2016 Annual Summary Report on Casing Integrity

Submitted: May 5, 2017

EXECUTIVE SUMMARY

Casing Failures

- Total number of casing failures in 2016 (all depths) was 52, versus 87 in 2015.

Near Surface

- 20 wells with failures in 2016, versus 25 in 2015.
- Failure frequency of 0.38% of wells per year in 2016.
- No failures in 2016 had an environmental consequence above Level 0 (no adverse impact).
- All 20 failures in 2016 were on low pressure wells or wells already suspended and had no potential for liquid release.
- 19 failures were detected operationally through visual checks and 1 failure was detected through regulatory pressure tests on a suspended well.
- 18 wells repaired by surface casing patch, 1 well remained zonally abandoned, as the failure was detected during regulatory pressure test, 1 well was slimholed.

Intermediate Depth

- 23 wells with failures in 2016, versus 37 in 2015.
  - 17 of 23 failures were on low and high pressure active wells, the lowest number and frequency on active wells in those categories since 2005.
  - 6 of 23 wells were zero pressure wells (suspended or rig on well) with no potential consequence.
- Failure frequency of 0.44% of wells per year in 2016.
  - Lowest failure frequency since 2005.
- No failures in 2016 had an environmental consequence above Level 0 (no adverse impact).
- 6 high pressure failures in 2016. No mud kills. All were successfully managed by flowing up the tubing with nitrogen (N2) on the annulus to maintain the fluid level below the casing failure.
- No multi-well failures occurred in 2016.
- 13 casing failures detected operationally, 10 of which by passive seismic.
- 10 casing failures detected with casing integrity (CI) checks, which include 4 identified on wells already suspended.
- 1 well is currently being depressured so that a service rig can move to the well. 10 wells repaired or have planned repairs (i.e. slimhole, MH Patch), 1 well suspended, 6 wells zonally abandoned, 5 wells were zonally abandoned or temporarily suspended at the time of failure discovery, and were left as such.

Clearwater

- 9 failures in 2016, versus 25 failures in 2015.
- No adverse environmental impacts.

Well Casing Repairs

- Casing repairs completed on 46 wells in 2016 that returned to service.
  - Includes 13 wells which were proactively repaired with a slimhole due to casing impairments.

Casing Failure Detection Initiatives

Alarm Management

- Automated software for real-time passive seismic alarms now functional for high pressure pads, accelerating response time to a potential casing failure detected by the passive seismic systems.

Near Surface Casing Integrity Initiatives

- Continuation of a field trial applying high temperature resistant metallic aluminum coating to select well near surface production casings to evaluate effectiveness in reducing corrosion rates.
- Imperial has adopted ultrasonic (UT) inspection technology for thermal wellbores, leveraging long term industry experience with UT on surface equipment such as tanks, vessels and piping. Completed external UT inspections on 57 wells. As a result of UT inspection, 21 wells returned to high pressure HPCSS operation that were previously identified as having higher wall loss.
- Concluded external corrosion measurement 'log-off' of 9 in-well wall loss measurement tools to evaluate which technologies are most suitable for Cold Lake thermal wellbores.
- Casing protective shroud redesign underway to improve strength and ease of installation and removal.

Intermediate Depth Casing Integrity Initiatives

Wellbore Environment Control

- Near 100% compliance of N2 purge practices to reduce risk of sulphide stress cracking (SSC) failures.
- Discontinued N2 purging on low pressure pad wells (reservoir pressure <4 MPa for remaining life). No adverse results are expected, and increase focus can be placed on N2 purging for high pressure pad wells.

Casing Repair Technology

- Continued to progress two high pressure – high temperature steamable casing patch trials in 2016:
  - Saltel casing patch installed in four wellbores and exposed to partial steam cycles in all wells. Two of the wells have undergone full steam cycles. Results are favorable.
  - Schlumberger MHE patch installed in one wellbore and exposed to two partial steam cycle and one full steam cycle. Results are favorable.

Casing Fatigue Research

- Analysis was completed which determined that there was no value to increasing the current 7" 23lb/ft casing to a heavier 7" 32lb/ft casing for new drill wells. This design change will not be pursued further.

1.0 INTRODUCTION

Pursuant to the requirements of AEUB Decision 99-22, condition #9 and clause 6.2 of AEUB Approval 8558, Imperial hereby submits the 2016 Annual Summary Report on Casing Integrity and remediation efforts.

This report has been submitted annually since 2000 and as such builds on information that was included in previous reports, with focus on 2016 performance.

For the purpose of this report, a casing failure is defined as a break or crack in the production casing that results in the well's inability to contain pressure. A primary failure is defined as being limited to a single well; a secondary (or multi-well) failure occurs when fluid loss from a primary failure results in immediate adjacent well failures. Casing failures have been classified by the following three depth intervals:

- Near surface (0 to ~25 mTVD).
- Intermediate, including the Quaternary, Colorado group, and Grand Rapids formations.
- Clearwater, at the interface between the Clearwater formation and the Grand Rapids formation or lower.

Undetected, high pressure, near surface and intermediate well failures in the upper part of the wellbore have potential for environmental consequence due to aquifer contamination or breach to surface. Clearwater production zone failures only affect the operability of the well. The existing casing integrity program for Cold Lake was designed to address the concerns associated with the near surface and intermediate depth intervals, and was not intended to deal with failures within the production zone.

Near surface and intermediate depth casing failures with potential for adverse environmental impact are assigned an environmental consequence level. Clearwater failures do not have an adverse environmental impact, and therefore are not assigned one. Casing failures that occur within the Glacial Till or within 75 meters of the Colorado Shale group (bedrock) top and have produced fluid loss are ESRD (now AER) reportable. The response follows the Cold Lake Operations Incident Response Plan. Consequence levels are assigned jointly by environmental and engineering personnel utilizing the descriptions provided in Table 1.

Table 1: Environmental Consequence Matrix for Casing Failures

Consequence Level	Environmental Consequence Description
Level 0	- Failure occurred within the bedrock with fluid loss below the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m^3 produced fluid, dependent on proximity of wellbores at failure depth) - Failure occurred within the Glacial Till, but only released inert fluid (e.g. N_2 gas) or minimal produced fluid not requiring remediation
Level 1	- Failure occurred within the bedrock with fluid loss above the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m^3 produced fluid, dependent on proximity of wellbores at failure depth) - Failure released fluid into the Glacial Till and there is low potential of the fluid migrating to a freshwater aquifer (i.e. volume released from failure is low, or the aquitard layer is thick)
Level 2	- Failure with fluid release to surface or fresh water aquifer requiring longer term remediation efforts

Note: Bedrock is defined as solid rock that underlies unconsolidated surface material (i.e. Bedrock includes the Lea Park and/or Colorado Group and lower formations).

For the purpose of this report, failures are defined as being detected either operationally or through a casing integrity (CI) check. An operational detection is defined as a failure detected with the differential flow & pressure (DFP), nitrogen soak, passive seismic (PS) systems, or detected by visual means. A casing integrity check detection is defined as a failure detected as part of the pre-steam casing integrity process (identified through a service rig based casing integrity check, or Electro-Magnetic (EM) logging casing integrity check). The failures detected as part of the D013 five year pressure testing requirement of a suspended well are also considered as detected through a CI check.

2.0 CASING INTEGRITY DATA

A historical summary of well casing failures by depth interval at Cold Lake is provided in Table 2. All 23 of the intermediate depth casing failures detected in 2016 were classified as primary commercial intermediate failures originally completed with L-80 or N-80 casing strings. All of the near-surface and intermediate casing failures that occurred in 2016 were deemed to be Level 0 environmental consequence events. Of the 43 near-surface and intermediate failures detected in 2016, 32 were detected operationally and 11 were detected through casing integrity checks.

Table 2: Historical Failure Summary by Depth Interval

Depth Classification	Year											
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Surface	1	1	5	16	16	11	13	7	21	19	25	20
Intermediate	16	26	36	30	29	34	34	30	33	33	37	23
Clearwater	51	70	71	56	58	17	19	8	9	17	25	9
Total	68	97	112	102	103	62	66	45	63	69	87	52

2.1 Near Surface Casing Integrity Data

Since 1996, 196 commercial wells have failed in the near-surface region, including 20 near surface failures detected in 2016. Near surface casing failure frequency has increased in recent years. An analysis of this trend, as well as a mitigation plan is discussed in subsequent sections of this report. Details describing the failures that occurred in 2016 are provided below in Table 3. In addition to failed wells in 2016, one well was proactively repaired with a dig out repair due to high corrosion (U01-19).

Table 3: 2016 Surface Depth Failure Summary

No.	District	Well	Date	Depth(mKB)	Pad Cycle	Detection Method	Env Consequence Level	Repair
1	Mahihkan	J02-04	12/22/2016	1.0	11	Operational	0	Surface Patch
2	Maskwa	D03-06	12/15/2016	1.0	13	Operational	0	Surface Patch
3	Maskwa	E03-05	12/12/2016	1.0	8	Operational	0	Surface Patch
4	Maskwa	F06-21	11/11/2016	19.0	8	Operational	0	Surface Patch
5	Maskwa	D65-04	11/11/2016	1.0	8	Operational	0	Surface Patch
6	Mahihkan	J02-03	10/28/2016	4.3	11	Operational	0	Surface Patch
7	Maskwa	D04-03	10/17/2016	4.5	11	Operational	0	Slimhole
8	Mahihkan	J02-07	10/2/2016	4.6	11	Operational	0	Surface Patch
9	Mahihkan	J02-12	9/22/2016	4.3	11	Operational	0	Surface Patch
10	Maskwa	D53-15	9/5/2016	4.1	7	Operational	0	Surface Patch
11	Mahihkan	J07-01	7/14/2016	4.5	11	Operational	0	Surface Patch
12	Mahihkan	H25-22	7/10/2016	1.0	10	Operational	0	Surface Patch
13	Mahihkan	J07-14	6/30/2016	4.2	11	Operational	0	Surface Patch
14	Mahihkan	J07-13	6/21/2016	4.8	11	Operational	0	Surface Patch
15	Maskwa	E08-18A	6/21/2016	5.0	9	CI Check	0	Not Repaired - Well is Zonally Abandoned
16	Maskwa	D62-16	5/2/2016	4.0	8	Operational	0	Surface Patch
17	Mahihkan	J21-05	4/20/2016	1.0	9	Operational	0	Surface Patch
18	Mahihkan	J06-06	3/14/2016	4.0	10	Operational	0	Surface Patch
19	Mahihkan	H02-12	3/8/2016	4.5	11	Operational	0	Surface Patch
20	Mahihkan	R02-20	2/10/2016	5.3	7	Operational	0	Surface Patch

Historic consequence levels associated with near surface casing failures since 1996 are displayed in Figure 1. All near surface failures, except H01-03 in 1996, were assessed at a level 0 environmental consequence, including all 2016 failures.

