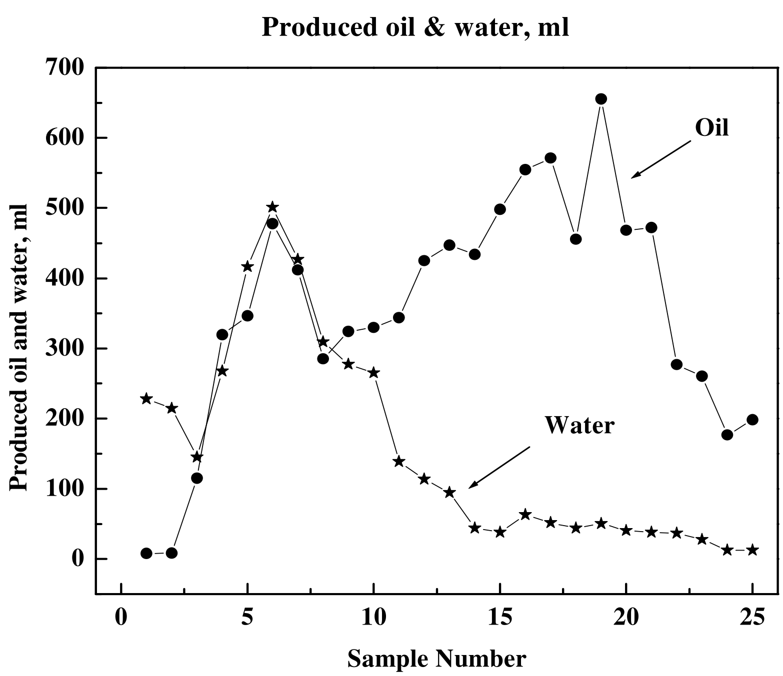


Figure 23 Cumulative Liquid Production, 3-D Cell

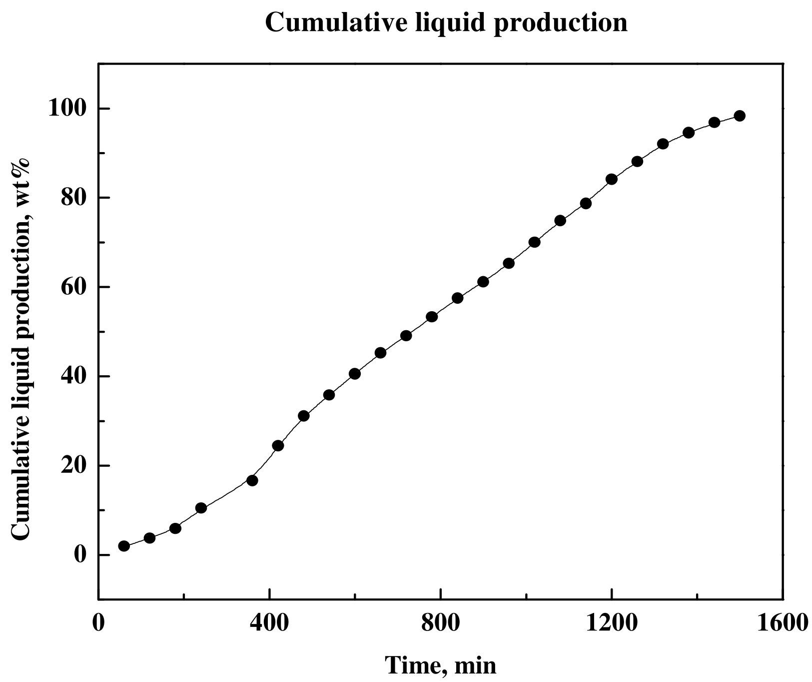


Figure 24 API Gravity @ 15.6 ºC, 3-D Cell

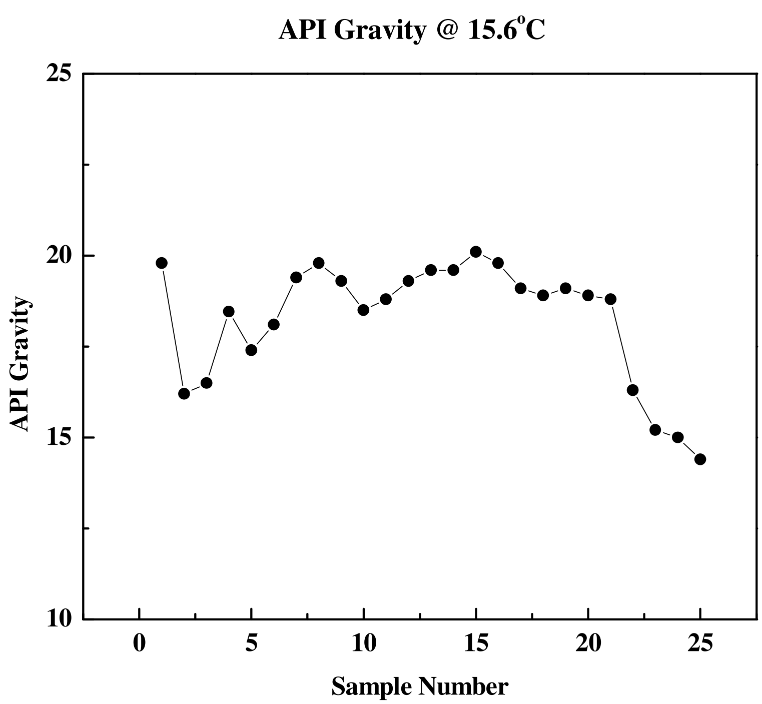


Figure 25 Density of Produced Oil, gm/cc @ 15 ºC , 3-D Cell

