SEAL POLYMER PROJECT
SCHEME APPROVAL No. 11320C

Annual Performance Presentation

June 20, 2016 – July 18, 2016 Update

MURPHY
OIL CORPORATION

Agenda

- **Subsurface**
- **Surface**

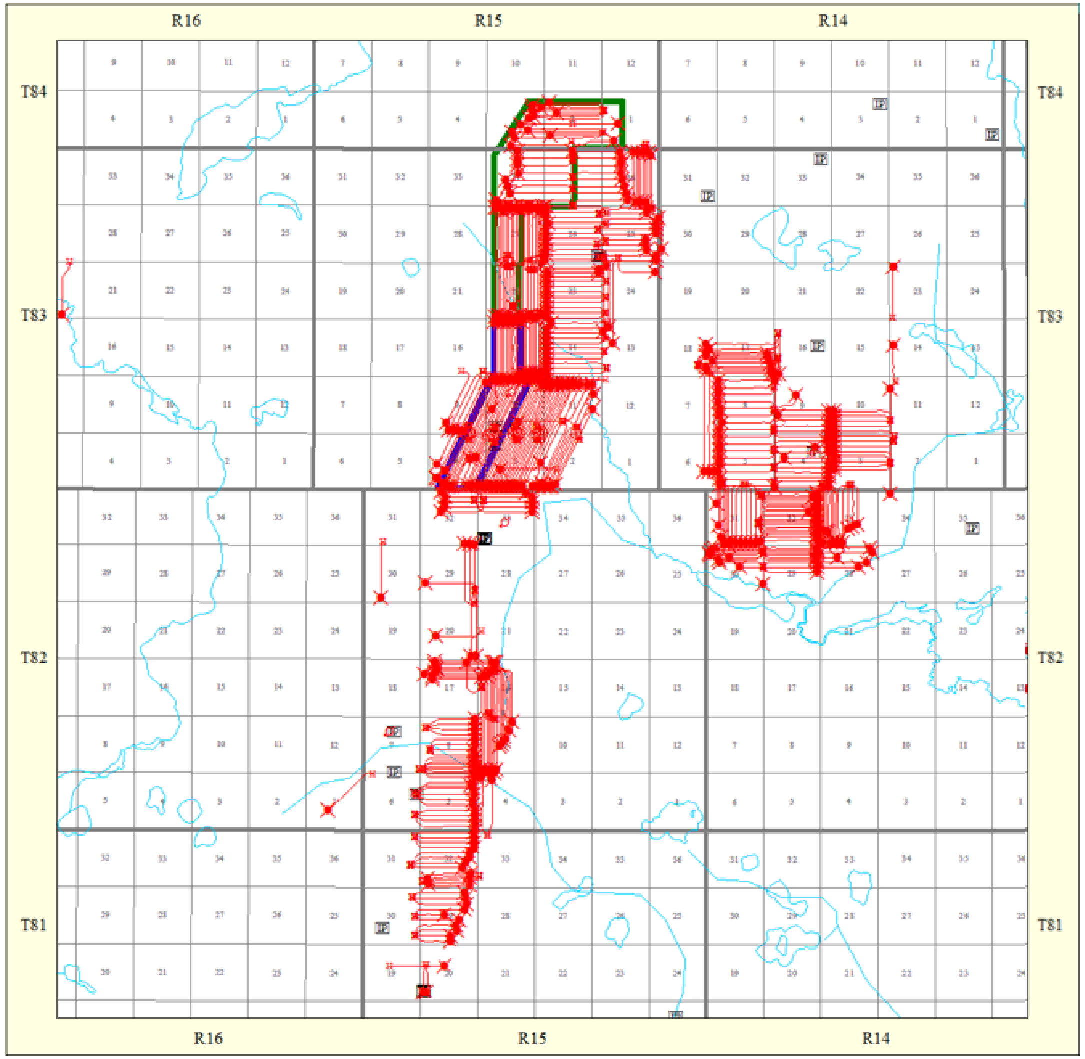
Subsurface

- Background
- Geology
- Drilling & Completions
- Flood Performance
- Injection Pressures
- Future Plans

Subsurface

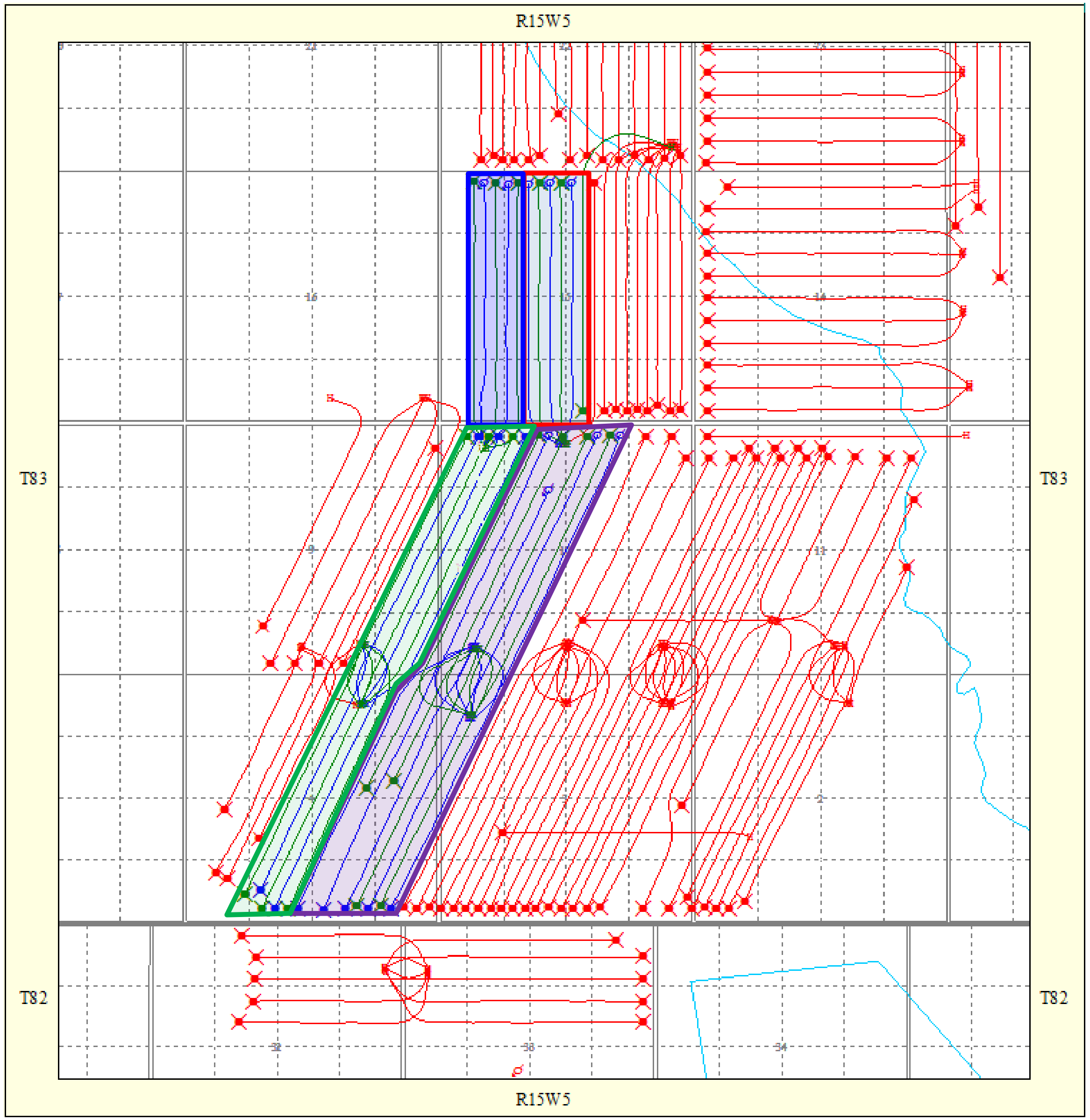
- **Background**
- Geology
- Drilling & Completions
- Flood Performance
- Injection Pressures
- Future Plans

Background – Map of Seal Central



- Polymer injection located in Central Seal
- Range 15 – Townships 83 & 84
- Terminology
  - Area 1 – Approval 11320B (Blue)
  - Area 2 – Approval 11320C (Green) Currently on hold

Background – Map of Seal Central Area 1



Area 1 consists of Pilot + 3 Phases of expansion

- Pilot operational Oct, 2010
- Phase 1 operational Sept, 2012
- Phase 2 operational Dec, 2012
- Phase 3 cancelled

Subsurface

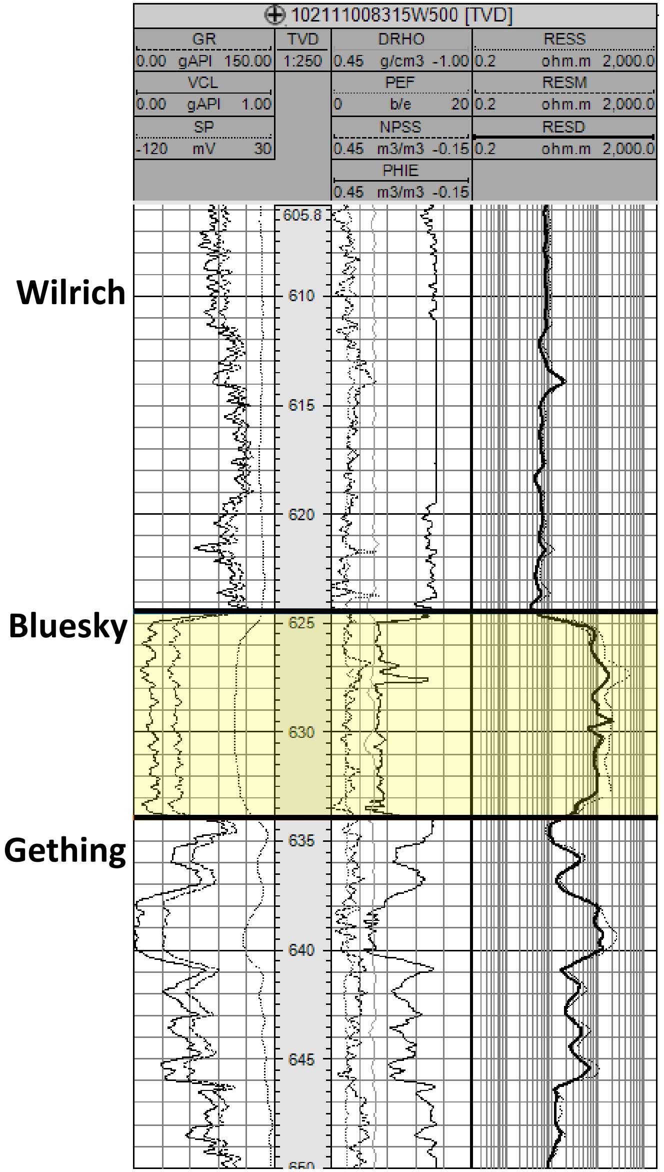
- Background
- **Geology**
- Drilling & Completions
- Flood Performance
- Injection Pressures
- Future Plans

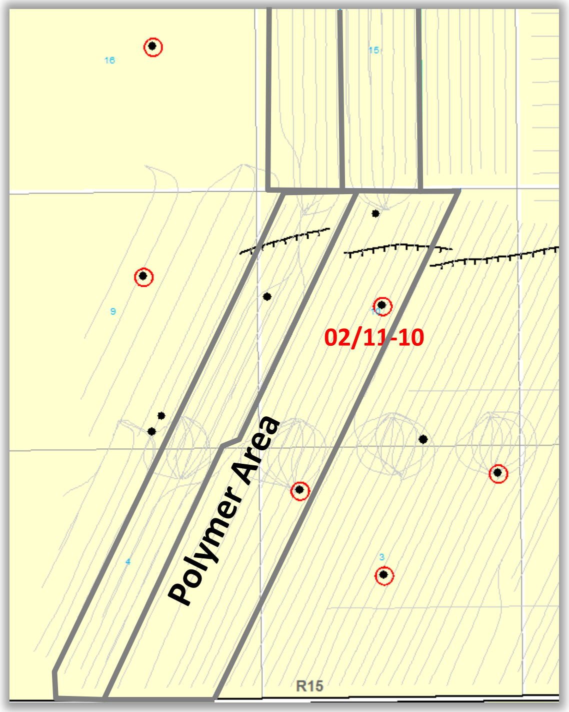
Geology – type log and reservoir properties

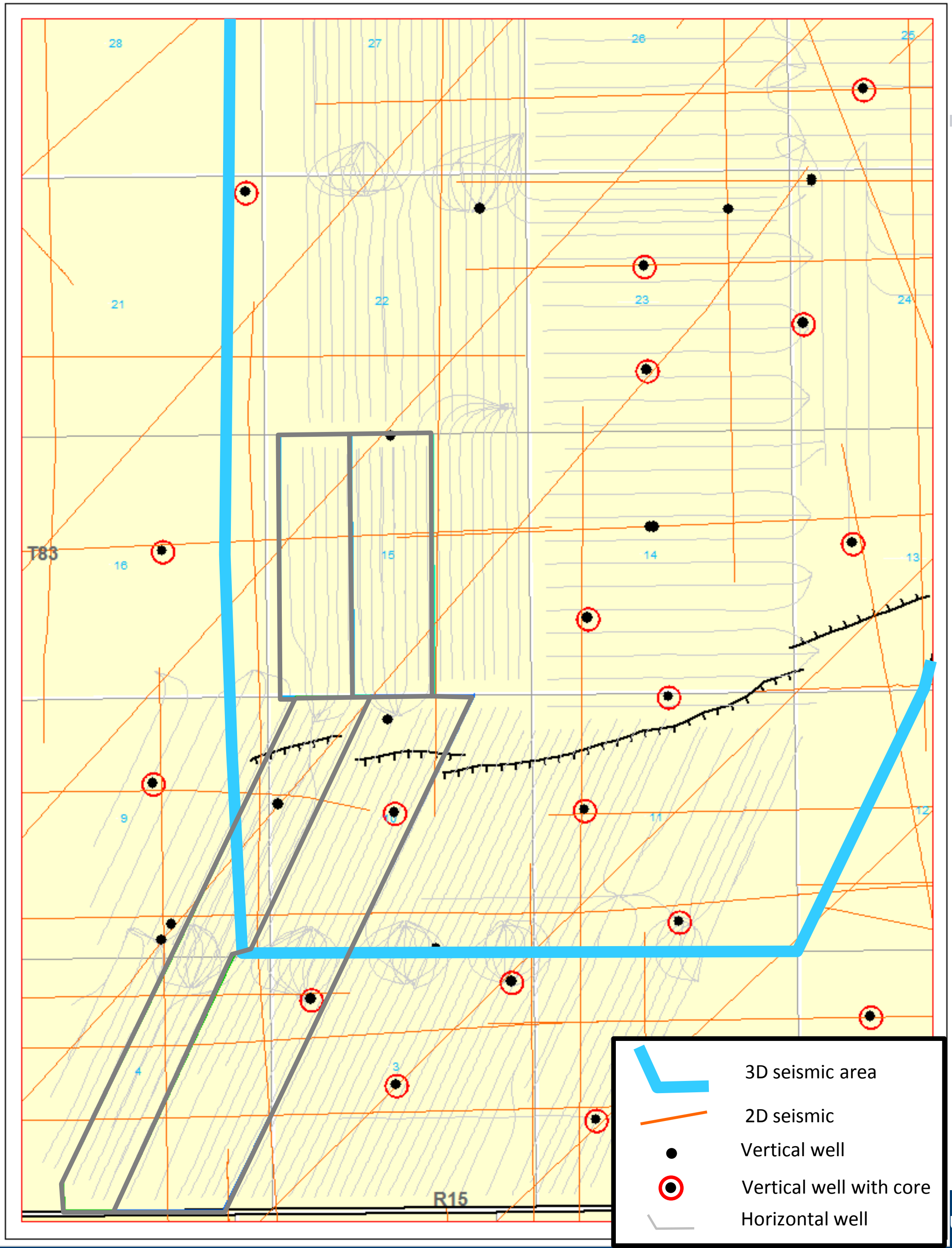
Bluesky reservoir properties in Polymer Area

- Quartz-rich litharenite
  - Qtz+chert comprises ~ 30-50% of rock
  - Clay content < 5%
  - Upper fine – lower medium grained
  - Moderate sorting

Depth:	625m TVD
Net Pay:	2 – 8 m
Total Porosity:	22 - 30%
Permeability:	500 – 2,000 mD
Res. Temp.:	19 °C
Water Sat.:	< 25%
Oil Viscosity:	15,000-30,000 cSt
	Avg ~25,000 cSt
Initial Res. P.:	4,500 – 5,000 kPa







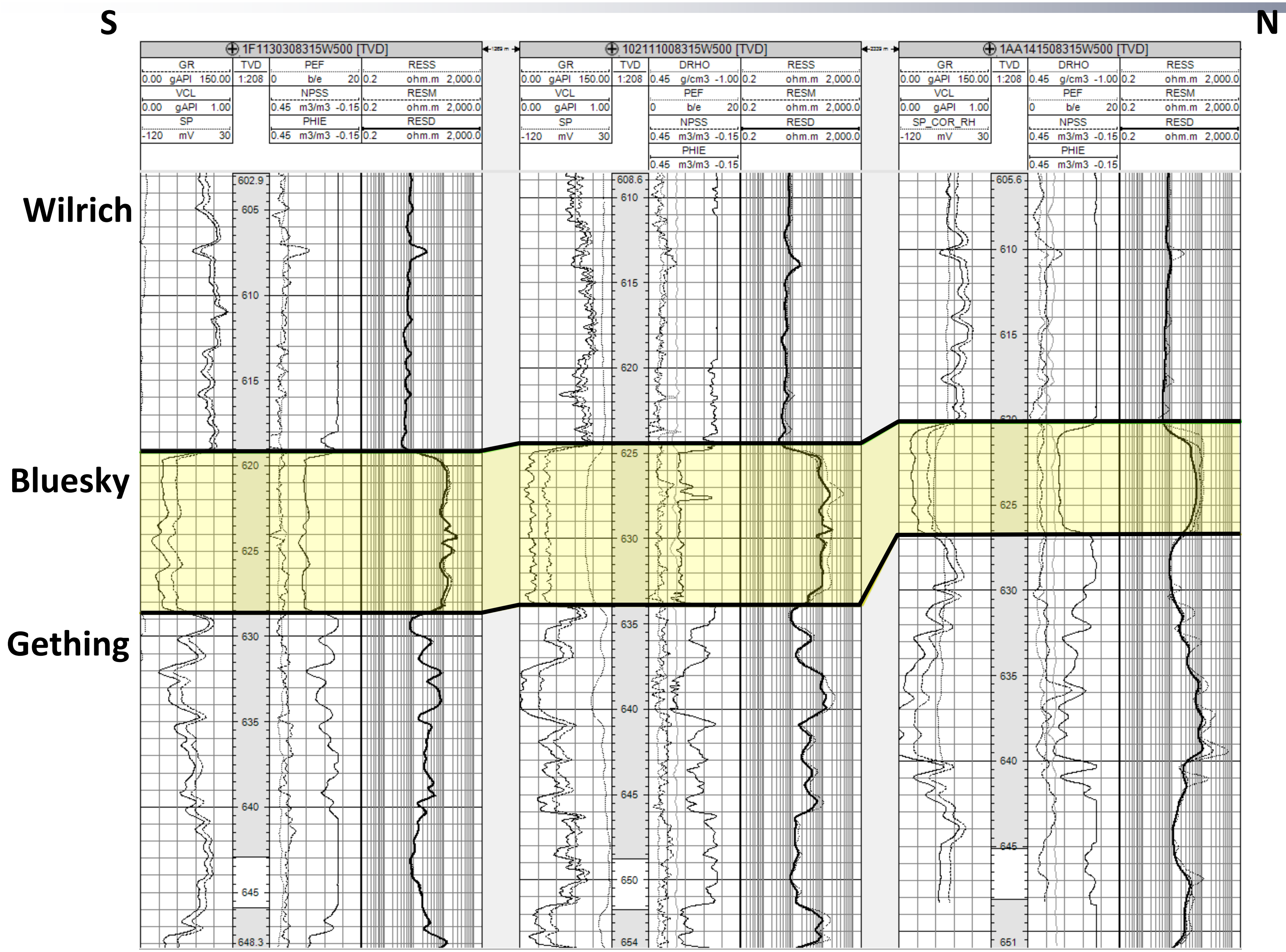
Location of 2D and 3D seismic in Seal Central area

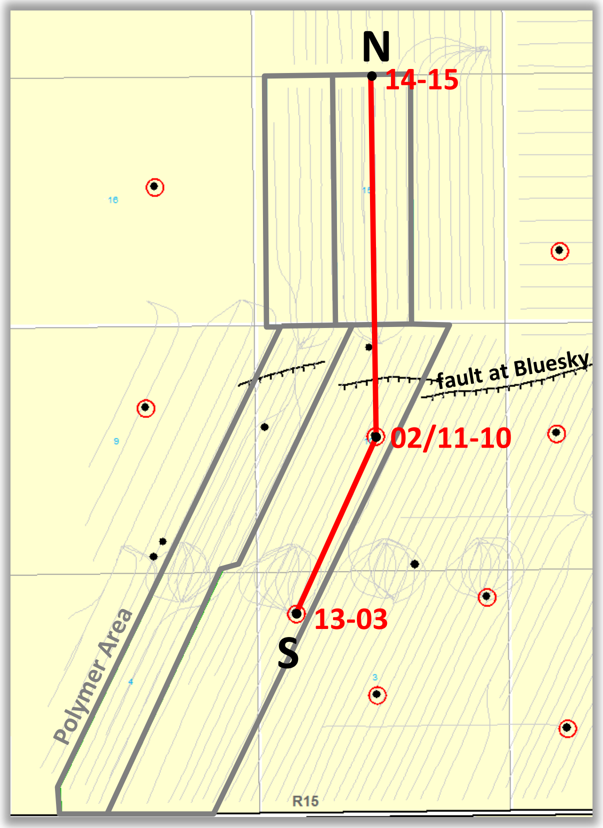
- **2D seismic:**
  - range of vintages - 1979 – 1997
  - Quality of 2D highly variable
  - Limited ability to phase and time tie 2D grid