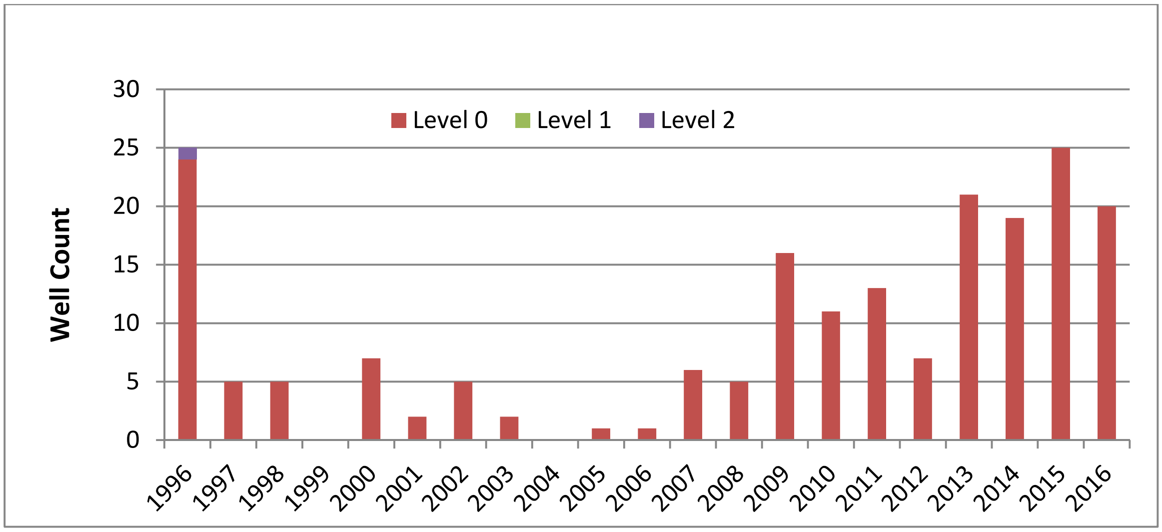

Figure 1: Cold Lake Surface Failures by Consequence Level

In 2016, all near surface corrosion failures occurred on late-life, low pressure wells with no potential to flow to surface. Hence, there are no potential adverse consequences associated with these failures. The majority of these failures were on wells aged 30+ years of operation.

The number and frequency of near surface external corrosion related casing failures for the commercial casing design in Cold Lake are summarized below in Figure 2. The 2016 near surface casing failure frequency was 0.38%. Failure frequency is the number of failures divided by the total number of wells operating. The peak failure frequency of 1.26% (red line) observed in 1996 marks the inception of Imperial's casing integrity operating practices. At that time, the bentonite top-up program was developed to reduce corrosion and subsequent improvement was observed with abatement of corrosion at the primary cement top depths. Failure frequency has increased in the 2009-2016 period. This increase is a result of the aging well population, with many low pressure operating wells now at 25-30 years-of-service. With abatement of corrosion at the original primary cement top, the corrosion cell has now been moved very close to surface. Finally, wells with corrosion that began as a result of lower quality bentonite top-ups and higher corrosion rates from the late 1990's through approximately 2010, are now reaching the point where near-surface failures are occurring.

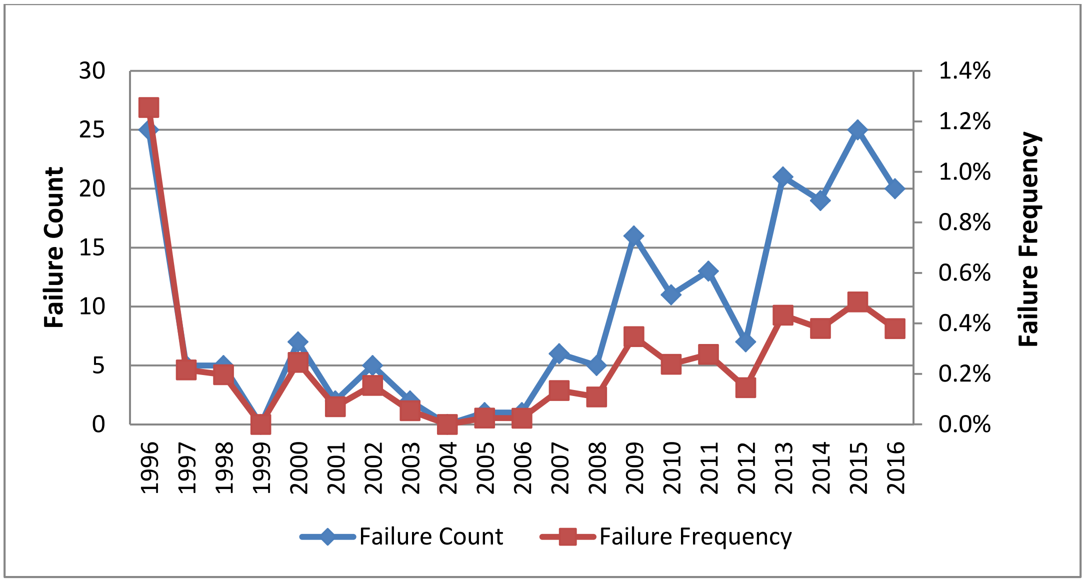

Figure 2: Commercial Near-Surface Failures and Failure Frequency

For information on near surface corrosion initiatives targeted at reducing failures at this depth, see Section 3.2.

In 2016, 19 of the near-surface casing failure events were found operationally via visual inspection. The remaining 1 failure was found through a regulatory pressure test on a suspended well. The historical detection trends are shown in Figure 3 below.

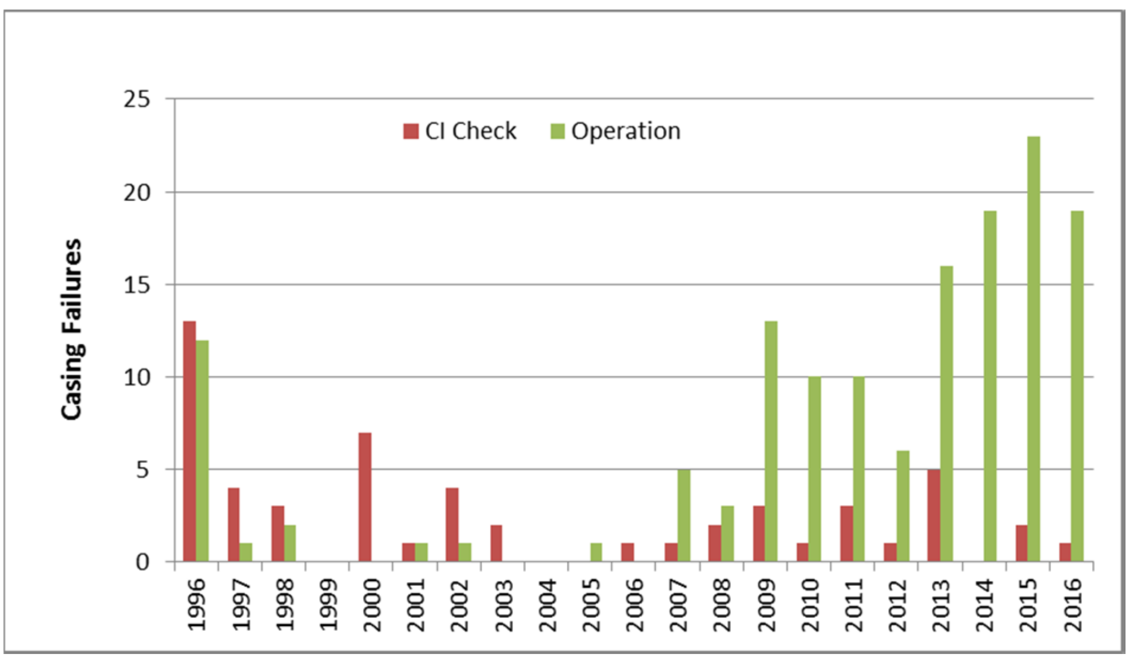

Figure 3: Commercial Surface Failures by Detection Method

Near Surface Depth Casing Failure Resolution:

Of the 20 near surface failures in 2016, 18 wells repaired by surface casing patch, 1 well remained zonally abandoned as the failure was detected during regulatory pressure test and 1 well was slimholed as two intermediate casing failures were identified with a service rig following detection of near surface failure.

2.2 Intermediate Depth Casing Integrity Data

The scope of this document includes intermediate depth failures that have occurred in wells with L-80 or IK-55 casing (also referred to as ‘commercial’ design), and does not include early casing designs, such as SOO-95. There were no failures in wells of pre-commercial casing design in 2016.

Since the implementation of the casing integrity operating practices in 1996, a total of 534 primary intermediate casing failures have been detected in wells with commercial casing designs. Approximately 57% of these failures were identified during rig-based casing integrity checks (i.e. pre-steam, Passive Seismic follow-up, regulatory D013 5 year pressure tests), with the remaining 43% identified through operational monitoring systems. Details of the 23 wells with casing failures occurring in 2016 are included in Table 4 below.

