Peace River In Situ Oil Sands Progress Report

Commercial Scheme Approval 8143

February 16th, 2017

TODAY'S AGENDA

Introductions and Background	Ivan Gonzalez
Subsurface Issues Related to Resource Evaluation and Recovery	
Geology/Geoscience	Robyn Gooler
Geophysics	Tam Pham
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Artificial Lift	Dan Syrnyk
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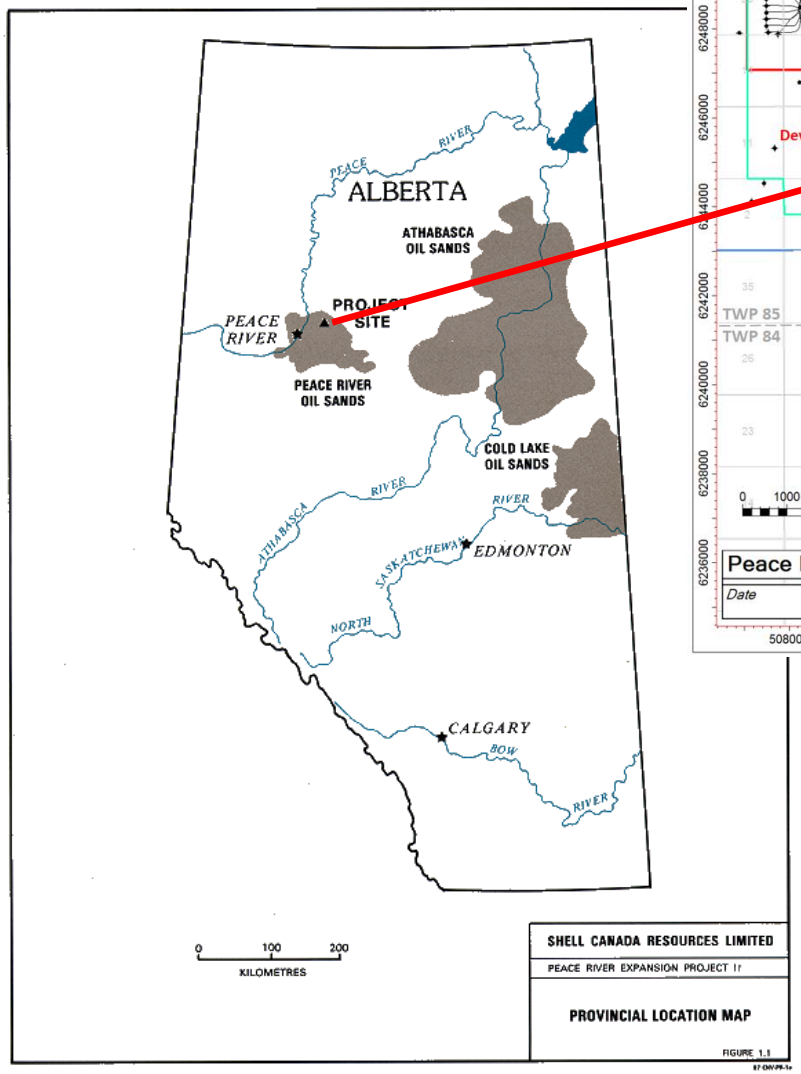
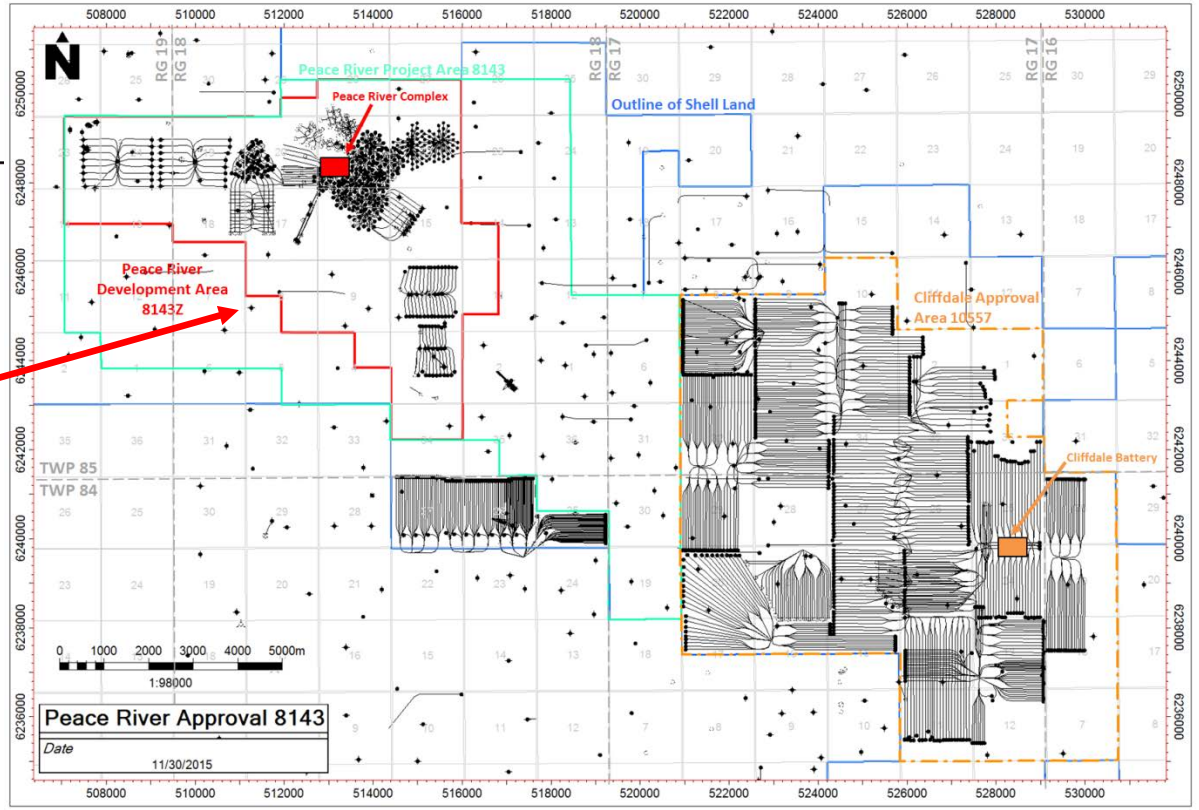
Future Plans	Ivan Gonzalez
Surface Operations, Performance and Compliance	
	Darcy Forman

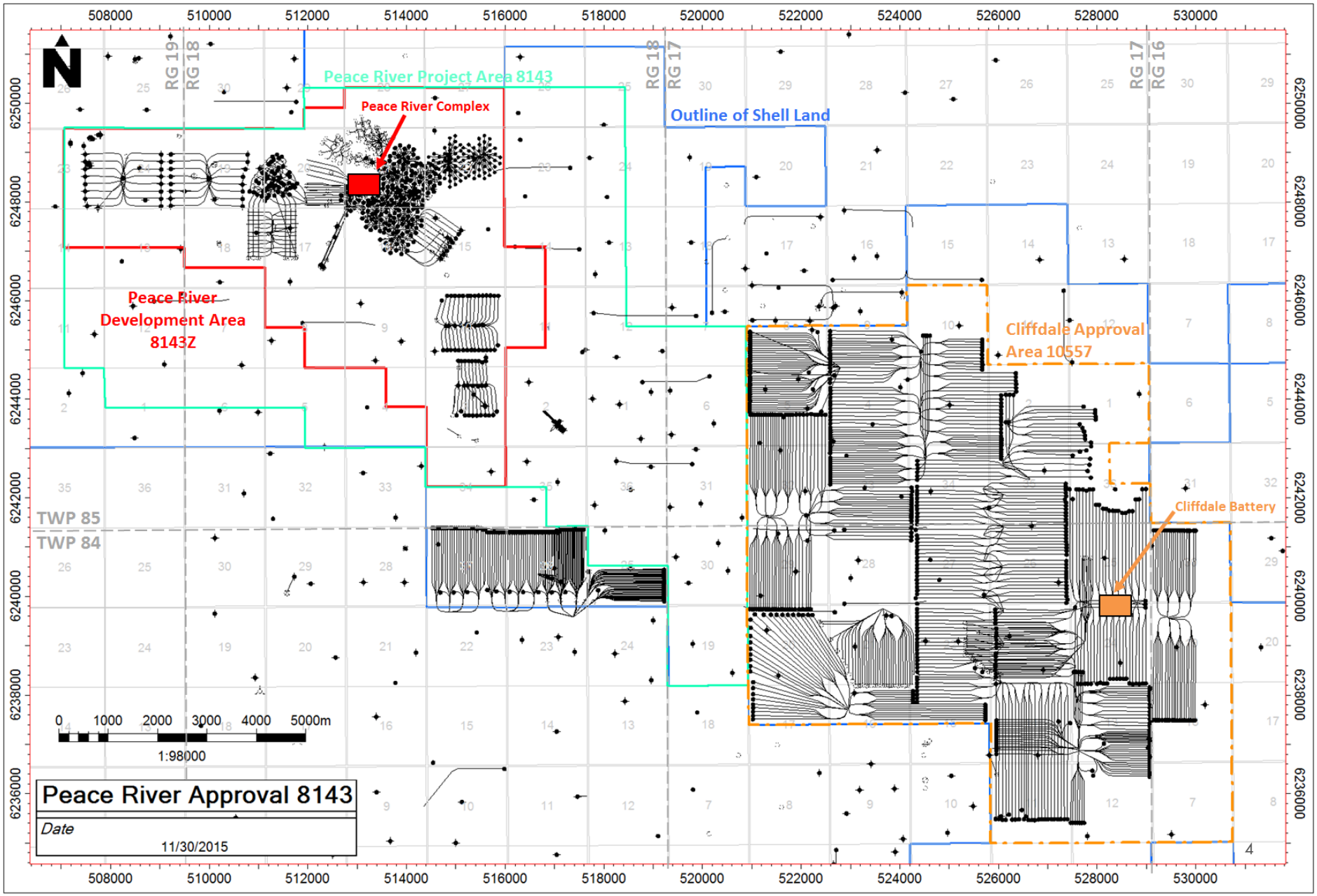
LOCATION





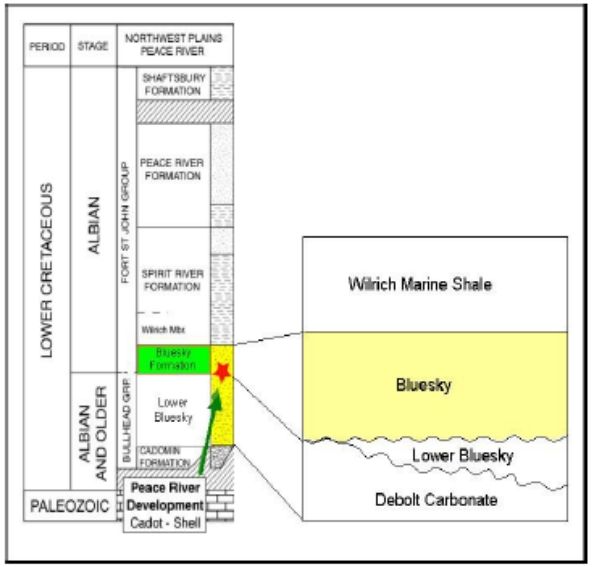
- Located in Northwestern Alberta
- 100% Shell Share
- OBIP 239 Million m^3 for the area in Approval 8143Z

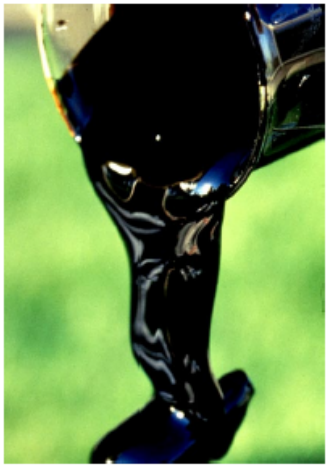
APPROVAL AREAS



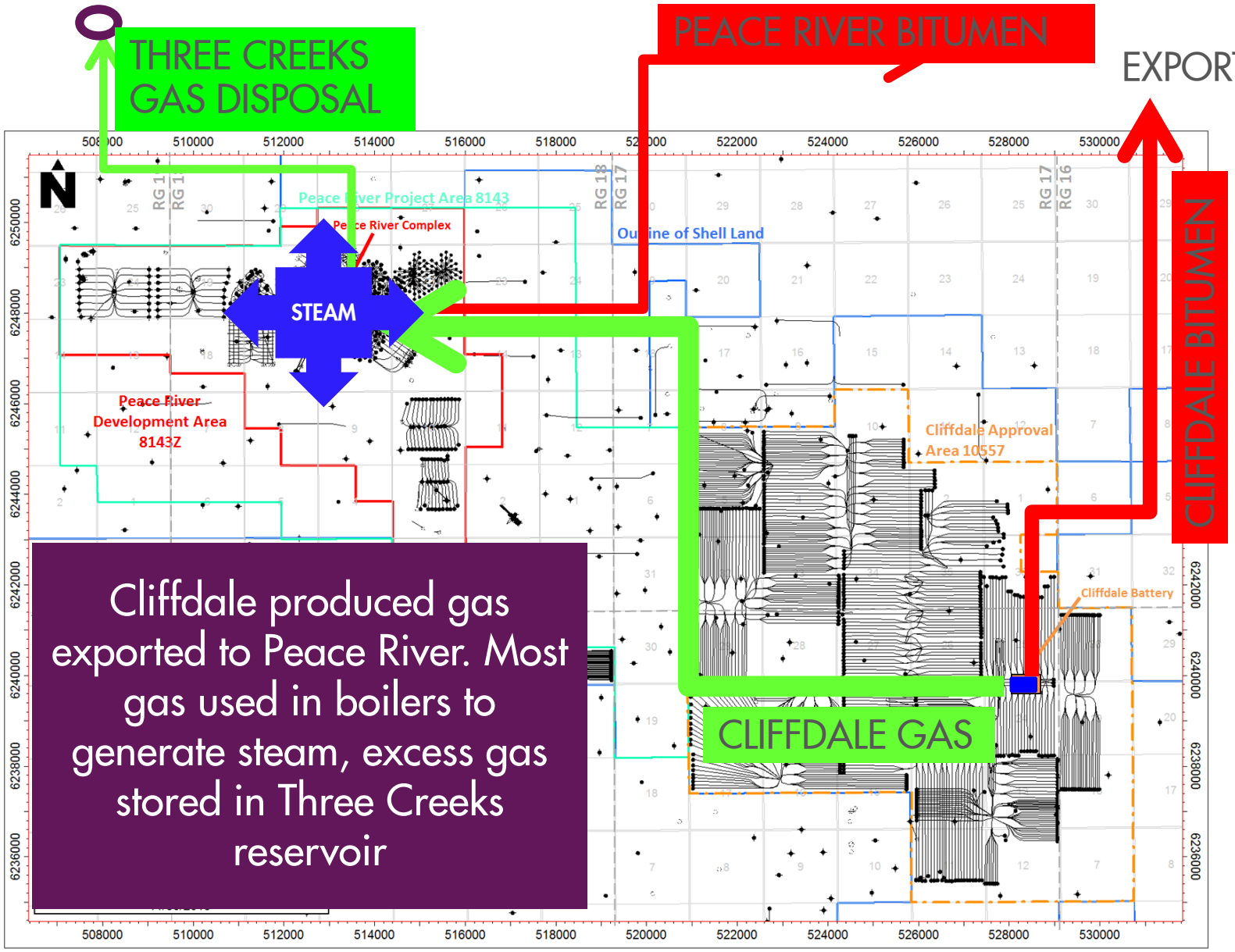
BLUESKY RESERVOIR PROPERTIES

- **Thickness**: 25-30 m
- **Depth:** 550-600 m TVD
- **NTG:** 0.8-1.0
- **API Gravity:** 6-11°
- **Porosity:** 0.25-0.30
- **Viscosity:** 10,000-1,000,000 cP (dead oil)
- **Initial pressure:** 3,800 kPa (sub-hydro)
- **Initial temperature:** 18°C
- **Horizontal permeability:** 0.1 – 10 D (air)
- **Kv/kh:** 0.3 – 0.9
- **Oil saturation (S_o):** 0.70 – 0.80





GAS INTEGRATION PEACE RIVER AND CLIFFDALE ASSETS



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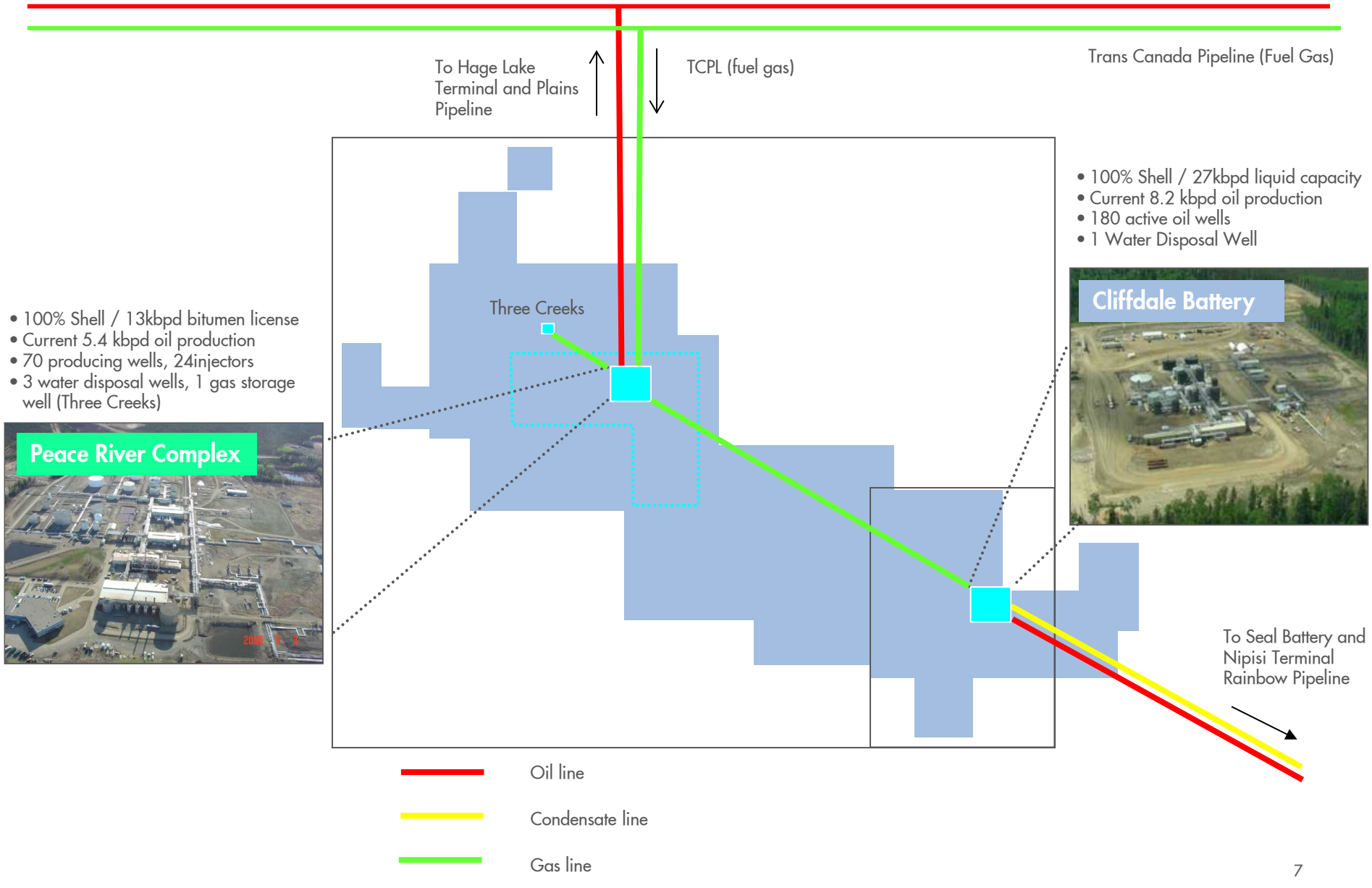
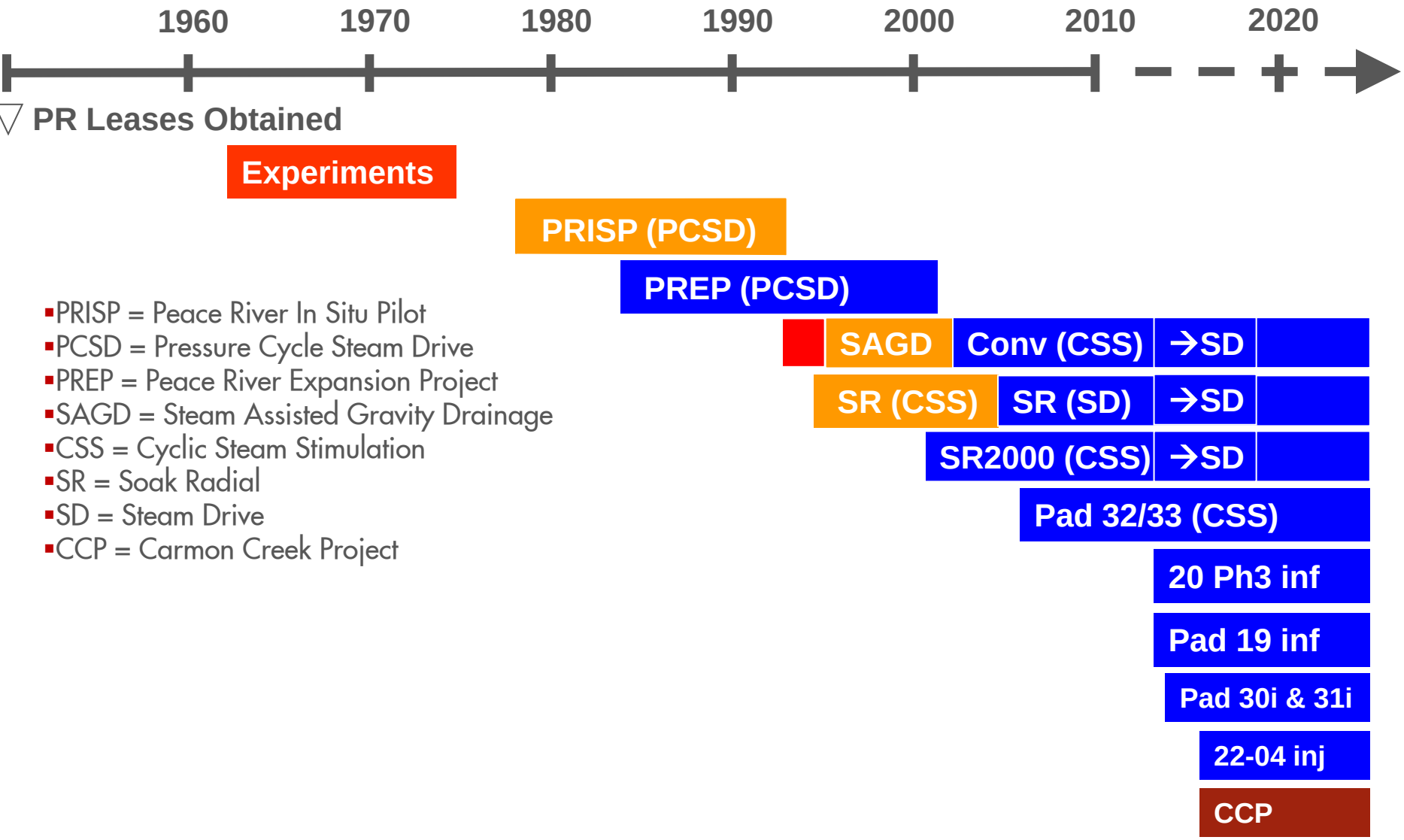


PEACE RIVER PROJECT HISTORY

Experiment to **Pilot** to **Demonstration** to **Commercial**



- PRISP = Peace River In Situ Pilot
- PCSD = Pressure Cycle Steam Drive
- PREP = Peace River Expansion Project
- SAGD = Steam Assisted Gravity Drainage
- CSS = Cyclic Steam Stimulation
- SR = Soak Radial
- SD = Steam Drive
- CCP = Carmon Creek Project

2016 OVERVIEW

Key 2016 PRC updates:

- Improved field production and SOR as a result of plant debottlenecking, infill well projects (22-04, 30/31 injectors), and steam optimization. 2016 year-to-date average field production is 842 m3/d compared to 770 m3/d yearly average in 2015
- Completed steam solvent pilot project on Pad 19 Sat 3 with positive production, SOR, and solvent recovery results
- Obtained AER Approval for Directive 81 waiver extension to December 2020
- Obtained AER Approval for Directive 65 amendment application to increase maximum Three Creeks gas storage reservoir pressure to 5,000 KPa
- Defined Carmon Creek Project suspension strategy
- Increased Cliffdale produced gas utilization in all steam generators
- Installed two power generators at PRC to further increase utilization of Cliffdale produced gas
- Positive feedback from two AER DOI's: Facility and Pipeline Inspections

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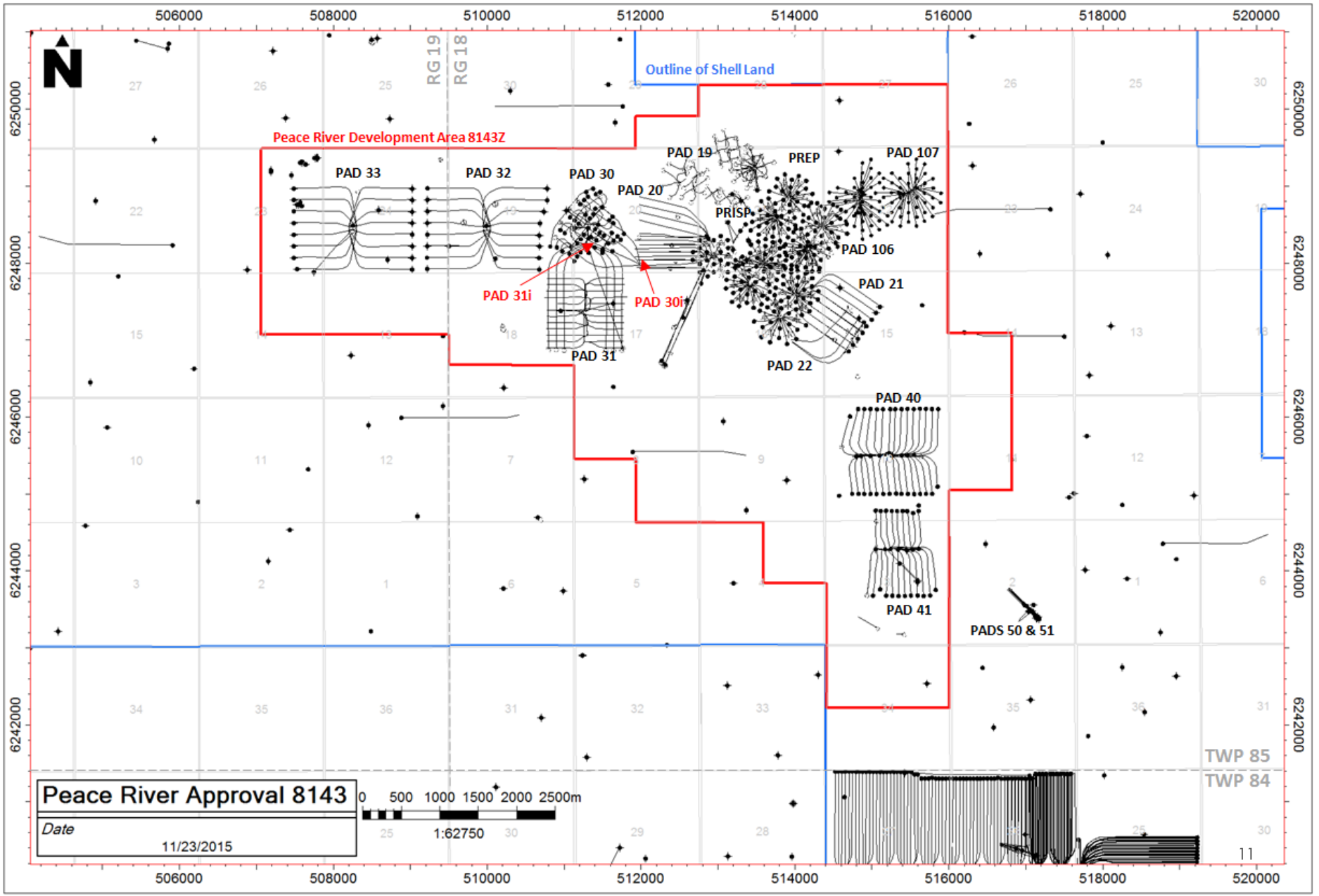
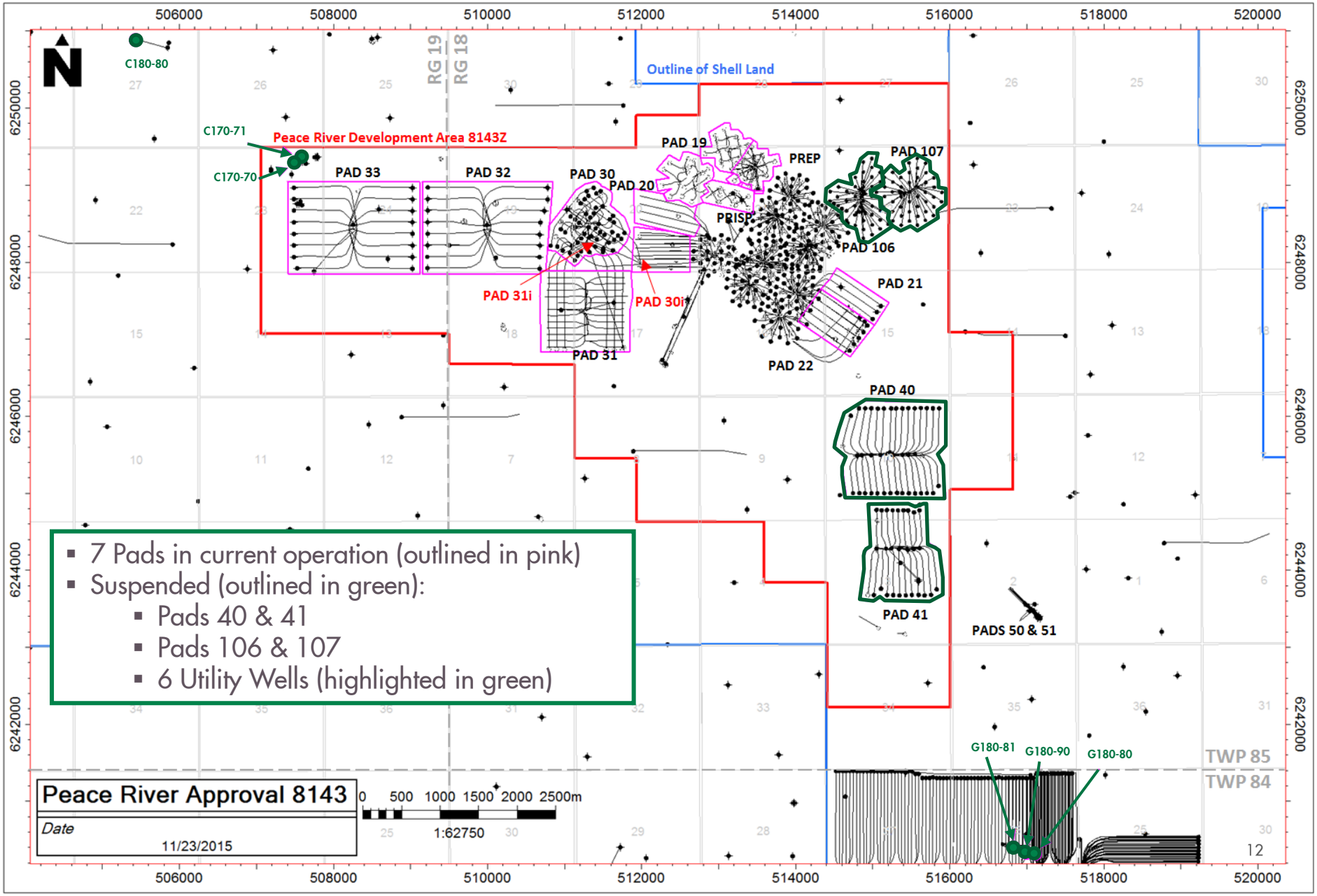
APPROVAL AREA



APPROVAL AND CURRENT OPERATING AREA



- 7 Pads in current operation (outlined in pink)
- Suspended (outlined in green):
  - Pads 40 & 41
  - Pads 106 & 107
  - 6 Utility Wells (highlighted in green)

VOLUMETRICS

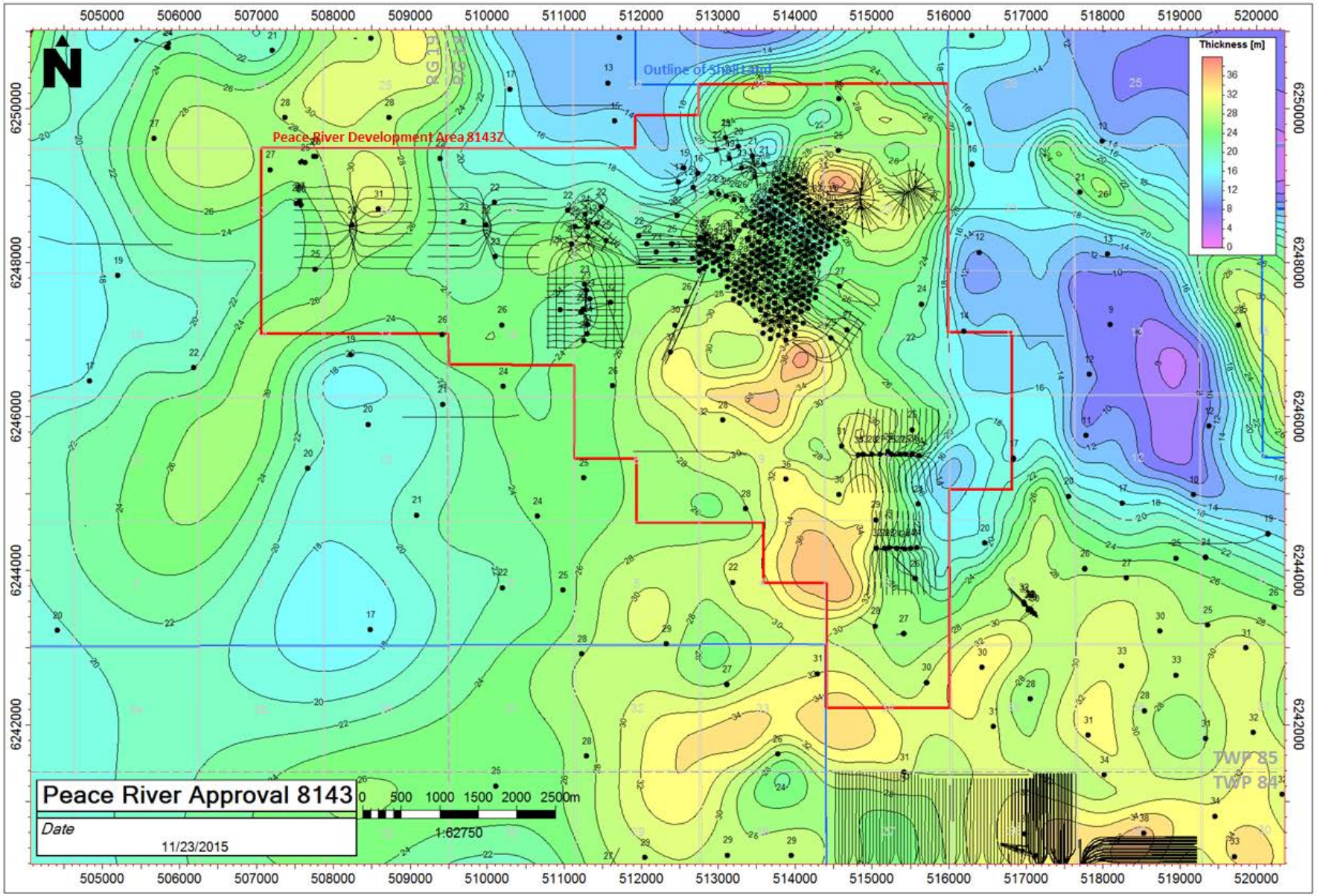
- **Methodology:** Well tops, 3D seismic surfaces (where available) and properties modeled in a 3D cellular static reservoir model (cell size: 50x50x1m)

	Units	**Development Area***	**Operating Area**
Original Bitumen In Place	**$10^6 m^3$**	**239**	**55.6**
Area	$10^6 m^2$	42.6	10.5
Average Net Pay	m	27	24
Average Porosity	1/1	0.27	0.28
Average Oil Saturation	1/1	0.81	0.81
Bo	1/1	1.004	1.004

*Calculations are based on the 8143Z development scheme approval area

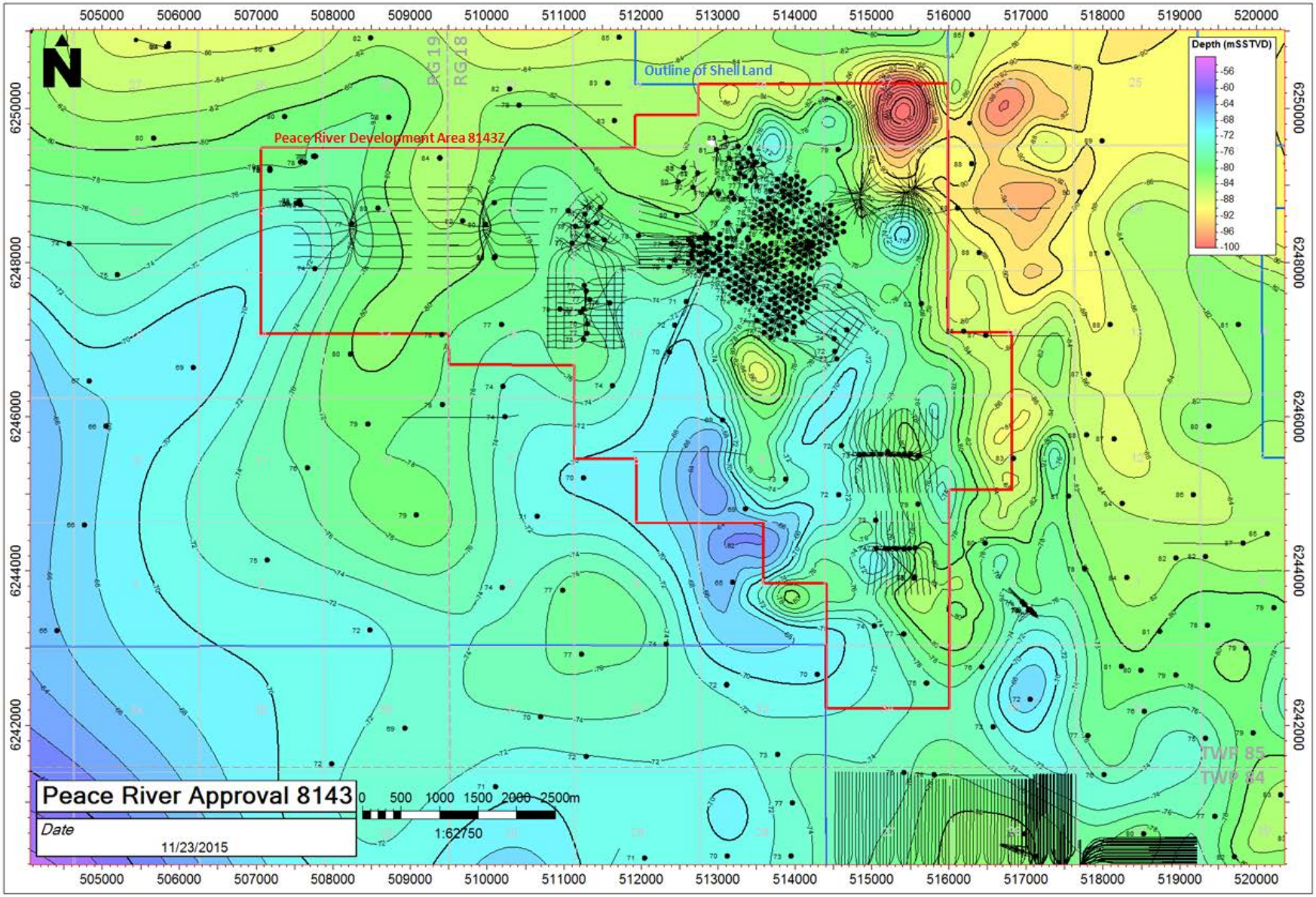
OPERATING AREA NOTE: Pad 40 & 41 are still included in the operating area as they are only suspended and Pad 106 and 107 have been excluded as they have not been completed

BLUESKY NET PAY



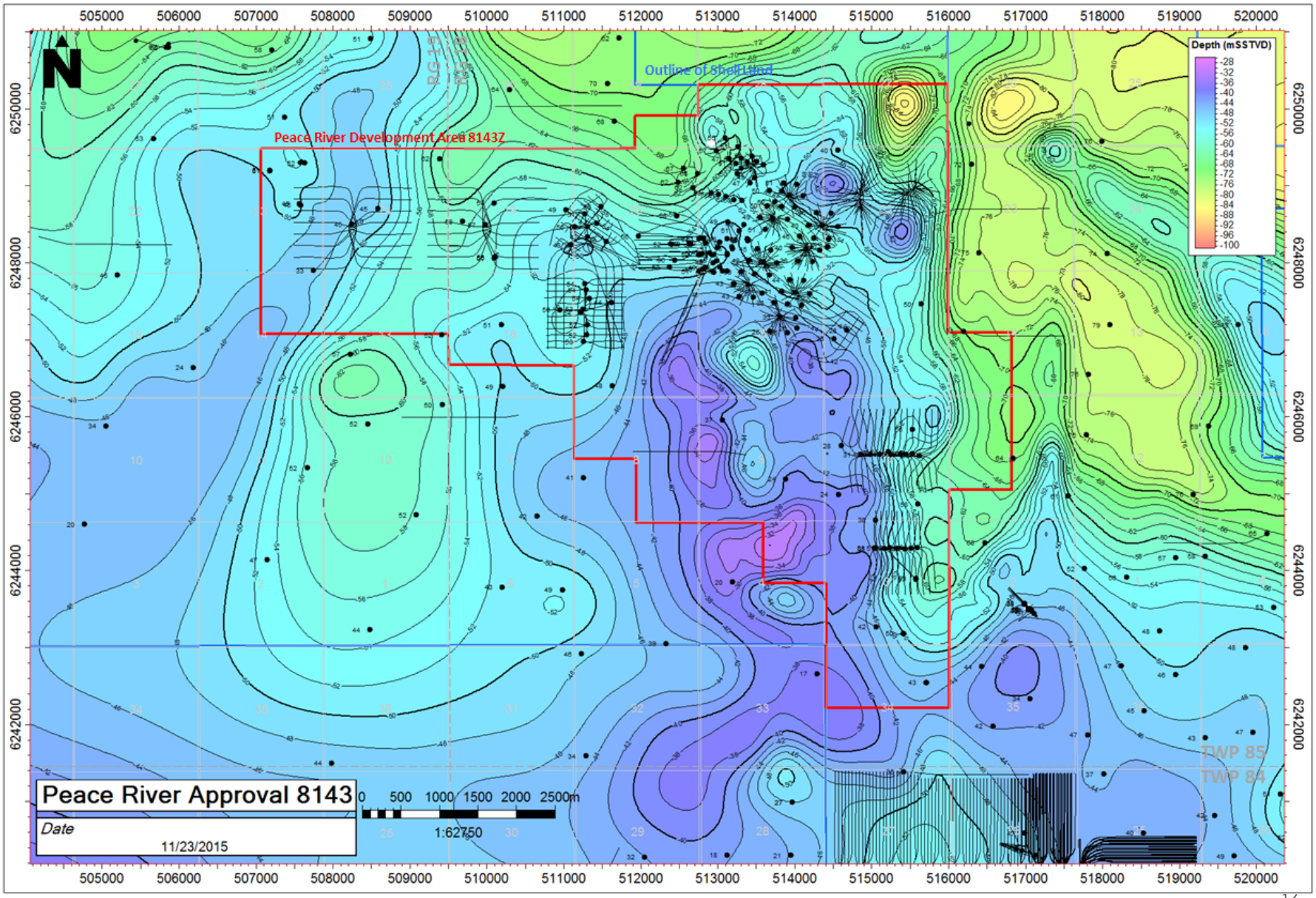
- Ranges from 14-38m in the approved area