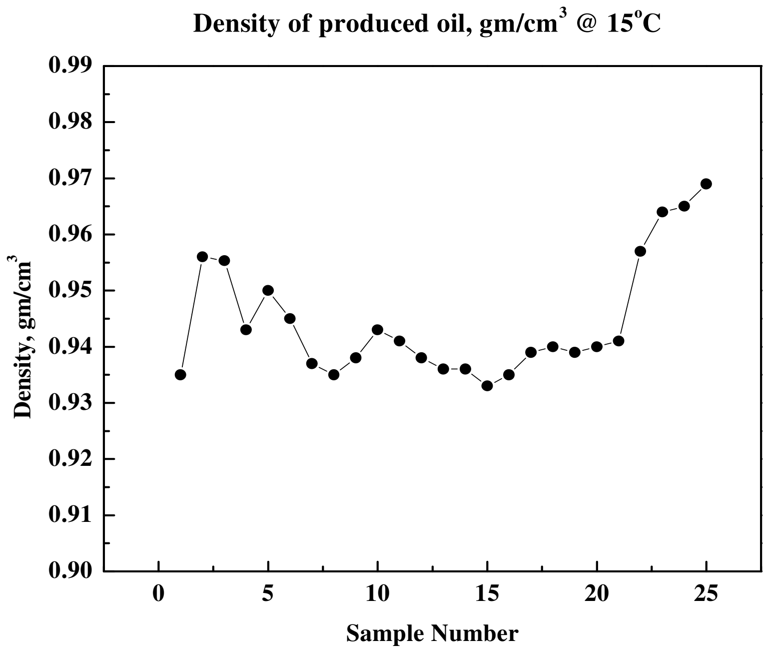


Figure 26 pH of the Produced Water, 3-D Cell

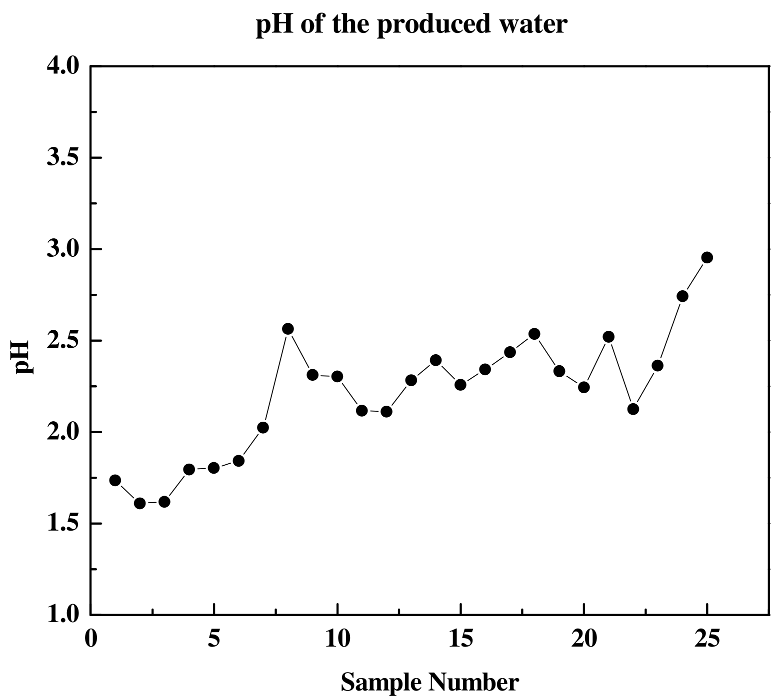


Figure 27 Viscosity of the THAI(tm) Oil Samples, 3-D Cell

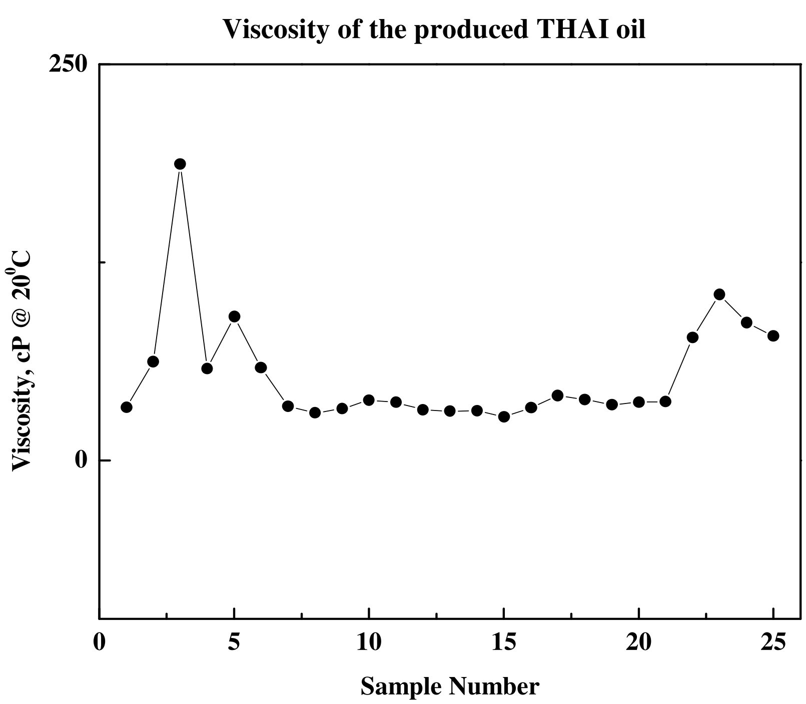
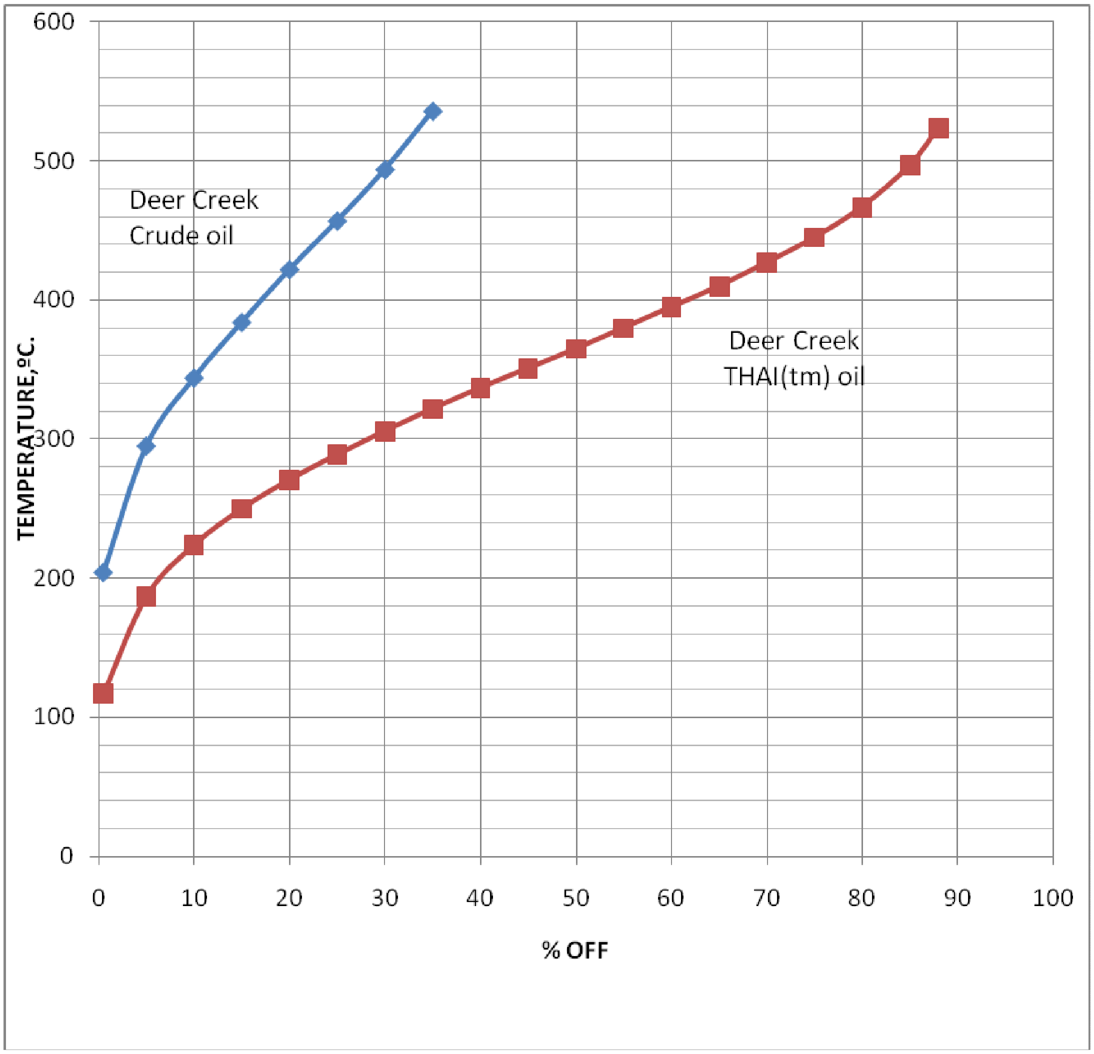