Table 4: 2016 Intermediate Depth Failure Summary

No.	District	Well	Date	Depth(mKB)	Depth (mTVD)	Pad Cycle	Formation	Pipe Body / Connection	Connection Type	Env Consequence Level	Repair
1	Mahihkan	H62-05	12/24/2016	260.0	258.2	6	Colorado Shales	Unknown	SWNA	0	TBD - Well is Depressuring
2	Mahihkan	H58-H06	12/19/2016	282.5	279.0	7	Colorado Shales	Connection	NSCC	0	Not Repaired - Well is Zonally Abandoned
3	Mahihkan	H69-H01	11/24/2016	260.0	259.9	5	Colorado Shales	Connection	SWNA	0	Slimhole
4	Mahihkan	H62-23A	10/19/2016	284.0	280.0	6	Colorado Shales	Connection	NSCCM	0	Slimhole
5	Maskwa	D04-03	10/17/2016	311.0	295.7	11	Colorado Shales	Pipe	OBTC	0	Slimhole
				221.8	217.0			Connection			
6	Maskwa	E11-14	10/14/2016	230.0	229.8	7	Colorado Shales	Connection	NSCC	0	Not Repaired - Well is Suspended
7	Mahihkan	J02-12	9/26/2016	265.0	264.2	11	Colorado Shales	Unknown	OBTC	0	MH Patch
8	Mahkeses	T07-14	9/15/2016	366.9	361.4	9	Colorado Shales	Pipe	NSCC	0	Slimhole
9	Mahkeses	T08-04	8/3/2016	357.2	344.8	11	Grand Rapids	Connection	NSCCM	0	Zonal Abandonment - TOC brought above the break
10	Mahihkan	H58-23	7/30/2016	216.5	216.4	7	Colorado Shales	Connection	NSCC	0	Slimhole
11	Mahihkan	H58-H01	7/18/2016	221.1	219.7	7	Colorado Shales	Connection	NSCC	0	Slimhole
12	Mahihkan	H02-04	7/1/2016	307.0	288.6	11	Colorado Shales	Unknown	OBTC	0	Zonal Abandonment - TOC brought above the break
13	Maskwa	D12-11	6/24/2016	278.4	267.2	10	Colorado Shales	Unknown	OBTC	0	Not Repaired - Well is Suspended
14	Mahihkan	R06-11	6/10/2016	200.9	197.6	6	Colorado Shales	Unknown	OBTC	0	Not Repaired - Well is Zonally Abandoned
15	Mahkeses	U04-21	5/5/2016	245.3	244.4	9	Colorado Shales	Pipe	NSCCM	0	Zonal Abandonment
16	Mahihkan	H51-19	4/26/2016	296.5	286.4	7	Colorado Shales	Connection	SWNA	0	Zonal Abandonment
				268.5	262.8			Connection			
				308.5	295.9			Connection			
				216.0	214.6			Connection			
				193.0	192.5			Pipe			
17	Mahihkan	L09-15	4/17/2016	284.3	283.3	5	Colorado Shales	Connection	NSCCM	0	Slimhole
18	Mahkeses	V04-02	3/24/2016	312.4	307.2	9	Colorado Shales	Unknown	NSCC	0	Not Repaired - Well is Zonally Abandoned
19	Mahihkan	J06-06	3/20/2016	291.9	271.8	10	Colorado Shales	Connection	OBTC	0	MH Patch
20	Mahkeses	V09-23	3/11/2016	236.6	235.4	8	Colorado Shales	Connection	QB2	0	MH Patch
21	Maskwa	D10-16	3/8/2016	234.0	222.7	10	Colorado Shales	Connection	OBTC	0	Zonal Abandonment - TOC brought above the break
22	Mahihkan	H47-01	2/28/2016	213.0	209.6	8	Colorado Shales	Unknown	NSCC	0	Suspension
23	Mahkeses	V13-23	1/1/2016	293.9	293.5	5	Colorado Shales	Connection	NSCC	0	Zonal Abandonment

Historic environmental consequence levels associated with intermediate casing failures since 1998 are displayed in Figure 4. In 2016 there were no intermediate casing failure events that were classified higher than a Level 0 Environmental Consequence event (no events resulted in adverse environmental consequences). Three historical intermediate failures have required aquifer remediation (H15-10 in 1999, H39-H04 in 2006, and V13-31 in 2012).

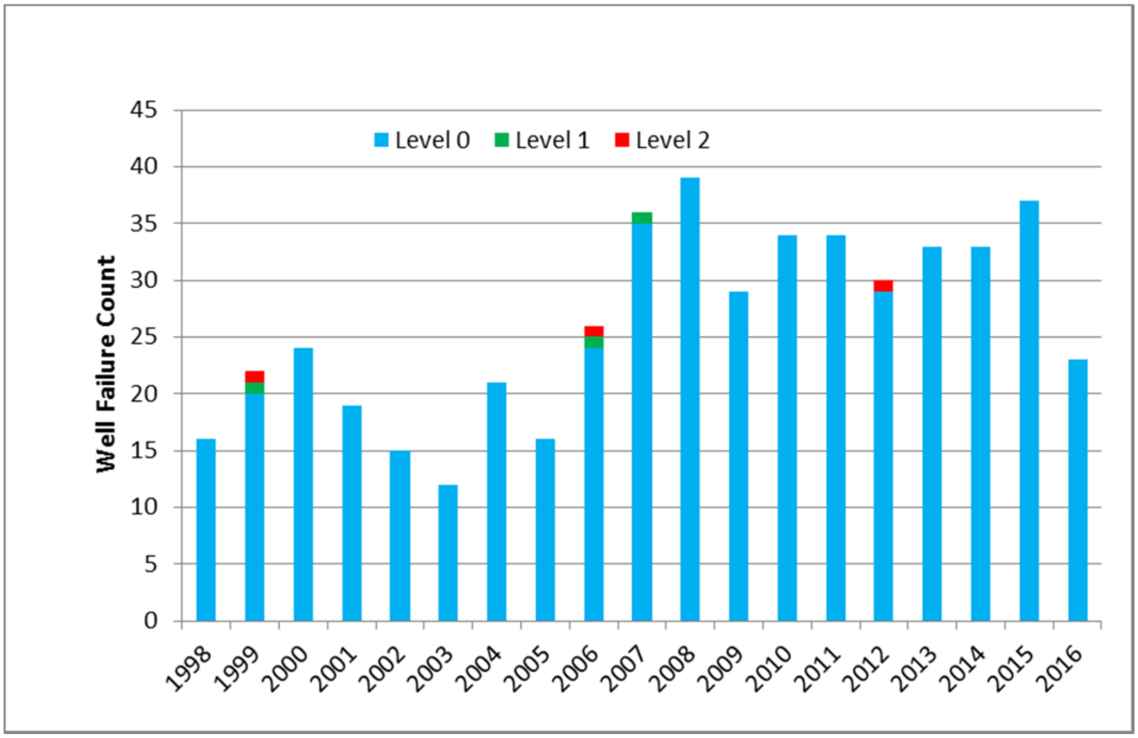

Figure 4: Cold Lake Intermediate Failures by Consequence Level

Many enhancements to Imperial's casing integrity processes and detection systems, as discussed in section 3.0, have led to a reduction in the rate of higher potential consequence events since 2007, as shown in Figure 5. In 2016 there were 6 high pressure failures, or 26% of the total intermediate failures. However, none of the intermediate casing failures required mud kills in 2016 and all were successfully managed by flowing up the tubing with N2 on the annulus to maintain the fluid level below the casing failure. The percentage of failures occurring at high pressure remains below that of the 2006-2007 timeframe.

In 2016, there were 6 failures (26% of total) discovered on wells that were already suspended or were at 'No Pressure' (eg. during pressure tests on suspended/zonally abandoned wells) with no potential for liquid loss. If these 'No Pressure' failures are excluded, there were a total of 17 failures on 'Low Pressure' and 'High Pressure' active wells. By trending the top of the violet colored bar in Figure 5, it can be seen that this is the lowest number of failures on active low and high pressure wells over the past 10 years.

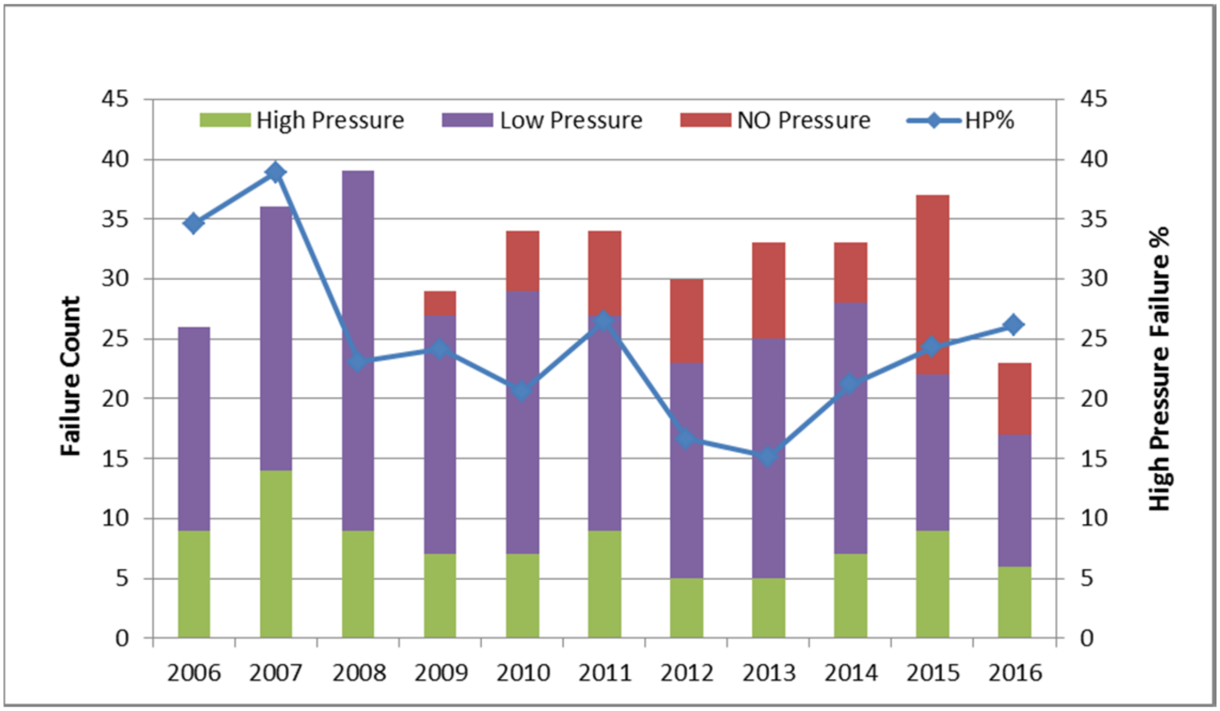

Figure 5: Intermediate Casing Failures by Pressure Category

In 2016, there were no casing failures with liquid losses which could have had an adverse impact on the integrity of adjacent wellbores, and there were no adverse environmental impacts. The total volume of liquid loss in 2016 was negligible, as shown in Figure 6.

