



2018 Annual Summary Report on Casing Integrity

Submitted: March 21 2019

EXECUTIVE SUMMARY

Casing Failures

- Total number of wells containing casing failures in 2018 (all depths) was 76, versus 104 in 2017.

Near Surface

- 37 wells with failures in 2018, versus 41 in 2017. Recent increases attributed to aging wellbores.
- Failure frequency of 0.70% of wells per year in 2018.
- All failures in 2018 were Level 0 (no adverse environmental consequence)
- All 37 failures in 2018 were on low pressure wells or wells already suspended, that had no potential for liquid release.
- 34 failures were detected operationally through visual checks, and remaining 3 were detected during rig work on isolated wellbores; 1 failure was identified during regulatory pressure testing, 1 failure was detected during a non-routine abandonment and 1 failure was detected during a reactivation job.
- 11 wells repaired by surface casing patch, 11 wells repaired by external composite wrap, 9 wells repaired by near surface dig-out and replacement, and 2 wells still awaiting repair implementation (currently suspended). Remaining 4 wells are suspended or zonally abandoned with no near term repair plan.

Intermediate Depth

- 36 wells with failures in 2018, versus 54 in 2017.
 - 19 of 36 failures were on low pressure, active wells.
 - 5 of 36 failures were on high pressure active wells.
 - 12 of 36 failures were zero pressure wells (suspended) with no potential consequence.
- Failure frequency of 0.68% of wells per year in 2018.
- All failures in 2018 were Level 0 (no adverse environmental consequence).
- 5 high pressure failures in 2018; 2 required heavy mud kills.
 - Lowest number of high pressure casing failures over 10 year period (same as 2012/2013/2017)
- No multi-well failures occurred in 2018.
- 15 casing failures detected operationally, 13 of which were detected by passive seismic and remaining 2 were detected by nitrogen soak.
- 21 casing failures detected with casing integrity (CI) checks, which include 6 identified on wells already isolated downhole (5 regulatory pressure tests & 1 zonally abandoned well with failure located during workover).
- 21 wells were repaired or have planned repairs (i.e. slimhole, MH Patch, Saltel Patch). The remaining 15 wells are suspended or zonally abandoned.

Clearwater

- 3 failures in 2018, versus 9 failures in 2017.
- No adverse environmental impacts.

Well Casing Repairs

- Casing repairs completed on 147 wells in 2018 that returned to service:
 - 31 repairs on near surface failures (11 near surface patches, 11 external composite wraps and 9 near surface dig-out and replacement)
 - 15 proactive repairs on high near surface corrosion wellbores (14 near surface dig outs and replacements and 1 near surface patch)
 - 36 repairs on intermediate failures (27 slimholes, 7 MH patches, 2 Saltel patches)
 - 65 proactive slimhole repairs on wellbores with intermediate impairments.

Casing Failure Detection Initiatives

Alarm Management

- Automated software for real-time passive seismic alarms is now functional for all pads, accelerating response time for a potential casing failure detected by the passive seismic systems. Real-time casing failure alarm notifications through email and text message directly to Cold Lake personnel.

Near Surface Casing Integrity Initiatives

- External corrosion: Silicate solution trial ongoing. 25 wellbores on a single pad had product pumped into the near surface external annulus outside of the production casing. Corrosion coupons were utilized as a means of corrosion progression and installed in both silicate injected well and non- silicate injected well on the same pad. At the 6 month mark, coupons were pulled and results were favorable. Expansion of trial planned for 2019.
- External corrosion: Continued application of high temperature resistant metallic aluminum external casing coating year round in a synergistic manner with external ultrasonic testing procedure that is used to measure remaining casing thickness. Wells returning to service after external ultrasonic testing results have external coating applied for future protection.
- External corrosion: Continued trial application of external composite wrap repairs on wells with near surface failures that will operate below 4 MPa and 230°C. Refining of installation programming for increased success of installation ongoing.

Intermediate Depth Casing Integrity Initiatives

- Single well trial of intermediate cemented patch in low pressure steam flood area for Producer Only status . Go forward patch to be pressure tested within 1 year of operation (May 2019). If favorable, additional future applications will be considered and progressed.
- Continued to commercialize two high pressure – high temperature steam-able casing patches;
 - Saltel casing patch installed in a total of six wells since 2016. Two of the six wells were installed in 2018 and placed back into operation.
 - Schlumberger MHE patch installed in 2016. Pressure test after full cycle was successfully completed in November 2017. Will apply technology again on next favorable candidate- none identified in 2018.

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 2018 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 2018 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	<ul style="list-style-type: none">- Failure occurred within the bedrock with fluid loss below the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m³ produced fluid, dependent on proximity of wellbores at failure depth)- Failure occurred within the Glacial Till, but only released inert fluid (e.g. N₂ gas) or minimal produced fluid not requiring remediation
Level 1	<ul style="list-style-type: none">- Failure occurred within the bedrock with fluid loss above the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m³ 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	<ul style="list-style-type: none">- 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), or by an integrity check conducted as part of another workover . 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 36 of the intermediate depth casing failures detected in 2018 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 2018 were deemed to be Level 0 environmental consequence events. Of the 73 near-surface and intermediate failures detected in 2018, 49 were detected operationally and 24 were detected through casing integrity checks.

Table 2: Historical Failure Summary by Depth Interval

Depth	Year										
Classification	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Surface	16	16	11	13	7	21	19	25	20	41	37
Intermediate	30	29	34	34	30	33	33	37	23	54	36
Clearwater	56	58	17	19	8	9	17	25	9	10	3
Total	102	103	62	66	45	63	69	87	52	105	76

2.1 Near Surface Casing Integrity Data

Since 1996, 274 commercial wells have failed in the near-surface region, including 37 near surface failures detected in 2018. Near surface casing failure frequency has increased in recent years, as the average age of wellbores has increased. Details describing the failures that occurred in 2018 are provided below in Table 3. In addition to failed wells in 2018, 15 well were proactively repaired due to high corrosion (14 near surface dig outs, 1 near surface patch)

