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Vermont Yankee – Engineering Department

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From Enrico Betti, Tom Marstaller, Joe Habich **W.O.#**

Subject Condenser Long Term Plan

References:

1. Longview Inspection, "Record of the 18th EC Inspection for the Main Condenser at VY, RFO-22, May, 2001".
2. Carl K. Kuester, "VYNPC Condenser Evaluation", November 1999", March 9, 2000.
3. Cramer & Lindell Engineers, Inc., "Record of the 11th EC Inspection for the Main Condenser at VY, August 20 to September 4, 1987'.
4. FAX Longview Inspection to Rico Betti, "Elliot Gage Data for RFO-22 Main condenser", 12/12101. (See Appendix C).
5. Burns Engineering Services, "Existing Circulation Water System Impact on Station Generation After Power Uprate and Potential Performance Improvements", November 7, 1998.
6. Cramer & Lindell Engineers, Inc., "Record of EC Inspection of Selected Tubes for the Main Condenser at VYNP, March/April 1995".
7. Longview Inspection, "Record of the 16th EC Inspection Second Year of a Two Year Inspection Program for the Main Condenser at VYNP March/April 1998".
8. Cramer & Lindell Engineers, Inc., "Record of the 13th EC Inspection of Selected Tubes for the Main Condenser at VYNP, March 1992".

Appendices:

A. Summary of Elliot Gage Testing Tube Schedule

B. Elliot Gage Testing Data.

C. FAX Longview Inspection to Rico Betti, "Elliot Gage Data for RFO-22 Main condenser", 12112/01

Objective and Scope of this Report

The objective of this report is to summarize key degradation mechanisms that challenge the operability of the VY condenser. This report details the maintenance plans, inspections scope, and associated schedules to track and manage these degradation mechanisms designed to minimize risk to generation. The schedule includes planning and scheduling for potential major repair items, including bundle replacement or retubing, staking, sleeving, and waterbox/tubesheet coating. This report also addresses the potential improvements in power production associated with condenser retubing. The scope and schedule of work .

recommended for these modifications will ensure VY is prepared to implement these modifications with minimal outage impact.

Summary of Condenser Recommended Maintenance

Condenser Vacuum-box Structure

The last loss of generation attributable to the condenser was a prolonged outage in 1993 due to a 6 foot crack in the condenser shell. More balancing tube cracking was found in 1995 and significant bracing failures were found in 1996. The condenser bracing was modified in 1996 to prevent future shell and bracing failures. The modified bracing and continued steam space inspections have successfully maintained condenser box structural Integrity since the last major failures were repaired in 1996.

1. Action: Continue with Outage Steam Space Inspections and Repairs. This is tracked by a PM. No further action is required.

Water-box Structure.

Cramer and Longview inspection reports have stressed that water-box shell ID corrosion and pitting is a problem. UT inspections are needed to quantify this corrosion and pitting. This will allow us to determine whether water-box shell coating is required to arrest the corrosion.

2. Action: Institute UT inspections of the water-box shell RFO-23. Generate WOR to perform the inspection.

Condenser Tubes; Maintaining Tubes through End of Current License (Year 2012)

On average the life of condenser tubes in nuclear plants is 20 to 30 years of service. This includes plants with both ocean and river cooled units and units with brass and other tube materials. VY has been fortunate to have our condenser tubes last 30 years. VY tube eddy current inspections include 100% of the unplugged SS tubes and 33% of the unplugged brass tubes each outage. Based on low plugging rates to date, this eddy current sample appears sufficient. VY also measures ID erosion of 0.5% of the brass tubes.

Pulling a recently plugged tube and metallurgical evaluation will help determine the cause of OD damage, provide erosion data along the tube length, and potentially provide early warning that tube vibration and fatigue is beginning to be a cause of failures. Based on the evaluation performed in this report we have selected two more brass tubes for removal in RFO-23 that were plugged in 2001.

3. Action: WO 02-38 was written to pull two additional tubes during RFO-23. No further action is required.

ID erosion of brass tubes (and the adjacent area of the tubesheet) is the main challenge to maintaining the current tube bundles through year 2012. ID erosion at the tube end will result in tube sheet joint leakage. General tube ID erosion will result reduced stiffness, potential tube vibration, and tube failure. Tube ID erosion is tracked via Elliot Gage ID measurements. VY does Elliot gage inspection of 0.5% of the brass tubes. The current erosion inspection sample is too small. Without more tube ID erosion data it is difficult to say whether tube erosion rates would necessitate preemptive repair or re-tubing before the end of current license. An expanded test sample for RFO-23 that includes more brass tubes and includes tubes most at risk to erosion has been included in Appendix A.

4. Action: Implement the Appendix A expanded test sample schedule for Elliot Gage Testing in RFO-23. This will be coordinated with the Vendor performing the inspection.