Figure 28 Simulated Distallation Curves, 3-D Cell



7 SIMULATIONS

7.1 Summary

This numerical simulation study was conducted to optimize the THAI™ horizontal producer well placement with a bottom active aquifer in Whitesands reservoir. In the existing wells P1 encounter bottom water at the toe, P2 at the toe and in the middle, where as P3 is a zone with bottom water at the heel.

Whitesands THAI™ production is from the McMurray formation with 3 pairs of air injection and production. One well pair symmetry was used to simulate the behavior of the active aquifer with respect to the well placement.

STARS 2007.12v simulator with the THAI™ model was used in this study for 3 different well placements with two minimum bottom hole pressure constraints to a total of 6 runs.

7.2 Model Discussions

The base model for this study is a homogenous model that was built by Computer Modeling Group in August 2007. A modified three dimensional Cartesian model, I J K 208x21x20 was built on this CMG dataset to model the aquifer effect.

A grid size of 2.5m was assigned for 196 grids on I direction and all grids on J direction and 1.0m for K direction. Also, the reservoir was extended in I direction on both sides to account for the boundary effects and the size of the grids were gradually ranged at 2.5m, 5.0m 10m, 20m, 40m and 80m. Then the reservoir was divided into 20 layers of 1.0m thickness.

The top 18 layers were designated as oil zone and the bottom 3 layers active aquifer (water) zone. The vertical, depth averaged, gravity equilibrium pressure was calculated as 2629.3 kPa at the oil water contact. The discretized wellbore, horizontal producer well 490m of length of was advantageously placed as follows:

1. 1.5 m above the oil water contact (above the aquifer) at layer 16 as shown in Figure 29.
2. 0.5 m below the oil water contact (top of the aquifer) at layer 18 as shown in Figure 30.
3. 2.5m below the oil water contact (base of the aquifer) at layer 20 as shown in Figure 31.

To introduce the aquifer effect, a horizontal source water well and a horizontal sink water well were also placed at the base of the aquifer, one each on both ends of the reservoir along J direction. The producer well and the source and sink wells were constrained by the bottom hole pressure and hence 2 BHP cases were generated, one with the aquifer pressure of 2629.3 kPa (adjustment in equilibrium pressure was made for the well above aquifer case) and the other at a reduced pressure of 1500 kPa, as summarized in Table 11.

In order to save time in the extended hours of THAI™ simulation a half well symmetry was used for both air injection and production. The model was ran from 2001-01-01 to 2011-01-01 for 10 years on all 6 runs with 3 months of PIHC followed by the air injection.

7.3 Conclusions

The post-processed results from the numerical simulation results show that the oil production is profoundly influenced by the well placement with respect to the active aquifer as well as the minimum bottom hole pressure constraint.

2629 BHP Constraint Cases (half-well production):

- The well placed 1.5 m above the aquifer produced the lowest cumulative oil of 77,589 m3 and the lowest cumulative water production of 37,404 m3.

- The well placed on top of the aquifer produced a cumulative oil of 84,973 m3 with a nominal cumulative water production of 41,175 m3. This case also had a better early time recovery of oil.
- The well placed on bottom of the aquifer produced a cumulative oil of 85,183 m3 and the highest cumulative water production of 43,902 m3.

1. Gas production was same in all three cases.

Comparative cumulative plots are shown in Figure 32, Figure 33 Comparison of Cumulative Water, 2629 BHP Constraint Cases & Figure 34 for oil, water and gas.

1500 BHP Constraint Cases (half-well production):

- The well placed 1.5 m above the aquifer produced a cumulative oil of 67,136 m3 and a cumulative water production of 218,210 m3.
- The well placed on top of the aquifer produced a cumulative oil of 67,103 m3 with a cumulative water production of 217,980 m3.
- The well placed on bottom of the aquifer produced the lowest cumulative oil of 64,992 m3 and a cumulative water production of 216,540 m3.

2. Gas production was same in all three cases.

Comparative cumulative plots are shown in Figure 35, Figure 36, & Figure 37 for oil, water and gas.

7.4 Recommendations

- The optimum well placement strategy is to place the Horizontal well on top of the aquifer, which is 0.5m below the oil water contact to maximize the oil production at a nominal water production
- Production well Minimum BHP constraint to be maintained ideally at ~ 20 kPa above the aquifer pressure (2629.3 kPa) to avoid aquifer encroachment into the well bore.

