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# 2009 Annual Summary Report on Casing Integrity

Submitted: March 30, 2010

## EXECUTIVE SUMMARY

### Casing Failures

#### *Near Surface*

- 16 failures in 2009.
- 3 detected with casing integrity checks, 13 detected operationally.
- None in 2009 were assessed above a level zero environmental consequence.
- 7 wells in 2009 proactively repaired or taken out of steam service due to excessive wall loss.

#### *Intermediate Depth*

- 30 failures in 2009 (30 primary failures & 0 secondary failures) versus 39 failures in 2008. The number of failures and the failure frequency has reduced to pre-2007 levels.
- 15 detected with casing integrity checks, 15 detected operationally which includes 9 with passive seismic. The remaining 6 were detected operationally through the nitrogen soak and fluid level programs.
- No multi-well failures occurred in 2009.
- None in 2009 were assessed above a level 0 environmental consequence.
- 88 wells in 2009 proactively repaired or taken out of steam service due to impairment or deformation.

#### *Clearwater*

- 56 failures in 2009.
- No adverse environmental impact identified.

### Casing Failure Detection Initiatives

#### *Alarm Management*

- A new adaptive alarm trigger for the nitrogen soak program was developed in 2009 further enhancing the failure detection capability.
- A new method of filtering Delta Flow and Pressure (DFP) alarms was developed in 2009. Testing is currently underway; if proved to be successful, full implementation is planned for Q2 2010.

#### *Targeted Selection*

- Risk based process to identify which wells should receive minimum required casing integrity checks, as well as to identify wells that should be checked incremental to the minimum standard.

### Near Surface Casing Integrity Initiatives

#### *2009 Bentonite Top-up Program*

- Excluding approximately 910 below grade wells where bentonite top-ups are not able to be completed, 3778 of 3786 wells have received bentonite top-ups as of February 10, 2010. The remaining wells are scheduled to be completed in Q1 2010.
- Top-up compliance is now being stewarded.
- There are approximately 910 late cycle wells where bentonite top-ups are not able to be completed as conductor pipes are below grade level. An assessment was conducted to determine a maintenance strategy for these wells; a strategy was selected and testing will be conducted to determine its applicability.

#### *Casing Shroud Installation*

- Prototype designed and a successful 150 well trial was conducted in the summer of 2009.
- 3202 of 3786 wells have had casing shrouds installed as of February 10, 2010. Remaining 584 wells are to be completed in Q1 2010.

#### *Operating Practice Review*

- A technical review of Imperial Oil's Casing Integrity Operating Practices with respect to managing surface corrosion was conducted in 2009.

#### *New Well Corrosion Assessment*

- Corrosion assessments were completed on 20 'new' wells to further understand near surface corrosion rates.

#### *Alternative Corrosion Measurement Technologies*

- 5 logs were completed in 2009 to assess a new corrosion inspection tool, with evaluation of the results in progress.

#### *Surface Corrosion Mitigation for New Well Installations*

- Currently investigating high temperature external coatings for potential application to the top casing joint.

### **Intermediate Depth Casing Integrity Initiatives**

#### *Casing Retrieval*

- Casing retrieval operations complete on 4 wells. Analysis is complete on 3 of the 4 wells and show evidence of both embrittlement and ductile overload.

#### *Material Testing*

- Completed a series of tests using L80 grade material to determine the onset of sulphide stress cracking (SSC) as a function of temperature and H<sub>2</sub>S partial pressure.
- Results predict micro-cracks to form at H<sub>2</sub>S partial pressures above 3 kPaa and temperatures of 60°C or lower.
- In 2009, a program was implemented identify, shut in and nitrogen purge producing wells at risk of SSC based on these findings. To date, 569 wells have been sampled and no wells have exceeded the <60°C & >3 kPaa criteria; only four wells have been found in the 1 kPaa to 3 kPaa range.

#### *Instrumented Well / Wellbore Environment Model*

- Instrumented Well – equipped well T06-09 with downhole instrumentation to measure temperature, pressure, H<sub>2</sub>S concentration, and take liquid samples to determine acidity. Monitoring was put into operation in July 2009.
- Wellbore Environment Model – a numerical model has been developed which can predict partial pressure of H<sub>2</sub>S as a function of wellbore temperature and pressure. Actual data from instrumented well is being used to tune the model which may then be used to predict downhole conditions based on surface measurements.

#### *Geological Study of the Colorado Shales*

- Geological review of the Colorado Shales which was begun in 2008 continued through 2009 examining stratigraphy and depositional environment of the shales at multiple pads.
- The presence of small-scale normal faults would appear to be a contributing factor to well deformations and failures.

#### *Well Load and Resistance Studies*

- Model studies continued in 2009 using a layered rock property model coupled with well and connection sub-models incorporating metallurgical properties of the casing body and connections to predict the distribution and magnitude of plastic strain and estimate when material failure will occur.
- Model was unable to match individual well failures as they occurred in the field; however, current plan is to use the model to develop a software tool to manage steam injection strategies.

- Participating in Noetic joint industry project (JIP) to study synergistic thermo-mechanical and environmental loads on casing.

#### *Steaming Practices*

- Conducted assessment of steaming practices on several Mahkeses pads in 2009. The assessment did not establish a clear correlation between steam injection volume or pattern and frequency of casing failures.

#### *Well Design*

- Imperial believes the use of L80 steel is the optimum casing material to balance post-yield material properties and SSC resistance.
- Model studies were conducted in 2009 to evaluate connection design improvements. Work will continue in 2010.

## 1.0 INTRODUCTION

Pursuant to the requirements of AEUB Decision 99-22, condition #9 and clause 6.2 of AEUB Approval 8558, Imperial Oil Resources hereby submits the 2008 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 2009 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 according to the following three depth intervals:

- Near surface (0 to ~25 mTVD).
- Intermediate depth 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 potential aquifer contamination or breach to surface. Clearwater failures only affect the serviceability 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 Bedrock top, and have potential for fluid loss are Alberta Environment 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"> <li>- Failure occurred within the bedrock with fluid loss below the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m<sup>3</sup> produced fluid, dependant on proximity of wellbores at failure depth)</li> <li>- Failure occurred within the Glacial Till, but only released inert fluid (e.g. N<sub>2</sub> gas) or minimal produced fluid not requiring remediation</li> </ul>
Level 1	<ul style="list-style-type: none"> <li>- Failure occurred within the bedrock with fluid loss above the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m<sup>3</sup> produced fluid, dependant on proximity of wellbores at failure depth)</li> <li>- 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)</li> </ul>
Level 2	<ul style="list-style-type: none"> <li>- Failure with fluid release to surface or fresh water aquifer requiring longer term remediation efforts</li> </ul>

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 the 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, or passive seismic (PS) systems, or detected by visual means. A casing integrity 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).

## 2.0 CASING INTEGRITY DATA

A historical summary of casing failures by depth interval at Cold Lake is provided in Table 2. All 30 of the intermediate depth casing failures detected in 2009 were classified as primary commercial intermediate failures (no early casing design failures). None of the 46 near surface or intermediate failures in 2009 were assessed an environmental consequence above level 0. Of the 46 surface and intermediate failures detected in 2009, 28 were detected operationally and 18 were detected through casing integrity checks.

Table 2: Historical Failure Summary by Depth Interval

Depth Classification	Year					
	2004	2005	2006	2007	2008	2009
Surface	0	1	1	5	5	16
Intermediate	21	16	26	36	39	30
Clearwater	57	51	70	71	81	56
Total	78	68	97	112	125	102

Casing integrity data for the three failure depth intervals is presented in the following subsections.

### 2.1 Near Surface Casing Integrity Data

Since 1991, 107 commercial wells have failed near surface, including 16 surface failures detected in 2009. Details describing these failures (including primary cement tops) are provided in Table 3. In addition to failed wells, a further 116 wells have either been proactively repaired or taken out of steam service due to excessive wall loss.

Table 3: 2009 Surface Depth Failures Summary

No.	WELL INFORMATION				FAILURE INFORMATION							
	Well	License	UWI	Primary Cement Top mGL	Detection Date mm/dd/yy	Detection Method		Depth		Cycle	Environmental Consequence Level	
								mKB	mGL			
1	R02-14	134605	107/04-23-065-04W4	>60	01/15/09	Operational	CI Check	13.1	8.8	8	0	
2	M03-16	132059	102/05-26-065-04W4	7.0	02/03/09	Operational	CI Check	4.1	-0.2	7	0	
3	U05-17	253326	105/03-09-065-03W4	0.0	03/03/09	CI Check	CI Check	10.0	5.0	6	0	
4	J01-06	109495	110/08-21-065-04W4	13.8	03/11/09	Operational	N2 Fluid Level	4.7	0.3	14	0	
5	F02-18	204946	102/16-18-065-03W4	0.9	03/28/09	CI Check	CI Check	5.3	1.0	8	0	
6	L11-27	191769	102/12-28-065-04W4	0.0	04/07/09	CI Check	CI Check	4.5	0.2	8	0	
7	A06-17	103880	103/08-15-065-04W4	9.5	05/13/09	Operational	Visual	4.2	-0.4	9	0	
8	J21-04	118568	103/12-15-065-04W4	0.0	06/02/09	Operational	Visual	4.2	-0.1	12	0	
9	A06-07	103914	106/12-14-065-04W4	14.5	06/29/09	Operational	Visual	3.8	-0.2	9	0	
10	D25-07	115015	108/09-02-065-04W4	5.2	06/30/09	Operational	Visual	2.8	-1.7	13	0	
11	D25-09	115017	109/12-01-065-04W4	1.8	07/21/09	Operational	Visual	4.7	0.2	13	0	
12	J02-06	108966	100/12-22-065-04W4	8.9	07/22/09	Operational	Visual	4.3	0.0	11	0	
13	H01-17	109046	108/08-21-065-04W4	10.7	08/11/09	Operational	Visual	5.4	1.3	12	0	
14	H02-13	108832	105/10-21-065-04W4	3.3	08/12/09	Operational	Visual	4.5	0.1	12	0	
15	R01-18	133052	108/09-15-065-04W4	0.8	10/03/09	Operational	Visual	4.2	-0.1	8	0	
16	H01-18	109047	109/08-21-065-04W4	9.9	11/16/09	Operational	Visual	5.5	1.4	12	0	

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 the 16 near surface failures detected in 2009.