One preemptive measures to prevent continued tube end and tubesheet erosion would be epoxy coating of the tube sheet and the tube ID adjacent to the tubesheet. Tube staking would prevent potential tube vibration that results from tube erosion. Certainly if power uprate was implemented the condenser should be staked. These measures would prolong the life of the bundles. The following are preliminary cost estimates [2, pg 25] for staking and coating:

Staking 10560 stakes	$250,000
Epoxy Coating	$285,000

One alternative to epoxy coating is expanding and flaring a short sleeve in the tube ends. This would eliminate problems with tube to tube sheet leaks. The length of the sleeve is designed to minimize turbulence and tube erosion at the sleeve end. Tube end sleeving is estimated to cost $150,000 [2]. Installing sleeves would be considerably easier and less costly than epoxy coating and have much smaller impact to outage schedule. The hurdle to using sleeves is to demonstrate that sleeves can be designed to assure minimal increase in inlet velocity, pressure drop, and Interference with eddy current probes. It is recommended that a sleeving vendor be invited to propose the best sleeve for VY and install two test sleeves in tubes with severe erosion. The adjacent tubesheet and tube should be inspected after installation and after one cycle of operation to assess if accelerated erosion is occurring at either the tubesheet or tube adjacent to the sleeve.

5. Action: Initiate modification process and WOR to install two approved sleeves RFO-23.

The coating (or sleeveing) and staking are better done soon before leaks occur. The planning for epoxy coating, sleeving, and staking should begin this coming outage. The Elliot gage, eddy current, and tube pull data collected this outage will be used to determine the latest date that epoxy coating, sleeving, or staking should be implemented. It will also help us know when retubing would be required without the preemptive repairs.

6. Action: Benin planning/engineering for tubesheet coatingtube end sleeving, and staking repairs RFO-23. No commitment item required.

There are significant stainless steel tubes in the vent pipe region of the NN water-box that have been plugged due to pitting. While the plugged tubes in this area represent a small percentage of all condenser tubes (including brass and stainless), plugging tubes in the vent region can impact the performance of the NN water-box vent, non-condensible removal, and subsequently performance. Performance data does not indicate that the stainless steel plugging has affected Condenser A performance as a whole. Ineffective venting in the NN bundle of Condenser A can cause excess water intrusion into the NN vent duct. It can also result in pockets of non-condensables that will accelerate OD tube corrosion.

7. Action: Scope a TM to test and evaluate Condenser Vent System Performance during RFO23.

Retubing the **Condenser for** License Extension

It is unlikely even with preemptive repairs the current tubes could be maintained long beyond year 2012. Retubing as early as possible would reduce the risk of condenser leaks. Tube replacement would also reduce the outage tube inspection work scope in subsequent outages. Certainly if life extension was imminent, it would be cost affective to retube the condenser and forgo preemptive measures including epoxy coating or sleeving. Retubing would be more efficient without the complication added by tubesheet coatings or sleeves.

While many utilities that retube also add stakes to assure current HE! maximum span requirements are met, it would more efficient to install stakes after retubing.

Rough cost estimates for retubing would be in the 3 to 5 million dollar range and 40 days. One vender with recent BWR retubing experience has estimated that VY can retube in 25 days at a cost of 11 Million dollars. For minimum outage impact retubing would need to be scheduled with an extended outage such as a generator rewind effort. This accelerated schedule would require that rigging for water-box removal and rigging and access for new tube transport to the condenser be put in place the preceding outage. Therefore a retube effort would need to begin two outages before actual retubing. The first outage to plan and layout the rigging and access. The second outage to install the rigging components. Then the retubing could be done in the third outage.

There are a small percentage of condenser tubes currently plugged in the VY condenser. The VY condenser admiralty brass tubes have superior heat transfer properties over other tube materials. Therefore retubing alone would provide negligible improvement in plant efficiency.

8. <u>Action: VY Design Engineering and Maintenance to begin Planning and Engineering for Tube replacement (or bundle replacements during RFO-23. No commitment item required.</u>

<u>Options for Improved Plant Performance</u>

The VY condenser was designed to achieve a 2.25 in hgA back pressure with 75^{2}F inlet water at full power with 85% cleanliness factor. As shown in Figure 1, based on 2001 plant data, the condenser performed at design with 225 in hgA back pressure with 75F inlet water. While this is a performance is a testament to VY maintenance on this 30 year old condenser, in today economy, a VY condenser would be designed for lower back pressure with a higher inlet temperature.