Table 3: 2018 Surface Depth Failure Summary

N0.	District	Well	Date	Years since first steam	Depth (mKB)	Pad Cycle	Detection Method 1	Env Consq	Repair Method
1	Mahihkan	H01-11	2018-12-21	33.3	5.0	11	Operational	0	Awaiting Repair
2	Maskwa	D62-12	2018-12-20	24.8	5.0	8	Operational	0	Awaiting Repair
3	Mahihkan	H22-08	2018-11-18	22.9	5.0	11	Operational	0	Surface Digout
4	Maskwa	A02-07	2018-11-09	33.5	5.0	13	Operational	0	Surface Digout
5	Maskwa	F07-18	2018-10-22	18.8	5.0	7	Operational	0	External Composite Wrap
6	Mahihkan	L06-10	2018-10-17	23.2	5.0	11	Operational	0	Surface Digout
7	Mahkeses	OCC-08	2018-10-08	34.8	5.0	10	CI Check	0	Zonal Abandonment
8	Maskwa	D62-11	2018-09-27	24.8	5.0	8	Operational	0	Surface Digout
9	Maskwa	B05 Infill-40	2018-09-18	22.1	5.0	6	CI Check	0	Suspension
10	Maskwa	D22-08	2018-08-08	32.6	5.0	11	Operational	0	Zonal Abandonment
11	Mahkeses	G03-01	2018-07-27	18.8	5.3	10	Operational	0	Surface Patch
12	Maskwa	D63-12	2018-07-10	24.8	5.0	9	Operational	0	Surface Digout
13	Maskwa	E11-42	2018-06-27	10.3	5.0	8	CI Check	0	Suspension
14	Mahkeses	ONN-28	2018-06-09	21.4	5.0	10	Operational	0	External Composite Wrap
15	Mahkeses	OFF-05	2018-06-04	32.8	5.0	10	Operational	0	External Composite Wrap
16	Maskwa	D62-19	2018-05-17	24.9	5.0	8	Operational	0	Surface Digout
17	Mahihkan	J01-14	2018-05-11	33.4	5.0	10	Operational	0	Surface Patch
18	Mahihkan	J05-12	2018-05-08	33.2	5.0	11	Operational	0	Surface Patch
19	Mahihkan	J04-02	2018-05-08	32.4	5.0	10	Operational	0	Surface Patch
20	Maskwa	D64-03	2018-05-02	24.9	5.0	8	Operational	0	Surface Digout
21	Mahkeses	T14-09	2018-04-25	8.4	5.0	7	Operational	0	Surface Digout
22	Maskwa	F01-06	2018-04-15	19.9	5.0	8	Operational	0	External Composite Wrap
23	Mahihkan	J12-19	2018-04-09	31.5	4.2	9	Operational	0	External Composite Wrap
24	Mahkeses	G02-33	2018-04-05	18.8	4.7	10	Operational	0	External Composite Wrap
25	Maskwa	A04-20	2018-03-12	33.6	5.0	14	Operational	0	External Composite Wrap
26	Mahkeses	ONN-21	2018-03-08	21.4	4.8	10	Operational	0	External Composite Wrap
27	Maskwa	C08-22	2018-02-28	11.5	5.0	7	Operational	0	Surface Patch
28	Maskwa	F04-29	2018-02-16	19.8	5.0	9	Operational	0	External Composite Wrap
29	Maskwa	F03-28	2018-02-16	19.8	5.0	8	Operational	0	External Composite Wrap
30	Mahihkan	J21-10	2018-02-16	32.6	5.0	9	Operational	0	External Composite Wrap
31	Mahihkan	J02-01	2018-02-06	33.2	4.8	11	Operational	0	Surface Digout
32	Maskwa	D63-06	2018-01-22	24.8	4.3	9	Operational	0	Surface Patch
33	Mahkeses	G03-11	2018-01-18	18.7	4.3	10	Operational	0	Surface Patch
34	Maskwa	D10-09	2018-01-17	31.7	4.2	10	Operational	0	Surface Patch
35	Mahihkan	J03-15	2018-01-16	32.9	5.0	10	Operational	0	Surface Patch
36	Mahihkan	H02-10	2018-01-03	33.0	4.4	11	Operational	0	Surface Patch
37	Maskwa	A04-13	2018-01-03	33.6	3.8	14	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 2018 failures.

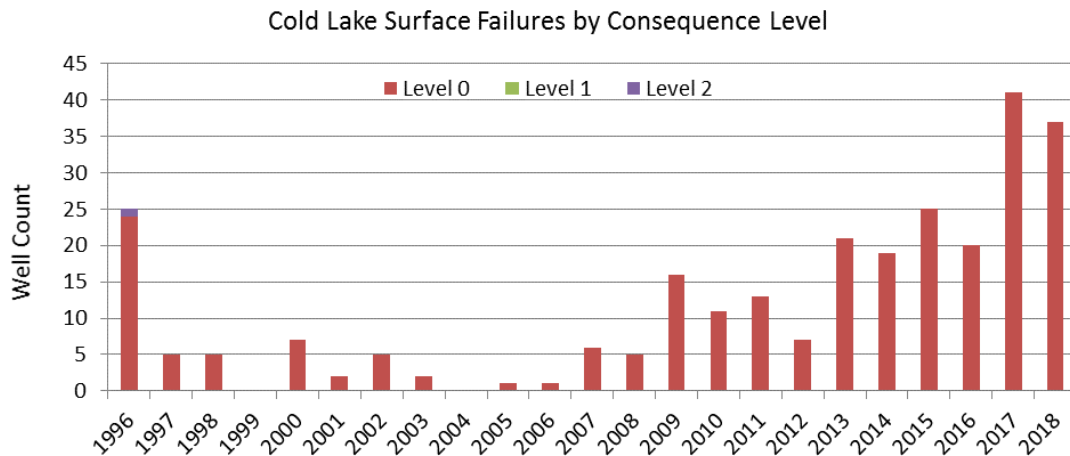


Figure 1: Cold Lake Surface Failures by Consequence Level

In 2018, all near surface corrosion failures occurred on late-life, low pressure wells with no potential for liquid release at surface. Hence, there were no potential adverse consequences associated with these failures. The average years in operation for these failed wellbores was 26 years.

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 2018 near surface casing failure frequency was 0.70%. 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 reduction of corrosion at the primary cement top depths. Failure frequency has increased in the 2013-2018 period. This increase is a result of the aging well population, with many low pressure operating wells now at 25+ years-of-service. With a decrease of corrosion at the original primary cement top, the corrosion cell has moved very close to surface (within 1 meter).

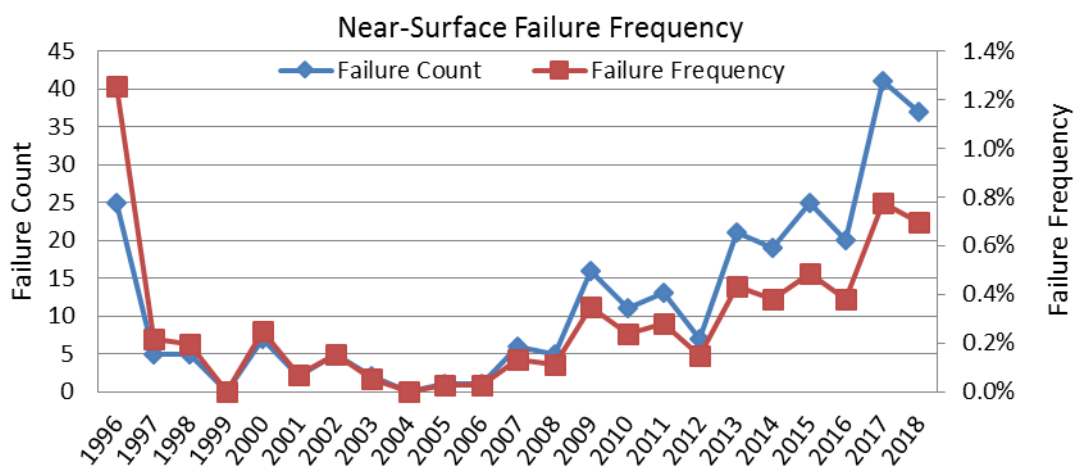


Figure 2: Commercial Near-Surface Failures and Failure Frequency

For information on near surface corrosion initiatives targeted at reducing failures at this depth, and new repair strategies for failures in aging areas, see Section 3.2.