TOP BLUESKY STRUCTURE



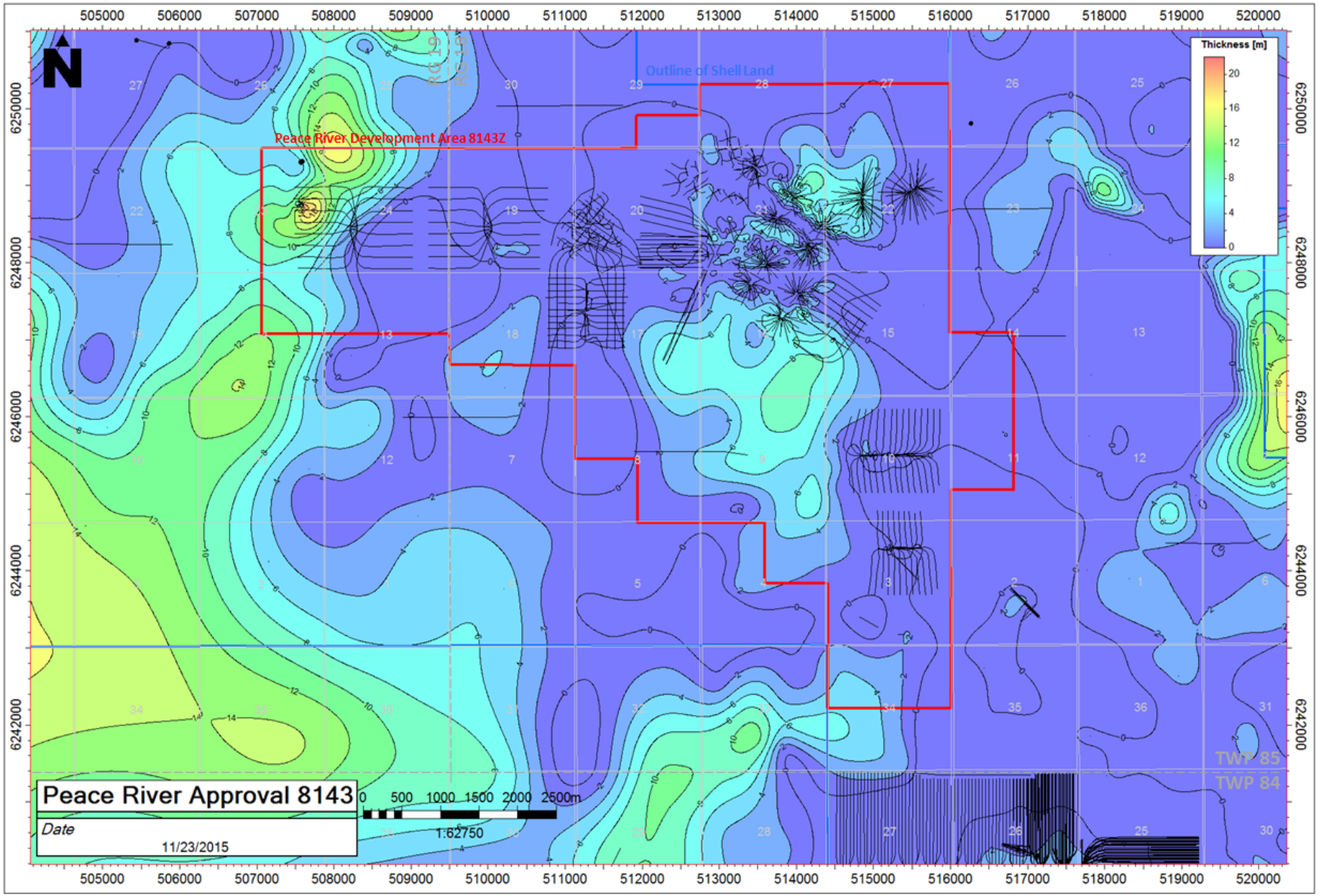
- Ranges from 70-86 m SS in the approved area

BASE BLUESKY STRUCTURE



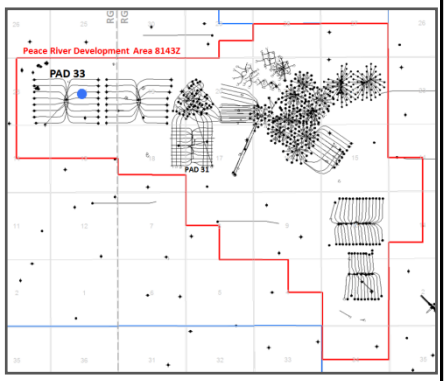
- Ranges from 36-68 m SSTVD in approval area

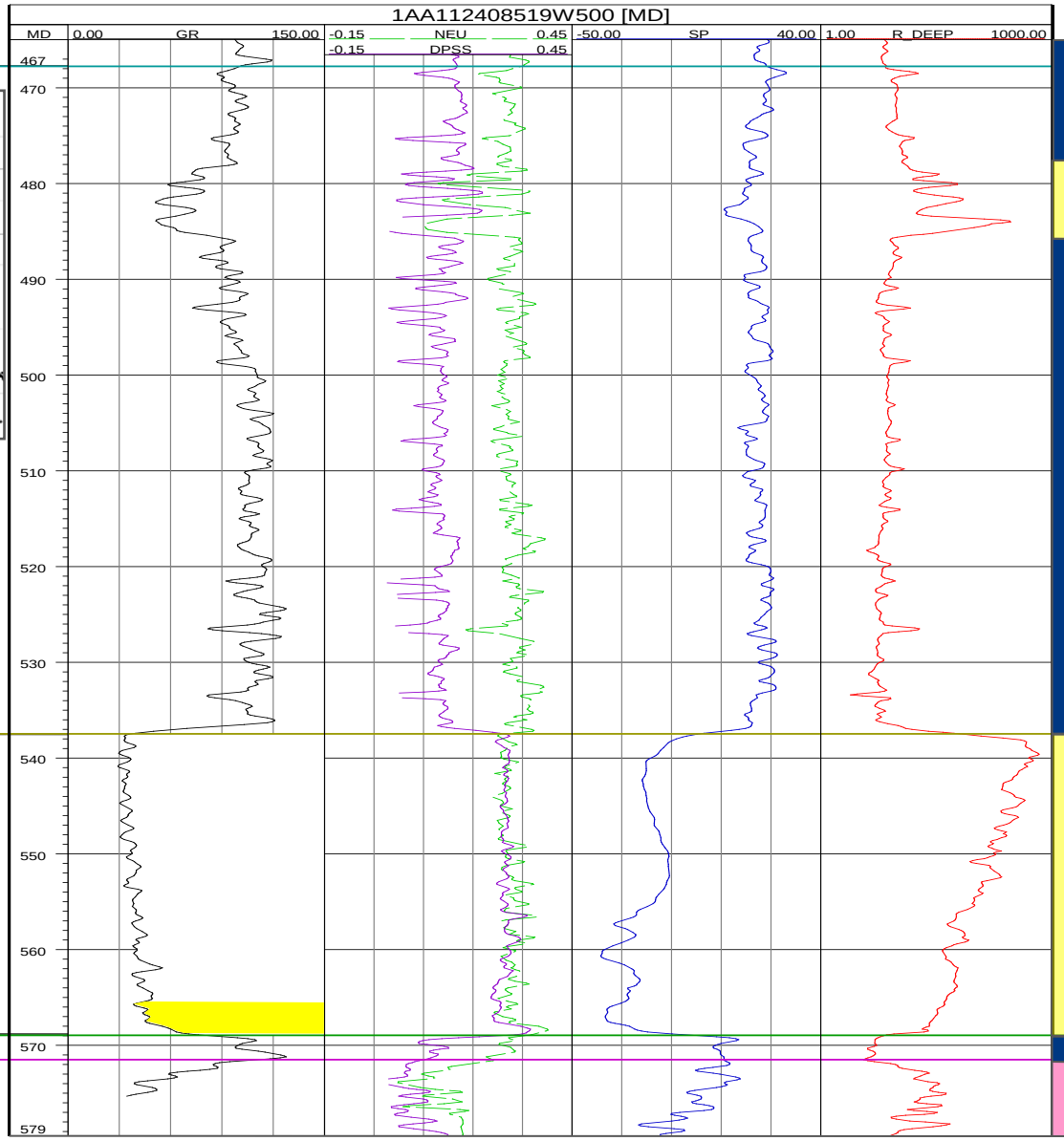
BASAL WATER ISOCHORE



- Basal Water is a transitional zone of increasing water saturations in the Bluesky that is defined by a Sw > 0.31.

COMPOSITE WELL LOG 1AA/11-24-085-19W5/00





Top Wilrich

Top Bluesky

Top Gething

Legend:

Well Logs

- Gamma Ray
- Neutron porosity
- Density porosity
- Spontaneous potential
- Resistivity

Fluids

- Bitumen

Rock framework

- Shales
- Sands
- Carbonate

DATA ACQUISITION

- There have been no new wells drilled and no new data acquired this year

INTERPRETED BREAKDOWN PRESSURES AND CAP ROCK INTEGRITY

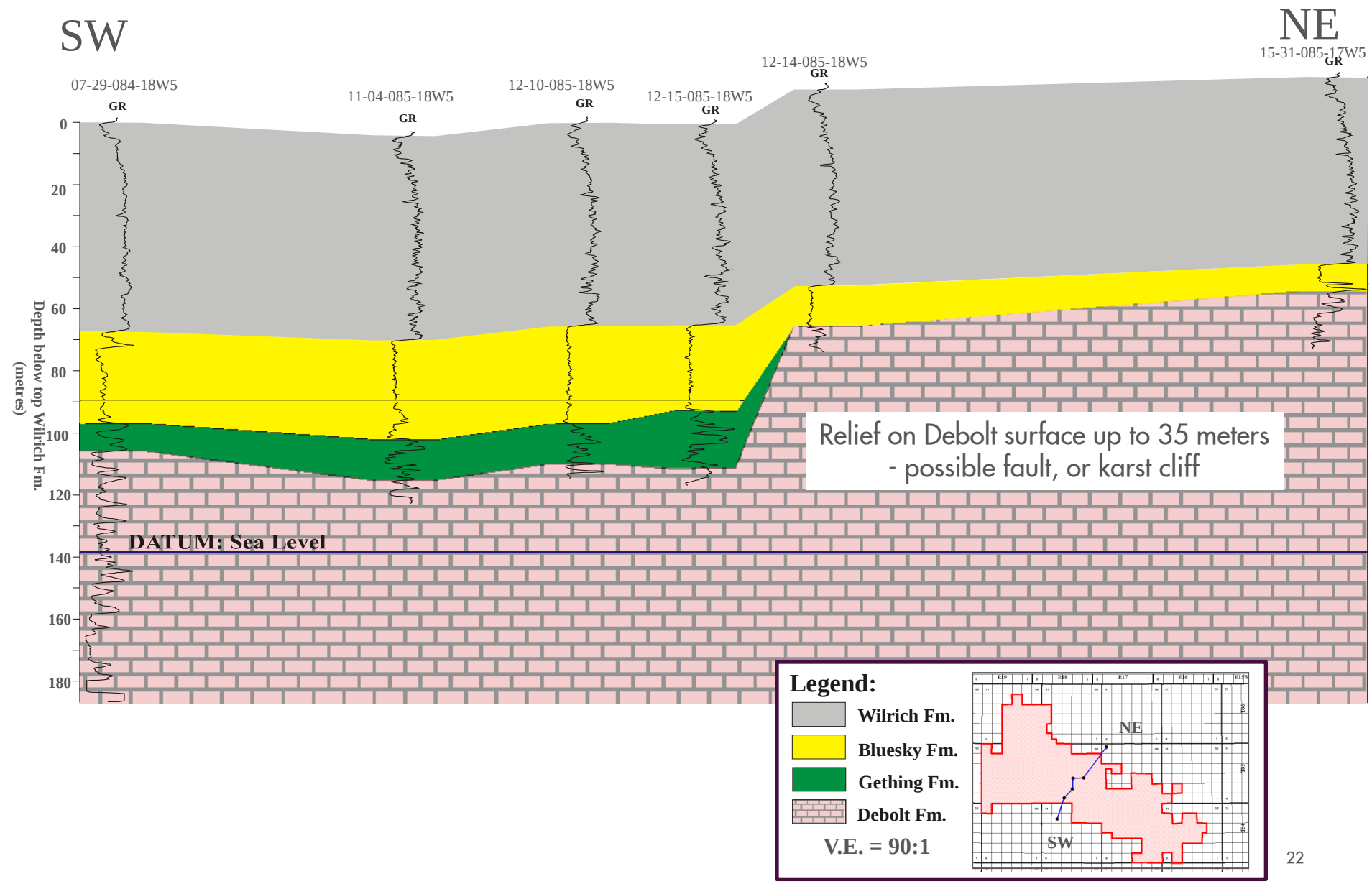
- Cap rock: consists of the highly continuous Spirit River Formation (Wilrich/Falher/ Notikewin) which has a minimum thickness of 240m over the approval area.

- 2012 Stress Testing:
  - 12 in-situ cap rock stress tests, 3 wells @ 3 different depths in Wilrich, 1 depth top Bluesky
    - Measured Minimum Stress Wilrich = 19.6-22.7 kPa/m, avg 20.9 kPa/m
    - Calculated Minimum Stress Wilrich = 21.6-22.2 kPa/m
    - Measured Minimum Stress Bluesky = 14.7-20.2 kPa/m, avg 16.6 kPa/m
  - 2 additional in-situ stress tests in 1 well in Notikewin and Fahler formations
    - Fahler Measured Breakdown Stress = 28.7 kPa/m
    - Fahler Measured Minimum Stress = 20.0 kPa/m
    - Fahler Calculated Minimum Stress = 21.3 kPa/m
    - Notikewin Measured Breakdown Stress = 29.1 kPa/m
    - Notikewin Measured Minimum Stress = 19.0 kPa/m
    - Notikewin Calculated Minimum Stress = 21.0 kPa/m

STRESS TESTING IN DEEP FORMATIONS

- Q4 2014 Stress Testing:
  - 3 tests were conducted on 3 of the Carmon Creek Utility Wells:
    - Nisku Formation In-situ stress test @ G180-80 (102/07-26-084-18W5/02)
      - Openhole test with 1.7m straddle packer used to obtain minimum horizontal stress (28.3MPa), Vertical stress (38.4MPa), Breakdown pressure (40.1MPa) at 1573m TVD
    - Leduc Formation In-situ stress test @ G180-81 (100/07-26-084-18W5/00)
      - Cased hole with 50m perforated zone (1694.9 -1744.3m TVD) didn't achieve fracture. Pressures reached 30.4MPa.
    - Leduc Formation Step rate test on G180-80 (102/07-26-084-18W5/02)
      - Cased hole with 50m perforated zone (1684.6 – 1734.4m TVD). Initial breakdown of 39MPa.

DIP STRUCTURAL CROSS SECTION



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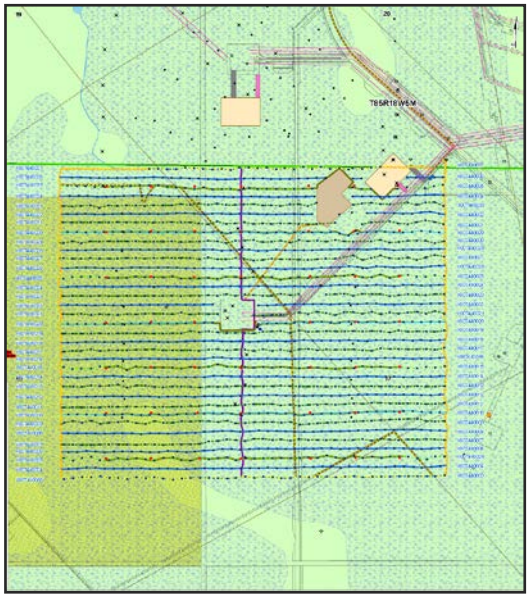
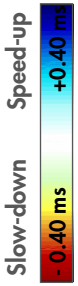
CONTINUOUS REFLECTION MONITORING AT PAD 31



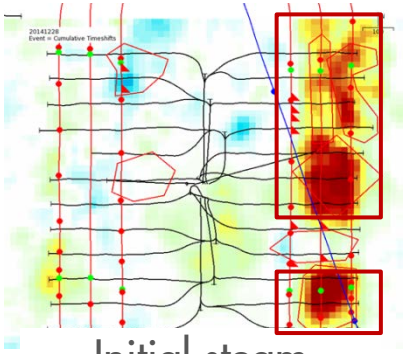
- Recording May 2014 – May 2016
- Time shifts are measurable and relate to production

Decommissioning underway:

Phase 1: Shutdown/Disconnection of electrical power (June 7-9)
Phase 2: All field equipment picked up and cached in piles along seismovie grid (completed Oct 12, 2016)
Phase 3: Pick up cached piles for recycle or landfill (~ early December)

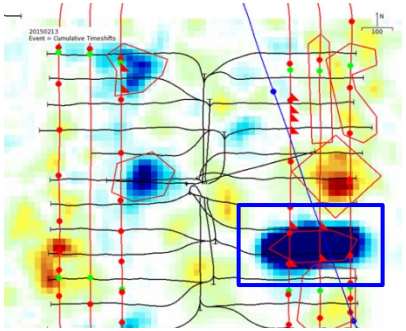


Week 05



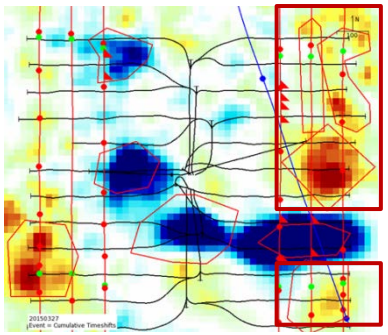
Initial steam conformance

Week 12



Connection to mobile zone ➔ conformance suffers

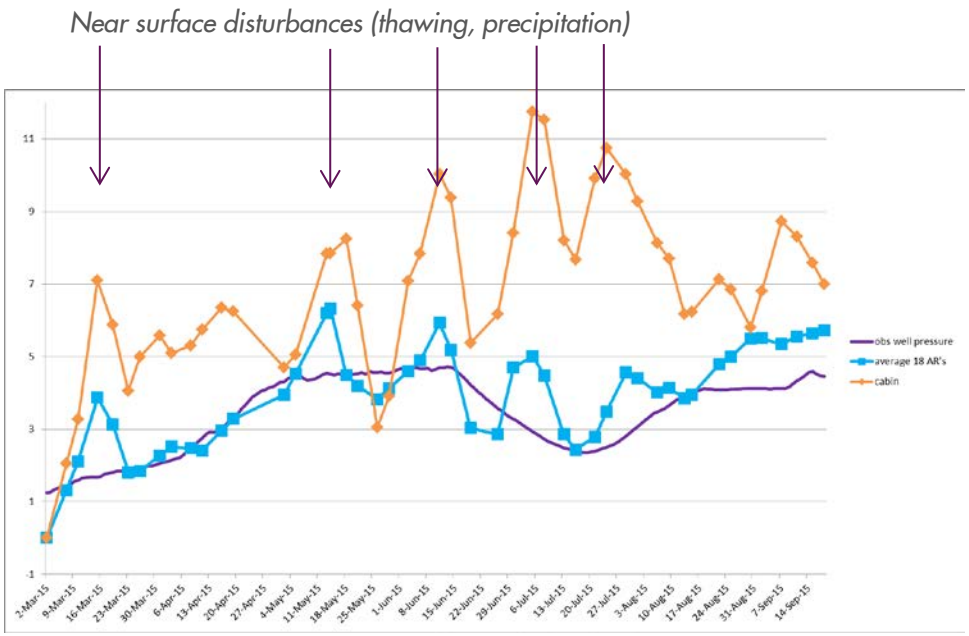
Week 18



Reduce pump rate ➔ conformance improves

INSAR AT PAD 31

- Cemented corner reflectors installation Feb 2015
- Data acquisition complete May 2016
- Surface deformations (measured with InSAR) correlate well with reservoir pressure changes



Decommissioning Underway:

- **Cabin attached artificial reflectors (6) to be removed December 2016**
- **Cemented Artificial Reflectors (18) to be left in place**

cabin attached

- Less stable

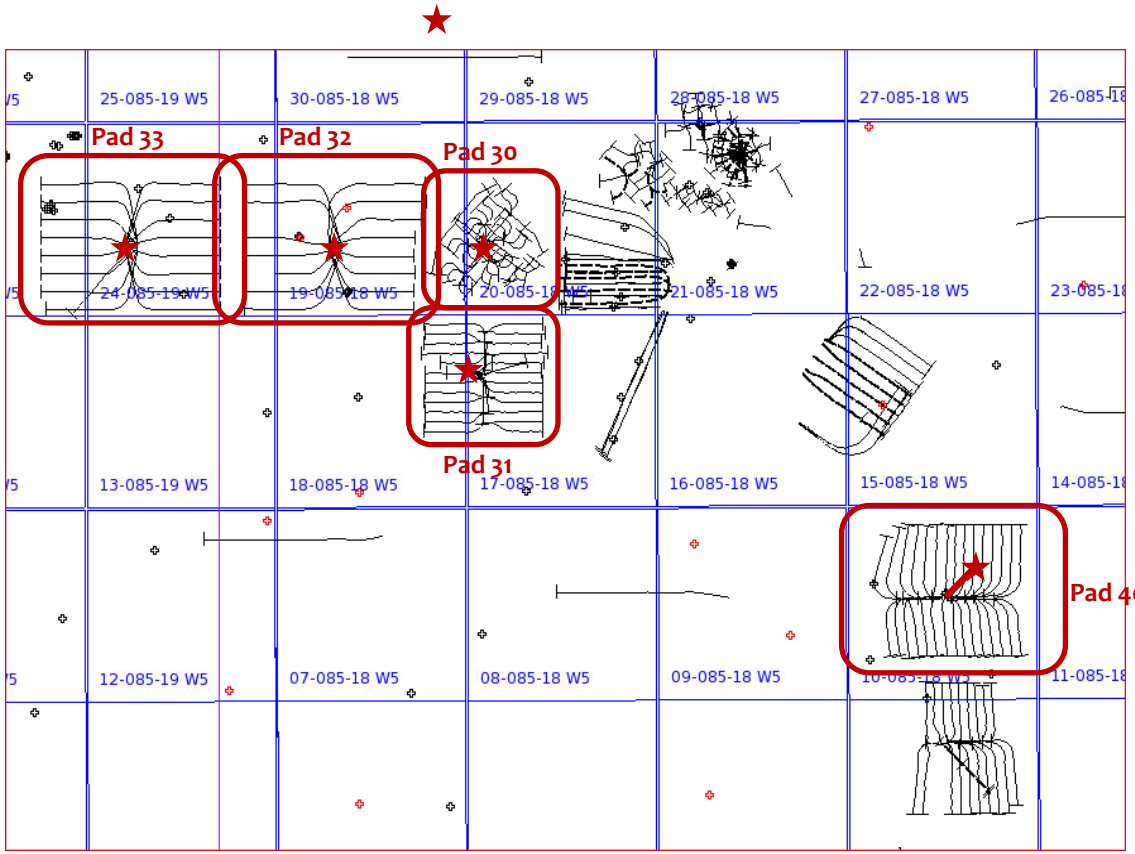
RRs recommended for the InSAR monitoring program over Pad 31.

- More stable

cemented into ground

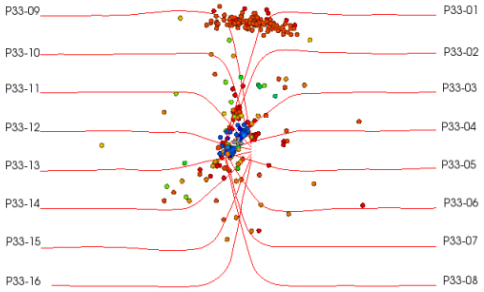
MICROSEISMIC MONITORING CONTINUES

- Microseismic monitoring is ongoing at Pad 30,31, and 40 to monitor caprock and wellbore integrity, as well for out of zone injection.
- Microseismic receiver arrays installed in the Observation wells
- Microseismic monitoring provides an early alert/detection of event activities which might correspond to possible casing failures and/or out of zone injection
- Any such event data is reported by the vendor and analyzed in-house
  to determine its significance for further
  follow-up action
- Follow- up actions can range from data
  gathering through to well interventions

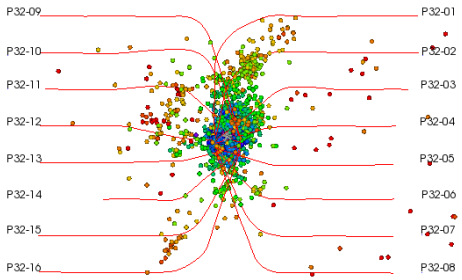


MICROSEISMIC – TOTAL EVENTS TO DATE

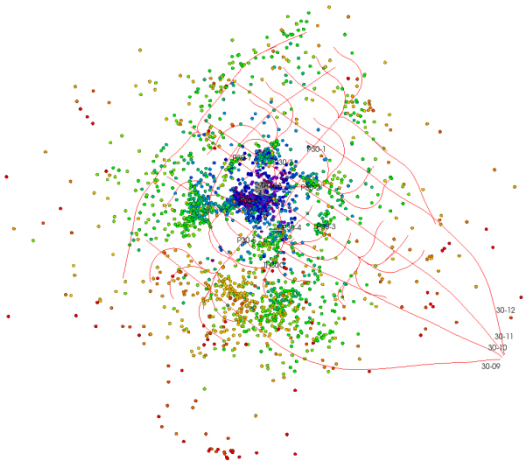
Pad 33 – Apr 2007

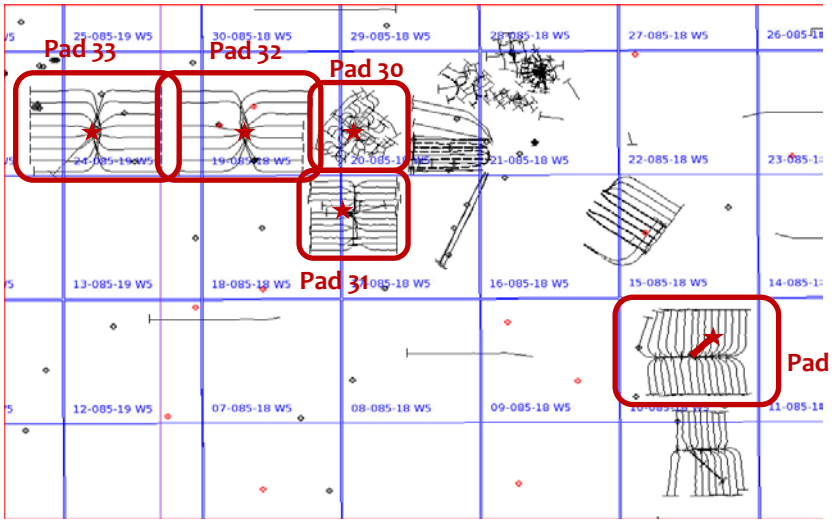


Pad 32 – June 2007

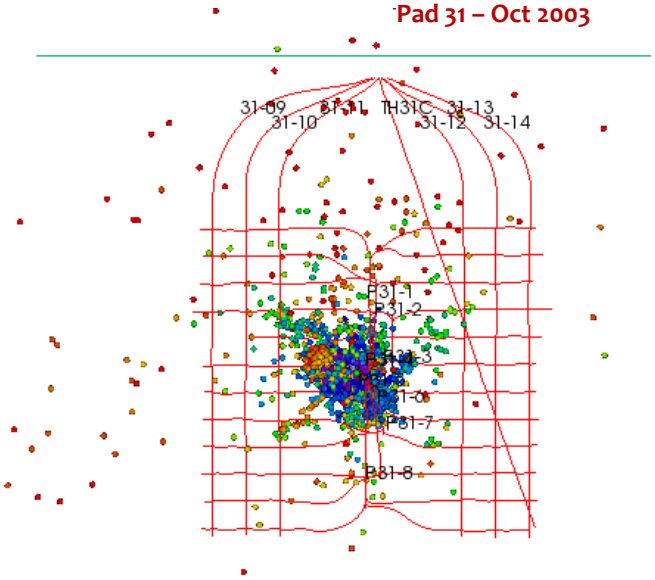


Pad 30 – Oct 2003

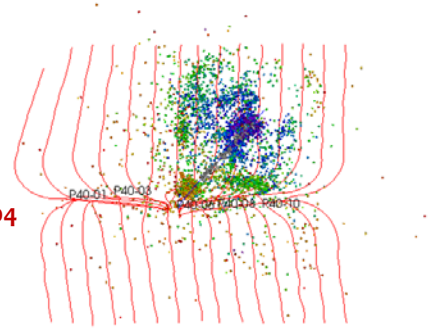




Pad 31 – Oct 2003



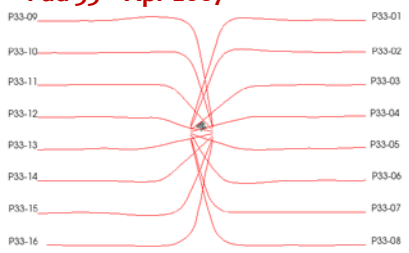
Pad 40 – May 2004



MICROSEISMIC EVENTS FROM THE PAST YEAR

(NOV 1 2015 -OCT 31 2016)

Pad 33 – Apr 2007



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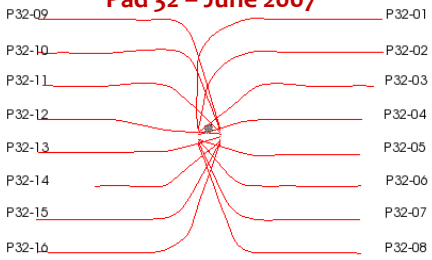
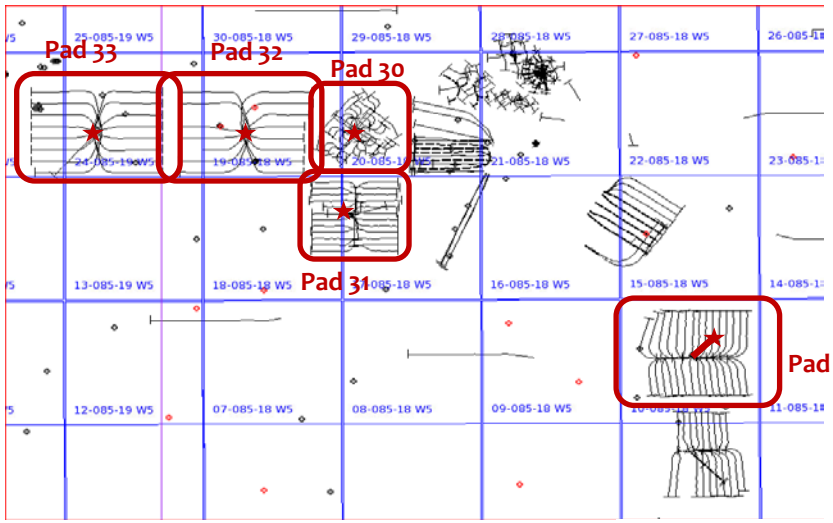
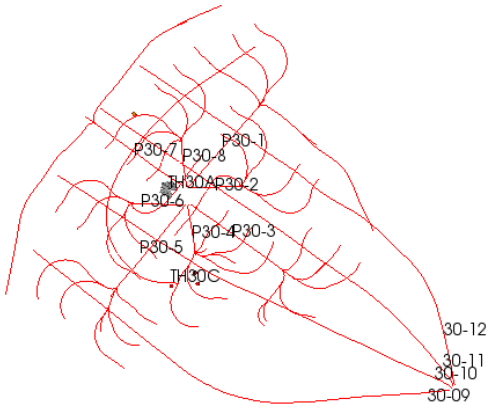
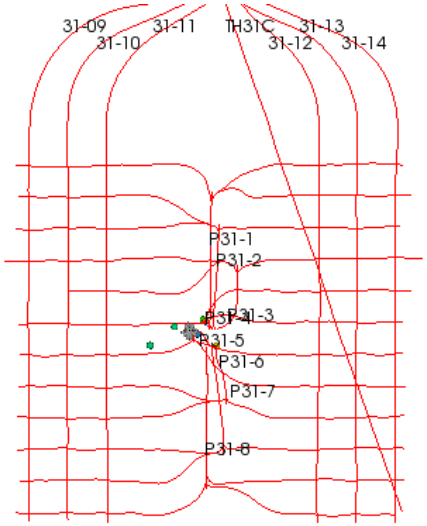




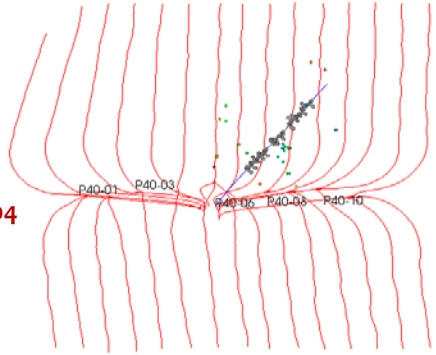
Pad 30

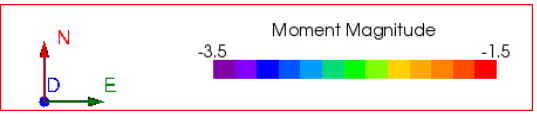


Pad 31

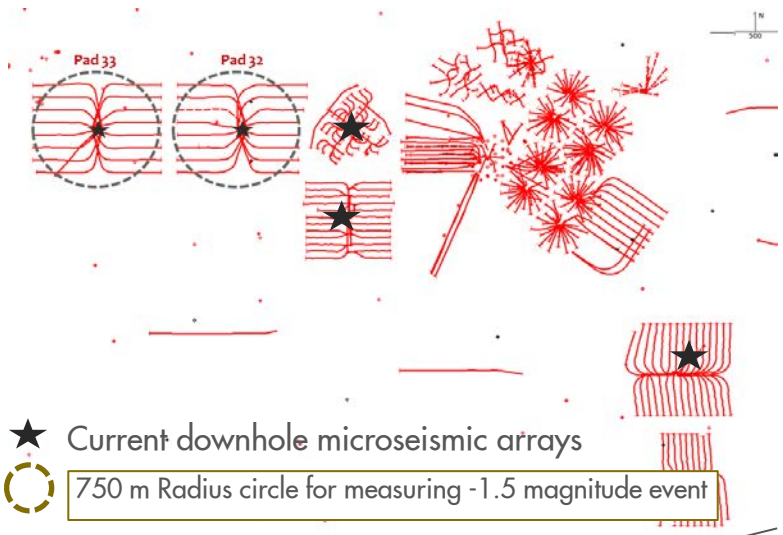


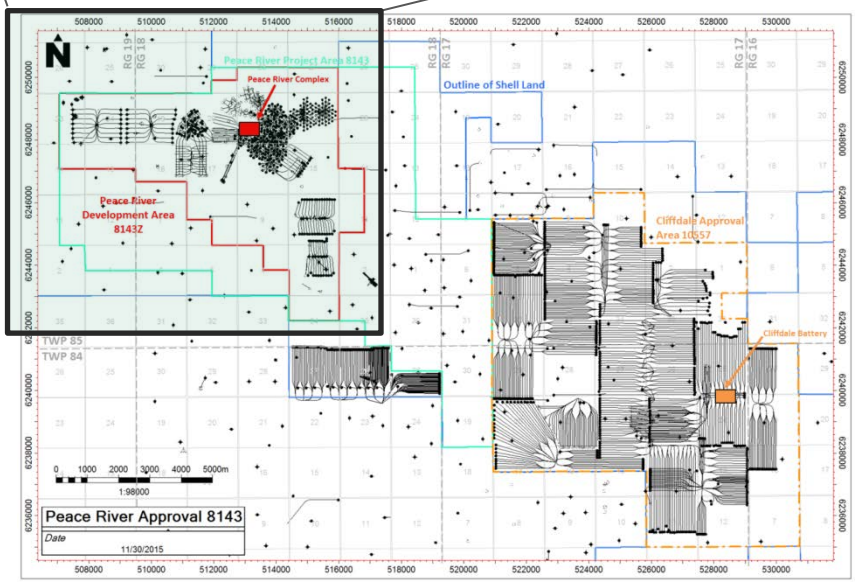
Pad 40 – May 2004





Pad 32 & Pad 33 Microseismic Array Issues



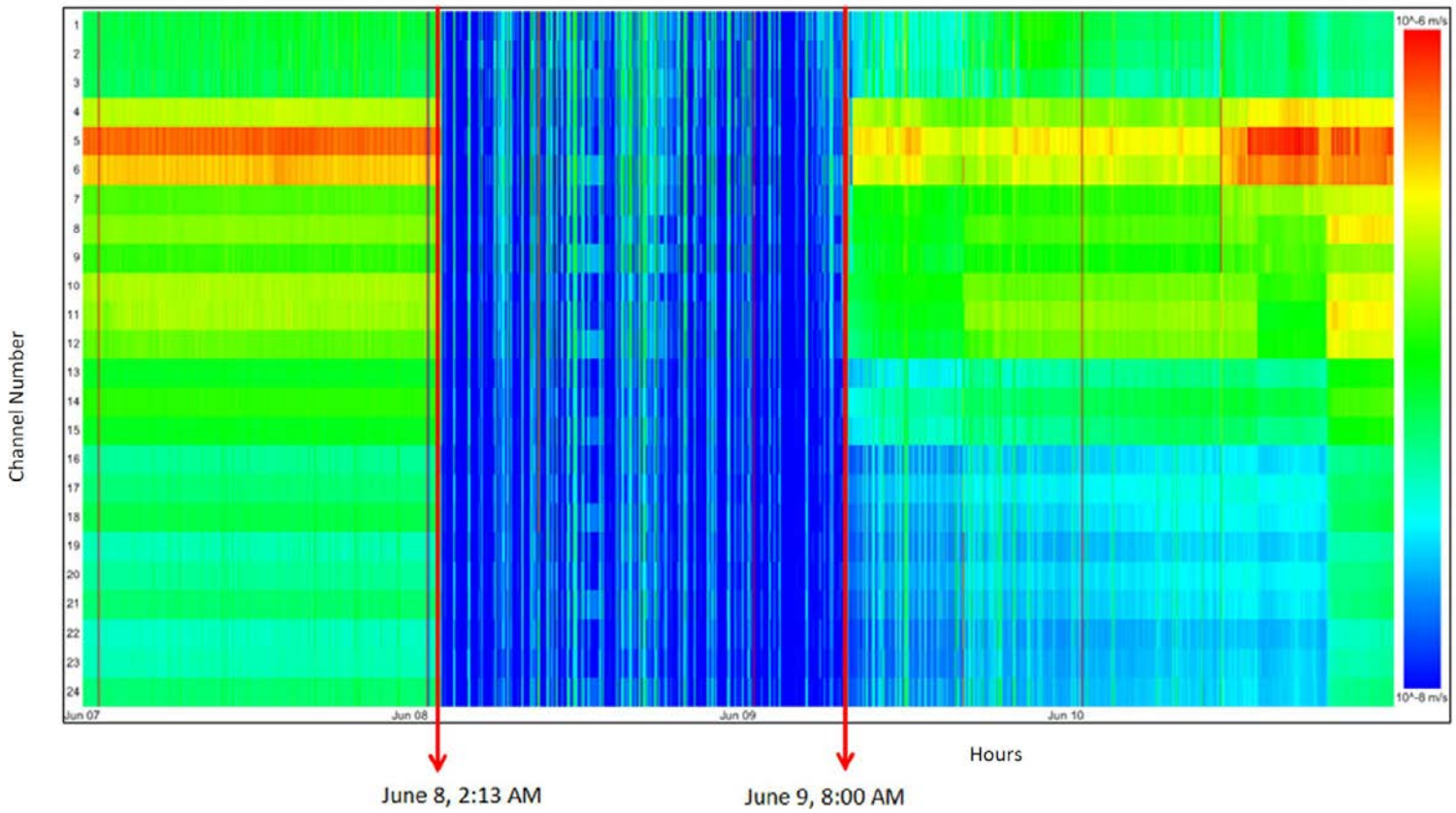


- Operations on Pad 32 and 33 started in 2006
- Downhole microseismic arrays active since Aug 2006
- Noise levels on Pad 32 and Pad 33 microseismic arrays have risen to levels where they are impacting the ability of the arrays to detect events
- Potential sources of noise:
  - Interference from unknown external source
  - Weak tool coupling
  - Downhole tool failures (some geophones on Pad 33 were damaged during 2006 installation as well)
- Suspended the microseismic monitoring on Pad 32 and Pad 33 until issues are resolved or alternative method of monitoring are in place

Background Noise Assessment

Pad 32- June 7-9, 2016

An acceptable level of background noise would show up as **blue**

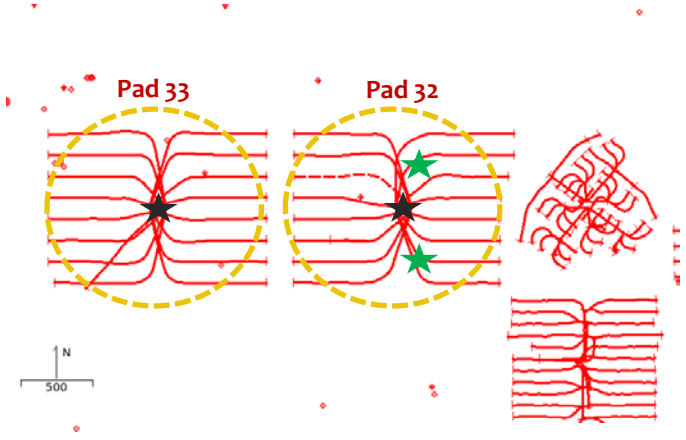


During the planned pad outage between June 8-9, the noise level decreased significantly which indicates some noise could be caused by an external source

Pad 32 Controlled Well Shut-Down Tests

- Two controlled well shut-down tests were conducted to determine which wells on Pad 32 are contributing to noise the most and if any actions can be performed to mitigate the noise to acceptable levels
- Shut-Down Test 1: Wells were sequentially turned off on Pad 32. Was able to pinpoint 5 wells contributing most to noise on the array.
- Shut-Down Test 2: Was able to further pinpoint 2 wells when off, noise levels are acceptable
- Currently testing if well interventions on those wells alleviates the noise

Pad 32/33 MS Array Issues Plan forward



Current microseismic arrays

750 m Radius circle for measuring -1.5 magnitude event

Potential new arrays in observation well

- On Pad 32, currently investigating what is the source of noise from the two wells found in the controlled well shut-down tests. Once an understanding of what is happening on Pad 32 is achieved Pad 33 will also be investigated.
- Investigating alternatives for monitoring:
  - Potential installation of new downhole array in existing observation wells for Pad 32 if technically and economically feasible
  - Looking for technical and economically feasible options for Pad 33
- Continuing to perform SITS on an opportunity basis
- On injection wells, ongoing casing integrity alarms that can detect sudden drops in pressure which may be indicative of out of zone injection

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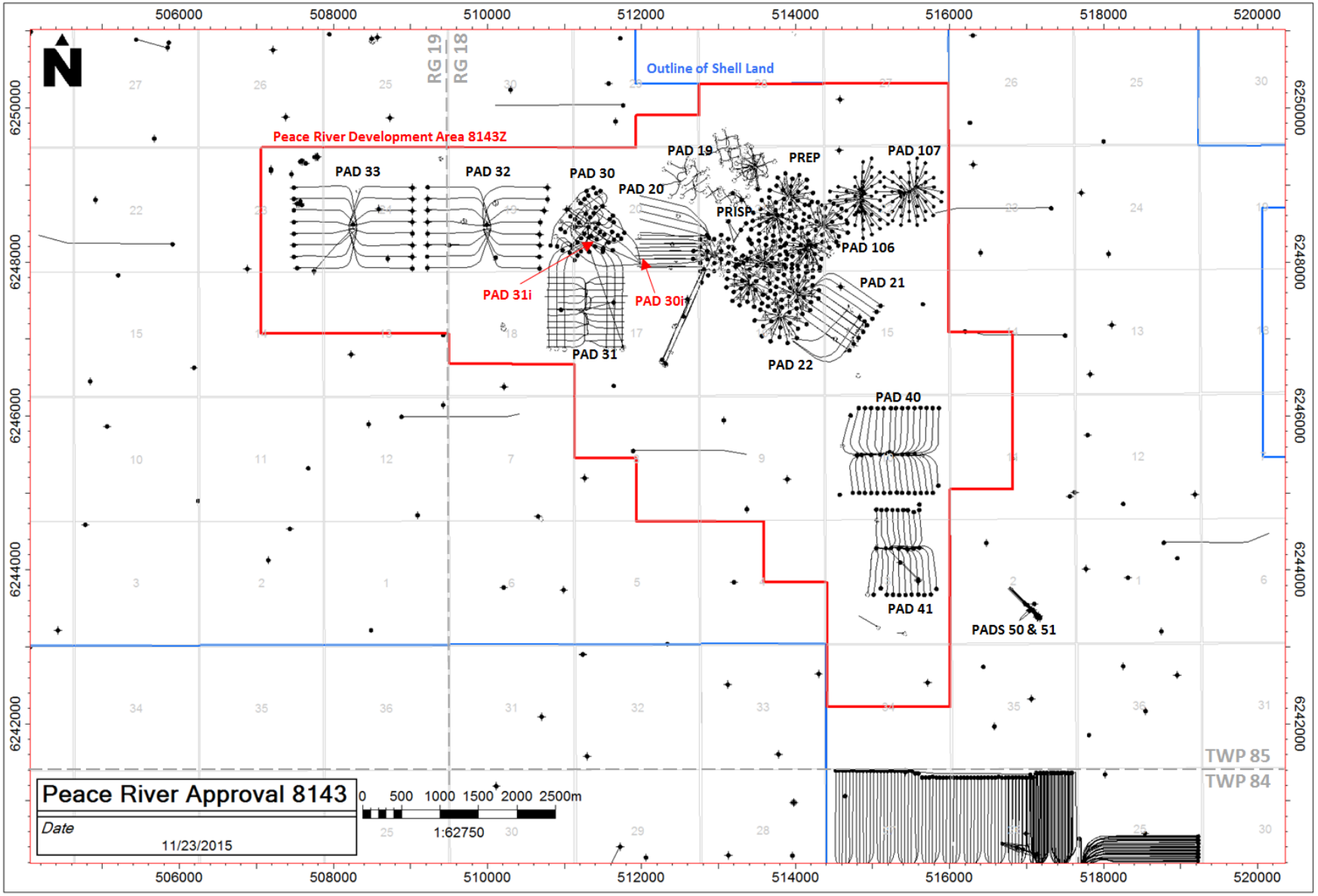
Future Plans	Ivan Gonzalez
Surface Operations, Performance and Compliance	
	Darcy Forman