With 85F inlet water the VY condenser back pressure was 3.2 in hgA. The condenser design *curve would indicate backpressure should be 2.9 in hgA with 85^{2}F inlet water. This may not* be an indication of poor condenser performance. The condenser design curve assumes the heat load on the condenser is at the design 3605 Mbtu/hr. As shown in Figure 2 with a 3.2in hgA back pressure the turbine gross megawatt production is 531 MW, 7 MW less than the 538 MW GE turbine design value. This would indicate that the 0.3 in hgA increase in *condenser pressure with 85^{9}F inlet water may be partially due to poor turbine performance* and increased condenser heat load.

The key item to note in Figure 2 from the VY 2001 data is with 2 in hgA condenser backpressure (70^{2}F inlet water temperature) VY generates 545 MW gross. With 3.2 in hgA condenser backpressure (85^{4}F inlet water temperature) VY generates only 531 MW gross. This indicates that If the condenser tube bundles were redesigned with increase surface area *(or U) to provide 2 in hgA pressure with 85^{9}F inlet water the gross generation would be kept* above 545 MW throughout most of the year. VY would realize a substantial increase output in the summer months when power is at peak demand. This translates to roughly a 5 MW increase in the average gross power generation and approximately $5M' year in increased revenue.

Preliminary calculations indicate that redesigning the condenser bundles for an 85°F inlet temperature and 2 in hgA backpressure may be feasible. The bundle redesign would need to be matched to the circulation system capabilities. The downside is condenser bundle redesign and .replacement would significantly increases the cost and installation window over a straight retube effort. It is estimated the bundle replacement and associated changes would

' $1M per MWe assumed.

be approximately $10 to $15M and the outage duration 40 days. However, given the substantial increase in generating revenue, this option merits a detailed feasibility and cost benefit assessment.

9. Action: Perform a detailed feasibility, schedule, and cost benefit assessment for retubing and bundle design and replacement.

A condensed summary of RFO-23 work is included below.

Summary of Condenser Work for RFO-23			
Task ID	Task to be Performed in RFO-23	Currently in Planning	Responsible Group
pro-outage	Feasibility of Condenser Upgrade	No	Systems/Design Engineering
	Tube Cleaning	**Yes**	Maintenance
2	Water-box Cleaning	Yes	Maintenance
3	Eddycurrent	Yes	Maintenance
4	Tube Sample	**Yes**	Systems Engineering
5	Tube ID Erosion Measurement	Yes	Maintenance
6	Test Installation of Tube End Sleeves	No	Maintenance
7	Stm Space Inspection	Yes	Maintenance
8	Stm Space Repairs (TE2001-047)	Yes	Maintenance
9	Vibration Stake As-Built	No	Design Engineering
10	UT Water-box	No	Systems Engineering
11	Coating Contractor Walkdown	No	Maintenance/Design Engineering
12	Staling Contractor Walkdown	No	Maintenance/Design Engineering
13	Retubing Company Walkdown	No	Maintenance/Design Engineering
14	Walkdown for TM for Vent System Performance	No	Systems/Design Engineering
15	Preliminary Design of Retubing Rigging	No	Design Engineering

The attached Table 1 includes a more comprehensive schedule for condenser work scope for the coming outage and outages through Year 2012. This scheduled may be modified to reflect the most recent Inspection findings as we go forward.

Management Disposition:

The recommended actions will be presented to Senior Management for disposition as part of the closeout of commitment item UND2002-042_7.