Table 11 Well Placement Run Data

THAI™ STARS SIMULATION

ACTIVE AQUIFER MODEL

WELL PLACEMENT RUN DATA

- Grid Size (I J K) : 208 X 21 X 20
- Dimensions: 805 m X 50 m X 20 m
- Pay Thickness: 17 m Oil & 3 m Bottom Water
- Saturations (Oil/Water): 0.8/0.2 & 0.2/0.8
- Horizontal Length: 477.5 m / 80.0% completed
- Well Spacing: 100 m

- Discretized Well bore model with Dilation included
- Active Aquifer model with Hz Source and Sink Wells along J direction

THAI™ SIMULATION ON CMG STARS

WELL PLACEMENT RUN SUMMARY

RUN NO.	HZ PRODUCER WELL PLACEMENT	SENSITIVITY	INJ. CONSTRAINTS		PROD. CONSTRAINTS		COMMENTS
			Air Inj. Rate	Max BHP	Liquid Rate	Min BHP	
			m^3/d	kPa	m^3/d	kPa	
1	Top of Aquifer - 2629	Aquifer Pressure at Layer 20	85,000	10, 000	200	2629	10 years. Run completed.
2	Top of Aquifer - 1500	Reduced Pressure	85,000	10, 000	200	1500	10 years. Run completed.
3	Base of Aquifer - 2629	Aquifer Pressure at Layer 20	85,000	10, 000	200	2629	10 years. Run completed.
4	Base of Aquifer - 1500	Reduced Pressure	85,000	10, 000	200	1500	10 years. Run completed.
5	1.5m Above Aquifer - 2609	Adjusted Pressure for Layer 20	85,000	10, 000	200	2609	10 years. Run completed
6	1.5m Above Aquifer - 1500	Reduced Pressure	85,000	10, 000	200	1500	10 years. Run completed