In 2018, 34 of the near-surface casing failure events were found operationally via visual inspection. The remaining 3 were detected during rig work on isolated wellbores; 1 failure was identified during regulatory pressure testing, 1 failure was detected during a non-routine abandonment and 1 failure was detected during a reactivation job. The historical detection trends are shown in Figure 3 below.

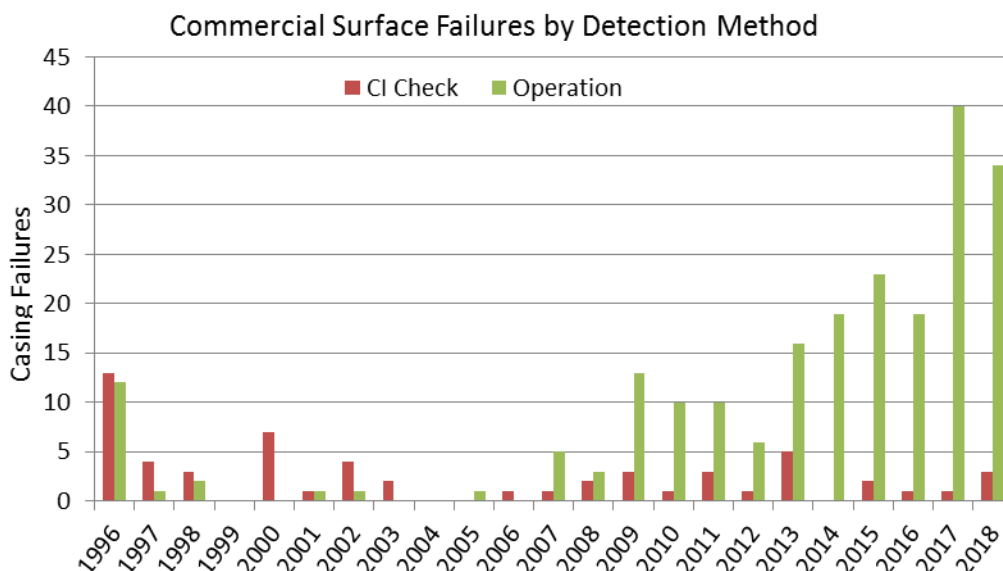


Figure 3: Commercial Surface Failures by Detection Method

Near Surface Depth Casing Failure Resolution:

Of the 37 near surface failures in 2018, 11 wells were repaired by surface casing patch, 11 wells were repaired by external composite wrap, 9 wells were repaired by near surface dig-out and replacement, and 2 wells are still awaiting repair implementation (currently suspended). Remaining 4 wells are suspended or zonally abandoned with no near term repair plan.

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 2018.

Since the implementation of the casing integrity operating practices in 1996, a total of 624 primary intermediate casing failures have been detected in wells with commercial casing designs. Approximately 58% of these failures were identified during rig-based casing integrity checks (i.e. pre-steam & regulatory D013 5 year pressure tests), with the remaining 42% identified through operational monitoring systems (DFP, N2 soak or passive seismic). Details of the 36 wells with casing failures occurring in 2018 are included in Table 4 below.

Table 4: 2018 Intermediate Depth Failure Summary

No.	District	Well	Date	Depth(mKB)	Depth(mTVD)	Pad Cycle	Formation	Pipe Body / Connection	Connection Type	Env Conseq	Repair Method
1	Maskwa	E11-H06	2018-12-24	212.0	209.9	8	Colorado Shales	Connection	SWNA	0	Suspension
2	Maskwa	E11-28	2018-12-21	299.0	296.4	8	Colorado Shales	Connection	NSCC	0	
3	Nabiye	N01-02	2018-12-12	277.0	275.7	8	Colorado Shales	Connection	NSCC	0	Suspension
4	Maskwa	D06-13	2018-11-17	256.0	256.0	6	Colorado Shales	Connection	STC	0	Slimhole
5	Mahihkan	H26-07	2018-11-08	269.0	267.9	11	Colorado Shales	Pipe	NSCC	0	Suspension
6	Maskwa	D12-18	2018-10-30	239.2	231.2	10	Colorado Shales	Connection	OBTC	0	Suspension
7	Mahkeses	G03-21	2018-10-07	304.5	287.4	10	Colorado Shales	Pipe	OBTC	0	Suspension
8	Maskwa	D62-11	2018-09-30	291.8	290.0	10	Colorado Shales	Connection	NSCC	0	Suspension
9	Maskwa	D22-08	2018-08-13	268.0	257.0	8	Colorado Shales	Connection	OBTC	0	MH Patch
10	Mahkeses	V13-27	2018-07-29	255.0	254.7	11	Colorado Shales	Pipe	OBTC	0	Not Repaired - Zonal Abandonment
11	Mahkeses	U09-02	2018-07-27	225.0	225.6	11	Colorado Shales	Connection	OBTC	0	
12	Mahkeses	V13-24	2018-07-04	243.0	242.4	5	Colorado Shales	Connection	NSCC	0	Slimhole
13	Maskwa	E11-15	2018-06-29	269.0	267.7	9	Colorado Shales	Unknown	TenarisBlue	0	Suspension
14	Maskwa	D24-11	2018-06-04	290.6	290.0	5	Colorado Shales	Connection	SWNA	0	Slimhole
15	Mahihkan	H04-03	2018-05-28	306.0	301.7	8	Colorado Shales	Connection	NSCC	0	Not Repaired - Zonal Abandonment
16	Mahihkan	J04-02	2018-05-13	223.0	217.4	11	Colorado Shales	Connection	OBTC	0	Suspension
17	Maskwa	D64-03	2018-05-07	291.0	266.7	9	Colorado Shales	Pipe	OBTC	0	Suspension
18	Mahihkan	H57-09	2018-05-01	259.5	246.5	10	Colorado Shales	Connection	OBTC	0	MH Patch
19	Maskwa	D07 Infill-H03	2018-04-30	329.0	311.0	8	Colorado Shales	Connection	OBTC	0	MH Patch
20	Maskwa	E11-11	2018-04-29	230.0	230.0	7	Colorado Shales	Unknown	SWNA	0	Slimhole
21	Mahkeses	T15-21	2018-04-25	300.5	295.8	5	Colorado Shales	Connection	NSCCM	0	Slimhole Planned
22	Mahihkan	J10 Infill-H01	2018-04-15	212.0	211.6	8	Colorado Shales	Connection	SWNA	0	Not Repaired - Zonal Abandonment
23	Mahihkan	H11-15	2018-04-11	234.0	234.0	6	Colorado Shales	Connection	TenarisBlue	0	Slimhole
24	Mahihkan	H51-03	2018-04-11	298.0	296.8	2	Colorado Shales	Connection	OBTC	0	Slimhole
25	Mahihkan	M07-15	2018-04-08	215.0	215.0	9	Colorado Shales	Unknown	NSCC	0	Not Repaired - Zonal Abandonment
26	Mahihkan	H63-22	2018-04-04	280.6	276.7	8	Colorado Shales	Unknown	SWNA	0	Slimhole
27	Maskwa	E11-17	2018-04-04	308.0	285.2	7	Colorado Shales	Unknown	BTC	0	Saltel Patch
28	Maskwa	A04-20	2018-03-18	312.5	303.4	5	Colorado Shales	Connection	SWNA	0	Saltel Patch
29	Mahihkan	H62-11	2018-03-04	276.4	274.7	8	Colorado Shales	Unknown	NSCC	0	Suspension
30	Mahihkan	L09-11	2018-02-12	282.0	257.1	14	Colorado Shales	Connection	OBTC	0	MH Patch
31	Mahihkan	J02-01	2018-02-09	232.5	232.4	6	Colorado Shales	Connection	SWNA	0	Slimhole
32	Mahihkan	H02-01	2018-02-09	238.0	237.9	5	Colorado Shales	Connection	NSCC	0	Slimhole
33	Mahihkan	T18-25	2018-02-02	250.0	250.0	5	Colorado Shales	Connection	NSCCM	0	Slimhole
34	Maskwa	E11-38	2018-01-30	286.0	271.4	11	Colorado Shales	Connection	OBTC	0	MH Patch
35	Mahihkan	H62-03	2018-01-18	285.0	283.0	5	Colorado Shales	Connection	NSCC	0	Suspension
36	Maskwa	A04-13	2018-01-07	172.0	171.8	8	Colorado Shales	Unknown	NSCC	0	Slimhole
				233.0	232.9	6	Colorado Shales	Connection	SWNA	0	Slimhole
				292.4	290.7	14	Colorado Shales	Connection	OBTC	0	MH Patch