Figure 1:
BP vs Inlet Temp 1967 Westinghouse vs 1999 and 2001 Actuals

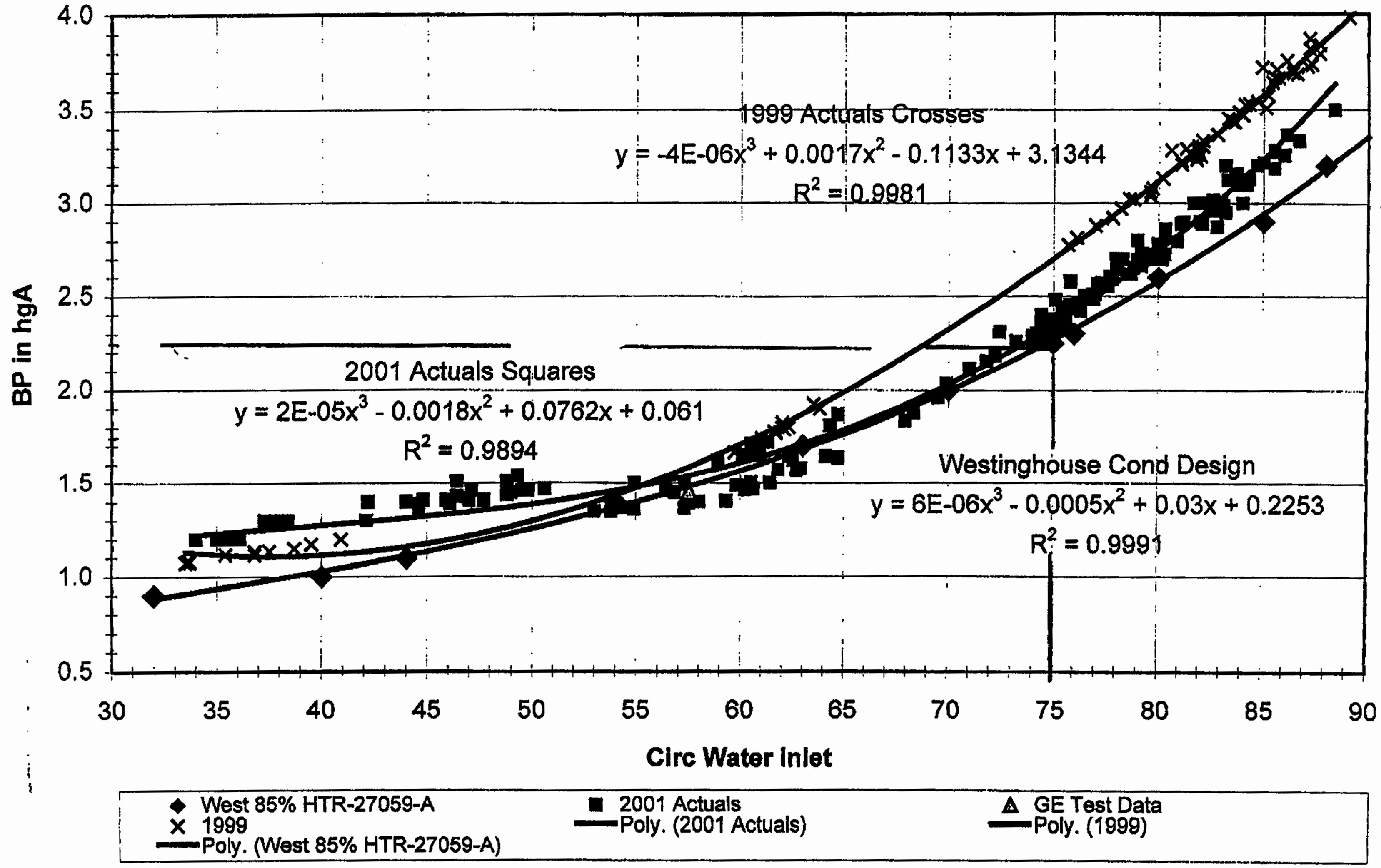

Figure 2
Gross MWe vs Inlet Temp

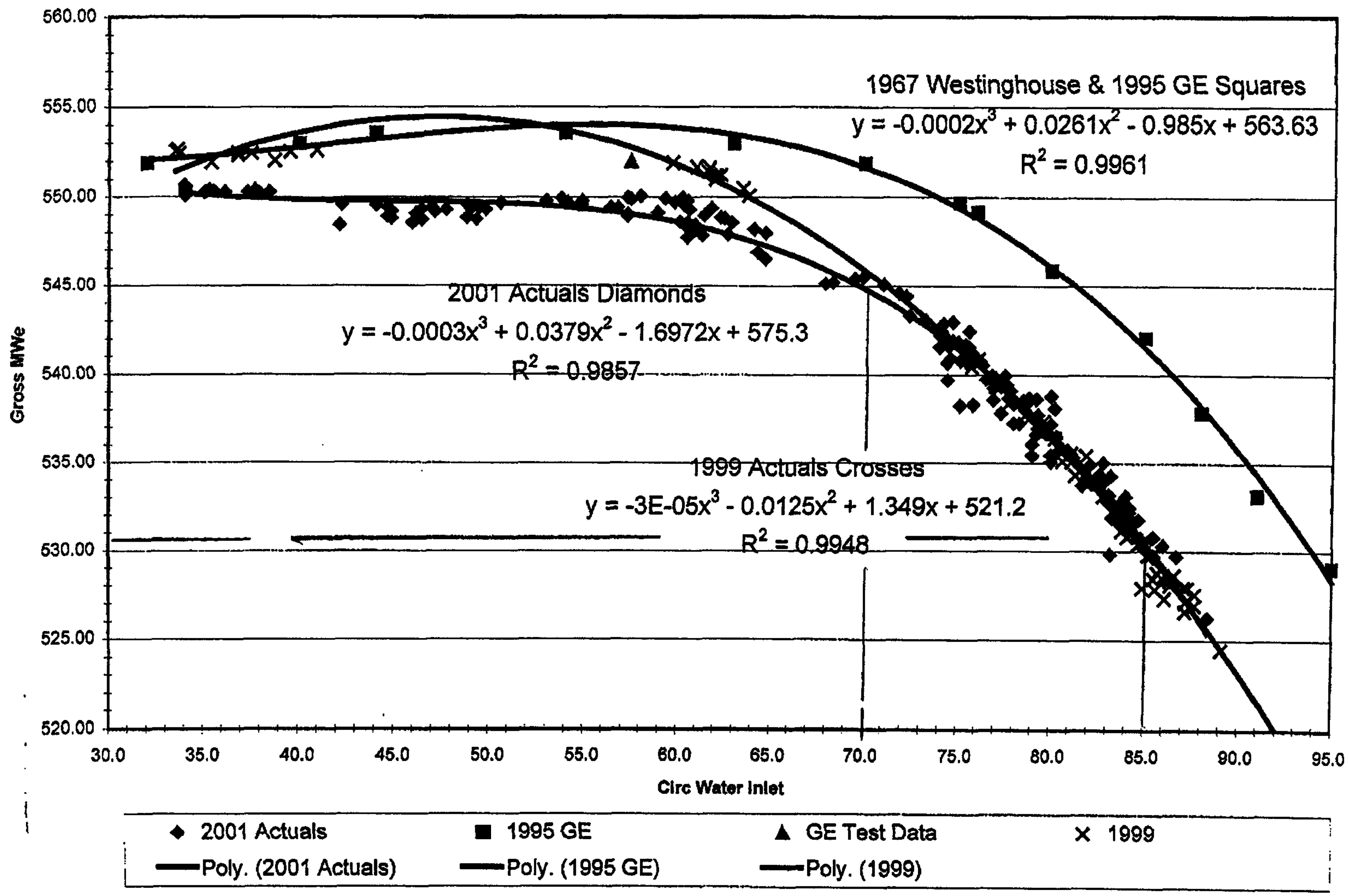

Table 1
Schedule for Condenser Work

Year	2002	2004	2005	2007	2008	2010	2011		
Refuel Outage Number	**23**	**24**	25	**26**	27	**28**	29		
Length of Refuel Cycle	1.5	1.5	1.5	1.5	1.5	1.5	1.5	Planned	Description of Work Activity
g	x	x	x	x	x	x	x	**Yes**	Tube Cleaning
g	x	x	x	x	x	x	x	Yes	Waterbox Cleaning
		To Be Determined							Condenser Diaphragm Replacement
vy									
y	x							Yes	Perform
p	x							**Yes**	)
	x			x	x	x	x	**Yes**	(pp
	x							No	
Inspect Test Inspection End Sleeves		x						No	Inspect test tubesheet and tube adjacent to use end sleeve for erosion
Stm Space Inspection	x	x	x	x	x	x	x	**Yes**	Perform steam space inspections.
Stm Space Repairs	x	as. required	as-required	as-required	as-required	as-required	as-required	Yes	Perform steam space repairs Including: bracing, bypass piping support repair, and extraction steam piping lagging repairs (TE2001-047). Work Orders in Place .
Vibration Stake As-Built	x							No	Do as-built of condenser vibration stakes. Add to 'lent condenser drawings.
UT Waterbox	x	x						No	Locate exterior areas for Inspection. Remove insulation at these locations. Draw a Grid and ID

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Table 1
Schedule for Condenser Work

Year	**2002**	2004	**2005**	2007	**2008**	2010	2011		