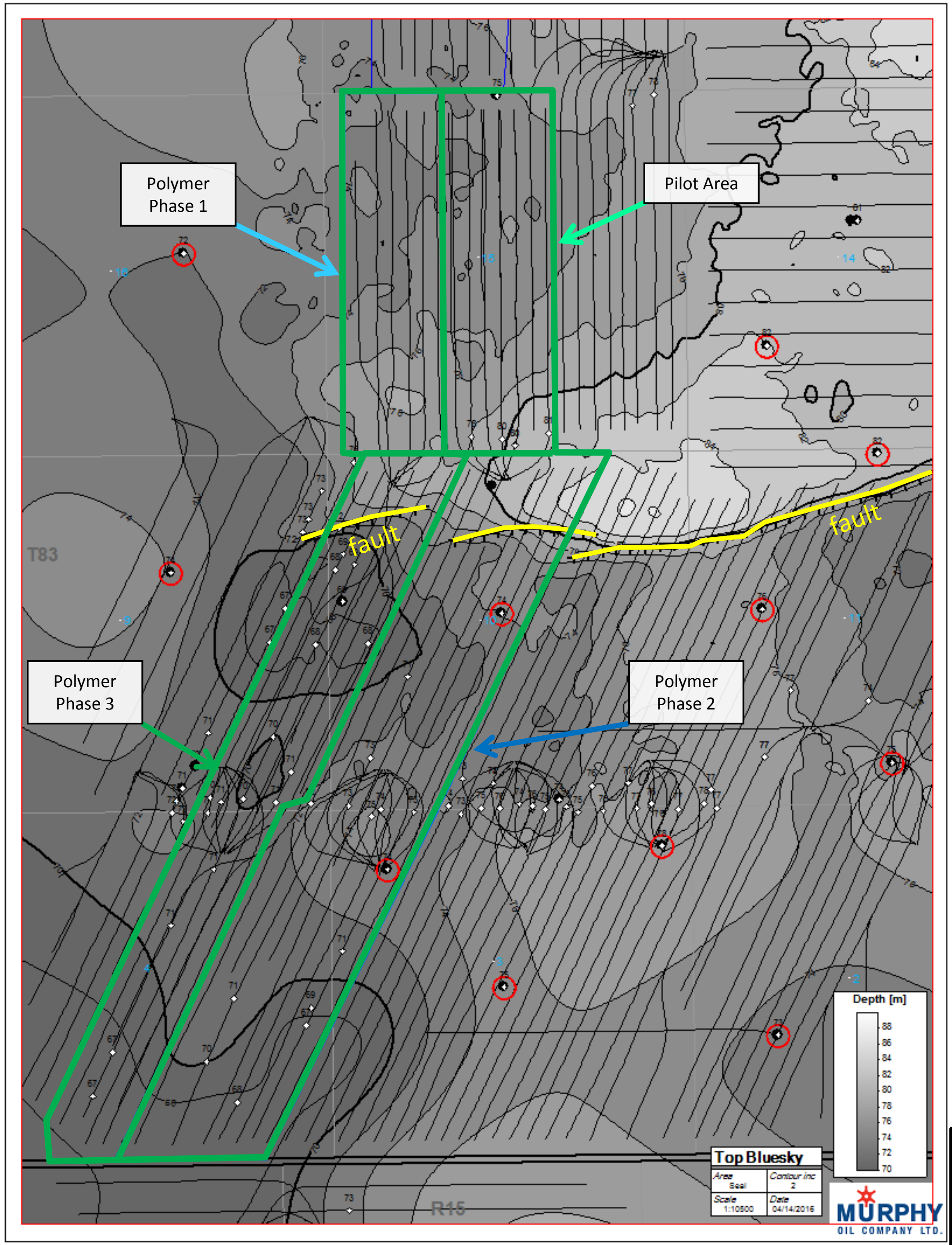
- **3D seismic:**
  - shot December 2014 – March 2015
  - Average fold at Bluesky reservoir depth = 26
  - 132m shot and 99m receiver spacing with 16.5m x 16.5m bin size

- 3D seismic shot for Central thermal development to east of Polymer Area
- Interpretation of 3D allows for more detailed interpretation of fault zone

Geology – Structural Cross Section: South to North



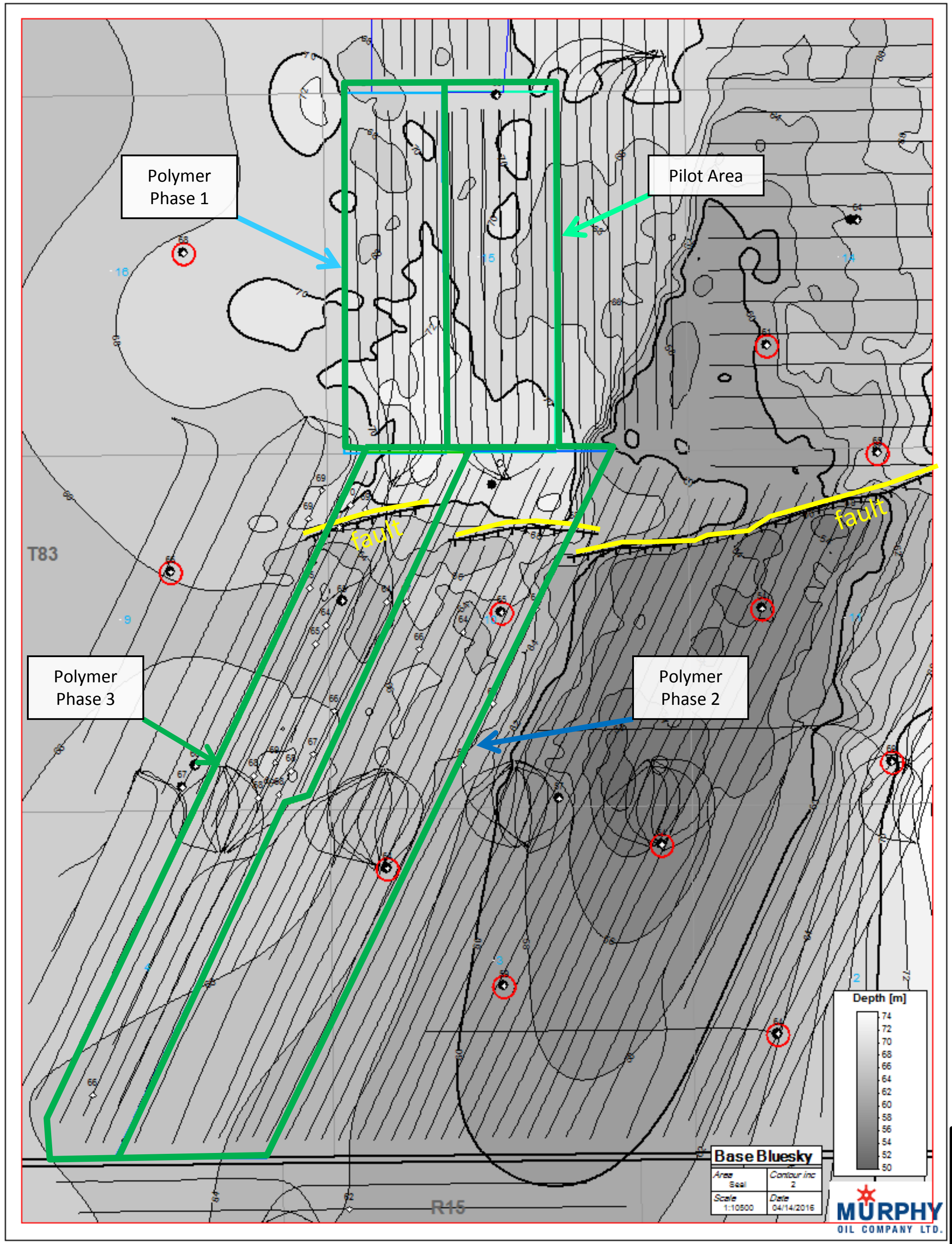




Structure: Top Bitumen Pay (Top Bluesky)

- Regional structural dip of 0.1°
- Flexure across fault zone is 5-9 m over 100-400 m (~2.5° - 4.5°)
- Normal displacement, footwall down to the south
- Horizontal wells demonstrate reservoir sand continuity across fault

●	Vertical well
◉	Vertical well with core
	Horizontal well



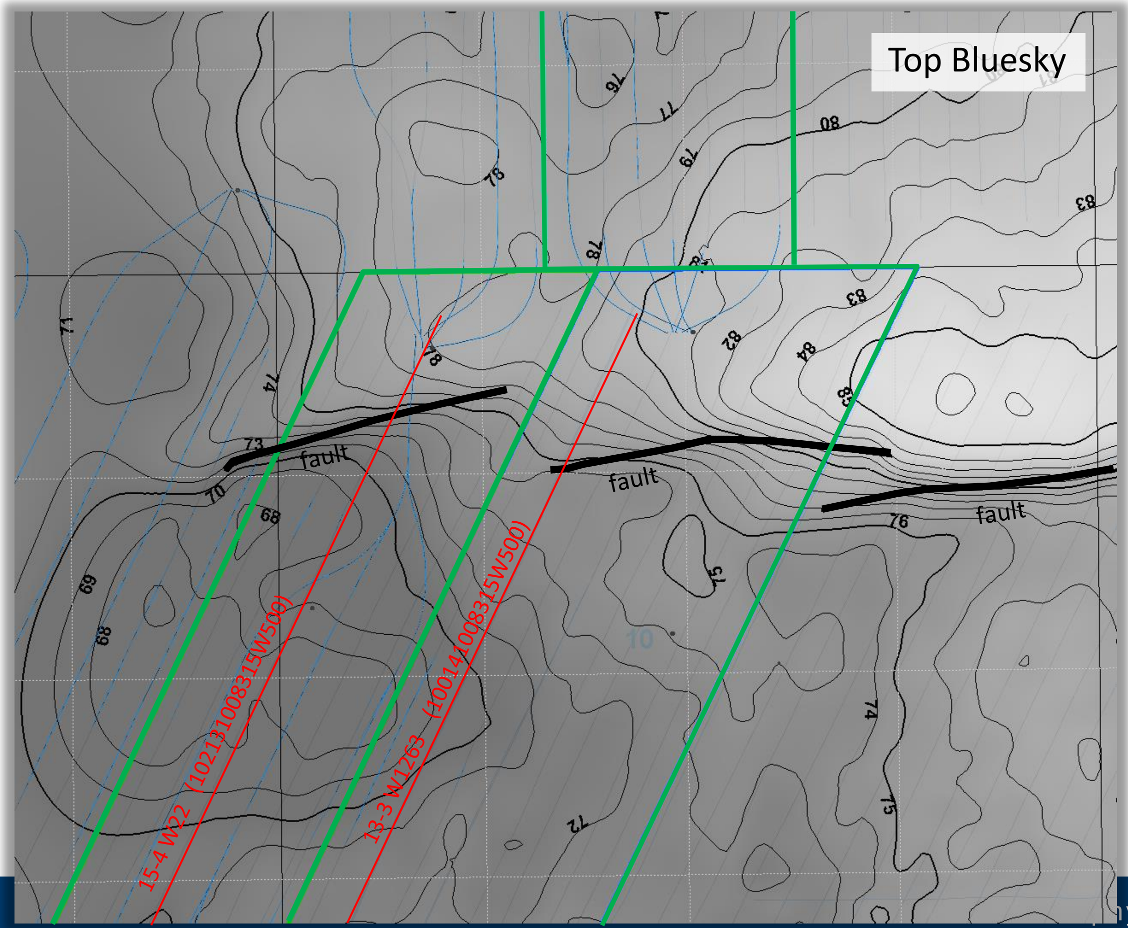
Structure: Base Bitumen Pay (Base Bluesky, Top Gething)

- Base Bluesky Bitumen pay is equivalent to top Gething
- Gething comprises a mixture of non-reservoir continental to estuarine deposits
- Average structural dip of 0.1°
- Flexure across fault zone is 5-9 m
- Channel-cut morphology immediately east of Polymer Area

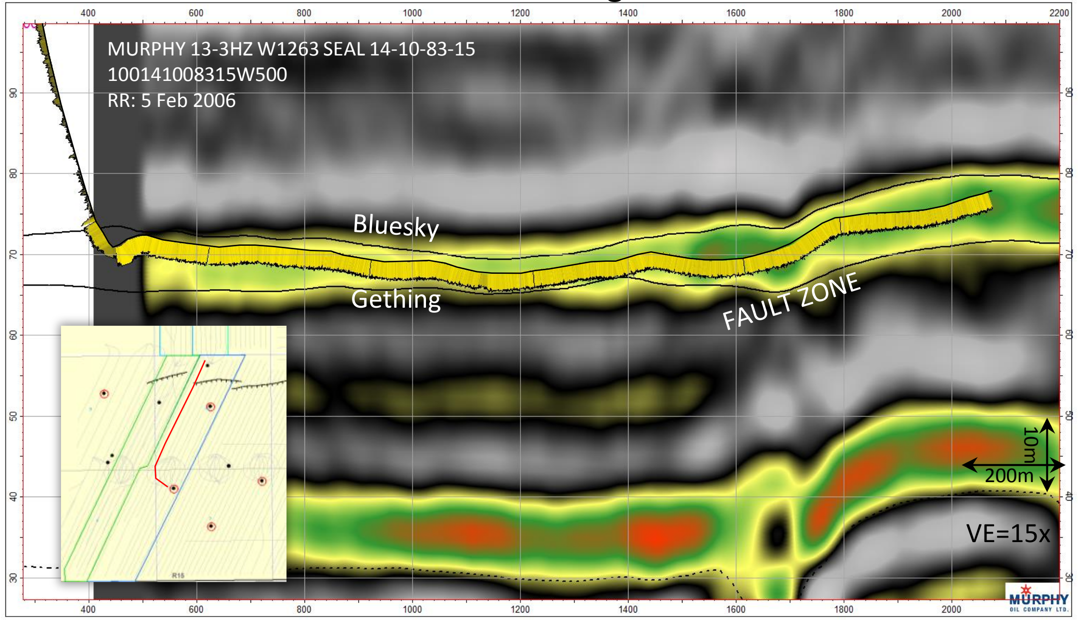
Vertical well
Vertical well with core
Horizontal well

Fault and horizontal wells

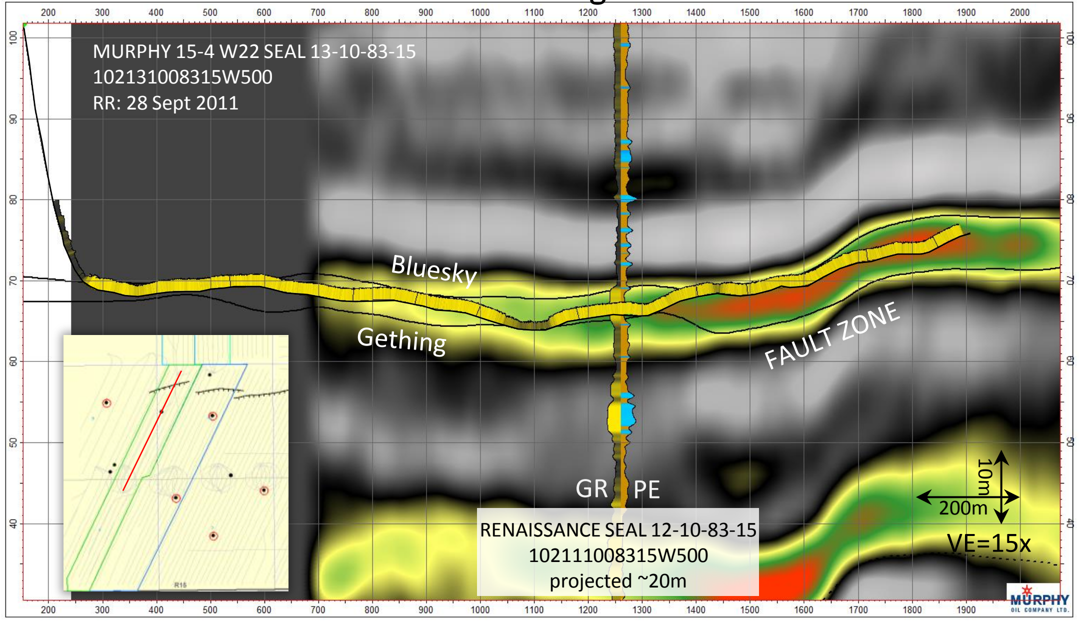
- 3D seismic clarifies interpretation of the fault zone
- Reservoir flexure across fault zone is 5-9 m
- Fault zones show en-echelon pattern
- Fault is a zone of flexure at Bluesky level across ~400 m
- Horizontal wells crossing fault zone demonstrate continuity of sand
- Bluesky reservoir shows consistent isopach across fault zone

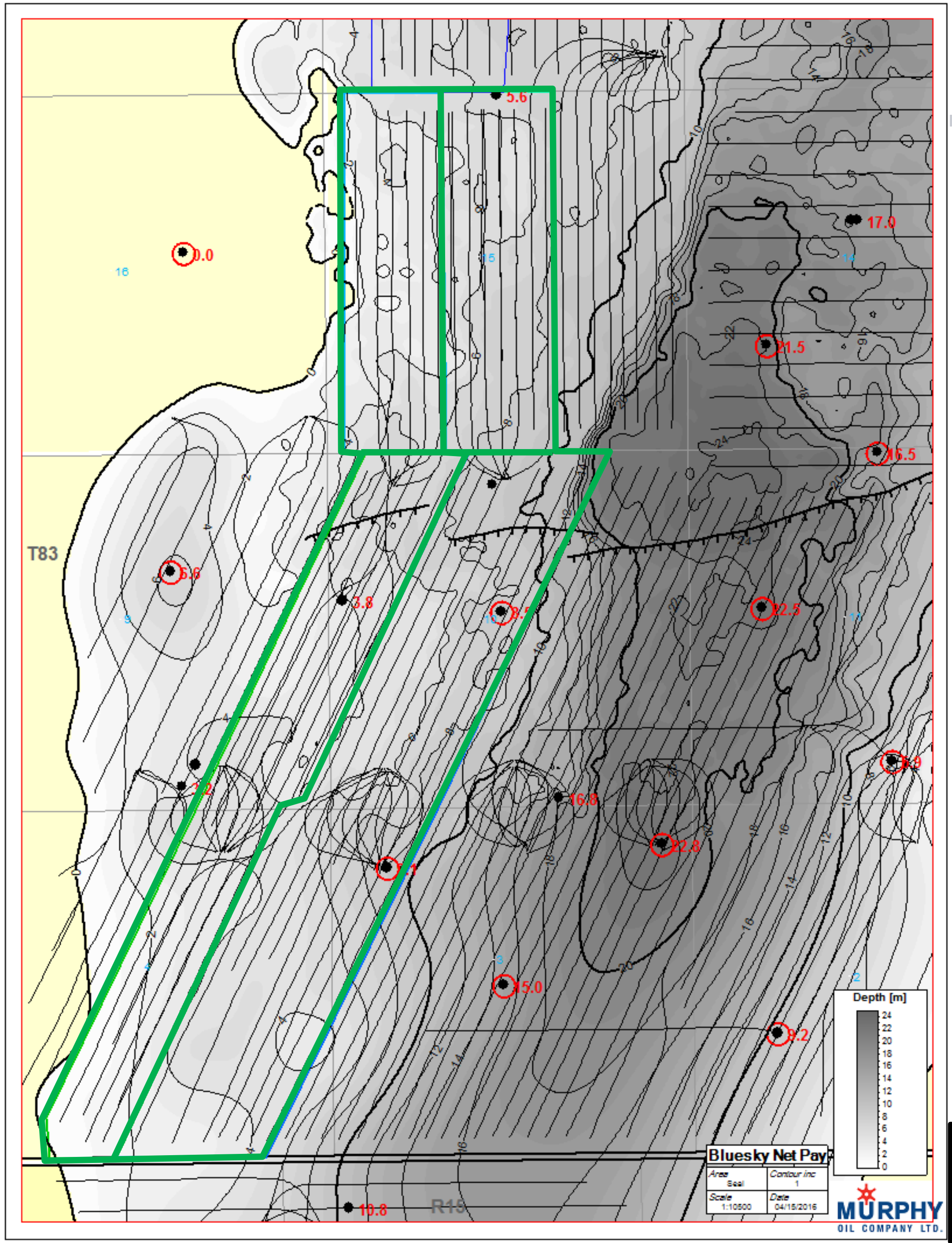


S 13-3 W1263: section along horizontal well N



S 15-4 W22: section along horizontal well N





Net Bitumen Pay (Bluesky)

- **Net Bitumen Pay calculated from:**
  - VCL <40 (~75-80 API GR)
  - PHI_e >17%
  - Sw_e <30%
- Pay ranges from 2 m to 10 m in Polymer Area
- Depth converted seismic and MWD Gamma from horizontal wells incorporated into net pay mapping
- OOIP – 5,161,000 m^3 (32,500,000 bbl)

Vertical well
Vertical well with core
Horizontal well

Subsurface

- Background
- Geology
- **Drilling & Completions**
- Flood Performance
- Injection Pressures
- Future Plans

Drilling & Completions

Pilot + Expansion Locations:

- Lowest viscosity compared to other locations
- <10 m net pay
- Murphy 100% working interest
- Flowline production

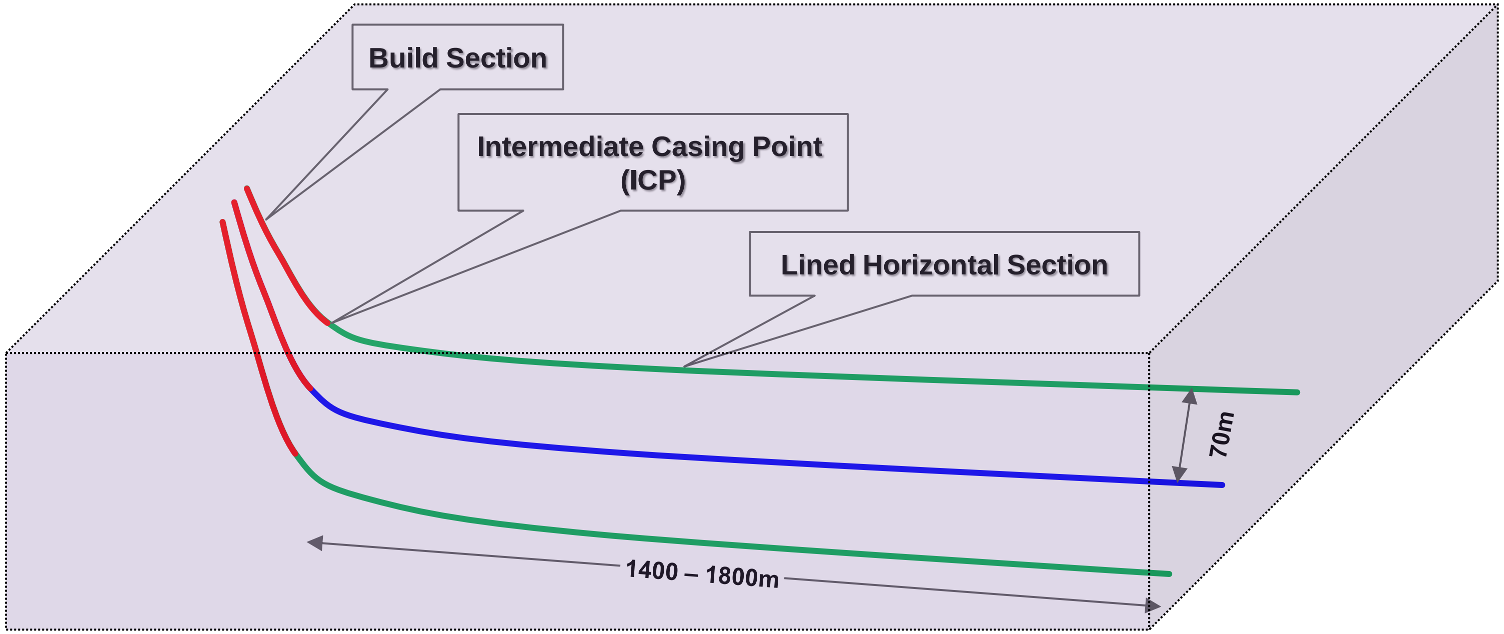
Well Placement Criteria:

- Well placement within the top 5 meters of the Bluesky due to low viscosity and high permeability in uppermost Bluesky

Oil Viscosity in Targeted Zone:

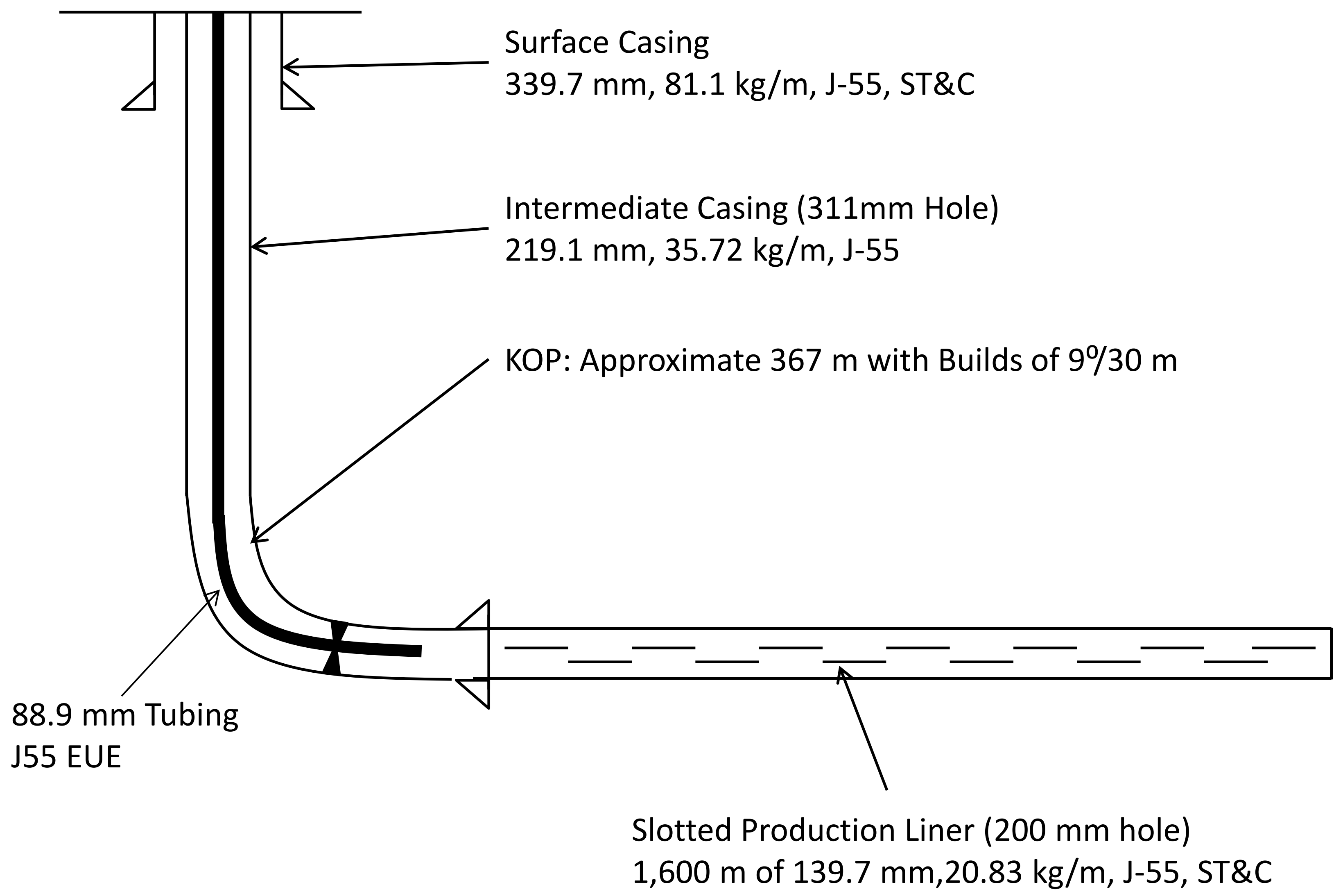
- Phase 1: 14,500-15,500 cPs. Average: 15,000 cPs
- Phase 2: 15,000-40,000 cPs. Average: 25,000 cPs.

D&C - Typical Drilling Configuration



- Original well spacing was 140 meters with infills drilled at 70 meters
- Injector and producing wells are at 70 meter spacing

D&C - Typical Completion Details

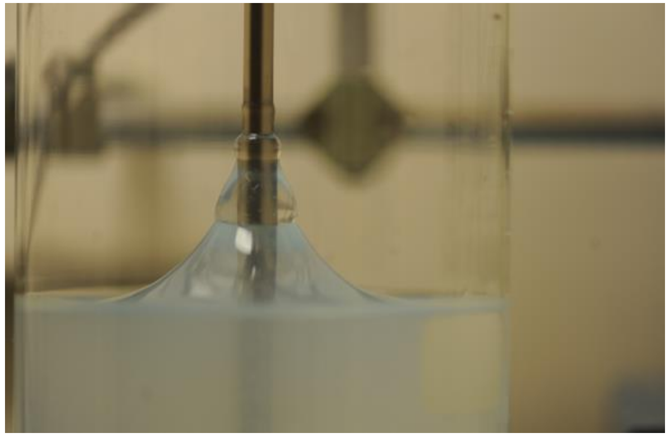


Subsurface

- Background
- Geology
- Drilling & Completions
- **Flood Performance**
- Injection Pressures
- Future Plans

Performance – Polymer Flood

- First Polymer Injection in October 2010
- Hydrating polymer concentrations: 1,000-1,500 ppm = 40-60 cp
- Polymer trace in produced water: >900 ppm within pilot
- Live oil mobility ratio: 34-53
  - The polymer viscosity is the only variable available in achieving a target mobility ratio due to the uncertainty surrounding permeability and in-situ oil viscosity

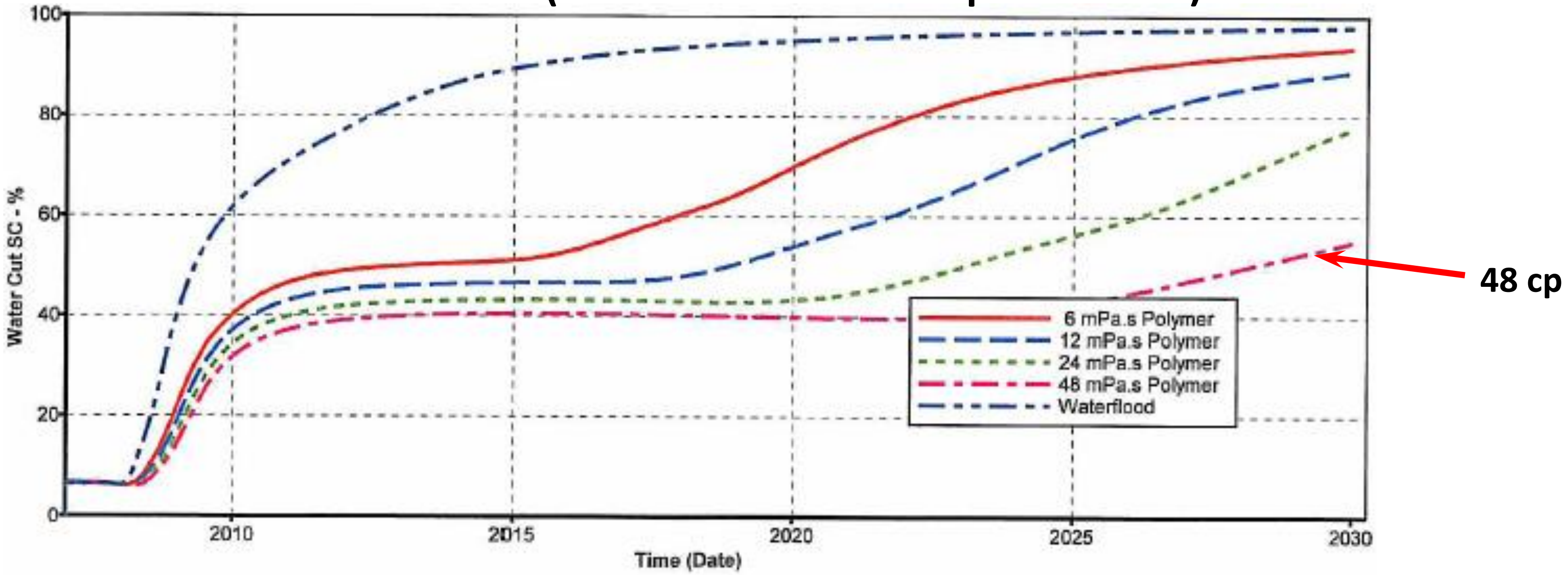


Polymer Injection – Why 48 cp?

Oil Recovery (Simulation Results – Sproule 2006)

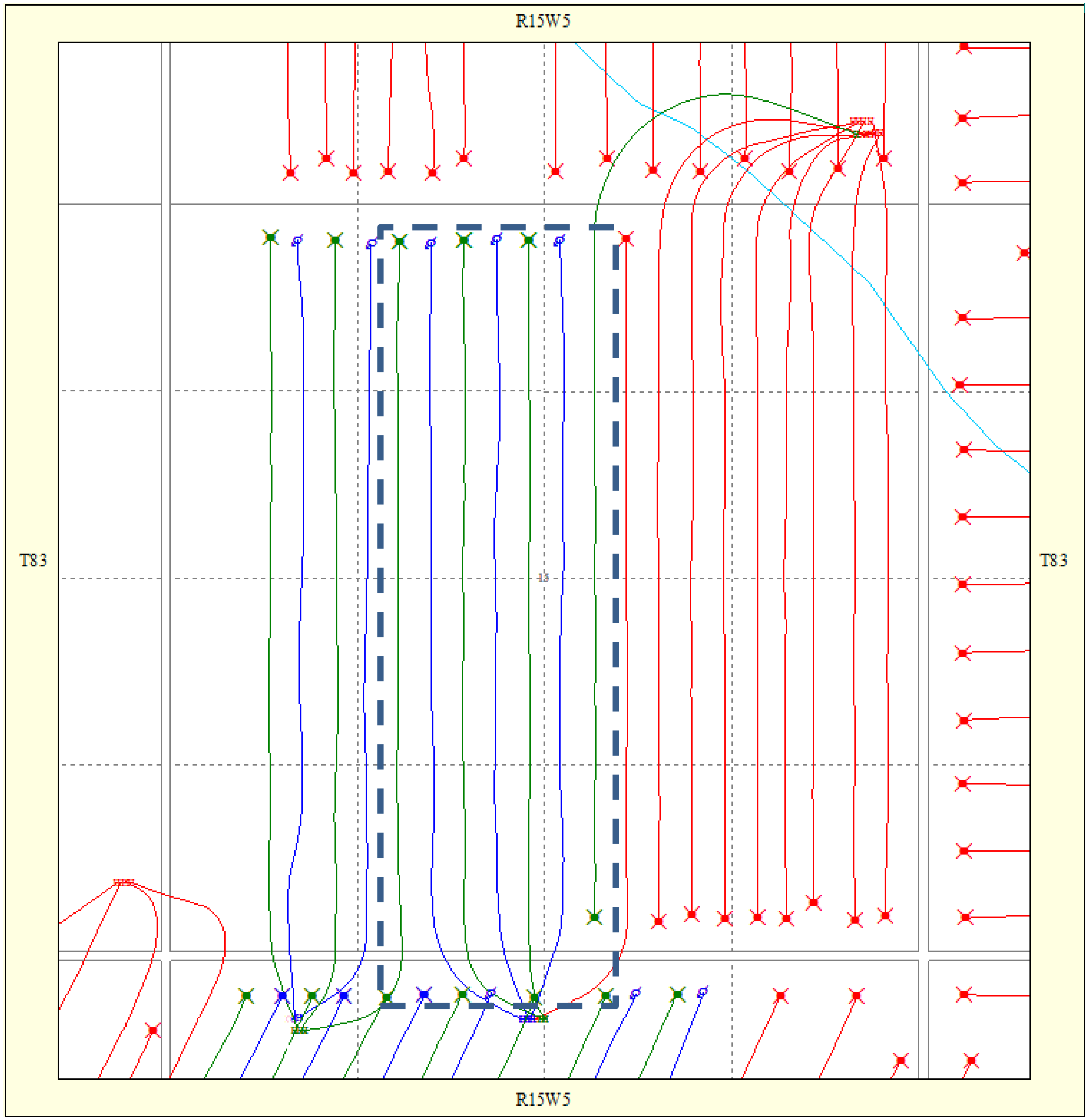
CASE	6000 mPa.s Oil			24000 mPa.s Oil		
	OIL (10^3 m^3)	INJECTION (10^3 m^3)	RECOVERY %OOIP	OIL (10^3 m^3)	INJECTION (10^3 m^3)	RECOVERY %OOIP
Primary Production	139	0	14.1	68	0	6.9
Waterflood	258	3211	26.1	128	1208	13.0
Polymer flood; 6 cp	321	1247	32.4	126	271	12.7
Polymer flood; 12 cp	326	848	33.0	120	223	12.1
Polymer flood; 24 cp	330	633	33.3	115	196	11.6
Polymer flood; 48 cp	319	515	32.3	111	177	11.2
CO2 WAG Flood	277	3192	27.9	138	1116	13.9
Cyclic Steam Stimulatio	217	531	21.9	155	525	15.7
SAGD, 2 well pairs	338	3142	33.8	212	2411	21.2

Water Cut vs Time (Simulation Results – Sproule 2006)



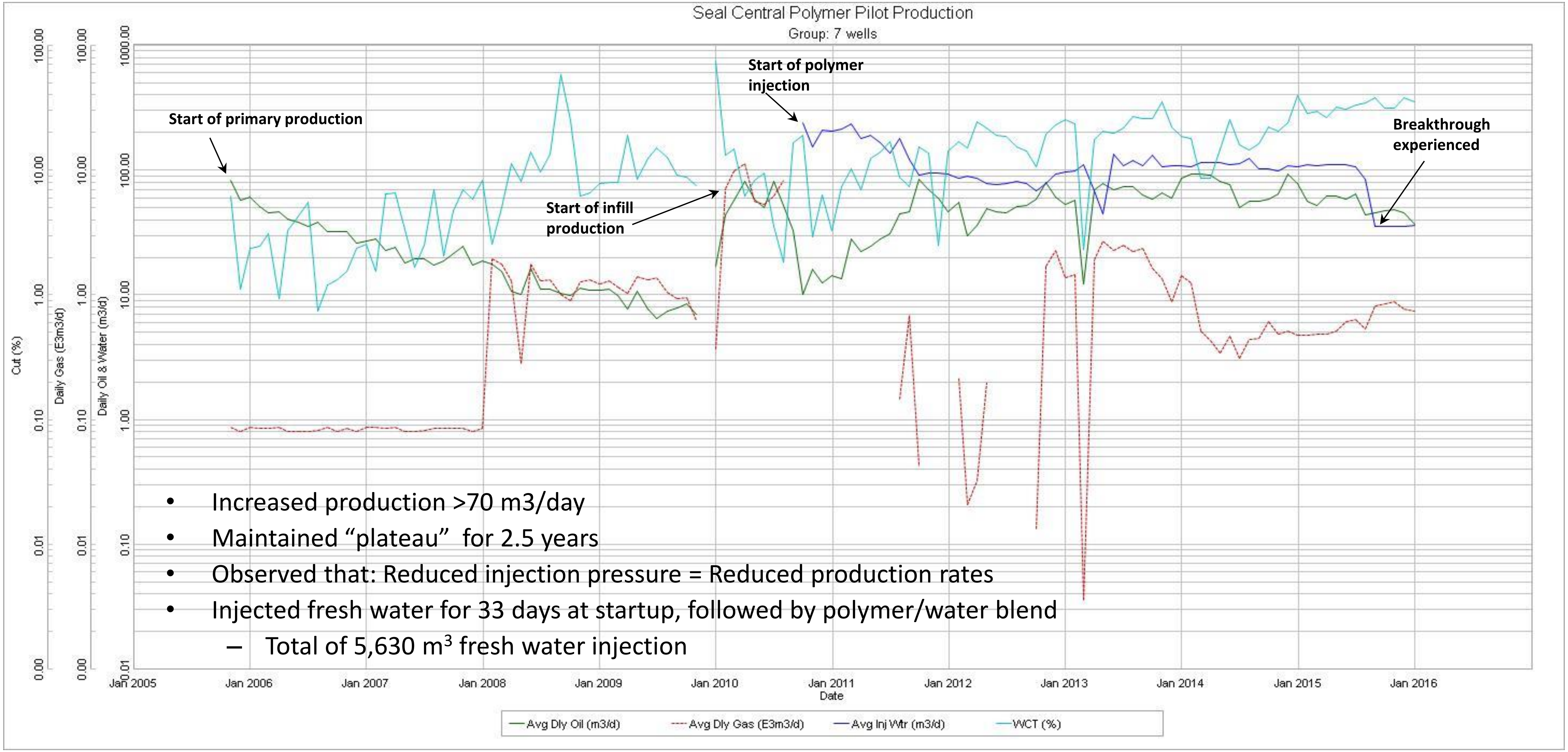
- Simulation results of oil recovery at 48 cp viscosity injected fluid are comparable to lower viscosity injected fluids (table at top left), however the biggest economic impact is associated with the reduced water handling costs, and more importantly the reduced costs associated with polymer injection (plot at bottom left)

SEAL Polymer Pilot



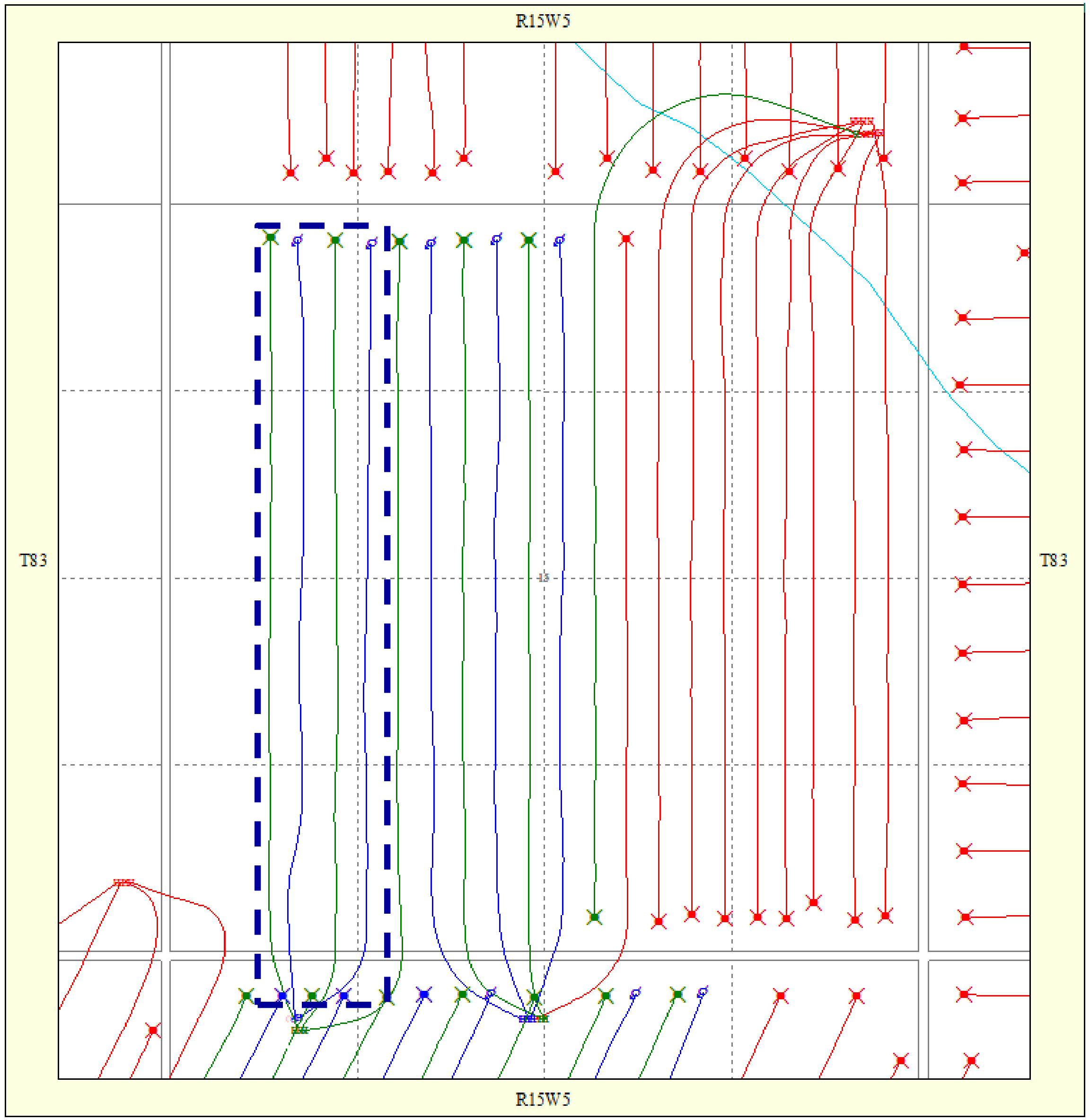
- Pilot consists of 3 injectors and 4 producers.
- Approval No. 11320B to downspace on the East side of the pilot.
- 70 meter spacing
- Injection started Q4 2010, production response has been observed since Q3 2011
- Current RF: 10.8%
  - 3.4% Primary
  - 7.4% Secondary
- Ultimate RF: 15.8%
  - 3.4% Primary
  - 12.4% Secondary