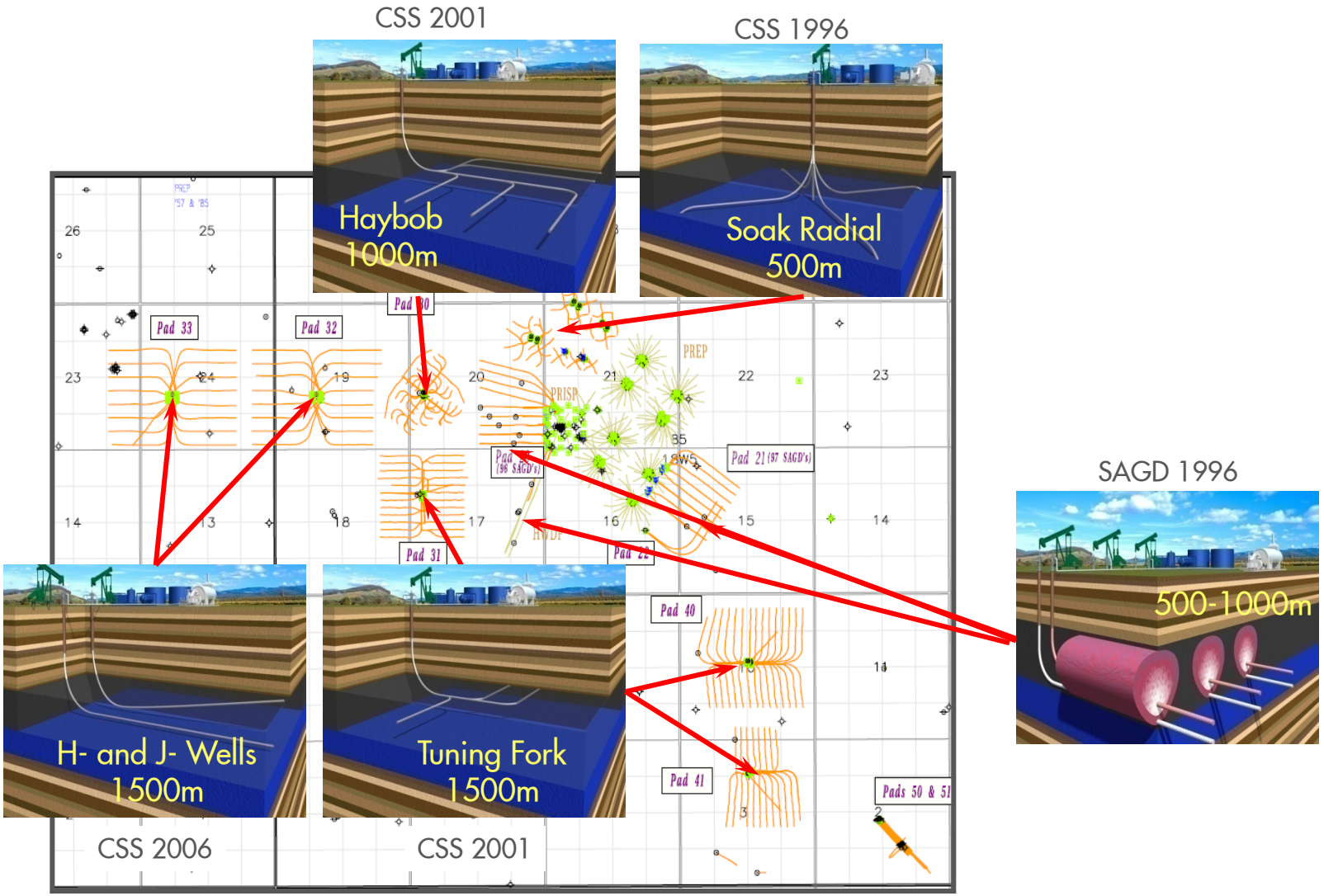
DRILLING AND COMPLETION OVERVIEW

- PRISP & PREP (1979)
  - 31 wells and 212 wells, 7 spot pattern
- Disposal Wells (1978 & 2008)
  - 3 brine disposal, 2 water disposal
- Pad 19 (1996 and infills drilled in 2011)
  - 1 test hole and 15 producers, "soak radial" design
  - Pad 19 infill wells: 10 new producers and 8 new injectors (vertical wells)
- Pad 20/21 SAGD (1997 and phase 3 infills drilled in 2011)
  - 5 well pairs, 5 dual wellbores, 9 observation wells
  - Pad 20 phase 3 injectors (4 new horizontal wells)
- Pad 30/31/40/41 Multi Laterals (2000)
  - 8 "haybob", 25 "tuning fork", 6 observation wells
- Pad 20/21 Conversions, Infills, 19 SD (2004)
  - Converted SAGD well to CCS, drilled 7 single lateral infills, 2 steam wells on pad 19
- Pad 32/33 Horizontals (2005)
  - 16 wells per pad, 3 obs wells
- Pad 22 Steam Injectors (2006)
  - 2 steam injectors running over pad 21 conversions, acting as steam drive
- Pad 30 & 31 Steam Injectors (2014)
  - 10 steam injectors 4 over Pad 30 & 6 over Pad 31
- 2 Carmon Creek Wells (2014)
  - Brine disposal well (02/15-27-85-19W5)
  - Delineation well (AA/04-26-85-18W5, D&A)
- Pad 22 Steam Injector (2015)
  - Top down Steam Drive injector 22-04
- Carmon Creek Wells 2015
  - Pad F106
    - 46 wells + 1 Observation well
  - Pad F107
    - 46 wells + 1 Observation well
  - 2 Acid gas injection well & 1 monitoring well
  - 2 water back producers
- No Drilling Activity in 2016

FIELD MAP


506000
508000
510000
512000
514000
516000
518000
520000
6250000
6248000
6246000
6244000
6242000
RG 19
RG 18
Outline of Shell Land
Peace River Development Area 8143Z
PAD 33
PAD 32
PAD 30
PAD 20
PAD 19
PREP
PAD 107
PRISP
PAD 106
PAD 21
PAD 31i
PAD 30i
PAD 31
PAD 22
PAD 40
PAD 41
PADS 50 & 51
TWP 85
TWP 84
Peace River Approval 8143
Date
11/23/2015
0 500 1000 1500 2000 2500m
1:62750

WELL TYPE OVERVIEW



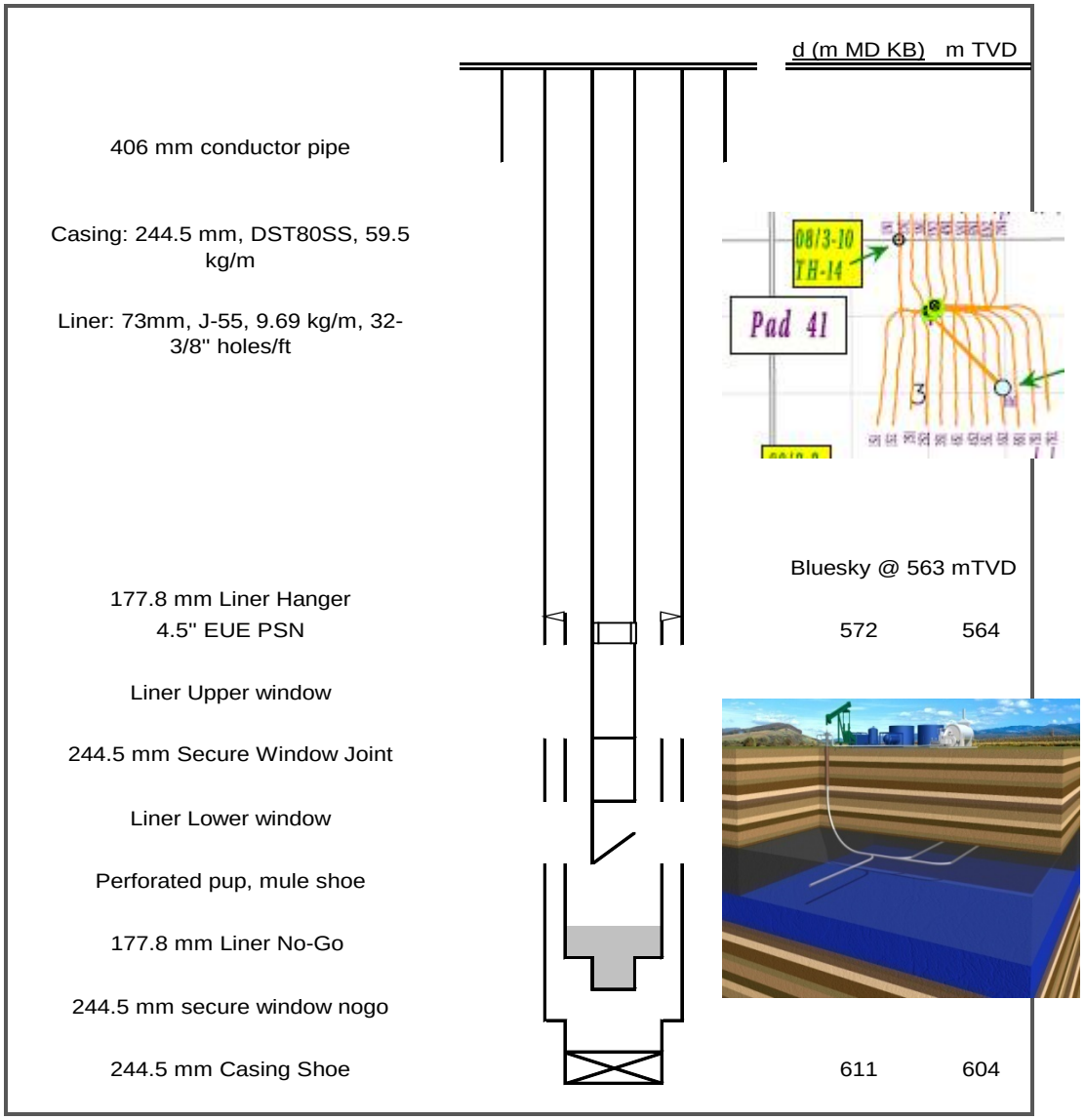
REPRESENTATIVE WELL SPACING FOR INDIVIDUAL PADS

- **Pad 19**
  - 100 m horizontal separation between injector and producer vertical wellbores
  - 150 m horizontal separation between producer vertical wellbores
  - Subsurface spacing variable due to soak radial geometry
- **Pad 20**
  - 5m vertical separation between SAGD injectors and producers
  - 100m horizontal separation between SAGD pairs and J-wells
  - 100m horizontal separation between new phase 3 infill injectors
  - 50m horizontal separation between a phase 3 injector and an original SAGD well pair
  - Vertical separation between a phase 3 injector and an original SAGD well pair is 3m to 15m
- **Pad 21/22**
  - 5m vertical separation between SAGD injectors and producers

  100m horizontal separation between SAGD pairs and J-wells
- **Pad 21/22 (continued)**
  - 90m horizontal spacing between pad 22 injectors
  - Pad 22 injectors are 10m to 17m above original SAGD producers
- **Pad 30**
  - Highly variable due to Haybob geometry
  - **2014 injector spacing – 150 – 250m**
- **Pad 31**
  - 80 m horizontal separation between laterals
  - **2014 injector spacing 100m**
- **Pad 32**
  - 150 m horizontal separation between horizontal wells
- **Pad 33**
  - 150 m horizontal separation between horizontal wells
- **Pad 40**
  - 80 m horizontal separation between laterals
- **Pad 41**
  - 80 m horizontal separation between laterals

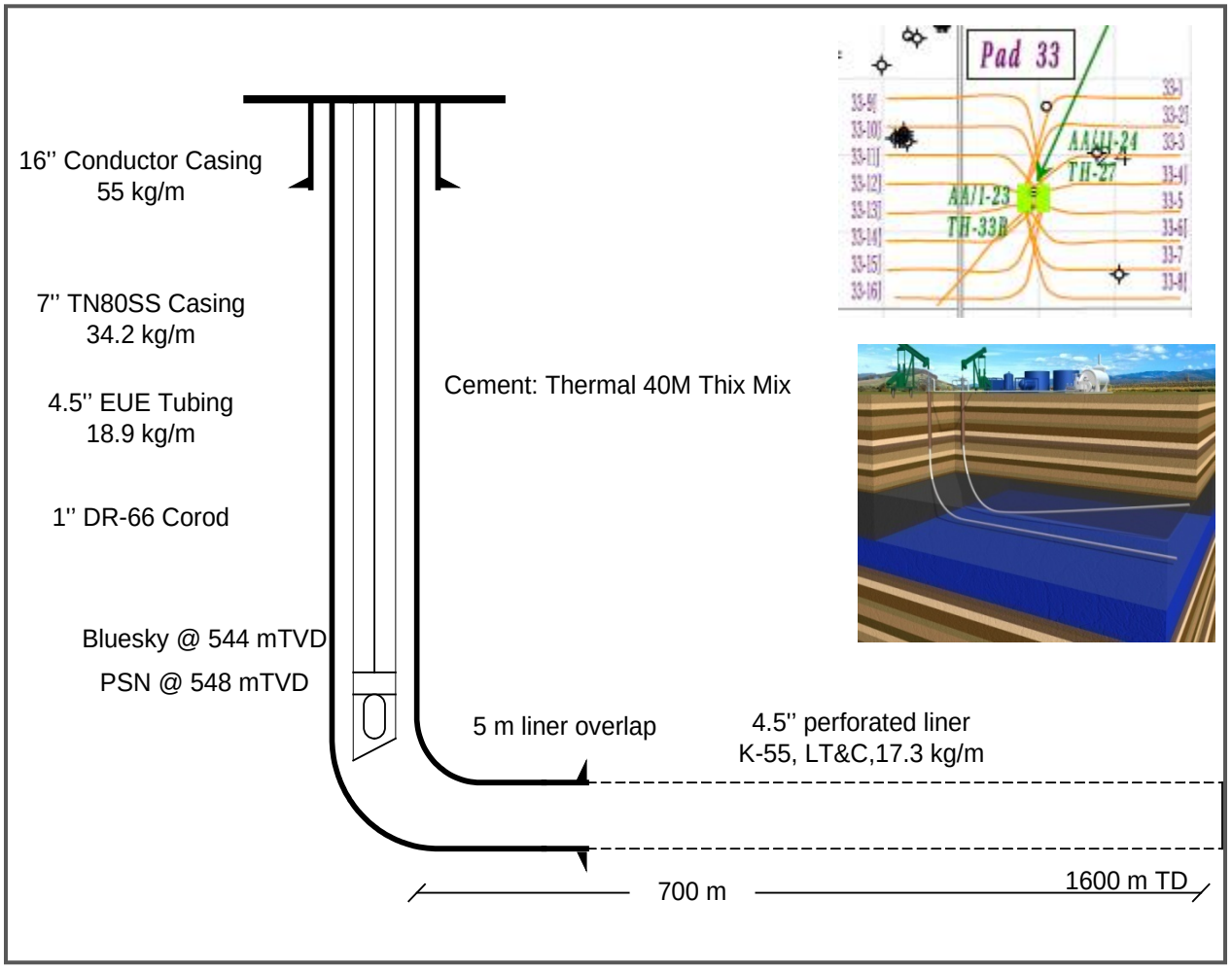
TYPICAL MULTI LATERAL PRODUCER COMPLETION

- Pads 30, 31, 40 &41
- 9 5/8’’ Casing
- 7’’ Window sleeve
- 2 7/8’’ Liner
- Thermal 40F cement
- 4.5’’ tubing
- Insert pumps
- 550-700m laterals
- During full steam cycles, the pump is removed and steam is injected down the tubing of the well.
- For mini soaks (steam injection volumes 500-2000 t) the pump is unseated and steam is injected down the casing.



TYPICAL SINGLE LATERAL COMPLETION

- Pads 32 & 33
- 7’’ Casing
- 4.5’’ perforated liner
- 4.5’’ Tubing
- Insert pumps
- Thermal 40M cement
- 500-700 m lateral



PAD 19 SAT 3 – WELL SCHEMATIC – START-UP 2013

Producer Well Design

General Data:

Surface hole size: : 374mm (14-3/4”), depth 250m – 310m

Inclination in surface section 0º - 20º

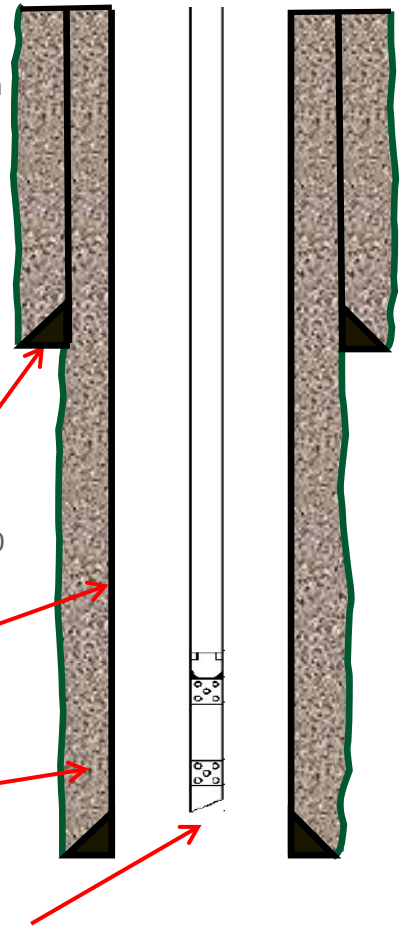
Main hole size: 273 mm (10-3/4”), TD 590m – 688m MD (~585m TVD)

Inclination at TD 13º – 47º

Casing Data:
- Surface casing: 298.5mm (11-3/4”) 62.5 kg/m (42 lb) H40 STC
- Production Casing: 219.1mm (8-5/8”) 47.6 kg/m (32 lb) L80IRP TS3SB

Cement:
Both strings cemented to surface with RFC Thermal (thixotropic, ~40% silica, 1740 kg/m3)

Tubing:
88.9mm, 13.84kg/m, J55 EUE



Injector Well Design

General Data:

Surface hole size: 311mm (12-1/4”), depth 250m – 310m

Inclination in surface section 0º - 21º

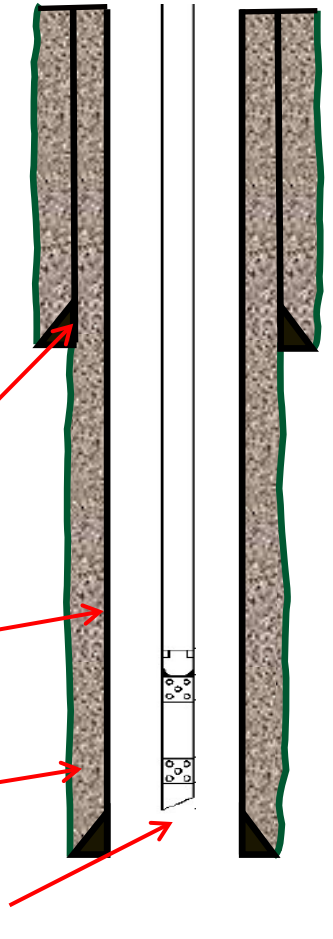
Main hole size: 216mm (8-1/2”), TD 599m – 646m MD (~585m TVD)

Inclination at TD 29º – 45º

Casing Data:
- Surface casing: 244.5mm (9-5/8”) 47.6 kg/m (32 lb) K55 TBlue
- Production Casing: 177.8mm (7”) 34.2 kg/m (23 lb) L80IRP TBlue

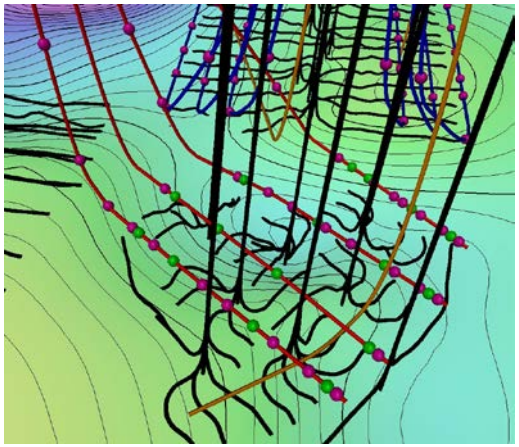
Cement:
Both strings cemented to surface with RFC Thermal (thixotropic, ~40% silica, 1740 kg/m3)

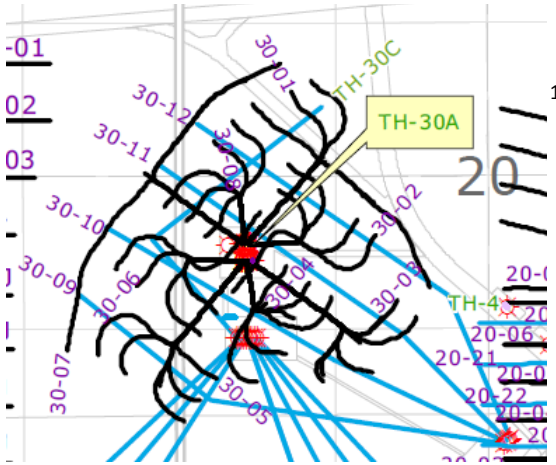
Tubing:
73mm, 9.67kg/m, J55 EUE

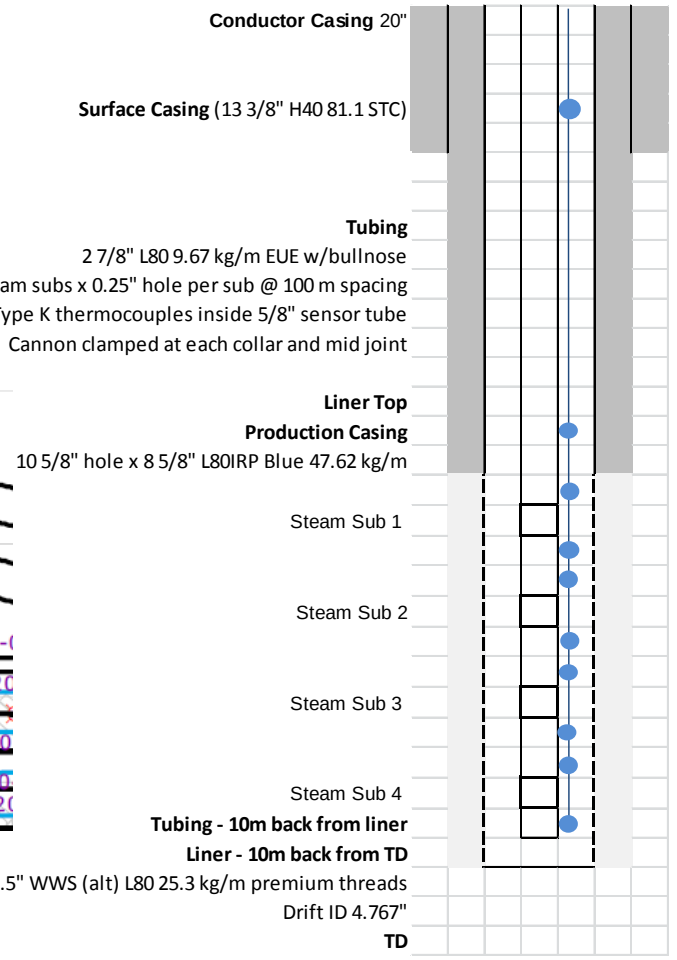


PAD 30I INJECTOR COMPLETION – START UP JAN 2015

- **Pads 30i**
- 4 Single Laterals
- Instrumented coil tubing with thermocouples
- 30 -11 has DTS
- 8 5/8" Casing
- 2 7/8" tubing with 4 x ½" steam subs
- 5 ½" wire wrap liner
- 400-800 m lateral

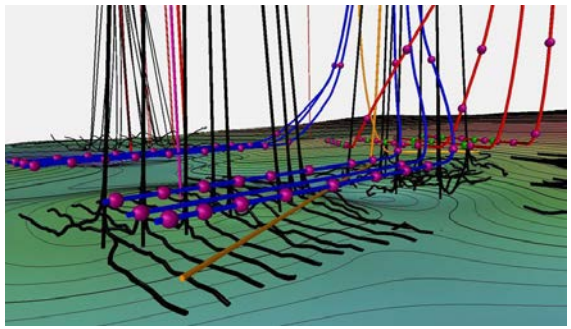


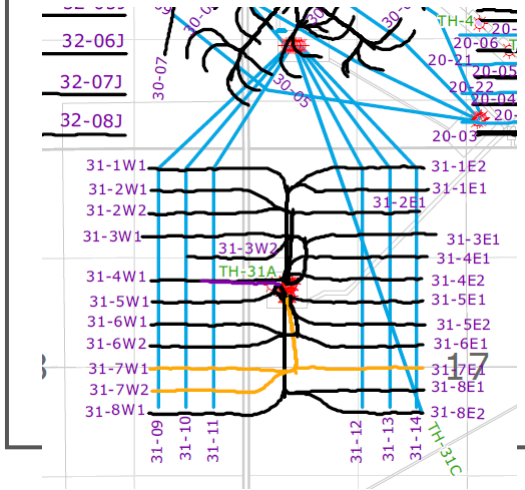




PAD 31I INJECTOR COMPLETION – START UP NOV 2014

- **Pads 31i**
- 6 Single Laterals
- Instrumented coil tubing with thermocouples
- 31-10 & 31-13 have DTS
- 9 $^{5}/_{8}$'' Casing
- 3 $^{1}/_{2}$'' long string tubing
- 2 $^{7}/_{8}$'' short string
- 7" wire wrap screen liner
- 950 m lateral

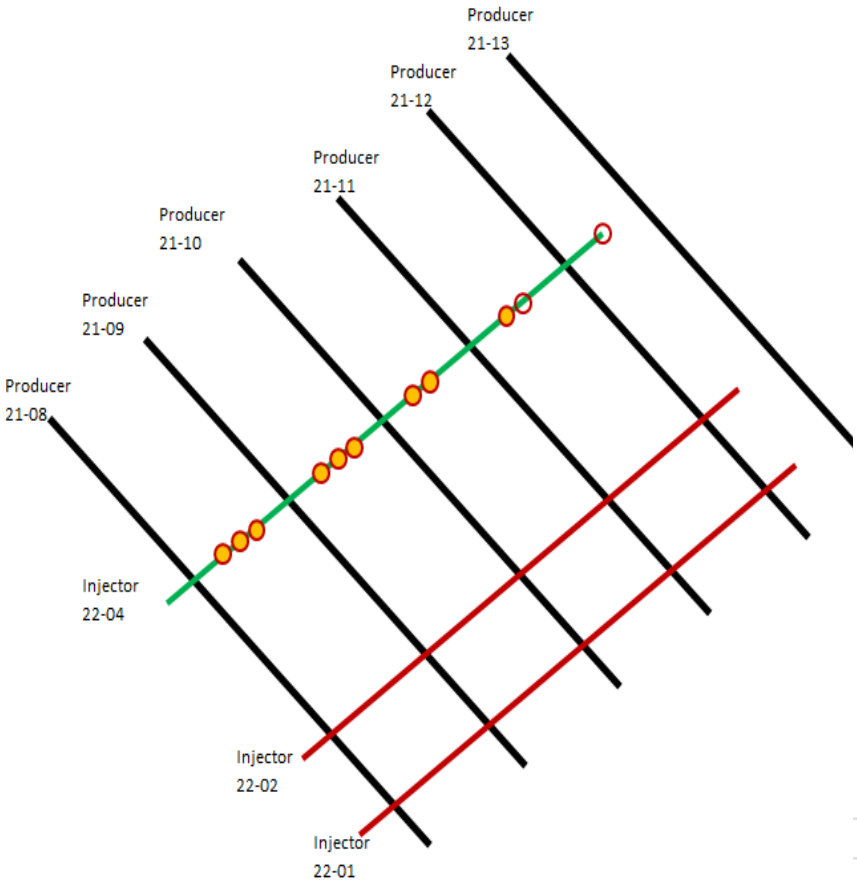




PAD 22 (22-04) – WELL SCHEMATIC – START UP NOV 2015

Well equipped with

- VIT from surface to 300 mKB
- 10 ICD subs at 4 Intervals
- 10 Type K thermocouples

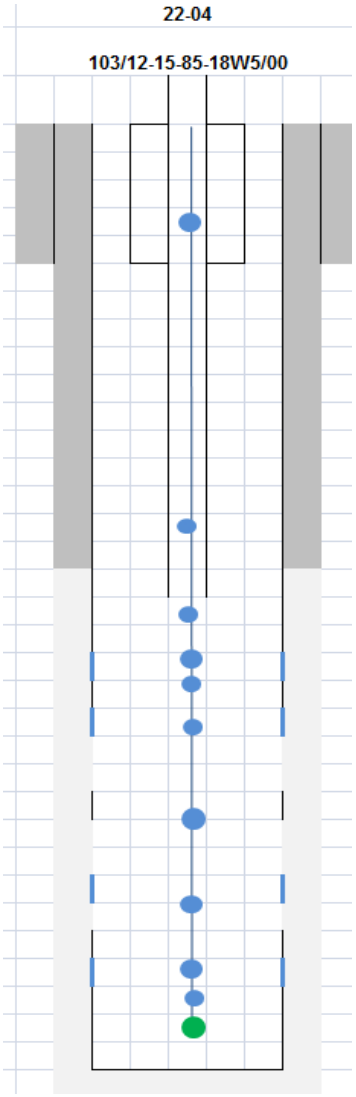


Surface Casing	
Size	339 mm
Weight	81.1 kg/m
Grade	J55 STC
mKB	301
SC Cement Top	Surface

Production Casing	
Size	244 mm
Weight	59.53 kg/m
Grade	L80 IRP T-Blue
mKB	859
PC Cement Top	Surface

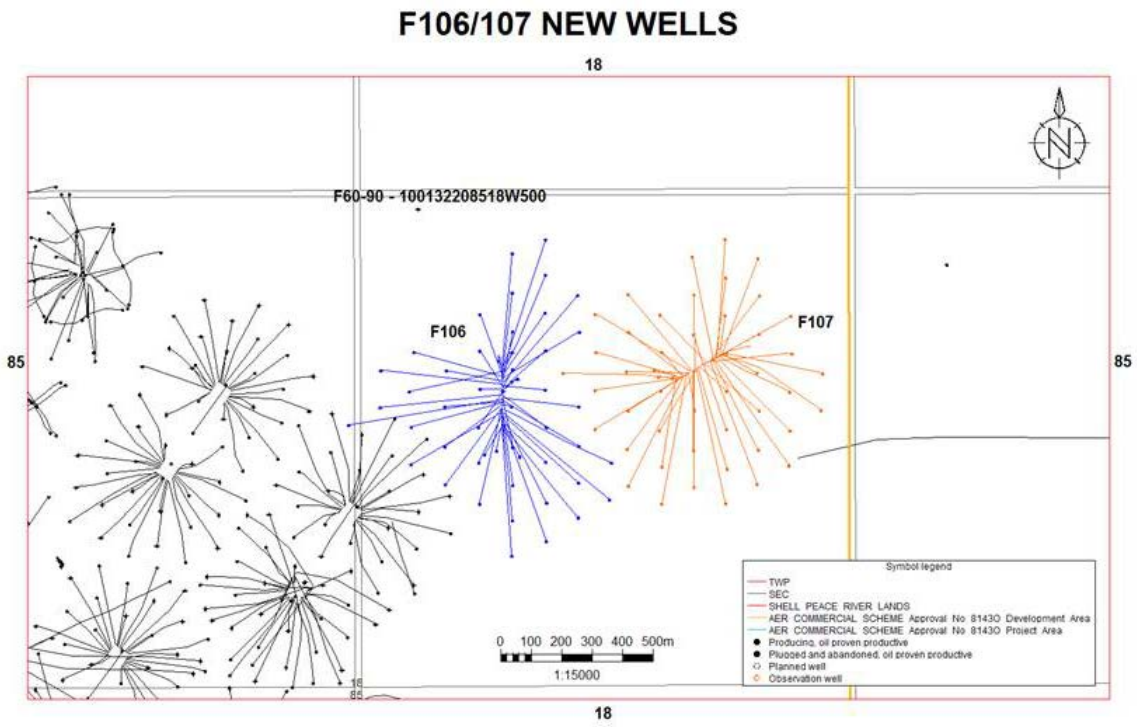
Tubing	
Size	88.9 mm
Weight	9.67 kg/m
Grade	J55
mKB	830

Liner	
Size	177 mm
Weight	34.23 kg/m
Grade	L80 DWC/C
Liner, mKB	1305
Open hole TD, mKB	1314



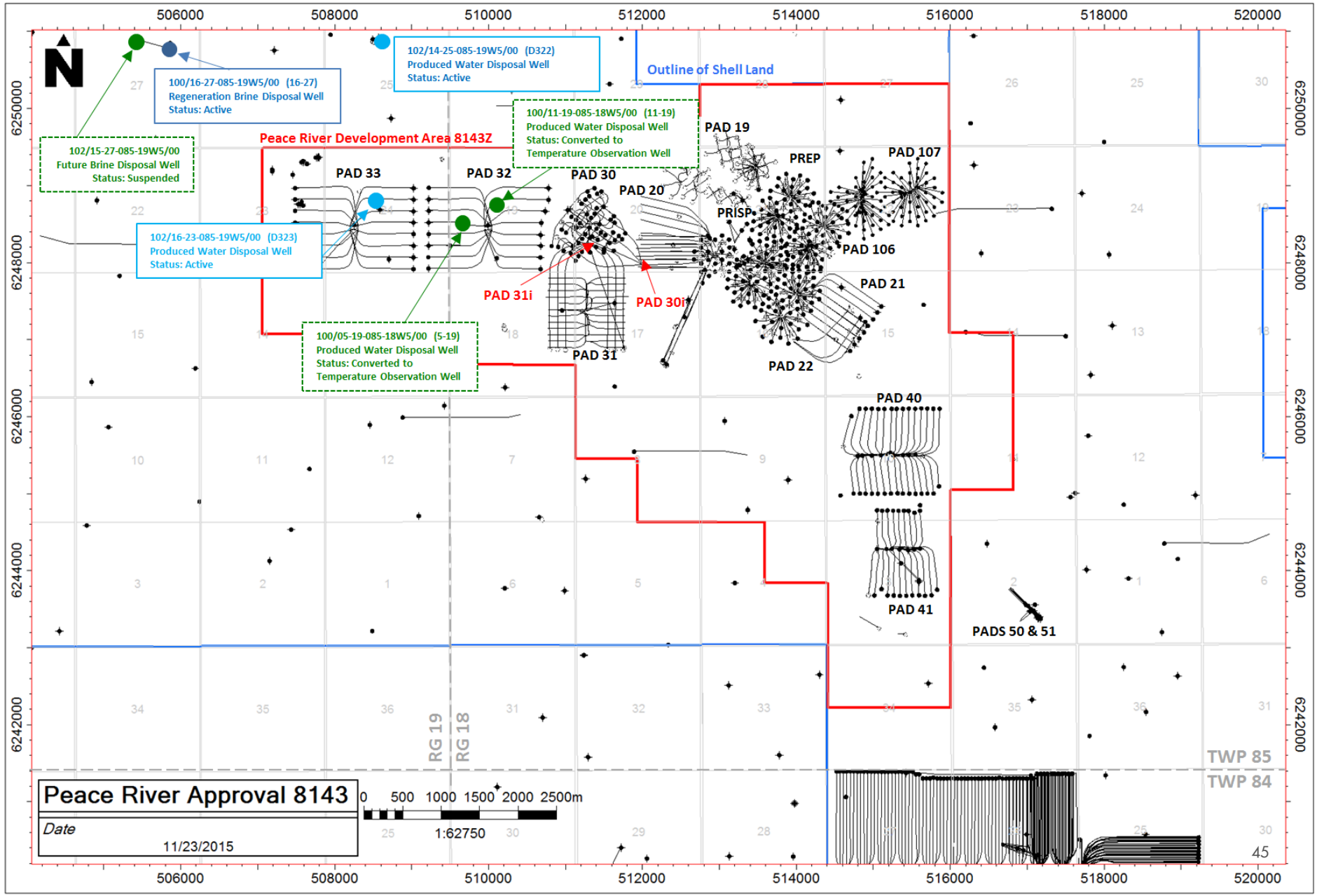
CARMON CREEK PAD WELLS

- **Pad 106** production wells
  - 43 production wells, 3 surface holes
  - Drilled Sept 2014-Oct 2015
  - No completion
  - Standing, suspended
- **Pad 106-90 Observation well**
  - Drilled Sept 2014-Sept 2015
  - Two external pressure gauges @ 324 and 509 mMD
  - No completion
  - Standing, suspended
- **Pad 107** production wells
  - 46 production wells
  - Drilled Apr – Aug 2015
  - No completion
  - Standing, suspended
- **Pad 107-90 Observation well**
  - Drilled Apr 2015
  - Two external pressure gauges @ 310 and 510 mMD
  - No completion
  - Standing, suspended



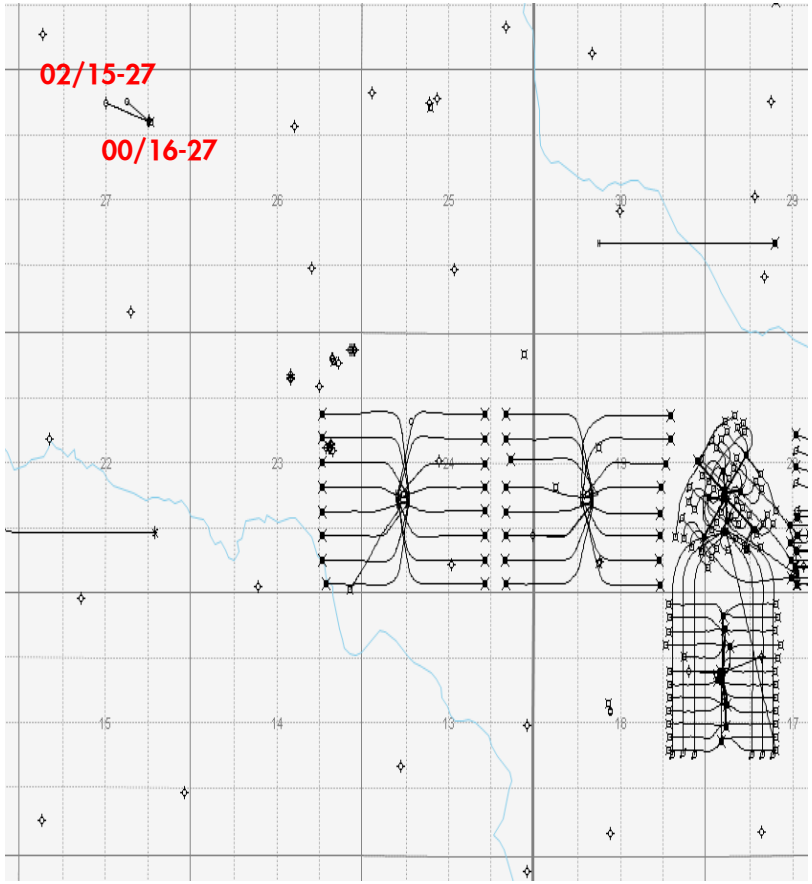
- **Pad 101, 104, and 105**
  - Civil earthworks complete
  - Conductors installed
- **Pad 102 and 103**
  - Civil earthworks completed
- **Pad 108, 109 and 110**
  - Licensed, no field work executed

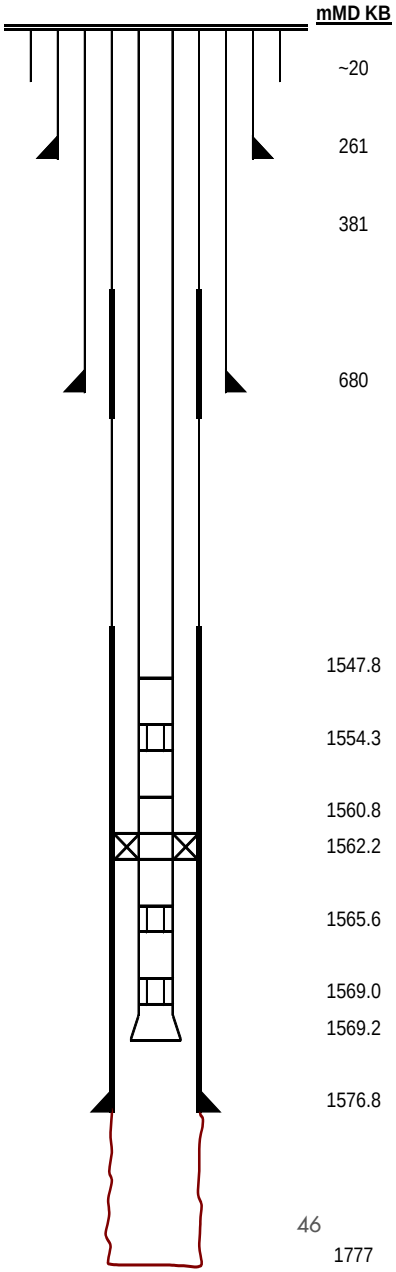
DISPOSAL WELL LOCATIONS



TYPICAL BRINE DISPOSAL WELL COMPLETION- 15 &16 - 27

Softener regeneration waste water is currently disposed into the 16-27 well. 02/15-27 Standing back up brine disposal well.