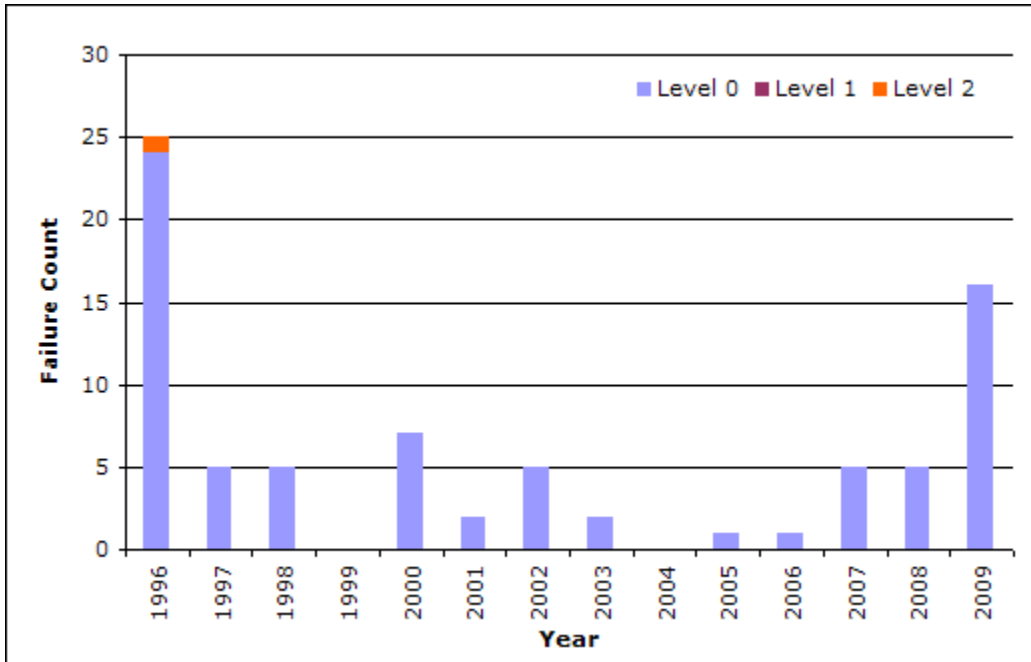


Figure 1: Cold Lake Surface Failures by Consequence Level

The number and frequency of surface casing failures for the commercial casing design in Cold Lake are summarized in Figure 2. Failure frequency is the number of failures divided by the total number of wells operating. The peak failure rate observed in 1996 marks the inception of the Casing Integrity Operating Practices, at which time the cement and bentonite top-up program was initiated to mitigate the occurrence of surface failures. Positive results were observed and the surface failure frequency declined; however, failure frequency has increased in recent years.

In 2009, 13 out of 16 of the failures occurred on 'old' wells (steamed prior to 1996, before the implementation of the Casing Integrity Operating Practices). The bentonite top-up program and production casing inspection practices have been targeted to mitigate the risk associated with a high pressure (capable of flow) casing failure where there is potential for environmental impact, and have done so effectively. All 16 near surface casing failures detected in 2009 occurred on low pressure wells with negligible environmental impact.

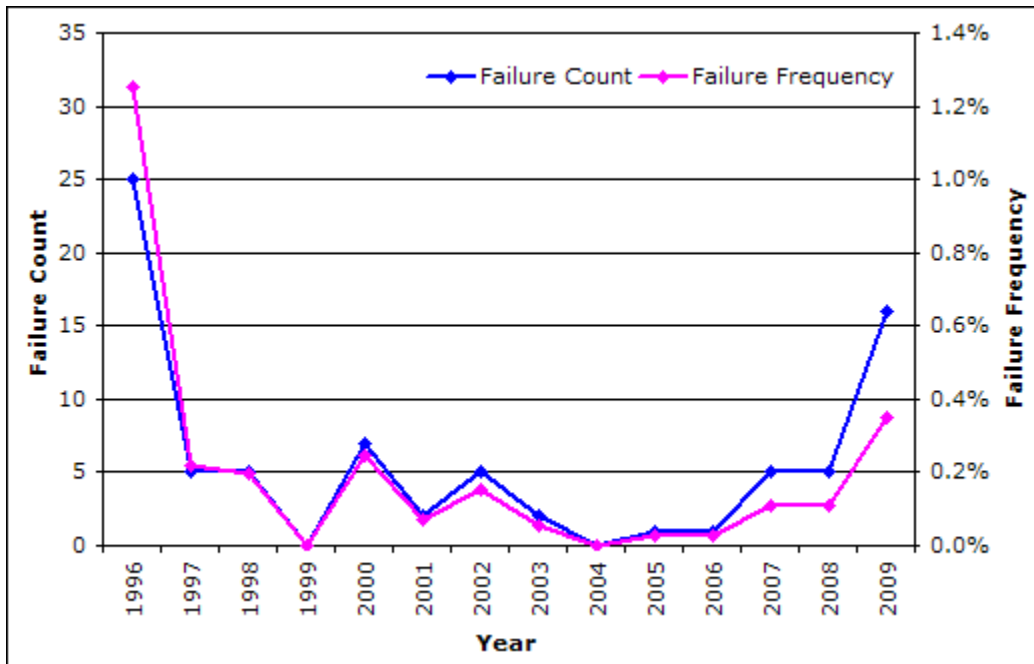


Figure 2: Commercial Surface Failures and Failure Frequency

Near surface failure detection method is displayed in Figure 3.

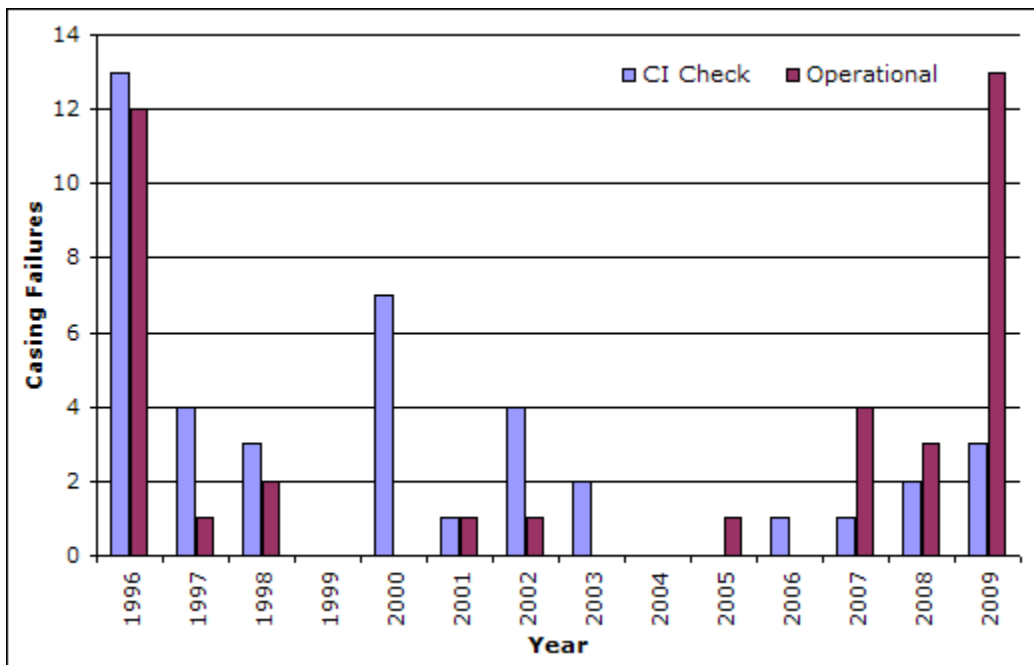


Figure 3: Commercial Surface Failures by Detection Method

## 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 earlier casing design in cyclic steam stimulation (CSS) operation in 2009.

Since the implementation of the Casing Integrity Operating Practices in 1996, a total of 303 primary intermediate casing failures have been detected in wells with the L-80 or IK-55 casing designs. Approximately 64% of these failures were identified during pre-steam casing integrity checks. In addition, 496 wells were taken out of steam service or repaired due to intermediate impairments or excessive deformation. There have been two intermediate failures which have required aquifer remediation (H15-10 in 1999 and H39-H04 in 2006). There have been two multi-well failure events since 1996:

- T09-01 primary intermediate casing failure in 2006 with one secondary failure on T09-07 in 2006.
- H33-06 primary intermediate casing failure in 2007 with secondary failures on H33-08 and H33-10 in 2007, as well as H33-01, H33-12, and H33-15 in 2008.

Details on the 30 primary intermediate failures, which occurred in 2009, are provided in Table 4.