Performance – Pilot Prod./Inj. Profile



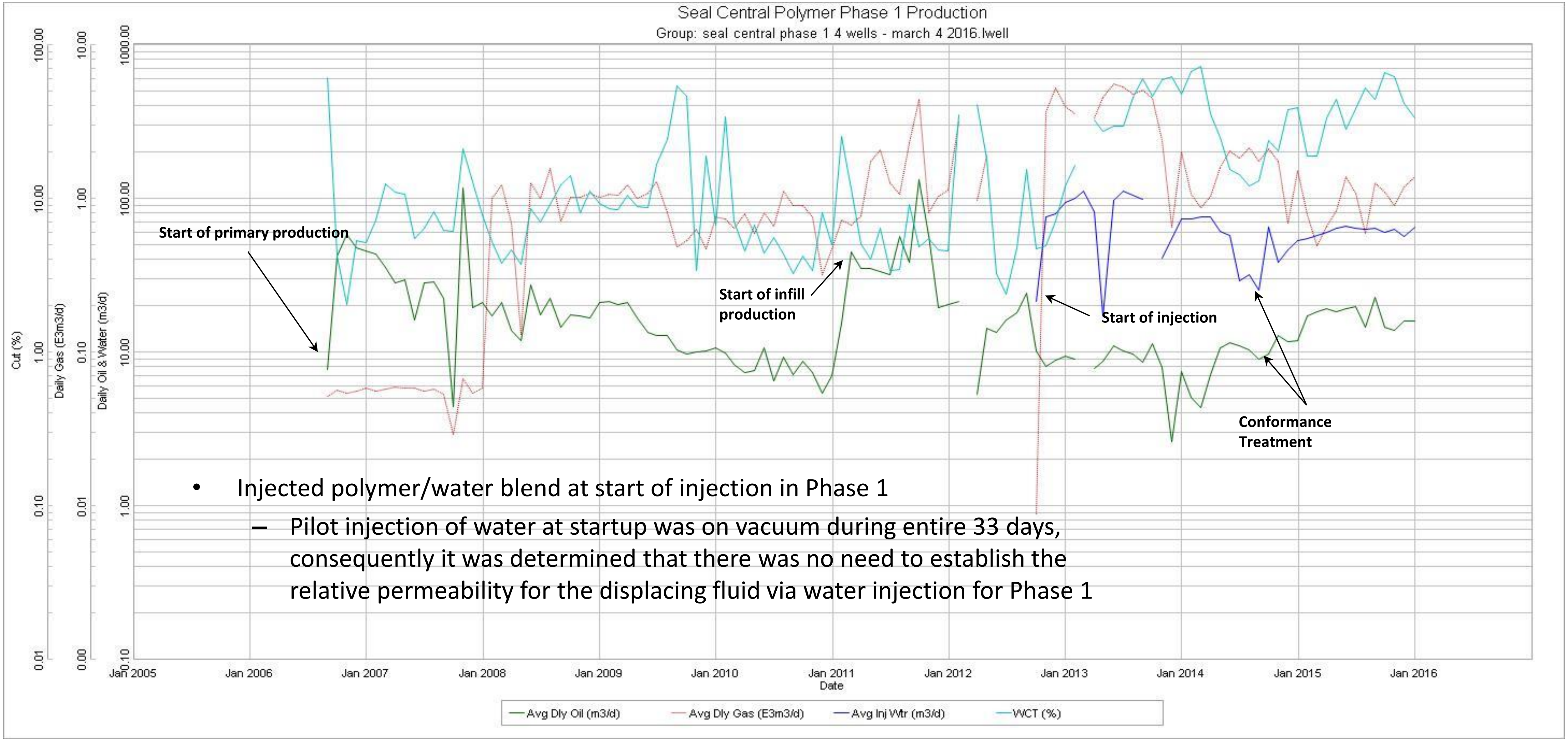
- Increased production >70 m3/day
- Maintained "plateau" for 2.5 years
- Observed that: Reduced injection pressure = Reduced production rates
- Injected fresh water for 33 days at startup, followed by polymer/water blend
  - Total of 5,630 m^3 fresh water injection

SEAL Polymer Phase 1



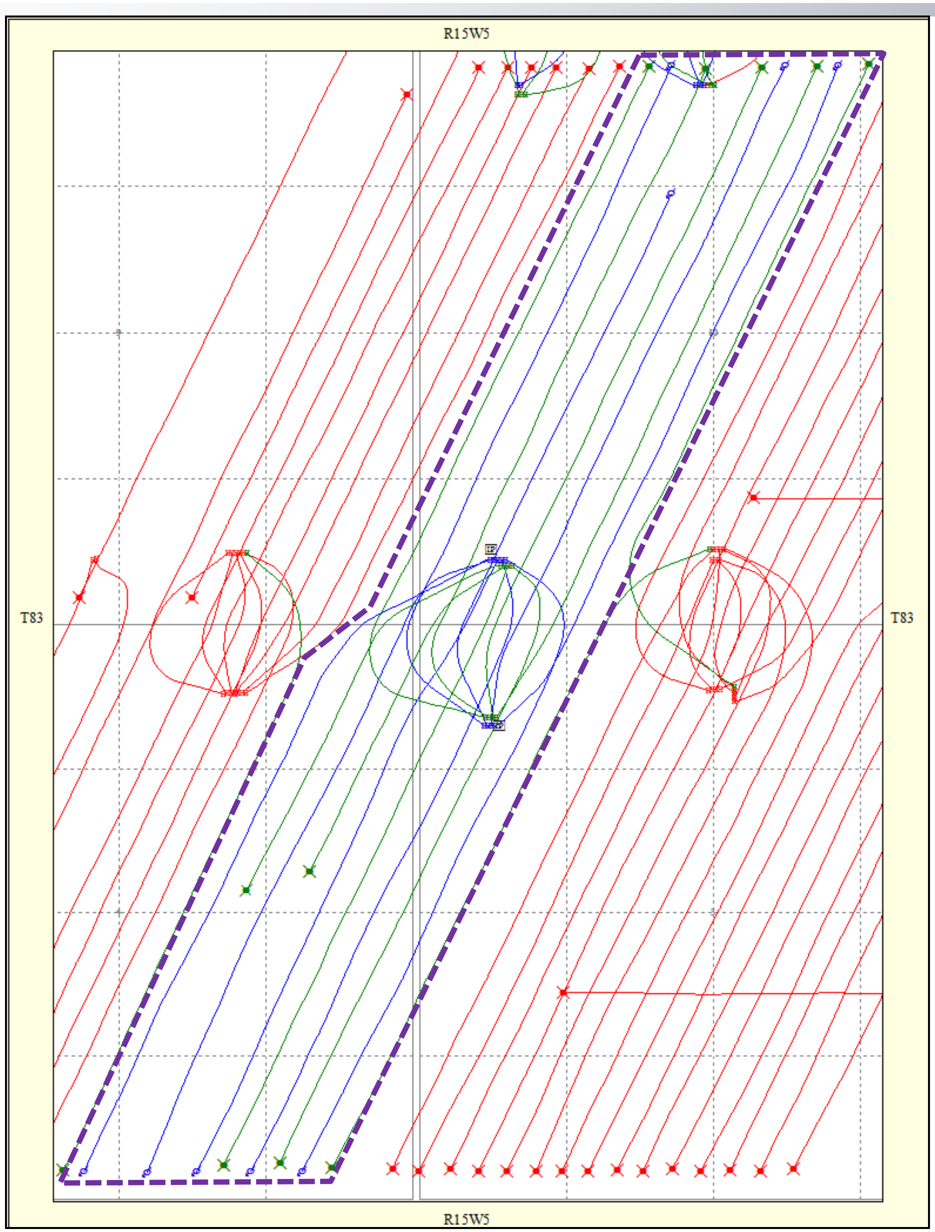
- Phase 1 consists of 2 injectors and 2 producers.
- 70 meter spacing
- Injection started Q3 2012, response observed in Q4 2014, after conformance treatment
- Current RF: 8.9%
  - 6.8% Primary
  - 2.1% Secondary
- Ultimate RF: 14.9%
  - 6.8% Primary
  - 8.1% Secondary

Performance – Phase 1 Prod./Inj. Profile



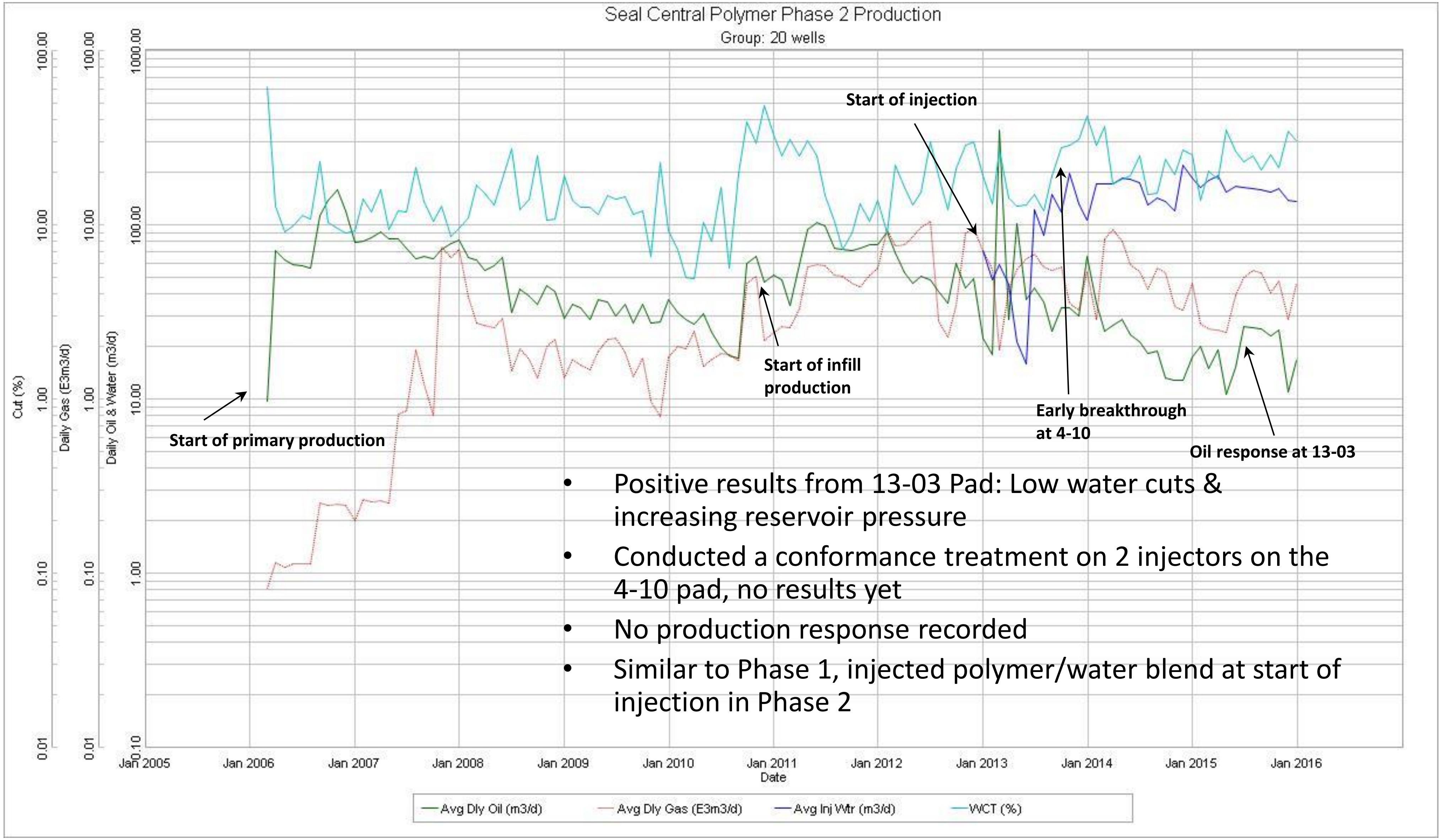
- Injected polymer/water blend at start of injection in Phase 1
  - Pilot injection of water at startup was on vacuum during entire 33 days, consequently it was determined that there was no need to establish the relative permeability for the displacing fluid via water injection for Phase 1

SEAL Polymer Phase 2



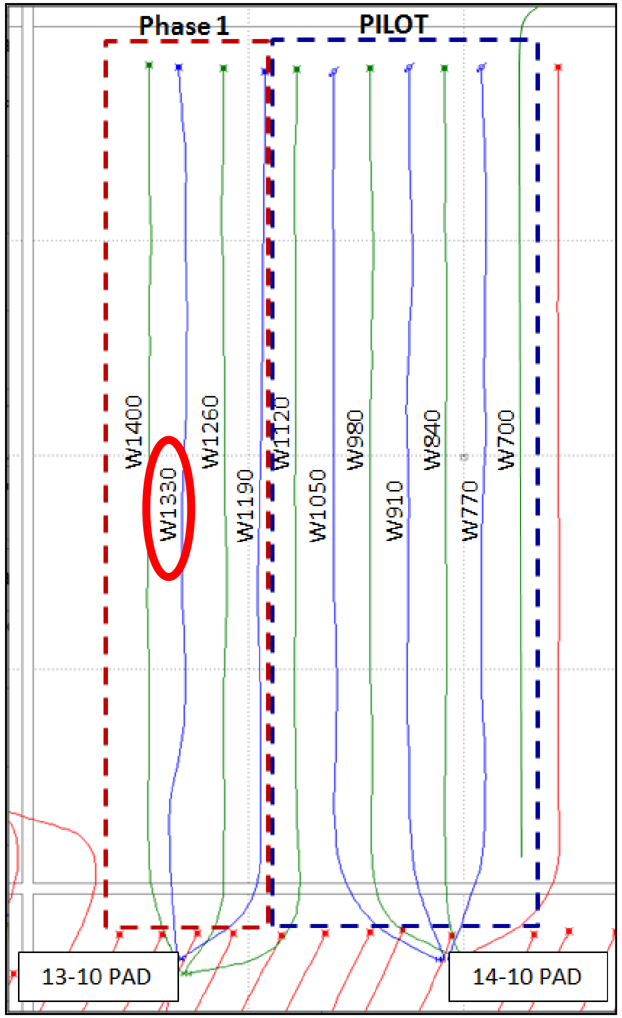
- Phase 2 consists of 9 injectors and 11 producers.
- 70 meter spacing
- Injection started Q4 2012 on the south pad & Q2 2013 on the north pad, water cuts increased Q3 2013 on the north pad
- Current RF: 5.6%
  - 4.8% Primary
  - 0.8% Secondary
- Ultimate RF: 7.9%
  - 4.8% Primary
  - 3.1% Secondary

Performance – Phase 2 Prod./Inj. Profile



- Positive results from 13-03 Pad: Low water cuts & increasing reservoir pressure
- Conducted a conformance treatment on 2 injectors on the 4-10 pad, no results yet
- No production response recorded
- Similar to Phase 1, injected polymer/water blend at start of injection in Phase 2

Conformance Treatments



- **Conformance treatment performed on Phase 1 injection well W1330/13-15 (13-10 pad) in September 2014**
  - Blend of polymer and polymer cross-linker injected into W1330 well
  - Conformance plug allowed to set (5 days) prior to resumption of offsetting producing wells and 12 days prior to resumption of injection into W1330 well
- **Offsetting producers W1260/13-15 & W1400/13-15 had reduced water cuts after conformance treatment**
  - W1260 water cut dropped from 40% to 30%
  - W1400 water cut dropped from 80% to 40%
- **Two injection wells in Phase 2 area (W102 02/02-04 and W257 03/02-04, both on the 4-10 pad) had conformance treatments completed in late 2014, however the results of these treatments are unknown at this time due to the production being shut-in at the 4-10 pad due to economics**

Performance – Polymer Flood

- Pilot has best production results within the project
- Phase 1 has seen good results, with some issues around conformance and early breakthrough
- Phase 2 – 4-10 pad did not reach fill up when it experienced breakthrough and the success of the conformance treatment is unknown
- Phase 2 – 13-3 pad has recently reached fill up and is starting to see moderate oil response in most producers
- Maintaining reservoir voidage within the project area
  - Volume of injected polymer to date 402,891 m^3
- Expected incremental recovery factor after polymer flood 8.8%
- Produced solution gas from the pilot & expansion is captured and tied in to 4-33 battery.

Phase 2 Results – Additional Information

Summary of Infill Primary Production Prior to Initiation of Polymer Injection

Area	Post Infill Primary Prod	
	m^3	%STOOIP
Pilot	6,956	0.5%
Phase 1	9,913	1.7%
Phase 2	26,507	1.0%

- **Phase 2 infill producing wells had significant production in advance of initiation of polymer/water injection compared to Pilot and Phase 1 areas**
  - 10 of 11 infill wells were produced in advance of initiation of injection
- **Phase 1 area also had premature breakthrough at two producing wells, mitigation achieved via conformance treatment at W1330/13-15 well**
  - Both infill wells had primary production in advance of initiation of injection
- **Pilot area had the least amount of primary production of all of the polymer areas**
  - 2 of 4 infill wells had primary production in advance of initiation of injection

Performance – Key Learning’s

- **Injectivity is a non-issue with wells on vacuum at the start of injection**
- **Start injection before or soon after infill producers are drilled**
  - Injection should commence as soon as practical, and analysis of reservoir voidage should be completed to understand the amount of fill-up require to get back to (or close to) initial reservoir pressure in advance of initiation of production
  - This will allow for a more evenly distributed pressure bank from the injection, in an attempt to mitigate early breakthrough at the producing wells, thereby increasing secondary recovery
- **Conformance treatments can offer potential mitigation to early breakthrough**
- **Source water quality is a key driver in project economics and operability**
  - Lower salinity water reduces the polymer required for desired viscosity, and also increases viscosity retention time due to reduced viscosity degradation that is found in higher salinity source water

Subsurface

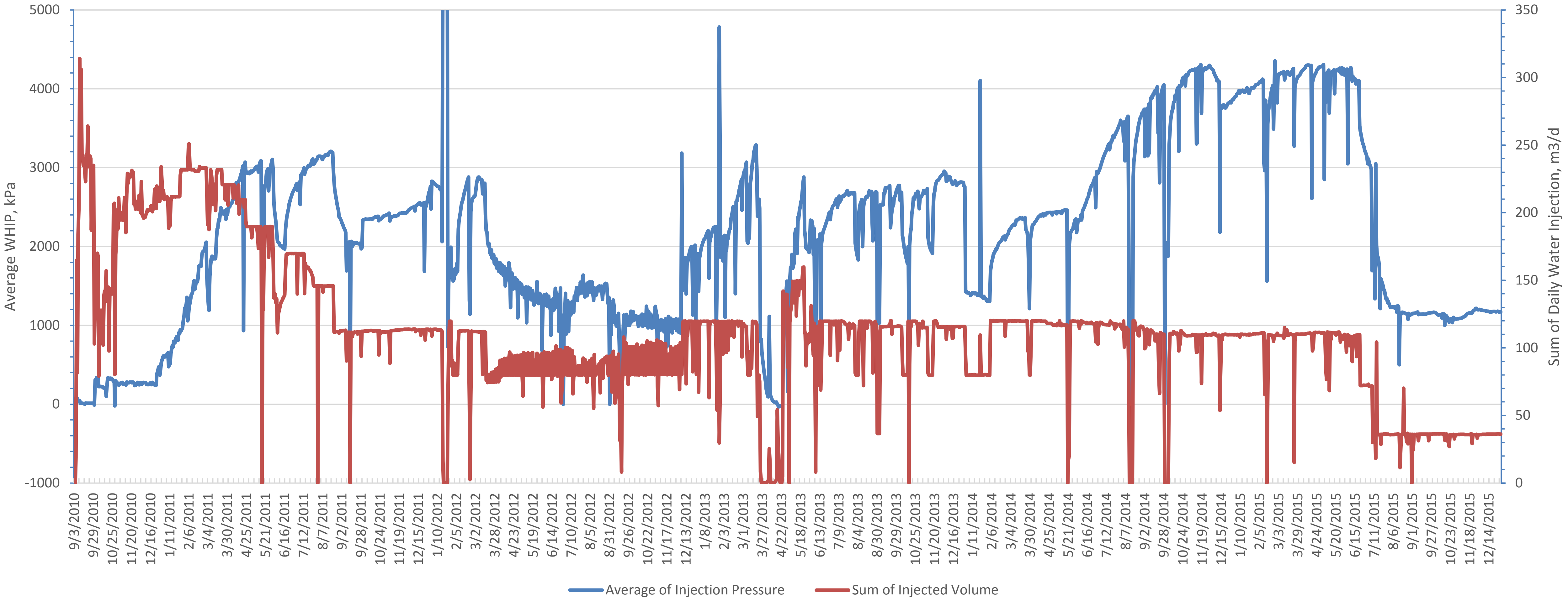
- Background
- Geology
- Drilling & Completions
- Flood Performance
- **Injection Pressures**
- Future Plans

Injection Pressures

- Polymer Injection Approval Pressure (Approval # 11320C)
  - MAWHIP 4,900 kPa
  - MABHIP 11,500 kPa