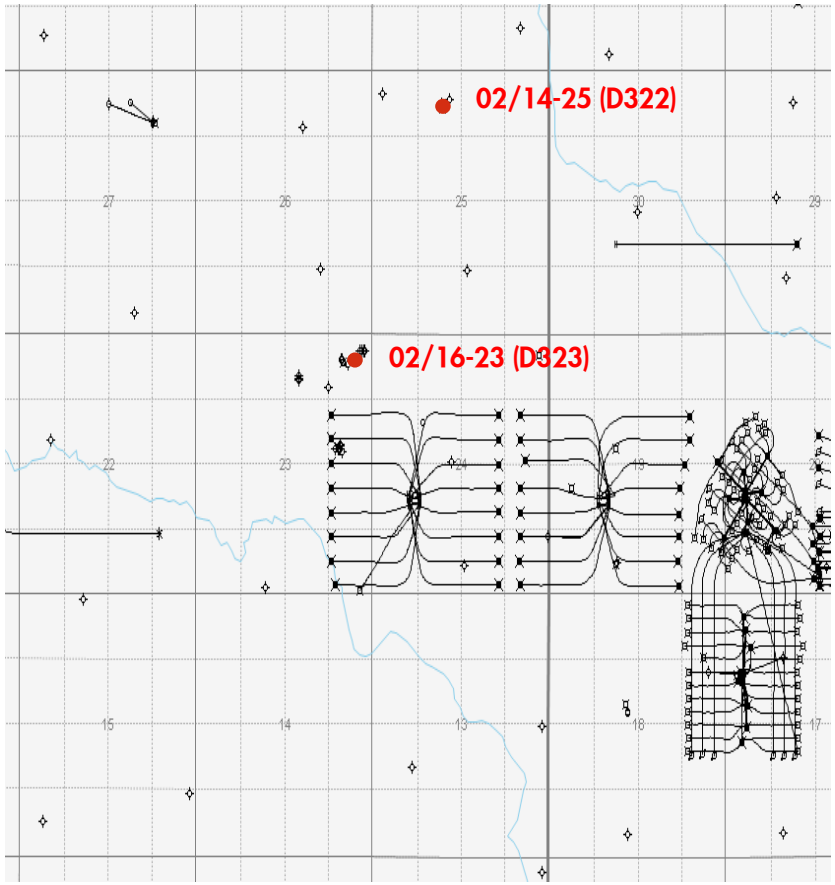


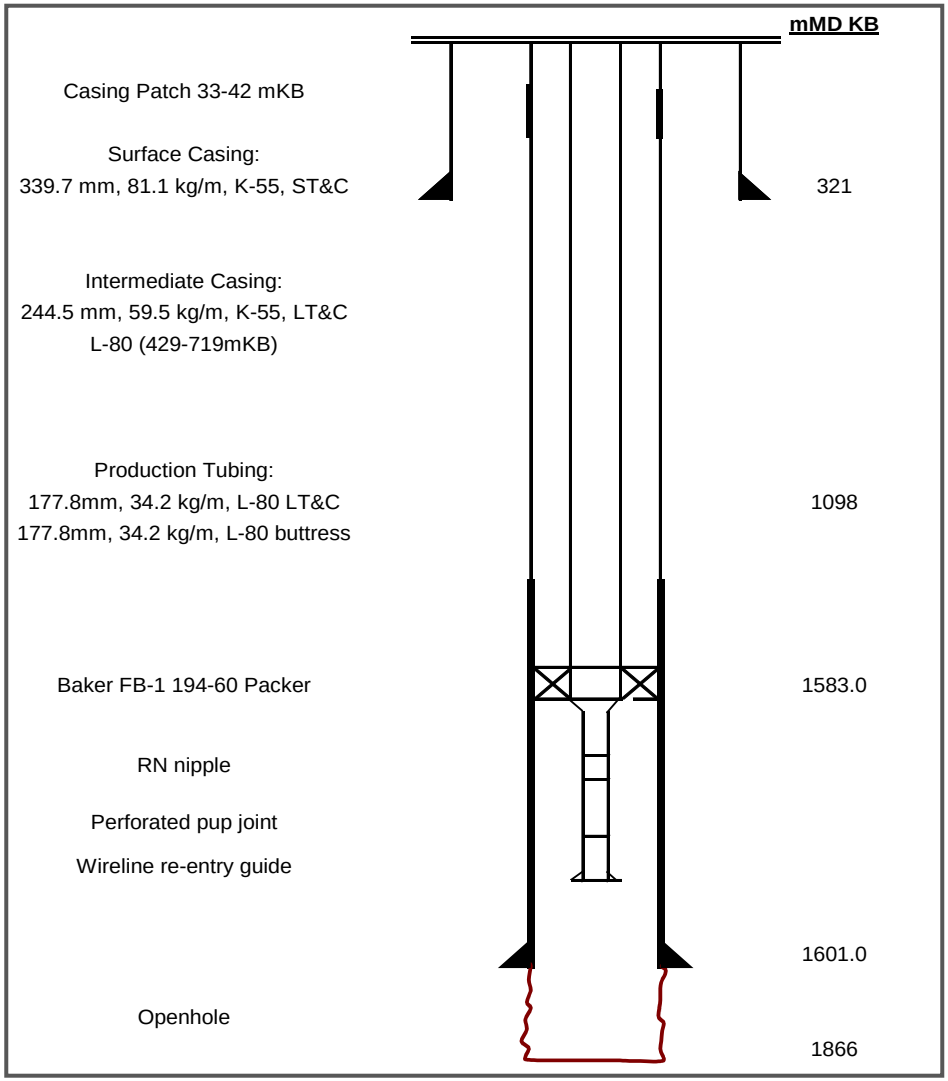


	mMD KB
Conductor 508 mm	~20
Surface Casing 339.7 mm, 81.1 kg/m, J-55, ST&C	261
Base Groundwater Protection	381
Intermediate Casing 244.5 mm, 53.4 kg/m, J-55, LT&C	680
Production Tubing 88.9 mm, 13.8 kg/m, L-80, Hydril 553 to 1557 m *Internally coated w/ TK-69 (5.3 - 8.8 mil thick)*	1547.8
OTIS X nipple (89 mm, Hydril 553, ID - 69.85 mm)	1554.3
Baker Model K22 Anchor Seal (89 mm, Hydril 553)	1560.8
Baker Model SAB-3 Production Packer (89 mm, Hydril 553)	1562.2
OTIS X nipple (89 mm, Hydril 553, ID - 69.85 mm)	1565.6
OTIS XN nipple (89 mm, Hydril 553 x EUE, ID - 69.85 x 66.93 mm)	1569.0
Baker Wireline Re-Entry Guide (140 mm x 89 mm, EUE)	1569.2
Production Casing 177.8 mm, 34.2 kg/m, L-80, NSCC-M & LT&C **NSCC-M Casing: 472 - 722 m & 1519 - 1577m**	1576.8
Openhole 158.8 mm	1777

TYPICAL PRODUCED WATER DISPOSAL WELL COMPLETION

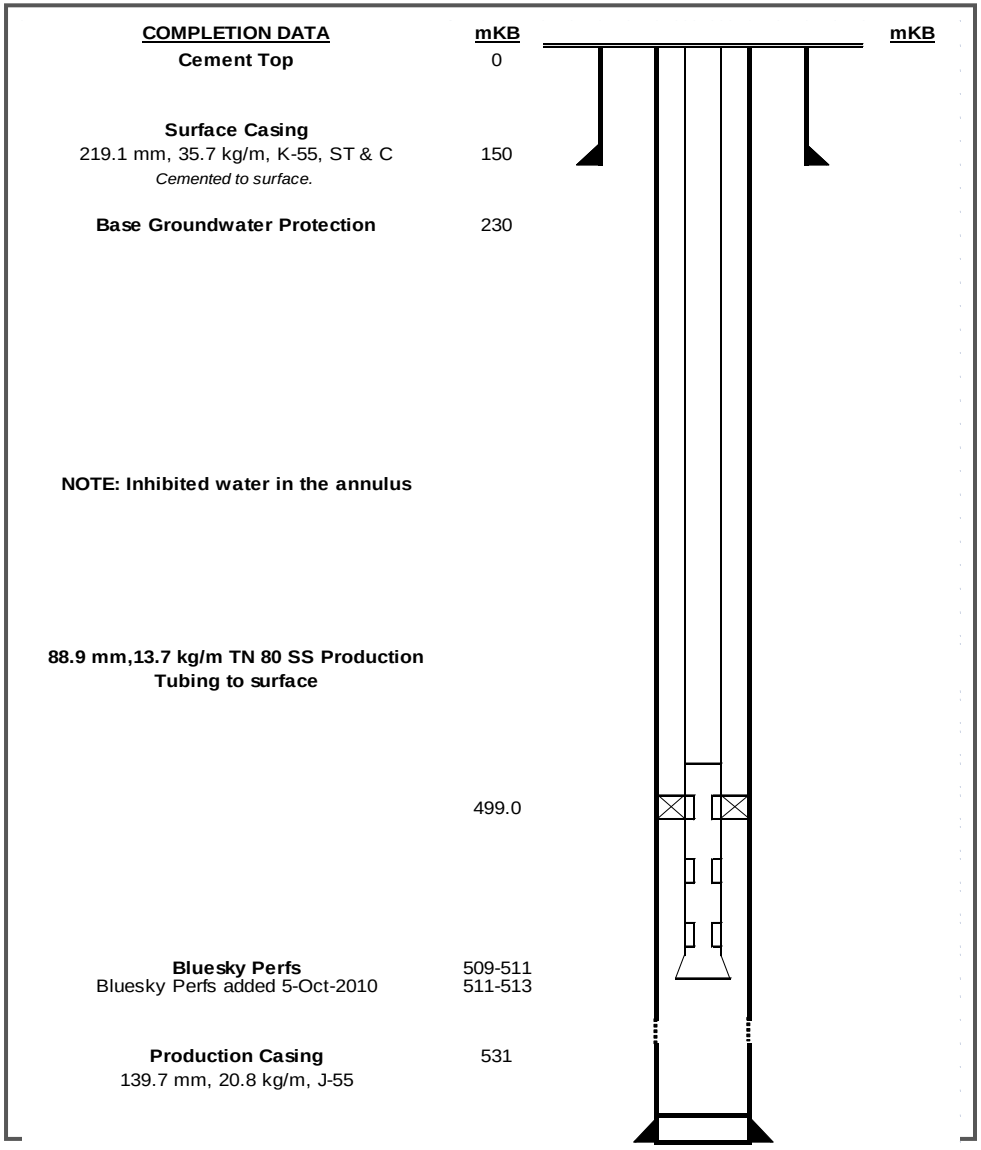
02/16-23 & 02/14-25 dispose of produced water and boiler blowdown into the Leduc formation.





SOUR GAS INJECTION WELL COMPLETION

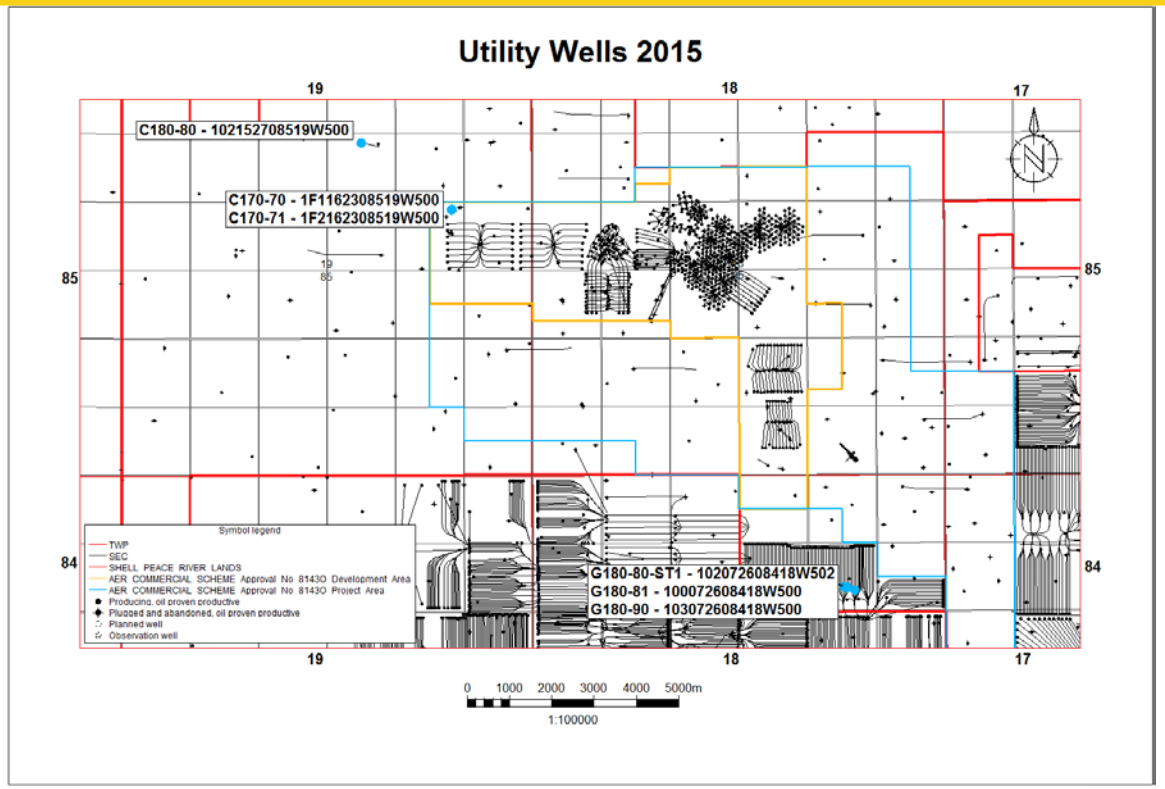
- The 8-11 sour gas injector was completed Nov 2009 as part of the Three Creeks Sour Gas Storage project.
- Injection started Aug 2010.



CARMON CREEK UTILITY WELLS (LEDUC)

Oct 2014 – Oct 2015:

- **C180-80** Brine Injection Well Completion
  - Drilled Mar/Apr 2014
  - Completed
  - Suspended
- **G180-80 and G180-81**, Two injectors
  - Drilled Sept-Dec 2014
  - G180-80 required acid wash, step rate test OK
  - Perforated (50m) liner across Middle Leduc
  - No completion hardware installed
  - Suspended
- **G180-90**, One monitor well
  - Drilled Sept-Dec 2014
  - TD in Winterburn Formation
  - No completion
  - Suspended
- **C170-70 and C170-71,** Water back producers
  - Drilled Dec 2014 – Jan 2015
  - Did not reach target depth on either well
    - C170-70 cemented intermediate casing @ 1603 mKB, called TD
    - C170-71 int casing @ 1610 mKB, drilled and open to TD @ 1776 mKB
  - No completion
  - Suspended



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ARTIFICIAL LIFT – ROD PUMPING EQUIPMENT

Pumping Units: Max.Capacity:

- Pumpjacks:144″ – 260″ stroke
  - Lufkin/Legrand Pump Jacks 280 m3/d
  - Rotaflex: 288″ stroke 250 m3/d

Automation:

- Pump Off Controllers(POC): load cells, motor sensor, crank sensor, VFD
- XSPOC: Real-time pump cards
- LOWIS: Pilot deployed in August 2015

Pumps:

- Insert rod pumps, 2.0 – 3.25″ barrel, 1″ continuous rod, rod string designs
- Continuous improvement initiatives ongoing (improved rod-string designs, POC pump checks, dynagraph verification, fluid shots, etc.), POC fluid level verification

Stuffing Boxes:

- High temperature stuffing boxes are installed on every pumping well. The cone packing is used while pumping and it has rubber elements with brass supports.
- Packing Leak Containment devices (complete with high-level- shut-down switches) have been installed on all wells.
- There have been no offsite emulsion releases in 2016

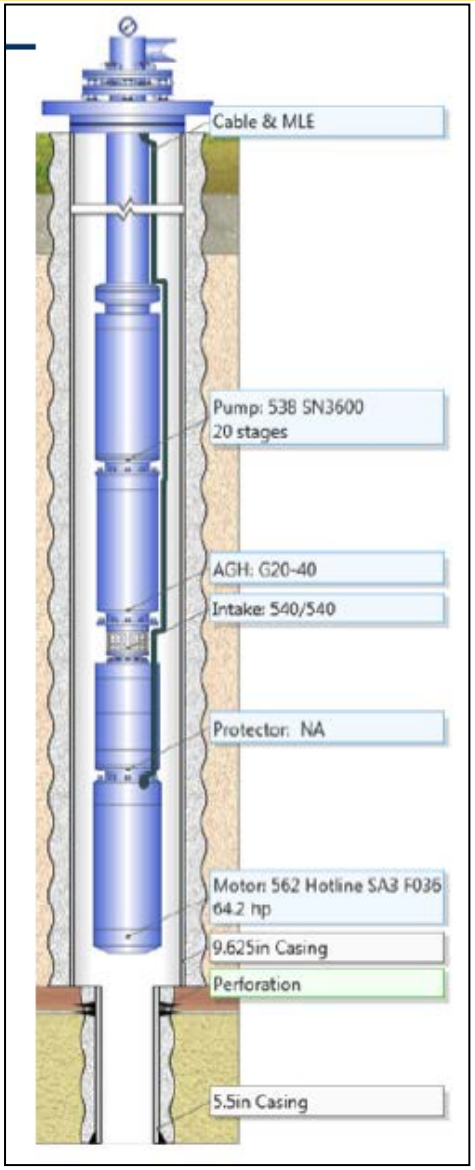
ARTIFICIAL LIFT – ESP WELLS

Pumping Units: **Max.Capacity:**

- Schlumberger ESP D2400N SA-3 360 m3/d
- Schlumberger ESP D1800N SA-3 280 m3/d
- All ESP's removed in 2016 due to economics

Automation:

- Downhole pressure and temperature monitoring to optimize subcool
- ESP's equipped with VSD



ESP Completion

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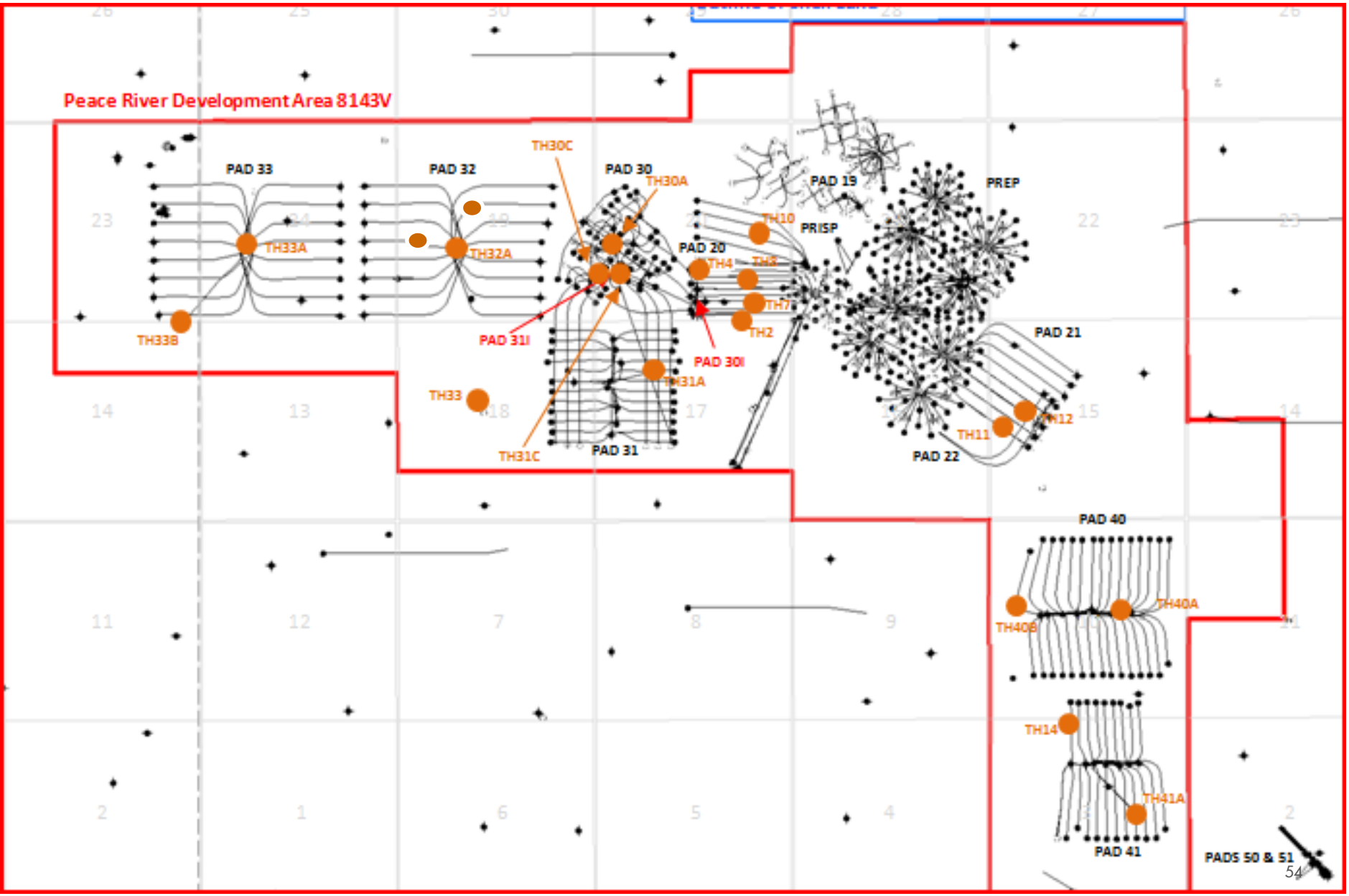
OBSERVATION WELLS - 19 Wells Over Existing Pads



ACTIVE OBSERVATION WELLS

Well Name	Type of observation well
TH33	Pressure and temperature
TH33A	Temperature and micro seismic
TH33B	Temperature
TH32A	Temperature and micro seismic
TH30A	Temperature and micro seismic
TH31A	Temperature and micro seismic
TH6	Temperature
TH7	Temperature
TH8	Temperature
TH9	Temperature
TH10	Temperature
TH11	Temperature
TH12	Temperature
TH40A	Temperature and micro seismic
TH40B	Temperature
TH14	Temperature
TH41A	Temperature
D320 (5-19)	Temperature via DTS
D321 (11-19)	Temperature – via DTS
12-35	Pressure

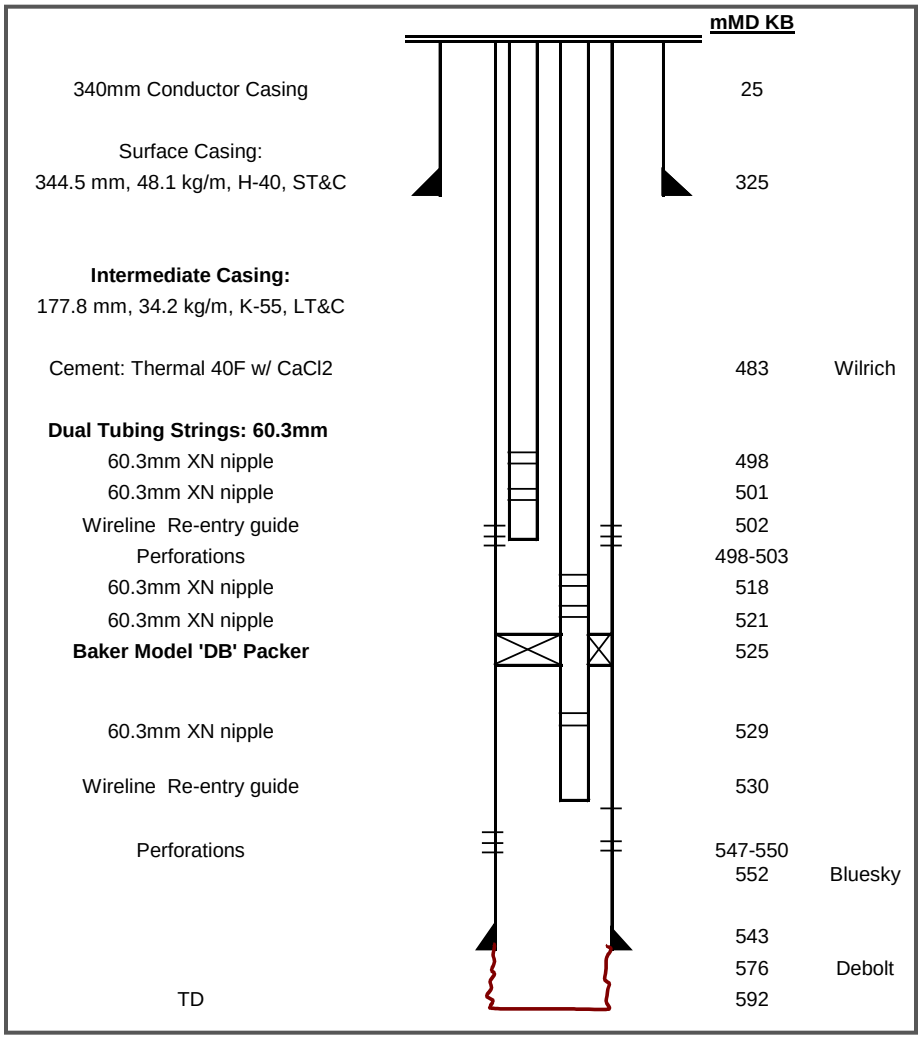
TEMPERATURE OBSERVATION WELLS

Well	Pad	Current Max Temp (°C)	Current Avg Temp (°C)	Temp trend (last 7 d)
TH-6	P20	39	33	↑
TH-7	P20	73	38	↓
TH-8	P20	148	79	↓
TH-9	P20	99	82	↑
TH-10	P20 I	87	71	→
TH-11	P21	47	44	→
TH-12	P21	208	187	→
TH-30A	P30	57	52	→
TH-31A	P31	57	52	↓
TH-32A	P32	20	19	↑
TH-33A	P33	20	19	↓
TH-33B	P33	80	55	↑
TH-40A	P40	43	36	↓
TH-40B	P40	134	106	→
TH-41A	P41	45	34	↓
TH-14	P41	26	25	↓

THREE CREEKS

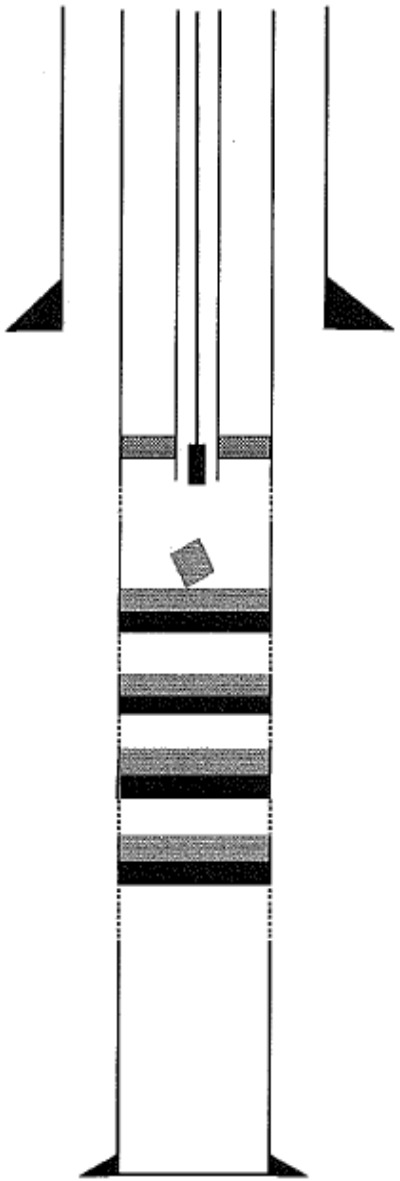
	Current P (kPa)	P trend (last 7 d)
12-35	2633	↑

PRESSURE MONITORING OF WILRICH –WELL TH33



- Wilrich shale pressure and temperature are monitored. The Bluesky gauge failed in 2007.

THREE CREEKS PRESSURE OBSERVATION WELL 12-35



Depths
0 m KB

303 m KB
325 mKB

513 m KB
520 mKB
522.5 m KB

538 m KB

546 m KB
550 m KB

583 m KB
586 m KB

650 m KB
656.5 m KB

980 m KB

998 mKB

1042 m KB

1600 m KB (TD)

Stage 1 (1600-1042mKB); 25.8 tonnes Class G cement. 3m3 cement returns.

Stage 2; 15.2 tonnes Class G cement (1042-650mKB) 10.8 tonnes Class G (650-400mKB).

219.1 mm, 35.7 kg/m, J-55. Cemented to surface with 26.7 tonnes Class G cement.
Cement Top from Bond log

73mm, 9.67 kg/m L-80 EUE tubing
0.1 % inhibited water in annulus
Retrievable Packer
Downhole Pressure Gauge
Bluesky Top. Bluesky Perfs 522.5-525 m KB

Lost Perf Gun

Bridge Plug
Perforations (550-555 m KB)

Bridge Plug
Perforations (586-591 m KB)

Bridge Plug
Perforations (656.5-661 m KB)

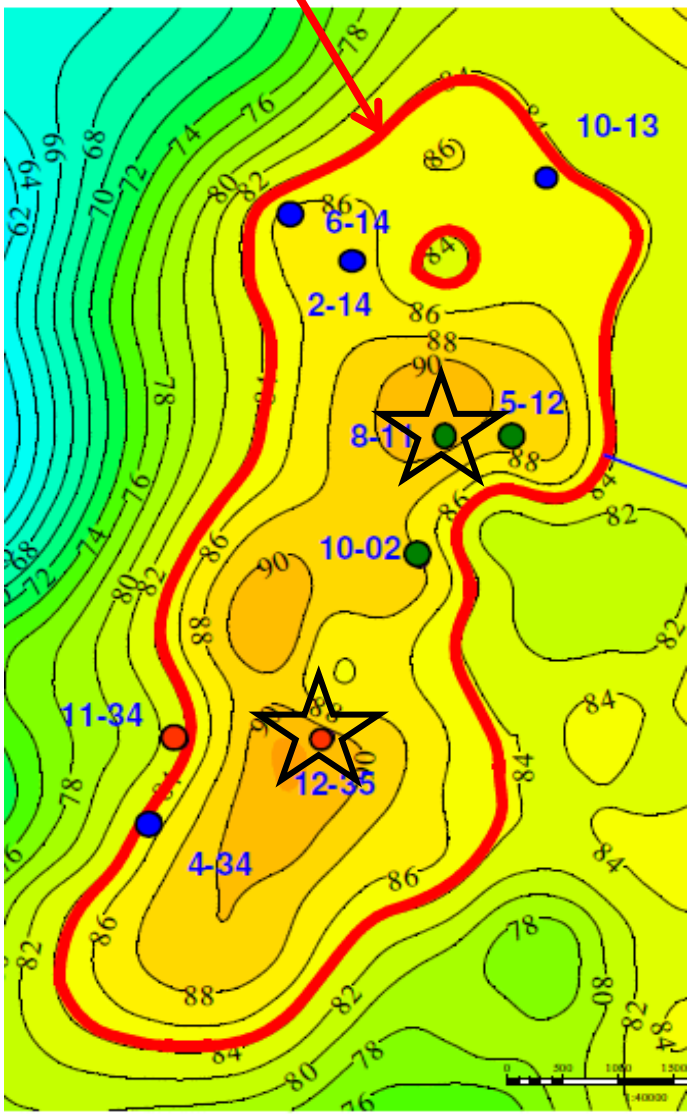
Bridge Plug

Perforations (998-1000 m KB)

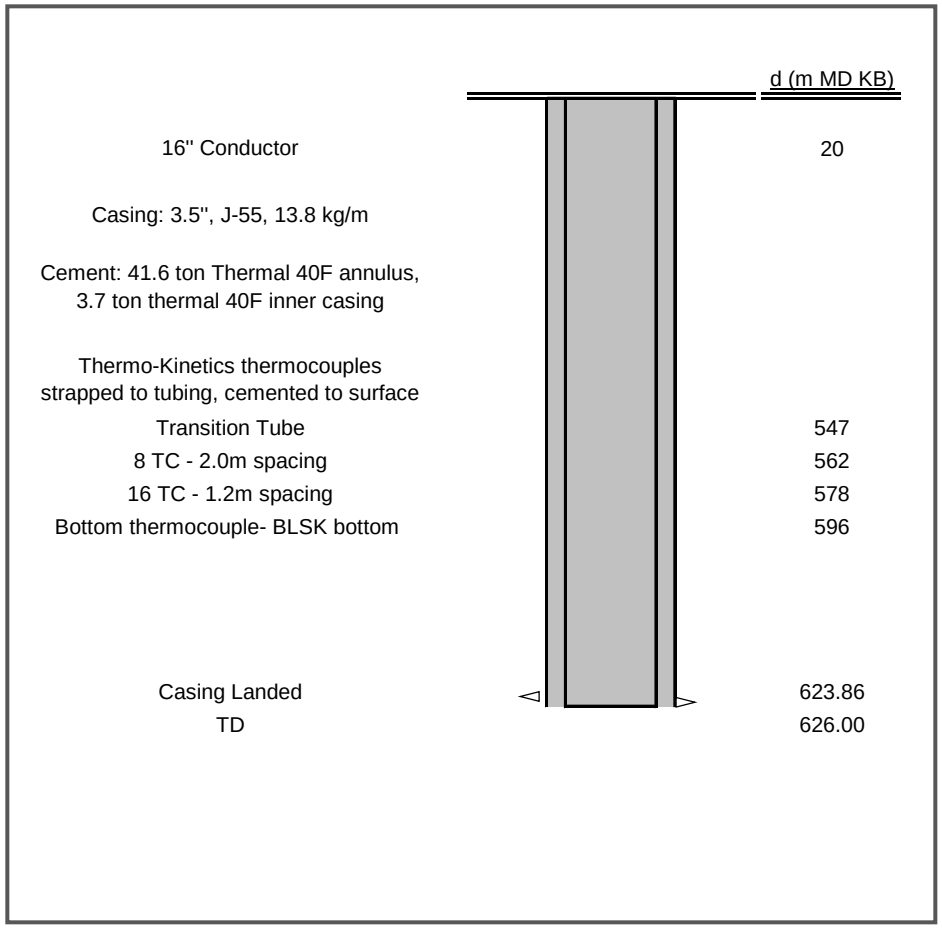
Stage Tool

139.7 mm, 23.1 kg/m, J-55 casing.

Three Creeks gas cap

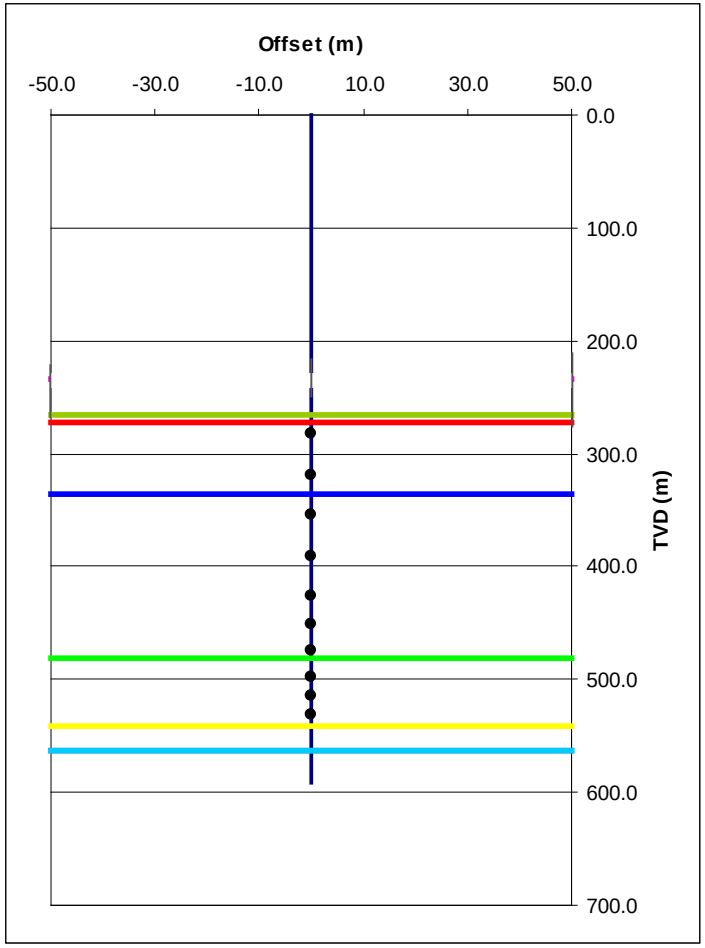


TEMPERATURE OBSERVATION WELL COMPLETION – TH40-B



- Thermocouples situated from the Wilrich to the Debolt formations to monitor steam chamber rise and temperature variations over cycle(s). The thermocouples are cemented in the well to surface.

OBSERVATION WELL – GEOPHONE LOCATIONS



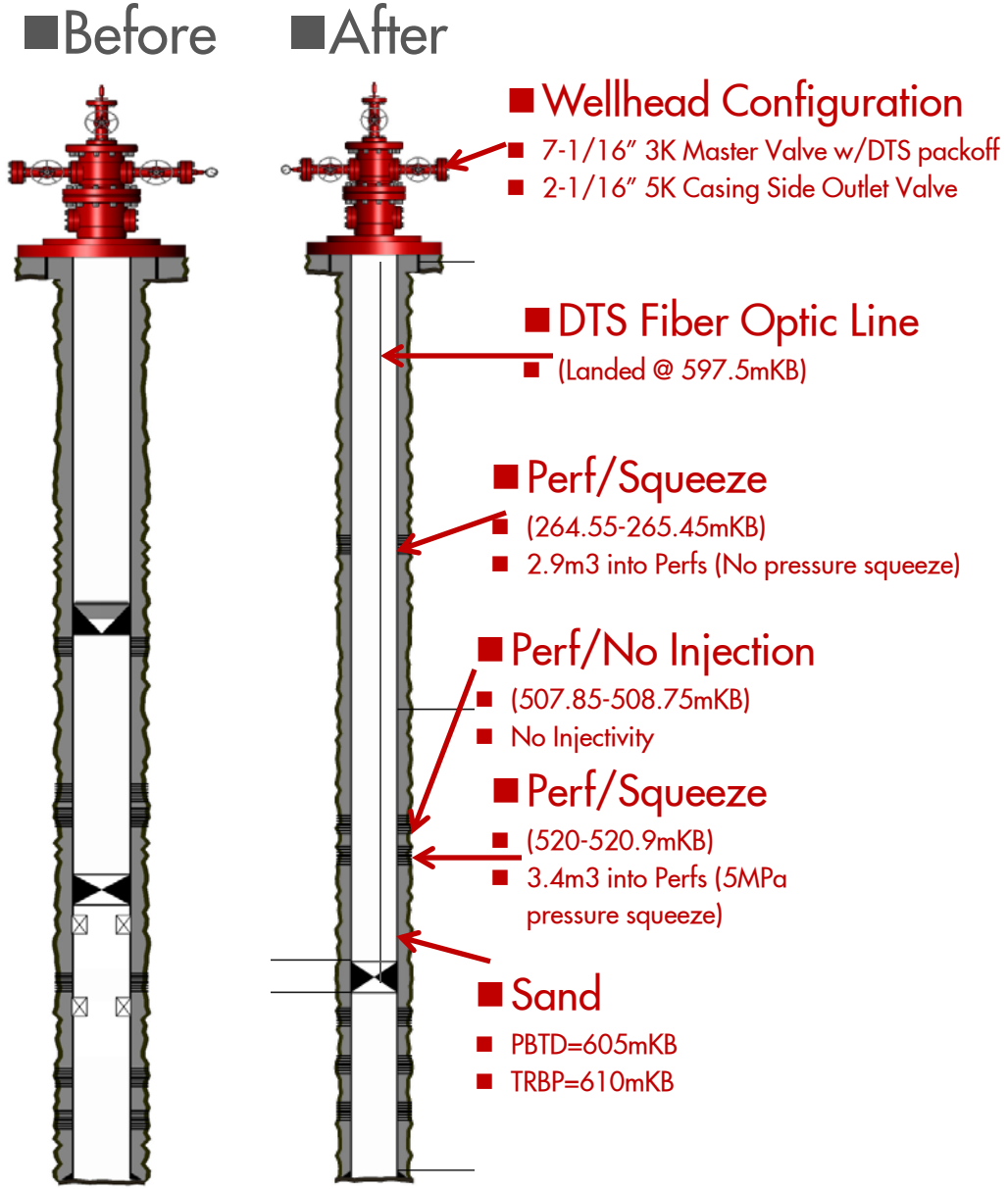
Geophones located in Obs wells:

TH40A, TH30A, TH31A, TH32A, TH33A

Geophones placement

Paddy/Cadotte	
Harmon Shale	
Notikewan	
Falher	
Wilrich	
Bluesky	
Detrital	
Debolt	

2014 DTS INSTALLATION AT 00/05-19-85-18W5 (D320)



- The 5-19 water disposal well was drilled and completed with the 11-19 well in 1978 as part of the PRISP (Peace River In Situ Pilot) disposal scheme
- The well injected produced water until 1986, and then water softener backwash brine, until 2009, into the Debolt formation.
- Observed casing head pressures of around 16MPa, though a hydraulic pressure test later confirmed casing and bridge-plug integrity.
- Obtained cement, behind-casing fluid, and integrity data by means of caliper, ultrasonic, and saturation logs on the 5-19 well.
- Well perforated in the Wilrich (520 – 520.9 mKB) and cement squeezed with T-Mix thermal cement.
- Drilled out cement and logged to evaluate isolation – Confirmed isolation to the Bluesky however wanted to ensure we had better isolation above.
- Re-perfed 507.85 – 508.75 – obtained no injectivity – confirmed pressure integrity to 10 Mpa at perf face.
- As per the AER requirements we perfed 264.55 – 265.45 mKB and performed a cement squeeze (to isolate the Paddy Cadotte)
- Isolation was confirmed - Installed DTS Fiber

WELLHEAD CONFIGURATION

- Before

- After

- 7-1/16" 3K Valve, ½" termination port for DTS Line
- 2-1/16" 5K Valve, 2"LP crossover to ½" NPT needle and Pressure Gauge
- Junction Box

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Surface Operations, Performance and Compliance	
	Darcy Forman

WELL INTEGRITY: MONITORING PROGRAM

- All pads part of Shell's well integrity management program (WIMS)
- Risk based program that schedules preventative maintenance and associated repair times to the severity of the failure and AER regulations.
- All well histories being updated in eWIMS repository.
- Wellhead Integrity Tests (WITS) carried out on cycle basis:
  - Majority of surface components (casing heads, trees, stuffing boxes, valves, BOPs etc are pressure tested before steam injection)
- SCVFs conducted on yearly basis
    - 17 non-serious SCVF being monitored at present as per ID2003-01 (includes wells drilled for Carmon Creek (see Table 1)
- Subsurface Integrity Tests (SITS)
  - Production casing inspections (deformation, wall thinning, corrosion logging, hydraulic integrity, packer isolation tests)
  - SITs begin on a sample of CSS wells (1 well per pad/10% wells) beginning at their 5th CSS cycle. Addition logs (CEL, Caliper, Pressure test etc) run on ad-hoc basis based on non-invasive triggers (eg passive seismic, opportunity)

WELL INTEGRITY: SCVF Wells

Table 1 :

2016 Results:

UWI	LIC NUM	STATUS	COMMENT	WELL NAME/ALIAS	Date Checked	Results/Obsevations	24 Hour Build Up
104/11-15-085-18W5/00	0310826	Open	Non Serious	SHELL P13 CADOT 11-15-85-18 (21-13)	12-Sep-16	No LEL/H2S, No vent flow observed - Could Close out - will monitor 1 more year	0 kPa
106/11-15-085-18W5/00	0361194	Open	Non Serious	SCL 22-01 CADOTTE 11-15-85-18	10-Sep-16	No LEL/H2S, Observed 60 bubbles/10 min	0 kPa
1F2/01-21-085-18W5/00	0411266	Open	Non Serious	SCL 547-D CADOTTE 1-21-85-18	4-Oct-16	Water Obs well, Observed 21 bubbles/10 mins	28 kpa
100/16-27-085-19W5/00	0389349	Open	Non Serious	SCL C89-01 CADOTTE 16-27-85-19	4-Oct-16	No LEL/H2S, Observed 60 bubbles/10 mins	51 kPa
104/06-20-085-18W5/00	0432193	Open	Non Serious	SCL HZ 20-20 CADOTTE 3-20-85-18	9-Sep-16	No LEL/H2S, Observed 100 bubbles/10 mins	60 kPa
105/03-20-085-18W5/00	0432195	Open	Non Serious	SCL HZ 20-22 CADOTTE 3-20-85-18	9-Sep-16	No LEL/H2S, No vent flow observed - Could Close out - will monitor 1 more year	73 kPa
106/03-20-085-18W5/00	0432196	Open	Non Serious	SCL HZ 20-23 CADOTTE 3-20-85-18	9-Sep-16	No LEL/H2S, Observed 6 bubble/10 mins	10 kPa
104/06-17-085-18W5/00	0464726	Open	Non Serious	SCL 31-13 CADOTTE 6-17-85-18	5-May-16	No LEL/H2S, No vent flow observed	0 kPa
105/06-17-085-18W5/00	0464727	Open	Non Serious	SCL 31-14 CADOTTE 6-17-85-18	5-May-16	No LEL/H2S, No vent flow observed - Could Close out - will monitor 1 more year	0 kPa
105/12-20-085-18W5/00	0464729	Open	Non Serious	SCL TH30C CADOTTE 12-20-85-18	11-Sep-16	No LEL/H2S, No vent flow observed - Could Close out - will monitor 1 more year	0 kPa
104/09-19-085-18W5/00	0464733	Open	Non Serious	SCL 30-11 CADOTTE 9-19-85-18	11-Sep-16	No LEL/H2S, Observed 6 bubbles/10 mins	10 kPa
117/11-22-085-18W5/00	0459072	Open	Non Serious	F107-16	27-Aug-16	No LEL/H2S, 0 bubbles/10 mins	0 kpa
106/07-22-085-18W5/00	0465846	Open	Non Serious	F107-18	27-Aug-16	No LEL/H2S, 0 bubbles/10 mins	56 Kpa
112/07-22-085-18W5/00	0459075	Open	Non Serious	F107-24	28-Aug-16	No LEL/H2S, 0 bubbles/10 mins	10 kpa
100/08-22-085-18W5/00	0459081	Open	Non Serious	F107-36	28-Aug-16	No LEL/H2S, 0 bubbles/10 mins	0 Kpa
103/15-22-085-18W5/00	0459082	Open	Non Serious	F107-39	28-Aug-16	3% LEL, no H2S, 487 bubbles/10 mins	10 kpa
104/09-22-085-18W5/00	0459087	Open	Non Serious	F107-47	28-Aug-16	5% LEL, no H2S, 730 bubbles/10 mins	20 kpa

WELL INTEGRITY: HISTORICAL REMEDIATION/INVESTIGATION

- D320 (5-19) Suspended water disposal well
  - Remediation plan (casing-cuts & cement squeezes) completed. AER engagement on 29th Oct 2012 and 19th Nov 2012 & Oct 2013.
  - Converted to temperature monitoring well via DTS installation.

- D321 (11-19) Suspended water disposal well:
  - During CEL assessment (Flexural Attenuation), a small hole/puncture was discovered in the casing joint at approximately 527-528m MDKB
  - AER DDS submission (ID: 1328497) was entered on 13/7/12
  - Remediation matured. AER engagement on 29th Oct 2012
  - Conversion to permanent temperature monitoring well via DTS installation.

- 40-08 Suspended thermal well on steam-drive (Pad 40):
  - MFC investigation and SIT revealed casing leak at 609m MDKB across the Wilrich shale. Well suspended with TRBP at 620 mMDKB
  - AER DDS submission was entered November 2012.
  - Approval granted for low pressure (<6 Mpa) use.