Historic environmental consequence levels associated with intermediate casing failures since 1998 are displayed in Figure 4. In 2018, 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).

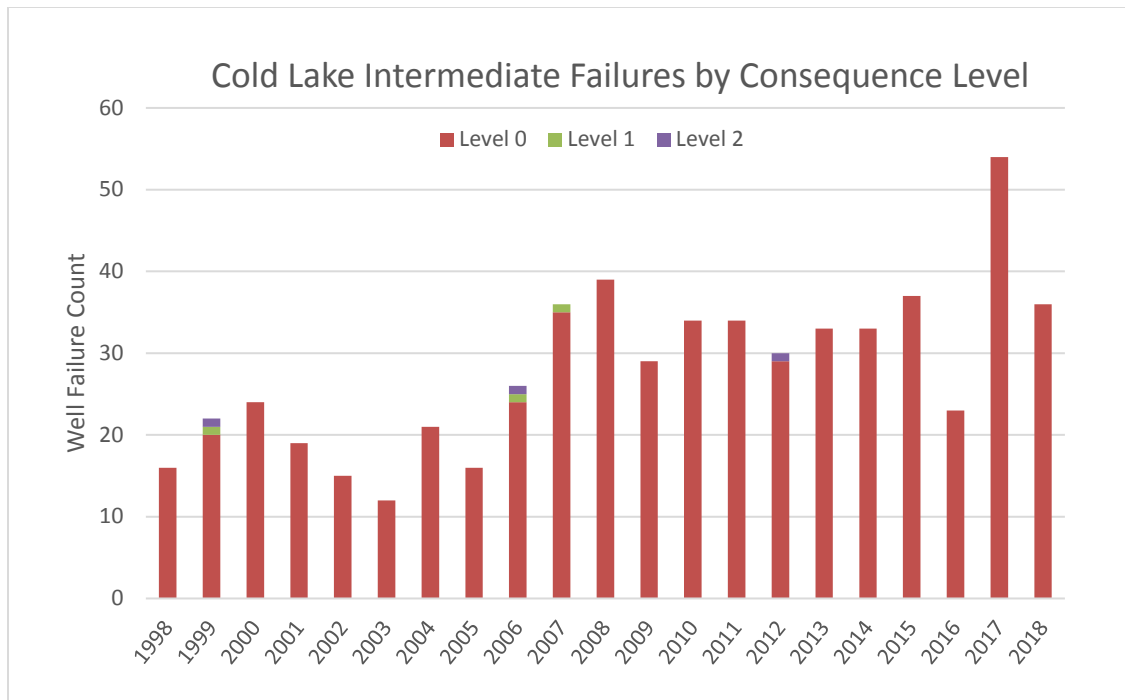


Figure 4: Cold Lake Intermediate Failures by Consequence Level

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 2018 there were 5 high pressure failures, or 13.5% of the total intermediate failures. The high pressure failure frequency is at a historic low, and has been decreasing over time. The trend 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. Of the 5 high pressure failures, 2 were heavy mud kills, and 3 were successfully managed by flowing up the tubing with N2 on the annulus to maintain the fluid level below the casing failure.

In 2018, there were 12 wells with intermediate failures located on already suspended/zonally abandoned wells or on 'No Pressure' (e.g. during pressure tests while rig on well) with no potential for liquid loss (33% of total). If these 'No Pressure' failures are excluded, there were a total of 24 wells with failures on 'Low Pressure' and 'High Pressure' active wells. The green bars show that this is the historic low for high pressure failures over the last 10 years (similar to 2012, 2013 & 2017).

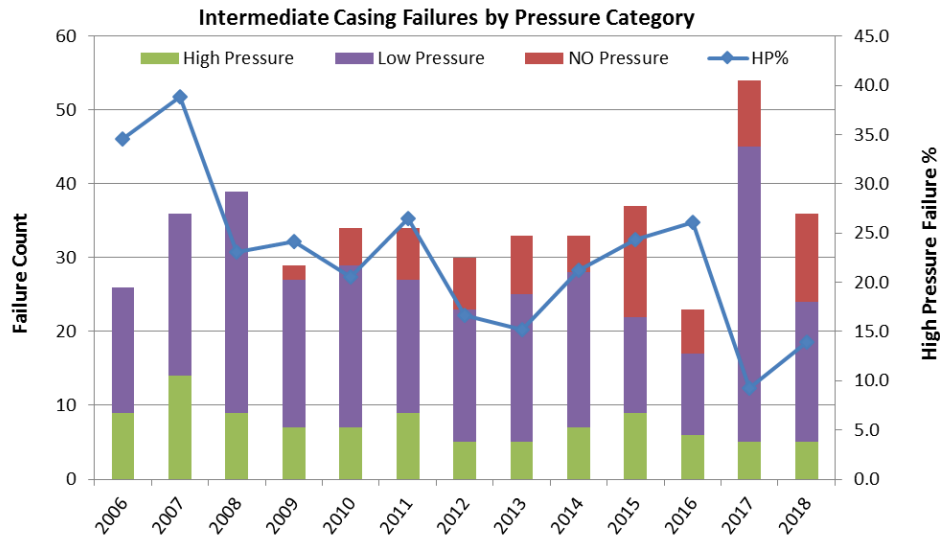


Figure 5: Intermediate Casing Failures by Pressure Category

In 2018, there were no casing failures with liquid losses that 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 2018 was 102 m3, 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 materials 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.