Refuel Outage Number	**23**	**24**	25	**26**	27	**28**	29		
Length of Refuel Cycle	1.5	1.5	1.5	1.5	1.5	1.5	1.5	Planned	Description of Work Activity
Feasibility of Condenser Upgrade	x								Determine scope and feasibility of condenser upgrade prior to the outage, perform necessary walkdowns during the outage.
Coating Contractor Walkdown	x							No	Bring in waterbox/ tubesheet/ tube coating specialists to develop estimate and schedule for coating work. Define infrastructure required to support work. Equipment, Ventilation, Power and Access.
Staking Contractor Walkdown	x							No	Bring in staking companies for walkdowns to develop estimate and schedule for staking work. Define infrastructure required to support work including equipment, lighting, ventilation, power, and staging.
Retubing (or bundle replacement) Company Walkdown	x							No	Bring in Retubing (or bundle replacement) companies for walkdowns to develop estimate and schedule for Retubing (or bundle replacement) work. Define infrastructure required to support work including equipment, ventilation, electrical power, access & staging and potential hazardous materials. Define tube disposal costs and methods.
Walkdown for TM for Vent System Performance	x							No	Walkdown Vent Sytem to scope possible vent system
Preliminary Design of Retubing (or bundle replacement) Rigging	x							No	te replacement deveooppreliminary g g and structural design for tube box rigging, and rigging for water box removal.