The primary response to a high pressure intermediate casing failure is to control the fluid level below the casing break depth with nitrogen on the annulus and flow back fluids up the tubing to avoid produced liquid losses through the casing break, with concurrent de-pressuring of the reservoir in the area of influence as needed. Imperial maintains all necessary kill fluid additives in the field in order to perform a high pressure mud well kill if this primary response procedure is not possible or practical, as outlined in Section 3.5.

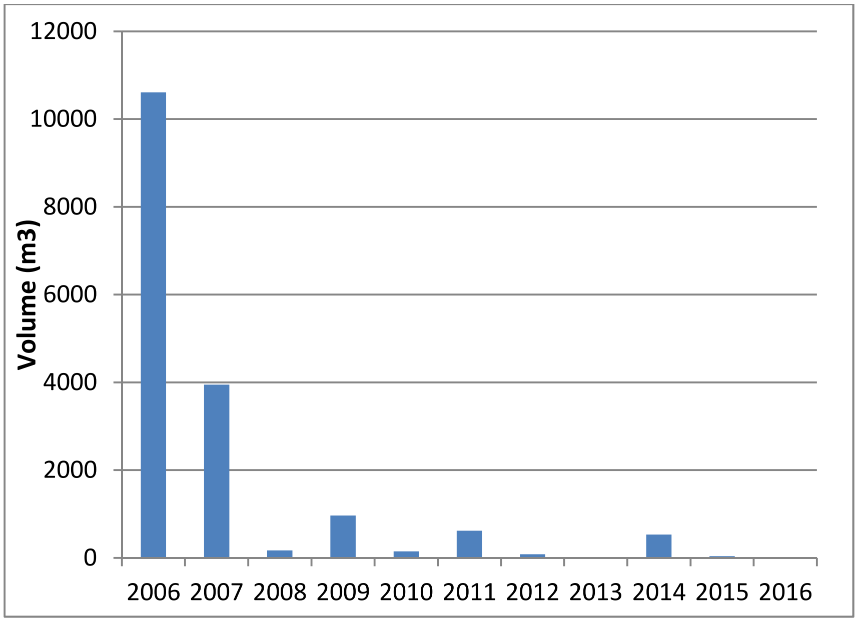

Figure 6: Intermediate Failure Liquid Loss by Year

The primary intermediate casing failure frequency for commercial casing design and total Cold Lake district well count are presented in Figure 7. Intermediate casing failure frequency for 2016 was 0.44%. The number and frequency of failures in 2016 is the lowest since 2005. The predicted failure frequency is ~0.60-0.63%, based on adding low pressure wells with passive seismic events that may confirm a failure during casing checks performed prior to next steam. This predicted frequency would remain among the lowest in a decade. Improvement in Imperial's casing integrity performance is a result of continued casing check program optimization, improvements in risk-based targeted selection of wells checked, and enhanced usage of the PIMFET shear stress management tool which helps to define steaming strategies.

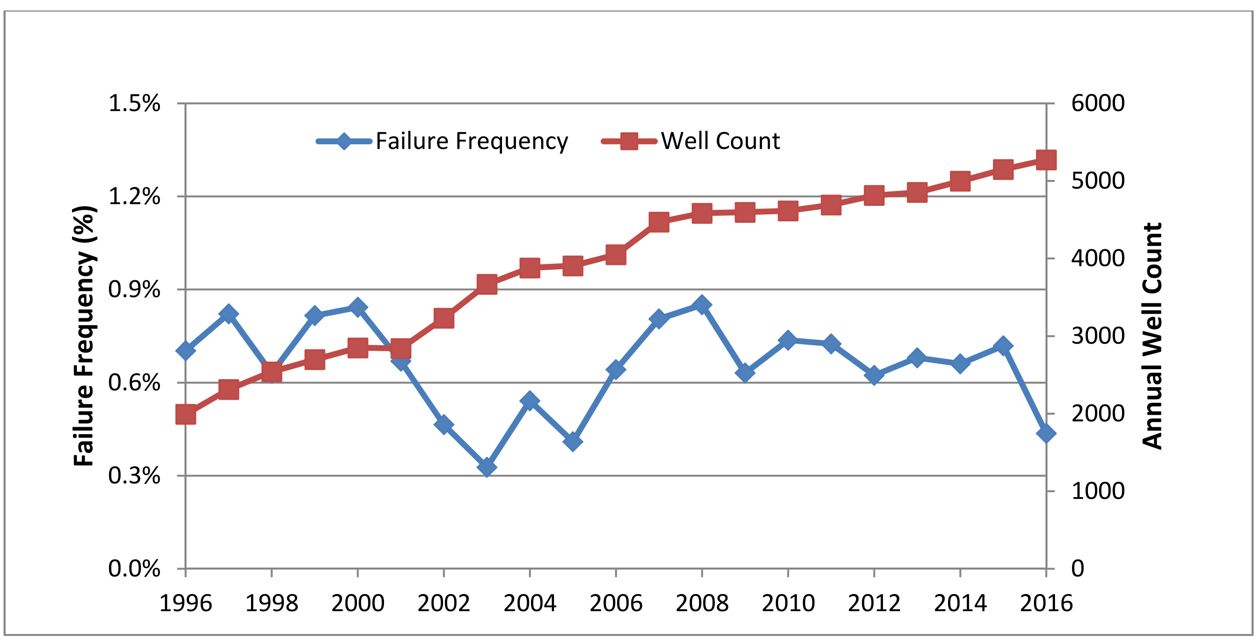

Figure 7: Intermediate Casing Failure and Well Count

In Figure 8, the number of primary intermediate casing failures for Cold Lake commercial casing design are stacked by early (1-4), mid (5-7), and late (8+) cycle periods. The aggregate early cycle failures continue to be lower than mid and late cycle failures. In 2016, for mid-cycle failures, 91% are found through Passive Seismic (8/11 failures) and N2 Soak monitoring (2/11 failures). For late-cycle failures, 75% are identified through Casing Integrity Checks – 3/12 follow-up from near surface failures, 3/12 from D013 - 5 Yr Pressure tests, 3/12 from pre-steam Casing Integrity Checks and the remaining 3/12 from N2 fluid monitoring and Passive Seismic.

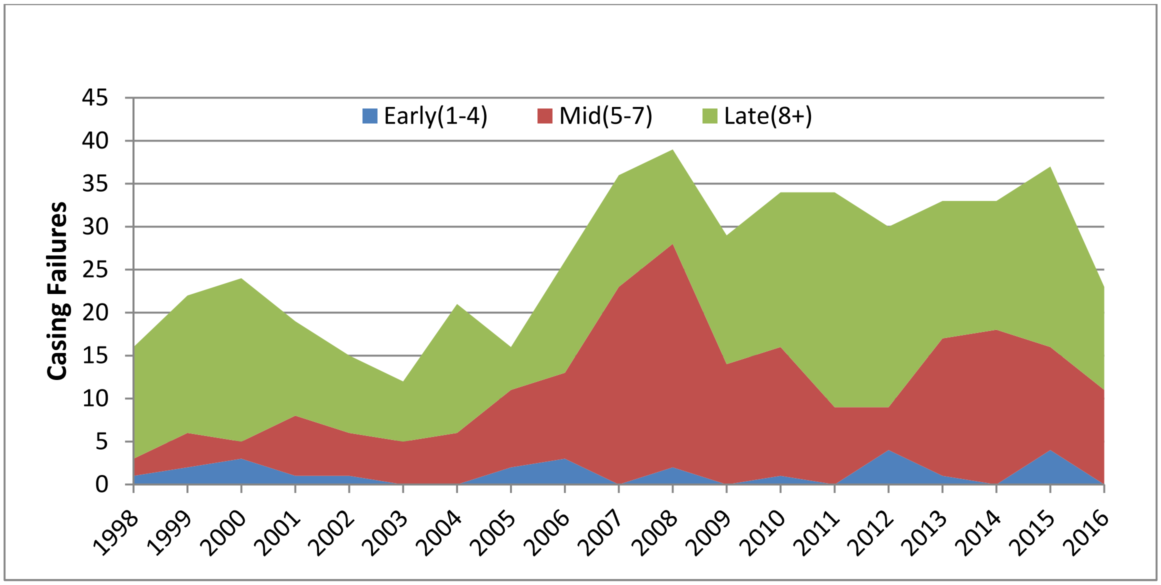

Figure 8: Intermediate Failures by Cycle Range

In Figure 9, the intermediate failure frequencies for commercial casing design data are again divided into early (1-4), mid (5-7), and late (8+) cycle classifications. The failure frequency is calculated by dividing the number of failures in a cycle classification by the total number of wells in that classification. Early cycle failure frequency is driven by unique wells or rare events. Mid cycle failure frequency steadily increased between 2004 and 2008 due primarily to failures at Mahkeses, and again from 2012-2014 as Mahihkan North moved through that stage of well life. The number of mid cycle failures has fluctuated annually, dependent on how many pads are moving through this period where casing failures generally start to be observed. The late cycle and total failure frequency trends have stayed fairly consistent for the past several years. The total number of wells in each of the three cycle classifications is distributed as follows:

- No significant changes or trends
- Early cycle: ‘15 increase on early-cycle is Nabiye collapses (both cycle1), and T18-05 (cycle4)
- Mid cycle: ‘14 spike on mid-cycle due to Y32 and Mahihkan North; ‘15 is primarily Mahihkan North
- ‘Late cycle continues to drop with LP operations

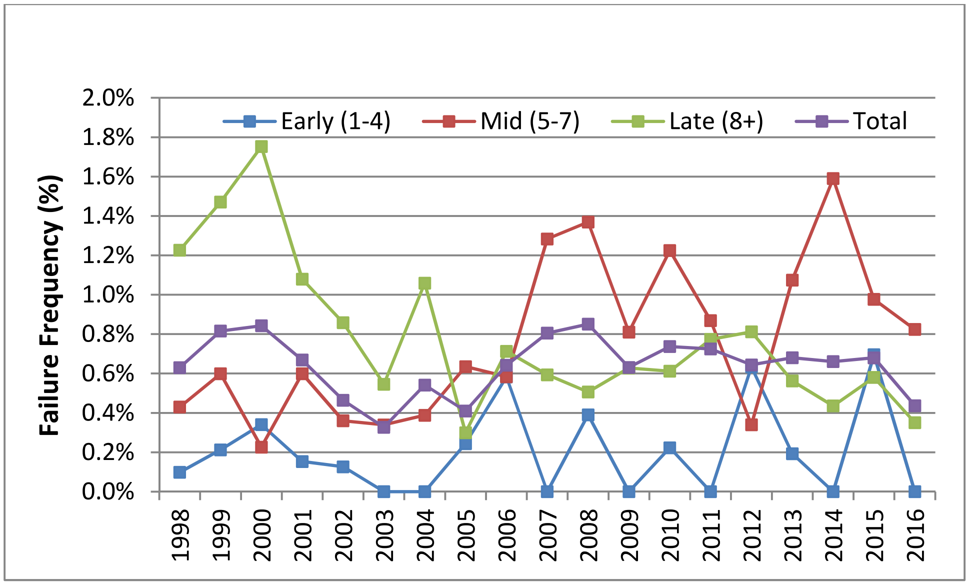

Figure 9: Intermediate Failure Frequency by Cycle Range

The intermediate failure detection method is displayed in Figure 10. Approximately 57% of intermediate casing failures are identified during rig based casing integrity checks (i.e. pre-steam, Passive Seismic follow-up, regulatory D013 5 year pressure tests) since 1996. However, the percentage of operationally identified casing failures has generally increased since 2002, mainly due to increased detection capabilities and enhancements through the passive seismic and nitrogen soak monitoring programs.