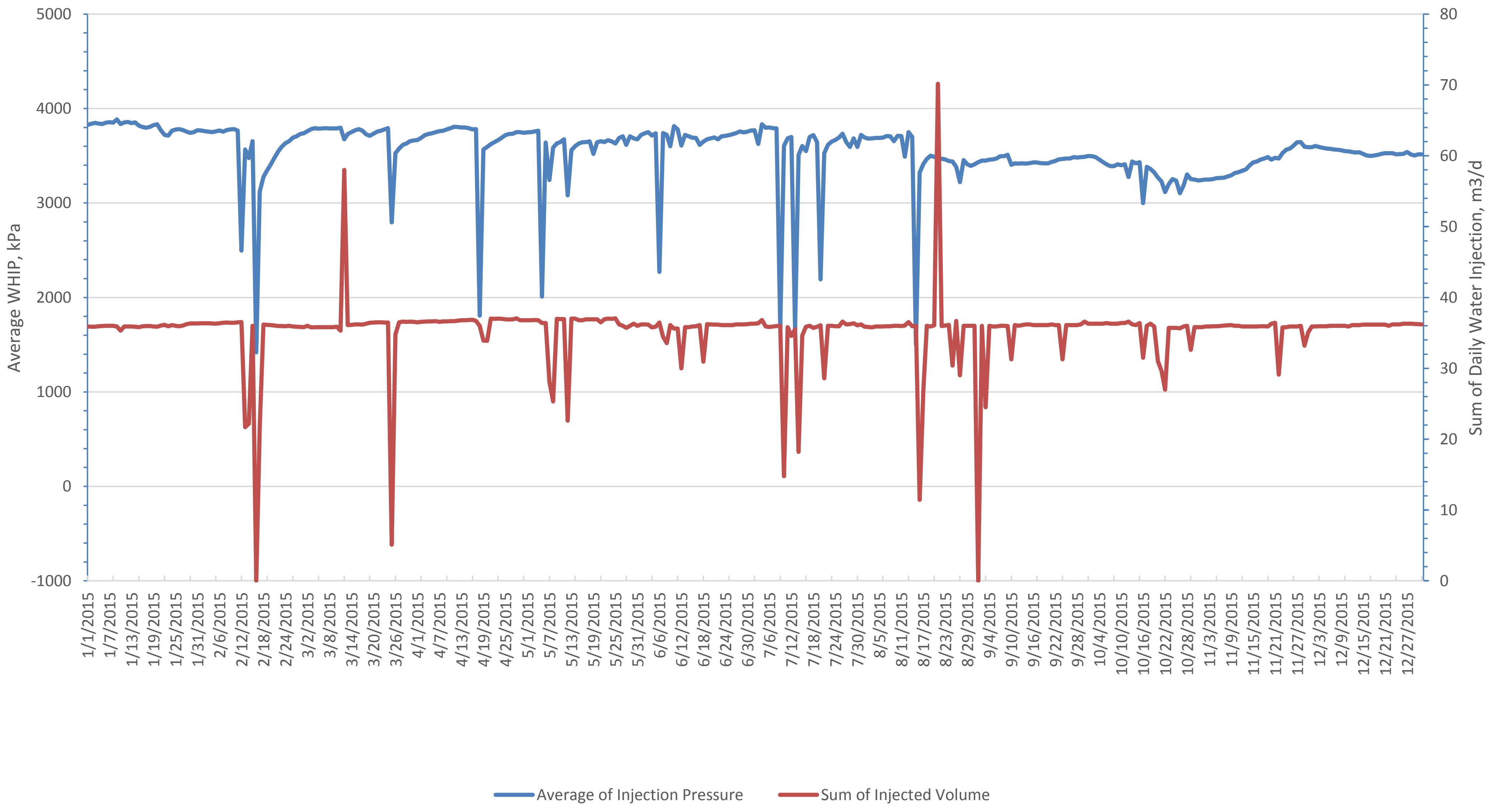
- Monitoring Injection Pressure
  - Surface pressure recorded daily and monitored to ensure MAWHIP is not exceeded

Injection Pressure - Pilot

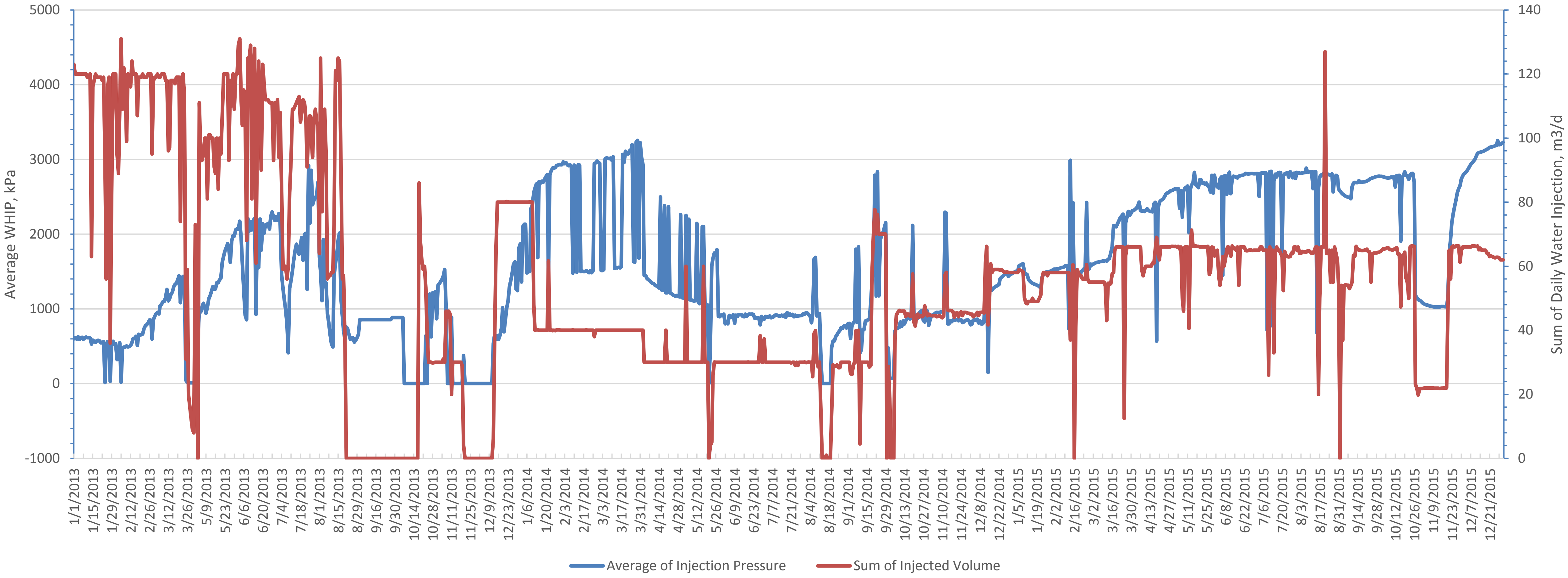


- Two injectors were shut in on the 14-10 pad due to high water cuts seen on one offset producer, one of the injectors has been re-started as of Jan-2016 with no impact to water cut in offset producers

Injection Pressure – 14-10_00/14-15 Injector Only

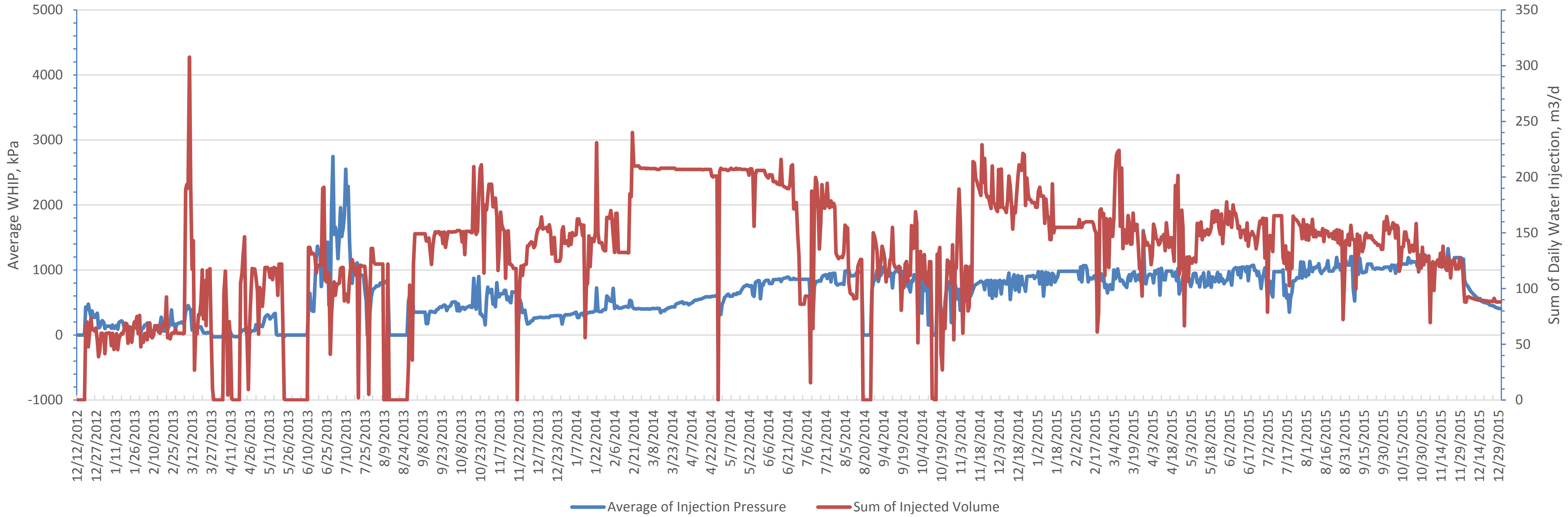


Injection Pressure – Phase 1



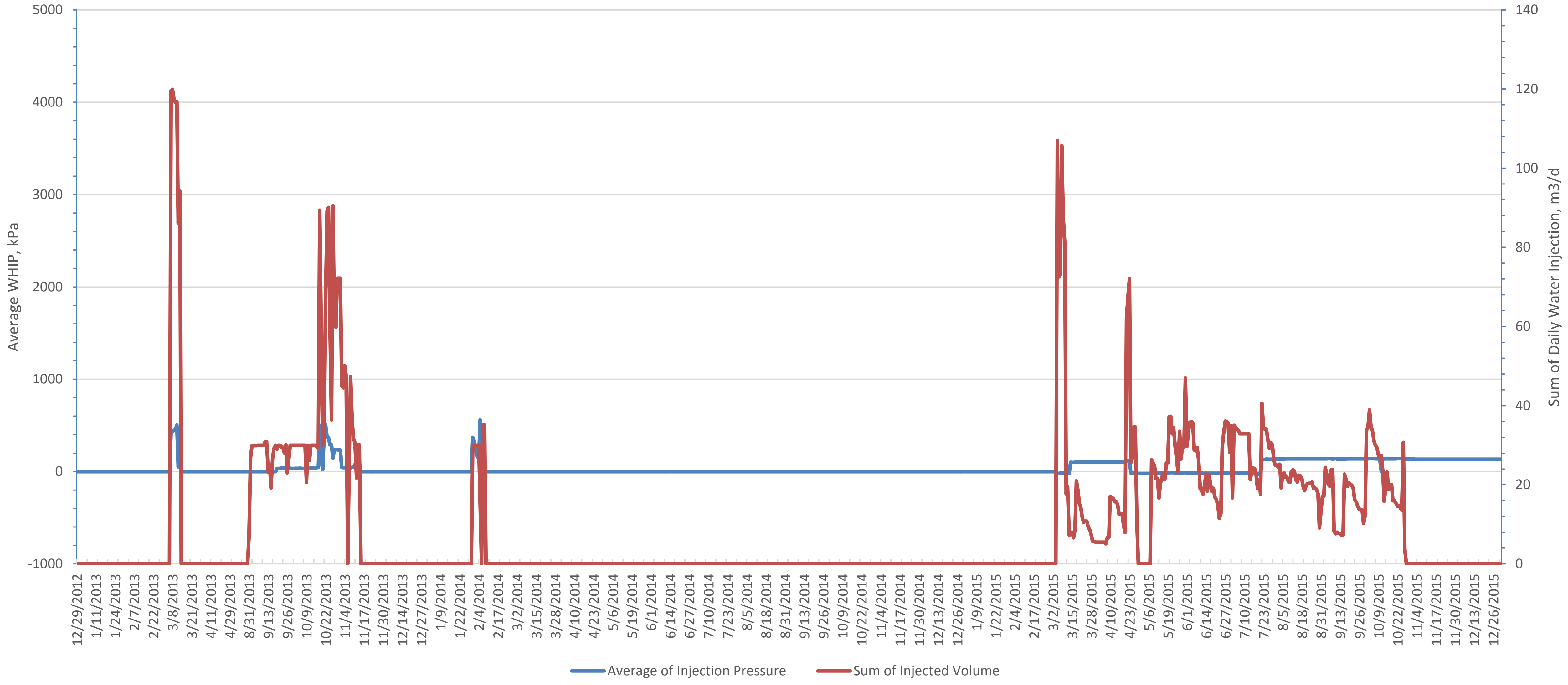
- Cumulative voidage replacement reached 1.0 for the 03/14-15 injector pattern
- The conformance treatment done on 00/13-15 in 2014 has allowed for that injector pattern to replace voidage effectively, leading to higher injection pressures

Injection Pressure – Phase 2

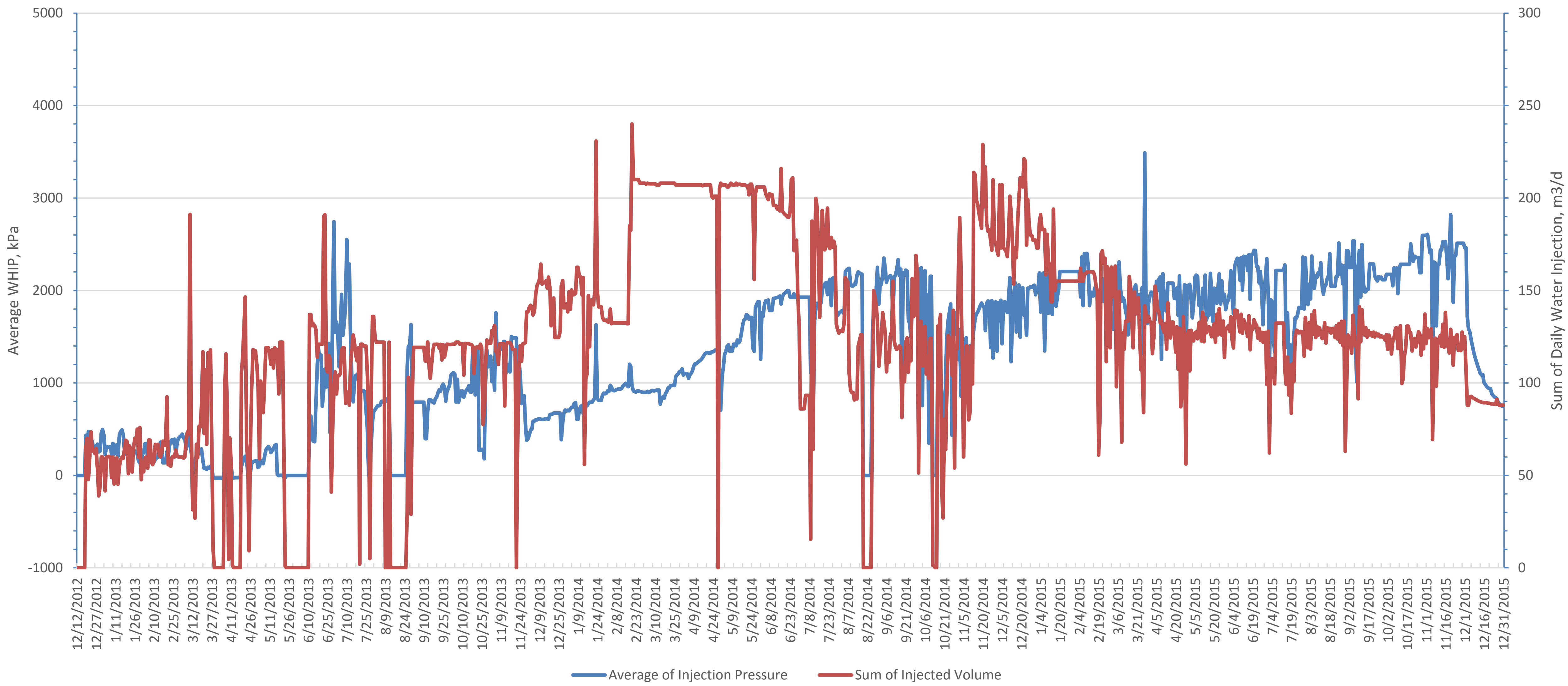


- All injector patterns on the 13-03 pad reached a cumulative VRR of at least 1.0 in 2015
- Four of the Five injectors on the 04-10 pad injected < 10 m^3/d for parts of 2015, all injection and production was shut in Nov-2015 due to economics
- The 13-03_00/11-10 and 00/14-10 injectors were shut in Dec-2015 due to high injection pressures, will be re-started after winter 2016

Injection Pressure – Phase 2_04-10 Pad



Injection Pressure – Phase 2_13-03 Pad



Subsurface

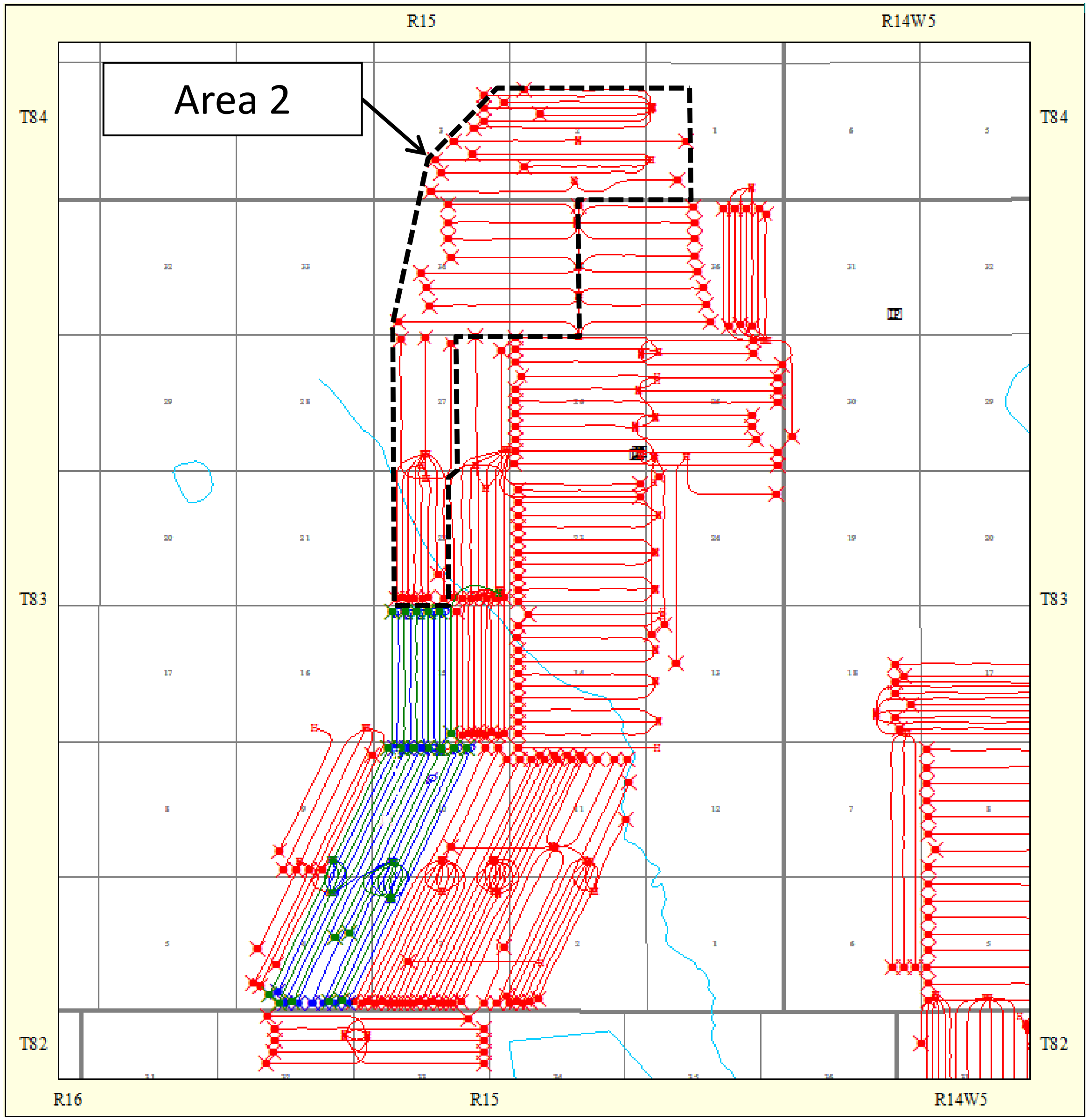
- Background
- Geology
- Drilling & Completions
- Flood Performance
- Injection Pressures
- **Future Plans**

Future - Expansion Plans

- Area 2:
  - This area has been put on hold until the project is economical.