Figure 29 Well Above Oil-Water Contact

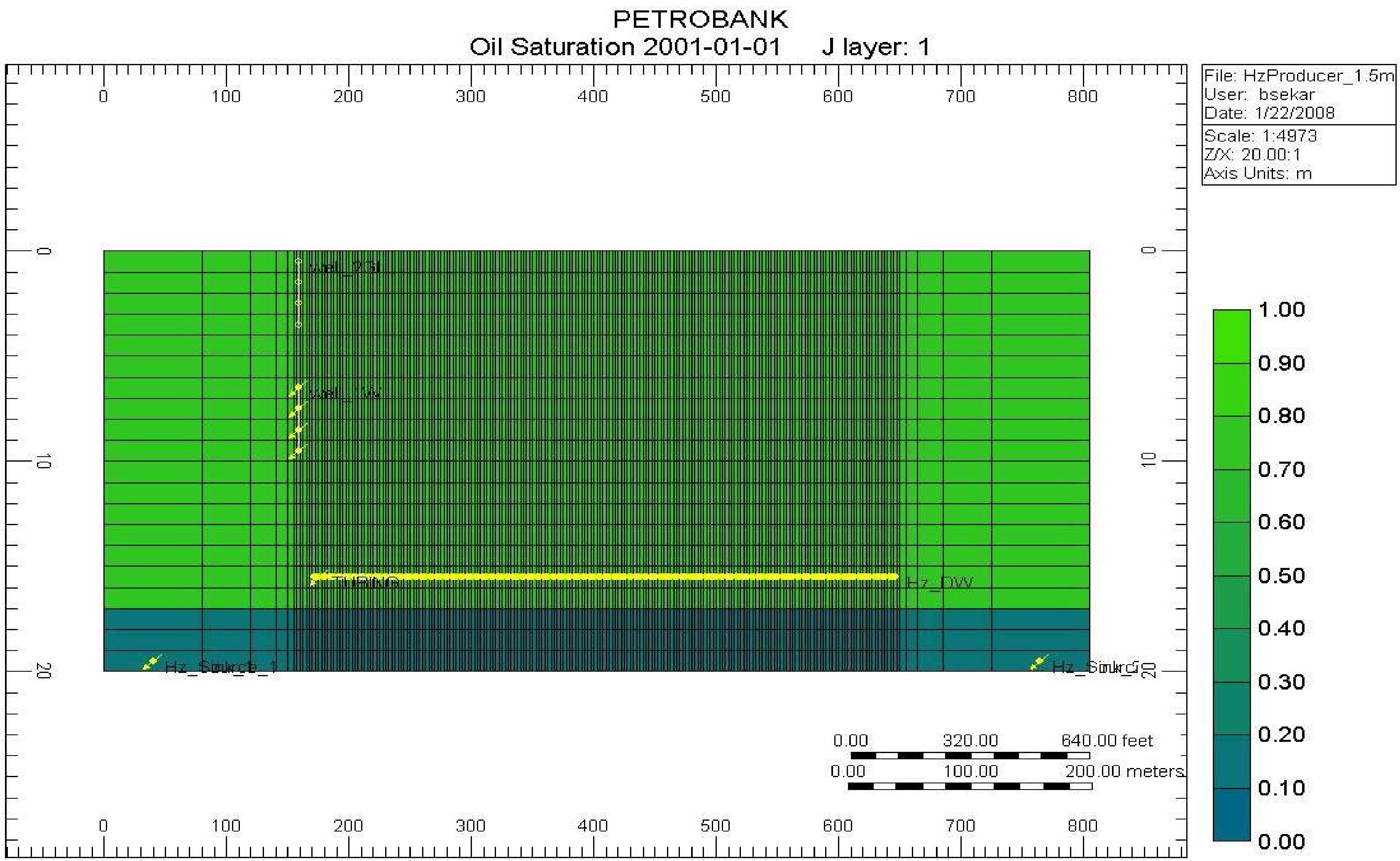


Figure 30 Well Below Oil-Water Contact

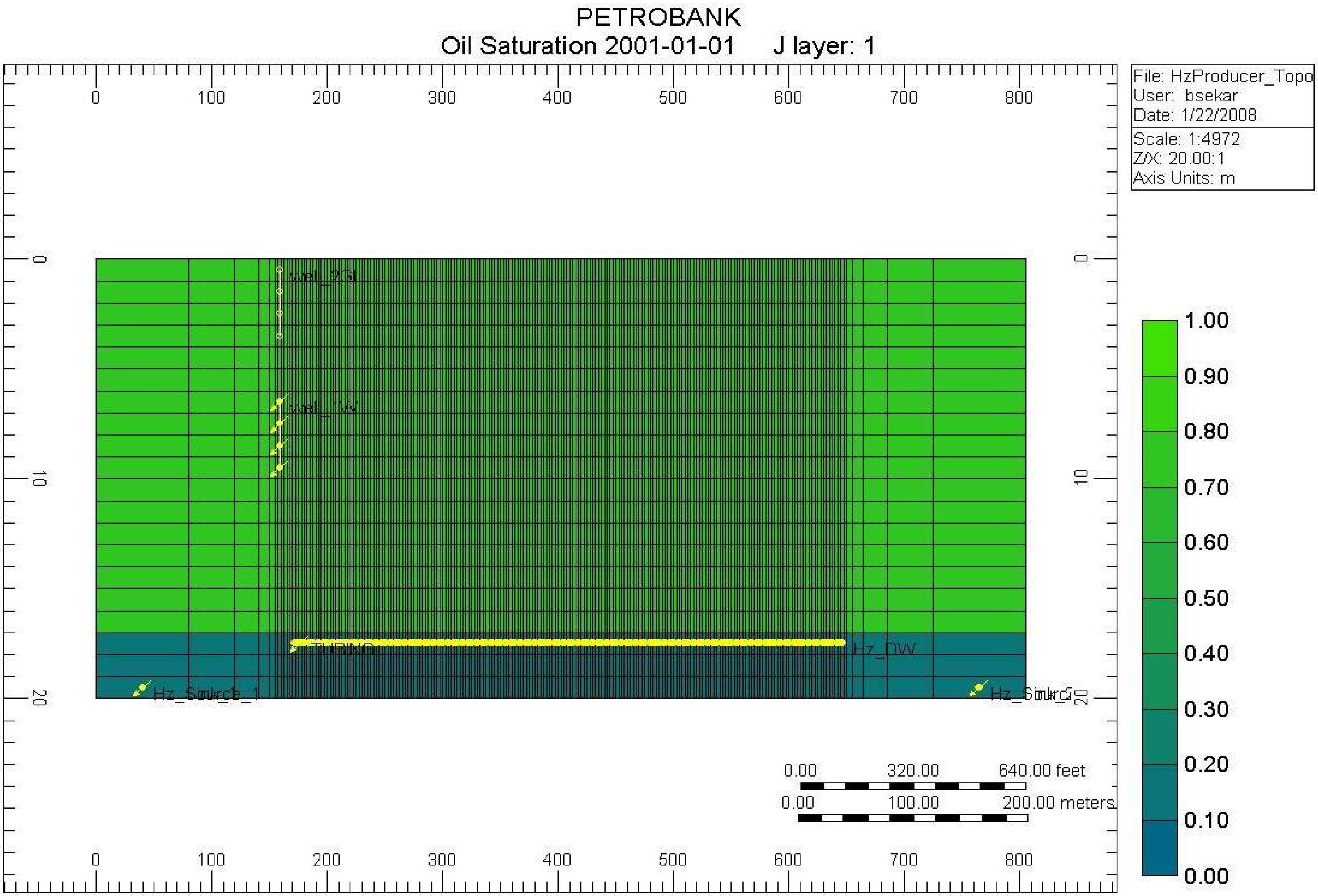


Figure 31 Well at Base of Bottom Water