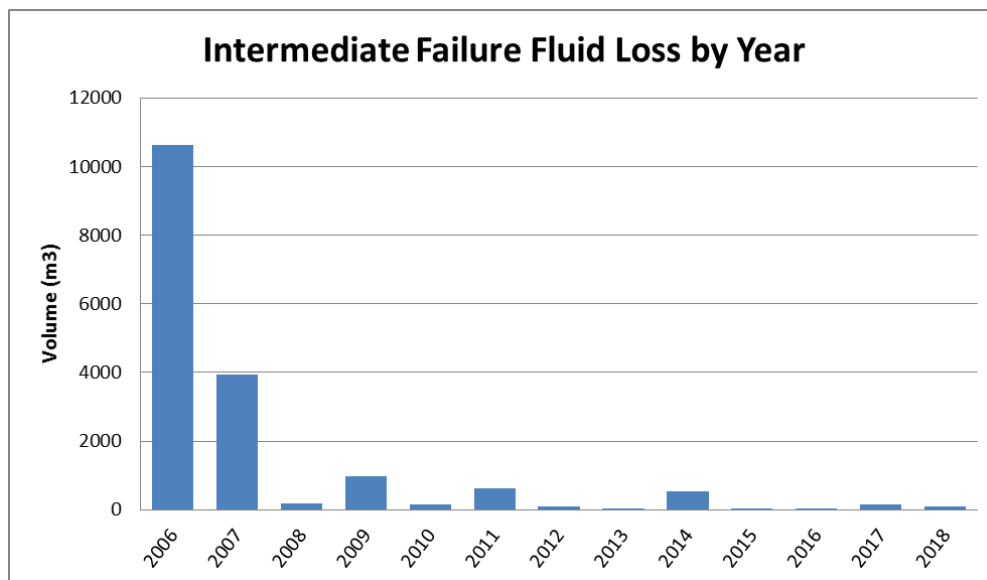


Figure 6: Intermediate Failure Liquid Loss by Year

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 2018 was 0.68%. The increases throughout the last several years are attributed to aging wellbores and is also driven by the steam schedule, which ultimately increases/decreases based on the number of pre-steam checks required each year.

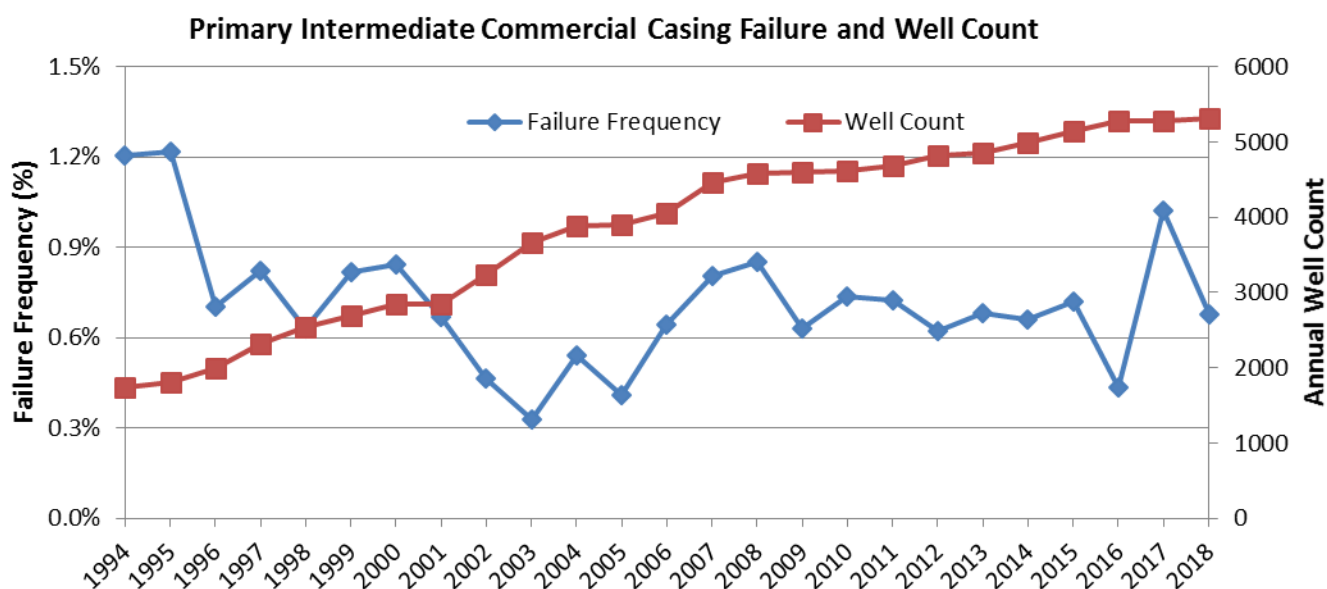


Figure 7: Intermediate Casing Failure and Well Count

In Figure 8, the number of primary intermediate casing failures for Cold Lake commercial casing design wells are stacked by early (1-4), mid (5-7), and late (8+) cycle periods. Early cycle failures continue to be lower than mid and late cycle failures.

In 2018, there was only one early cycle failure which was detected through Casing Integrity Check.

For mid-cycle failures, 69% were found through Passive Seismic (9/13), 31% were found through Casing Integrity Checks (4/13).