Of the 10 failures in 2016 detected by casing integrity check, 4 occurred on wells that were already suspended and isolated from the Clearwater reservoir (i.e. rig based D013 5-year pressure tests on suspended wells or during other wellwork activities on prior suspended wells), 3 occurred on wells following the identification of a near surface failure and the remaining 3 failures were found during standard CI checks as part of Imperial's integrity monitoring process.

Of the 13 failures in 2016 detected by operational monitoring systems, 10 were initially identified by passive seismic and 3 were identified by nitrogen soak/fluid shot monitoring programs.

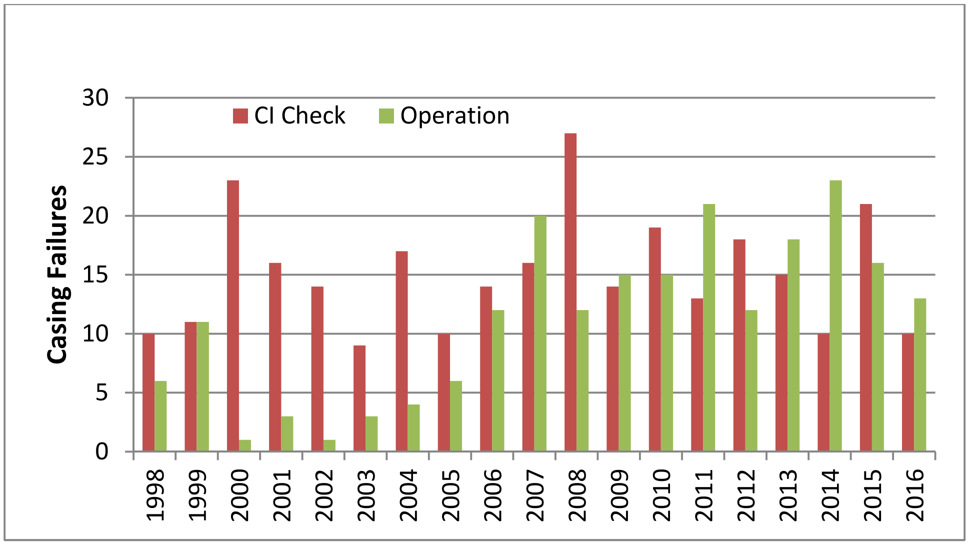

Figure 10: Primary Intermediate Failures by Detection Method

<u>Intermediate Depth Casing Failure Resolution:</u>

The 23 intermediate depth well failures discovered in 2016 were managed in the following way:

- 1 well is currently flowing up the tubing with Nitrogen to keep fluid below the break so that a service rig can move to the well
- 7 wells repaired with a slimhole liner
- 3 wells repaired with a retrievable casing patch (near surface failure also repaired with a retrievable near surface patch)
- 1 well suspended
- 3 wells zonally abandoned with cement brought above the break.
- 3 wells zonally abandoned.
- 3 wells that were already zonally abandoned remained in that configuration
- 2 wells that were already suspended remained in that configuration

The cemented slimhole liner remains a common repair procedure to return wells to high pressure steaming operations. In total there were 27 slimhole repairs completed in 2016. Of these 27 wells, 13 were performed proactively on wells with casing impairments (not casing failures).

Overall, 46 wells were repaired in 2016 and returned to service. This consists of repairs to intermediate depth failures and impairments (27 by slimhole, 3 by retrievable casing patch), and near surface depth failures (18 by near surface patch, 1 with surface digout). Note – 3 wells had a near surface patch and a MH patch set for a total of 49 casing repairs in 46 wells.

2.3 Clearwater Casing Integrity Data

In 2016 there were 9 Clearwater casing failures detected. Well failure details are displayed in Table 5.

Table 5: 2016 Clearwater Failures Summary

No.	District	Well	Date	Depth (mKB)	Depth (mTVD)	Pad Cycle	Depth Class
1	Mahkeses	T01-18	10/12/2016	636	488	9	Clearwater
2	Mahihkan	H58-23	7/30/2016	546	422	7	Clearwater
3	Maskwa	A03-14	6/21/2016	434	417	10	Clearwater
4	Mahkeses	0DD-18	6/6/2016	479	429	9	Clearwater
5	Mahkeses	V10-12	4/12/2016	690	438	6	Clearwater
6	Mahihkan	H65-21	3/21/2016	543	433	6	Clearwater
7	Mahihkan	H63-22	2/21/2016	539	435	4	Clearwater
8	Mahihkan	H63-15	2/7/2016	435	433	4	Clearwater
9	Nabiye	N01-09	1/31/2016	515	487	3	Clearwater

The number and frequency of Clearwater casing failures for the commercial casing design in Cold Lake since 1998 are presented in Figure 11. Clearwater failure performance has stayed in a similar range since 2010, which represents a step change reduction from earlier Clearwater failure rates. The reduced failure frequency is likely attributed to a larger portion of the field moving to low pressure operations, an increase in horizontal well development, and enhanced intermediate depth shear stress management having a collective effect on Clearwater top formation movement.

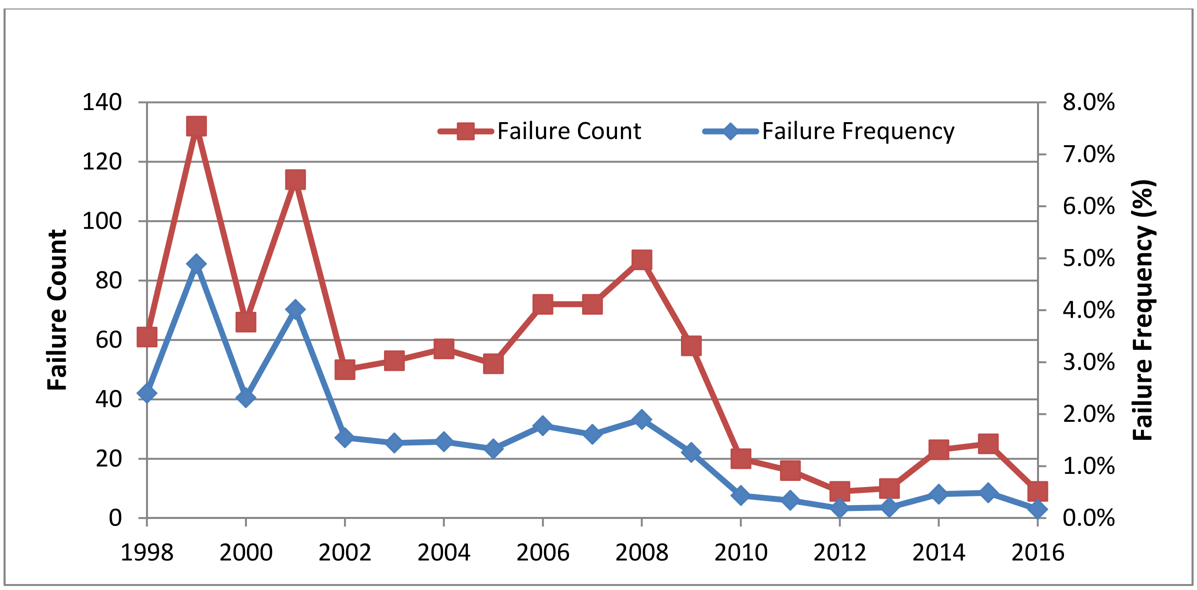

Figure 11: Clearwater Failures and Failure Frequency

2.4 Directive013 Pressure Tests

The table in Figure 12 displays the results of regulatory D013 5-Year pressure tests on suspended wells. In 2016, 213 wells required pressure tests and integrity of the suspension plug was confirmed on all 213 wells.

In three wells (H02-04, D12-11, and R06-11), a new intermediate casing failure was discovered above the top of the isolation plug. In one well (E08-18A), a new near surface depth casing failure was discovered.

New intermediate and surface depth failures found during the 5-Year pressure test are noted in the columns in Figure 12. These are called 'No Pressure' failures since the suspension plugs were isolating the Clearwater perforations from the upper wellbore. These failures are also included in the report sections above.