WELL INTEGRITY: HISTORICAL REMEDIATION/INVESTIGATION

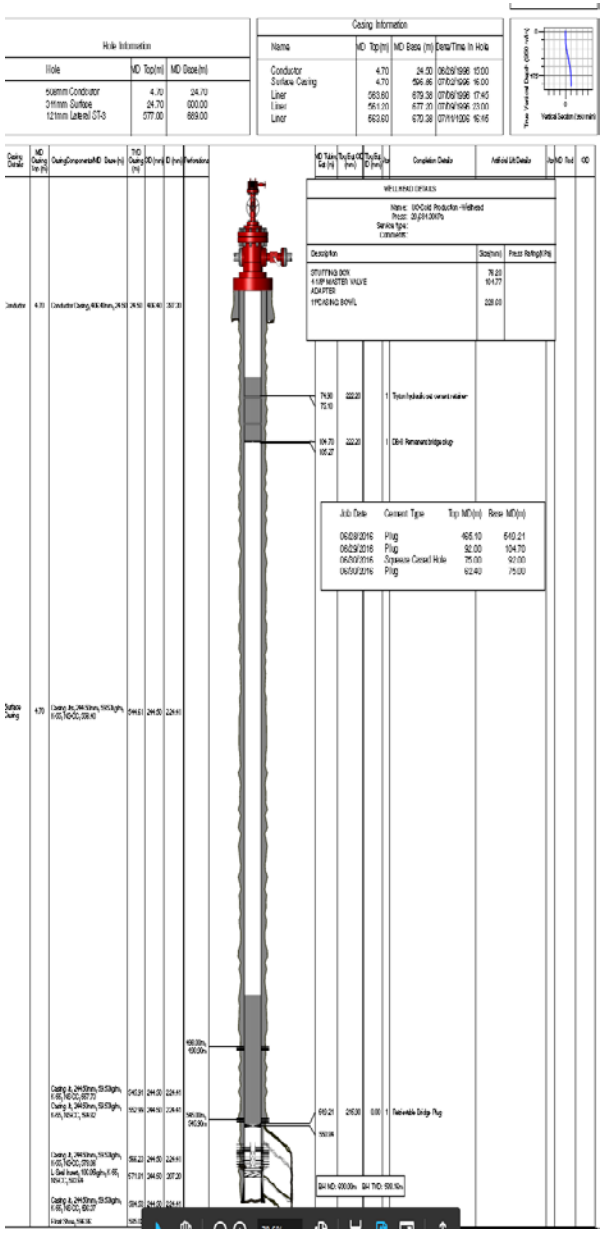
- 100/03-28-85-18W5 (SR -12) Soak Radial – Pad 19 Satellite 4:
  - Parted casing detected at 120 mKB depth via a calliper log. Appears to be a pin-box (straight tensile) pull.
  - Retrievable bridge plug was installed (top of BP at 556 mKB) with 20 m of Thermal cement for subsurface isolation.
  - AER DDS submission (ID: 1410655) entered on June 11, 2013. Repair extension approval granted Dec. 10, 2013.
  - Abandonment planned in 2017

- 107/15-21-85-18W5 (19-3-PH{15}) and 103/03-28-85-18W5 (19-3-PK{17}) Pad 19 Satellite 3:
  - A collapsed/buckled casing section was detected via a downhole camera run performed on October, 2013. Failure depth is ≈ 276mKB on19-3-PH{15} and 190.3 mKB on 19-3-PK{17}.
  - AER DDS submission (ID: 1456424 & ID: 1441050) made in Oct, 2013.
  - Both wells abandoned Jan 2014 as per Directive 20

- Pad 19 Satellite 3: Injectors (4) with casing collapse
  - A collapsed/buckled casing section was detected via a downhole camera runs performed Nov 2013. AER DDS submissions Dec 2013.
  - All 4 wells successfully abandoned Q-1 2015. Cut and cap completed 2015.

WELL INTEGRITY: ONGOING REMEDIATION – (SR -3) 02/12-21-85-18W5 - Licence # 0186658

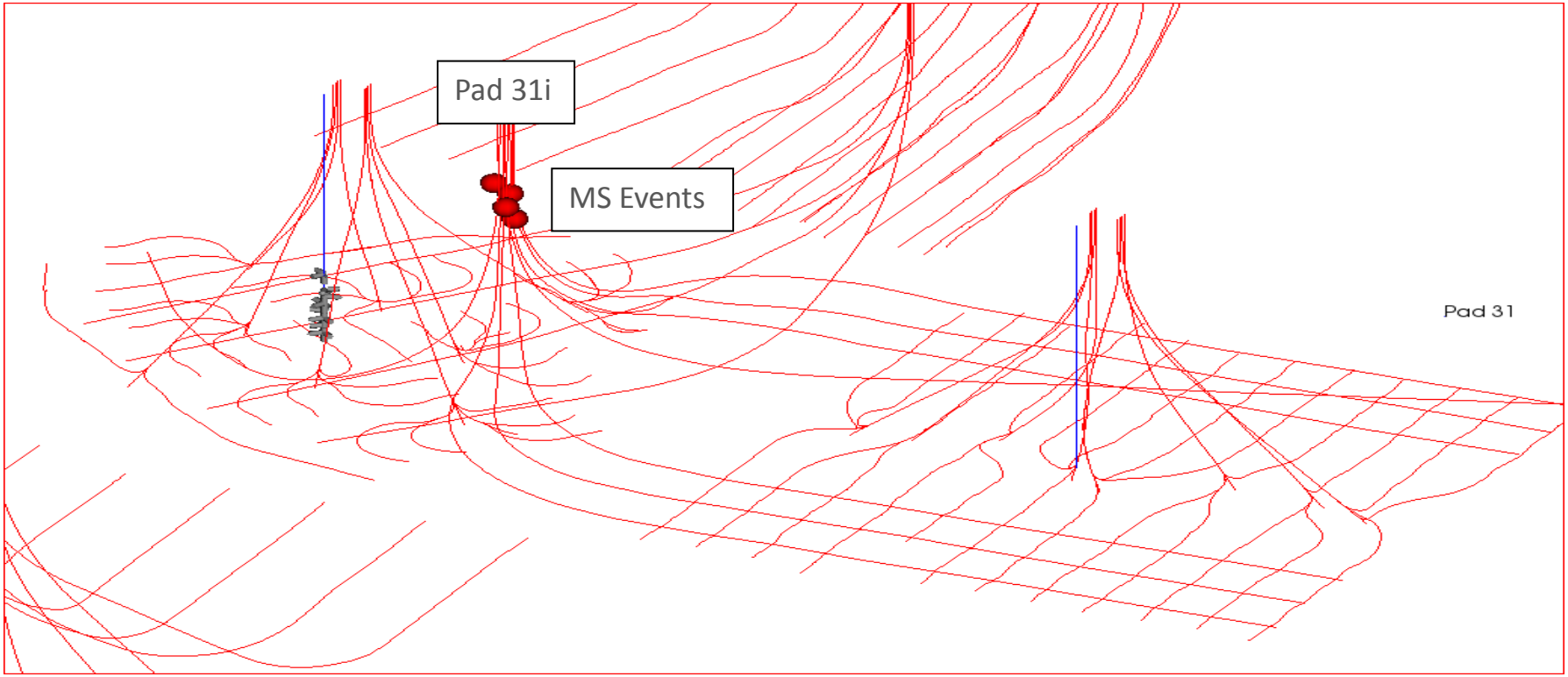
- On February 25, 2015 gas emission detected with an an infrared camera during routine monthly inspection . Gas is intermittent (flares up and dies off). Readings of 50 to 75 PPM of H2S have been recorded around the wellhead. No H2S can be detected outside of a radius of 2 ft from the wellhead.
- On March 14, 2015 we commenced an investigative workover program to inspect the production casing. We detected a pin-collar straight tensile failure had occurred at ~94m
- On May 14, 2015 we ran noise-temperature and CHAT tools to further investigate the potential source of gas.
- On July 12, 2015 Perforate and attempt to squeeze 545 – 545.9mKB. Perfs would not take any fluid. July 13, 2015 perforate/acidize and attempt to squeeze 498 – 498.9 mKB - very limited injectivity (6-8 liters/min).
- Vent Nanny installed to continuously monitor vent volumes and pressures
- May 17, 2016 Shell receives approval of program for non-routine abandonment
- June 27 - 30 Wellbore abandoned as per approved program
- Cut & cap will be executed after 2017 breakup to allow for monitoring



CASING LEAK (31-13 INJECTOR) – 04/06-17-85-18W5 Lic # 0464726

- January 2016 – micro-seismic event was recorded in the vicinity of the Shell Peace River Pad 31i wells.
- Nitrogen purge investigation identified casing leak at 31-13
- A Magnetic Thickness Detector (MTD) and a 56-finger caliper log was performed which showed pitting corrosion in the casing from 86 -186 m KB; and a series of packer isolation tests confirmed the presence of a single point leak at a casing connection at ~128 mKB

Micro-seismic Events



CASING LEAK (31-13 INJECTOR) – 04/06-17-85-18W5 Lic # 0464726

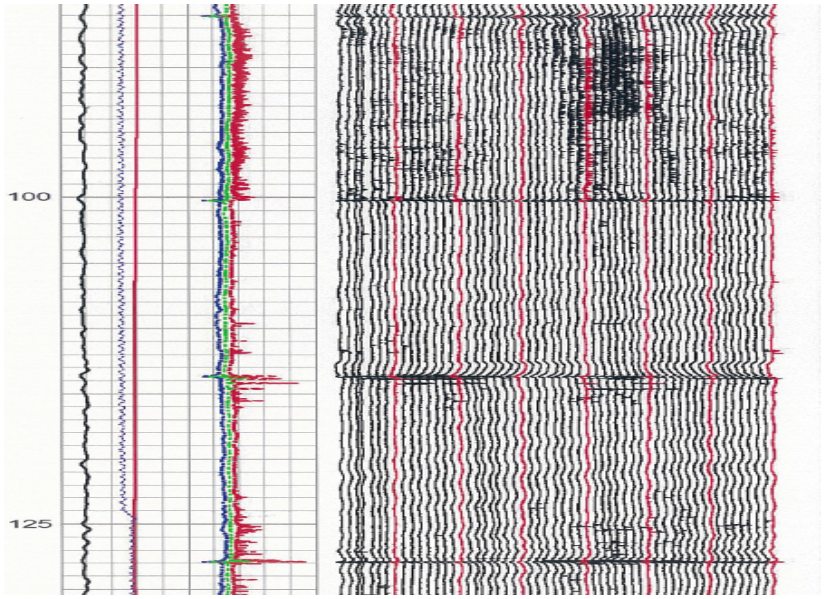
- April 5, 2016 – AER repair extension granted to investigate cause of pitting and casing failure.

- Root cause investigation potential sources of failure:

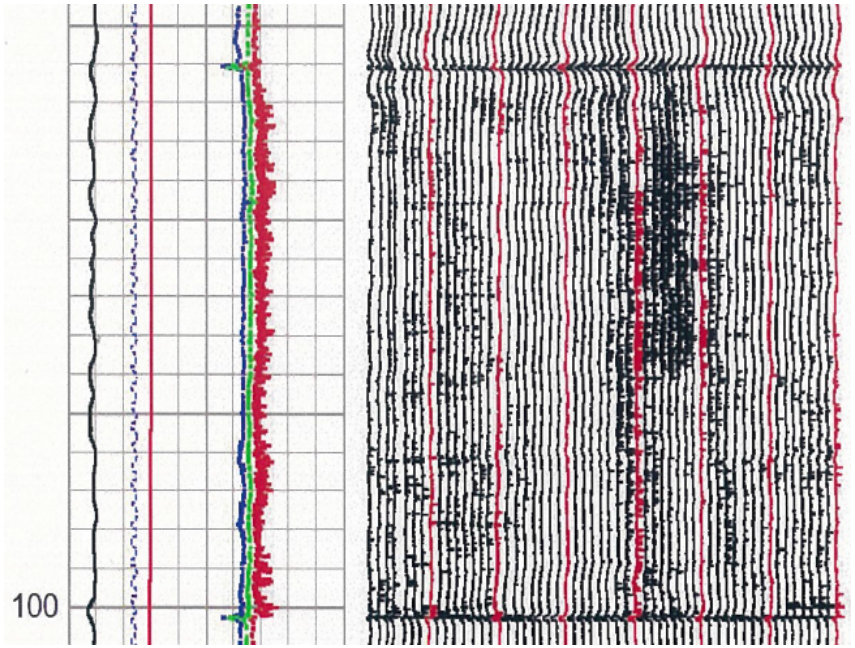
  - **Mechanical weakening of connecting integrity** due to tong slippage (abnormal make-up torque)
  - **Thermal Stresses of expansion and contraction** (seismic event detected 8 days after steam was stopped on well – during cooling period)
  - **Incorrect Pipe Dope (Thread Lubricant) used** – drilling program was not followed and the pipe dope used was not developed for thermal use

- Shell evaluating remediation plans for the wellbore – will comply to the timeline as per extension approval

MFC Log

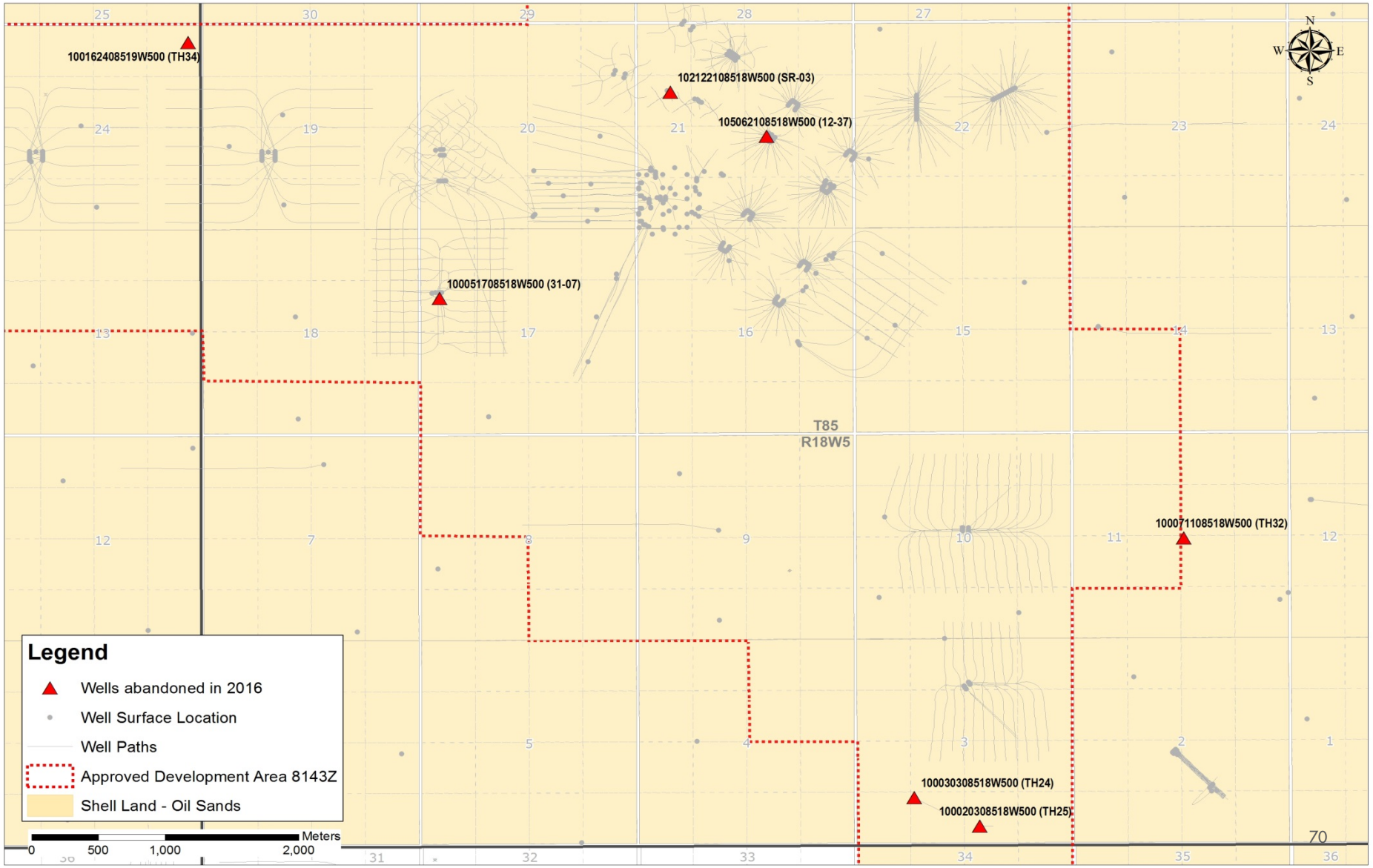


Enlargement of Pitted Joint 86-100 mKB



2016 ABANDONED WELLS

In 2016 Shell abandoned 7 well in the approval no. 8143Z area :

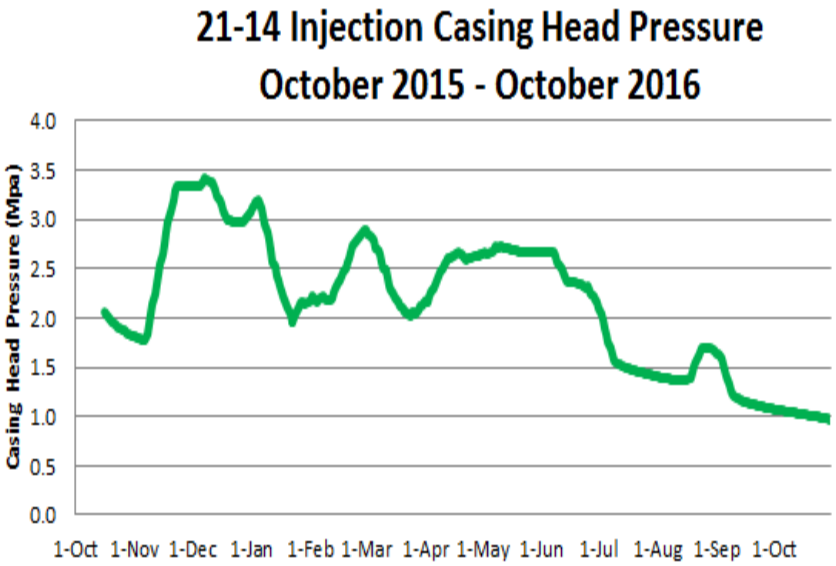


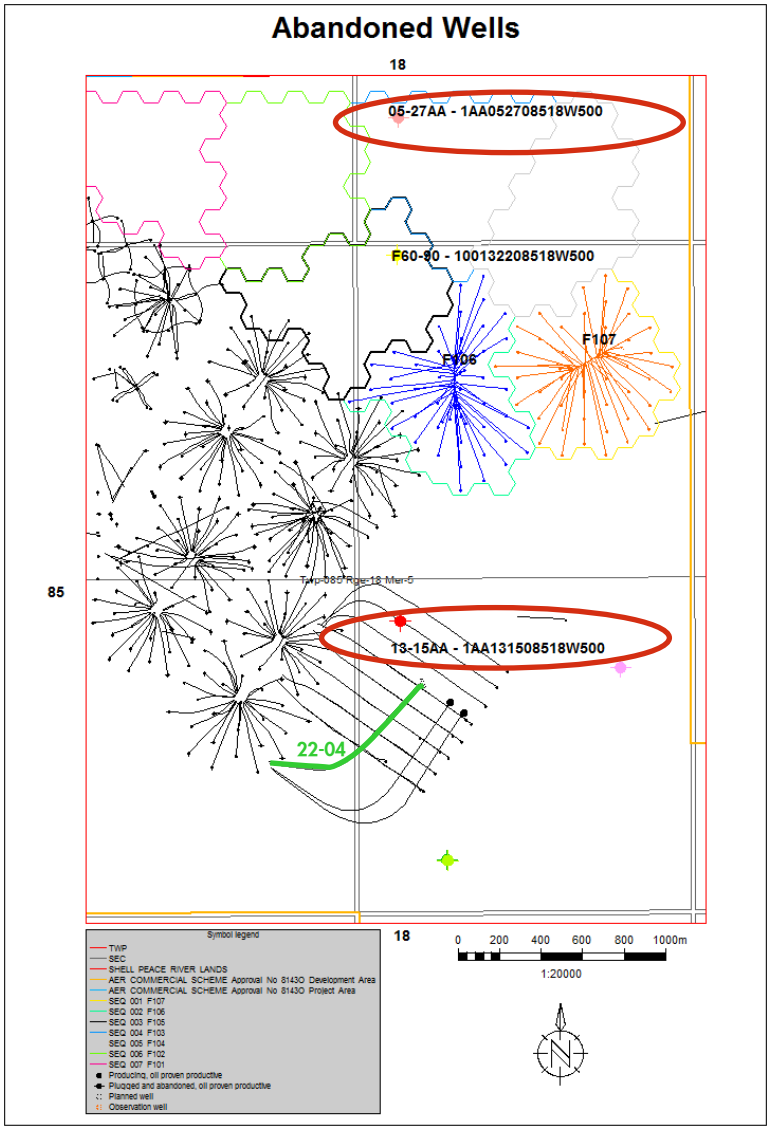
PREVIOUSLY ABANDONED WELLS

Update required as per AER approval no. 8143Z

Oct 2015 – Oct 2016:

- 1AA052708518W500
  - Pad 106 wells drilled 400m to south – no production
  - Closest production wells on Pad 19 > 1000m
- 1AA131508518W500
  - Low pressure injection on Pad 21/22
  - New steam injector well 22-04 (green) drilled
  - No changes observed





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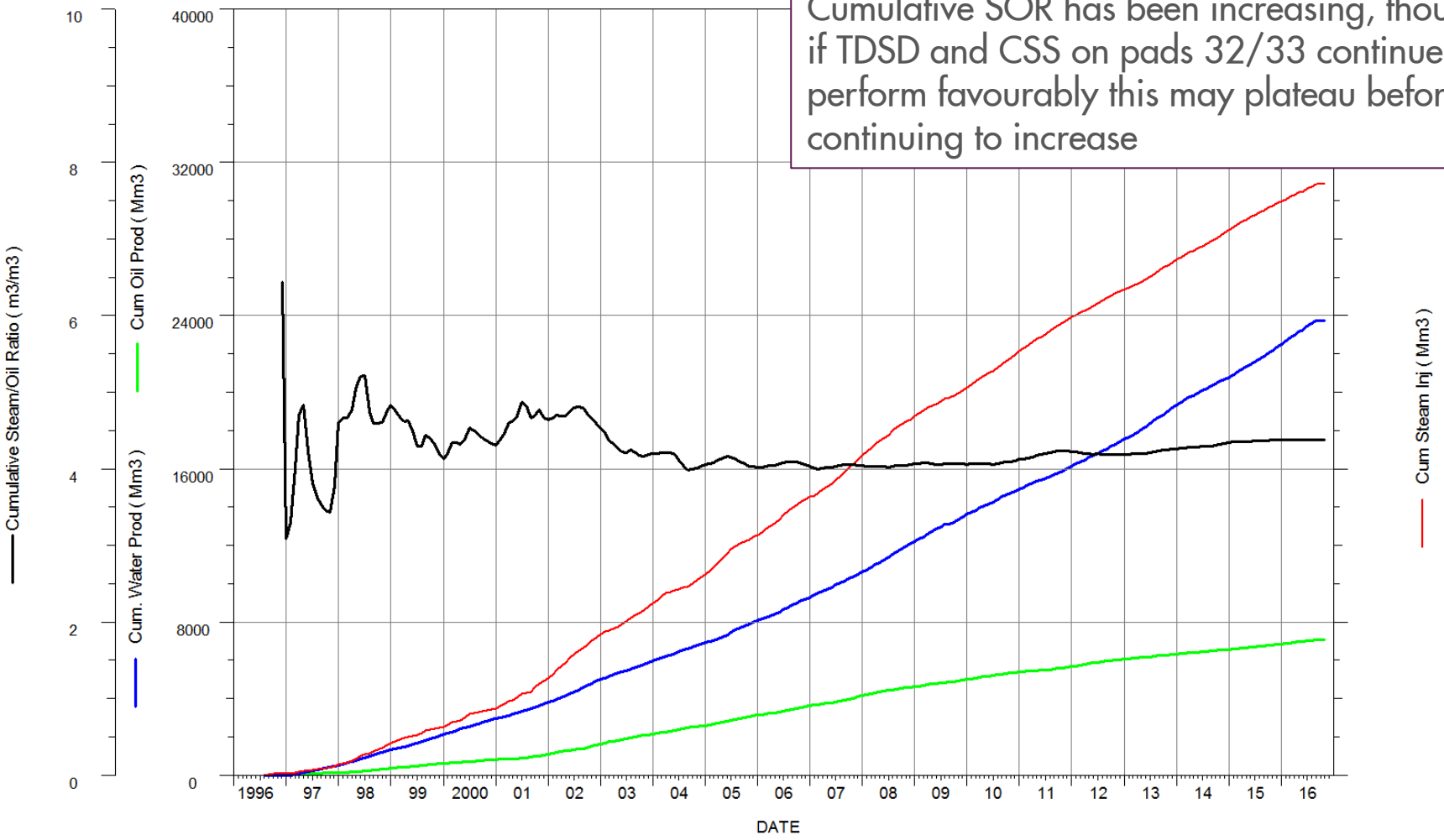
SCHEME PERFORMANCE PREDICTION

- The basis for Scheme performance prediction estimation based on historical cSOR increase for steam drive pads, and water cut increase with recovery factor for blow down pads.

Pad	Recovery Process	Date of Conversion
19 Sat 1 and 2	Lateral Steam Drive	Oct 2012
19 Infills	Vertical Well Steam Drive	July 2013
20 Conv	Top-Down Steam Drive	July 2012
20 Infills	Lateral Steam Drive	June 2012
21 Conv	Top-Down Steam Drive	Jan 2009
21 Infills	Lateral Steam Drive	Nov 2011
30	Top-Down Steam Drive	Dec 2014
31	Top-Down Steam Drive	Nov 2014
40	Suspended	Converted to LSD June 2012 Blowdown June 2014 Suspended October 2015
41	Suspended	Converted to LSD June 2012 Blowdown June 2014 Suspended October 2015
32/33	Cyclic Steam Stimulation (CSS)	Converted to LSD December 2012 Converted to CSS August 2014

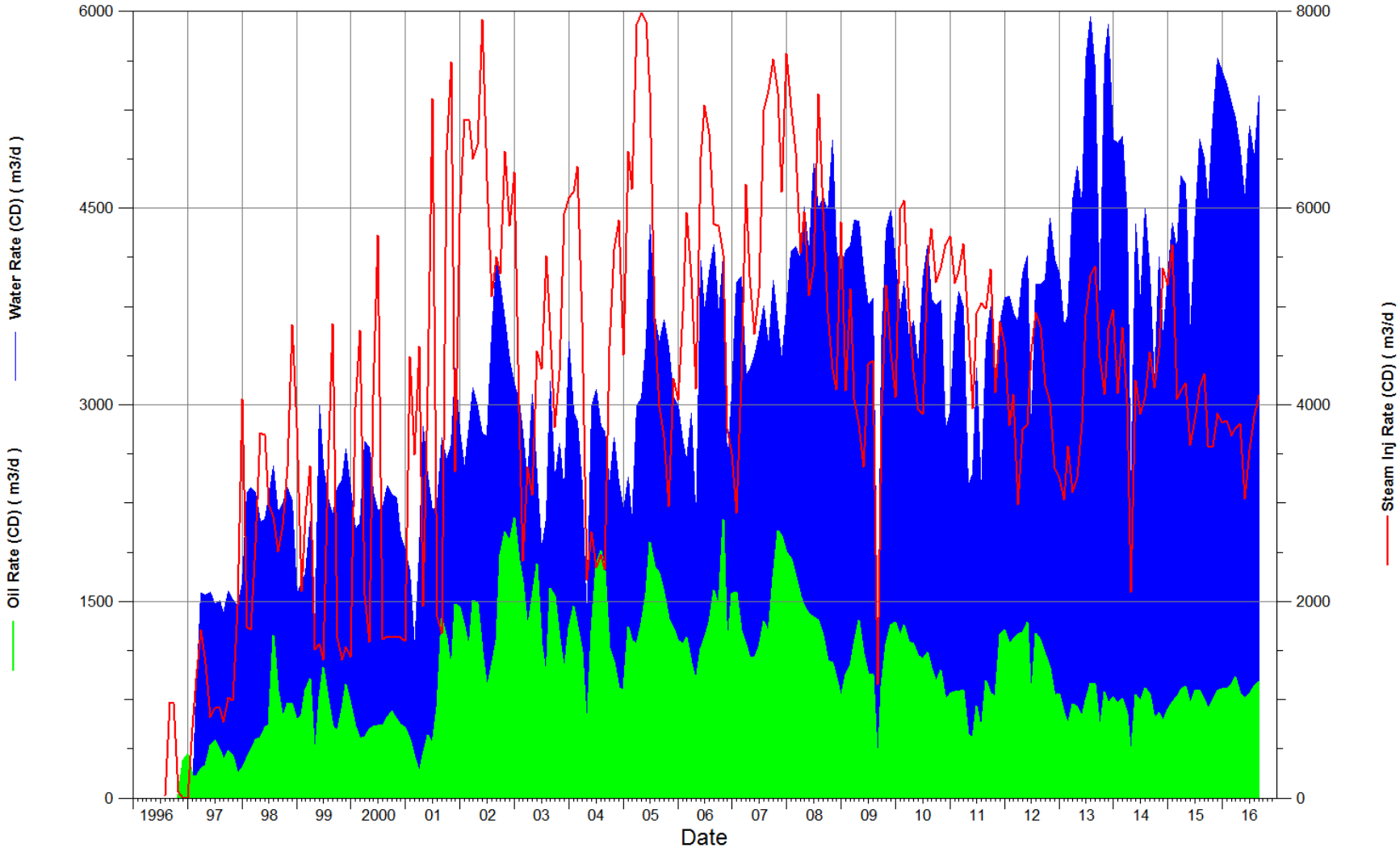
PEACE RIVER PRODUCTION HISTORY

Cumulative SOR has been increasing, though if TDSD and CSS on pads 32/33 continue to perform favourably this may plateau before continuing to increase



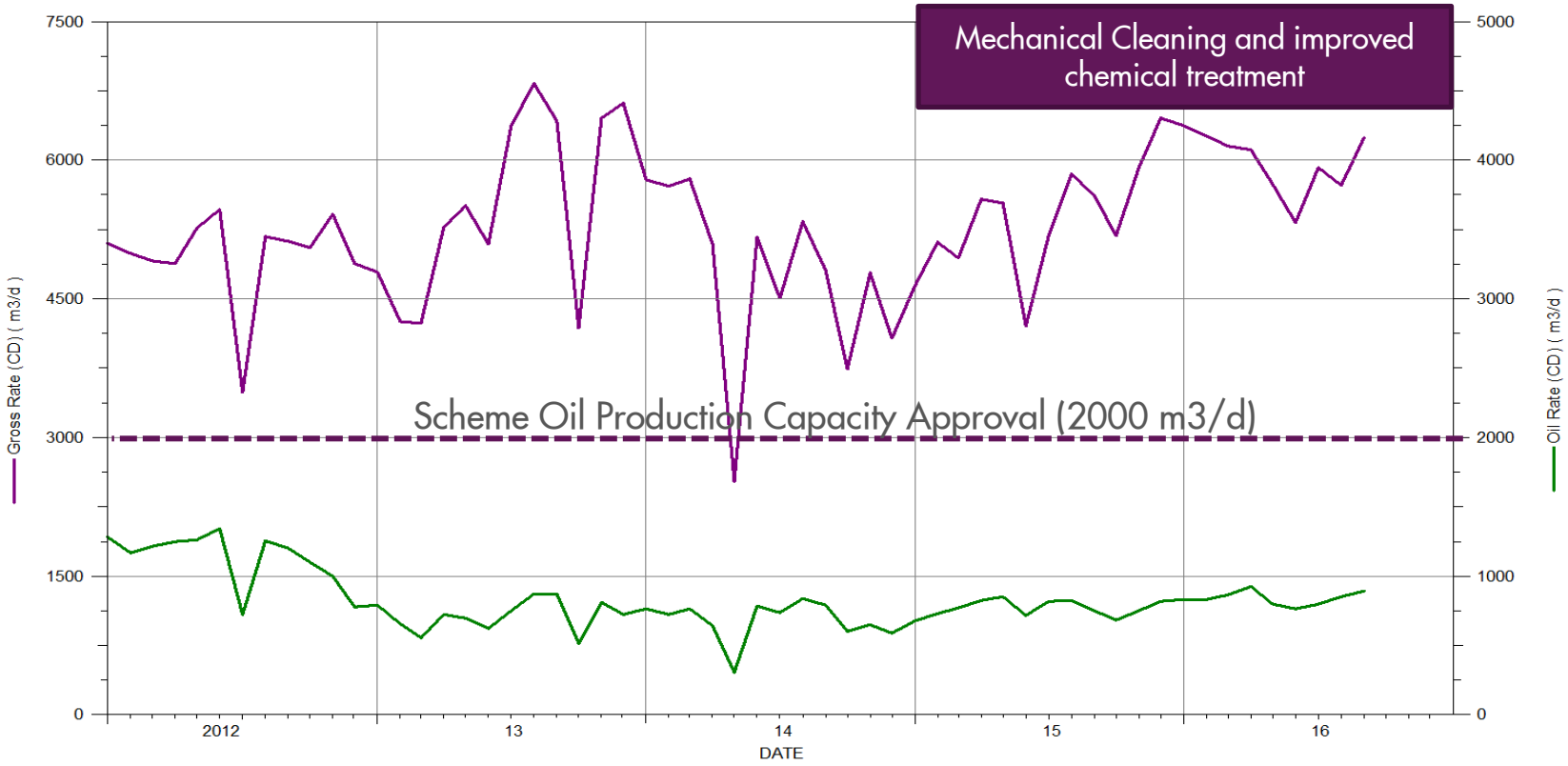
- All data current as of Oct 2016
  - Cumulative SOR = 4.38
  - Cumulative WSR = 0.77
  - Cum Oil: 7,055 Mm3
  - Cum Wtr: 23,754 Mm3
  - Cum Stm: 30,867 Mm3

PEACE RIVER PRODUCTION HISTORY



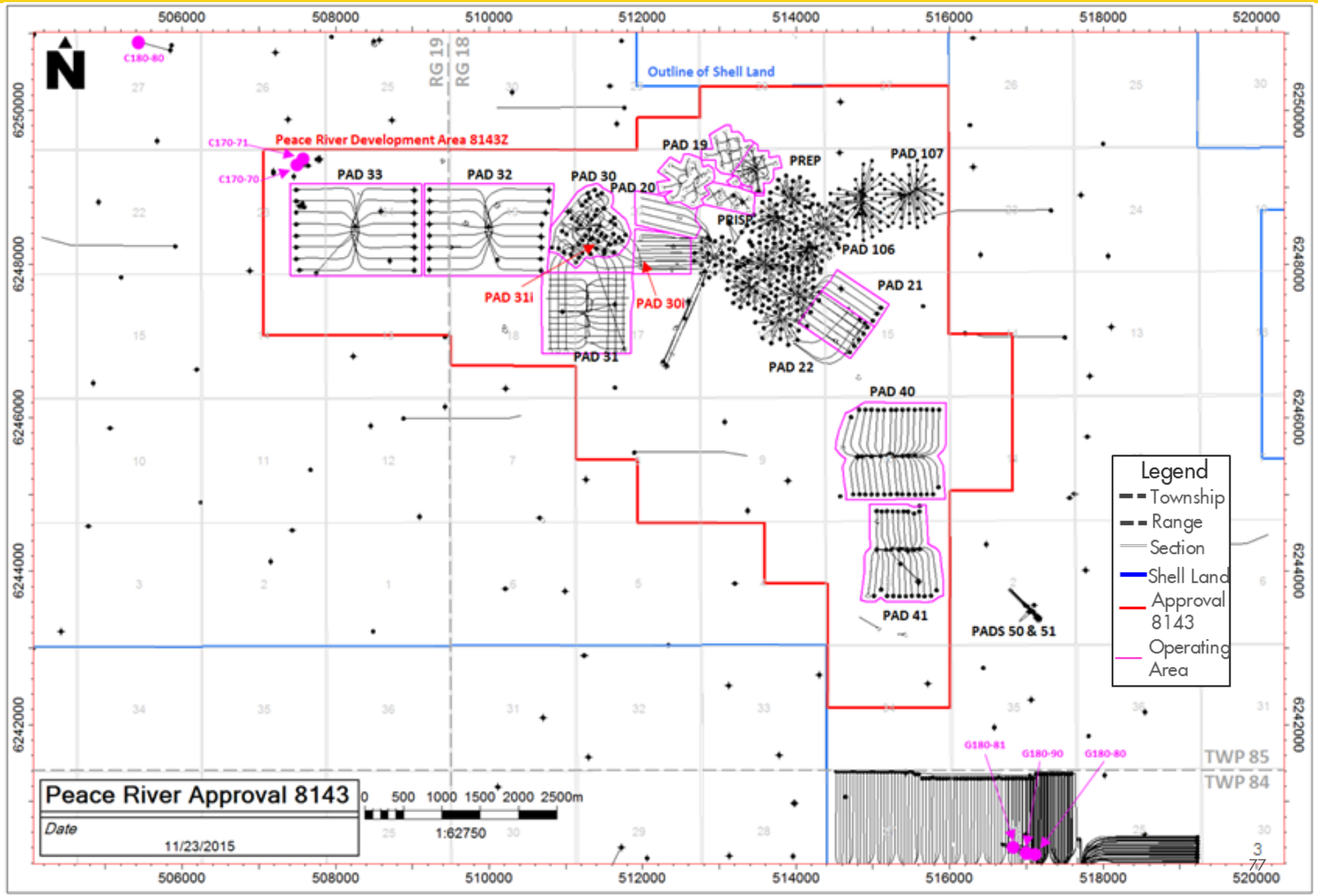
- 2016 YTD average as of Oct. 31. 2016:
  - Oil rate = 842 m^3/d
  - Injection rate = 4436 t/d
- 2015 Average was 770 m3/d, improvement due to infill well projects (22-04, 30/31 injectors), plant debottlenecking and steam optimization

ACTUAL PRODUCTION VS. APPROVAL CAPACITY



- Production capacity limit raised to 2000 m^3/d (from 1900 m^3/d) annualized average on April 30, 2002 as part of Amendment F to 8143 approval.
- Bitumen production has decreased from peak rates in Nov/Dec 2007 due to maturing pads.
- 2013 - 2015 production were also impacted by produced water scaling issues, gas injection compressor issues and multiphase pump reliability issues. June 2013 water processing lines were mechanically cleaned, 2015 the skim and surge tank were cleaned, and in mid 2015 new chemical treatment was introduced, increasing gross emulsion processing capacity.

AREA FOR VOLUMETRICS



PAD OBIP VALUES

Pad	Area (m2)	Height (m)	NTG (frac)	Porosity (frac)	So (frac)	Bo (m3/m3)	PV (m3)	OBIP (m3)
SR 1-3	199,482	23	1.00	0.290	0.83	1.01	1,330,545	1,093,418
SR 4-7	359,361	16	1.00	0.290	0.83	1.01	1,667,435	1,370,268
SR 8-11	256,081	22	1.00	0.290	0.83	1.01	1,612,254	1,306,774
SR 12-15	249,546	19	1.00	0.290	0.83	1.01	1,374,998	1,129,949
Pad 20 Infills	373,386	21	1.00	0.280	0.82	1.01	2,195,510	1,782,493
Pad 20 Conv	410,545	22	1.00	0.280	0.82	1.01	2,528,957	2,053,213
Pad 21 Infills	279,163	25	1.00	0.280	0.82	1.01	1,954,141	1,586,530
Pad 21 Conv	427,746	25	1.00	0.280	0.82	1.01	2,994,222	2,430,953
Pad30	758,773	24	1.00	0.290	0.82	1.01	5,281,060	4,287,593
Pad31	1,239,870	23	1.00	0.285	0.82	1.01	8,127,348	6,598,441
Pad40	1,626,190	25	1.00	0.265	0.80	1.01	10,773,509	8,533,472
Pad41	1,077,660	24	1.00	0.265	0.80	1.01	6,853,918	5,428,846
Pad 32	1,725,020	24	1.00	0.275	0.78	1.01	11,385,133	8,792,479
Pad 33	1,805,980	24	1.00	0.275	0.78	1.01	11,919,467	9,205,133
Total								**55,599,562**

- Net pay calculated based on the net pay map (shown in the Geology section)
- Area and OBIP for Pad 19 Sat 3 (SR8-11) have been modified to reflect new Pad 19 Infill wells

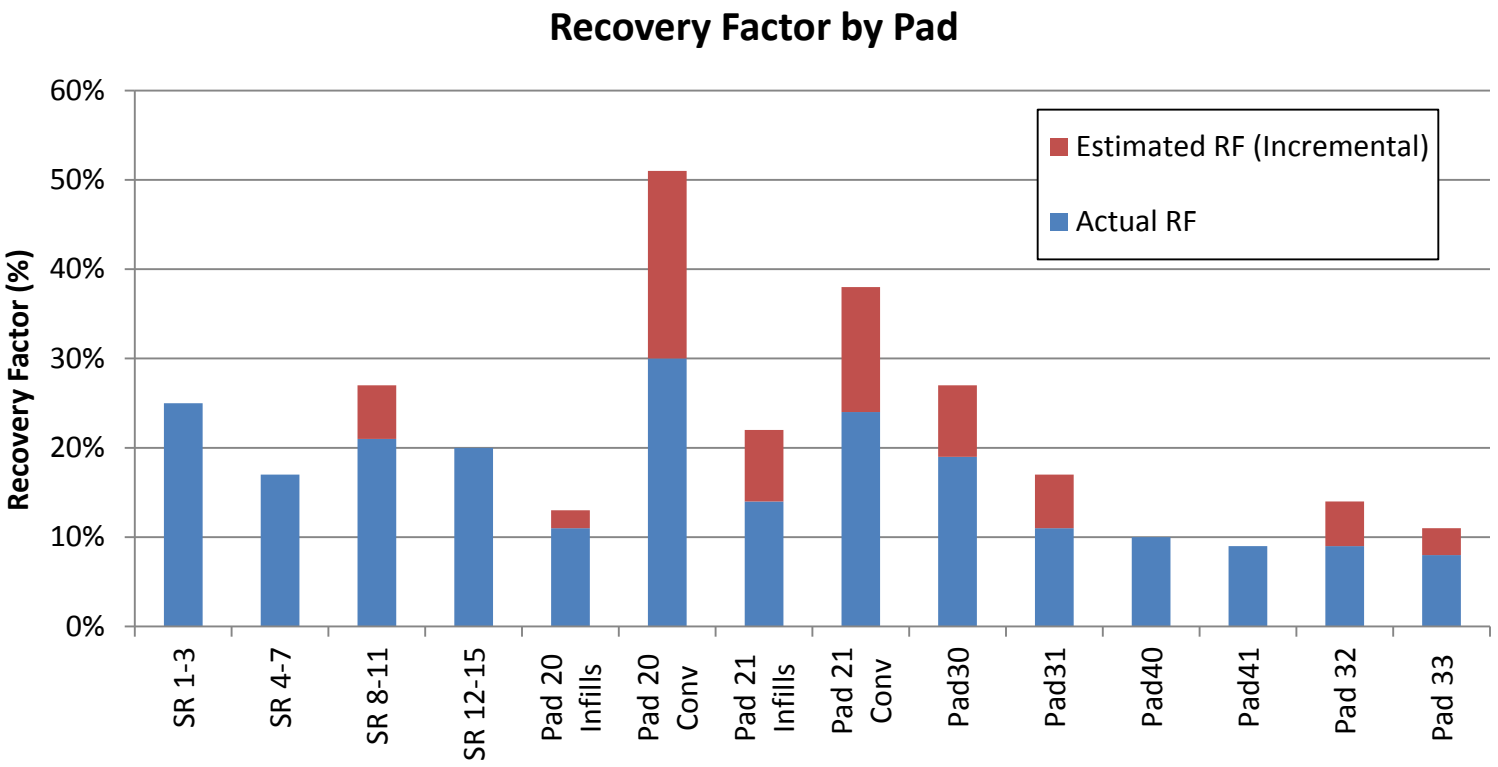
PAD RECOVERY FACTORS

Pad	OBIP (e3m3)	Cum Produced 30.09.2016 (e3m3)	Expected Ultimate Recovery (e3m3)	Actual RF at 30.09.2016 (%)	Estimated RF* (%)
SR 1-3[1,4]	1,093	272	272	25%	25%
SR 4-7[4]	1,370	234	232	17%	17%
SR 8-11[4]	1,307	269	352	21%	27%
SR 12-15[4]	1,130	223	223	20%	20%
Pad 20 Infills	1,782	195	231	11%	13%
Pad 20 Conv[2]	2,053	606	1050	30%	51%
Pad 21 Infills	1,587	226	354	14%	22%
Pad 21 Conv[3]	2,431	571	948	24%	38%
Pad30[5]	4,288	799	1,145	19%	27%
Pad31[5]	6,598	730	1,112	11%	17%
Pad40[6]	8,533	847	847	10%	10%
Pad41[6]	5,429	483	483	9%	9%
Pad 32	8,792	821	1192	9%	14%
Pad 33	9,205	774	1083	8%	11%
Total	**55,598**	**7,055**	**9,524**	**13%**	**17%**

NOTES:

1. SR 1-3: 17% recovery from CSS, additional recovery from steam drive from wells SR-16+17
2. Pad 20 Conv wells : 14% recovery from SAGD operations, 8% recovery from CSS, remaining RF from Top down Steam Drive
3. Pad 21 Conv wells: 6% recovery from SAGD operations, 4% recovery from CSS, remaining RF from Top-down Steam Drive
4. Pad 19 SR 1-3, 12-15 currently shut in due to poor economics and high watercut. SR 6 is producing, SR 8-10 are part of the Pad 19 Infills
5. Pad 30 and 31 had injectors added in 2014, will see remaining RF recovered via Top down Steam Drive.
6. Pad 40 and 41 suspended. Remaining OBIP to be recovered via future project