For late-cycle failures, 21% were identified through Passive Seismic (5/24), 46% were found through Casing Integrity Checks (11/24), 25% were found through regulatory pressure testing (6/24), and 8% were found through N2 soak monitoring (2/24)

Primary Intermediate Commercial Failures by Cycle Range

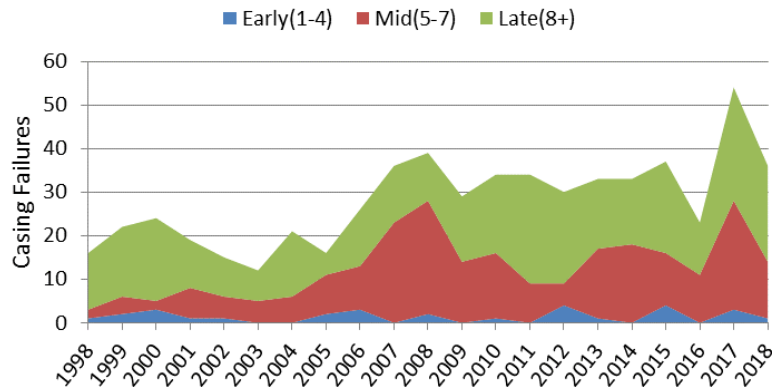


Figure 8: Intermediate Failures by Cycle Range

Figure 9 shows intermediate failure frequencies for commercial casing design wells, which 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 typically driven by unique wells or rare events. Mid cycle failure frequency steadily increased between 2004 and 2008, due primarily to failures at Mahkeses. Similar increases have occurred from 2012-2018 as Mahihkan North pads have become mid cycle. The number of mid cycle failures has fluctuated annually, dependent on how many pads are moving through this period when casing failures generally start to be observed. The late cycle failure frequency trend has stayed fairly consistent for the past several years. The total number of wells in each of the three cycle classifications is distributed as follows:

- Early (1-4) – 295 wells
- Mid (5-7) – 1422 wells
- Late (8+) – 3569 wells
- Total – 5310 wells

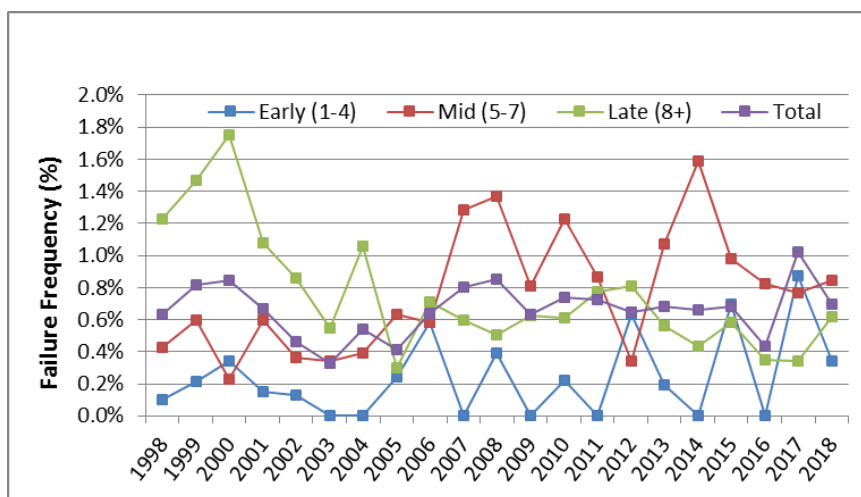


Figure 9: Intermediate Failure Frequency by Cycle Range

The intermediate failure detection method is displayed in Figure 10. Approximately 58% of intermediate casing failures are identified during rig based casing integrity checks since 1998. 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.

15 failures were detected by operational monitoring systems in 2018. 13 were initially identified by passive seismic and 2 were identified by nitrogen soak/fluid shot monitoring programs.

21 failures were detected by casing integrity checks in 2018. 6 occurred on wells that were already 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/abandoned wells).

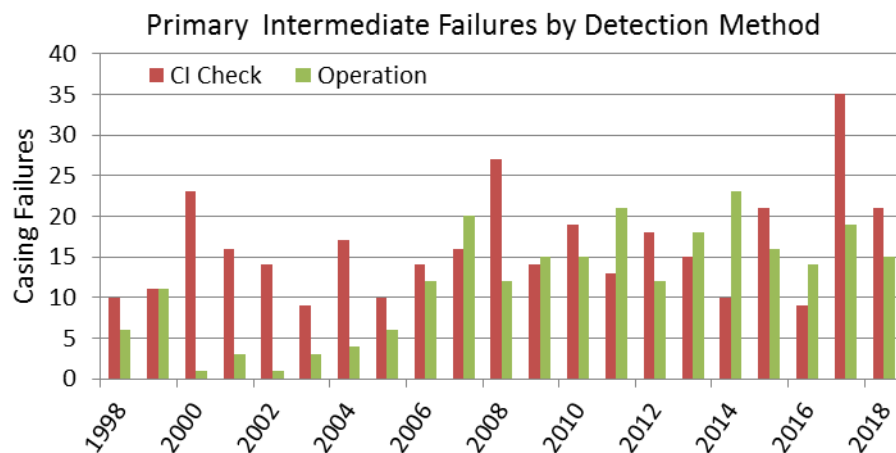


Figure 10: Primary Intermediate Failures by Detection Method

Intermediate Depth Casing Failure Resolution:

The 36 intermediate depth well failures discovered in 2018 were managed in the following way:

- 12 wells repaired with slimhole repairs
- 1 well is awaiting a slimhole repair (plug set)
- 6 wells repaired with a retrievable MH Casing Patch
- 2 wells repaired with a Saltel Patch
- 11 wells suspended
- 4 wells zonally abandoned

The cemented slimhole remains the most common repair procedure to return wells to high pressure steaming operations. In total there were 92 slimhole repairs completed in 2018. Of these 92 wells, 65 were performed proactively on wells with casing impairments (not casing failures).

2.3 Clearwater Casing Integrity Data

In 2018 there were 3 Clearwater casing failures detected. Well failure details are displayed in Table 5.

Table 5: 2018 Clearwater Failures Summary

No.	District	Well	Date	Depth(mKB)	Depth(mTVD)	Pad Cycle	Depth Class
1	Nabiye	N07-10	10/15/2018	467.00	441.58	5	Clearwater
2	Nabiye	N06-16	7/29/2018	446.70	431.41	6	Clearwater
3	Mahihkan	H62-22	2/2/2018	574.60	427.50	6	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.

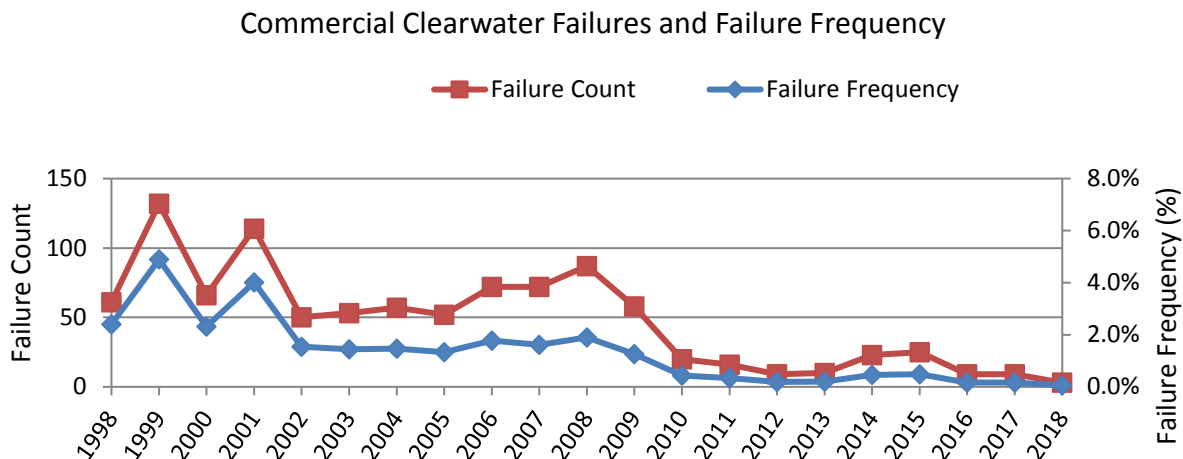


Figure 11: Clearwater Failures and Failure Frequency

2.4 Directive013 Pressure Tests

The table in Figure 12 displays the results of regulatory D013 5-Year pressure tests on suspended wells. In 2018, 179 wells required pressure tests and integrity of the suspension plug was confirmed on 178 wells. One well (U06-20) had the suspension plug fail and required modifications to the isolation.