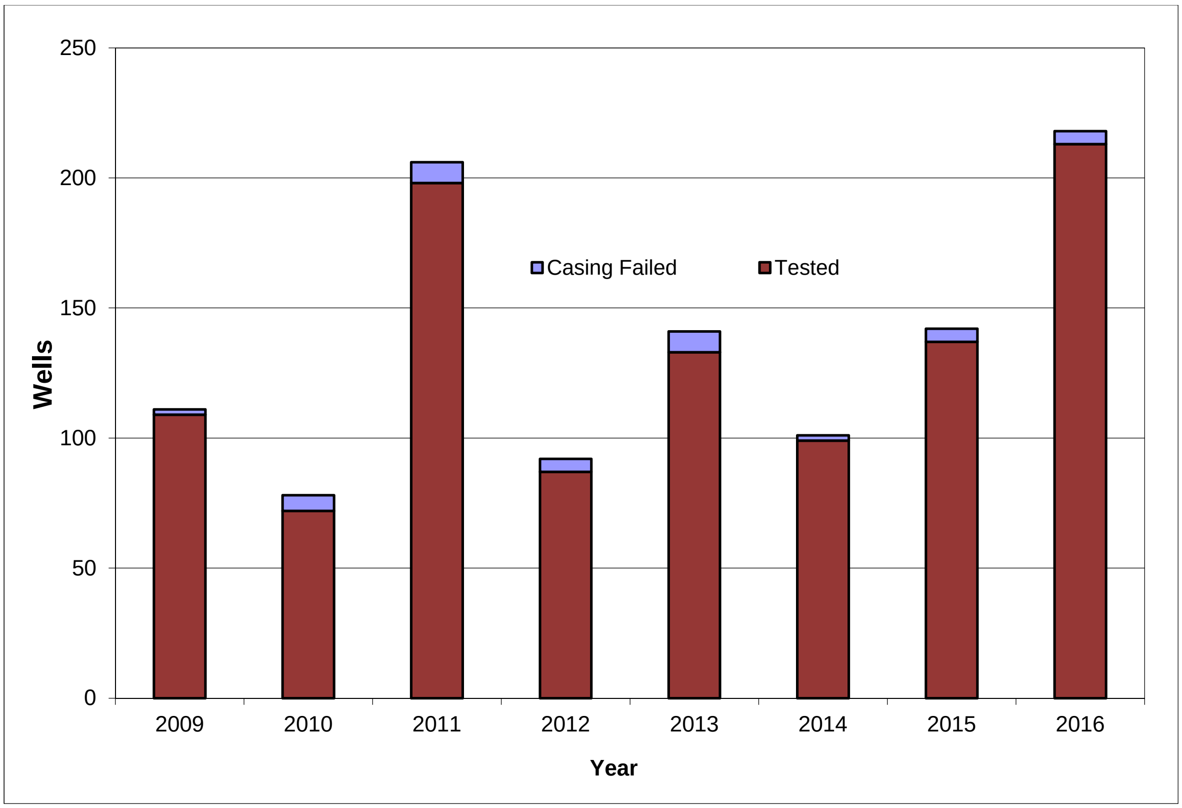

Figure 12: Suspended Well Five Year Pressure Test Performance

3.0 COLD LAKE CASING INTEGRITY MANAGEMENT

Casing integrity is a critical component of the Operations Integrity Management System in Cold Lake. Primary failure mechanisms that have been identified in Cold Lake wells are external corrosion (near surface failures), stress corrosion cracking (SCC), sulphide stress cracking (SSC), and metal fatigue (high strain – low cycle) due to formation movement and slip. The Cold Lake Casing Integrity Operating Practices were formally introduced in 1996 providing improvements in three major areas – prevention, detection, and response to casing failures. Through a continuous improvement approach, the Casing Integrity Operating Practices have been enhanced, modified, and updated with new learnings since their implementation. These practices are reviewed and updated annually.

Improvements and initiatives in detection and prevention (with respect to the three depth classifications), and response to casing failures relevant to 2016 and the future will be discussed in the following sections.

3.1 Casing Failure Detection

The manner in which casing failures are detected at Cold Lake has evolved through time. Imperial continues to rely on several complimentary and overlapping detection systems including:

- Differential Flow and Pressure (DFP) alarms and steam trend analysis during steam injection
- Nitrogen Soak monitoring during soak and shut-in
- Pressure and fluid level monitoring during soak, trickle flowback, and shut-in
- Passive seismic monitoring
- Groundwater monitoring
- Casing integrity check process
- Visual monitoring

Current initiatives will be discussed in the following subsections.

3.1.1 Alarm Management

The monitoring system used during the steam injection portion of the cycle is known as the Delta Flow and Pressure (DFP) program. Steam injection and pressure trends are analyzed on a 15 minute frequency to detect pressure drops and corresponding flow increases. Varying levels of alarms are generated for pressure drops between 25 kPa and 250 kPa. All alarms are investigated and potential casing failure events are cross-referenced to other detection systems and responded to immediately in order to diagnose a potential casing failure. The DFP algorithm was most recently upgraded in 2013 to reduce the number of false alarms and streamline failure detections after prototype test verification.

In a 2014 review of passive seismic performance, moving forward there will be increased focus on passive seismic systems that are operating in high pressure pad areas (>6MPa). Hindcasting of failure data has shown that passive seismic is highly successful at detecting casing failure events on high pressure pads and this strategy will best utilize the system's strengths. Passive seismic systems on lower pressure pads (<6MPa) will be taken out of service, since low pressures cannot enable fluid excursion out of intermediate casing failure depths. This will improve the focus on the high pressure pad systems.

In 2016, additional upgrades to the passive seismic event screening process and assessment tools were made. The software for real-time passive seismic alarms is now functional for high pressure pads which allows for earlier identification and communication of potential casing failure events, with a proven record of earlier detection of several cases in 2016.

3.1.2 *Casing Integrity Check Process*

Since the inception of the Casing Integrity Operating Practices in 1996, casing integrity checks have been conducted proactively to detect casing failures and impairments. A basic casing integrity check consists of both a 21 MPa pressure test and a gauge ring/scraper run to at least the top of the Clearwater formation. Although a well may pass the 21 MPa pressure test, information from the gauge ring/scraper pass can initiate further diagnostics which are used to confirm if well integrity remains acceptable for steam injection activities. This is commonly completed with a multi-sensor caliper log run to determine the extent of a potential casing impairment or deformation. Corrosion inspection logs in the top 50 meters of the wellbore are performed on wells at a prescribed age. Corrosion inspection logs are being synergized with earlier cycle casing integrity checks to optimize the logging schedule and ensure corrosion data is collected on each well prior to its tenth year of operation.

The required casing integrity checks performed on a pad prior to steaming is defined as part of the Casing Integrity Operating Practices, and is provided as Attachment 1. The casing integrity check frequencies were increased in 2007 for wells with metal-to-metal connections (called “upgraded” commercial casing) and for pads without passive seismic wells to enhance pre-steaming confirmation of well integrity. Certain circumstances (e.g. known impairments, passive seismic events, unusual fluid levels and nitrogen soak trends) can trigger additional checks incremental to this minimum standard.

In 2007 a risk-based targeted selection process was implemented to select which wells should be inspected prior to being placed on steam. This assessment may be completed through casing integrity checks or incremental checks, by reviewing data indicating a potential casing failure that requires mandatory analysis and closure of passive seismic casing events, suspect nitrogen soak trends and fluid levels, DFP alarms, and suspect steam trends. There are defined standards describing when targeted selection requirements are to be completed and closed out prior to beginning steam injection. As further understanding of casing failure mechanisms is developed the targeted selection criteria are updated accordingly. Wells deemed as having higher potential for sulphide stress cracking based on H_2S sample partial pressure data were incorporated into the process in 2013.

A 2015 analysis of casing failure data has shown that failure frequency rates for larger 9-5/8” cased horizontal wells are statistically lower than that of deviated 7” well casing; Section 3.3.3 touches on some of the current modeling efforts in this area. Statistically valid data for 9-5/8” CSS wells was available up to and including cycle 7. The presence and rate of casing impairments mirrors the casing failure performance and shows limited impairments occur on 9-5/8” horizontal wells through the early and mid-cycles. Based on this statistical evidence, EM log inspections will be used as the standard casing integrity check technique through these first seven operating cycles for 9-5/8” wells. In addition, traditional rig based integrity checks will continue to be completed synergistically on 9-5/8” wells with tubing movement maintenance activities to check and verify well impairment performance. This change is shown in Attachment 1 (5th column).

The above mentioned casing failure statistical analysis also revealed that for 7” new/upgraded casing (majority of active 7” wells in Cold Lake), both casing impairments and failures start to occur during cycle 5; one cycle ahead of the prescribed first round of CI checks (pre-cycle 6). To more proactively identify and mitigate mid-cycle integrity issues, the first round of CI checks for pads with commercial new/upgraded casing that have a passive seismic well will occur one cycle earlier prior to cycle 5. These checks consist of traditional CI checks and synergistic checks completed with other tubing movements in early cycles. This practice will allow for proactive measures to be taken (i.e. slimhole, shear liner, take out of steam service) that will aid in reducing the overall casing failure frequency. This change is shown in Attachment 1 (4th column).

In 2015, guidelines were developed for more proactive use of shear liners. A shear liner is a joint (or multiple joints) of non-cemented casing which is suspended in a wellbore from a hanger across a section of known casing damage. The frictional fit provides mechanical reinforcement to inhibit further damage to the production casing from strain concentration. In prior years, shear liners have been installed on occasion. An assessment of results from those installations has shown success in reducing casing impairment growth and failures.

The total well count in Cold Lake has increased over time and the frequency of casing integrity checks increases over time with a given pad's cycle number. However, the continuously changing mix of early, mid, and late cycle wells and the variety of depletion methods (e.g. high pressure CSS, low pressure CSS, steamflood) will cause fluctuations in the total number of casing integrity checks each year. Figure 13 shows the number of casing integrity checks performed each year since 2001. The numbers from 2013 forward include wireline based Electro-Magnetic (EM) Scan checks. The percentage of casing integrity checks that found near surface or intermediate depth failures is also plotted in Figure 13. The peak number of integrity checks from 2007 to 2009 were primarily due to numerous Mahkeses wells reaching their first round of casing integrity checks and the 2007 increase in casing integrity check frequency. Since those peak years the total number of casing integrity checks have generally been decreasing due to a higher number of early cycle wells being steamed, an increasing percentage of multi-bottom hole location horizontal wells per pad, an increase of injector-only infill wells, and an increase in low pressure steam flood operations. In 2016 there were a total of 225 CI checks completed (172 rig based and 53 EM Scan checks), with 11 combined near surface and intermediate depth failures identified. The percentage of wells which receive an integrity check and identify a casing failure has generally increased over time, since the targeted selection practice identifies wells with a higher probability of a failure. As well, several failures were identified from casing checks triggered by D013 5 year pressure tests, rig based casing integrity check following identification of near surface casing failures and EM Scanner follow-up.