Table 4: 2009 Intermediate Depth Failures Summary

No.	WELL INFORMATION			FAILURE INFORMATION										
	Well	License	Unique Well Identifier	Detection Date mm/dd/yy	Detection Method	Depth		Depth Class	Pipe Body / Connection	Connection Type	Primary / Secondary / Slimhole	Cycle	Environmental Consequence Level	
						mKB	mTYD							
1	H26-05	179219	103/08-03-066-04W4	01/15/09	CI Check	CI Check	221.2	216.3	Fish Scale Fm	C	OBTC	P	8	0
2	D33-10	225544	110/15-02-065-04W4	02/09/09	Operational	N2 Fluid Level	271.5	268.2	Westgate Fm	C	NSCC	P	8	0
3	D62-04	157790	102/14-36-064-04W4	02/24/09	Operational	PS - LP	284.0	272.6	Westgate Fm	C	OBTC	P	8	0
4	G03-21	222508	104/10-09-065-03W4	02/28/09	Operational	PS - LP	313.3	310.7	Joli Fou Fm	C	NSCC	P	8	0
5	T09-21	248740	104/15-29-064-03W4	02/25/09	Operational	PS - LP	283.0	281.3	Fish Scale Fm	C	NSCC	P	7	0
6	U03-08	253368	100/09-04-065-03W4	03/15/09	CI Check	CI Check	251.5	250.7	Fish Scale Fm	C	QB2	P	6	0
7	H03-09	108956	108/01-28-065-04W4	03/30/09	Operational	N2 Fluid Level	261.2	260.6	Westgate Fm	C	OBTC	P	10	0
8	H27-07	182080	100/06-03-066-04W4	04/01/09	Operational	N2 Fluid Level	250.9	240.8	Westgate Fm	C	OBTC	P	7	0
9	E05-17	287872	109/08-01-065-04W4	04/10/09	Operational	PS - LP	227.0	227.0	Fish Scale Fm	C	NSCC	Slimhole	6	0
10	D27-04	114780	100/06-01-065-04W4	04/11/09	CI Check	CI Check	262.0	250.3	Westgate Fm	C	OBTC	P	12	0
11	L11-25	191760	102/16-29-065-04W4	04/24/09	CI Check	CI Check	270.1	256.2	Westgate Fm	C	OBTC	P	8	0
12	U06-09	273183	100/01-09-065-03W4	05/13/09	CI Check	CI Check	244.0	244.0	Fish Scale Fm	C	NSCC	P	6	0
13	T08-09	237209	104/01-32-064-03W4	05/24/09	Operational	PS - HP	282.8	278.0	Fish Scale Fm	C	NSCC	P	8	0
14	FF-09	116843	1A/F/16-07-065-03W4	06/02/09	CI Check	CI Check	214.2	213.9	Fish Scale Fm	Pipe	OBTC	P	9	0
15	L05-14	191753	106/11-28-065-04W4	06/03/09	CI Check	CI Check	252.0	251.2	Westgate Fm	C	OBTC	P	8	0
16	E01-H4	291795	103/07-12-065-04W4	06/22/09	CI Check	CI Check	291.0	290.7	Joli Fou Fm	C	NSCC	P	6	0
17	H23-04	180093	108/15-34-065-04W4	06/23/09	Operational	N2 Fluid Level	285.2	268.0	Westgate Fm	C	OBTC	P	8	0
18	A06-07	103914	106/12-14-065-04W4	07/03/09	CI Check	CI Check	302.5	291.2	Joli Fou Fm	C	OBTC	P	9	0
19	Y16-15	256880	103/01-01-065-04W4	07/17/09	Operational	PS - LP	255.5	253.5	Fish Scale Fm	C	NSCC	P	6	0
20	GG-07	127854	103/03-07-065-03W4	07/29/09	CI Check	CI Check	324.5	309.1	Joli Fou Fm	C	OBTC	P	7	0
21	00V-20	98153	1A/L/11-08-065-03W4	08/08/09	CI Check	CI Check	241.2	228.9	Westgate Fm	C	OBTC	P	8	0
22	H37-29	206981	111/08-03-066-04W4	08/17/09	Operational	N2 Fluid Level	219.5	213.4	Fish Scale Fm	C	OBTC	P	7	0
23	Y16-20	256884	107/13-31-064-03W4	08/19/09	Operational	PS - LP	252.1	251.3	Fish Scale Fm	C	VAM	P	7	0
24	Y16-22	256886	106/14-31-064-03W4	08/31/09	CI Check	CI Check	351.5	336.1	Joli Fou Fm	C	VAM	P	7	0
25	E03-03	199234	102/15-01-065-04W4	09/22/09	CI Check	CI Check	425.1	403.8	GP Member	C	OBTC	P	7	0
26	H11-13	278383	106/14-21-065-04W4	09/30/09	CI Check	CI Check	260.5	260.3	Westgate Fm	C	NSCC	P	6	0
27	U06-22	273196	105/04-10-065-03W4	10/02/09	Operational	N2 Soak	247.0	246.7	Fish Scale Fm	C	NSCC	P	7	0
28	F03-20	209499	100/01-18-065-03W4	10/26/09	Operational	PS - LP	302.5	301.8	Joli Fou Fm	C	OBTC	P	7	0
29	L05-15	191751	107/11-28-065-04W4	12/08/09	Operational	DFP	(185.0)	(183.5)	(Upper Colorado Shale)	Unk	OBTC	P	9	0
30	D63-13	158392	100/06-36-064-04W4	12/14/09	CI Check	PS - LP	307.4	305.5	Joli Fou Fm	C	OBTC	P	8	0

Note: (mKB/mTYD) indicates diagnostics with rig are not complete. Depths are estimated from fluid levels during initial response.

A summary of the connection type for primary intermediate connection failures detected in 2009 is provided in Table 5. Note that both NSCC & QB2 thread designs have a metal-to-metal seal. It is difficult to draw any conclusions from the data presented due to the varying installation phases with the different connection types, and limited sample size with the QB2 design. Currently in operation there are 2644 wells with OBTC connections, 989 with NSCC, 503 with QB2, and 215 with other types in commercial wells.

Table 5: 2009 Primary Intermediate Connection Failures by Connection Design

Connection Type	Cycle Number												Total
	1	2	3	4	5	6	7	8	9	10	11	12	
OBTC	0	0	0	0	0	0	5	7	1	1	0	1	15
NSCC	0	0	0	0	0	5	2	3	0	0	0	0	10
QB2	0	0	0	0	0	1	0	0	0	0	0	0	1
Other	0	0	0	0	0	0	2	0	0	0	0	0	2
<b>Total</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>6</b>	<b>9</b>	<b>10</b>	<b>1</b>	<b>1</b>	<b>0</b>	<b>1</b>	<b>28</b>

Note: excludes FF-09 (pipe body failure) and L05-15 (investigation not complete)

Historic consequence levels associated with intermediate casing failures since 1996 are displayed in Figure 4. None of the 30 intermediate failures that occurred in 2009 were assessed higher than a level 0 environmental consequence.

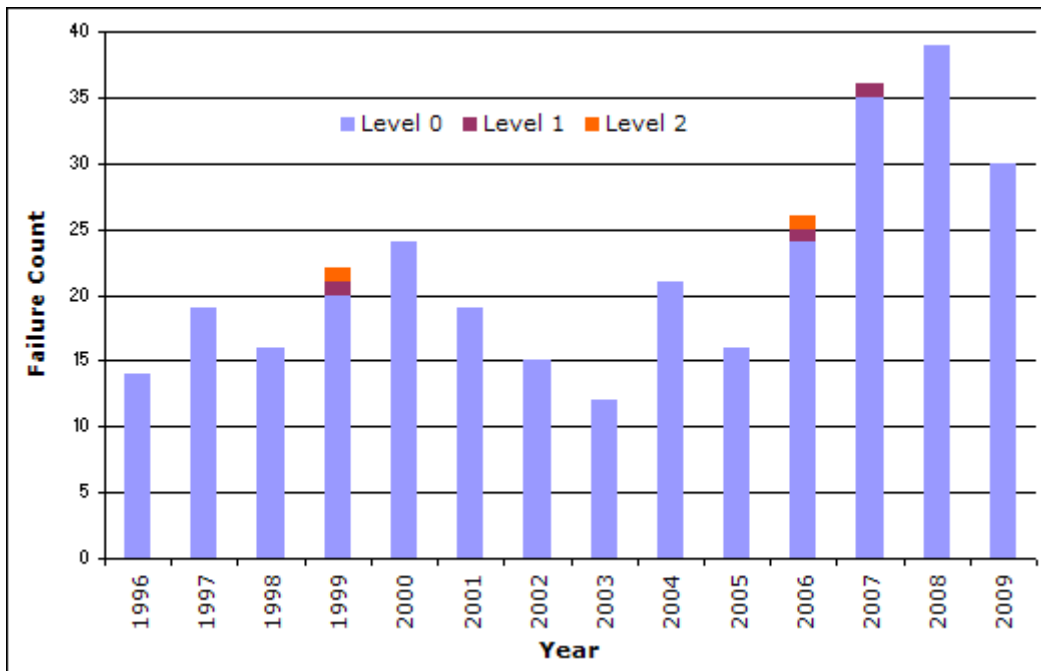


Figure 4: Cold Lake Intermediate Failures by Consequence Level

The number and frequency of primary intermediate casing failures for the commercial casing design in Cold Lake are summarized in Figure 5. The number and frequency of failures were reduced in 2009 to pre 2007 levels.

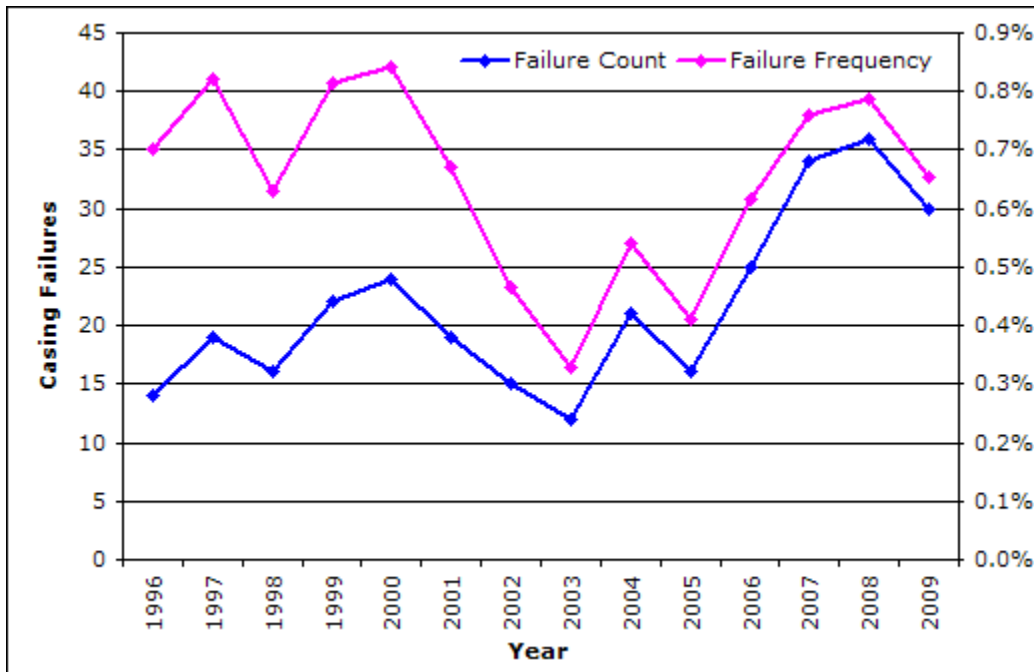


Figure 5: Primary Intermediate Commercial Failures and Failure Frequency

The primary intermediate casing failures for the commercial casing design in Cold Lake are summarized in Figure 6. The data is stacked into early (1-4), mid (5-7), and late (8-12) cycle classifications. The number of early cycle failures has historically been lower than mid and late cycle failures and continues to be so. Mid cycle failures have generally been increasing since 1996; however, a significant decrease was observed in 2009. Late cycle failures have generally been declining since 1996, although a slight increase occurred in 2009.