In seven wells (E11-17, E11-28, D12-18, G03-21, H04-03, H11-15 & H26-07) new intermediate casing failures were discovered above the top of the isolation plug. In one of these eight wells (E11-28), two new intermediate casing failures were located. In an additional eighth well (B05-IOI-40), a near surface 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.

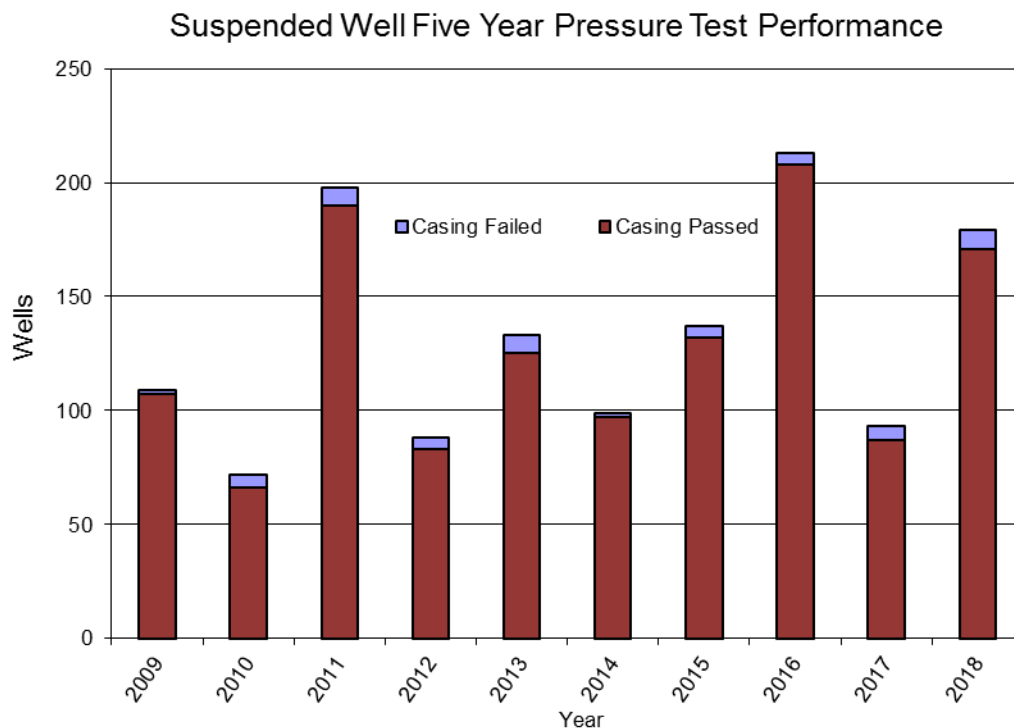


Figure 12: Suspended Well Five Year Pressure Test Performance

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 2018 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
- N₂ blowdown testing on steam injection wells
- 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 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.

A passive seismic performance review in 2014 recommended an increased focus on systems operating in high pressure pad areas (>6MPa). Hind-casting 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 strategy will improve the focus on the high pressure pad systems.

In 2017 and 2018, 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 all high pressure pads, allowing for earlier identification and immediate notification to Imperial's passive seismic team located in Calgary. An improvement in 2018 is that the notifications come directly via email and text message to personnel in Cold Lake.

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/scrapper 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/scrapper 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 inspections are performed on wells at a prescribed age. Either an in hole corrosion inspection log or an external ultrasonic test is completed to verify corrosion. Corrosion inspection logs are being synergized with earlier cycle casing integrity checks to optimize the logging schedule and ensure a sample set of corrosion data is collected on each pad. In 2017, corrosion assessments practices were changed such that deviated wells will be assessed one year earlier, prior to their ninth 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. 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 is completed through review of data such as prior casing integrity check results, passive seismic casing events, 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 H₂S sample partial pressure data were incorporated into the process in 2013.

In 2012 Imperial qualified the use of through tubing Electro-Magnetic (EM) logging as a method of performing a casing integrity check. Through tubing logging, 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 objective of the integrity check.

In 2015 an analysis of casing failure data showed that failure frequency rates for larger 9-5/8" cased horizontal wells were statistically lower than that of deviated 7" well casing. Statistically valid data for 9-5/8" CSS wells were available up to and including cycle 7. The presence and rate of casing impairments mirrored 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 began to be used as the standard casing integrity check technique through the first seven operating cycles for 9-5/8" wells. In addition, traditional rig based integrity checks 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 previous commencement 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 now occurs one cycle earlier prior to cycle 5 (as of 2016). These checks consist of traditional CI checks and synergistic checks completed with other tubing movements in early cycles. The practice allows for proactive measures to be taken (i.e. slimhole, shear liner, take out of steam service) that aids 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 2005. The numbers from 2013 forward include Schlumberger wireline EM scan log checks. The percentage of casing integrity checks that initially 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 2018 there were a total of 320 CI checks completed (252 rig based and 68 EM Scan checks), with 15 intermediate depth failures identified during these casing integrity checks (not including regulatory pressure testing). The percentage of CI checks which identify a casing failure has generally increased over time, since the targeted selection practice identifies wells with a higher probability of a failure. The increase is also attributed to aging wellbores.