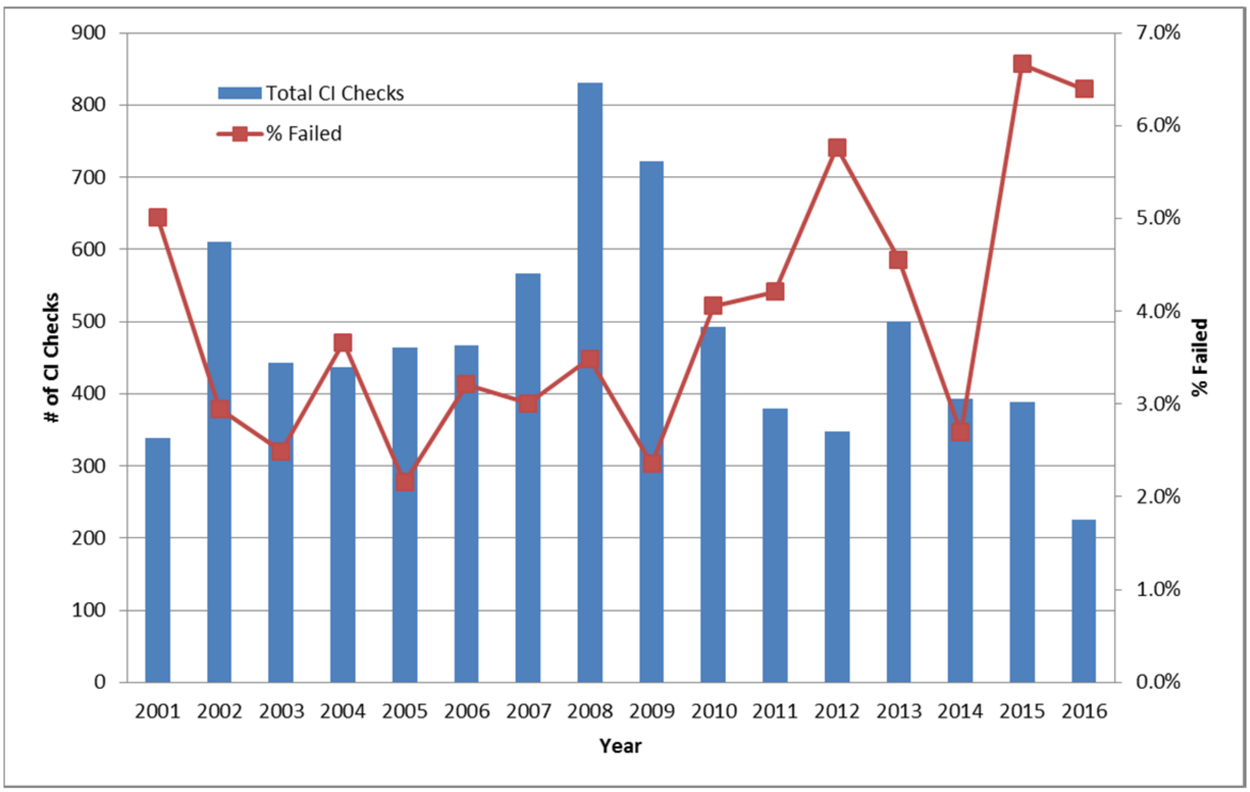

Figure 13: Casing Integrity Check History

In 2012 Imperial qualified the use of through tubing EM logging as a method of performing a casing integrity check. Through tubing logging and specifically the Schlumberger EM Pipe Scanner Inspection Tool was field trialed and qualified in Cold Lake. The through tubing logging technique is a less invasive method of evaluating the current casing string condition and does not require a service rig. Imperial has implemented the use of the Schlumberger EM Pipe Scanner as a method of casing integrity check for specific applications where determining if the casing has a failure is the only function of the integrity check.

3.2 Near Surface Casing Integrity Management

The mechanism for near surface casing failures is external corrosion. Minor wellhead packing leaks, precipitation and surface water run-off collect in the conductor pipe or surface casing - production casing annulus forming a corrosion cell. Water typically accumulates in the conductor annulus due to cement slumping (after primary cementing) or cement degradation at the oxygen interface over time.

Corrosion inspection logs (electromagnetic flux leakage) and casing pressure tests are completed as part of the Casing Integrity Operating Practices. Wells identified as having potential corrosion concerns are either pressure tested to ensure suitability for service, repaired, or taken out of steam service. In 2011, corrosion log inspections were changed to be triggered by well age, on a years-in-service basis, instead of number of completed cycles. This will more proactively identify wells with higher external corrosion and lead to earlier intervention activities

Imperial's bentonite top-up program and production casing inspection practices have been utilized since 1996 to manage near surface depth corrosion and confirm well integrity prior to steam. The practices have been targeted to mitigate the risk associated with a high pressure (capable of flow to surface) casing failure where there is the potential for environmental impact. Since the implementation of the Casing Integrity Operating Practices in 1996 there have been no surface depth casing failures of consequence beyond Level 0.

Improved primary cementing practices for new wells enhance the ability to achieve and maintain cement tops at or near surface. All wells that do not have cement full to surface level are topped up with bentonite after the first steam cycle and the protective shrouds installed above the annulus. The bentonite top-ups and shrouds are maintained throughout the operating life of the wellbore.

The bentonite program's management process was further upgraded in 2013 from an annual well inspection to regular real-time inspection during operator rounds, allowing for more timely top-up and shroud maintenance. A design change was also made reducing surface casing size on some new drill well classes. This sizing reduction will decrease the amount of oxygen available to feed the corrosion cell within the production casing - surface casing annulus. This should reduce corrosion rates on new wells throughout the operating life.

In 2016 improvements were made to the casing shroud design which has been installed on all wells since 2010. The improvements made to the shroud include changing the material from a galvanized to a stainless steel to prolong the life. A second change is to how the shroud is attached around the well to make easier for installation and removal as well as ensuring there is an overlap of material to improve the strength. Currently there are 5 of these improved shrouds installed. Once the design is finalized, the shrouds will be upgraded when the existing are replaced

In 2014, Imperial initiated a field trial in the application of a high-temperature, high-performance metallic aluminum external coating material to near-surface production casing on operating wells. The product selected has been tested and used in process facility operations with a temperature rating of 400°C, which makes it suitable for CSS injection conditions. In 2014-2016 the coating product was applied to 87 candidate wells with moderate near-surface corrosion. The work plan calls for an evaluation of coating quality over time, and changes in longer term corrosion rates of the coated wells through corrosion measurements. If proven successful, the coating application may become a more wide-spread Cold Lake practice in the future.

3.2.1 Alternative Corrosion Measurement Technologies

Magnetic flux leakage tools have been used for conducting corrosion assessments since the mid 1990's. It has been demonstrated as an effective technology for identifying external corrosion near surface. To foster continuous improvement, Imperial has also been investigating alternative products such as a thru-well ultrasonic logging tool, as well as other flux leakage tools, to identify further opportunities in data collection or measurement.

In 2016, surface corrosion at 57 wells were inspected using external Ultrasonic (UT) inspection. Imperial has adopted this technology for thermal wellbores, leveraging long term industry experience with UT on surface equipment such as tanks, vessels and piping. The external UT inspection resulted in confirming 21/30 wells with lower wall loss (capable of high pressure CSS) that had a previous in-well log indicating higher wall loss (low pressure CSS or producer only well status). The external UT inspection is completed by digging around the well, removing the conductor and cement around the production casing, buffing the casing, completing the external UT inspection and finally re-installing the conductor and backfilling. The benefits of the external UT inspection are cost savings for not using a service rig as well as more accurate external corrosion measurements. Continued use of UT technology is planned for Cold Lake wells

In 2016 an assessment of various wall loss measurement technologies was concluded. This assessment had the objective of evaluating the accuracy and capability of different in-well logging tools, to determine which technology is most suitable for in-well logging in Cold Lake. A total of 9 tools from 7 companies were evaluated. Two tools have been identified for further testing in the coming year.

3.2.2 Alternative Casing Repair Technologies

Imperial's original repair practice for wells with near surface failures is a surface dig out repair. This operation involves suspending the well, excavating to below the failure depth, replacing the failed section of casing with new casing, and reactivating the well. The surface dig out is a proven repair method to return wells to high pressure CSS service, but is complex and cannot be economically justified for all wells. In 2011, Imperial tested a new near surface casing patch technology. The system utilizes a MH patch set below the failure, L80 patch pipe, and a threaded wellhead connection. The near surface patch is suitable for either lower pressure steaming (<4 MPa) or producer only well candidates (up to 10MPa) that cannot justify a surface dig out repair for full high pressure steam service. In 2016, 18 of these patches were installed.

3.3 Intermediate Depth Casing Integrity Management

The majority of intermediate depth casing failures are caused by a combination of SSC and high strain, low-cycle fatigue. Beginning in 2006 Imperial implemented a number of wellbore design and operational changes to improve performance, including:

- Connection spacing offset away from known weak layers (slip planes)
- Enhanced shear stress management tools
- Adjusted steam volumes and strategy
- Targeted selection criteria for casing integrity checks
- Improved nitrogen purge management
- Producing well annulus gas testing environmental control

The nitrogen purge management and producing well environment control are both aimed at reducing the risk of SSC. Nitrogen purging is used to reduce the presence of H_2S in the casing - tubing annulus during shut-in periods. Nitrogen purge compliance for 2016 was 99.7% with a total of 8,688 purges during the year. Wells not achieving the purge within the 48 hour requirement are identified for follow-up testing through the casing integrity check targeted selection process.

Producing well annulus gas testing is aimed at reducing risk of SSC while operating due to temperatures below 60°C and a corrected H_2S partial pressure above 3kPaa. These wells were shut-in and purged with nitrogen until either the next steam cycle begins or a warm-up is performed.

The nitrogen purge requirements continue to evolve as wellbore performance knowledge is gathered. Utilizing the T06-09 monitoring wellbore to test nitrogen purge performance during the low pressure 'end of cycle' and high pressure 'after steaming' periods, H2S concentration data was captured over an extended time to better understand this behavior. At high wellbore pressure (>4 MPa) current N2 purge practices were found to be effective in maintaining the wellbore environment with a high concentration of

N2, where SSC should not be of concern. At low wellbore pressure (<4 MPa) the study found that the N2 concentration goal was not being achieved consistently with the existing practices. To improve N2 performance, volumes have been increased by 50% on low pressure N2 purges to help eliminate the atmosphere where SSC may begin to occur. This procedural change was implemented in 2013.