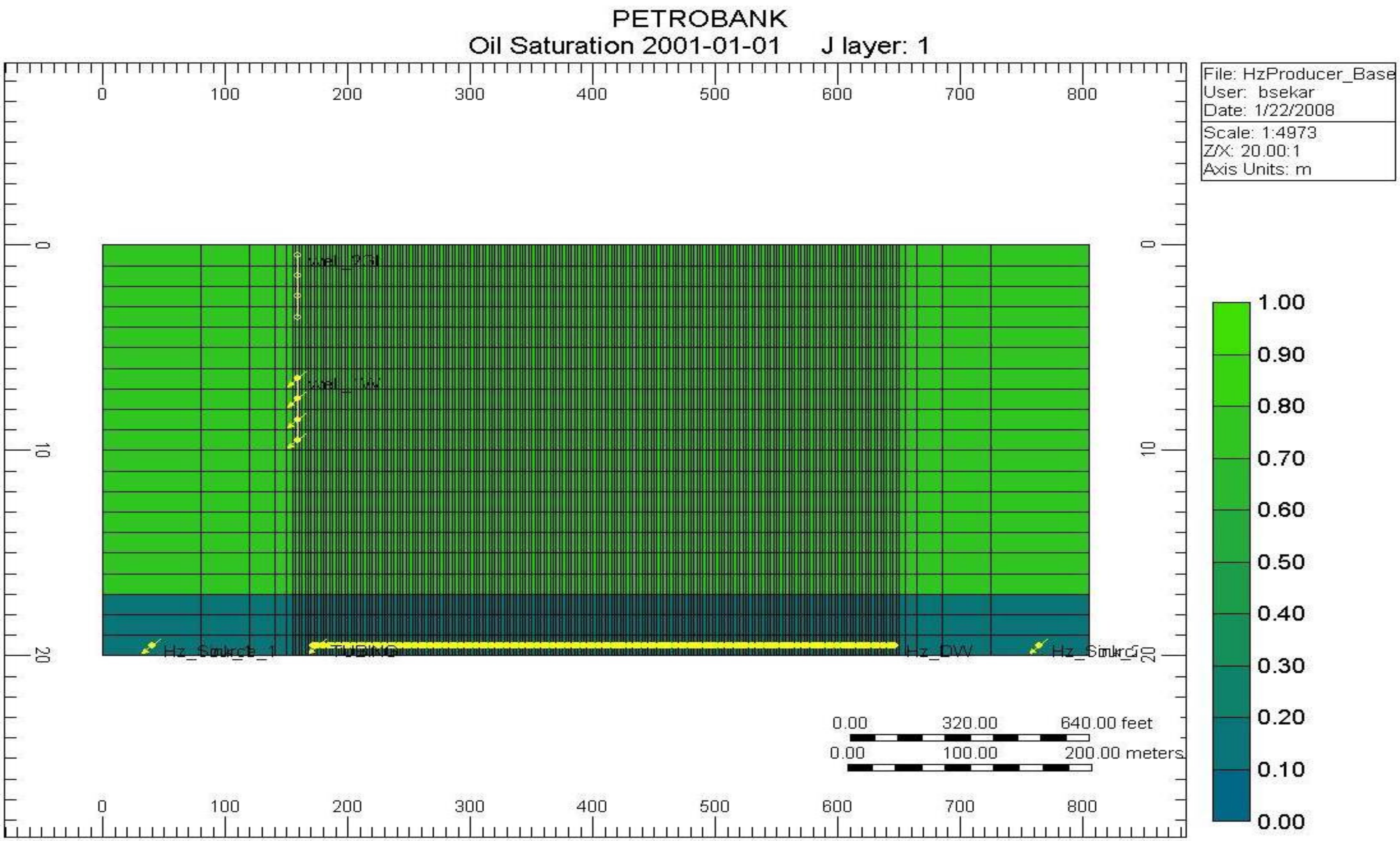


Figure 32 Comparison of Cumulative Oil, 2629 BHP Constraint Cases

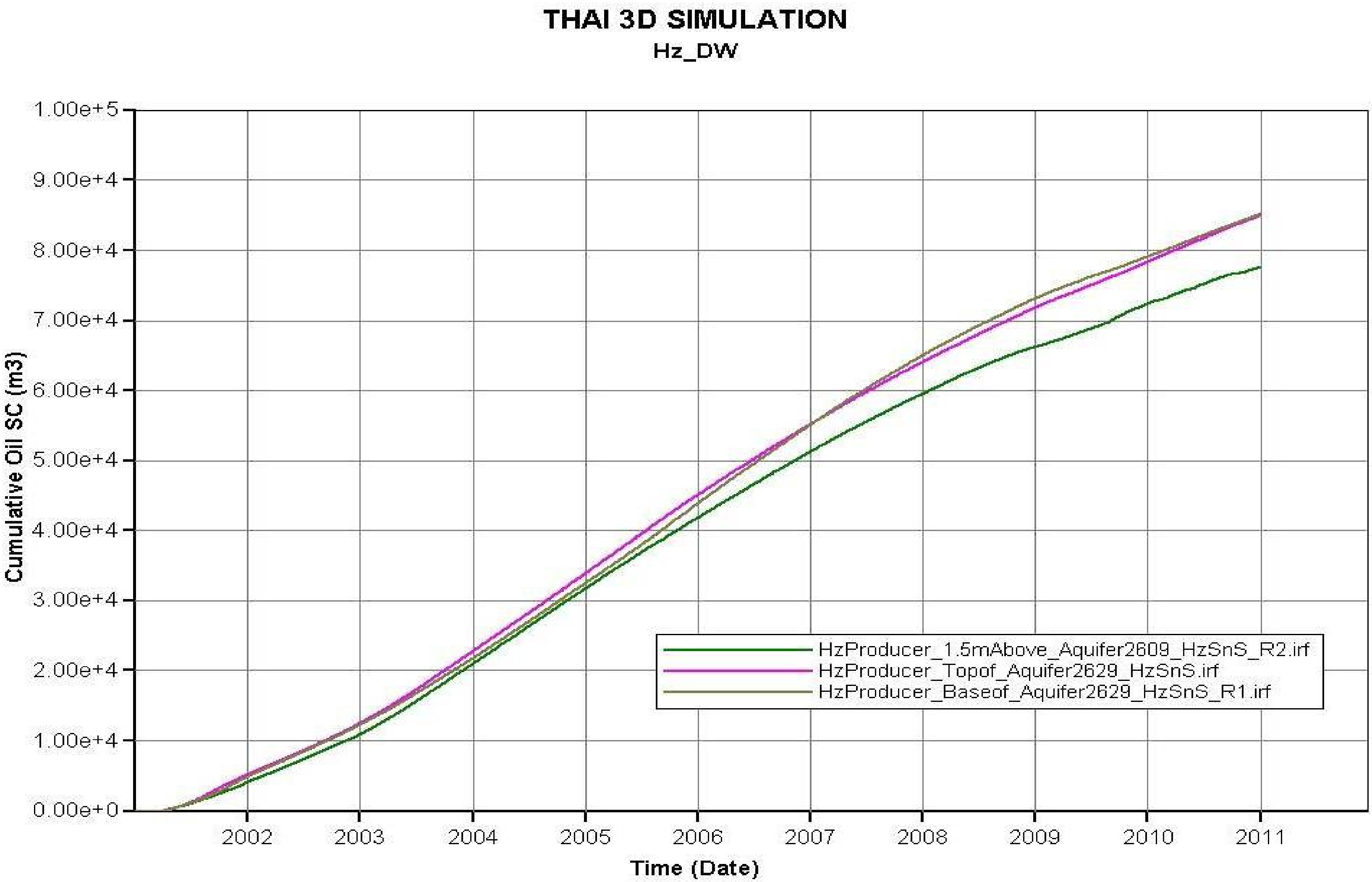


Figure 33 Comparison of Cumulative Water, 2629 BHP Constraint Cases