PAD RECOVERY FACTORS

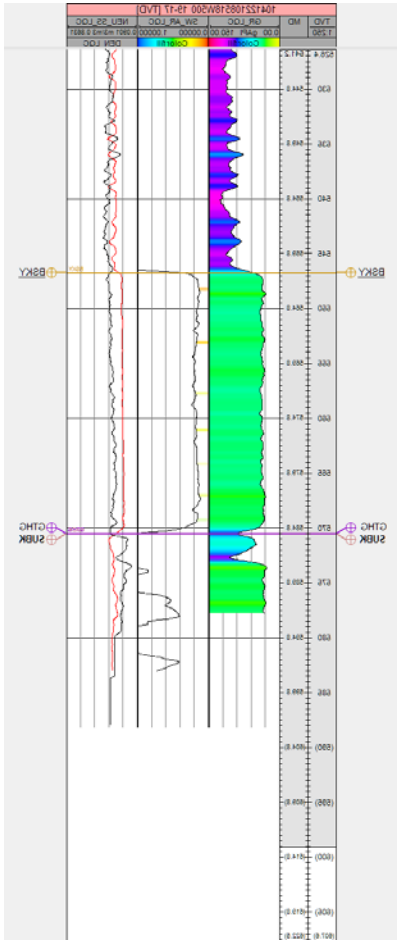


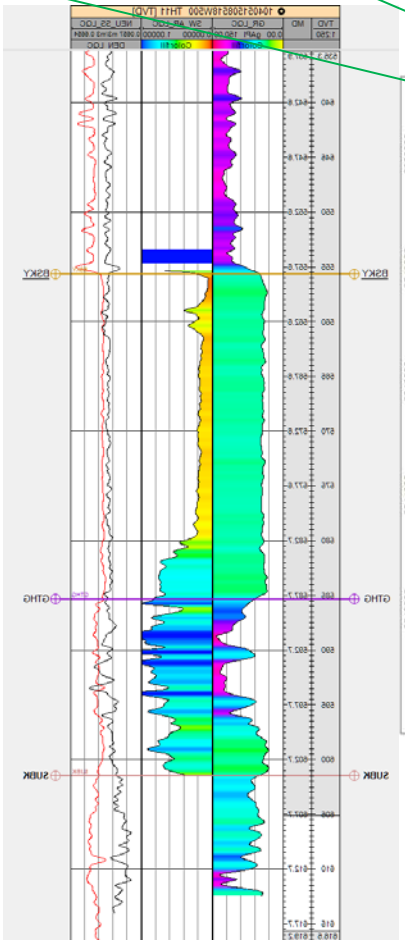
- Pads 40/41 – Low performing CSS / lateral steam drive pads, suspended Oct 2015
- Pad 19 – Overall medium recovery with CSS and vertical steam drive
- Pads 20, 21/22 – High performing TDSD pads
- Pad 20/21 infills – Medium-performing LSD pads

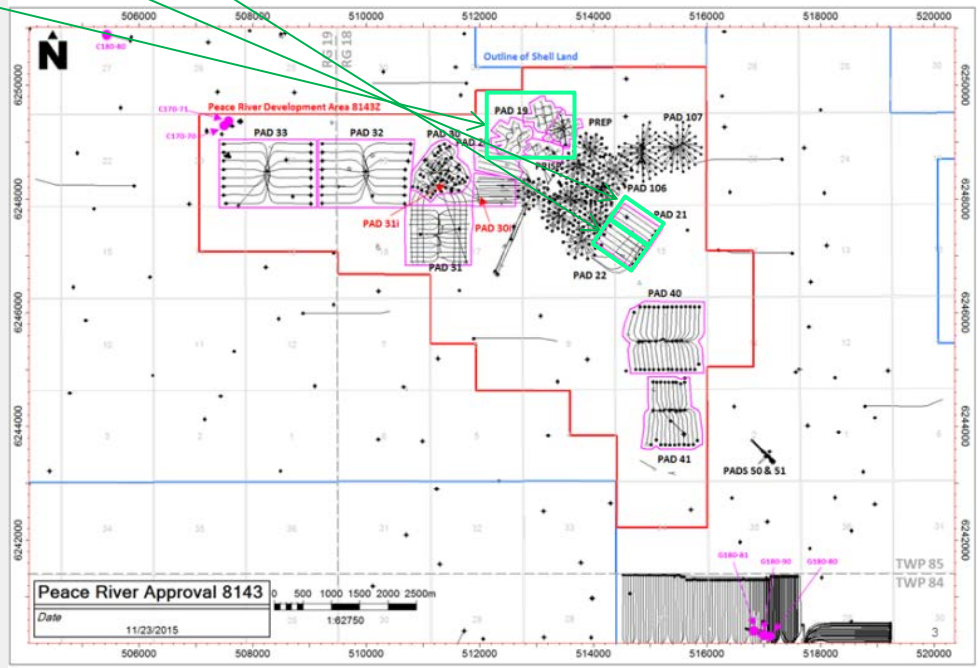
RECOVERY EXAMPLES

Cyclic Steam Followed by Vertical Steam Drive Pad19

Top Down Steam Drive Pad21 Lateral Steam Drive Pad 21 Infills



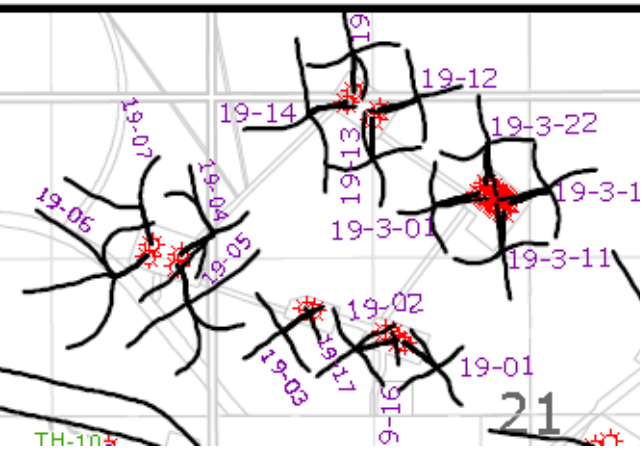


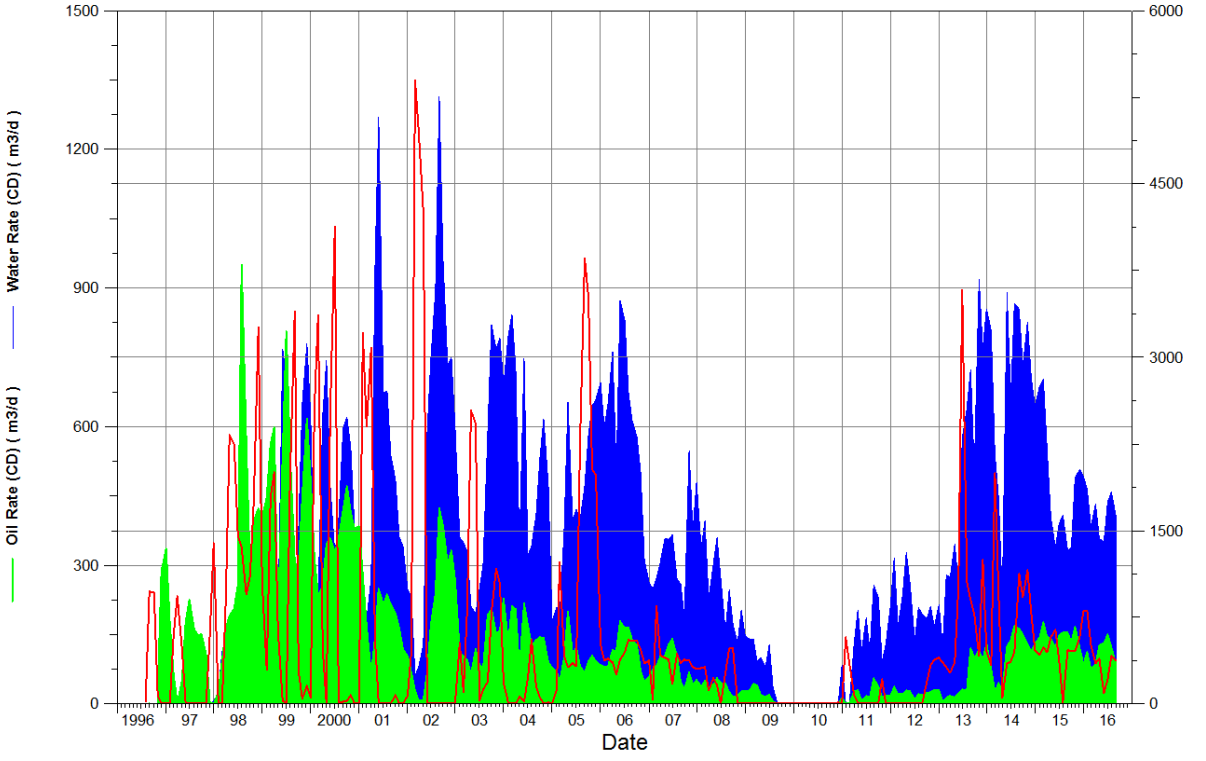


RECOVERY EXAMPLE – PAD 19: CSS AND VSD

- Originally 15 Soak radial wells, 2 vertical injectors
- 8 CSS cycles completed on SR1-3; converted to steam drive Feb 2003. Restarted 2011, shut in Dec 2014 due to high watercut
- 6 CSS cycles completed on SR 4-7; SR6 restarted 2011 – supported by pad 20 injection
- 8 CSS cycles completed on SR 8-15; restarted 2011 with additional 7 infill wells and 4 infill injectors. Steam drive ongoing
- VSD post CSS increases recovery factor

	As of 30.09.2016
Cumulative Oil	998 e^3m^3
Current RF	20%
cSOR	4.35



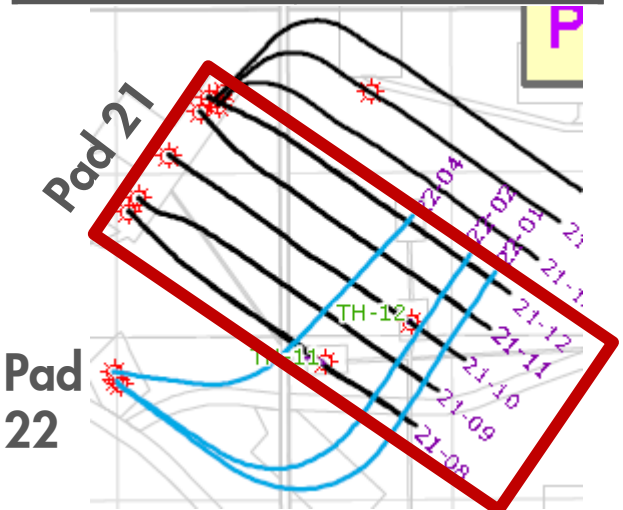


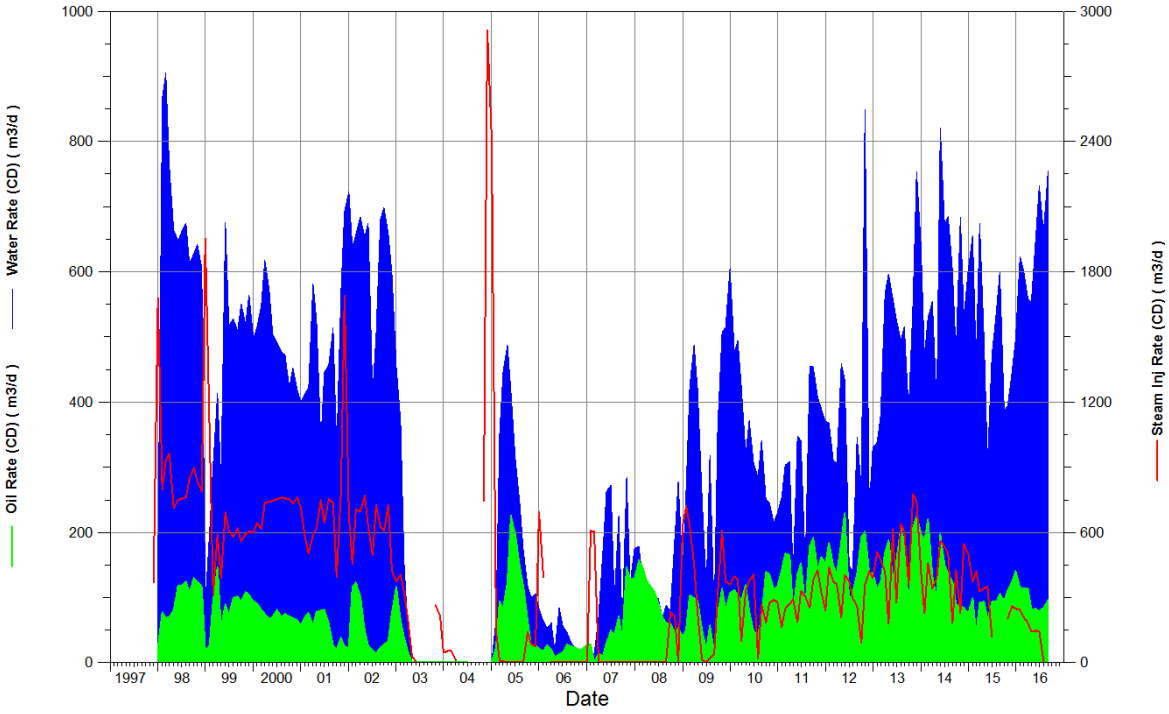
RECOVERY EXAMPLE PAD 21/22 TDSD

- **Pad 21 SAGD pairs [21-08 to 21-12]**
  - Injector legs 5 m above producer legs
  - SAGD operation from 1997 - 2003
  - CSS operation from 2003 -2008
    - Steam injection through injection legs
    - Production from production legs
  - Steam drive from 2008 onwards
    - Steam injection through pad 22 injectors
    - Production from 21-8-12 production legs

- **Pad 22 wells [22-01, 22-02, 22-04]**
  - Two single laterals drilled perpendicular to existing wells higher in the reservoir
  - Initial cold production test in February 2007
  - Cold produced October 2007 to August 2008
  - Steam drive to Pad 21 conversion wells below since November 2008
    - Top-down steam drive was pursued for Pads 20 and 21 as a follow-up process to CSS, as CSS performance was worsening in subsequent cycles
    - Well configuration on Pads 20 and 21 was appropriate for TDSD as these wells were drilled as SAGD well pairs

SD performance	As of 30.09.2016
Cumulative Oil	574 e3m3
Cumulative Steam	2599 e3m3
Cumulative SOR	4.53

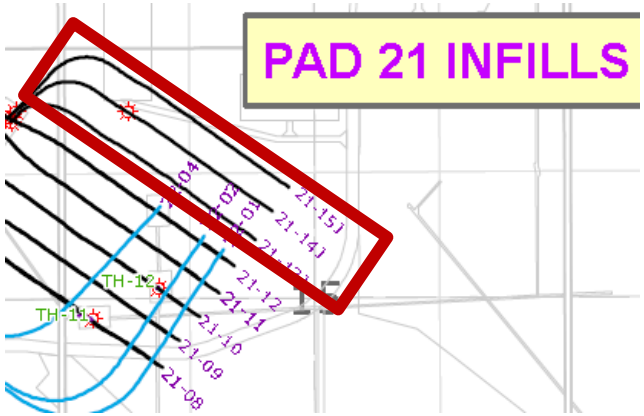


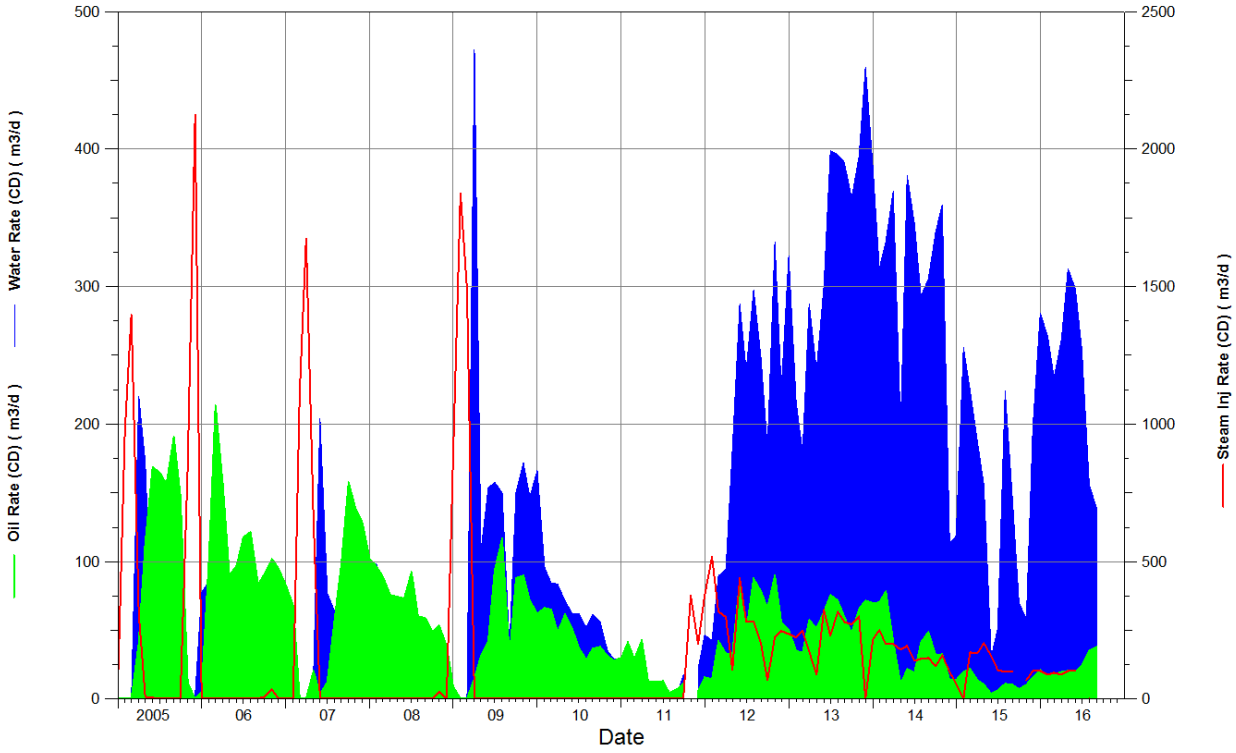


RECOVERY EXAMPLE PAD 21 INFILLS LSD

- **Pad 21 Infills [21-13, 21-14, 21-15]**
  - 3 J-wells, drilled 2004
  - CSS operation, 4 cycles completed
  - Converted to lateral SD in November 2011
    - 21-14 converted to dedicated injector
    - TDSD was not pursued on Pad 20 Infills or Pad 21 Infills due to the J-well producer configuration (vertical spacing of infill injectors and producers is suboptimal)
  - Significant improvement in SOR performance once communication between injector and producer established

SD performance	As of 30.09.2016
Cumulative Oil	226 e3m3
Cumulative Steam	724 e3m3
Cumulative SOR	3.21





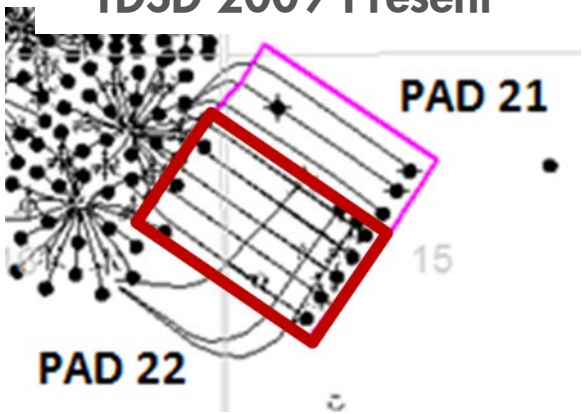
KEY LEARNINGS OF RECOVERY MECHANISMS IN PR

- **Pressure Cycle Steam Drive (PCSD)** *1979-2001*
  - Approximate reservoir pressure range: 1-12 MPa
  - Need steam to rise and gravity to drain oil
  - Performance hindered if pressure interference exists
  - Demonstrated vertical well steam drive to be feasible
- **Steam Assisted Gravity Drainage (SAGD)** *1997-2003*
  - Approximate reservoir pressure range: 2-6 MPa
  - Uneconomic due to wellpairs placed low in reservoir (high Sw), and difficult to operate due to well completion
- **Cyclic Steam Stimulation (CSS)** *1997 - present*
  - Approximate reservoir pressure range: 1-12 MPa
  - Steam growth for horizontal wells limited by poor steam quality and reservoir heterogeneities
  - Works well with vertical wells if reservoir is conditioned properly
- **Horizontal Well Steam Drive (SD)** *2005 - present*
  - Approximate reservoir pressure range: 2-6 MPa
  - Need established fluid pathways between wells
  - Maintain low pressure operation
  - Horizontal well steam drive demonstrated feasible in mature areas

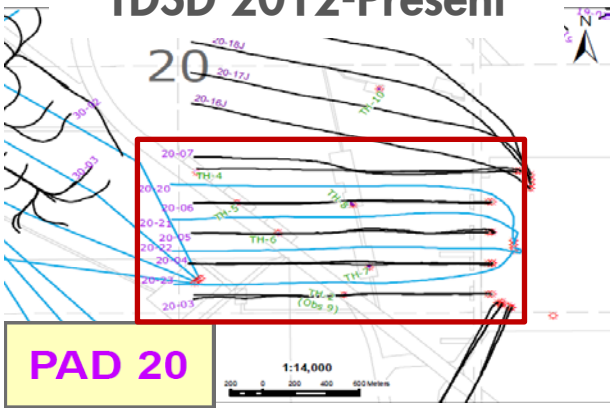
KEY LEARNINGS OF TOP-DOWN STEAM DRIVE IN PR

- **Top-Down Steam Drive (TDSD)** *2009-Present*
  - Approximate reservoir pressure range: 1.5 – 6 MPa
  - Dedicated injectors target unswept oil and reduce SOR and WC
  - Performance hindered by inconsistent steam delivery and well completion – old producers have single tubing string and in pads 30/31, suspected liner collapse.
  - Best performers: Pads 20 and 21/22, Worst performers Pads 30 and 31

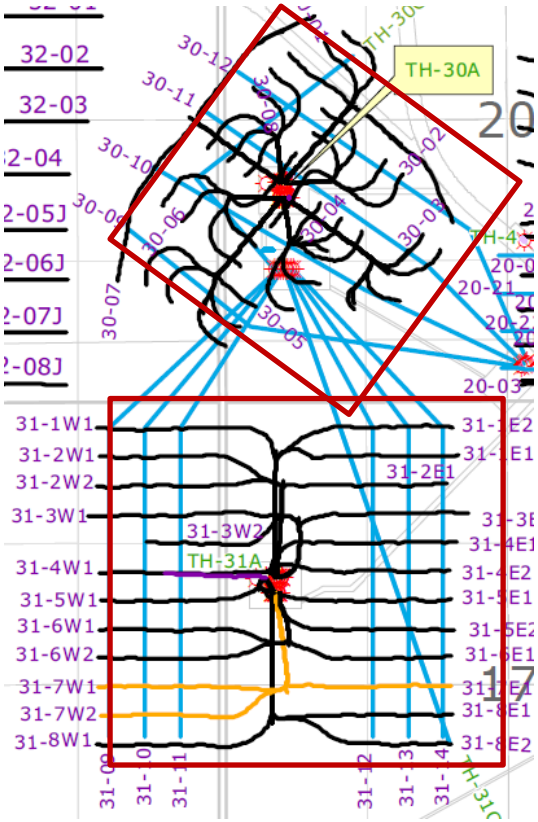
TDSD 2009-Present



TDSD 2012-Present



TDSD 2014-Present

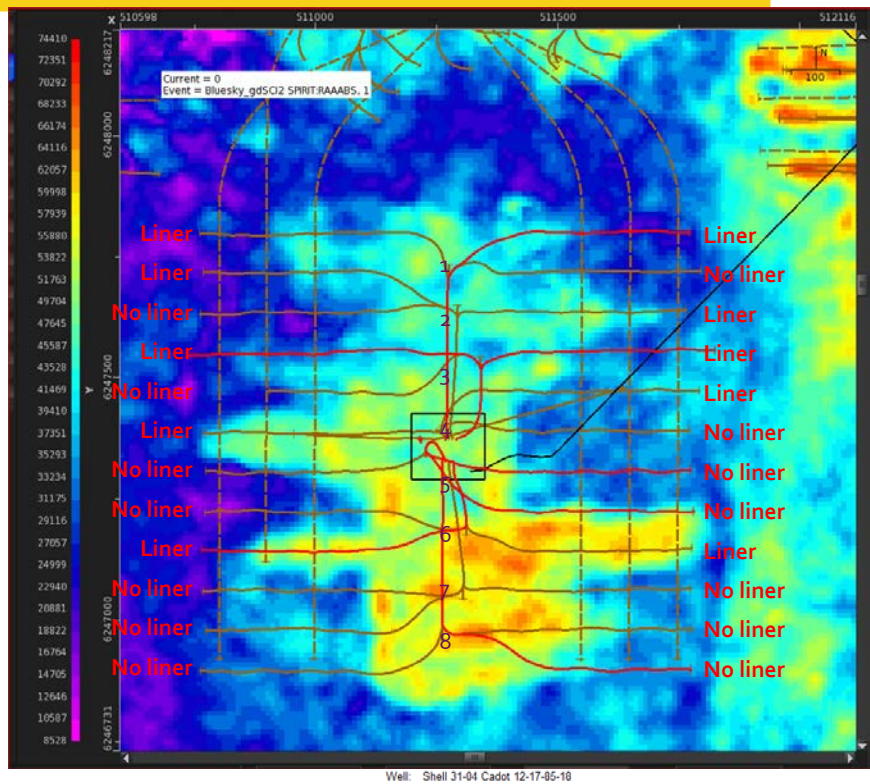


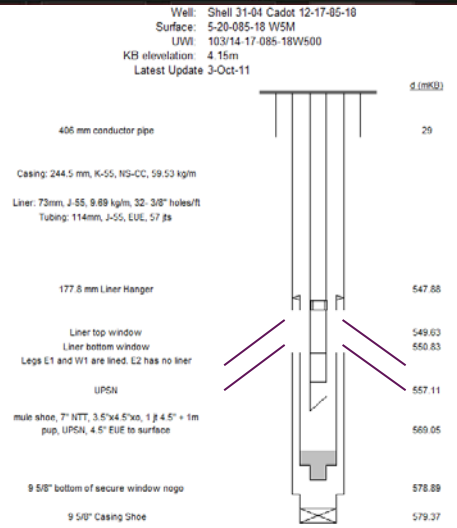
FACTORS IMPACTING RECOVERY

- **Well design**
  - Multi and single lateral J wells have no clear performance advantage
  - Difficult to control subsurface steam movement in multilaterals
- **Inter-well or Inter-pad Communication**
  - Examples include: pad 40-41, pad 32-30, pad 32-33, pad 20 infills-conv, pad 21 infills-conv)
  - If evidence of well established communication exists:
    - Temporarily shut in well adjacent to steaming if necessary
    - Production may not require additional steam (ex SR6 supported by 20-18)
  - If not well established
    - Monitor pressure and temperatures
- **Steam Drive**
  - Well completion design limits ability to target unswept reservoir areas
- **Geology**
  - The presence of shale layers is variable across the leasehold and shows some impact to injector / producer communication. However, good communication has been established in top-down steam drive pads which suggests that these shales act as baffles not barriers.

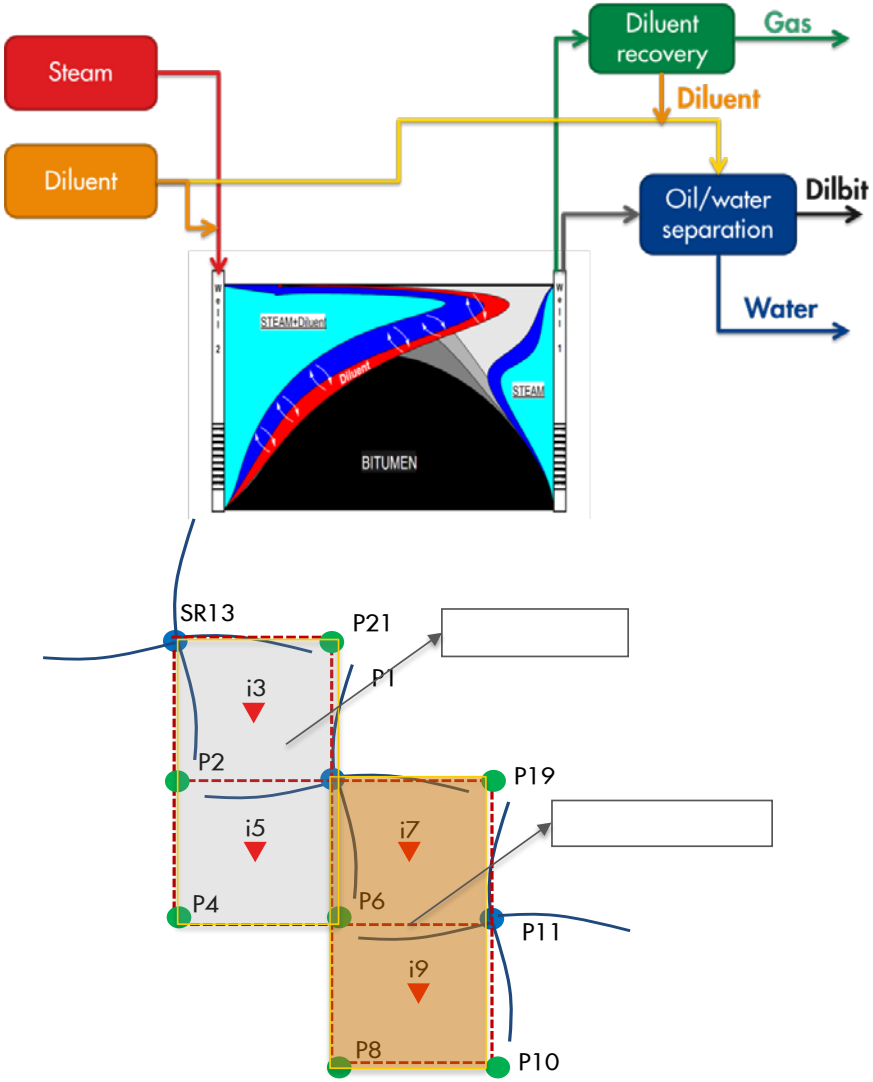
FACTORS IMPACTING RECOVERY

- Low Recovery factors:
  - Seismic from 2009 indicates that the well completions for the multilateral wells in Peace River were inefficient. Several legs were unlined and may have collapsed – steam did not go to all legs equally.
  - Example Pad 31 to the right. Warm colors indicate steam affected zones.
  - The completion assembly had large openings near the well center where legs met the central well, steam preferentially flowed into the reservoir at the center vs the legs.





SOLVENT ENHANCED STEAM DRIVE PILOT OVERVIEW



- **Field**: Brownfield, previously CSS'ed, infill wells to increase recovery
- **Technology**: Solvent (diluent) is co-injected with the steam into the reservoir
- **Pilot**: 4 inverse 5 spot patterns (2 steam-only, 2 steam-solvent)
- **Steam-solvent patterns**: 2 month SD → 4 month solvent injection (15 wt%) → followed by SD and surveillance for solvent recovery
- **Measurement:** Pad facilities, all streams (CVG and tubing) metered and sampled (auto-samplers)
- **Objectives**: Oil production uplift over steam, Solvent recovery, Model validation, Operational experience

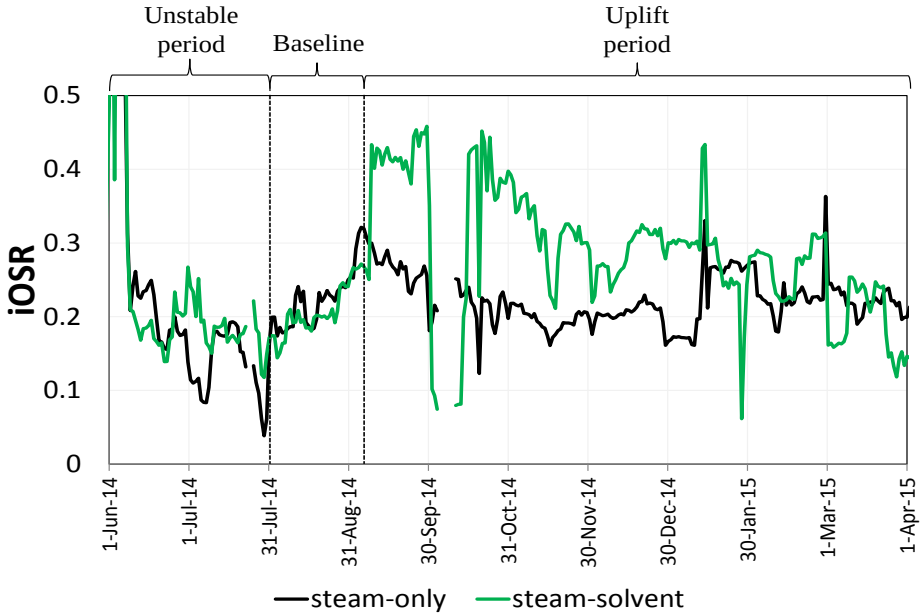
PILOT INTERPRETATION

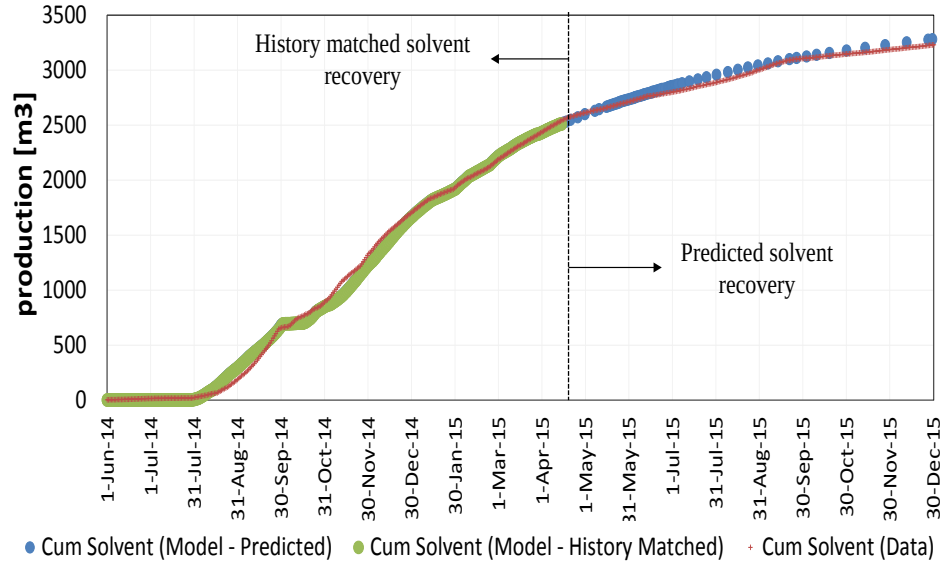
Heavy Oil Uplift:

- OSR improved by 38% due to solvent injection, estimated uplift 2520 m3. Solvent efficiency (uplift/injected solvent) at 0.49 m3/m3
- Data accurately history matched with reservoir model

Solvent Recovery:

- Recovery after 13 months is 63%
- Model history matched to first 8 months of solvent production. Model predicted solvent recovery of 62% after 13 months.
- Solvent recovery forecast after 3 years is 90%





SOLVENT PILOT LEARNINGS AND CONCLUSIONS

- Intense and redundant metering and well testing checking were key on reducing data uncertainty and achieving confidence in the pilot results
- Frequent sampling was required to generate a conclusive interpretation of the pilot
- A single hydrocarbon splitting method (developed internally) was screened in for robustness on assumptions
- The Solvent Enhanced Steam Drive pilot results demonstrated a successful technology and the benefits of using solvent in a steam-drive application

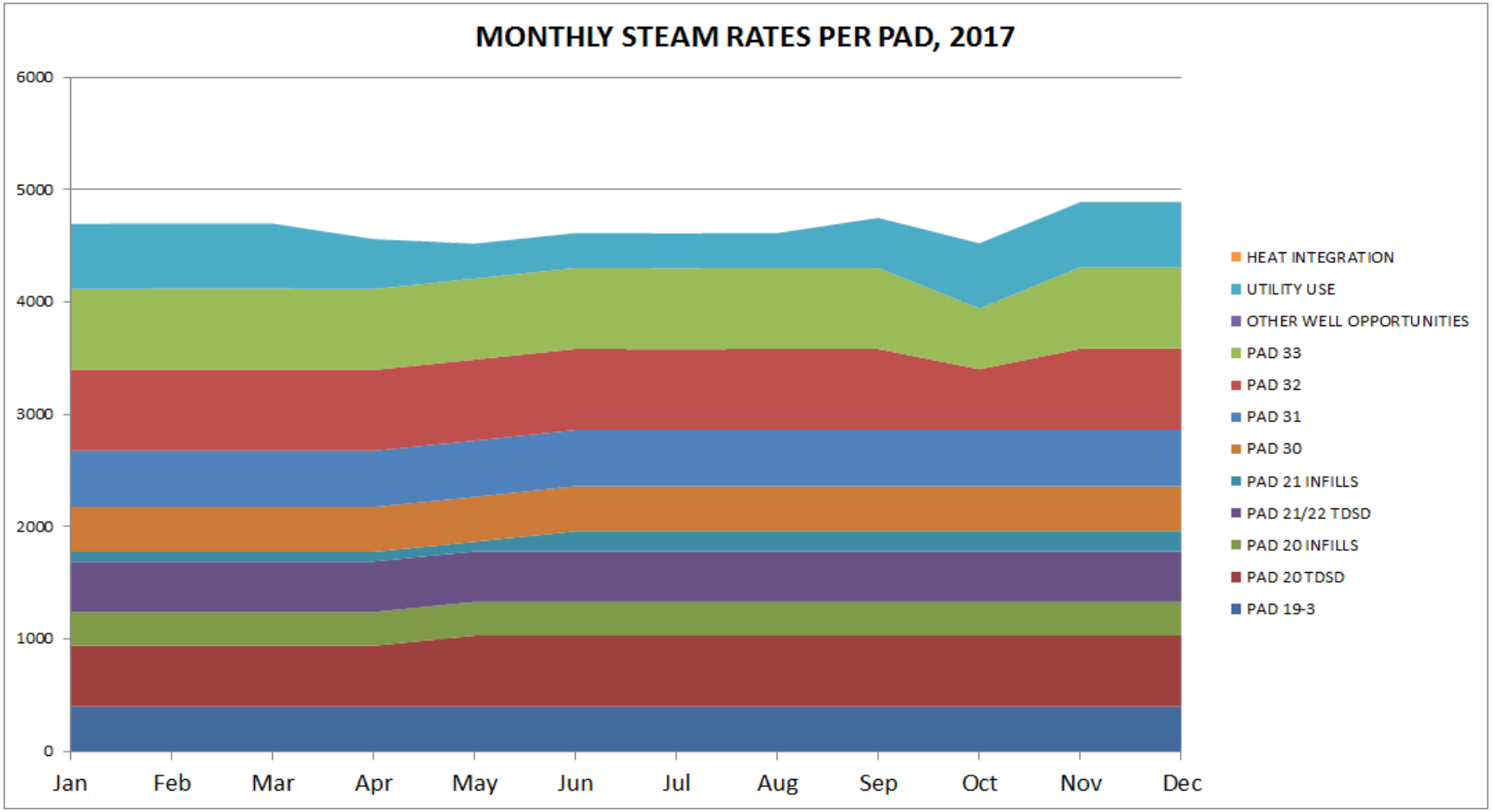
Future Development:

- Technology is ready for deployment and is selectable for future steam-drive developments in Peace River area

Publications:

- SPE185014, SPE179815, SPE175414, SPE169070

STEAM SCHEDULE



- Pad 19 SAT1 : Blowdown (No further steam injection)
- Pad 19 Infills: Steam Drive
- Pad 20 Phase 3: Top-Down Steam Drive
- Pad 20 Infills: Lateral Steam Drive
- Pad 21 Conv/Pad22 : Top-Down Steam Drive
- Pad 21 Infills: Lateral Steam Drive
- Pad 30: Top-Down Steam Drive
- Pads 31: Top-Down Steam Drive
- Pad 32/33: CSS

5-YEAR OUTLOOK OF PAD ABANDONMENT

- Plan to abandon 6 wells in 2017
- Any future uneconomic wells will be suspended as per Directive 13

	Well Abandonment – 5-Year Outlook				
Year	2017	2018	2019	2020	2021
# Wells Abandoned	6	10	10	10	10

TODAY'S AGENDA

Introductions and Background	Ivan Gonzalez
Subsurface Issues Related to Resource Evaluation and Recovery	
Geology/Geoscience	Robyn Gooler
Geophysics	Tam Pham
Drilling and Completions	Dan Syrnyk
Artificial Lift	Dan Syrnyk
Instrumentation in Wells	Dan Syrnyk
Well Integrity	Dan Syrnyk
Scheme Performance	Laura Mislan
Future Plans	Ivan Gonzalez
Surface Operations, Performance and Compliance	
	Darcy Forman

FUTURE PLANS: SAGD Pilot Project and 100% Steam Quality

SAGD Pilot Project

- Shell is currently progressing a two SAGD well-pair pilot project north of Pad 32 to prove SAGD feasibility in an important area of the Peace River lease. Expected spud date in Q3 2017 pending final investment decision.