Table I
Schedule for Condenser Work

Year	2002	2004	2005	2007	2008	2010	2011		
Refuel Outage Number	23	**24**	25	26	27	28	29		
Length of Refuel Cycle	1.5	1.5	1.5	1.5	1.5	1.5	1.5	Planned	Description of Work Activity
Option 1- Retubing (or bundle replacement) and Stake									
Final Rigging Design								No	Go over details with tubing contractor
Install Rigging			To Be Determined					No	Install Rigging steel for Retubing (or bundle replacement)
Retube the Condenser				To Be Determined				No	
Remove rigging steel					To Be Determined			No	
Option 2 - Epoxy Coat (or Sleeve) and Stake								No	
Epoxy Coat Waterboxes, Tubesheet, and Tube ID Ends or **Sleeve**			To Be Determined					No	
Inst nti-Vibration a mg				To Be Determined				`Q	

Brass Tube ID Erosion

Brass tube ID erosion is tracked by measuring the tube ID with an Elliot gage. Figure 3 depicts average inlet side tube ID data from all Elliot gage testing. Figure 4 includes the maximum inlet side tube ID data. The tube ID's were measured in 1987,1992,1995, 1998, 1999, and 2001. The ID data depicted for 1972 represents the nominal thickness of the new tubes. The ID data depicted for 2012 is the 10 erosion limit. The erosion limit is based on 45% wall loss. With 45% loss [2] there would significant increase in the potential for tube sheet joint leakage, tube vibration and tube failure, and a forced outage.

A summary of the Elliot gage testing at VY is summarized in Table 2 below. As shown in the 120 tube sample used in 1995 through 2001 represents just 0.5% of the 22684 brass tubes in the VY condenser.

The sample of tubes used in Elliot testing changed from 1987 to 1992 and again from 1992 to 1995. The 1987 sample included 244 tubes and the 1992 sample included 281 tubes. In 1995, 1998, 1999, and 2001 a common sample was used that included 15 tubes in each water-box, 120 tubes total. The 120 tubes are all at the periphery of the bundle. Tubes tested in 1987 and 1992 include tubes in sample rows from the bundle periphery to the center. As can be seen in Figure 3 average ID dimension from the more recent 1995, 120 tube sample were lower (had less erosion) than the 1992 sample. The 1995 average ID data was on par (equivalent erosion) to the 1987 sample thirteen years earlier.

The Elliot test tube sample will be expanded starting in RFO-23 to included ID erosion data of the most suspect tubes. The Elliot gage testing in RFO-23 will include rows of tubes tested in 1987 and 1992 to depict how erosion is progressing throughout the bundle. In addition a number of tubes in the NN and SS Inlet water-boxes that have the worst erosion at the tubesheet adjacent to the tube inlet will be included. For RFO 23 the 1995 to 2001 test sample of 120 tubes be expanded to included:

- Tubes tested in 1987 in a single row that had at least one tube with an inlet ID greater than 0.930".
- Tubes tested in 1992 in a single row that had at least one tube with an inlet ID greater than 0.940".
- Ten additional tubes from each of the NN and SS inlet water-boxes with the most severe tubesheet erosion at the tube flare region. (This condition is reported to be prevalent in these two water-boxes.)

Tables Al through A8 included in Appendix A include a expanded test sample for RFO-23 for each water-box based on the above criteria.

This expanded sample will bring the Elliot gage sample from 120 to 371 locations. We will *continue with the practice of taking data at V47, 3", and 8" from the TS face at each* location.

