Q. What has been the lost time or lost opportunity for each Unit, by year for the past 7 years due to operating problems or failures? What root causes were identified for these operating problems and failures? What systemic issues have already been able to be identified, even without the proposed Condition Assessment?

A. Please refer to the attached tables outlining the root causes for all three units over the past 7 years. As indicated, there are four major causes for these failures: Air Heater fouling, Condenser leaks and fouling, Boiler tube leaks and Hydrogen leaks.

Air Heater Fouling is a culmination of several issues: The type of fuel oil being burned, the mode of dispatch (loading), the physical size of the Air Heater units, operating hours and severe operating conditions. The first two are external issues and not related to plant equipment or operation. The third is a design issue. The fourth relates to overall deterioration in the structures due to age and operating conditions and although they undergo extensive annual maintenance, they cannot be returned to a state that will prevent fouling and air leakage.

Condenser leaks and Fouling results from two main causes.
"Fouling" is a result of biological growth at specific times of the operating season. Better cleaning methods and practices plus the installation of anti fouling equipment has reduced this problem.
"Leaks" are a direct result of the aging equipment. Each condenser consists of approximately 8000 tubes, each 30 ft in length. These tubes circulate seawater to cool the steam in the boiler/turbine cycle and are continuously

subjected to erosion and chemical attack. Although thickness testing is performed regularly and failed tubes plugged as a result, replacement would be considered as the proper remedial action.

Boiler Tube Leaks although occurring on all units, have been most pronounced on Unit #2. The two Combustion Engineering boilers (Units 1 & 2) were installed in 1969 and are nearing their useful life in regard to the condition of the waterwall exposure. (Also attached is a letter dated Feb. 6/06 from John McMillan, Engineering Manager, Alstom Power. Tube failures have resulted both from internal exposure to boiler water chemistry and from external exposure to residue from burning #6 fuel oil. In 2006, a substantial portion of the waterwall surface in the concerned area was replaced in #2 boiler (internal damaged) and in 2007 the Superheater section will be replaced (external damaged). It is expected that this boiler tube repair/replacement process will continue in future.

Hydrogen Leaks have been a cause of unit failures, but most frequently on Unit #1. Hydrogen is used as a cooling medium in the generators and due to the potential of explosion, even minor leaks cannot be tolerated. This problem resulted from a combination of equipment vibration and inadequate mounting design. General Electric has redesigned the installation of the generator external piping which has reduced this potential significantly.

Unit 1 1999-2005

Year	Air Heaters		Condenser		Boiler tube leaks		Hydrogen leaks	
	Outage Hours	Failure	Outage Hours	Failure	Outage Hours	Failure	Outage Hours	Failure
1999	0		0		0		78	cracked pipe
2000	23	Fouling	31	leaks	0		0	
2001	100	Fouling/bearing fail	0		0		15	cracked pipe
2002	106	fouling	2	leaks	0		58	flange fail
2003	202	fouling	7	fouling	72	econ tube	24	leak coil shield
2004	181	fouling	35	fouling	0		0	
2005	123	fouling	12	fouling	0		0	

Unit 2 1999-2005

Year	Air Heaters		Condenser		Boiler tube leaks		Hydrogen leaks	
	Outage Hours	Failure	Outage Hours	Failure	Outage Hours	Failure	Outage Hours	Failure
1999	139	fouling	0		0		0	
2000	0		0		0		0	
2001	17	fouling	13	leaks	0		0	
2002	78	fouling	20	leaks	180	SSH	48	Pipe break
2003	152	fouling	9	fouling	0		0	
2004	221	fouling	25	fouling	241	SSH	0	
2005	122	fouling	0		381	SSH, WW, Econ	0	

Unit 3 1999-2005

Year	Air Heaters		Condenser		Boiler tube leaks		Hydrogen leaks	
	Outage Hours	Failure	Outage Hours	Failure	Outage Hours	Failure	Outage Hours	Failure
1999	0		22	fouling	0		0	
2000	0		4	fouling	0		0	
2001	124	fouling	17	fouling	0		10	pipe ext
2002	59	fouling	10	leaks	326	ww, econ, tube	0	
2003	45	fouling	21	fouling	0		0	
2004	21	fouling	0		127	bot E. WW	0	
2005	162	fouling	177	CWT design	0		0	

Year	Unit 1 Hours	Unit 2 Hours	Unit 3 Hours	Plant Hours	Plant Days	Plant Weeks	Unit 1 Weeks	Unit 2 Weeks	Unit 3 Weeks
1999	78	139	22	239	9.96	1.42	0.5	0.8	0.1
2000	54	0	4	58	2.42	0.35	0.3	0.0	0.0
2001	116	30	151	297	12.38	1.77	0.7	0.2	0.9
2002	166	326	395	887	36.96	5.28	1.0	1.9	2.4
2003	304	161	66	531	22.13	3.16	1.8	1.0	0.4
2004	217	487	148	852	35.50	5.07	1.3	2.9	0.9
2005	134	503	338	975	40.63	5.80	0.8	3.0	2.0
7 yr Avg	153	235	161	548	23	3.26	0.91	1.40	0.96

Information obtained from GES for the past 7 years gives the above equivalent outages for each Unit and Plant caused by Air heater, Condenser, Boiler and Hydrogen problems and failures.

ALSTOM

Power Service

Newfoundland & Labrador Hydro | February 6, 2006

Attention: Terry LeDrew
Manager,Thermal Generation

Further to our meeting at Hydro Place on February 1, 2006, ALSTOM was requested to comment on the risks and consequences of further tube failures as a result of the discussion and the action plan being instituted for unit #2. The plan includes a replacement of waterwall sections which will include the affected tubes. As this replacement will not occur for two months, a review of possible risks of additional tube failures in this two month window is outlined below.