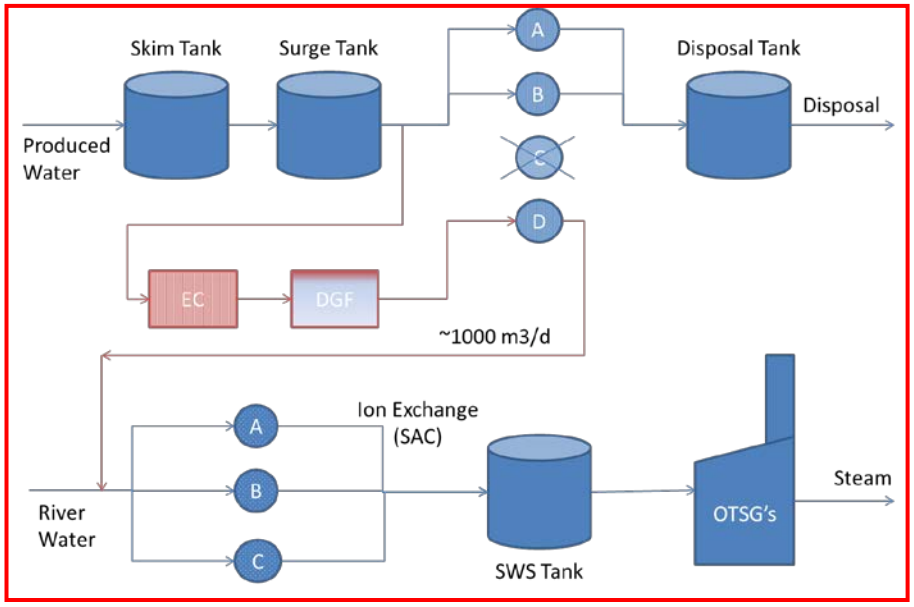
100% Steam Quality

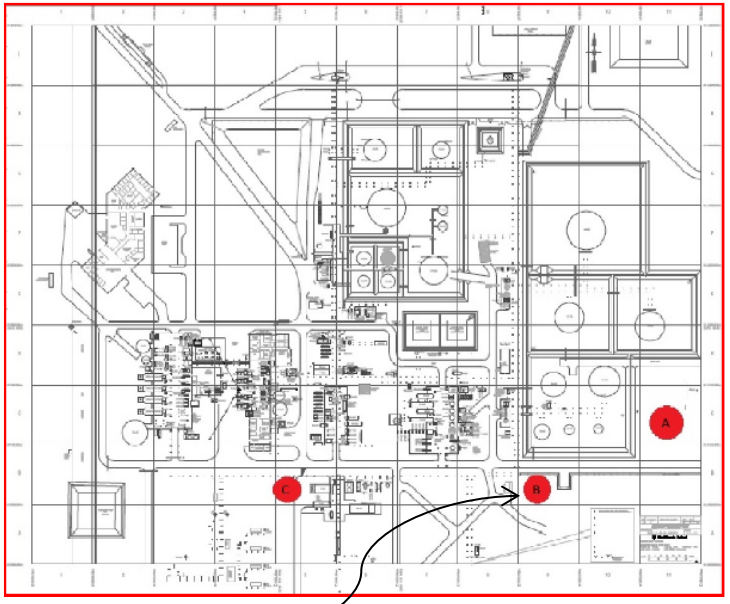
- Re-instate existing Steam Separator (PV5.01)
  - Supports SAGD pilot project and production improvement of existing top-down steam drive pads
  - Support produced water treatment plant (D81 compliance)
- To be implemented during June 2017 turnaround

FUTURE PLANS: Water treatment Demo Unit

Water Treatment Commercial Demonstration Unit (CDU)

- A CDU will be implemented in 2017 to better understand the operational implications of the Electrocoagulation (EC) + Dissolved Gas Flotation (DGF) water treatment process
- Tie-ins planned for June 2017 turnaround
- Installation in Q4 2017 and startup in Q1 2018 (operate 6 months)



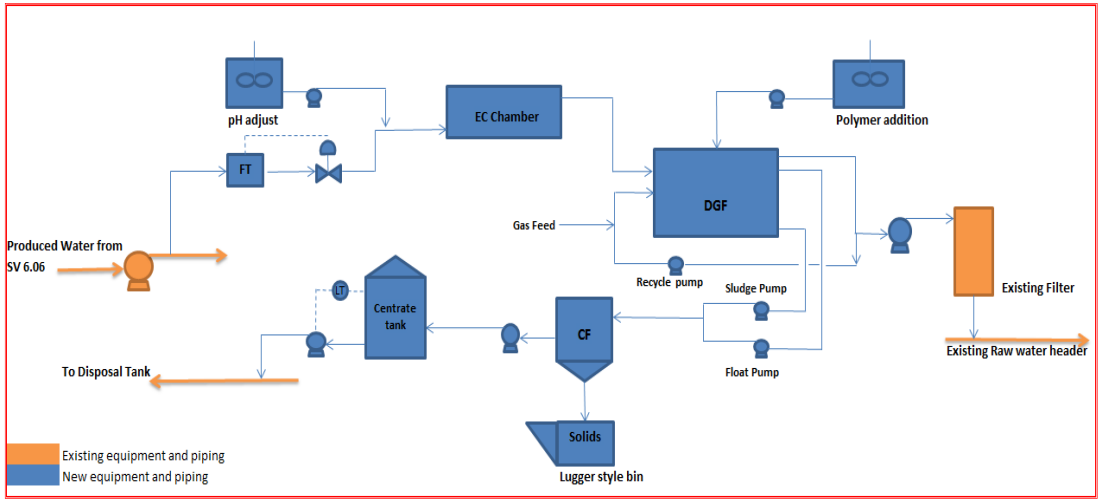


Selected Location

FUTURE PLANS: Full-scale Water Treatment System

Full Scale Commercial Produced Water Treatment System

- Once CDU is complete, final process selection can be made
  - Alternative include Zero Lime Softening (ZLS) and ceramic Nanofiltration (NF)
- Switch to 100% steam quality for removal of TDS from the produced water circuit
- Heat integration will be a significant component of any water treatment efforts



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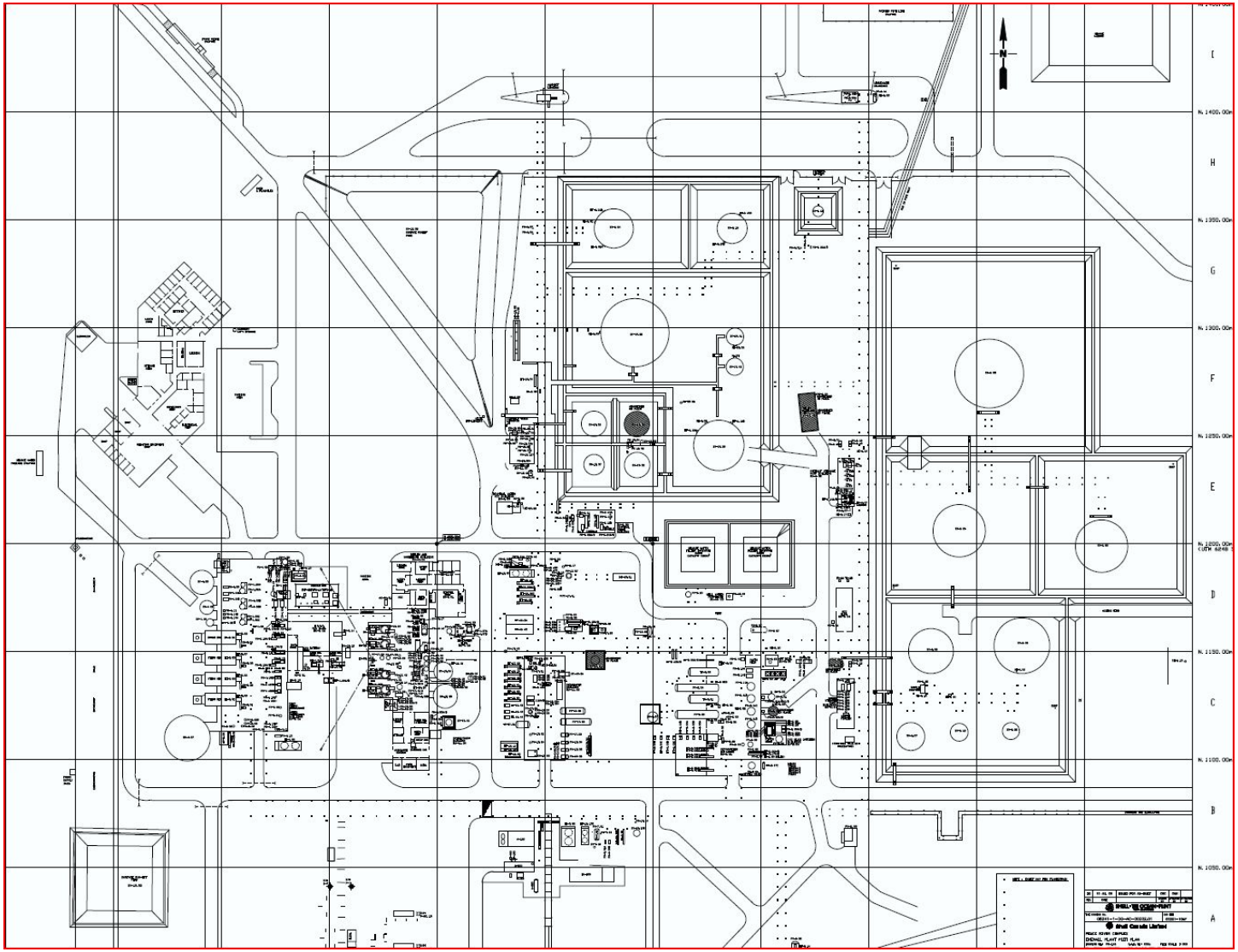
Surface Operations, Performance and Compliance	
	Darcy Forman

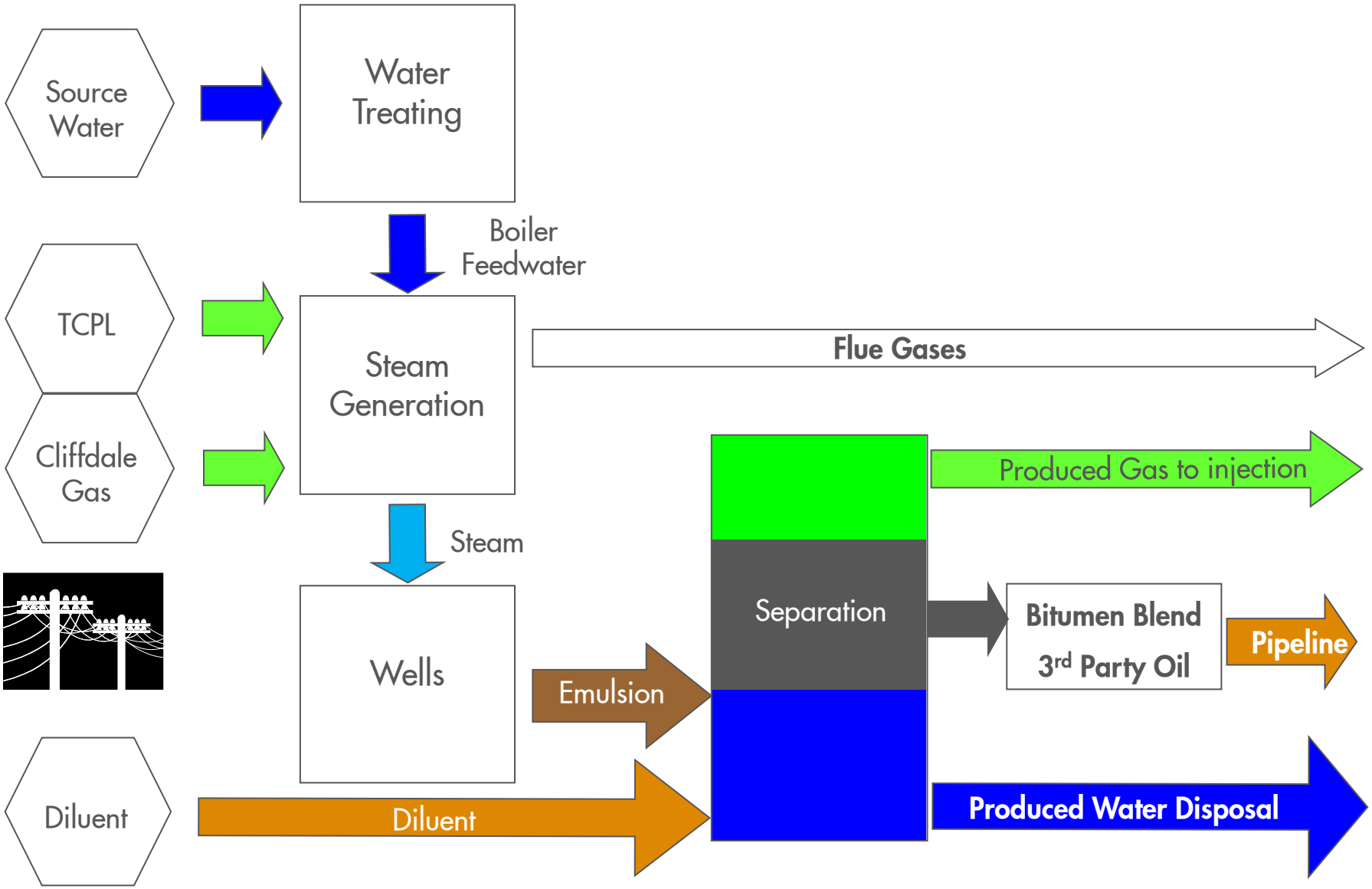
PLOT PLAN WITH 2013 MODIFICATIONS



No modifications in 2016

PEACE RIVER PLANT

THERMAL PRODUCTION TREATING: PROCESS FLOW DIAGRAM



FACILITY OVERVIEW

- PR is a thermal facility
- Recovery mechanism is a combination of steam drive and cyclical steaming.
  - In cyclical steaming, the wells are left shut-in for a period of time to soak. Subsequently the wells are flowed back until they reach flowline pressure (1,300 kPa) at which point pumps are installed.
  - In steam drive, steam is injected through dedicated injectors and water and bitumen are produced through dedicated producers at some distance from the injectors
- Production is pumped into the production pipeline. The casings are vented into a casing vent line that runs on plant line pack (250 kPa). Pad 32/33 have multiphase pumps that compress the casing gas back into the production line.
- Emulsion enters the plant for oil, water, and gas separation.
- Bitumen treating consists of degassing, separating & treating. The separation process is enhanced by controlled heat exchange and addition of demulsifier & diluent.
- The produced gas is compressed and injected into a formation for future usage
- Production averages around 40% of 2,000 m^3/day licensed capacity.

FACILITY PERFORMANCE: PRODUCED WATER TREATMENT

- Produced water is treated & disposed into two injection wells completed in the Leduc Zone
- Produced water is:
  - Taken off the separators and treaters
  - Cooled using exchangers with boiler feedwater as the cooling medium
  - Sent to the skim tank and surge tank for additional retention time and oil separation
  - Passed through the sand filters
  - Sent to disposal tank
  - Sent to Leduc injection wells
- Produced water recycle percent = 0%
- Typical water quality:
  - Produced water TSS 30 mg/L, Oil and Grease 75 ppm, Total Hardness 374 mg/L, Chlorides 3190 mg/L
- Solids are periodically disposed of through approved waste stream treating companies
- Designed produced water handling and injection capacity is 7977 m3/day.

FACILITY PERFORMANCE: SOURCE WATER TREATMENT

- PRC pulls water from the Peace River on a continuous basis. Shell has a source water treatment facility located on the east bank of the Peace River
- PRC is licensed to withdraw 4.3 e^6m^3 of water from the Peace River per year (11,813 m3/day)
- Historical water usage range is 5,000 m^3/day to 11,000 m^3/day
  - YTD fresh water withdrawal (as of Sep 30th) is 1.6 e^6m^3 or an average of 4,512 m^3/day
- Before being sent to the main complex, fresh water from source water is treated to:
  - less than 5 ntu, and less than 0 ppm oxygen
- Water is clarified in a reaction clarifier. After passing through gravity sand filters, the water is vacuum deaerated.
- The water is pumped to the main complex through a 20 km pipeline
- Main PRC water treatment consists of water softening using the sodium zeolite resin exchange process to remove calcium and magnesium
- The water softeners were converted to shallow shell technology in 2016
- Waste brine is disposed down a disposal well (16-27) in the Leduc formation

FACILITY WATER SOURCE:

- Peace River Complex pulls water from the Peace River through our source water facility
- The removal of water is covered under three Water Act Licences:
  - 00030033-00-00
  - 00030034-00-00
  - 00030035-00-00

  Each of the licences have been amended three times

2016 Water Treatment

Electrocoagulation (EC) Pilot Trial

- Small (20 gpm) pilot trial conducted in Q1 2016
- Proof of Concept achieved
- Some uncertainties remain around operational/economic aspects of the EC process → commercial demonstration unit recommended

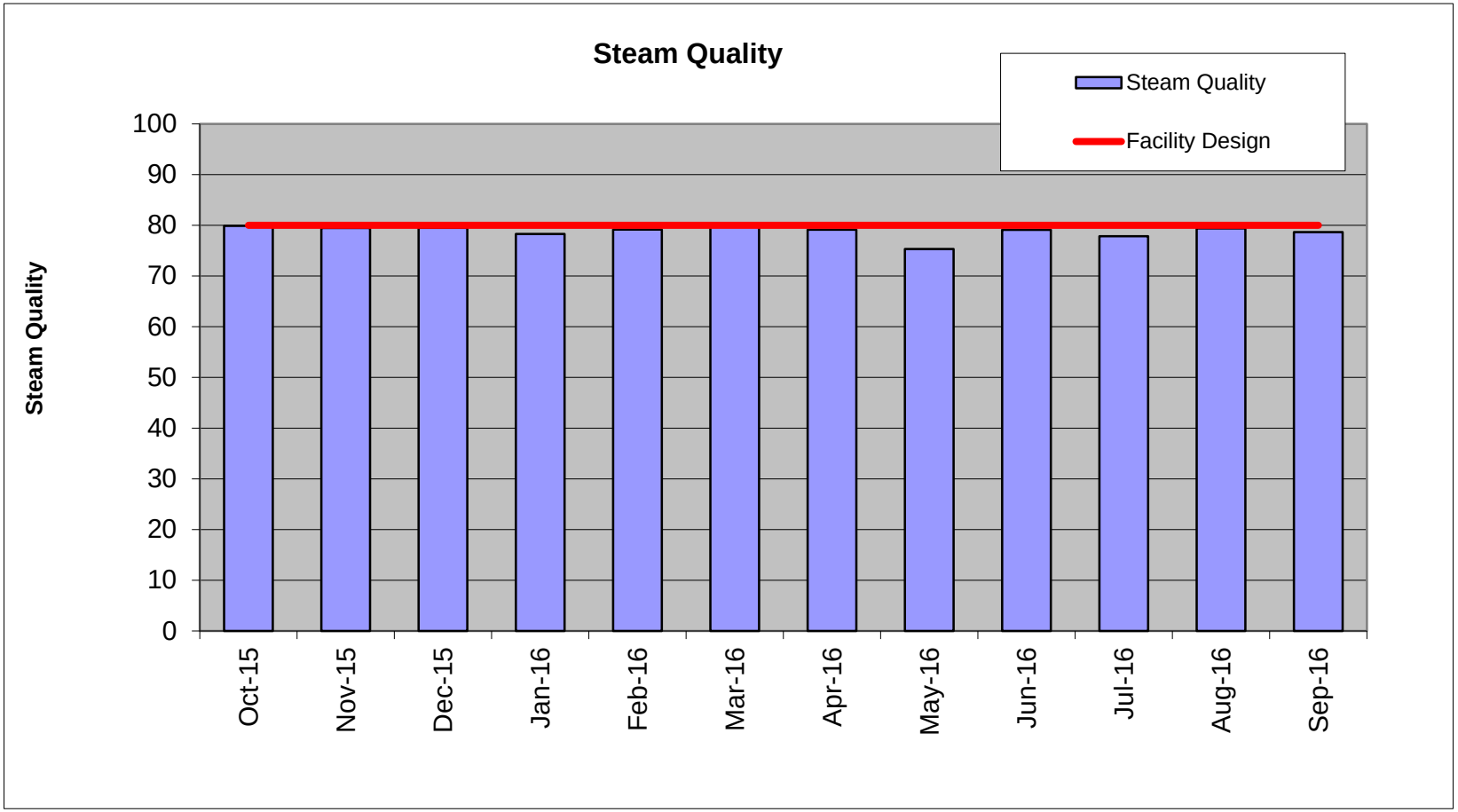
Directive 81 (D81) Compliance

- Application submitted Q2 2016
- Waiver extension granted Q3 2016
- Approval subject to construction of a commercial produced water treatment and recycling facility before end of 2020

FACILITY PERFORMANCE: STEAM GENERATION

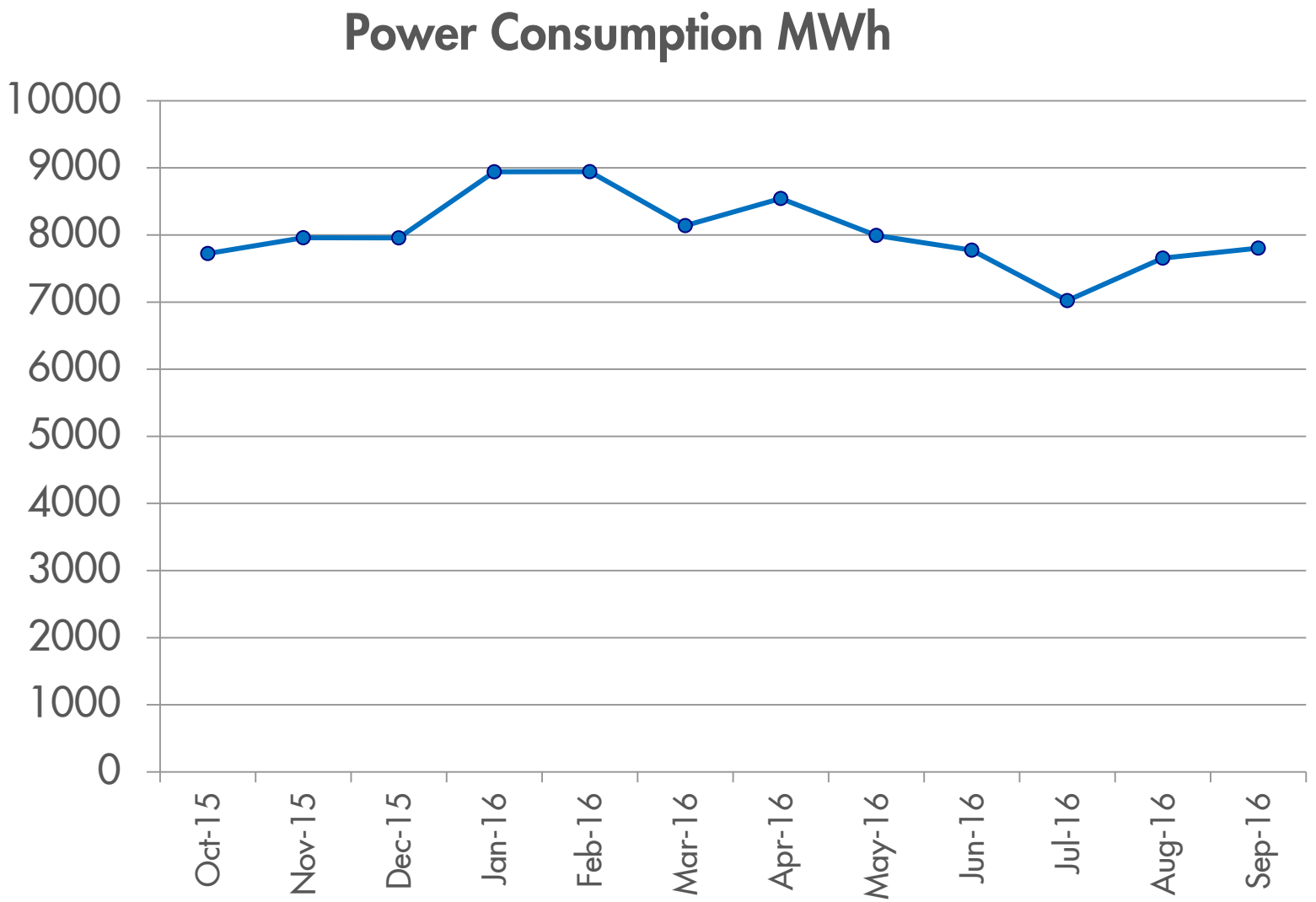
- PRC generates 80% steam quality from four once through steam generators.
- The four steam generators have a total capacity of approximately 8,000 tons of 80% quality per day. Steam pressures of 14 MPa and 335 °C.
- The main complex takes formation steam off the high pressure injection line and utilizes it in the utility steam system. The utility steam uses 700 to 1,500 t/d based on seasonal requirements.
- PRC has a100% utility steam system blowdown recycle back in to the plant steam condensate recovery system.
- All Steam Generators can now use a mixture of up to 75% Cliffdale and 25% Natural Gas by volume as their fuel source. The original design called for 60% Cliffdale and 40% Natural Gas and this change was made in June of 2016.
- Currently doing detailed engineering work to convert the Peace River steam system back to 100% steam quality to the field. Targeting an implementation date of mid 2017.

FACILITY PERFORMANCE: STEAM GENERATED



- Four PREP boilers at 2000 tons/d capacity each

FACILITY PERFORMANCE: POWER USAGE



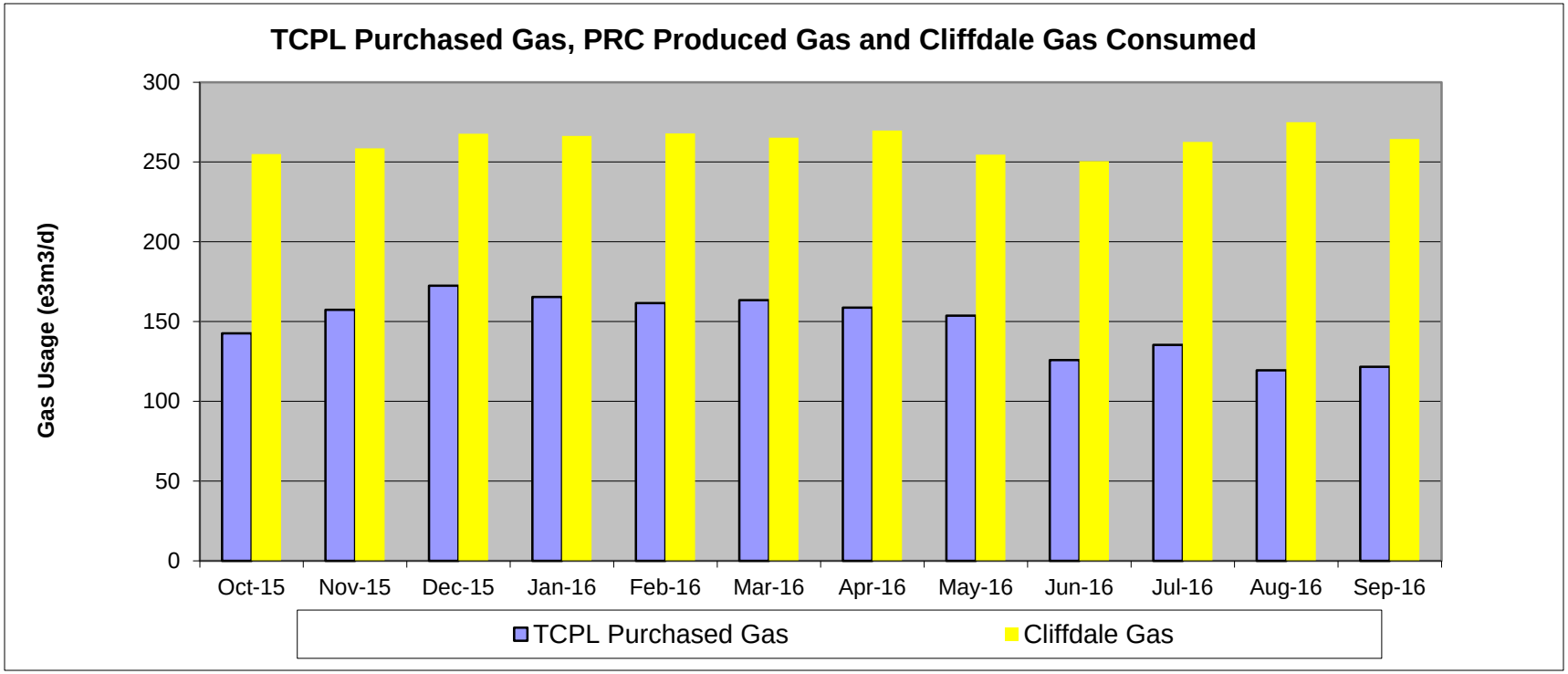
FACILITY PERFORMANCE: GAS USAGE

- Natural gas is purchased from TransCanada for use as fuel.
- Since June 2010, CVG from the Cliffdale field is being imported to PRC as a fuel source to the boilers
- EPEA licence restrictions limit using sour fuel in the boilers to events less than 72 hours in duration. While Peace River has the capability to burn sour mixed gas it has not been done since 2010.

FACILITY PERFORMANCE: Three Creeks Compressor

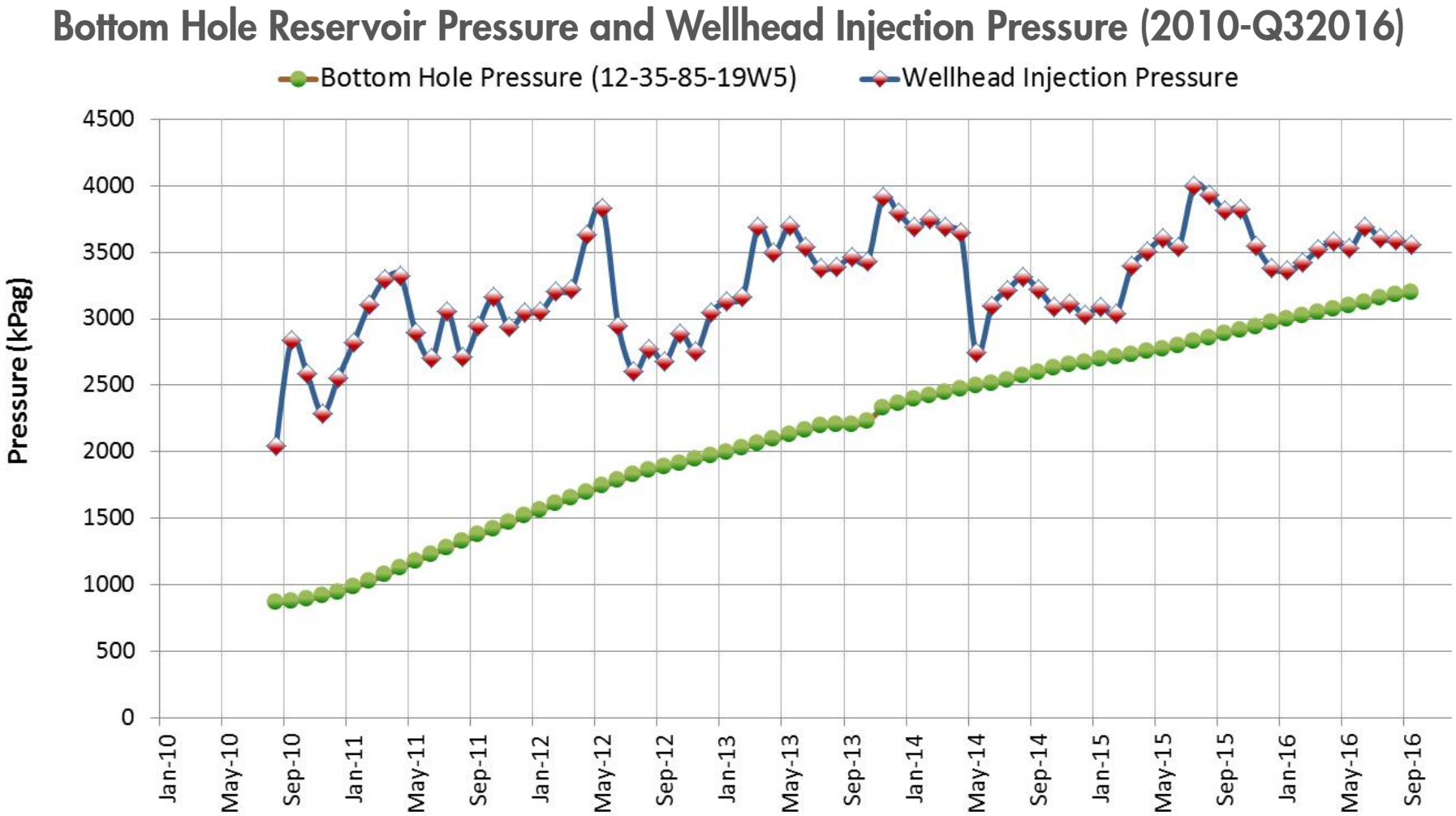
- Three Creeks Gas injection facility has been operational for six years.
- Gas is currently analyzed once per month at the Three Creeks dehydration outlet to the Three Creeks gas injection pipeline. Analysis done by a outside lab.
- Compressor turnaround completed June 2016
- 2016 Injection facility reliability is currently 99 %. This includes planned maintenance shutdowns.

FACILITY PERFORMANCE: GAS USAGE



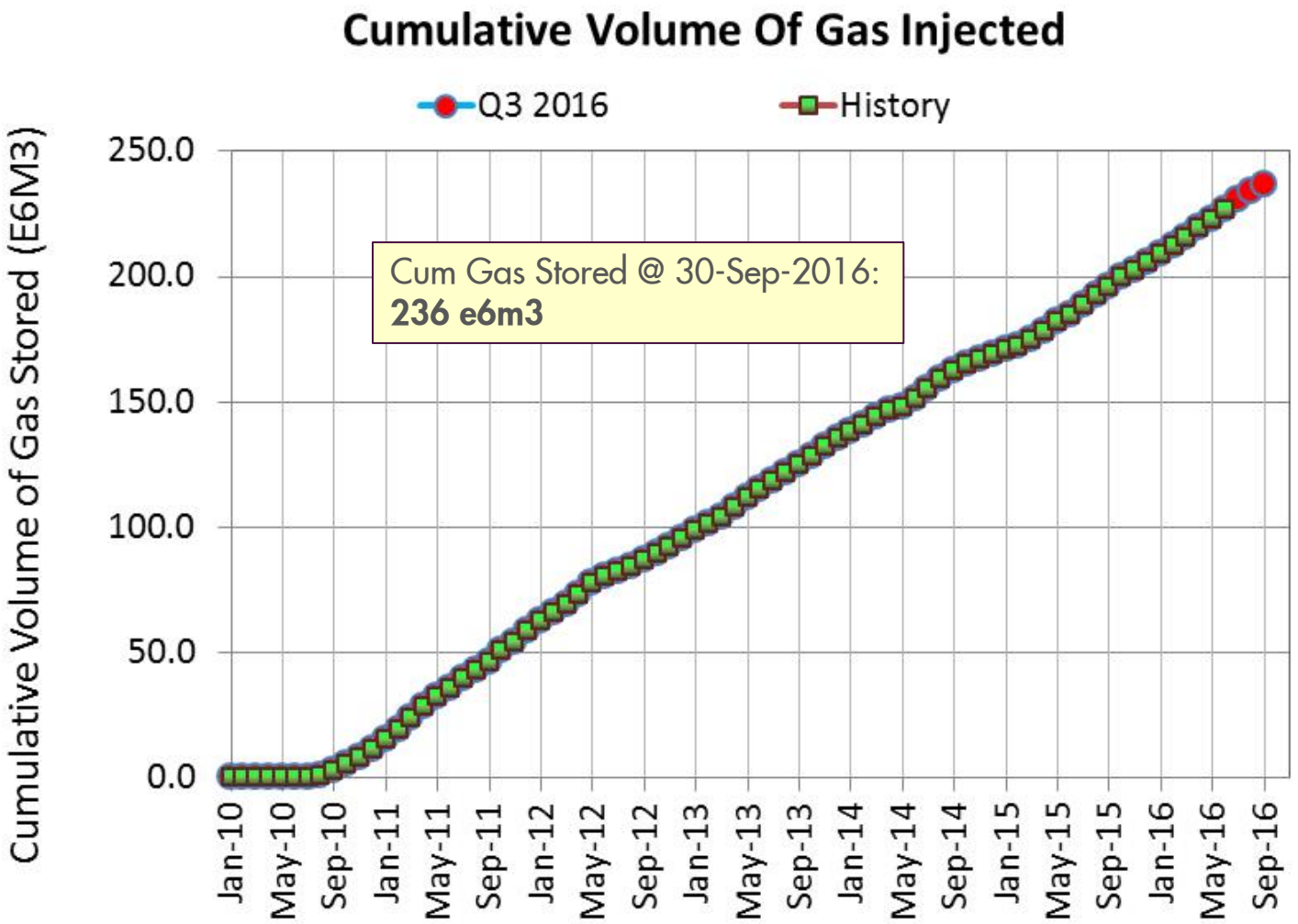
- PRC produced gas is no longer consumed in boilers but injected into the Three Creeks reservoir since September 2010

THREE CREEKS SUBSURFACE INFORMATION



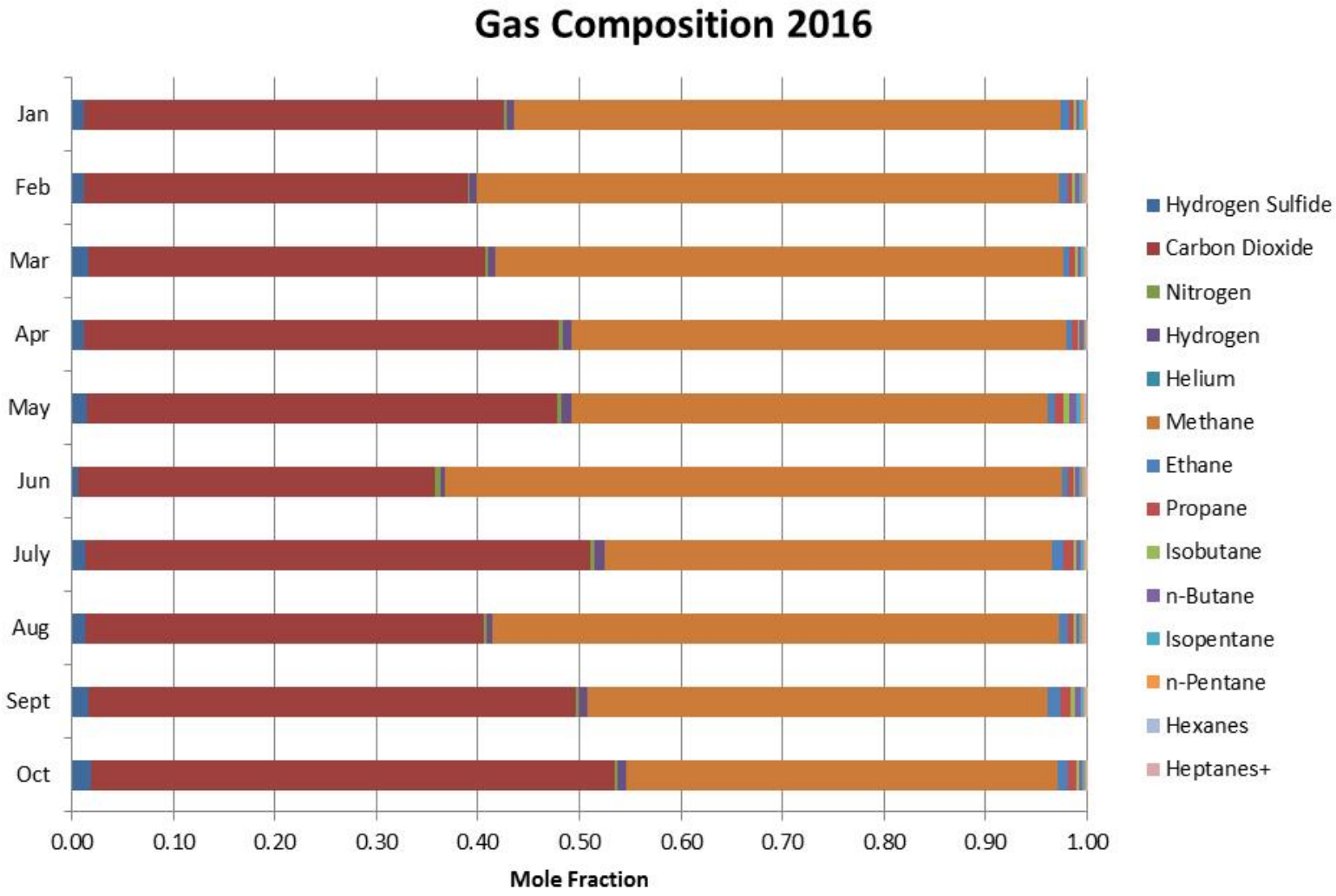
- Data as per Three Creeks annual progress report submitted Nov 2016
- Obtain D65 approval in October 2016 to store gas up to 5,000 kPa(a) static reservoir pressure

THREE CREEKS SUBSURFACE INFORMATION



THREE CREEKS SUBSURFACE INFORMATION

- Injected gas stream is analyzed once each month. The graph below presents the gas analysis from January to October.



THREE CREEKS SUBSURFACE INFORMATION

- Injected gas stream is analyzed once every month. The table below presents the gas analysis for July, August and September 2016.

Component	July 2016	August 2016	September 2016
	Mole Fraction (As Received)		
Hydrogen	0.01024	0.00582	0.00731
Helium	0.00003	0.00003	0.00005
Nitrogen	0.00349	0.00295	0.00358
Carbon Dioxide	0.49703	0.39319	0.47969
Hydrogen Sulfide	0.01404	0.01270	0.01650
Methane	0.44075	0.55792	0.45377
Ethane	0.01154	0.00787	0.01308
Propane	0.00966	0.00575	0.01042
Isobutane	0.00283	0.00269	0.00332
n-Butane	0.00422	0.00380	0.00550
Isopentane	0.00240	0.00249	0.00272
n-Pentane	0.00205	0.00205	0.00239
Hexanes	0.00118	0.00141	0.00119
Heptanes+	0.00054	0.00133	0.00048
TOTAL	**1.00000**	**1.00000**	**1.00000**

MEASUREMENT, ACCOUNTING & REPORTING PLAN (MARP)

- A MARP was approved in July 2009. Most recent MARP update was submitted on February 25, 2016.

- The following changes to the Measurement, Accounting and Reporting Plan were included in the last submission:
  - Removed Pad 40 wells (suspended)
  - Removed the Temporary Approval #1812468
  - Added the Chemical Dilution Fresh Water to (Floc Skid, Reverse Emulsion Breaker & Clarifier)
  - Added the Boiler Winterization Steam

PRODUCTION WELL TESTING

- Each well is directed to a test vessel on the pad, except pad 19 sat 1,2,4 & 20
- Well test duration/frequency largely dependent on purge time & number of wells tied into each test separator:

Pad	Separator	Purge time*	Duration	Frequency
21	2 phase	~3-8 hrs	~24 hrs	3-4x/month
19 sat 1-2-4 & 20	3 phase	~ 1 to 8 hrs	~ 10 hrs	3-4x/month
19 sat 3	2 phase	~0.5 hrs	~ 24 hrs	3-4x/month
30, 31	2 phase	~ 0.5 hrs	~ 10 hrs	4-5x/month
32, 33	2 phase	~ 0.5 hr	~ 10 hrs	4-5x/month

* Purge time varies for each test, as it is dependent on the production rate of the well. A pre-determined purge volume is applied to each vessel

- Flow rates are measured by a Coriolis meter
- Water/bitumen cuts are determined by inline BS&W analyser
- Reported volumes are prorated based on measured total volumes at the plant
- Details of measurement and reporting procedures can be found in the Peace River MARP

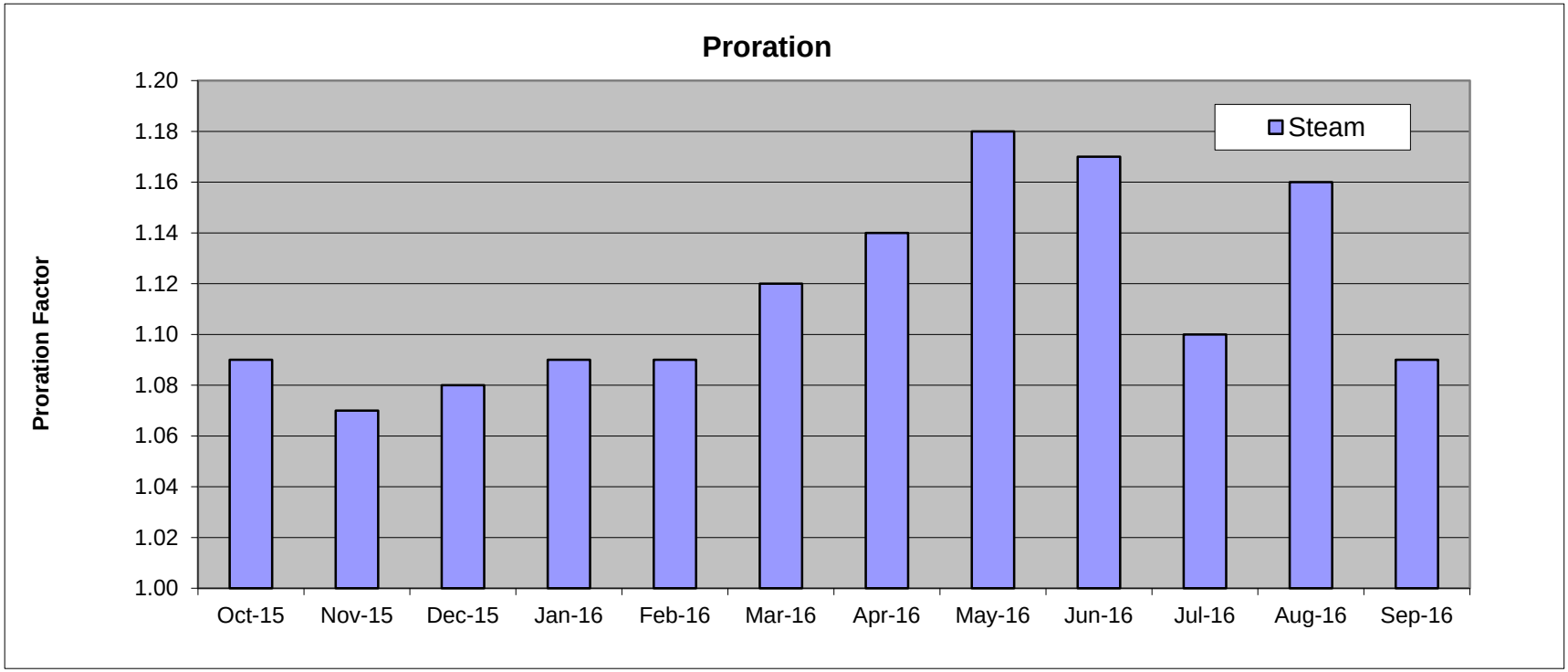
WELL TESTING

- Reliability
  - 100% compliance was not achieved for the year. June, July Sept and Oct 2016 were not compliant.
  - Test compliance issues:
    - June – Steam system repair on Pad 19-3. Steam is required for pressure makeup in the test separator
    - July – faulty watercut meter. Found debris on the probe.
    - Sept & Oct – Blocked flow in Pad 32 test separator

- Year To Date Activities
  - Implemented new steam pressure make up control on 19-3 for improved level control.
  - Conducted investigation of blocked flow in Pad 32 test separator piping, valves, and vessel.
  - Field wide AGAR calibration campaign conducted in Oct and Nov. Samples were obtained to implement new watercut curves.