Figure 3
Average ID Inlet End

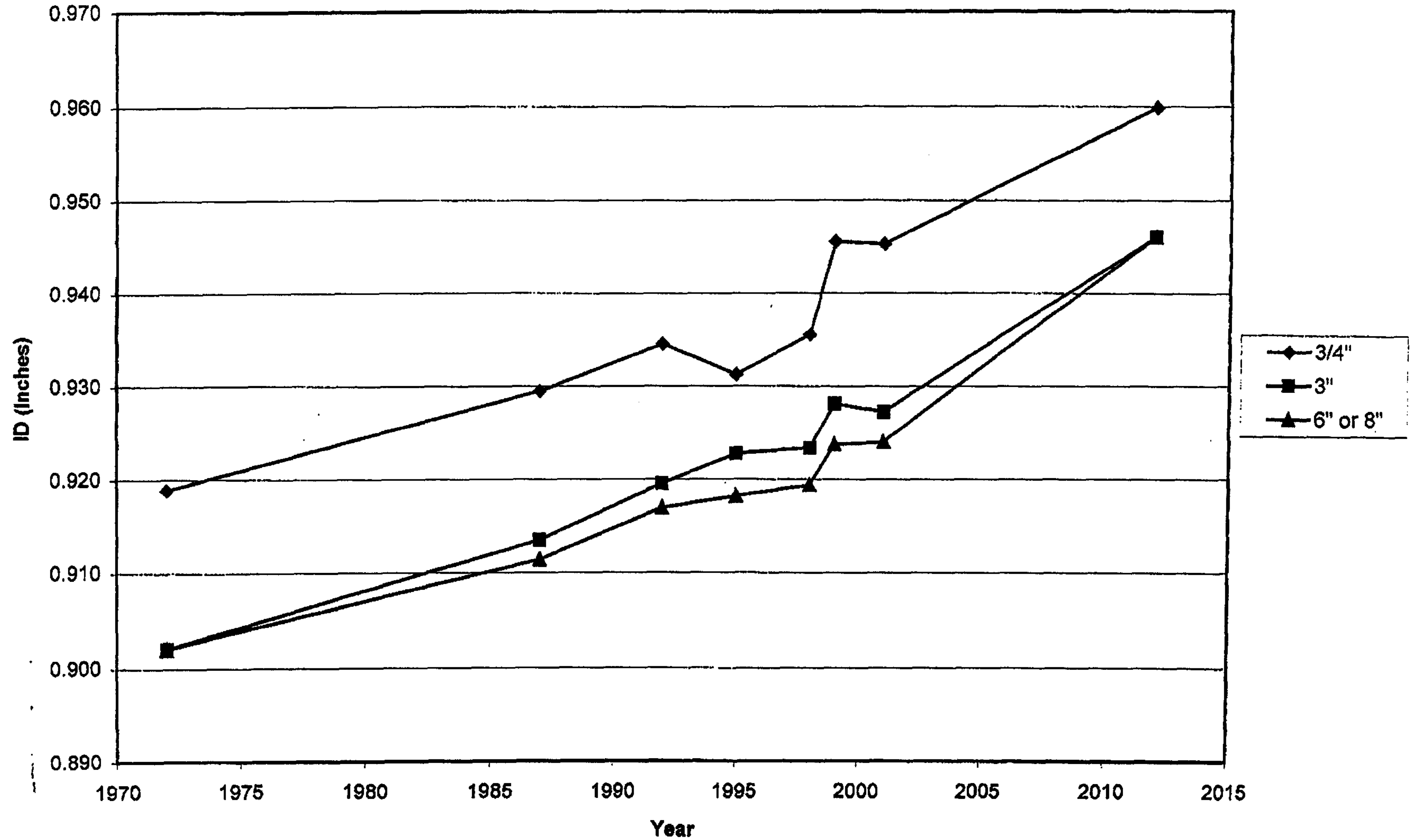

Figure 4
Maximum ID Inlet End

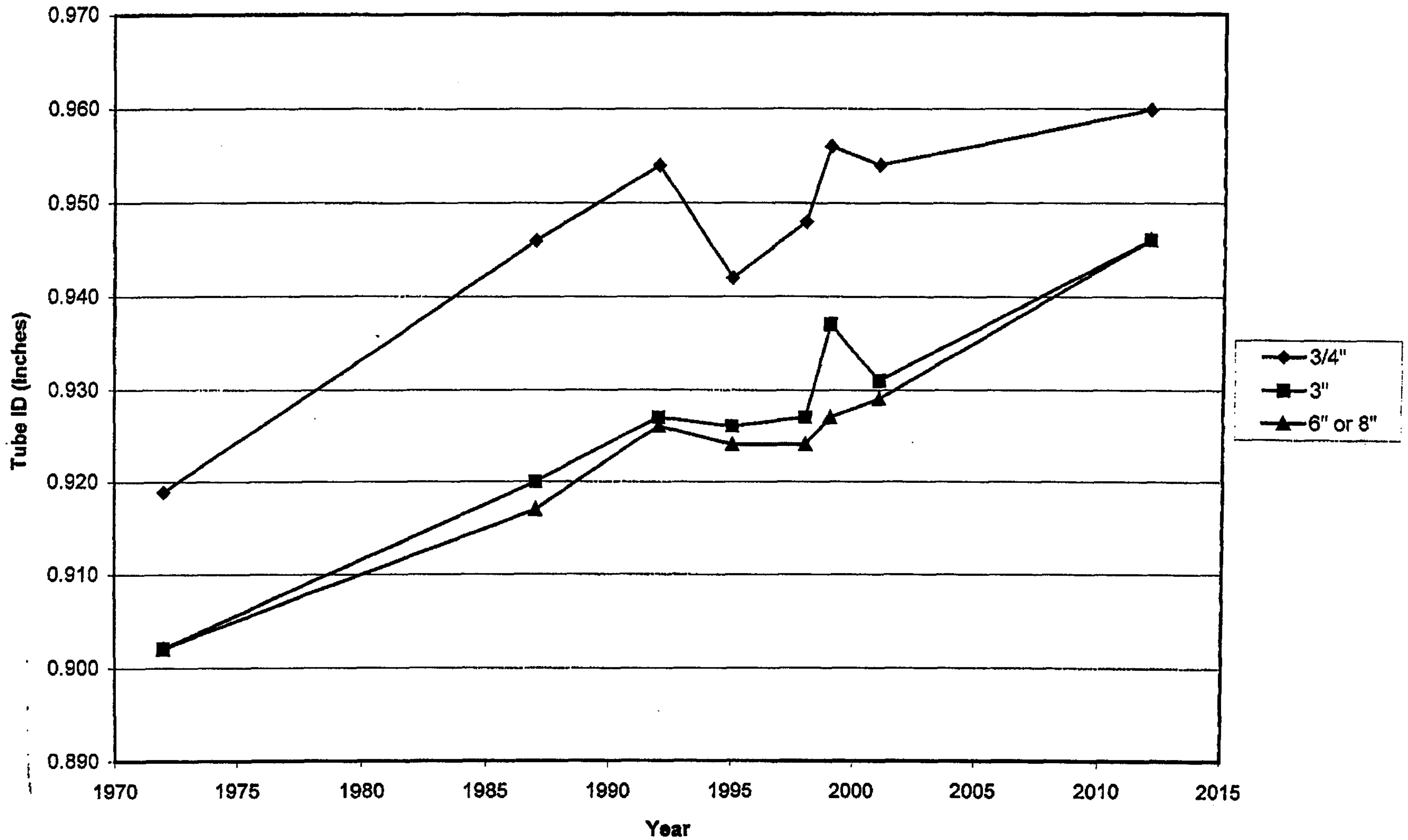

Table 2. Summary of Tubes Elliot Gage Testing Previous and Sample for RFO-23 Refs [1,2, 3, 4, 6, 7, 8]								
WaterBox	1987	1992	1995	1998	1999	2001	Total tubes	RFO-23
NN-I	0	64	15	15	15	15	89	30
NS-I	120	64	15	15	15	15	196	108
SN-I	0	64	15	15	15	15	79	43
SS-I	124	64	15	15	15	15	205	149
NN-O	0	6	15	15	15	15	21	15
NS-O	0	7	15	15	15	15	23	15
SN-O	0	6	15	15	15	15	21	15
SS-O	0	6	15	15	15	15	21	16
Totals	244	281	120	120	120	120	655	391
	Percent of Brass Tubes Tested							
All	1.1%	1.2%	0.5%	0.5%	0.5%	0.5%	2.9%	1.7%
		(	No. of brass tubes		22648	)		

<u>Kuester's ID Erosion Limits</u>

The Kuester limit Is based on 45% wall loss. He performed vibration calculations in 1999 that Indicated that at 45% loss with the 46" VY tube support spacing tube vibration could become a problem. The Kuester [2] vibration analysis looked at both 100% power as well as 105% power. Another tube vibration evaluation by Burns [5] indicated that the HEI allowable length for an unsupported tube span with no erosion at 105% power to be *35.75".*[2] *The HEI limits tend to be conservative. Due to the high cycle nature of flow* induced vibration, after onset of tube vibration tube failure can rapidly occur. Reliably predicting the onset of tube vibration when support spans are in excess of HEI limits is not easy.

Kuester Indicated that in the tubesheet rolled region at -45% wall loss tube-to-tubesheet leaks become a concern. (Kuester is forwarding a paper that supports the 45% pull out limit.) Based on our assessment, the pullout strength of the tube is far in excess of the pressure force on the tubesheet that acts on the