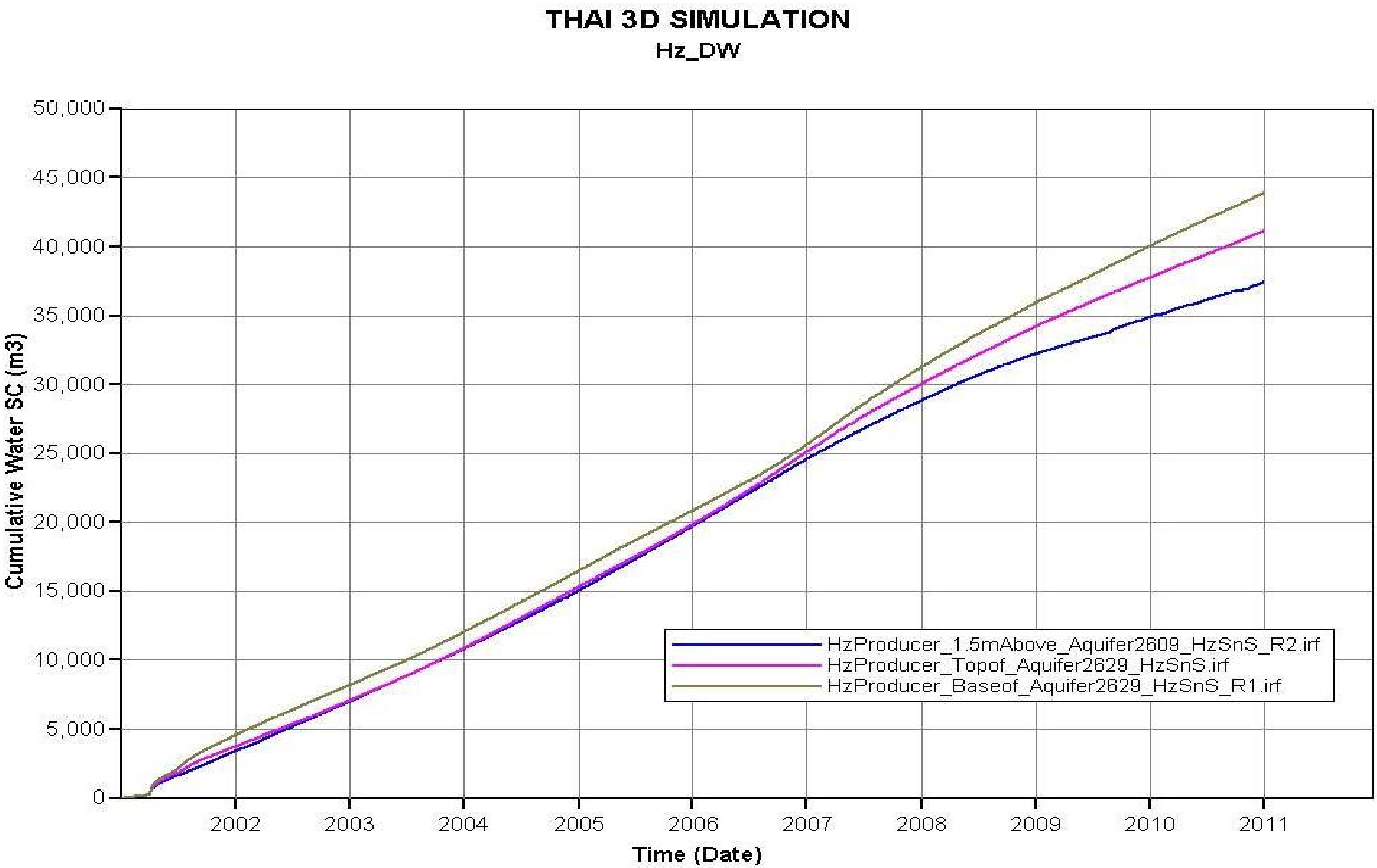


Figure 34 Comparison of Cumulative Gas, 2629 BHP Constraint Cases

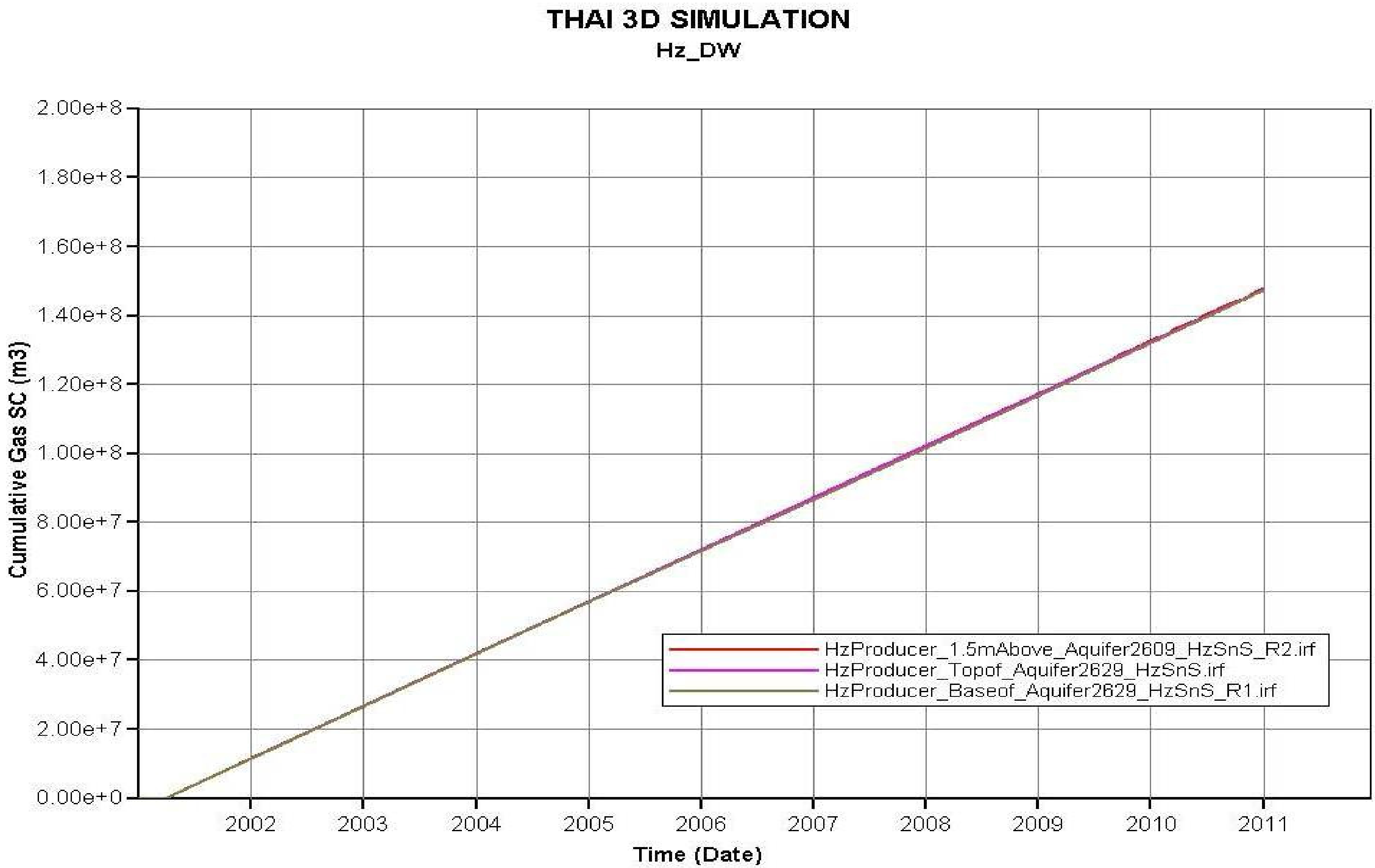


Figure 35 Comparison of Cumulative Oil, 1500 BHP Constraint Cases