- Area 1 – Phase 3:
  - Murphy has cancelled Phase 3 expansion plans and has no other plans for expansion in Area 1 at this time.
    - Secondary recovery risk associated with primary production at 70 m inter-well spacing (lessons learned from Phase 2) combined with dropping commodity prices in the second half of 2014 (that still persist today) have eroded the value associated with Phase 3 development

Future Plans- Expansion



- Located in Central Seal just North of existing pilot and expansion.
- Similar reservoir characteristics and viscosities

Agenda

- Subsurface
- **Surface**

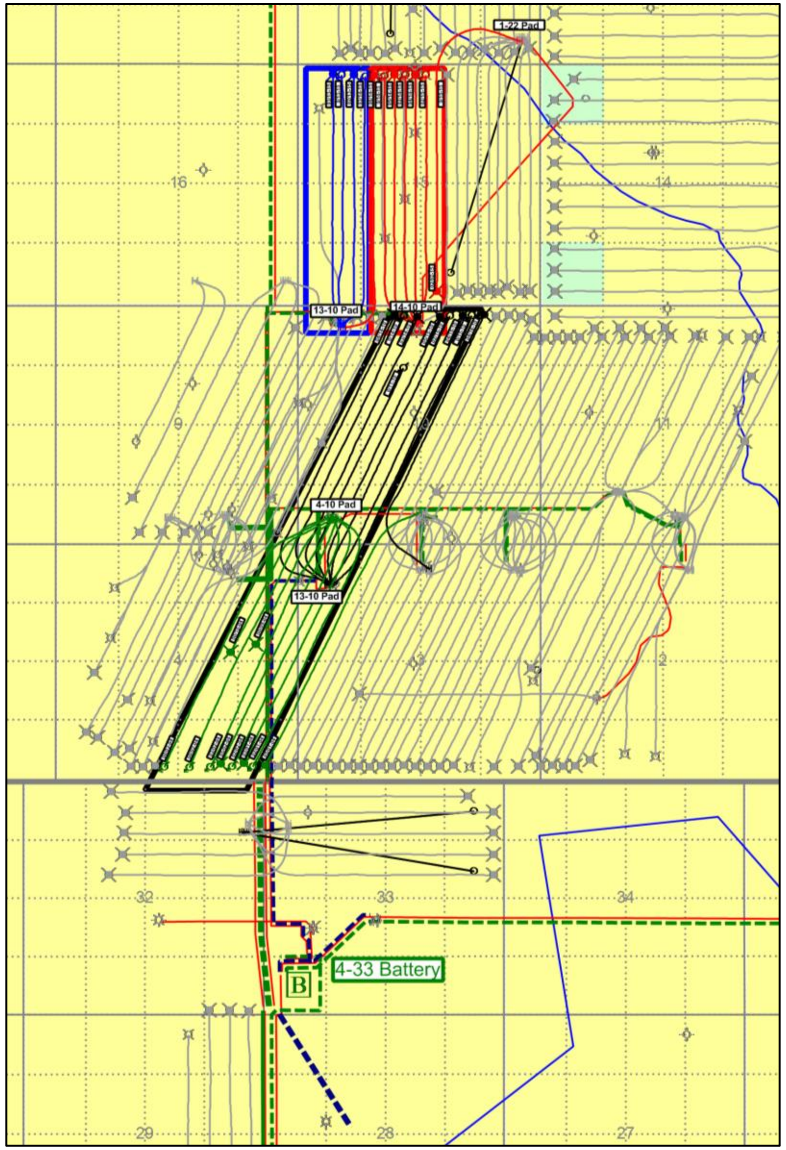
Surface

- Facilities
- Production Accounting
- Water & Gas Usage
- Regulatory
- Conclusions

Surface

- **Facilities**
- Production Accounting
- Water & Gas Usage
- Regulatory
- Conclusions

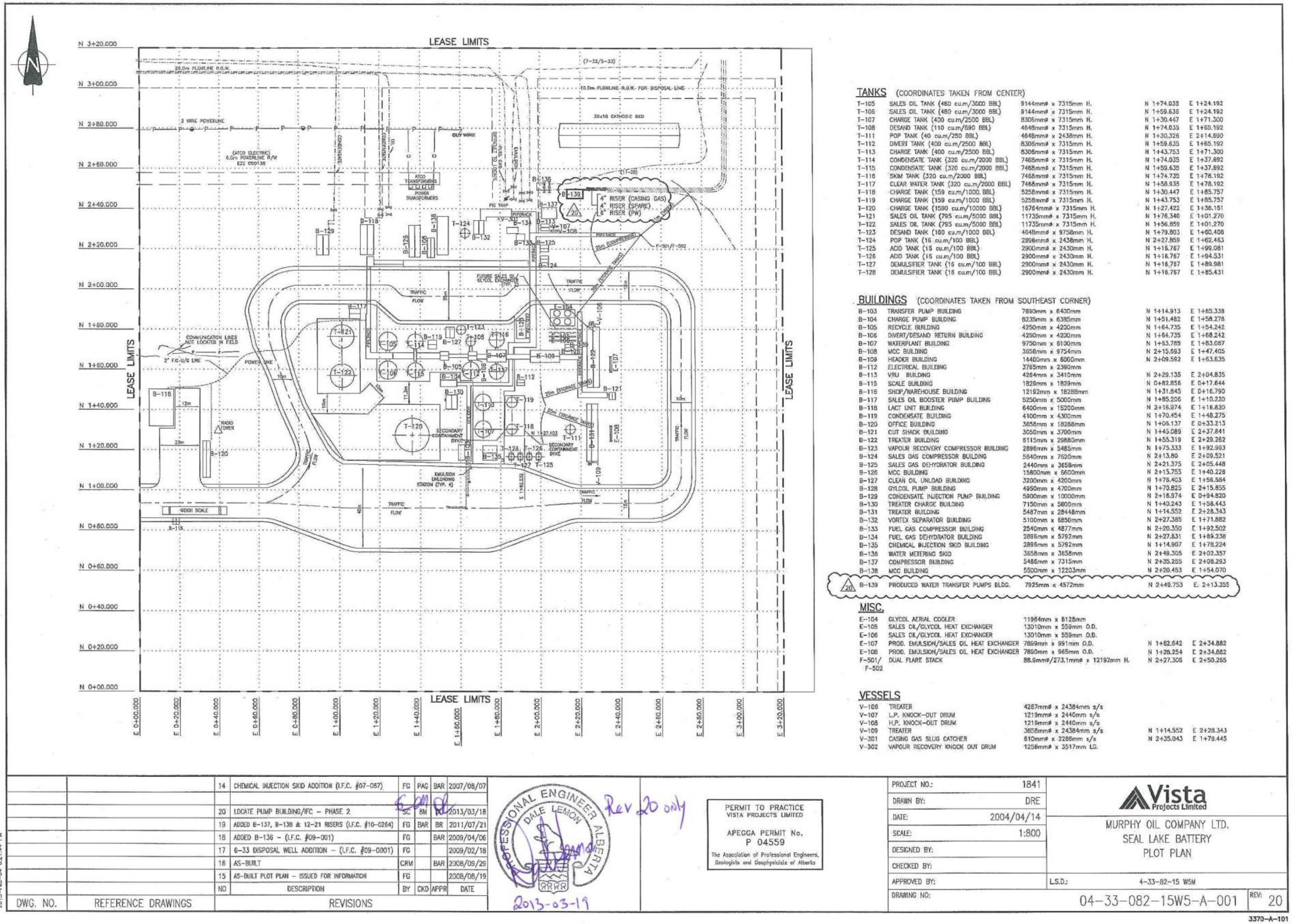
Facility Locations



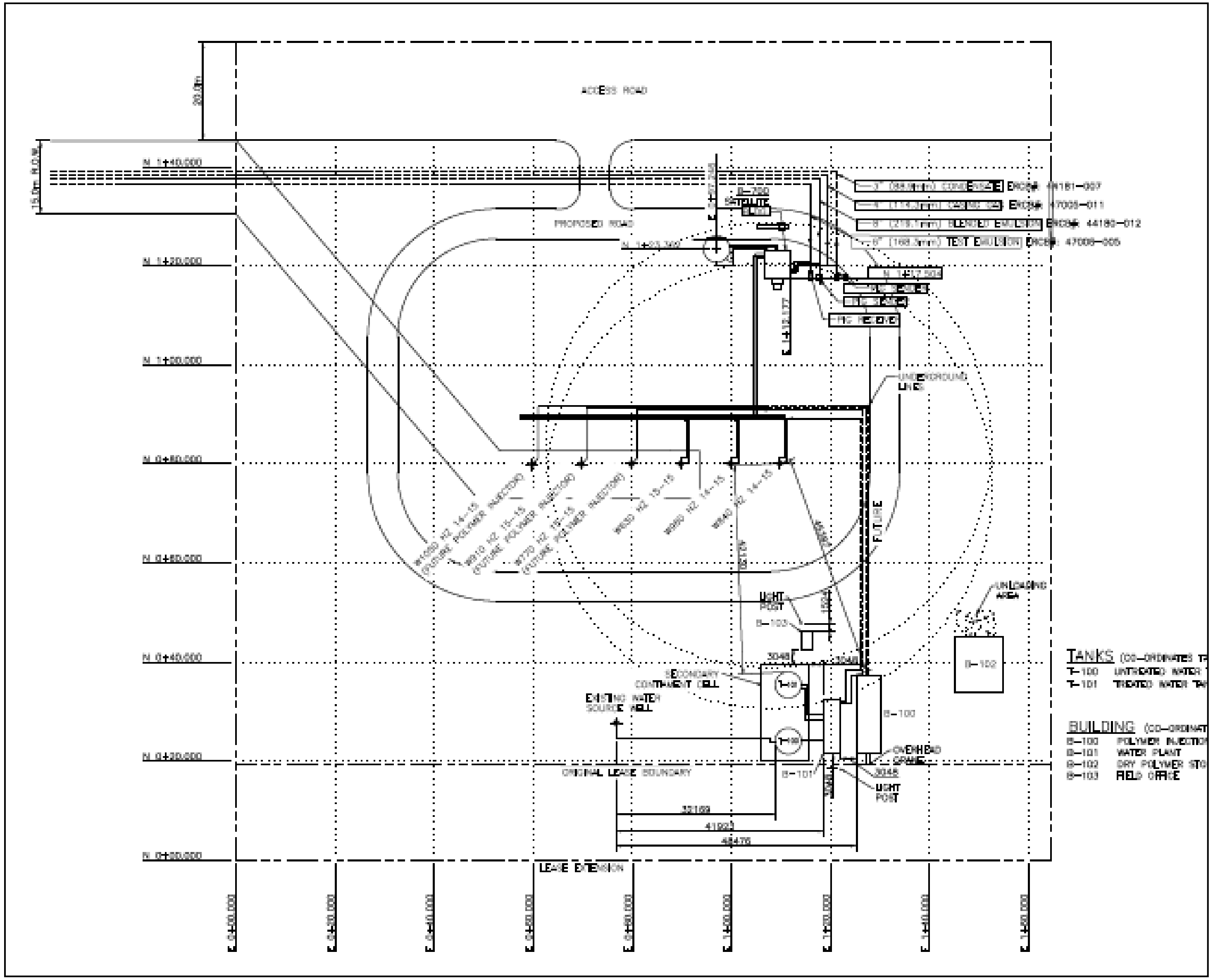
- Located in Central Seal
- All producing wells from the polymer pilot and Area 1 are flow lined to the 4-33 CPF
- All source water facilities are equipped to treat for iron, and oxygen in the water before hydration occurs
- Bacteria control is planned to be implemented at 14-10

ABIF	ABBT	ABCT	Description
0111879	0121572	N/A	14-10 Polymer Injeciton Facility
0129026	0129029	N/A	13-03 Polymer Injection Facility
N/A	0129032	N/A	
N/A	0094150	N/A	Flow line of 4-33 CPF
N/A	N/A	0133398	4-33 CPF
0080049	N/A	N/A	10-04 SWD
0088019	N/A	N/A	11-28 SWD
0107239	N/A	0133398	6-33 SWD