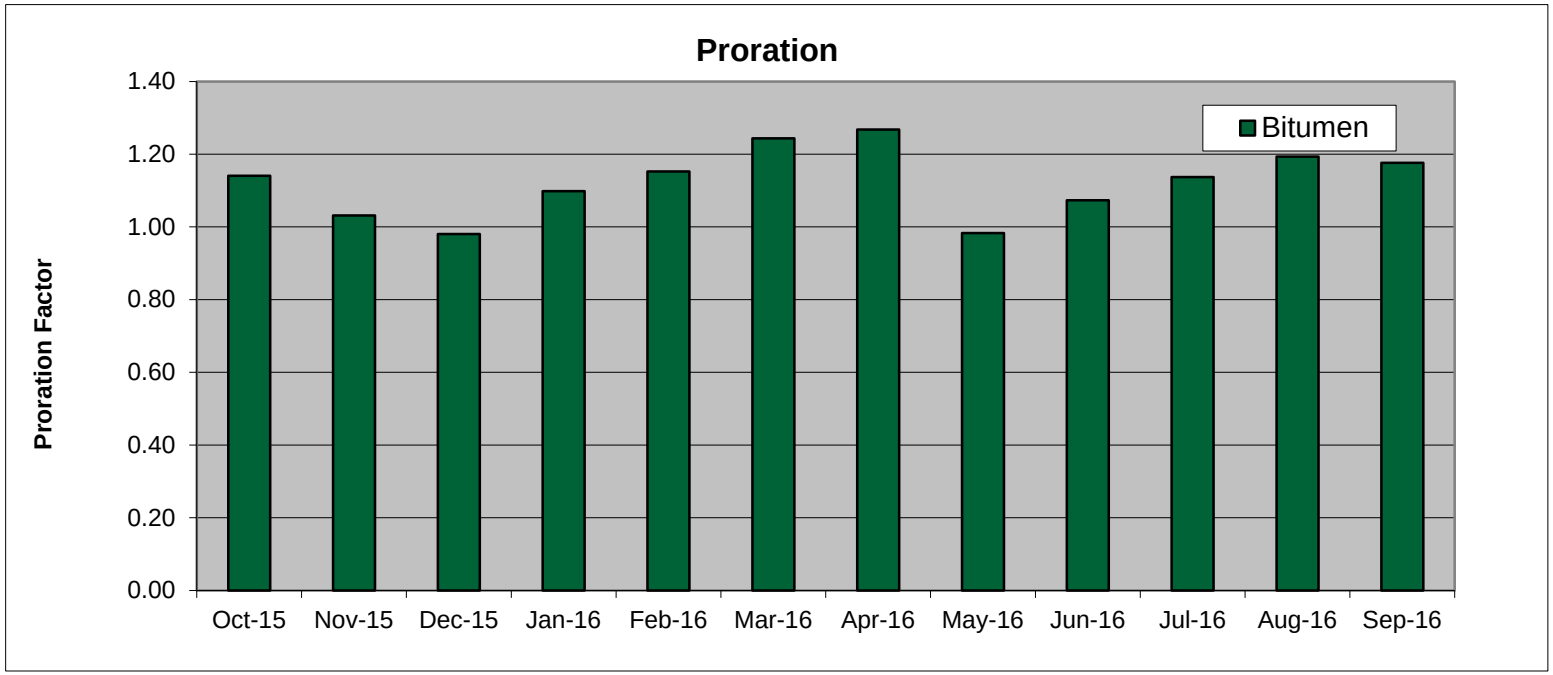
STEAM PRORATION

Proration	Oct 2015 – Sep 2016 Range	Oct 2015 - Sep 2016 Average
Steam	1.07 – 1.18	1.12



BITUMEN PRORATION

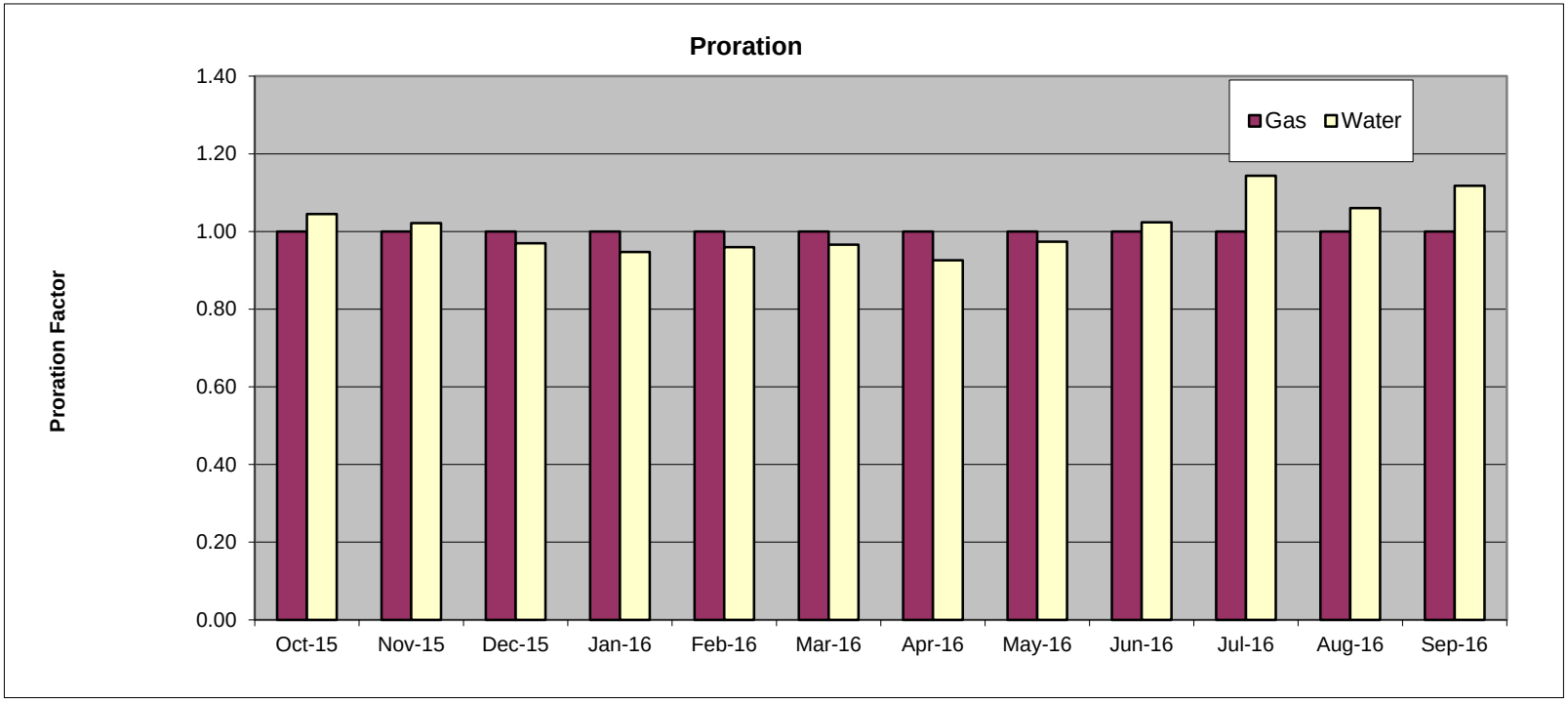
Proration	Oct 2015 – Sep 2016 Range	Oct 2015 - Sep 2016 Average
Bitumen	0.98 – 1.27	1.12



- In October 2016 we completed a field wide well sampling and AGAR meter calibration program.

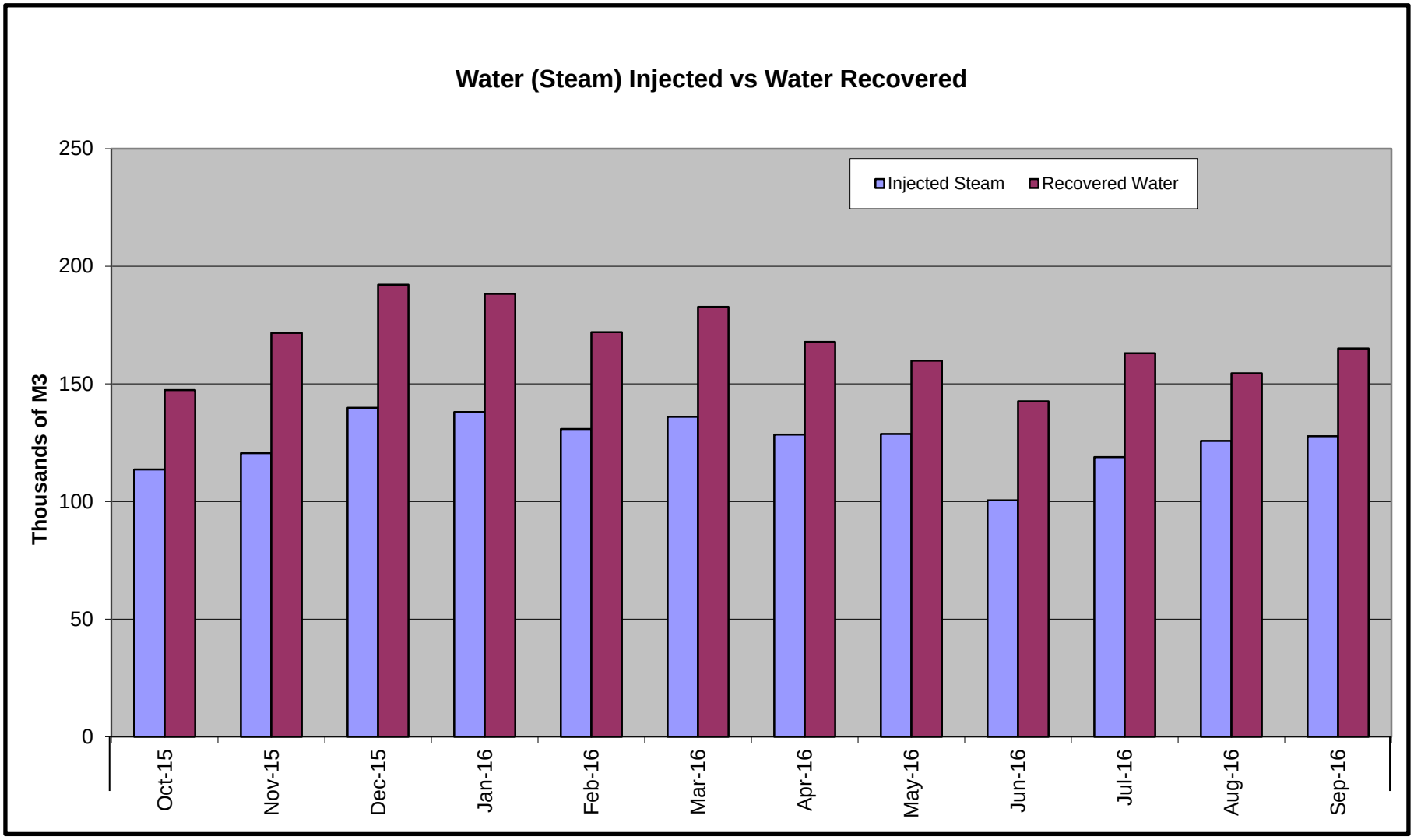
WATER & GAS PRORATION

Proration	Oct 2015- Sep 2016 Range	Oct 2014- Oct 2015 Average
Gas	1.00 – 1.00	1.00
Water	0.93 – 1.14	1.01

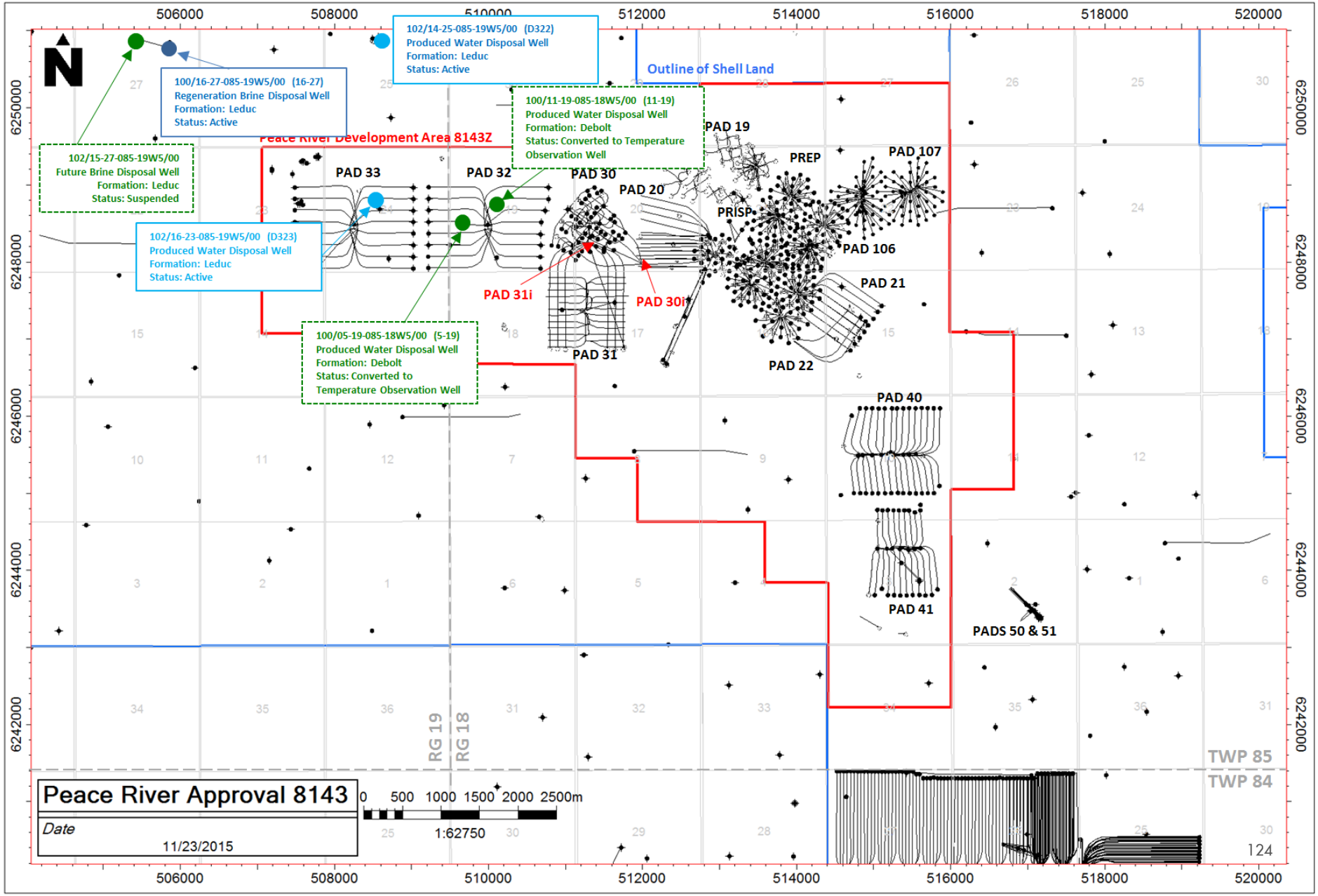


- Battery Level GOR x Prorated Well Oil Volume used for reporting PRC Produced Well Gas Volumes. Implemented the steam volumes used for winterization and test separator pressure into the water recycle calculation to correct the produced water volume.

STEAM INJECTED & PRODUCED WATER



WATER DISPOSAL WELLS



WATER DISPOSAL

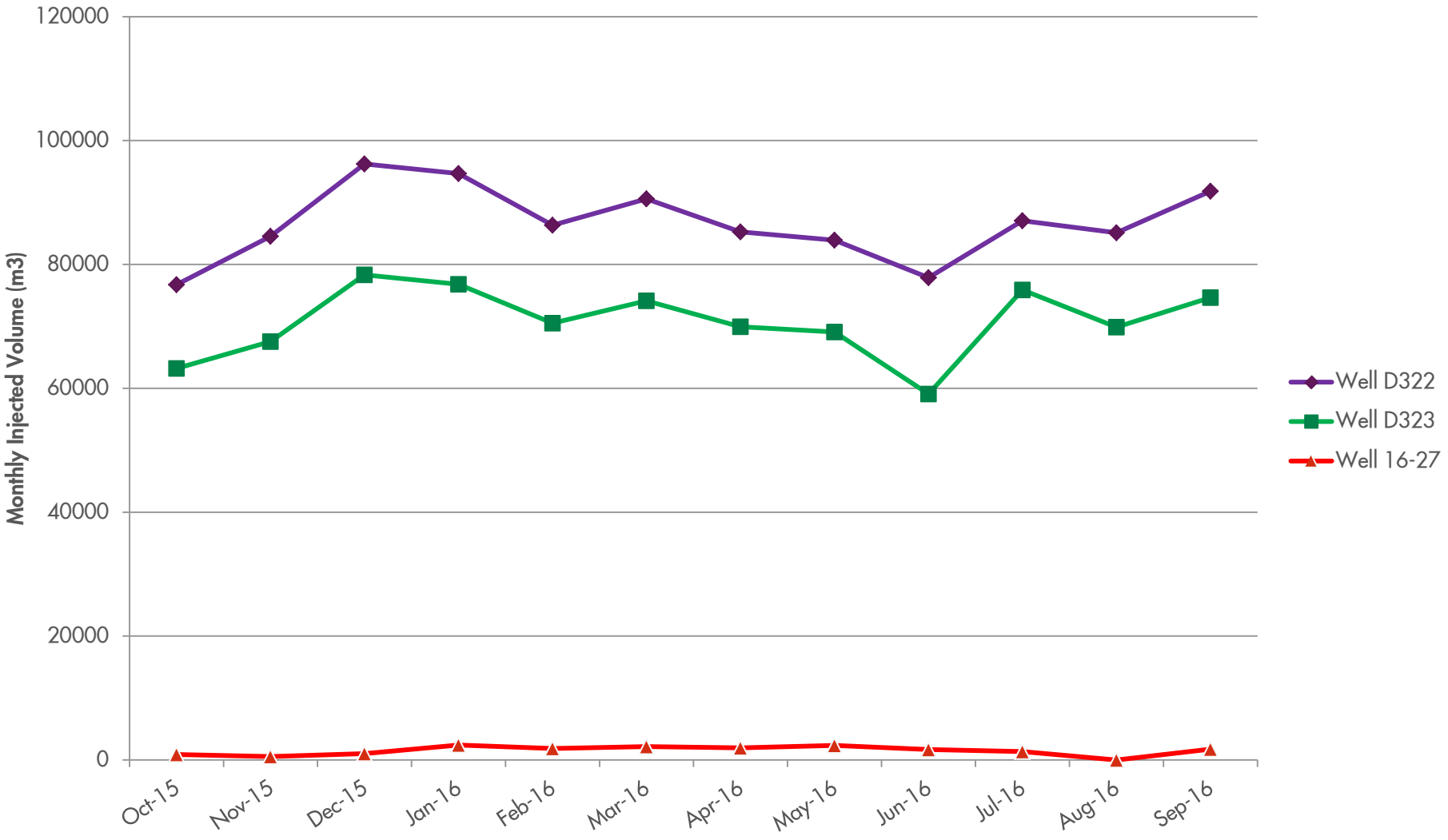
- **Brine Water Disposal Well** (100/16-27-85-19W5)
  - Disposing into the Leduc formation
  - Used for boiler feed water softener regeneration waste
  - Average Disposal Volume/Day = 53.5 m^3/d
  - Average Upstream Pressure = 2,780 kPa
  - Max Wellhead Pressure = 3602 kPa (Approved pressure = 4,500 kPa)
  - Typical Total Dissolved Solids (TDS) is 9000 g/m^3
  - Approval up to 4500 kPag wellhead injection pressure (as per approval no. 9953A)

WATER DISPOSAL

- **Produced Water Disposal Well 322** (102/14-25-85-19W5)
  - Disposing into the Leduc formation
  - Used as produced water disposal well
  - Average Disposal Volume/Day = 2,841 m^3/d
  - Average Pressure = 5,928 kPa
  - Max Pressure = 9984 kPa (Approved pressure = 18,000 kPa)
  - Average Temperature = 66 °C
  - Typical Total Dissolved Solids (TDS) is 5300 g/m^3
  - Approval up to 18,000 kPag (as per approval no. 6308)

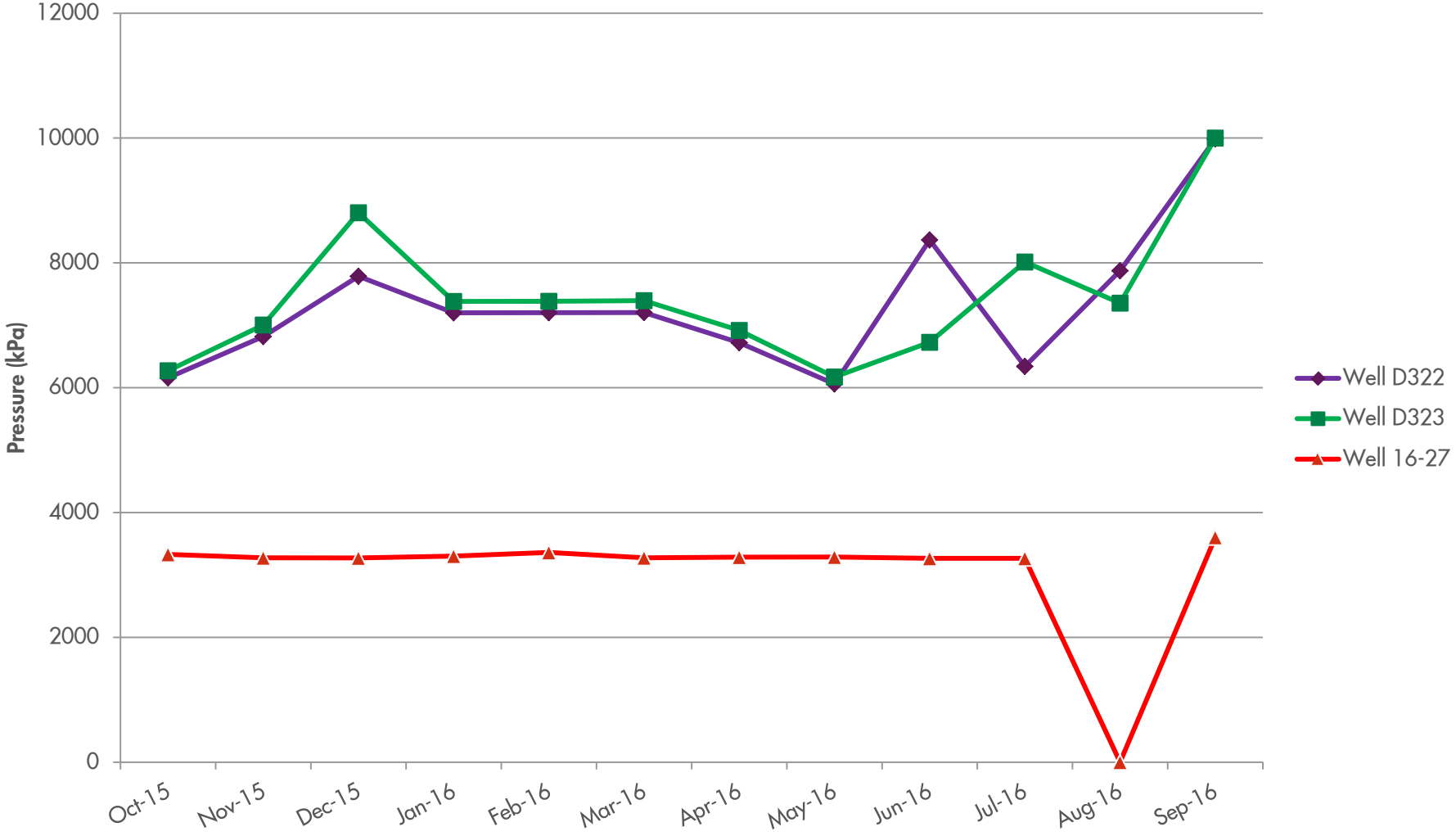
- **Produced Water Disposal Well 323** (102/16-23-85-19W5)
  - Disposing into the Leduc formation
  - Used as produced water disposal well
  - Average Disposal Volume/Day = 2,326 m^3 /d
  - Average Pressure = 6,019 kPa
  - Max Pressure = 10,000 kPa (Approved pressure = 18,000 kPa)
  - Average Temperature = 67 °C
  - Typical Total Dissolved Solids (TDS) is 5300 g/m^3
  - Approval up to 18,000 kPag (as per approval no. 6308)

WATER DISPOSAL MONTHLY VOLUMES



- Brine Disposal Well 16-27 had no injection in August due to a pipeline leak.

WATER DISPOSAL MAX MONTHLY INJECTION PRESSURES



- Brine Disposal well 16-27 was shut-in August due to a pipeline leak.

WASTE DISPOSAL

- Newalta-Red Earth (12-13-87-9W5)
  - Treatment, Recovery & Disposal (TRD) Facility
  - 131.0 m3 to October 2016
  - SLGHYD
- Newalta Seal Lake (11-07-82-15W5)
  - Treatment, Recovery & Disposal (TRD) Facility
  - SLGHYD
  - 176.6 m3 to October 2016
- RBW Waste Management
  - To Edmonton Facility for disposal 3907-69 Ave.
  - 0 m3 of waste solids (SOILCO) to October 2016

WASTE DISPOSAL

- Tervita Corporation– Peace River (12-24-85-19-W5)
  - Treatment, Recovery & Disposal (TRD) Facility
  - Primarily hydrocarbon sludge (NON-DOW, CAUS, COEMUL, SLGHYD, SOILCO, SOILEM, WSHWTR)
  - 12,687.02 m3 to October 2016

- Tervita (Hazco) Environmental (1/4-03-25-22W4)
  - Tervita Waste Management (TWM)
  - SOILRO, EMTCON and FILOTH
  - 42.75 tonnes to October 2016

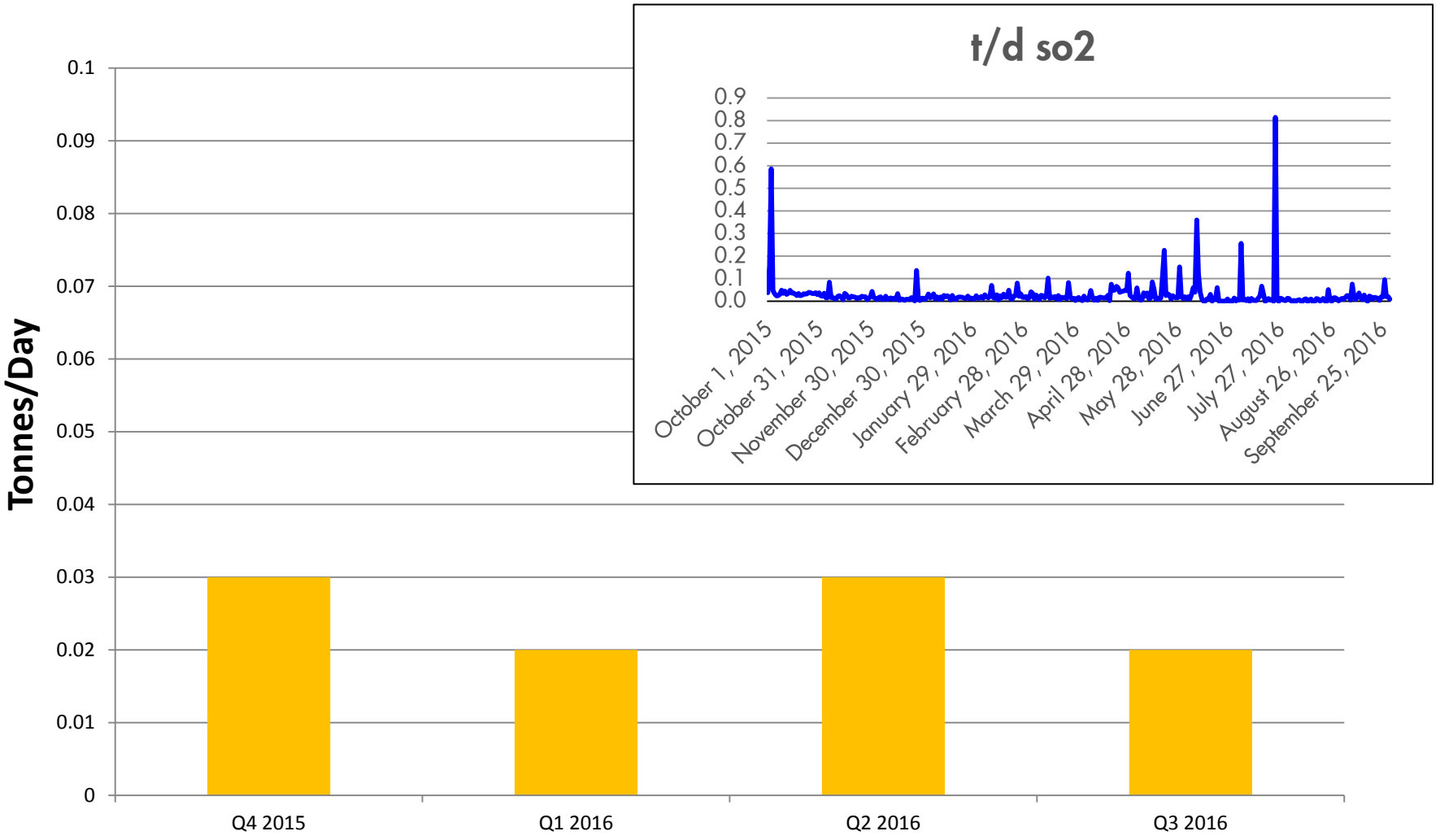
- Tervita Corporation– Spirit River (12-31-77-5W6)
  - Tervita Waste Management (TWM)
  - Activated Carbon ACTCRB
  - 0 m3 to October 2016

WASTE DISPOSAL

- Tervita Corporation– Valleyview (04-21-069-22W5)
  - Tervita Waste Management (TWM)
  - SLGHYD and LUBOIL
  - 42 m3 to October 2016

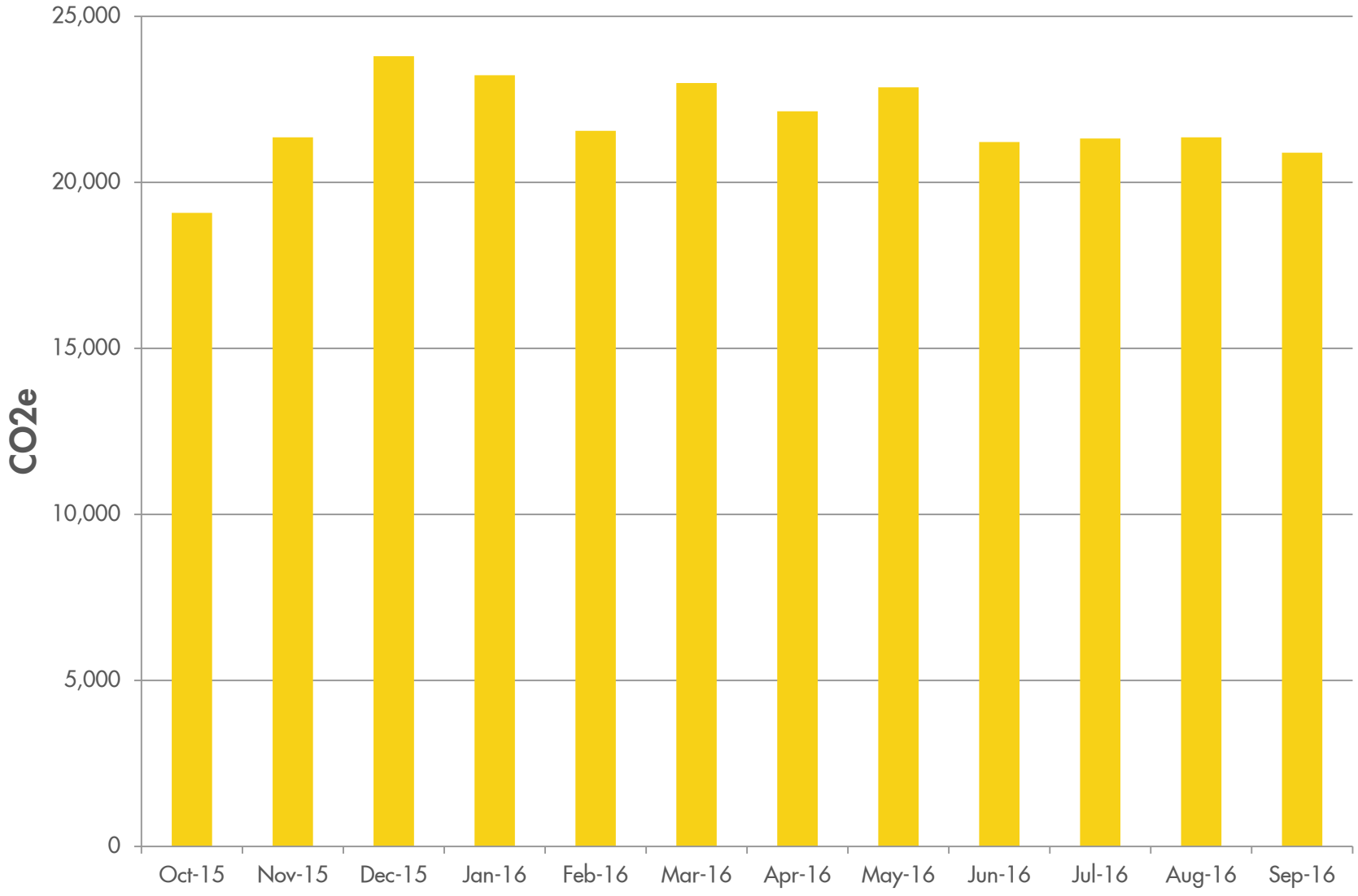
- Tervita Corporation – High Prairie (01-14-073-17W5)
  - Tervita Waste Management (TWM)
  - SLGHYD
  - 40 m3 to October 2016

SULPHUR EMISSIONS (< 1T/DAY)

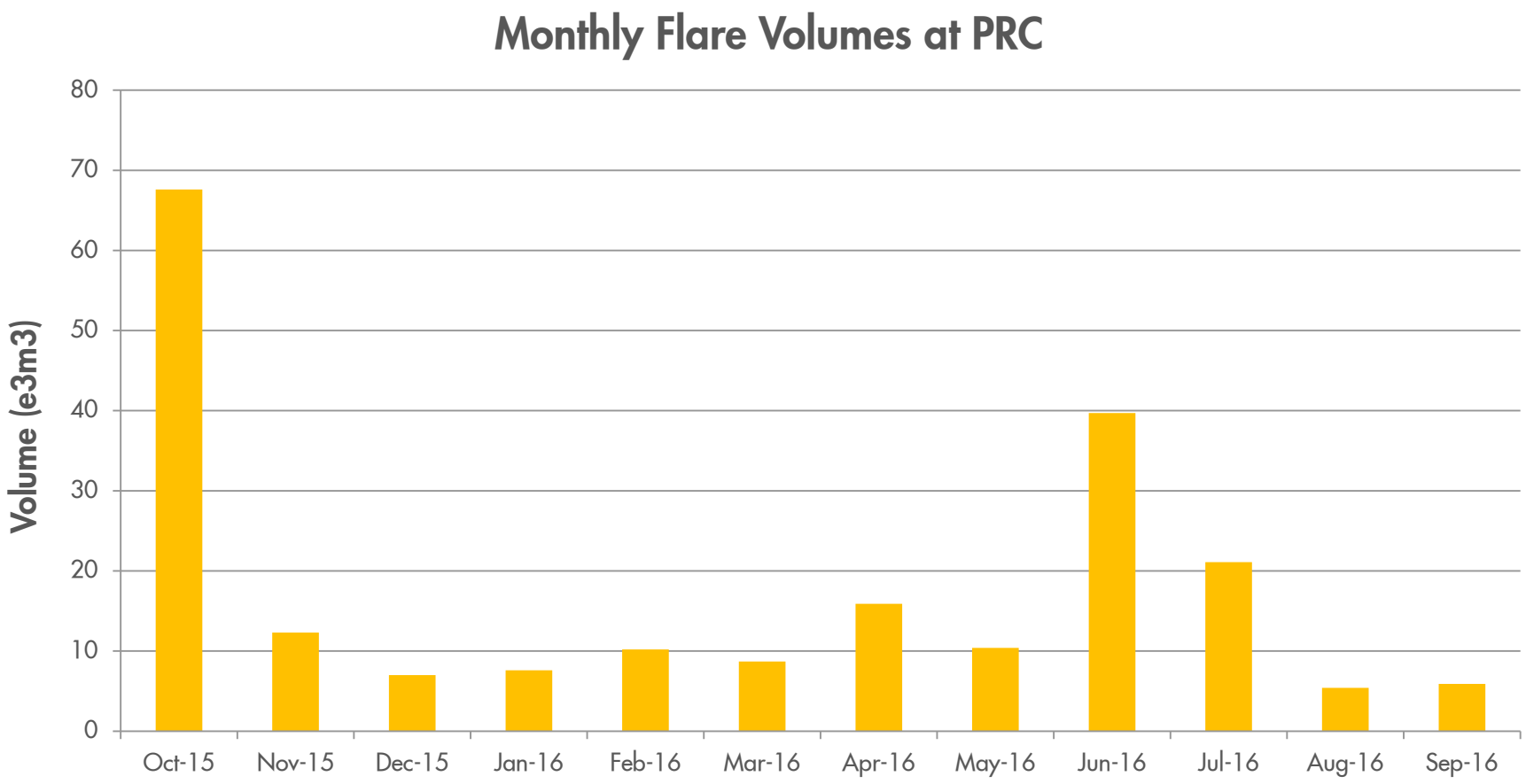


New AER Operating License has 0.99 T/Day continuous SO2
Sulphur emissions have reduced since 2010 due to PRC produced gas injection into Three Creeks.

GREEN HOUSE GAS EMISSIONS



FLARE VOLUMES



- The high flare volume in October was a result of a power outage. June's higher flare volume was due to turn around activities.

AMBIENT AIR MONITORING

Static/Passive Air Monitoring

- Twelve passive stations
- Gathers data on sulphur dioxide and hydrogen sulphide
- 2016 monitoring and reporting satisfactory

Continuous Ambient Monitoring data

- **Continuous Monitoring -** Monitored parameters: sulphur dioxide, hydrogen sulphide, methane, non-methane hydrocarbons, total hydrocarbons, total reduced sulphur, ambient temperature, wind speed and direction.

ENVIRONMENTAL COMPLIANCE

- There were no Ambient Air Exceedances at the PRC Environmental Trailer (EPEA Approval 1642-02-08) from October 2015-October 2016. The air trailer maintained over 90% uptime each month as per license requirements.

- Government (AER and/or AESRD) reportable spills and releases at PRC
  - 1 government reportable spills from October 2015 to end of September 2016.
  - July 15, 2016 we had a brine disposal pipeline failure. 32 m3 of brine was release and all contained to the Peace River Complex site.
    - Approximately 10 m^3 runoff water flowed off lease.
  - 2 releases to atmosphere from tanks (venting) from October and December 2015.
    - Total volume vented for this period was 0.0078 e^3m^3.
  - 2 releases to atmosphere from tanks (venting) from January to end of September 2016.
    - Total volume vented for this period was 0.0054 e^3m^3.

INDUSTRIAL RUNOFF PAD BERM AUTHORIZATION

- On February 2016, during a DOI audit with AER, we were informed that we are out of compliance with berms around existing well pads at Peace River.
- On November 10, 2016, Shell received approval from the AER to continue with a risk based approach to bring well pads at PRC into compliance with Conditions 4 and 5 of Schedule V, of Approval 1615-02-03.

Berm Completion Date	Pad Site
December 31, 2017	Pad 20, Pad 32, Pad 19-D [(SR-8-11)SAT3]
December 31, 2018	Pad 33, Pad D323, Pad 21
December 31, 2019	Three Creeks Gas Injection Pad, Pad 30, Pad 31

- This schedule addresses the higher risk pads first before the expiry of our existing EPEA Approval (August 31, 2020).

COMPLIANCE

To the best of Shell's knowledge, operations at Peace River are consistent with all conditions of our Peace River Thermal Scheme No. 8143.

Amendment	Approval Date	Description
O	October 2, 2012 April 26, 2013	Carmon Creek Phase 1 and 2 Project.
P	Oct 4, 2013	Carmon Creek changes to CPF designs and adding a third separator to all well pads.
Q	Dec 9, 2013	Peace River Project X –two injector pads for Pad 31 and 31.
R	Dec 12, 2013	Carmon Creek conversion of well pads from injectors to CSS producers.
S	March 6, 2014	Carmon Creek updates to the CPF
T	April 15, 2014	Directive 81 variance application for Peace River Complex
U	Oct 10, 2014	Peace River Pad 20 AGAR meter installation
V	Nov 7, 2014	Peace River Pad 22 addition of 2 infill wells
W	May 4, 2015	Carmon Creek – removing conditions to re-abandon, re-enter two wells in our original approval condition.
X	April 6, 2015	Carmon Creek- pressure monitoring wells-variance approval to not drill these wells.
Y	April 14, 2015	Peace River Pad 19-Sat 3- 6 additional well license approvals
Z	May 21, 2015	Carmon Creek development area expansion and additional 13 well pads approval.
AA	Jan 4, 2016	Steam Foam Proof on Concept (PoC) injection trial up to two wells within the existing Pad 19 Satellite 3 and the temporary surface facilities required to operate the PoC trial.
BB	Aug 5, 2016	Approval for Shell Directive 81 extension request and the addition of two generators in the Peace River Complex.

ENVIRONMENTAL APPROVALS

EPEA Operating Approval 1642-02-03 had 1 amendment during 2016.

- 1642-02-08 amendment incorporated two 1.25MW generator sets at Peace River Complex for generation up to 2.5MW of electricity for the plant.
- Shell also obtained written authorization from the AER to reduce the stack height of the two generator sets on October 3, 2016.

Shell's Surface Lands department deals with many amendments to leases as a part of day to day business.

ENVIRONMENTAL: MONITORING PROGRAMS RESULTS

Groundwater Program

- Per EPEA 1642-02-08, PRC has requirements for both groundwater and deep well water testing. Testing and reporting are both required on an annual basis.
- Testing was completed in October 2016.
- Results will be reported in the 2016 annual report.

Soil Monitoring Program

- Results to be reported in annual report.

ENVIRONMENTAL: MONITORING PROGRAMS RESULTS

Shallow groundwater monitoring program:

Groundwater testing occurred in November 2015 on plant piezometers.

Results of the GWMP were summarized in the 2015 Groundwater Monitoring Program Peace River Complex Project Report (Matrix, 2016) and submitted to AER in March 2016.

Continued groundwater monitoring per EPEA approval.

Shallow groundwater wells around reclaimed PSDS (Produced Solids Disposal Site):

PSDS has been reclaimed and well Pad 32 was built on the location.

Piezometers remain around perimeter of well pad

No impacts observed in these wells with little variation at a majority of the monitoring locations.

Results of the GWMP were summarized in the 2015 Groundwater Monitoring Program Peace River Complex Project Report (Matrix, 2016) and submitted to AER in March 2016.

Recommendations were made by Matrix in the 2016 EPEA GWMP report to discontinue the PSDS monitoring program in 2016. AER was notified of the change.

ENVIRONMENTAL: MONITORING PROGRAMS RESULTS

Deep Regional Wells

2004 drilling program (50 and 105 meter depth)

2005 drilling program (70 meter depth)

2009 drilling program (3 wells (each approximately 60, 120 and 270 meters deep)

Results of the deep regional well GWMP were summarized in the 2015 Groundwater Monitoring Program Peace River Complex Project Report (Matrix, 2016) and submitted to AER in March 2016.

Continued groundwater monitoring per EPEA approval.

ENVIRONMENTAL STUDIES PROGRAM

- Shell continues to monitor the aboveground wildlife crossing structures on above ground pipelines. This data will continue to be assessed and incorporated into the Comprehensive Wildlife Report. The next report is due in 2018.
- Multiple wildlife studies including bird surveys, winter mammal tracking, owl surveys, bat surveys, and amphibian surveys completed in 2015-2016.
  - All wildlife data for these surveys is uploaded into the Fish & Wildlife Management Information System (FWMIS) and incorporated into the Comprehensive Wildlife Reports
- Partnered with the Miistakis Institute in their Wildwatch Program. Training on the program is being implemented for key site personnel prior to being rolled out across the wider asset area.
- Wetland Monitoring Program implementation has begun in Q3 2016.
- eDNA partnered with the Alberta Conservation Association (ACA) on a 3-year amphibian study beginning in 2014 and concluding in 2016.
- Ongoing peatland reclamation research with NAIT Boreal Research Institute.

ENVIRONMENTAL STUDIES PROGRAM

EPEA Requirement	Report Name	Due Date	Status
CCP - Schedule VI (1)	Groundwater Monitoring Program (GWMP)	March 31, 2014	Submitted to Alberta Energy regulator (AER) on March 31, 2014; received written authorization from the Director on March 5, 2015.
CCP - Schedule VIII (4) & (9)	Wildlife Monitoring and Mitigation Program (WMMP) Proposal	March 31, 2014	Submitted to ESRD on March 19, 2014 and resubmitted to AER on May 26, 2015. SIRs received from AER in May 2015. Shell is working on addressing the SIRs for re-submission to the AER by December 31, 2016.
CCP - Schedule XI (1)	Wetland Monitoring Program (WMP) Proposal	December 31, 2014	Submitted to AER on December 24, 2014 - Awaiting AER written authorization as per Schedule XI, Clause 4. Shell has begun implementing portions of the program in Q3 2016.
CCP - Schedule IX (39)	Wetland Reclamation Trial Program Proposal	December 31, 2016	In preparation
CCP - Schedule IX (44)	Reclamation Monitoring Program (RMP) Proposal	December 31, 2016	In preparation
CCP - Schedule XI (26)	Project-Level, Conservation, Reclamation and Closure Plan (PLCRCP)	October 31, 2017	In February 2016, the AER has issued new guidelines to the preparation of the PLCRCP. The due date for this document has now been set by the AER to October 31, 2017 [E-File No. 4101-00001642-07].

Environmental research lead by NAIT

- Peatland Restoration
  - Funding from Shell is supporting peatland research around the Shell Peace River area (IPAD, pad removal and restoration study, wetland reclamation project at Airstrip and a third project in around the Carmon Creek area that is looking at impacts of linear disturbances on wetland function (carbon, plants etc.)
- Forest Reclamation
  - Shell Airstrip Research: field deployment and monitoring of mixed species container stock (hitchhiker planting), utilization of organic amendments on reclaimed sites, riparian area species selection and timing of plant deployment and integrated approaches (site preparation and native cover crops) to manage undesirable plants on reclaimed sites.

RECLAMATION PROGRAMS - DAR

- Various sites assessed for reclamation certificates – consultants currently working on the reports. Obtained **(16)** Reclamation Certificates in 2016.
- Completed **(12)** subsurface abandonment and finished **(10)** cut and cap work in Peace River and Cliffdale area.
- 14-36-084-17 W5M – Completed fixing the chip road and the reclamation work on the lease.
- Completed weed control and tree planting in various sites particular on 08-22-085-18 W5M and 13-29-084-17 W5M where we completed the pad removal in 2015. Completed tree fill planting the Peace River Air Strip due to dry season last year.
- Completed Phase II drilling at several remote sump sites: 9-23-085-19 W5M, 04-02-085-17 W5M, 08-23-084-17 W5M, 23/24-85-19 W5M.
- Completed Environmental Liability Assessments for both Peace River Complex and Cliffdale Battery.