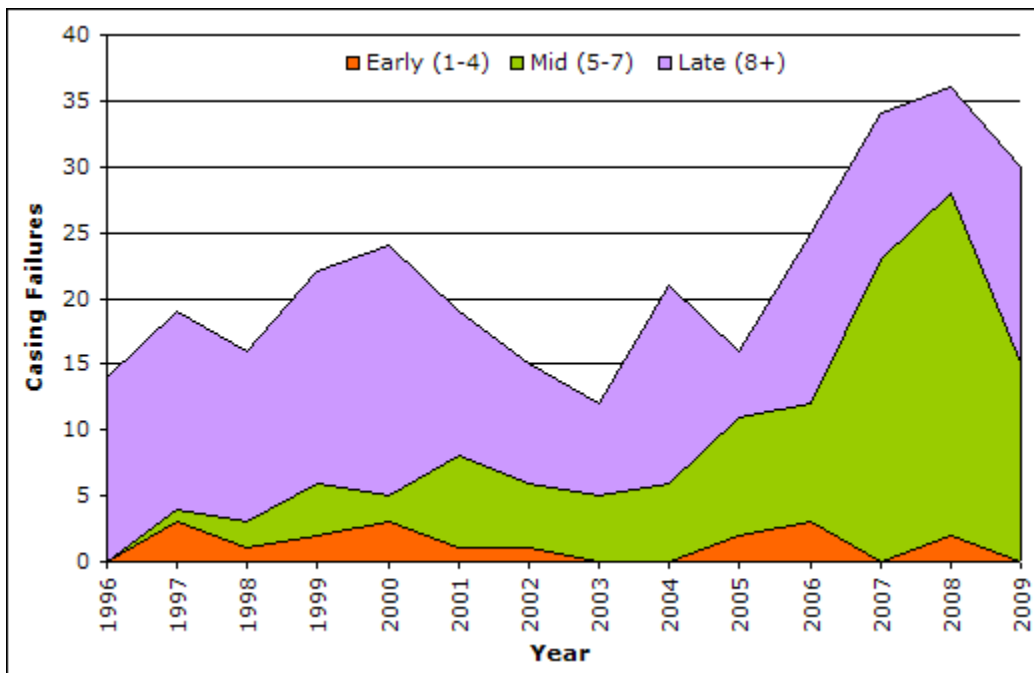


Figure 6: Primary Intermediate Commercial Failures by Cycle Range

Historical primary intermediate failure frequency for the commercial casing design is provided in Figure 7. The data is divided into early (1-4), mid (5-7), and late (8-12) cycle classifications. Early cycle failure frequency peaked in 2006 and has continued to decrease since. Mid cycle failure frequency steadily increased between 2004 and 2008; however, 2009 saw a marked reduction which is believed to be the result of many casing integrity initiatives underway since 2006. The failure frequency for later cycle wells has generally been declining since 1996, but a slight increase was observed in 2009.

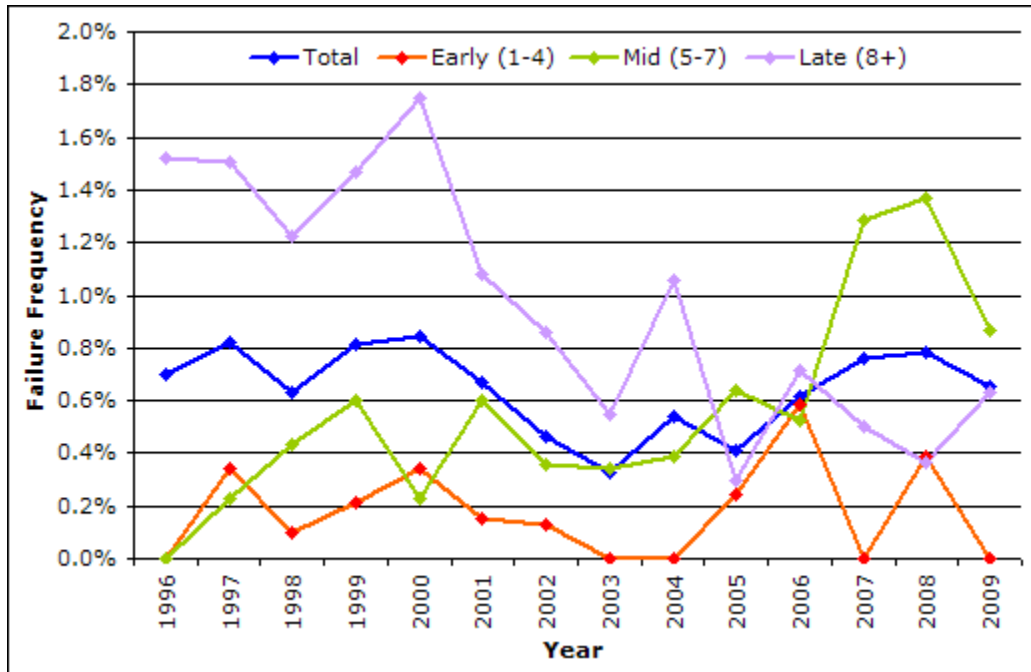


Figure 7: Primary Intermediate Commercial Failure Frequency by Cycle Range

Primary intermediate failure detection method is displayed in Figure 8. The pre-steam casing integrity process has detected a significant portion (approximately 65%) of the casing failures at Cold Lake since its inception in 1996. The percentage of operationally detected casing failures has generally increased since 2002, primarily due to the increased detection capabilities and enhancements with passive seismic and the nitrogen soak monitoring program. The number of casing failures detected through casing integrity checks has also increased significantly in recent years in large part due to the increased frequency of casing integrity checks as a result of enhancements made to the Casing Integrity Operating Practices. The number of casing integrity checks performed since 2001 is displayed in Figure 10, which is provided later in this report.

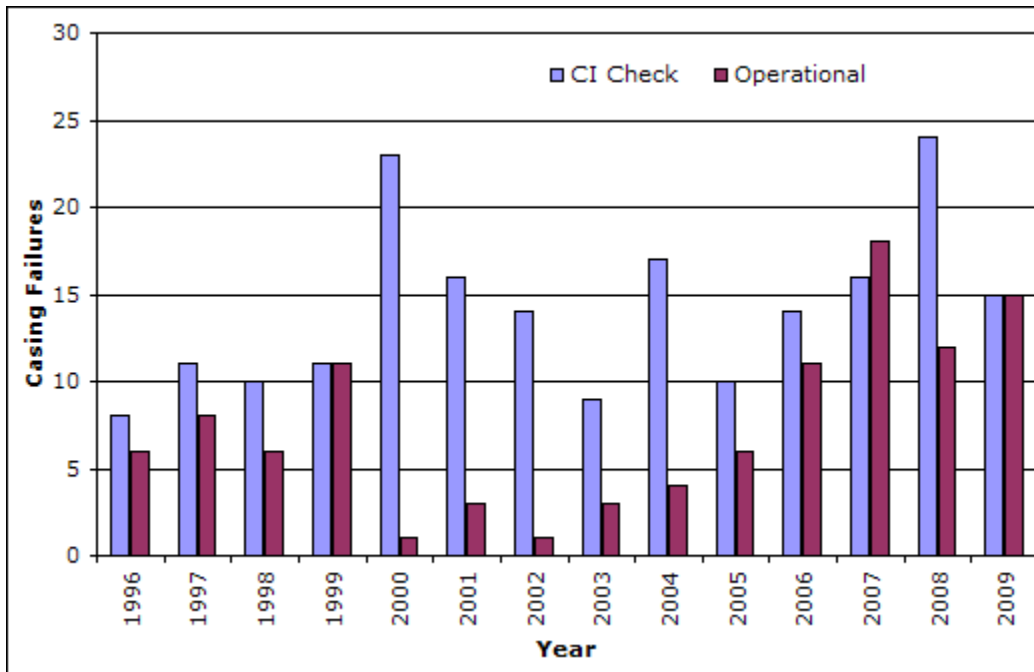


Figure 8: Primary Commercial Intermediate Failures by Detection Method

### 2.3 Clearwater Casing Integrity Data

In 2009, 56 Clearwater casing failures were detected. Details of these failures are provided in Table 6.