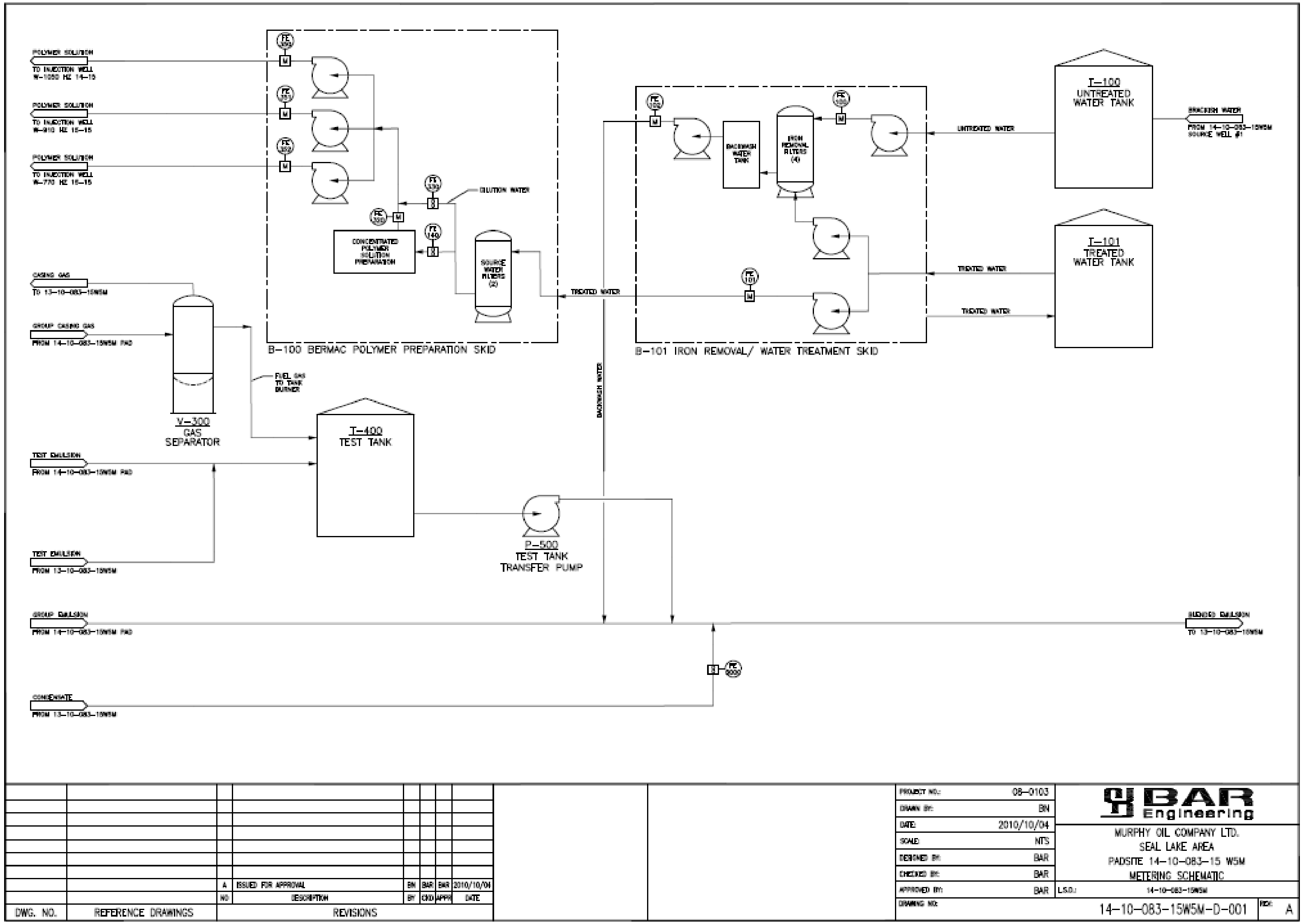
Facilities – 4-33 Plot Plan



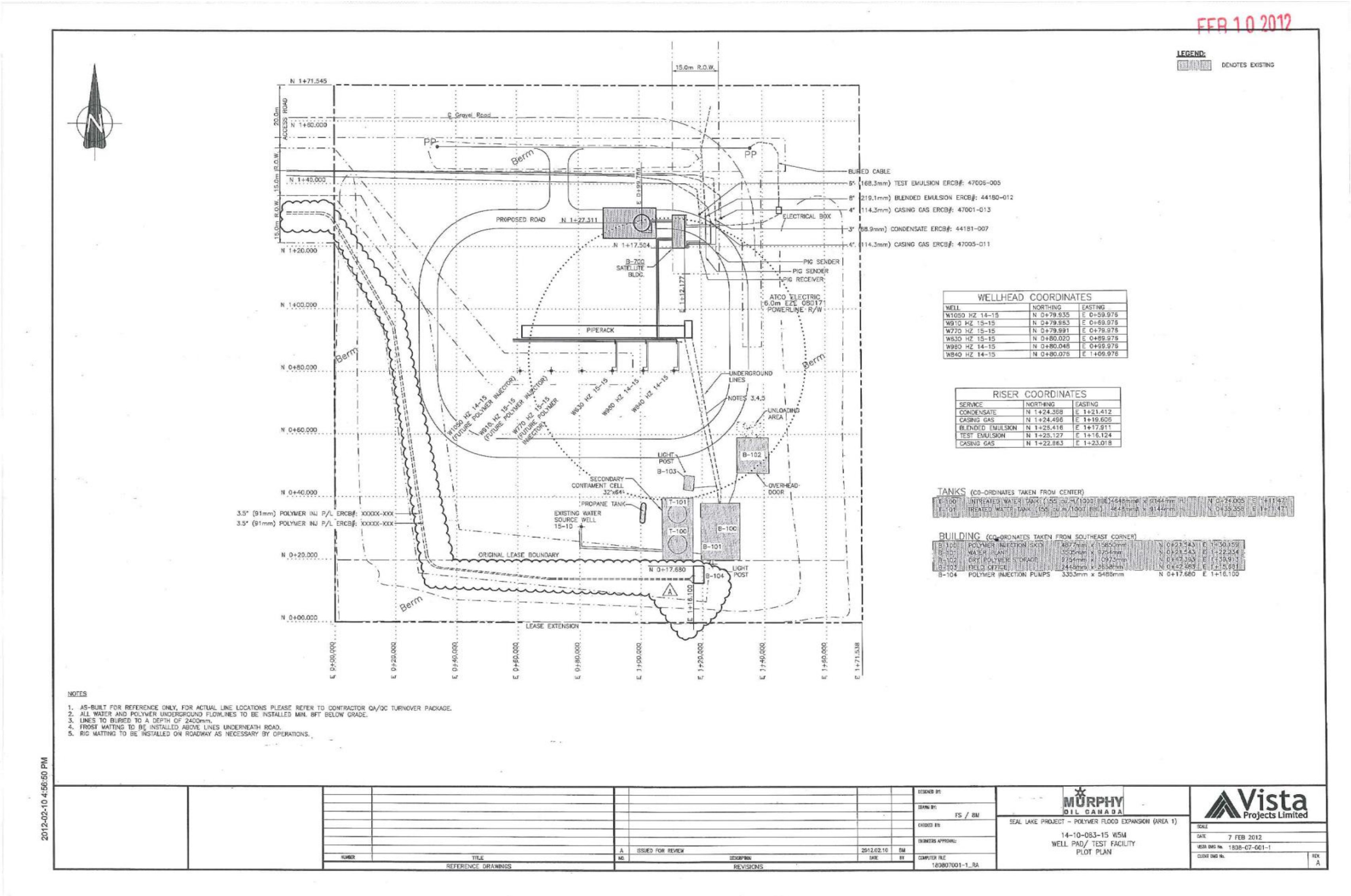
Pilot – 14-10 Plot Plan



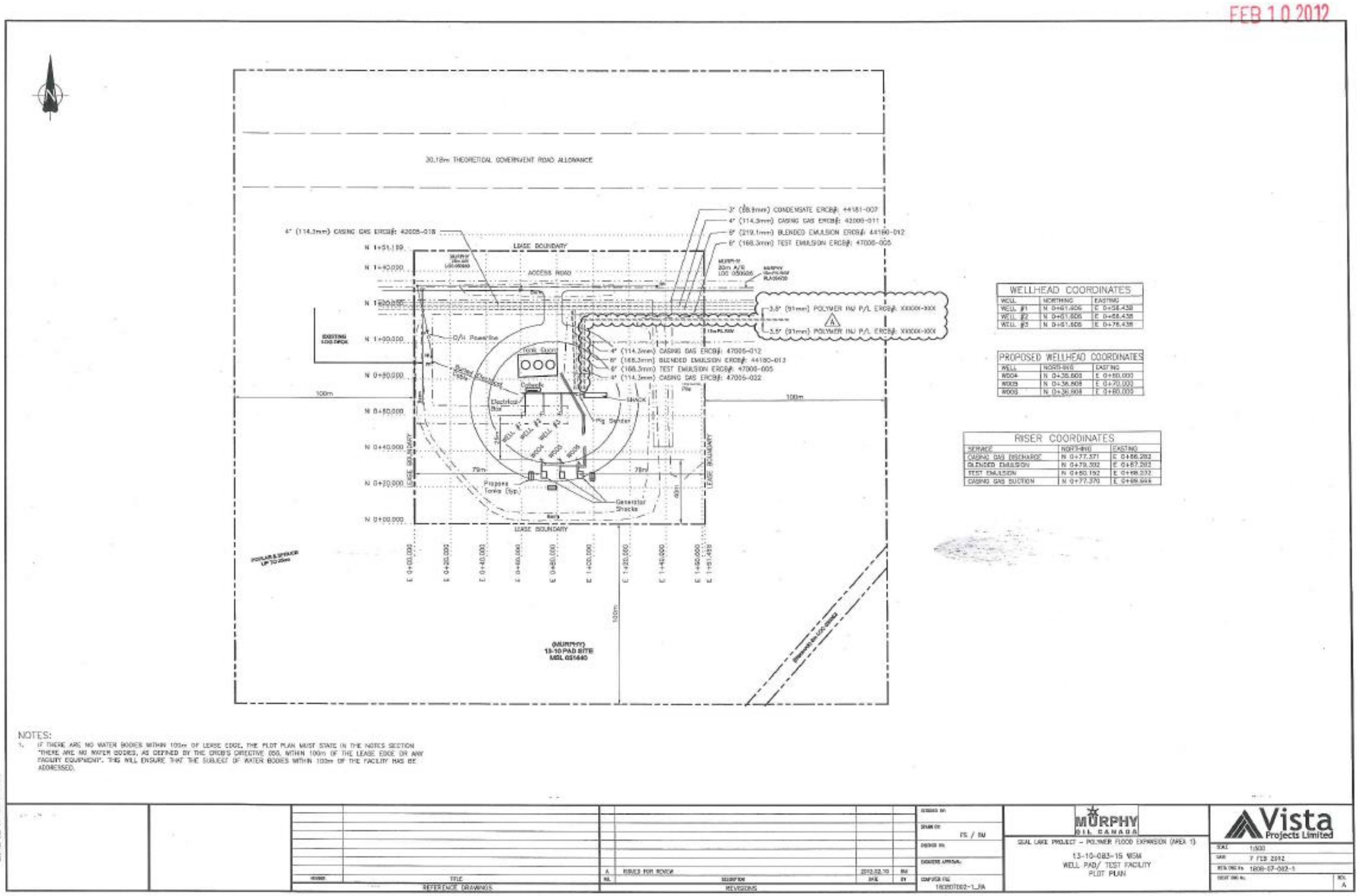
Pilot – Polymer PFD



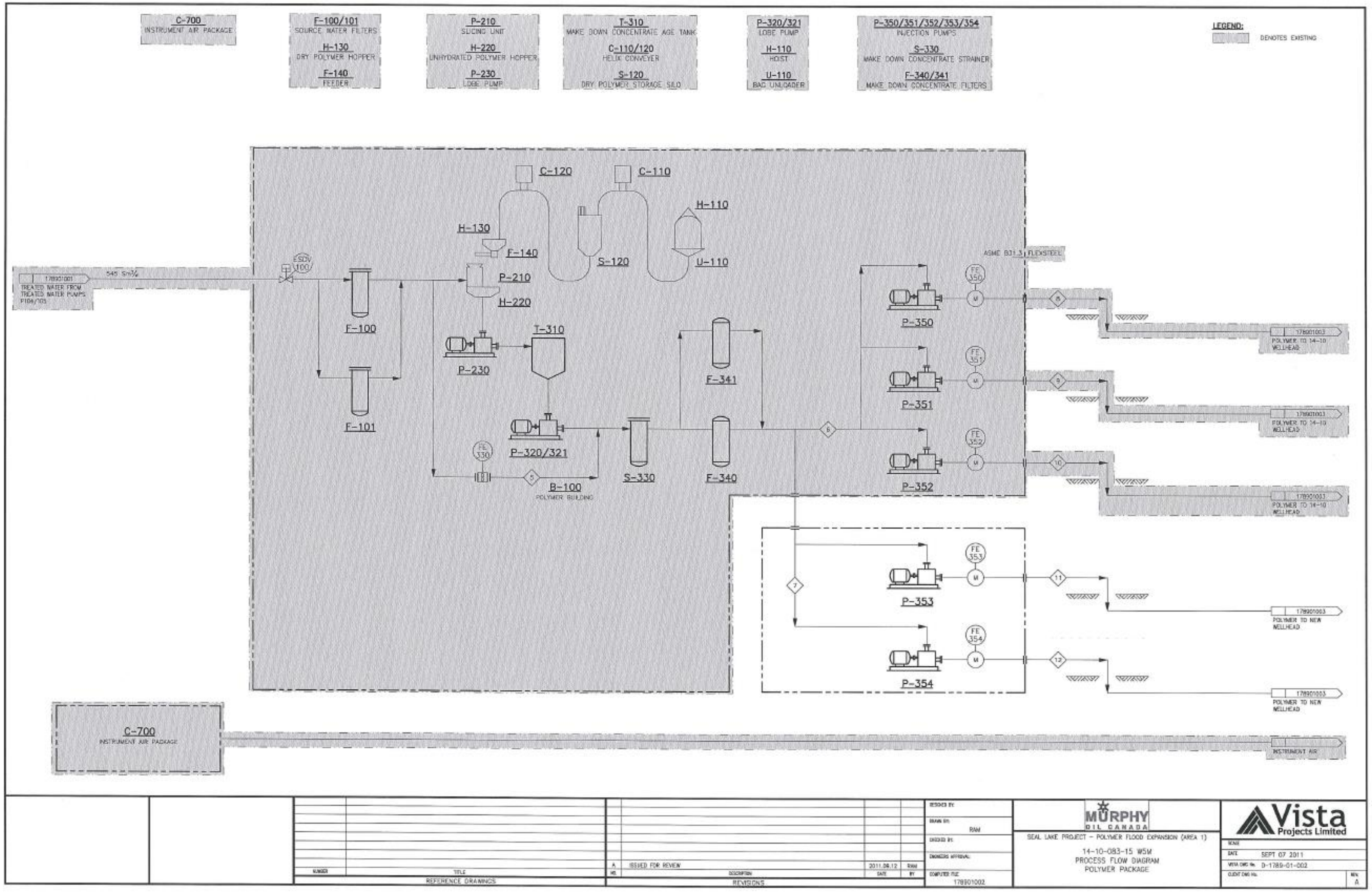
Area 1 Phase 1 – 14-10 Plot Plan



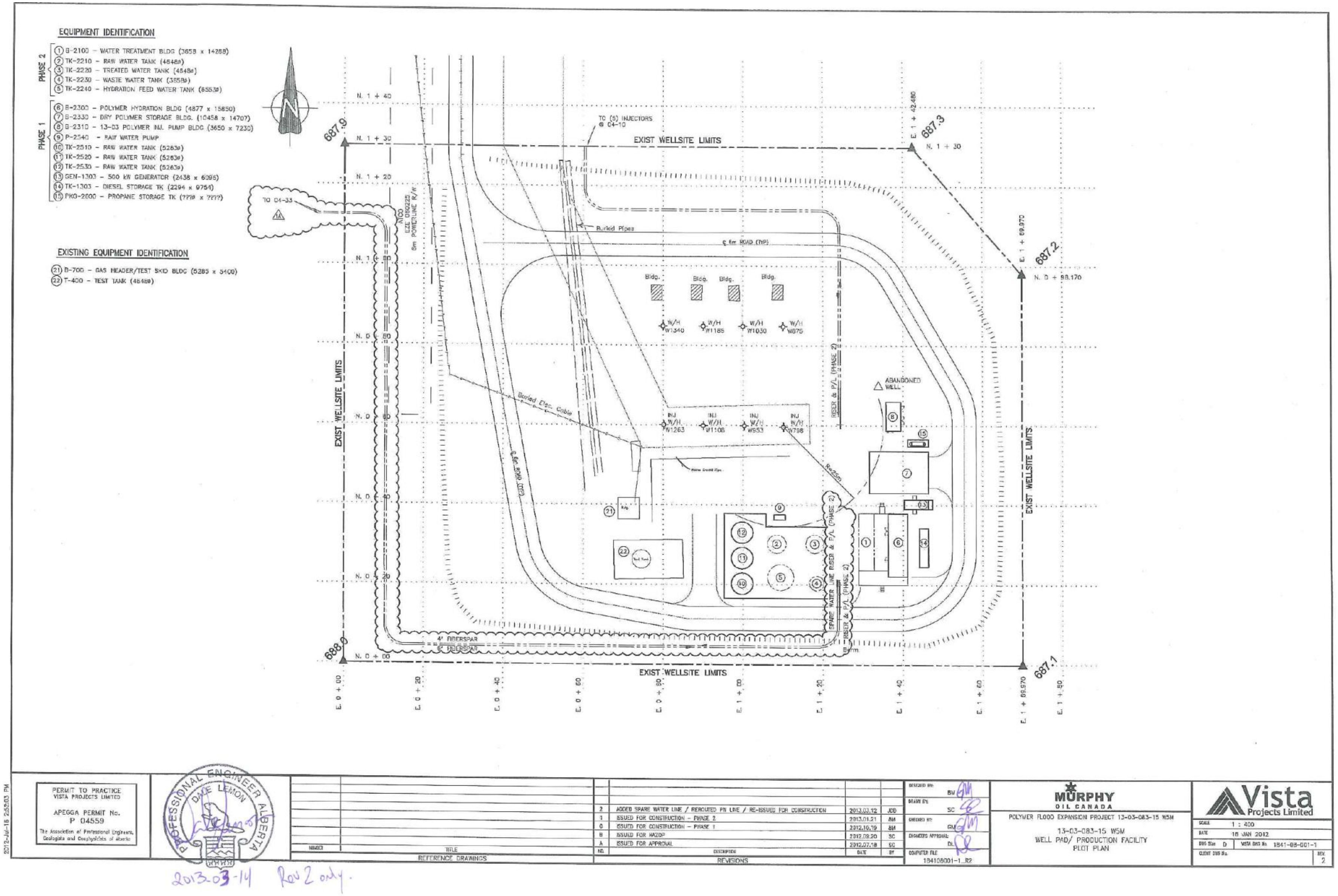
Area 1 Phase 1 – 13-10 Plot Plan



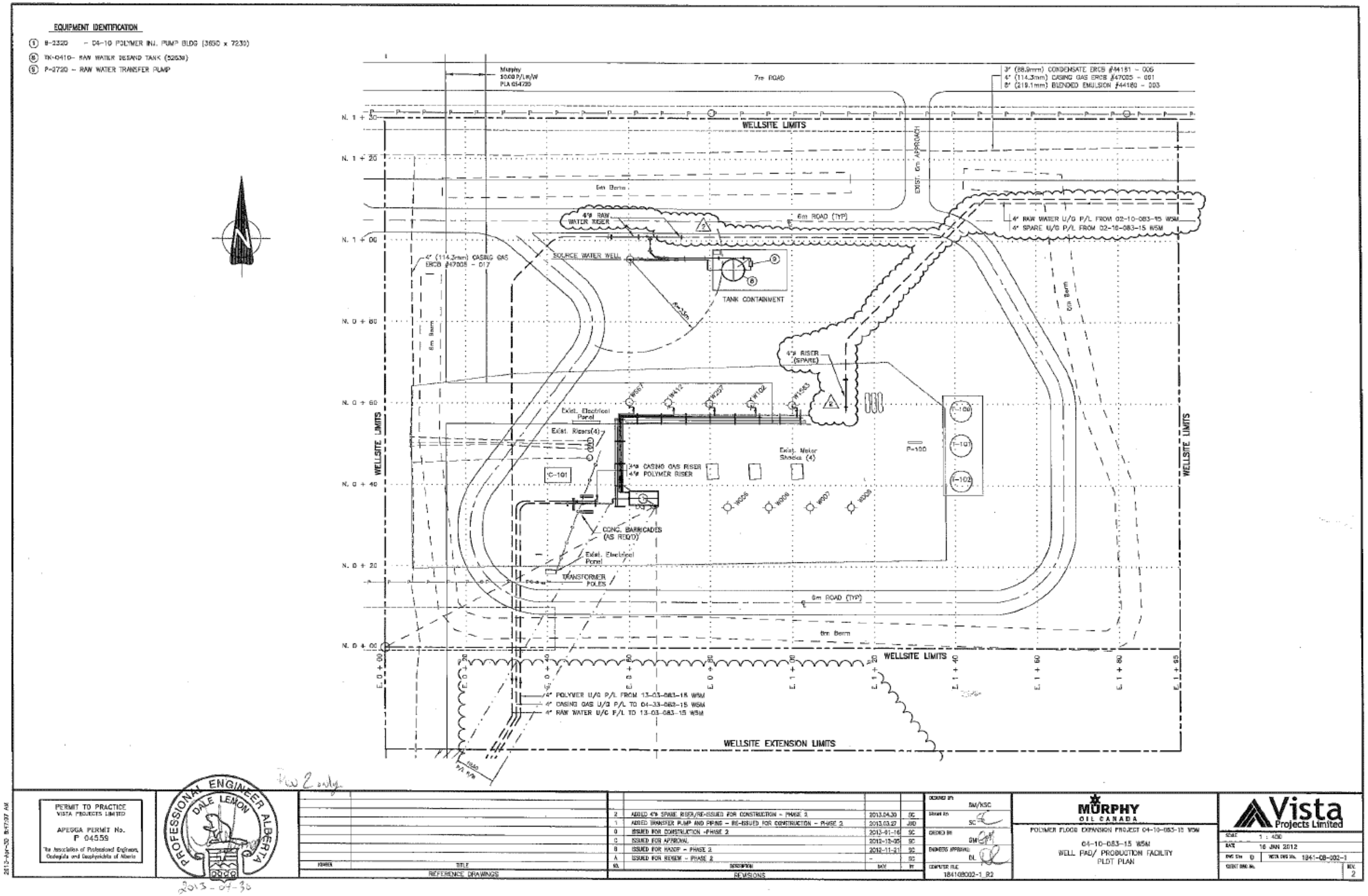
Area 1 Phase 1 – 14-10 PFD



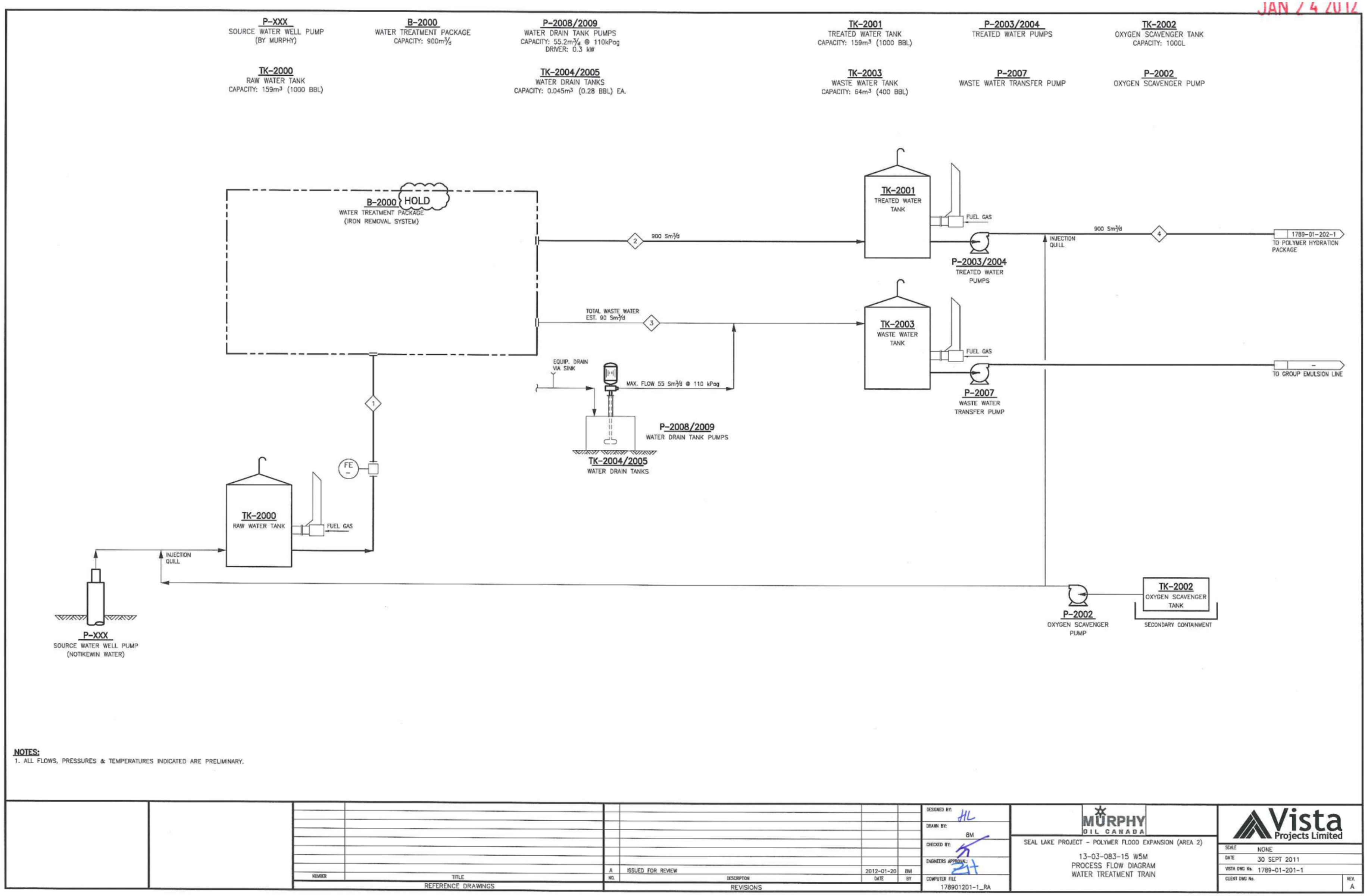
Area 1 Phase 2 – 13-3 Plot Plan



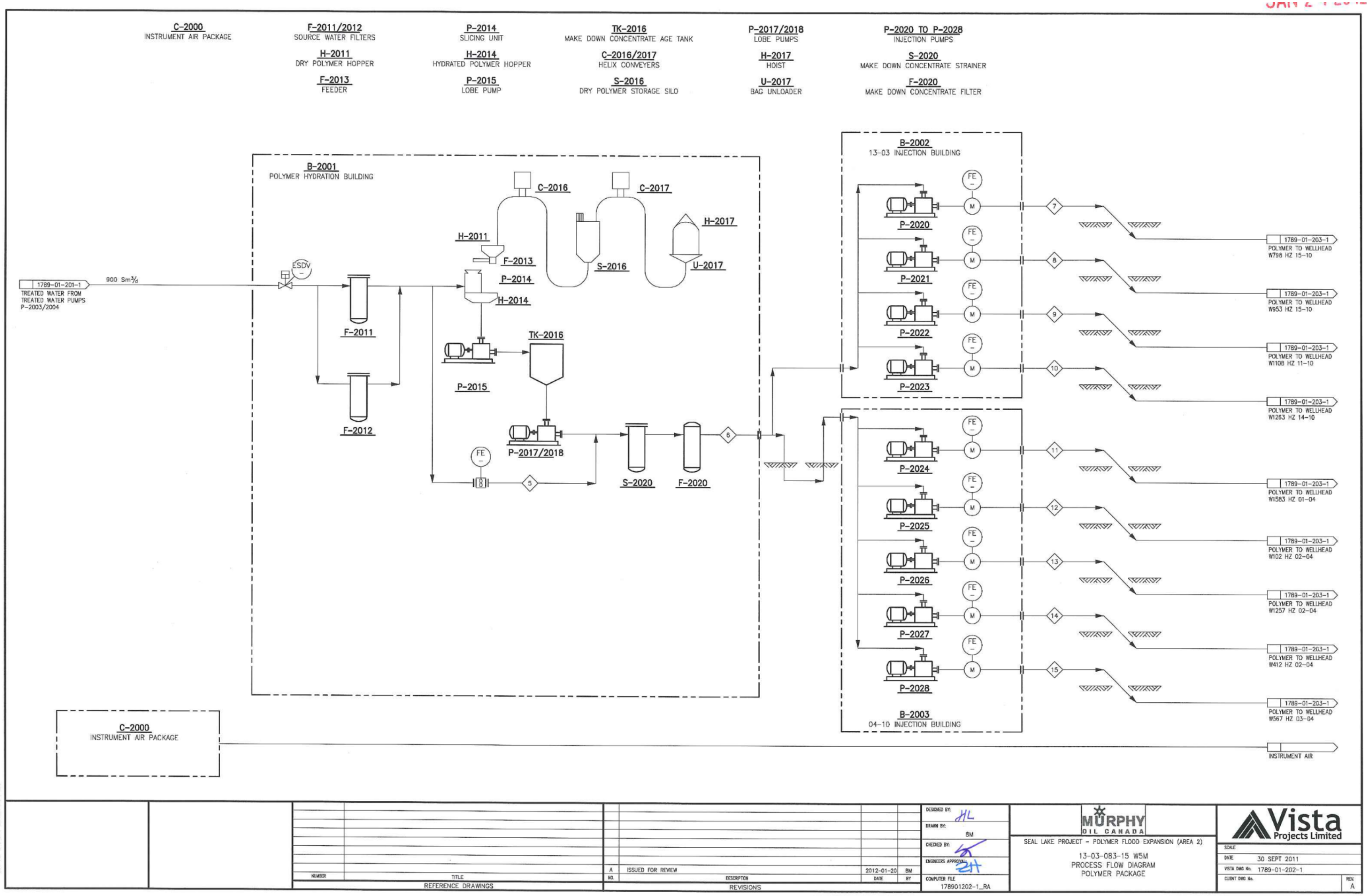
Area 1 Phase 2 – 4-10 Plot Plan



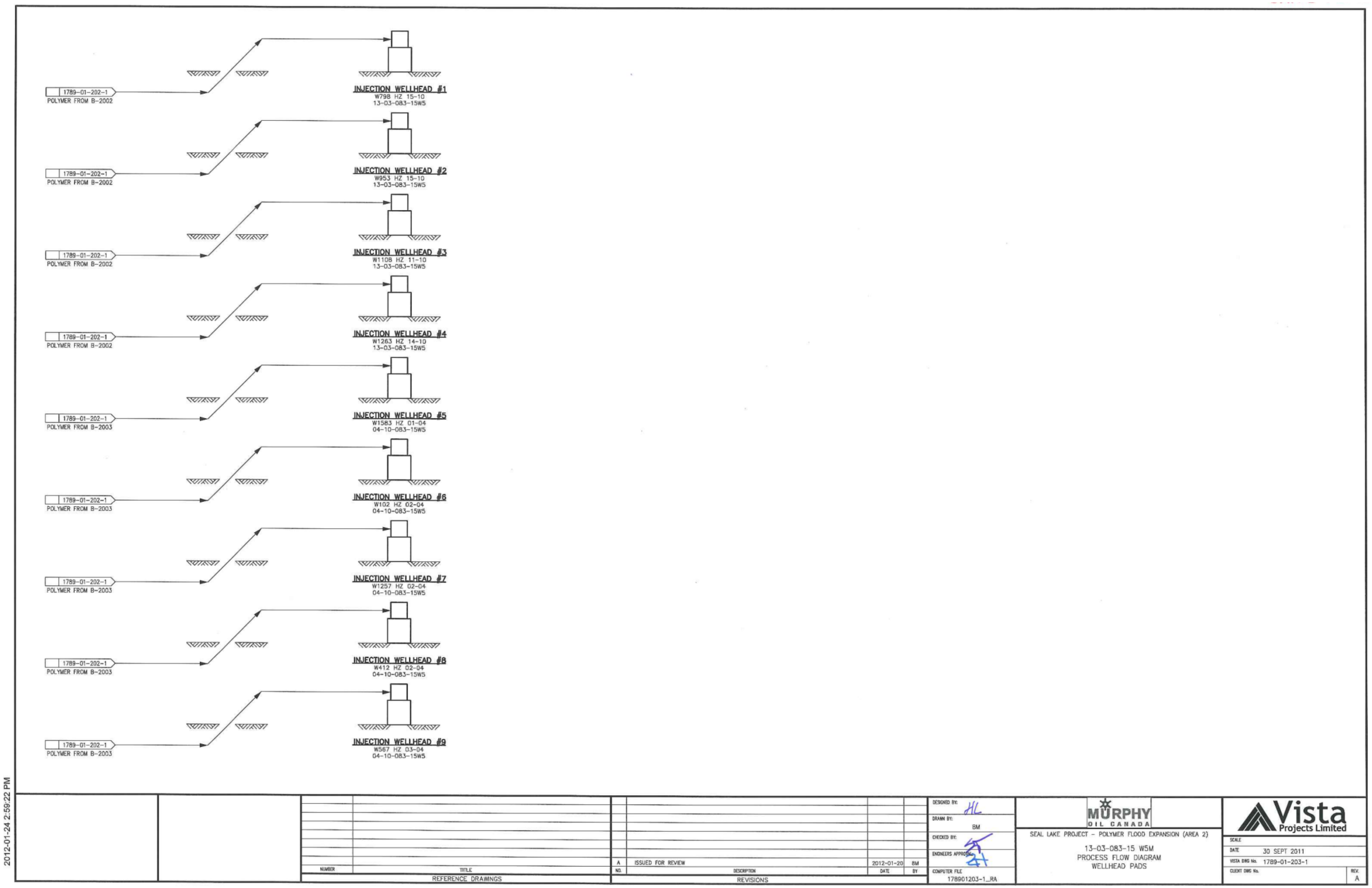
Area 1 Phase 2 - PFD



Area 1 Phase 2 - PFD



Area 1 Phase 2 - PFD



Surface

- Facilities
- **Production Accounting**
- Water & Gas Usage
- Regulatory
- Conclusions

Production Accounting Reported Proration

Production Date	Average of Oil Proration Factor	Average of Gas Proration Factor	Average of Water Proration Factor
2015-01	0.75293	0.65975	0.89101
2015-02	0.65653	0.65949	0.99656
2015-03	0.76721	0.59488	0.91042
2015-04	0.78929	0.67014	1.32765
2015-05	0.68602	0.84055	1.01891
2015-06	0.75899	0.88338	1.08248
2015-07	0.73371	0.99078	1.08696
2015-08	0.74931	1.11457	1.06865
2015-09	0.69933	1.05075	1.80416
2015-10	0.71314	1.12432	1.29159
2015-11	0.73747	1.06868	1.54575
2015-12	0.73333	1.25262	1.06338
Annual Average	0.73144	0.90916	1.17396

Surface

- Facilities
- Production Accounting
- **Water & Gas Usage**
- Regulatory
- Conclusions