Fire Side Tube Failures

The failure mechanism associated with the recent waterwall tube failures is overheating caused by internal deposits. These deposits insulate the tube from cooling, and combine with the heat flux from combustion to overheat the tube locally. It is important to note that not every tube is affected, as it has been seen that the majority of the tubes in the affected area show no signs of wall thinning. This failure mode can only occur on the fire side of the waterwall as it is driven by the heat flux of combustion. It can not occur on the casing side on the boiler.

The failure manifests itself either by forming a blister, which cracks and causes a leak, by thinning the wall of the tube through wastage to the point of producing a pressure failure, or by hydrogen attack caused by overheating together with the corrosive environment under the internal deposits on the fireside of the tube.

The recent inspection of the east wall found a total of 38 blisters. The failure which caused the most recent outage was due to hydrogen attack, and there were no tube failures due to wall thinning.

As it has been determined that the internal deposits range from "very difficult to virtually impossible" to remove chemically (Northland Consulting Ltd. Letter of January 26, 2006), the only way to reduce the risk of additional failures in the next two months is to reduce the heat flux to the affected wall area. Actions are being instituted which will accomplish this.

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With regard to the probability of another fireside tube failure occurring in the next two months, until the affected tubes are replaced, the potential still exits for another failure. However, recent and future actions will reduce this probability.

1. In the past three weeks an extensive inspection has been carried to isolate the boundaries of the damage and identify each tube that required repair/replacement. UT inspection, RT inspection, and internal boroscope inspection has resulted in a detailed mapping of the condition of each and every tube in the affected area. Although it is known that there are some tubes that remain with wall thickness less than 0.140" MWT, and it is possible that there are some tubes that may have hydrogen damage that was not detected, the thorough inspection has resulted in repairs and replacement of the blisters, cracks, and excessively thinned tubes (less than 0.100").
2. The predicted tube mid wall temperature is about 720°F, which is based on a clean tube. The damage that is being seen indicates that the metal temperature must be at least 900°F. This extra temperature is the result of the insulating effect of the internal scale. By operating the unit at 60MW or lower and reducing the drum operating pressure from 2050 psi to 1700 psi, the predicted metal temperature will reduce by 52°F. This reduction is due to a lower saturation temperature from the pressure reduction combined with a lower heat flux from the load reduction.
3. Another action that is being instituted is a change to the firing practice whereby only the lower elevation of burners would be placed in service and they will be placed in a downward tilt position. Also, multiple burners will be used. This action will further reduce the heat flux to the waterwall tubes in the affected area. This will result in a minor reduction of about 5°F in the tube temperature.
4. The combination of items 2 and 3 above will have a net affect of reducing the tube metal temperature by 57°F. This will provide an increased margin of protection as the ASME Code minimum wall requirement will drop from 0.191" MWT to 0.136" MWT based on the 2004 ASME Code. Thus, by reducing the tube temperature, the potential for further overheating failures is reduced.
5. Base on the ASME Code required wall thickness of 0.136" as indicated in item 4 above, 70% of this thickness is 0.095". There are currently no tubes that have a wall thickness below 0.100" .
6. The unit was recently subjected to two service pressure tests of 1885 psi. By reducing the operating pressure to 1700 psi, the waterwall tubing will be operating at a pressure about 10% below the successful service pressure test.

Although the above actions will not eliminate the risk of another fireside tube leak, this risk is reduced considerably by the detailed inspection/repair/replace actions and the limitations imposed on the future firing/operational practice.

In addressing the consequences of another leak, a couple of points need to be considered.

1. A fireside tube leak or failure does not affect personnel safety as the failure is completely contained inside of the boiler.
2. There have been two failure modes experienced from the overheating, cracks in blisters, and a blow out from hydrogen damage. To date there have been 38 blisters discovered and one (1) hydrogen blow out. The consequent of a blister crack occurring may not cause a unit outage if the crack is small enough not to affect the boiler operation. Of course, a large or multiple cracked blisters may cause an outage. A hydrogen blow out will definitely cause an outage.
3. The action plan also includes restricting access to this area, which will also provide safety assurances.

In summary, the worst case scenario would be a boiler outage and personnel safety is assured.

During our meeting, the possibility of adding refractory to the waterwall to reduce the tube metal temperature was discussed. Refractory has been added to waterwalls in the past to protect the walls from erosion and abrasion, and to act as a heat sink to retain the heat in the bottom of a bark fired industrial boiler for better combustion of moist fuel. The addition of refractory to protect waterwalls from overheating has not been done previously. As the current action plan provides for a replacement waterwall in two months, the practicality of the time and cost required to obtain the refractory material, and the time and cost required to install same for a two month operational period must be considered when weighing the risks. As noted above, the consequence of an additional failure will be a boiler outage which will require a tube replacement.

Casing Side Tube Failures

The recent tube failures, as described above, are isolated to the fireside exclusively. As there is no heat flux on the casing side, this type of failure can not happen on the outward side of the tube.

Failures that can occur on the casing side include corrosion fatigue, failures at points of attachments, original tube defects, pitting corrosion, etc. The risk of this type of failure occurring is no greater on this unit than any other 35 year old oil fired utility and the recent fireside failures do not increase this risk.

Membrane Failures

The membrane between two adjacent tubes is cooled by conduction from the tubing. Although some tubes have suffered from overheating, this is local to the crown of the tube, or close to the crown. The membrane is attached to the tube 90° away from the crown, where the tube midwall temperature is lower. Therefore the membrane should still have adequate cooling and will not experience elevated temperatures.

Therefore, there is no risk of a membrane failure caused by the same failure mechanism as the recent fireside failures.

John McMillan P.Eng.

John McMillan, P.Eng
Manager, Engineering