Table 6: 2009 Clearwater Failures Summary

No.	WELL INFORMATION			FAILURE INFORMATION			
	Well	License	UWI	Detection Date mm/dd/yy	Cycle	Depth mKB mTYD	
1	T12-16	268224	107/06-29-064-03w4	01/19/09	6	490.0	465.9
2	E01-18	291809	110/03-12-065-04w4	01/19/09	6	460.0	420.0
3	T08-21	237221	105/04-33-064-03w4	01/23/09	7	543.0	480.2
4	F05-04	213323	105/04-17-065-03w4	01/29/09	7	502.0	414.5
5	T11-16	268175	106/09-29-064-03w4	02/03/09	6	480.0	479.5
6	T07-02	248839	102/03-33-064-03w4	02/06/09	6	626.6	478.0
7	U06-12	273186	103/16-04-065-03w4	02/06/09	6	591.4	452.4
8	T07-03	248840	103/03-33-064-03w4	02/10/09	6	586.4	478.3
9	L07-06	200365	108/12-28-065-04w4	02/12/09	7	545.3	423.2
10	T08-15	237215	102/04-33-064-03w4	02/13/09	7	485.0	481.7
11	U06-10	273184	102/01-09-065-03w4	02/13/09	6	462.4	450.7
12	T08-07	237207	105/08-32-064-03w4	02/15/09	6	618.8	476.7
13	F03-19	209498	114/02-18-065-03w4	02/16/09	6	432.0	392.6
14	D1-OB2	117962	110/13-12-065-04w4	02/17/09	--	419.0	419.0
15	T11-11	268186	104/09-29-064-03w4	02/18/09	6	535.0	480.4
16	L06-15	173967	105/04-28-065-04w4	02/20/09	10	413.0	357.8
17	L07-08	200367	106/09-29-065-04w4	02/24/09	7	452.0	416.2
18	L07-21	200380	108/08-29-065-04w4	02/25/09	7	433.0	417.5
19	H26-01	179209	100/07-03-066-04w4	02/26/09	8	549.8	411.2
20	T02-15	237108	105/12-33-064-03w4	02/28/09	7	486.2	475.6
21	L07-10	200369	100/08-29-065-04w4	03/01/09	7	434.0	418.1
22	L07-02	200361	103/09-29-065-04w4	03/18/09	7	495.0	416.8
23	T01-05	1237997	104/06-33-064-03w4	03/19/09	6	491.0	484.4
24	T07-06	248843	104/14-28-064-03w4	03/22/09	6	682.0	481.4
25	G03-25	222512	106/10-09-065-03w4	03/25/09	3	450.5	425.5
26	F05-24	203246	100/14-08-065-03w4	03/31/09	6	521.4	419.7
27	L07-09	200368	107/09-29-065-04w4	04/01/09	7	442.0	423.3
28	L07-05	200364	107/12-28-065-04w4	04/01/09	7	517.3	421.5
29	L07-28	200387	105/01-29-065-04w4	04/03/09	7	490.0	421.0
30	T01-03	237995	105/11-33-064-03w4	04/08/09	6	591.3	482.8
31	L11-28	191766	103/12-28-065-04w4	04/18/09	8	461.0	412.1
32	V02-09	253842	103/05-34-064-03w4	04/12/09	6	493.0	481.5
33	T07-11	248847	105/14-28-064-03w4	04/30/09	6	540.2	479.7
34	D39-24	354027	112/11-12-065-04w4	05/05/09	3	466.9	420.5
35	U04-18	253430	107/11-04-065-03w4	05/09/09	6	489.0	447.0
36	U06-16	273190	104/01-09-065-03w4	05/09/09	6	460.8	449.7
37	U01-19	253513	105/01-04-065-03w4	05/10/09	6	665.5	472.6
38	G02-13	222369	106/04-16-065-03w4	05/14/09	8	549.0	426.9
39	U04-19	253431	108/11-04-065-03w4	05/14/09	6	489.5	453.6
40	U01-14	253508	102/01-04-065-03w4	05/17/09	6	526.5	474.1
41	T07-08	248845	104/03-33-064-03w4	05/22/09	6	545.2	480.4
42	C08-15	354894	103/09-12-065-04w4	05/26/09	3	437.5	418.0
43	C08-29	354900	106/07-12-065-04w4	06/05/09	3	541.0	270.1
44	U06-14	273188	103/05-10-065-03w4	06/07/09	6	509.5	452.5
45	C08-17	354896	105/10-12-065-04w4	06/17/09	3	530.0	415.3
46	H23-04	180093	108/15-34-065-04w4	06/23/09	8	511.0	422.8
47	A05-03	103921	103/11-14-065-04w4	06/24/09	10	482.0	420.3
48	H37-29	206981	111/08-03-066-04w4	08/17/09	7	528.1	419.5
49	E01-H02	291793	100/06-12-065-04w4	08/23/09	6	464.0	418.0
50	V01-20	254046	105/14-34-064-03w4	08/08/09	6	624.0	479.0
51	H59-14	323655	100/07-16-066-04w4	09/19/09	3	485.0	420.7
52	H11-09	278378	104/14-21-065-04w4	09/23/09	6	448.5	423.7
53	E03-15	199243	102/10-01-065-04w4	10/13/09	7	494.0	423.0
54	E03-08	199237	105/15-01-065-04w4	10/06/09	7	431.2	429.0
55	V03-23	253958	103/05-27-064-03w4	10/31/09	6	667.0	457.6
56	H11-14	278384	107/14-21-065-04w4	12/18/09	6	433.4	421.7

The number and frequency of Clearwater casing failures for the commercial casing design in Cold Lake are summarized in Figure 9. The frequency of failures has remained relatively constant since 2002.

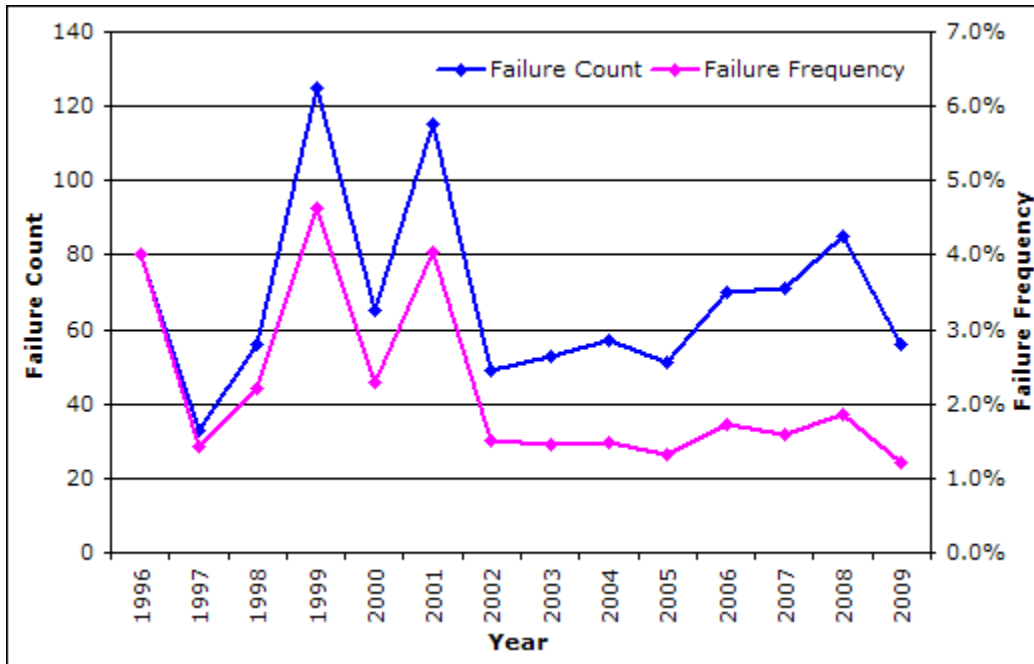


Figure 9: Commercial Clearwater Failures and Failure Frequency

### 3.0 COLD LAKE CASING INTEGRITY MANAGEMENT

Casing integrity is a critical component of the Operations Integrity Management System in Cold Lake. Continuous improvement with respect to casing integrity has been made throughout the history of Cold Lake Operations. Failure mechanisms that have been identified in Cold Lake wells are external corrosion (near surface failures), stress corrosion cracking (SCC), and sulphide stress cracking (SSC) with contributing factors such as metal fatigue (high strain – low cycle) and formation movement. The Cold Lake Casing Integrity Operating Practices were formally introduced in 1996 providing improvements in three major areas – prevention and detection of, 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. The Casing Integrity Operating Practices are reviewed and updated annually.

Improvements and initiatives in detection and prevention of (with respect to the three depth classifications), and response to casing failures relevant to 2009 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 during steam injection
- Nitrogen Soak pressure and fluid level monitoring during soak and shut-in
- Steam trend analysis
- Passive seismic monitoring
- Groundwater monitoring
- Casing integrity check process

Current initiatives and recent improvements in detection methods 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 passive seismic alarms and responded to immediately in order to confirm the potential casing failure.

A new method of filtering DFP events to reduce the number of false alarms and streamline casing failure detection was developed in 2009; a prototype test is currently in progress to verify its' validity. If the test proves successful, full implementation is planned for Q2 2010.

The nitrogen soak and fluid shot program is the primary monitoring system for casing failure detection for shut-in and soaking wells. After steam or during shut-in periods wells are purged with nitrogen to eliminate an environment susceptible to SSC, and to provide a liquid free annulus to enable casing pressure and fluid level monitoring. Real time wellhead pressures are monitored with the N2SOAK program for all wells across the district every half-an-hour. An adaptive alarm trigger was developed in 2009 further enhancing the failure detection capability of the N2SOAK system; the new trigger is now operational across the district. The N2SOAK program calculates the hourly average wellhead pressure ( $P_{new}$ ) and compares it with the hourly average from 3-hours ago ( $P_{old}$ ). If the change in pressure ( $P_{old} - P_{new}$ ) is greater than the alarm trigger limit, an alarm is generated and the operator is alerted. The alarm trigger limit is automatically calculated by the program, between 25 kPa and 90 kPa, depending on the historical pressure profile of the well. Fluid levels are also taken 1 hour, 24 hours, 3 days, 7 days, and

every 28 days thereafter the initial purge to monitor for casing failures on soaking wells. All alarms and/or rises in the fluid level are investigated and potential casing failure events are responded to immediately in order to confirm the potential casing failure.

### 3.1.2 *Passive Seismic Monitoring*

Passive seismic alarm coordination was implemented in 2007, triggering immediate action on potential intermediate casing failures. If the well with a potential casing failure is at low pressure (< 4 MPa), the well is checked with a service rig within 60 days of the event. If the well is at high pressure, the well is immediately put on nitrogen soak to confirm integrity. Beginning in 2007 additional geophones have been added within the Glacial Till on all new Passive Seismic installations to enhance casing failure detection within the upper portion of the wellbore.

Imperial Oil has been utilizing the passive seismic system to aid in the detection of Clearwater top (CWT) failures. When a medium to high probability Clearwater top passive seismic event (within 30 mTVD of CWT) is detected, the well is operated below the fracture pressure until a casing integrity check is performed (required prior to the next steam cycle). No action is required for low probability Clearwater top passive seismic events.

### 3.1.3 *Casing Integrity Check Process*

Since the inception of the Casing Integrity Operating Practices in 1996, casing integrity checks have been conducted pro-actively to detect casing failures. 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. If the gauge ring/scrapper combination identifies a new impairment or casing deformation, or there is a previously identified severe impairment requiring follow-up, a multi-sensor caliper is run to determine the extent of the deformation. Although a well may pass a 21 MPa pressure test, the information from the gauge ring/scrapper combination can trigger additional diagnostics, which are used to confirm whether or not the wells integrity is adequate for steaming operations. Corrosion inspection logs in the top 50 meters of the wellbore are performed in later cycles on wells that were installed prior to 1996. Also, if a near surface failure is detected, all remaining wells on the pad require a corrosion assessment or inspection log in the current or next casing integrity check.