Water Usage - Paddy Formation

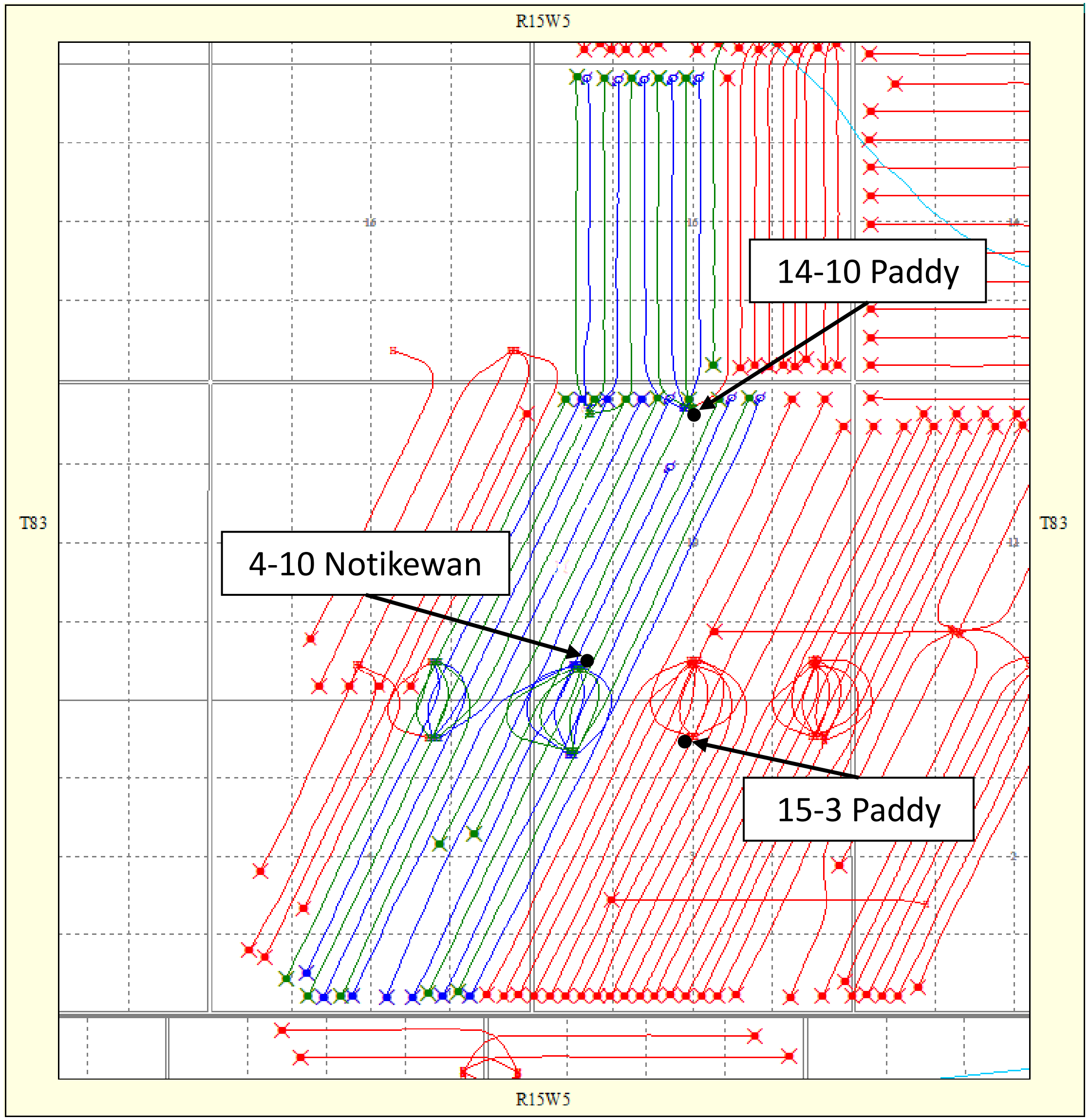
- UWI: 1F1/14-10-083-15W5/0
  - Murphy currently has term license 00289082-00-00 with Alberta Environment & Parks (AESRD, AB Env) for the diversion of up to 164,250 m^3 of Paddy water for injection with an expiry date of 2018-03-05
  - 3,750 ppm TDS
  - Fe was not detected

- UWI: 1F1/15-03-083-15W5/0
  - No TDL necessary with TDS testing >4,000 ppm
  - 5,383 ppm TDS
  - Fe was not detected
  - Not in use since 2013

Water Usage - Notikewan Formation

- UWI: 1F1/4-10-083-15W5
- TDL's are not needed for Notikewan wells with TDS >4,000 ppm
  - 10,592 ppm TDS
  - Fe was not detected
  - Current supply for the Polymer facility at the 13-03 Pad

Water Usage - WSW Locations



Water Usage – Produced Volumes

- Produced volumes are prorated back to the producing wells by periodic well tests performed at each pad and the proration meter at the 4-33 battery
- From the start of the polymer flood there has been a recorded 53,302 m^3 of water produced from the producing wells
- Water volumes are calculated through sampling the BS&W during the well test
- Produced water is currently being injected into the disposal well at 102/06-33-082-15W5/0 that is connected to the 4-33 battery by a pipe line
- There is no sulphur production at the polymer facilities. All gas is sent to third party gas plant (Tidewater) via 4-33 for sales and processing.
- Murphy is currently not recycling produced water from emulsion as per regulatory approval
- The 1-26 Facility is outside the current operating polymer flood and is considered out of scope for this update

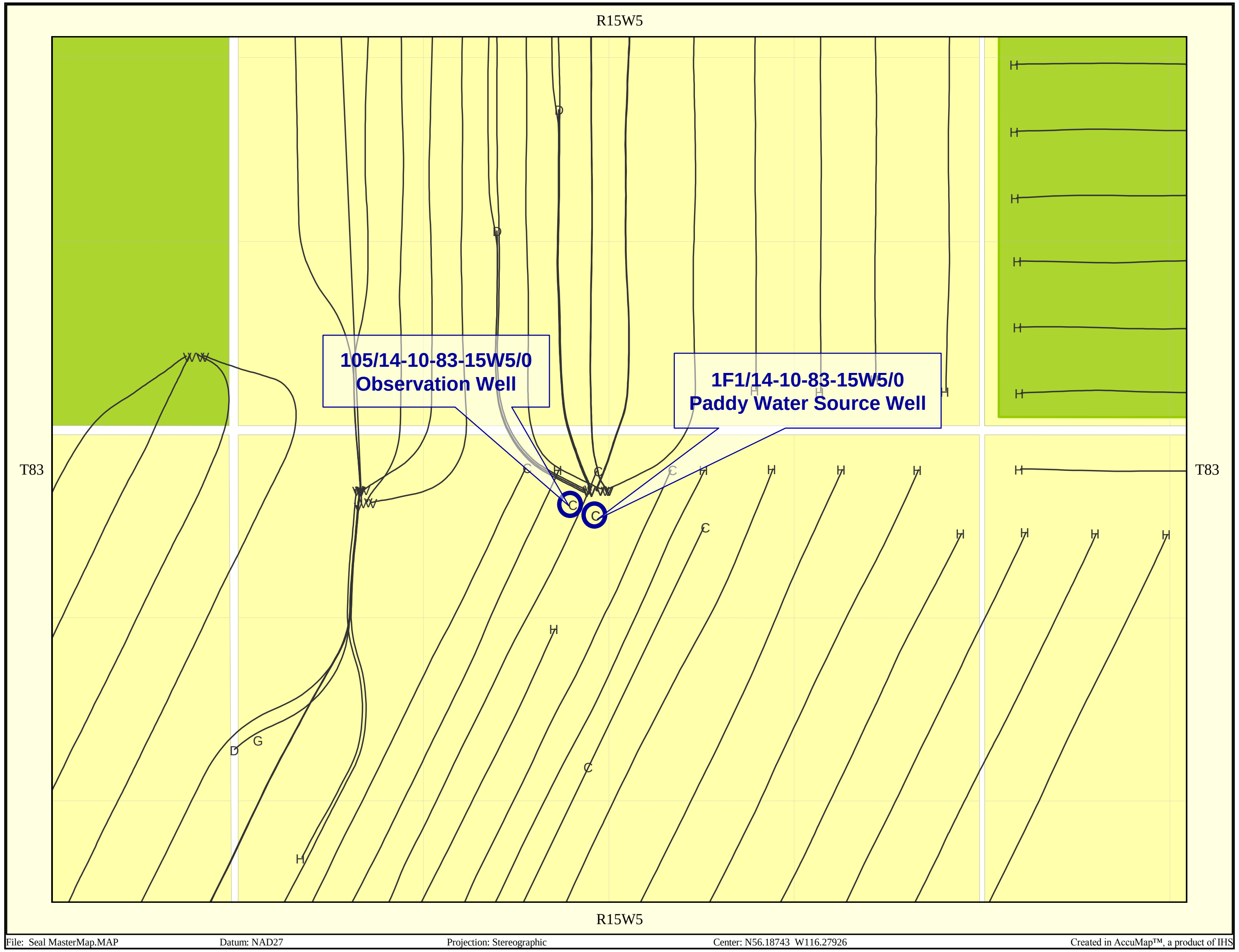
Water Usage – Volumes

2015 Source Water/Polymer Inj Water (m3)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1F1/14-10-083-15W5/0 (Fresh Water)	5,089.10	4,327.60	5,099.70	5,211.60	5,287.70	4,824.00	3,406.80	3,084.20	2,776.50	2,840.50	2,174.40	3,120.00
1F1/04-10-083-15W5/0 (Saline Water)	4,898.30	4,194.60	4,805.80	4,285.50	4,706.60	4,610.70	4,540.10	4,505.30	4,232.30	4,429.40	3,610.60	2,827.50
Total	9,987.40	8,522.20	9,905.50	9,497.10	9,994.30	9,434.70	7,946.90	7,589.50	7,008.80	7,269.90	5,785.00	5,947.50

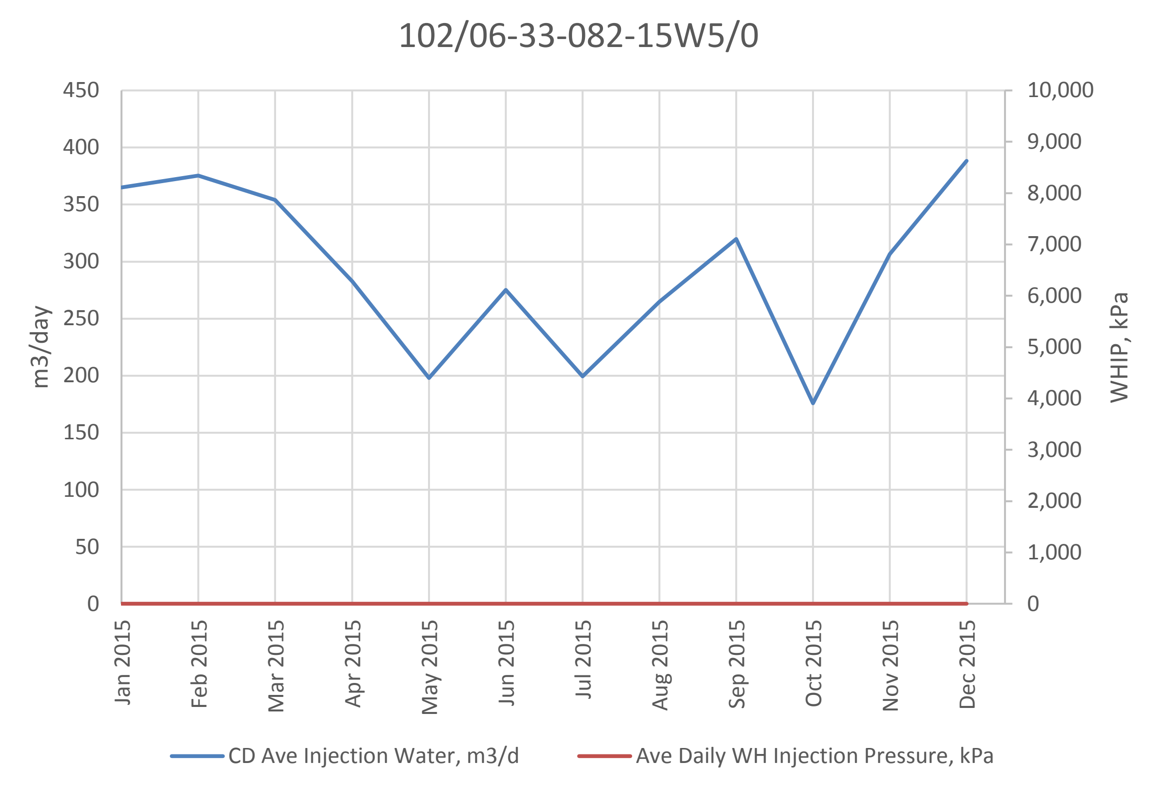
	4-33 Total Water Volumes (m3)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	Produced Water (Area 1)	915	714	1,029	1,014	1,149	1,500	1,476	1,624	1,632	1,212	724	1,081
	Produced Water (Field)	8,178	7,448	6,237	7,256	5,342	6,630	6,664	5,548	7,079	5,439	5,157	6,686
	Fresh Water *injected	5,089	4,328	5,100	5,212	5,288	4,824	3,407	3,084	2,777	2,841	2,174	3,120
	Saline Water *injected	4,898	4,195	4,806	4,286	4,707	4,611	4,540	4,505	4,232	4,429	3,611	2,828
	Third Party Disposal** (Field)	0	52	43	21	132	100	161	30	26	85	68	48
	Disposal Volumes** (Field)	11,311	10,909	11,091	8,530	6,173	8,300	6,180	8,232	9,595	5,447	9,362	12,582

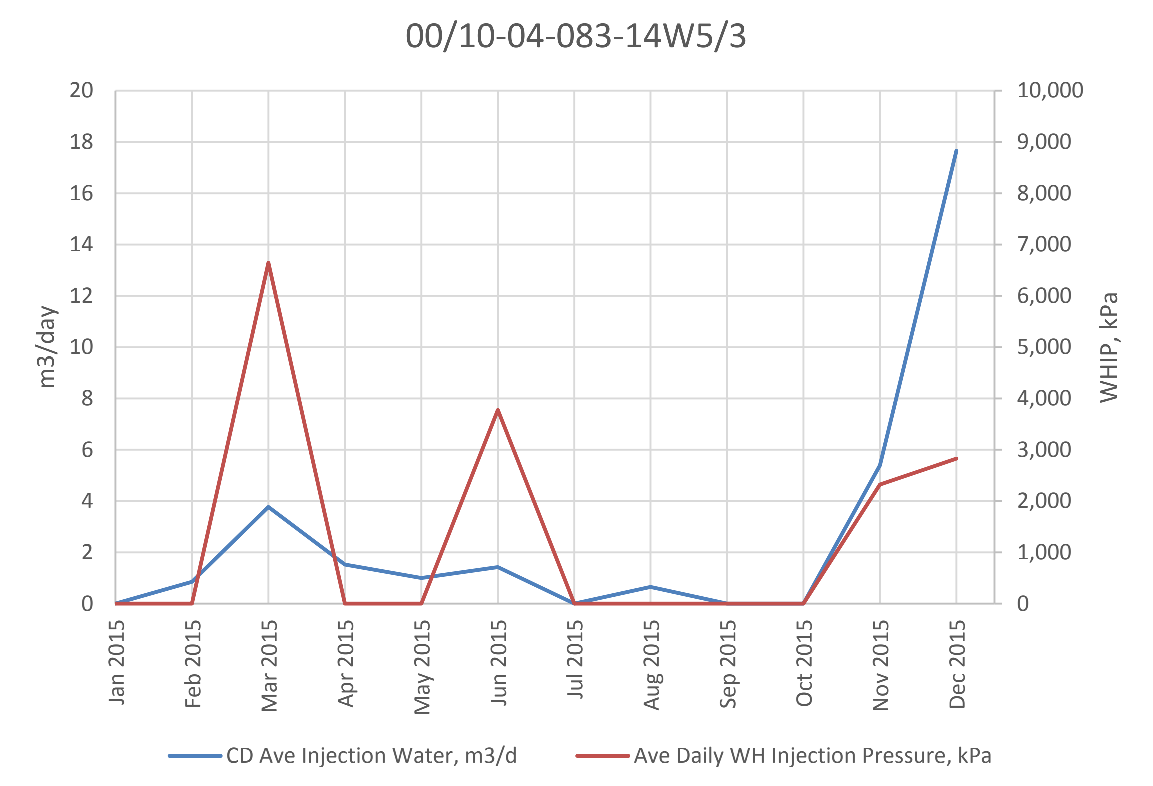
(Field) represents all field production pipeline connected to the 4-33 CPF

Water Usage - Paddy Well Location



Water Usage – Disposal Wells





UWI	Approval Number	Formation
102/06-33-082-15W5/0	11949	Debolt
100/10-04-083-14W5/3	11353C	Nisku
100/11-28-082-15W5/2 *(not active in 2015)*	11949	Debolt

Water Usage – Injected Volumes

Pilot

203,884 m^3 injected

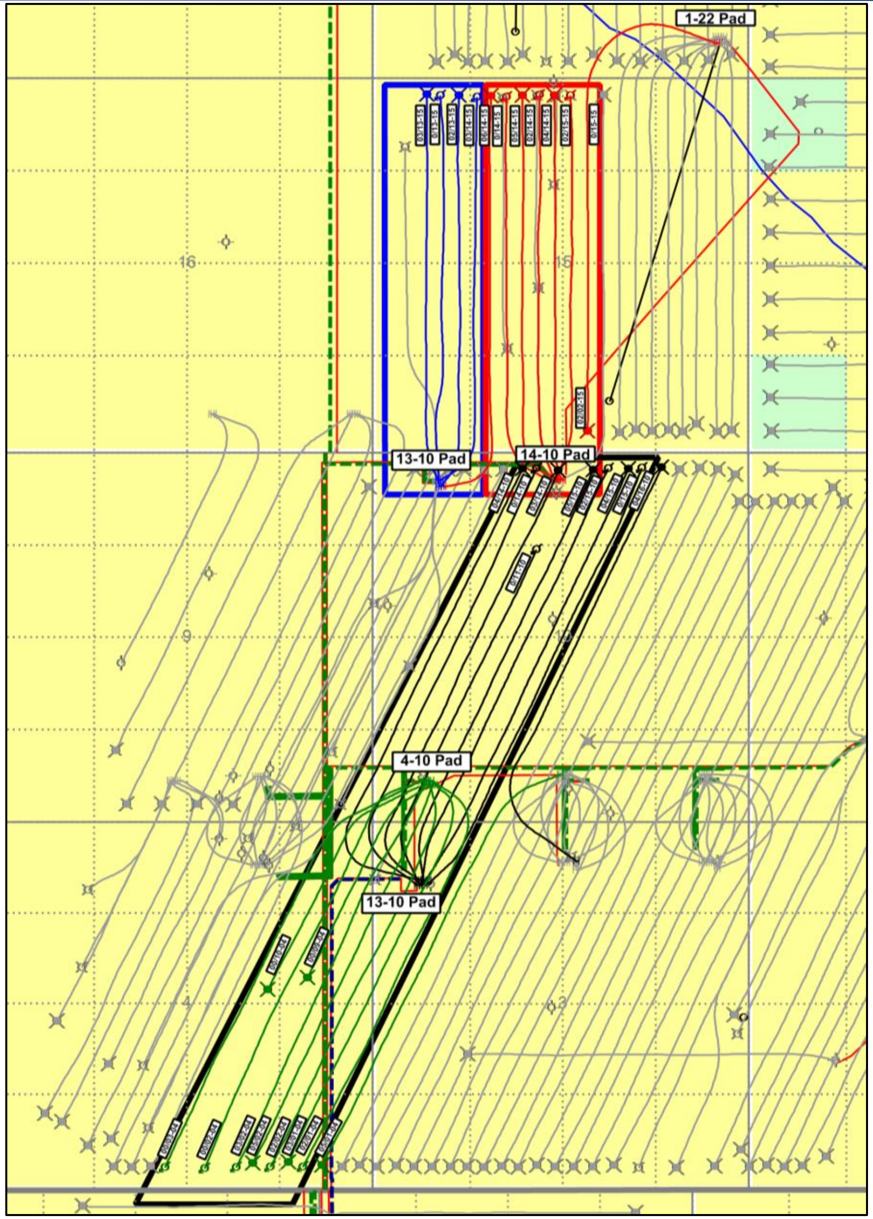
Phase 1

65,847 m^3 injected

Phase 2

133,160 m^3 injected

Total = 402,891 m^3 injected



Gas Usage – Volumes

- Gas usage shown in table below shows values reported into Petrinex,
  - breakdown of inlet and outlet gas into Murphy Oil Central Processing Facility at 04-33-82-15W5 (AB BT 0094150).
- Produced gas from polymer operation is associated with specific wells under Polymer scheme.
- Consumed gas is fuel gas used:
  - in the Field including polymer operations,
  - central processing facility at 4-33, and
  - custom treater level at 4-33: AB CT 0133398
- Flared and vented gas are reported at the 4-33 battery level (AB BT 0094150).
  - There is no flare for the polymer operation.
  - Vented gas takes into account field gas in solution from test tanks including polymer operations and reported at the battery level.

Gas Usage – Volumes

- **Petrinex Reported in 2015 for the Murphy Plant at 4-33 (ABBT 0094150). Gas Volumes in e3m3 (x 10^3 m^3 standard conditions).**

Inlets	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Produced Gas (Field + Polymer)	2556	2323	1896	1550	2089	1876	1871	2155	2036	2117	2179	2820
Produced Gas (Polymer only, Area 1)	125.9	83.9	93.8	97.9	175.1	205.6	220.6	258.7	197.5	202.7	113.3	216.5
Produced Gas (Field only)	2430	2239	1802	1452	1913	1671	1650	1896	1839	1915	2066	2603
Received (Gas from various batteries including third party)	827	932	854	1076	736	726	609	242	487	206	158	205
Total Inlets (Field + Polymer + Received)	3383	3255	2750	2626	2824	2602	2480	2397	2524	2323	2337	3025
Outlets	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
Consumed (4-33 Fuel)	191	178	70	679	344	340	407	285	450	285	205	772
Consumed (Fuel in Field + Polymer)	727	628	608	556	575	530	472	495	475	413	350	454
Consumed (Disposition, AB CT 0133398)	312	525	461	403	285	230	238	244	273	316	340	389
Flared	50	17	995	937	1072	1095	1044	1002	958	223	156	71
Vent (Field Gas in Solution)	16	12	10	10	2	6	3	2	0	0	0	0
Delivered (Disposition, AB GS 0095626)	2086	1896	606	40	546	402	316	369	368	1087	1286	1340
Difference	0	0	0	0	0	0	0	0	0	0	0	0
Total Outlets	3383	3255	2750	2626	2824	2602	2480	2397	2524	2323	2338	3025

Surface

- Facilities
- Production Accounting
- Water & Gas Usage
- **Regulatory**
- Conclusions

Regulatory - Scheme Approval

- Murphy is in compliance with conditions of the scheme approval and regulatory bodies (AER, SRD, and DFO)
- Now compliant with Water Use Reporting (AB Environment & Parks) indicated in Water Term Licence 00289082-00-00.
  - Submitted 2014 and 2015 annual report to WURS with disclosure and compliance plan.
  - To submit monthly data from April 2016 onwards.

Surface

- Facilities
- Production Accounting
- Water & Gas Usage
- Regulatory
- **Conclusions**

Conclusions

- Murphy is committed to maximizing the value of the resource for its shareholders and the Province of Alberta through it's royalty interest.
- Observations made over the past year will be applied to future polymer projects within Seal Lake. No current plans for expansion.
- Murphy's is committed to ensuring compliance with AER and Alberta Environment and Parks, with a strong focus on Water Use Reporting for 2016.