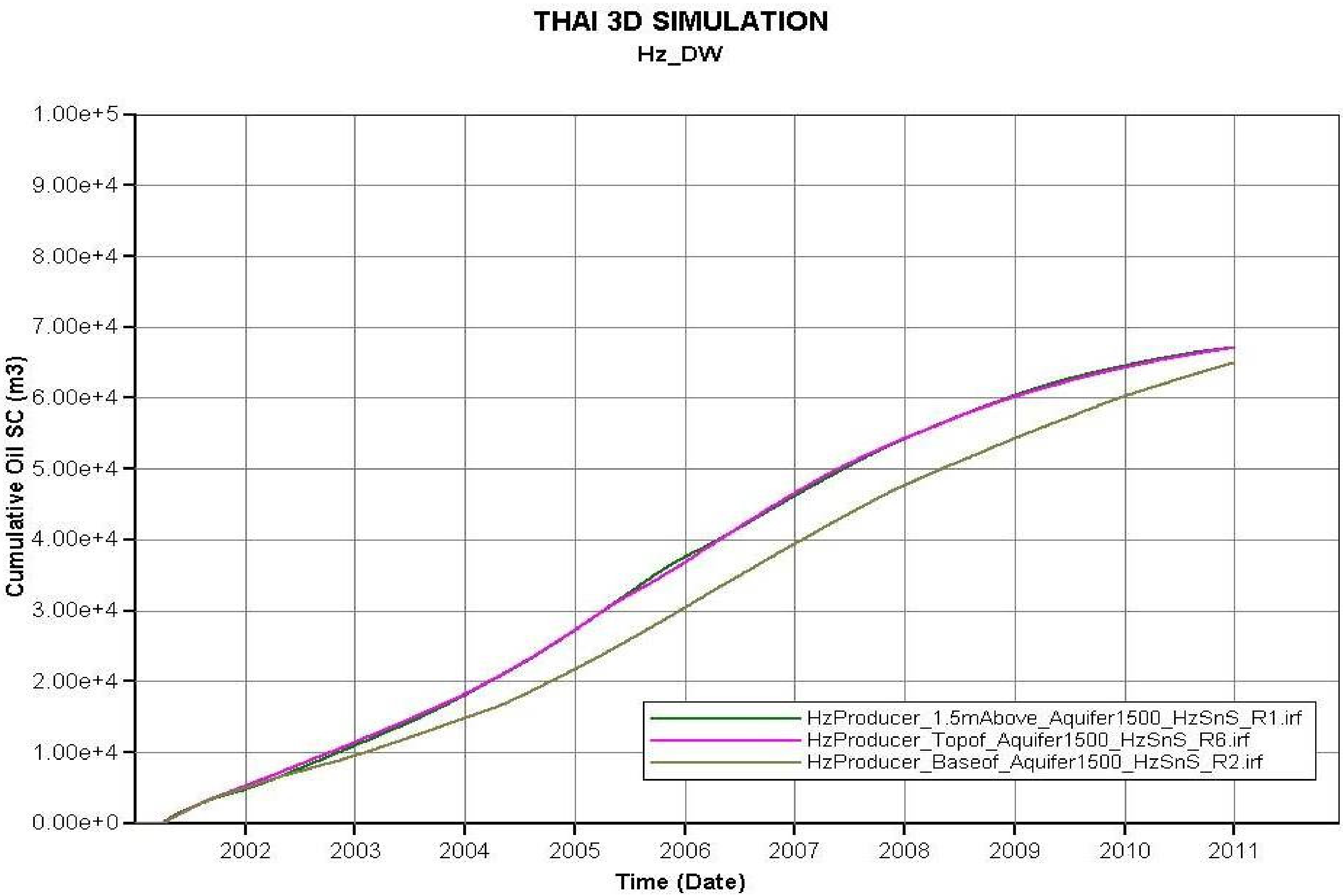


Figure 36 Comparison of Cumulative Water, 1500 BHP Constraint Cases

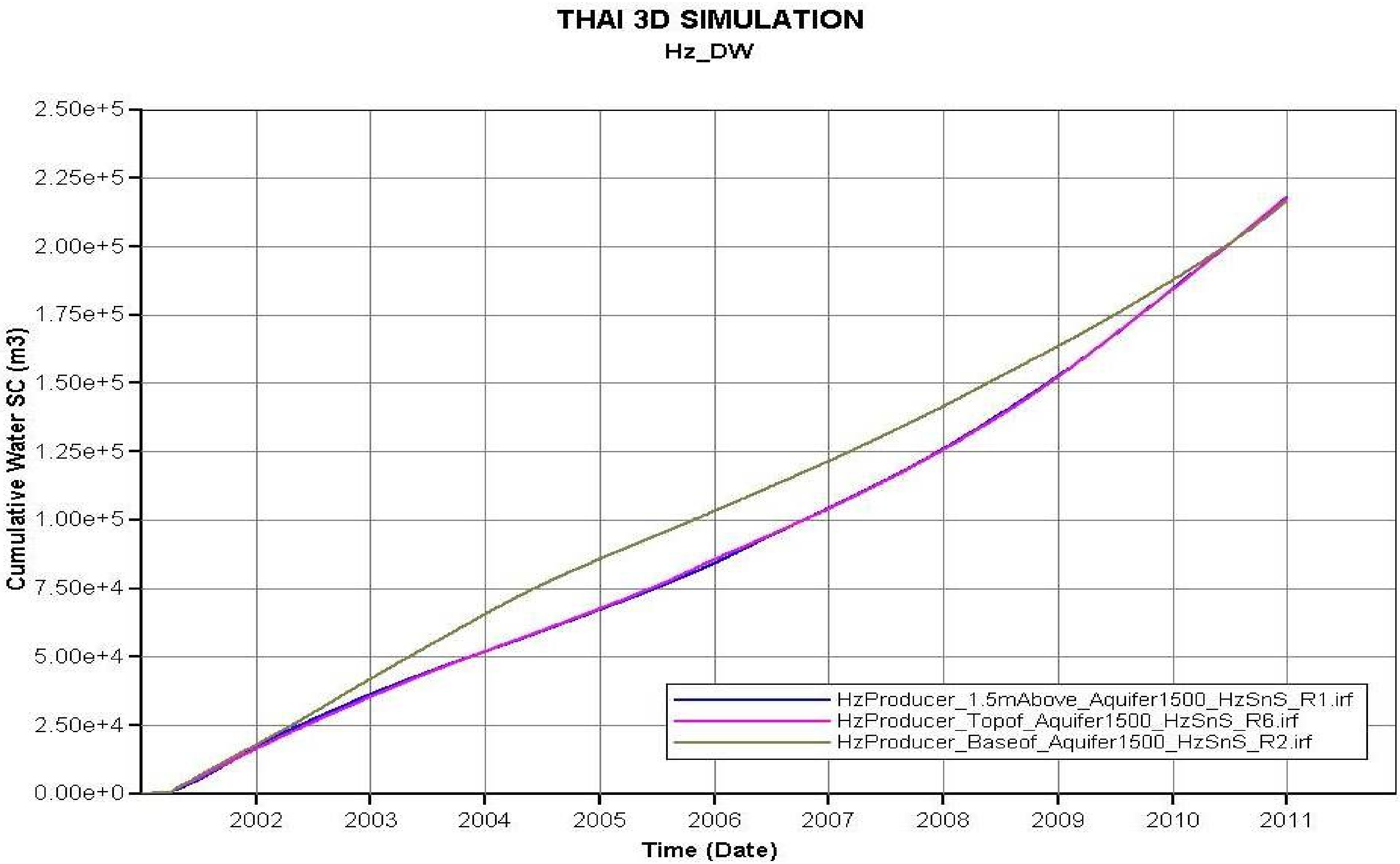


Figure 37 Comparison of Cumulative Gas, 1500 BHP Constraint Cases