The number of 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-steam 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.

A risk-based decision process is used to select wells that should be checked prior to being placed on steam. In 2007 phase 1 of our Targeted Selection process was implemented to select which wells should receive casing integrity checks, as well as to identify wells that should be checked incremental to the minimum standard. Targeted Selection phase 1 is aimed at reviewing data indicating a potential casing failure and includes a mandatory review and close-out 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 steam injection. Targeted Selection phase 2 is currently being developed and is aimed at reviewing data that may be a contributing factor in casing failures including such things as drilling documents noting any problems (mud rings, overpressure, lost circulation, difficulty running casing to final depth), connection make-up plots, and nitrogen purge compliance.

The number of wells in Cold Lake and the frequency of casing integrity checks required have increased. Figure 10 shows the number of casing integrity checks performed each year since 2001 as well as the percentage of casing integrity checks that found near surface or intermediate depth failures. The relatively high number of casing integrity checks performed in 2002 was due to pro-active checks being performed on H trunk wells looking for Clearwater top failures, as well as checks being performed on F

trunk wells looking for casing failures because of an oil-in-shale anomaly. These checks confirmed that the F trunk oil-in-shale anomaly was not due to casing failures.

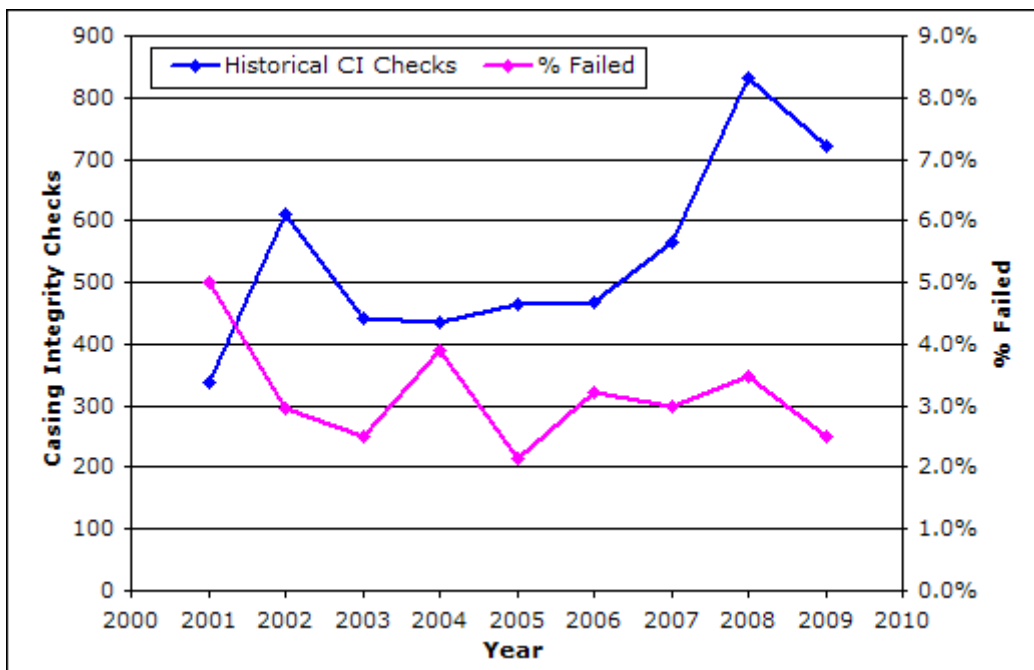


Figure 10: Casing Integrity Check History

### 3.2 Near Surface Casing Integrity Management

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

Corrosion inspection logs (electromagnetic flux leakage) and casing pressure tests are completed as part of the Casing Integrity Operating Practices. Wells identified with corrosion concerns are either pressure tested to ensure suitability for service, repaired, or taken out of steam service. Improved primary cementing practices for new wells enhance the ability to achieve and maintain cement tops at surface. However, if the cement quality is not adequate in the production casing, the well will be repaired or taken out of steam service. Wells that have cement tops near surface are topped up with bentonite during the first steam cycle; the bentonite top-ups are maintained throughout the life of the wellbore. Wells that have cement tops below the conductor pipe setting depth are repaired by running wash pipe down over the production casing to the top of cement and cementing it in place.

Imperial Oil'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, and Imperial Oil is confident that current practices will continue to confirm well integrity prior to steam.

It is the late cycle low pressure group of wells where the increase in near surface depth casing failures has been observed in 2009. The consequence associated with a near surface casing failure is low as these wells are not capable of flow to surface. In order to reduce corrosion rates and thus the number of near surface failures, several initiatives have been implemented or are being progressed. Details on these initiatives are described in the following subsections.

### 3.2.1 2009 Bentonite Top-up Program

A field wide inspection conducted in early spring of 2009 revealed that bentonite top-up degradation is occurring at a higher than expected rate due to rainfall, well work and operational activities including thawing wellheads in winter months (top few inches of bentonite washed away with water). As a result, the existing top-up program was enhanced to complete bentonite top-ups on all applicable wells this year. Excluding approximately 910 below grade wells where bentonite top-ups are not able to be completed, 3778 of 3786 wells have received bentonite top-ups. The remainder are scheduled to be completed in the first quarter of 2010. The Casing Integrity Operating Practices were updated as a result of our learnings; for these pads go forward, top-ups will be completed annually and before each steam cycle. It is believed that effective maintenance of bentonite tops will mitigate corrosion thus reducing the surface depth failure frequency.

Results and top-up compliance are now stewarded quarterly to ensure all requirements within the top-up program are met. This is expected to enhance compliance with our established practices over the long term.

There are approximately 910 late cycle wells where bentonite top-ups are not able to be completed as conductor pipes are at or below grade level. All wells in this category are operated at low pressure thus the risk associated with a surface failure is low, and all wells in this category require casing integrity checks to confirm integrity prior to steam. Imperial Oil conducted an assessment to determine a maintenance strategy for these wells; multiple options were investigated including pad re-grading, conductor pipe extensions, and various drainage or weeping tile systems. As a result of the assessment, the following forward strategy will be tested in 2010:

- Complete Infrared camera inspections to check for gas migration at surface outside of casing. This method is not yet proven.
- Conduct helium purging to confirm integrity of suspect wells.

If this trial is successful in identifying leaks, a survey of all below grade wells will be completed and appropriate additional surveillance plans will be determined.

Note that there are no below grade wells in the 'new' well category. Also, go forward all new drills are required to have a minimum of 6" (0.15 m) conductor or surface casing stick up at pad turnover to allow for bentonite top-up maintenance throughout the life of the pad.

### 3.2.2 Casing Shroud Installation

As a result of the increased surface failures and visual inspection confirming that top-up degradation is occurring at a higher than acceptable rate, a casing shroud was designed, tested, and installed on a number of wells. Casing shrouds prevent water accumulation in the conductor pipe thus increasing the longevity and effectiveness of bentonite top-ups. A prototype was designed and a successful 150 well trial was completed in the summer of 2009. 3202 of 3786 wells have now had casing shrouds installed and the remaining 584 wells are to be completed in the first quarter of 2010. The casing shrouds will be monitored annually in conjunction with the bentonite top-up program to ensure that they are effective in preventing excessive bentonite top-up degradation.

### 3.2.3 Operating Practices Review

A technical review of Imperial Oil's Casing Integrity Operating Practices with respect to managing surface corrosion was conducted in 2009. Imperial Oil is confident that the practices currently in place will mitigate the risk associated with a failure of consequence (high pressure). During this review it was recognized that integrity checks are not completed at late cycle pads operated at low pressure (< 4 MPa) for extended periods of time. In 2009, 13 of the failures detected fall into this category. Although surface integrity on these pads has not recently been confirmed, the consequence associated with a failure on these pads is negligible. Prior to steaming a well or an adjacent well, an in-depth casing integrity review is conducted as per the operating practices summarized above.

Bentonite top-ups continue to be evaluated as the most effective solution in mitigating near surface depth corrosion. They are completed after cycle 1 steaming, and then monitored on an annual and per cycle basis. Top-ups occur as required to ensure bentonite is level with the top of the conductor pipe.

#### *3.2.4 New Well Corrosion Assessments*

Imperial Oil has an extensive data set related to corrosion rates on 'old' wells in Cold Lake indicating corrosion rates (wall loss) are 3.5% per year pre top-up, and 2.0% post top-up. To further understand corrosion rates on 'new' wells Imperial Oil conducted corrosion assessments (Vertilogs) on 20 new wells. The candidates were picked based on age, operating strategy (e.g. infill or producer only), and visual inspection of bentonite top-up quality. Results indicate the corrosion rate (wall loss) on 'new' wells is 3.4% per year.

#### *3.2.5 Alternative Corrosion Measurement Technologies*

Imperial Oil has used Baker Atlas' Digital Vertilog (DVRT) for conducting corrosion assessments since the mid 1990's. During numerous reviews it has been deemed the most effective technology at identifying external corrosion near surface, however, changes in metal thickness, interference from the top of the conductor pipe, and changes in logging speed near surface affect the complexity and accuracy of the interpretation. In recent years Weatherford has released a new Corrosion Inspection Tool (CIT). In order to evaluate the new logging technology, 5 Weatherford CIT logs were ran in 2009 (selected from the 20 well candidate list for new corrosion assessments). Interpretation results are pending as interpretation is too complex to be completed in the field. Once complete, an assessment will be conducted to determine if any changes to Imperial's current logging program are required.

Imperial also attempted ultrasonic (UT) inspections on three wells in 2009; however, all three attempts were unsuccessful due to difficulties cleaning hard baked bitumen within conductor pipe and the inability to clean the casing sufficiently for inspection without introducing significant safety risks.

#### *3.2.6 Alternative Casing Repair Technologies*

An evaluation of alternative repair techniques was conducted in 2009. Imperial Oil's current repair practice for wells with near surface failures, a surface dig out repair, was determined to be the most practical and cost-effective. This work involves suspending the well, excavating to below the failure depth, replacing the failed section of casing with new, and reactivating the well. Imperial Oil will continue to evaluate alternative casing repair technologies for near surface casing failures as new technologies and methods become available.