In 2016, Imperial discontinued N2 purging at low pressure pads. Low pressure pads are defined as those with reservoir pressure below hydrostatics pressure (< 4 mPa), and where future operations will not increase pressure above that level. Discontinuing N2 purging on low pressure pads has no effect on detection of intermediate casing failures as the reservoir pressure is too low to cause the fluid level to rise. As well, low pressure wells don't have enough pressure to cause fluid loss or result in adverse effects.

Imperial also has an ongoing research program to investigate root causes, develop changes to operating practices, and enhance well construction techniques to reduce the number of intermediate depth casing failures. These initiatives are discussed in the following subsections.

3.3.1 Well Design - Casing Connection Design

In 2010, ExxonMobil Upstream Research Company (URC) completed detailed Finite Element Modeling of a new Fatigue Resistant connection that introduces modified connection geometry from the baseline connection to yield improved fatigue properties. The project moved to physical connection testing in 2011, redesign in 2012 after identifying seal-ability limitations, and repeated physical testing using the modified design in 2014.

Fatigue cycling of the modified fatigue resistant connection design showed minimal improvement when compared to the baseline performance of common metal-to-metal seal premium connections. Based on these results from the second design iteration, the fatigue resistant connection development project has been concluded.

3.3.2 Well Operability – Repair Technology

Identifying a repair technology that can maintain integrity throughout high pressure CSS operations, with fluctuations in operating temperature and wellbore fluids through a steam injection and production cycle has long been a materials design challenge. The current repair method, proven successful over many years, is to maintain high pressure steam injection by cementing a slimhole pipe inside the existing production casing. However, this repair method leads to a wellbore size reduction which can limit future operations.

In an effort to identify an alternative repair solution Imperial has investigated a number of different casing patch technologies or strategies throughout the last several years. Since 2012 a development program has been underway with Saltel Industries of Bruz, France, to attempt to design and test a product that can withstand high temperature, high pressure CSS operating conditions. After several design iterations and extensive laboratory testing and measurement, a prototype casing patch has been developed whose test results are comparable to those of casing buttress connections which historically have been used extensively in thermal well operations.

A Saltel patch field trial is now underway in Cold Lake. Four wells total, three wells with intermediate casing failures and one well previously a Grand Rapids monitoring well were repaired with the patch. All four wells have received a 'warm up' volume of steam injection. Post warm up rig based diagnostics demonstrated that the patches maintained the same acceptable level of pressure integrity as before the warm-up. Post steam rig based diagnostics indicates that the patch in one of the wells has maintained integrity and the other well has passed the 3 day N2 Soak integrity test. The next step for the field trial is to inject a full cycle volume of steam into the other two wells and perform similar post steam rig diagnostics on the remaining three wells.

Imperial is concurrently testing another high temperature – high pressure casing patch technology. A Schlumberger 'MHE' patch has been installed in H63-H12 over a set of perforations above the production zone. Two 'warm up' volumes of steam were injected into the wellbore. After each warm-up, a rig moved onto the well and completed post steam warm up diagnostics which confirmed patch integrity. The well has recently completed a full steam cycle and is now on N2 Soak where integrity is being confirmed with fluid shots. Once the well has depressured, a service rig will move to the well once conditions allow to complete a CI check.

3.3.3 Well Operability – Casing Fatigue Research

To continue enhancing the present understanding of casing performance and fatigue, URC has been involved in collecting wellbore boundary conditions to better correlate Imperial's casing fatigue models to field conditions. This is building on the Production Injection Management Fatigue Estimate Toolkit (PIMFET) software that was developed in 2011. Using the updated shear and slip shape functions, a closer correlation between PIMFET casing fatigue index and observed casing failures was observed, and was applied to PIMFET Version 1.2. After testing with select Cold Lake injection data to verify the new software version, it was released for use in 2014. The upgraded PIMFET has been able to enhance pad injection by micro managing the steam plan on high pressure pads and identifying shear stress critical injection wells which require extra attention. This new approach has enabled better pad pressure alignment and balance/symmetry through small steam rate adjustments which subsequently reduces the amount of fatigue induced on the casing. Application of this tool was continually optimized and enhanced throughout 2016, improving steam strategies and adapting operating practices for various well and pad scenarios.

In a related investigation, a review of historic casing failures have shown that larger 9-5/8" cased horizontal wells have been failing and showing well impairments at a lower rate than the traditional 7" deviated casing string design. Building on finite element analysis from prior connection studies and including factors for cement, formation, casing interaction, and having a casing connection at a slip plane offers a new approach to model casing response under shear and slip conditions. This modeling study assessed different casing grade (specifically 7" 23lb/ft, 7" 32lb/ft, and 9-5/8" 43.5lb/ft) and slip magnitude combinations to verify modeling performance remains consistent with the field results observed to date. In 2016 an analysis was completed to determine if 7" 32lb/ft casing would improve overall well integrity performance and whether heavier wall pipe should replace the existing 7" 23lb/ft pipe. The assessment determined that thicker pipes would result in a longer well life at lower slip magnitudes for both the pipe body and at the connection; however, the difference is negligible at higher slip magnitudes. The benefit over the entire well life was not enough to pursue this design change for new drill wells.

3.3.4 Well Operability – Materials Testing

In 2010 and 2011, an assessment was completed on higher grade T95 casing versus the existing L80 grade. The program concluded that T95 exhibited equal or better SSC resistance compared to L80 under standard loading conditions. However, T95 performance was similar to L80 in the cyclic loading environment. Further testing was conducted to compare the low cycle fatigue characteristics of T95 vs. L80 as well as some elevated temperature characteristics of T95 to understand the potential performance of the higher strength material. This additional testing, which is thought to be more representative of Cold Lake field conditions, demonstrated that T95 grade casing does not perform as well as the L80 casing currently being installed. A decision was made to not further pursue higher grade casing designs.

Imperial has also participated in a joint industry project (JIP) led by Noetic Engineering to study synergistic thermo-mechanical loads and environmental (H2S sour service) conditions on casing. This work shows the relationship between sour service and thermal well conditions are subject to synergetic effects in the level of casing strain, and that the mechanisms involved are quite complex. The latest phase of the project produced a relative ranking of casing fatigue life for commonly used casing grades.

3.4 Clearwater Casing Integrity Management

Formation movement is the primary mechanism for Clearwater casing failures. As a result of the CSS process, shear stresses develop which results in slip along structurally weak planes existing at the Clearwater - Grand Rapids interface. As this shear is localized, there is no impact on intermediate casing integrity. There is no evidence that Clearwater failures cause, or are related to other intermediate depth or near surface casing failures. Although there is no adverse environmental impact, operability of the well can be restricted. The existing casing integrity program for Cold Lake was designed to address the concerns associated with the near surface and intermediate depth intervals, and was not intended to deal with the Clearwater failures.

When Clearwater casing failures are detected the well is steamed below fracture pressure, unless the failure is repaired or the location of the failure is such that steam will not encroach on the Clearwater/Grand Rapids interface. Occasionally, Clearwater failures or impairments are mitigated through the installation of shear liners or cemented patches for structural support. Balanced steaming strategies to manage intermediate depth shear stress can also minimize formation movement at the Clearwater top in order to reduce casing damage.

3.5 Casing Integrity Response

Currently, Imperial maintains the following equipment and materials on-site: pre-mix and returns tanks, storage silo's, approximately 300 tonnes of barite, 400 tonnes of hematite, $140m^3$ of $1370kg/m^3$ $CaCl_2$ fluid, $140m^3$ of $1500kg/m^3$ $CaCl_2$ fluid and all necessary kill fluid additives in order to respond to high pressure casing failures in a timely manner.

In 2016, there were six high-pressure response events and no wells required a heavy mud kill.

ATTACHMENT 1: CASING INTEGRITY CHECK FREQUENCY

Casing Checks by Cycle and Design for High Pressure CSS Wells

Prior to Steam Cycle #	Commercial Old	Commercial New/Upgraded w/o PS	7" Commercial New/Upgraded w/ PS	8 5/8" & 9 5/8" Commercial New/Upgraded w/ PS	Environmental Old	Environmental New/Upgraded
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	0	0	0	0	0	0
4	0	0	0	0	0	0
5	33[1]	33[1]	33	0	100[1]	50[1]
6	33[1]	33[1]	33[1]	33[1] (EM Scan)	100[2]	50[1]
7	33[1]	33[1]	33[1]	33[1] (EM Scan)	100[2]	100[2]
8	100[2]	100[2]	50[1]	33[1] (EM Scan)	100[2]	100[2]
9	100[2]	100[2]	50[2]	50[2] (Rig CIC)	100[2]	100[2]
10	100[2]	100[2]	50[2]	50[2](Rig CIC)	100[2]	100[2]
11	100[2]	100[2]	100[2]	100[2](Rig CIC)	100[2]	100[2]
12	100[2]	100[2]	100[2]	100[2](Rig CIC)	100[2]	100[2]
12+	100[2]	100[2]	100[2]	100[2](Rig CIC)	100[2]	100[2]

Horizontal 9-5/8" high pressure CSS wells utilize the EM Scanner log for the above prescribed casing checks up to and including cycle 7, and also receive synergistic rig based checks with routine tubing maintenance wellwork jobs.

Near Surface Corrosion:

1. Wells require a corrosion log at or before this cycle only if a CI check is scheduled. Only one corrosion log is expected per well during this period. All wells on a pad must have a corrosion log within the first 10 years from initial steam date. For horizontal wells with 9 5/8" production casing (which use EM log up to cycle 7), a rig based casing inspection with near surface corrosion log is required no later than 10 years after first steam in date.
2. Future corrosion log requirements should be assessed on the actual results (well specific corrosion rate) from the existing corrosion log/s for that well.

Commercial:	L/MN-80 or IK-55 casing design with OBTC,NKEL or QB2 connections
Non-Commercial:	All casing designs prior to Commercial.
'Old' Wells:	Wells beginning steam prior to OP#9 inception, improved steam quality and lower volume steam injection (Jan 96).
'New' Wells:	Wells beginning steam after OP#9 inception, improved steam quality and lower volume steam injection (Jan 96).
Environmental:	Pads or wells within 500m of the historical high water level of a designated water body.
Upgraded Commercial:	New casing design coming out in 1998 with NSCC-M phosphate coated 'metal-to-metal' connections (VAM SWNA, Tenaris Blue, NSCCM, NSCC, and QB2).