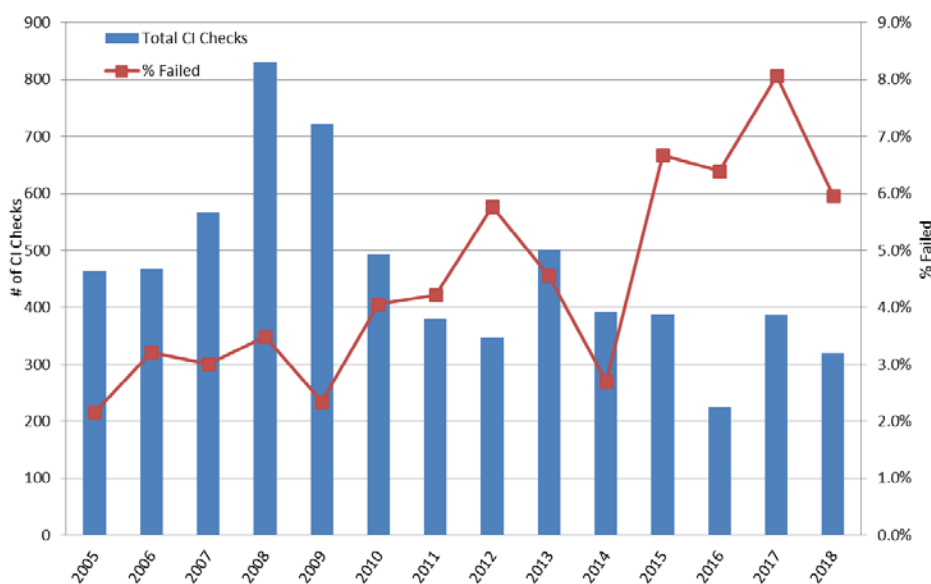


Figure 13: Casing Integrity Check History

3.2 Near Surface Casing Integrity Management

The mechanism for near surface casing failures is external corrosion. Water can collect outside the production casing through minor wellhead packing leaks, precipitation and surface water run-off from above, or condensed steam from overburden heating below. Oxygen is also present near surface and in the heated environment with various other elements, accelerated corrosion can result.

Corrosion inspection logs or external ultrasonic testing, 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 inspections were changed to be triggered by well age, on a years-in-service basis, instead of number of completed cycles. In 2017, the year-in-service was decreased from 10 years to 9 years for deviated wellbores, based on analysis of corrosion assessment results. 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 casing failures where there is the potential for environmental impact (higher pressure wells). 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 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.

Since 2010, casing shrouds have been installed on all wellbores to help prevent water from entering the production casing annulus. In 2016, the shroud material was upgraded from a galvanized to a stainless steel to extend life of the shroud. Additional changes were implemented in 2017 that improve how the shroud is attached to the wellbore to make for ease of installation and removal.

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 a temperature rating of 400°C, which makes it suitable for CSS injection conditions. From 2014-2018 the coating product has been applied to 127 candidate wells with moderate near-surface corrosion. In 2016, coatings began to be synergistically applied on wells that were dug out for external ultrasonic testing, and were remaining in service. Prior to December 2017, wells were only being synergistically coated if temperatures were steadily above 10°C to ensure proper curing of the coating. Changes have now been made to this process to allow wells to be synergistically coated year round by hoarding and heating of the exposed casing.

In 2018, Imperial initiated a single pad trial (V10 Pad) of Silicate Solution. The top 30-60 cm of bentonite was removed from the production casing annulus and replaced with a liquid silicate product. Observations were made to determine how the product behaved after application, and how it coated the casing. Corrosion coupons were inserted in treated and untreated wells to help demonstrate effectiveness of the product. At the 6 month mark some of the corrosion coupons were pulled and compared. Initial results were limited but favorable, indicating some visible corrosion on untreated coupons and no visible corrosion on the one treated coupon that was recovered. Imperial plans to do additional coupon inspections in 2019, and expand the pilot to additional pads.

3.2.1 Alternative Corrosion Measurement Technologies

From 2016-2018, surface corrosion on 215 wells was inspected using external ultrasonic testing (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 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.

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 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 do not require a surface dig out repair for full high pressure steam service. In 2018, 12 of these patches were installed (11 on failed wells, and 1 on a highly corroded well).

In 2017, Imperial obtained approval to trial a new near surface failure repair technology; the external composite wrap. This repair involves exposing the failure by excavating the well near surface, removing the outer casing string(s) and cement, and preparing the casing via sand blasting. Once the casing has the proper NACE finish, the external composite wrap is applied over a 0.5 m- 1 m interval with multiple layers of fiberglass and carbon fiber. The external composite wrap is suitable for producer only, low pressure operation (< 4 MPa), and has a 230°C temperature limitation. Eleven wells successfully had the repair installed to date and have been placed back in operation. These repairs have follow up helium testing completed once back in service after 1 month of operation and 6 months of operation. To date, 9 of the 11 successful repairs have been in service for 6+ months and have received successful 1 month and 6 month helium testing. 2 of the 11 have had successful 1 month helium tests, but have not yet been in operation for 6 months. Two additional repairs were completed on near surface failures and lost integrity during the installation testing process, prior to being placed back into operation. A detailed root cause failure analysis is being progressed on these two repairs and learnings will be used to further refine the installation process of these repairs.

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 H₂S in the casing - tubing annulus during shut-in periods. Nitrogen purge compliance for 2018 was 99.6% with a total of 8,863 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 at production temperatures below 60°C and a corrected H₂S partial pressure above 3kPaa. These wells are shut-in and purged with nitrogen until either the next steam cycle begins or a warm-up is performed.

On 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.

3.3.1 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.

Imperial has progressed the following technologies to provide additional well repair options:

- Imperial has worked with suppliers to develop different casing patch technologies and strategies. A development program began in 2012 with Saltel Industries to design and test a product that could withstand high temperature, high pressure CSS operating conditions. The Saltel patch field trial was successfully completed in 2017. Six wells have been repaired using this technology; five wells with intermediate casing failures and one well which was had a set of perforations above the production zone. Imperial has received AER endorsement to repair casing failures with this technology and return to HPCSS status after AER well specific approval is received. Additional Saltel patch installations are expected in the future.
- The Schlumberger 'MHE' patch is another high temperature – high pressure casing patch technology which was trialed in 2016 on 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 completed a full steam cycle and N2 Soak integrity was confirmed with fluid shots. A service rig completed a casing integrity inspection on the well in November 2017, which confirmed patch integrity. . No additional opportunities for this repair technique occurred in 2018, but the MHE patch will be considered for returning wells to HPCSS service in the future..

3.3.2 Well Operability – Casing Fatigue Research & Material Testing

URC studies on casing fatigue or material testing were completed in 2016. Below is a summary of the previous 2016 well operability studies that were progressed to completion;

- The Production Injection Management Fatigue Estimate Toolkit (PIMFET) software that was developed in 2011, was last optimized in 2016 to enabled better pad pressure alignment and balance/symmetry through small steam rate adjustments which subsequently reduces the amount of fatigue induced on the casing. This has resulted in improving steam strategies and adapting operating practices for various well and pad scenarios.
- 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.

3.4 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 casing integrity program for Cold Lake was designed primarily 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, 140m³ of 1370kg/m³ CaCl₂ fluid, 140m³ of 1500kg/m³ CaCl₂ fluid and all necessary kill fluid additives in order to respond to high pressure casing failures in a timely manner.

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

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).

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 deviated wells on a pad must have a corrosion log within the first 9 years from initial steam date. For horizontal wells with 9 5/8" or 8 5/8" production casing (which use EM log up to and including cycle 8), a 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 logs or external UT results for that well.