#### *3.2.7 New Well Installations*

Cathodic or sacrificial protection was evaluated in 2009 as a means of mitigating near surface corrosion; however, it was determined to be unfeasible from both practical and technical perspectives.

Imperial Oil is currently investigating high temperature external coatings to be applied to the top joint of production casing prior to cementing as an alternative means of mitigating near surface corrosion for new wells. Additional analysis is required before a decision can be reached.

### **3.3 Intermediate Depth Casing Integrity Management**

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

- Improved nitrogen purge management
- Adjusted steam strategy

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

### 3.3.1 Casing Retrieval

Imperial conducted operations to retrieve sections of casing on four wells (T11-09, E02-04, T07-15, and D33-10) with intermediate depth casing failures. Sample size and quality varied between wells due to difficulties encountered during workover operations. All samples were sent for analysis to ExxonMobil's Upstream Research Company, who conducted metallurgical examination of the samples. Techniques used in the examination included microscopic analysis, X-Ray diffraction, scanning electron microscopy, and bulk chemical analysis.

At this time, analysis is complete on three of the four wells. Analysis of the fourth well will be completed in 2010.

Based on the results from examination of samples to date, there is evidence of both embrittlement and ductile overload. The improvements made to nitrogen purging practices will reduce the likelihood of additional H<sub>2</sub>S exposure on existing wells, which is the most likely cause of embrittlement. However, some failures associated with embrittlement may continue to occur if wells have undergone SSC prior to the improvements to purging practices.

### 3.3.2 Material Testing

Imperial completed a series of tests using L80 grade material to determine the onset of SSC as a function of temperature and H<sub>2</sub>S partial pressure. The tests were based on a modified version of the NACE TM0198 slow strain rate test (SSRT) to better simulate the thermal well casing environment. The modifications included:

- The specimen was pre-strained in air to simulate joint make-up (3% strain).
- The specimen was soaked in a test environment for 3 hours to charge with hydrogen.
- The specimen was cyclically loaded such that 1% plastic strain was added for each cycle up to a total of 6 cycles. The final strain of 9% was chosen to simulate the maximum strain expected in a connection based on previous finite element analysis studies.

A graphical illustration of the strain loading is shown in Figure 11.

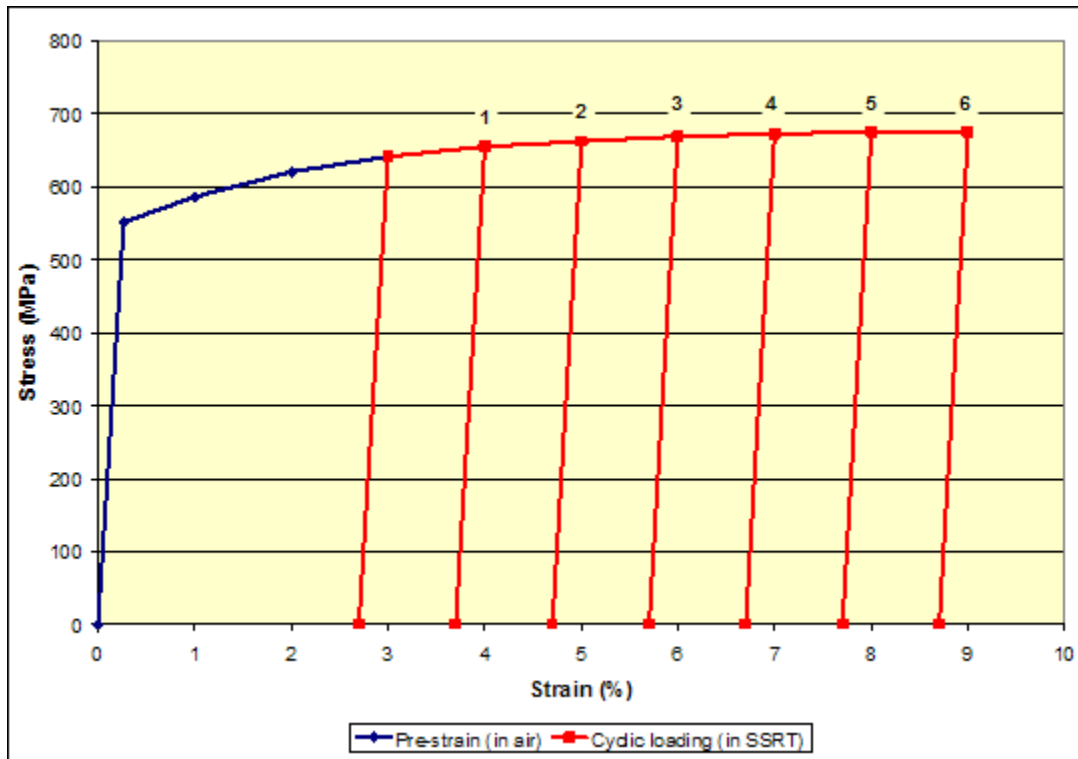


Figure 11: Strain Loading History for Slow Strain Rate Test

At the end of each test, the samples were removed and a metallurgical examination was conducted. The specimens were classified as follows:

- Failed (specimen parted) – the specimen parted prior to completion of the slow strain rate test.
- Failed (specimen micro-cracked) – the specimen remained intact, but evidence of micro-cracks were observed on the specimen.
- Scale micro-cracking – at higher temperatures, formation of an iron sulphide scale and subsequent cracking of that scale.
- Pass – no evidence of micro-cracking.

Results from the testing are summarized in Figure 12. The area below and to the right of the dashed line indicates the onset of SSC as opposed to scale micro-cracking. The scale micro-cracking is believed to be a laboratory phenomenon. Due to practical limitations of the laboratory equipment and the time required to conduct the testing, the rate of strain during the test is an order of magnitude higher than would be expected in the field. The higher rate of strain can lead to scale cracking and crack propagation due to anodic film dissolution. Higher temperature scale micro-crack propagation would not be expected to occur in the field at slower strain rates due to reformation of scale products.

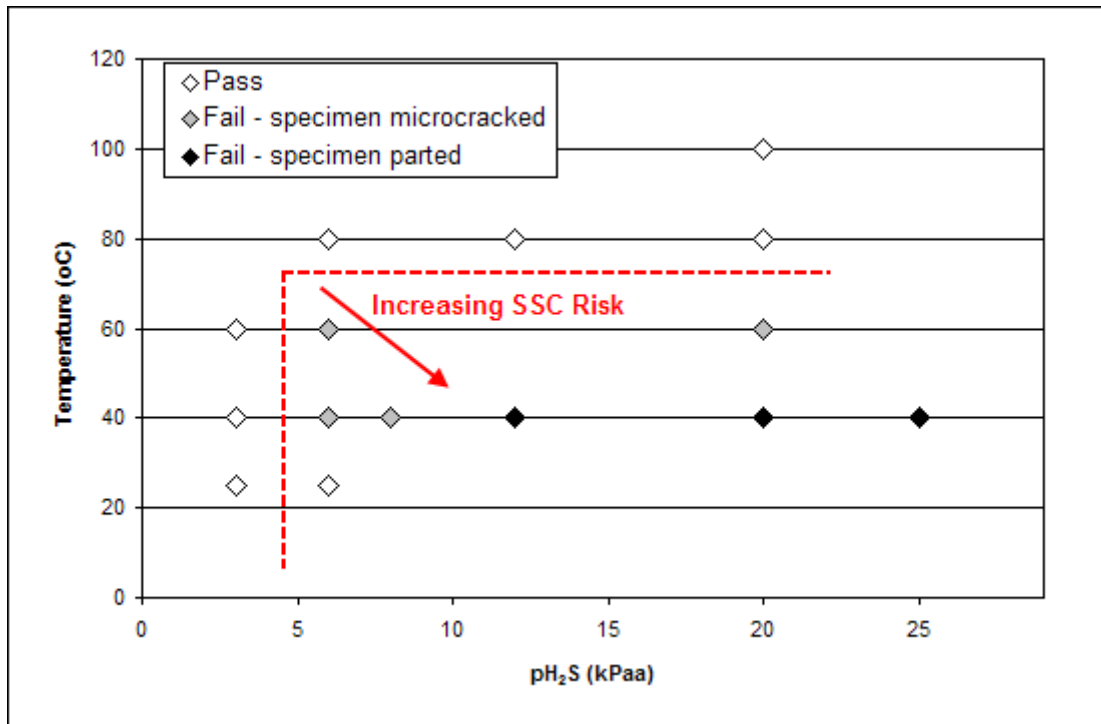


Figure 12: SSRT Results

Based on the results of this testing, micro-cracks are predicted to form at H<sub>2</sub>S partial pressures above 3 kPaa and at temperatures of 60°C or lower.

Most Cold Lake CSS wells produce at temperatures above 60°C and so are not expected to be at risk of SSC. In late 2009 Imperial implemented a program to identify wells producing at 70°C or lower and obtain gas samples from these wells. The purpose of the program is to identify, shut in and nitrogen purge producing wells at risk of SSC (T<60°C and H<sub>2</sub>S partial pressure > 3 kPaa). Wells below 70°C which have an H<sub>2</sub>S partial pressure between 1 kPaa and 3 kPaa are re-sampled monthly to monitor for any changes in the H<sub>2</sub>S partial pressure. To date, 569 wells have been sampled and no wells have exceeded the <60°C & >3 kPaa criteria; only four wells have been found in the 1 kPaa to 3 kPaa range.

### 3.3.3 Instrumented Well / Wellbore Environment Model

The gas sampling program described in the previous section relies on wellhead gas samples and temperatures to manage the risk of SSC. However, these surface samples do not measure partial pressure and temperature in the wellbore directly. Imperial has equipped well T06-09 with downhole instrumentation to measure temperature, pressure, and H<sub>2</sub>S concentration at different depths within the casing. The well is also equipped to obtain liquid samples from the wellbore to determine the acidity of the wellbore environment. The monitoring equipment on this well was put into operation in July 2009 and data collected by the downhole instrumentation is being compared to surface readings. Data is also being collected throughout the producing cycle to provide insight into how the wellbore environment changes as a function of temperature, pressure, and days on production. The impact of shut-ins and nitrogen purging on the wellbore environment is also being assessed.

A numerical model has been developed which can predict the partial pressure of H<sub>2</sub>S as a function of wellbore temperature and pressure. Actual data from the instrumented well is being used to tune the model, which may then be used to predict downhole conditions based on surface measurements.

### 3.3.4 *Geological Study of the Colorado Shales*

Imperial has continued the geological review of the Colorado Group which was begun in 2008. The review examined detailed stratigraphy and depositional environment of the shales at a number of pads in an attempt to correlate casing failures and deformations to the geology of the Colorado Group. The presence of small-scale normal faults would appear to be a contributing factor to well deformations and failures. In addition, the study has been expanded to include the Fish Scales formation.

### 3.3.5 *Well Load and Resistance Studies*

On behalf of and working closely with Imperial, ExxonMobil Upstream Research Company (URC) continued model studies using a coupled numerical model. The earth model uses geomechanical rock properties and Clearwater top dilation due to steam injection and fluid production to predict shear slip in the overburden. This model is then coupled with well and connection sub-models incorporating the metallurgical properties of the casing body and connections to predict the distribution and magnitude of plastic strain in the casing and estimate when the material will fail. A series of sensitivity studies were conducted to assess the impact of different steam strategies and wellbore configurations, and additional pad models were constructed to relate model predictions to actual failures.

The pad models were not able to match individual well failures as they occurred in the field. The inability to match failures is likely due to the number of variables which contribute to failures, which include Clearwater dilation volume, overburden rock properties, connection depth, and exposure to H<sub>2</sub>S. The reduced ductility caused by H<sub>2</sub>S exposure has not been incorporated into the casing failure model, and the samples of casing analyzed indicate that embrittlement and cracking have played a role in some failures. Despite the inability to match well failures, the modeling approach employed by URC contains improvements over Imperial's current approach using shear stress models. The current focus of the model effort at URC is the development of a software tool based on the coupled numerical models that can potentially be used to manage steam injection strategies to reduce well loading while maintaining bitumen recovery at current levels.

In addition to performing in-house modeling studies, Imperial is participating in a joint industry project (JIP) led by Noetic Engineering to study synergistic thermo-mechanical and environmental loads on casing. Project work is currently underway and Imperial has provided input to the scope of the project.

### 3.3.6 *Steaming Practices*

Imperial conducted an assessment of steaming practices on several Mahkeses pads in 2009. The assessment did not establish a clear correlation between the volumes of steam injected and the pattern of steam injection to the frequency of casing failures on individual pads. It is likely that varying levels of H<sub>2</sub>S exposure have played a role in a number of casing failures at Mahkeses, as evidenced by the samples of retrieved casing discussed in section 3.3.1.

### 3.3.7 *Well Environment*

Since 1996, Imperial Oil's operating practices have specified wellbore operating conditions that prevent corrosive environments within the wellbore. In the course of the soaking or shut-in portions of a cycle, the wellbore annulus is purged with nitrogen, mitigating the potential for SSC. Since implementing this standard, Imperial has purged all wells that have completed their steam cycle and gone into the soak portion of the cycle.

Enhancements to the wellbore environment control standards were implemented April 2007, requiring all wells to be purged within 48 hours of being shut-in. Nitrogen purging is used to reduce the presence of H<sub>2</sub>S in the casing - tubing annulus during shut-in periods, which helps to mitigate the occurrence of failures due to SSC. Through a continuous improvement approach, a sustainable improvement in purge compliance has been observed since the revised purging standards were first implemented. Improved nitrogen purge management will aid in the detection of low-rate casing failures. Nitrogen purge compliance for 2009 is displayed in Figure 13; it can be seen that current performance was at or near 100% throughout the year. The decrease in compliance seen in week 50 was due to a significant water / well shut-in due to the failure of the Maskwa-Leming-Mahkeses produced water transfer pipeline.

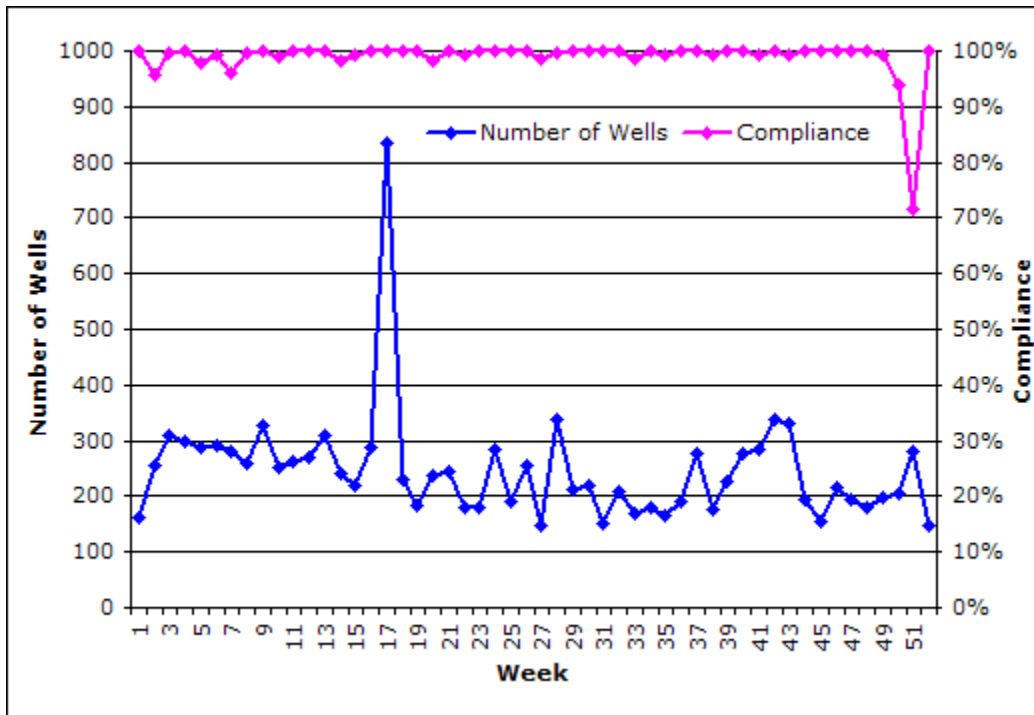


Figure 13: Weekly Nitrogen Purge Compliance

### 3.3.8 Well Design

To date, Imperial Oil has invested significantly in the design and testing of various types of casing connections for use in cyclic steam stimulation (CSS) service. Full-scale testing confirmed that metal-to-metal seal connections improve connection seal ability and, in turn, casing integrity. Since September 1999, metal-to-metal connections have been installed on all new CSS wells drilled in Cold Lake, minimizing the potential for future failures as a result of stress corrosion cracking.

Imperial believes that the use of L80 steel is the optimum casing material to balance post-yield material properties and SSC resistance. On behalf of Imperial, ExxonMobil Upstream Research Company (URC) has conducted model studies to vary connection grade and geometry to determine if there are any connection design improvement opportunities. This work will continue in 2010.

### 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, serviceability 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 into the overlying formation (Grand Rapids). Occasionally, Clearwater failures (or larger Clearwater impairments) are mitigated through the installation of shear liners for structural support.

### 3.5 Casing Integrity Response

Currently, Imperial maintains the following equipment and materials on-site: 2 pre-mix tanks, a return tank, 240 tonnes of barite, 360 tonnes of hematite, and all necessary kill fluid additives in order to respond to high pressure casing failures quickly.

In 2009, emergency response was initiated 8 times due to high pressure casing failures. In all cases, fluid loss to the break was minimized. Mud kills were required 3 times in 2009, details of which are provided in Table 7.

Table 7: 2009 Casing Failures Requiring Mud Kills

Well	Failure Detected yy/mm/dd hh:mm	Successful Mud Kill yy/mm/dd hh:mm	Time to Well Control hours	Reservoir Pressure MPa	Fluid Lost to Formation				
					N2 m3	Steam m3	Water m3	Liquid Hydrocarbon m3	Total m3
T08-09	09/05/24 11:40	09/05/25 18:15	31	9.0	0.0	0.0	0.0	0.0	0.0
U06-22	09/10/02 12:24	09/10/03 12:00	24	10.9	20.0	0.0	200.0	trace	220.0
L05-15	09/12/10 16:30	09/12/12 01:00	32	8.2	190.0	0.0	522.5	27.5	740.0

**ATTACHMENT 1: CASING INTEGRITY CHECK FREQUENCY**

Casing Checks by Cycle and Design

Beginning Cycle # %	Commercial Old %	Commercial New/Upgraded w/o PS %	Commercial New/Upgraded w/ PS %	Environmental Old %	Environmental New/Upgraded %
1	0	0	0	0	0
2	0	0	0	0	0
3	0	0	0	0	0
4	0	0	0	0	0
5	33	33	0	100	50
6	33	33	33	100	50
7	33	33	33	100	100
8	100 <sup>1</sup>	100	33	100 <sup>1</sup>	100
9	100 <sup>2</sup>	100	50	100 <sup>2</sup>	100
10	100 <sup>2</sup>	100	50	100 <sup>2</sup>	100
11	100 <sup>2</sup>	100	100	100 <sup>2</sup>	100
12	100 <sup>2</sup>	100	100	100 <sup>2</sup>	100
12+	100 <sup>2</sup>	100	100	100 <sup>2</sup>	100

Notes:

1. Wells require a Vertilog at or before this cycle.
2. Corrosion assessment (incremental 3.5%/yr from last Vertilog to projected steam in date) to be applied to determine operating strategy unless a current Vertilog is run to confirm.

**Additional Notes:**

If a surface failure is detected all remaining wells in the current or next CI check require Vertilogs or a corrosion assessment to assess pad condition.

Horizontals and Infill wells are included in the above designs.

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.  
 Water Bodies: Leming Lake, McDougal Lake, Bourque Lake, Un-named Lake in sec 35-64-04W4.  
 Upgraded Commercial: New casing design coming out in 1998 with NSCC-M phosphate coated 'metal-to-metal' connections (VAM SWNA, Tenaris Blue, NSCCM, NSCC, QB2).  
 Known Surface Failures: Wells located on a pad which have had corrosion related surface failures (0-25m).