tube joint. Tube joint forces created by differential expansion of brass tubes, condenser frame, stainless tubes, are much more difficult to predict. This would likely require finite-element analysis. We could can look into these numbers more, but allowing as much as 45% average wall loss on a small sample likely means there will be tubes out there with more severe erosion, and In-leakage problems would be likely.

<u>Tube Pull to Identify Possible Onset of Fatigue Cracking.</u>

The 1999 tube pull write-up page 19 [2] indicated that we should pull a tube in the steam lane that that had indications of OD cracking. Longview indicated that they expect the concentration of corrosive agents in this area could be lower and that the cracking in this area may be due to vibration induced fatigue. Given that that OD cracking is the most *common basis for Longview brass tube plugging recommendations, we are planning to* pull two more tubes.

[2] *In the Burn's evaluation [5] it was incorrectly assumed the condenser was fully staked. Therefore the unsupported span was Y2 x 46°, or 23" and the tubes would not vibrate after power* uprate.
[3] *Therefore many plants elect to stake their tubes and bring spacing within current HE[limits* when performing an uprate.

Based on a review of recent most recent tube plug and inspection data (Volume iI of the 2001 Longview Condenser Report [1]) the two best candidates included:

- SS B25-22 location of damage 8-9
- SS D51-24 location of damage 3-4

These tubes best meet the description of being in the steam lane and were reported to have ODD as the basis for plugging. Table 4.1 of Ref 1 Volume II indicates that ODD is for external Damage/Defect/Flaw. Work Order 02-52265 was generated 1-2-02 to include these tube pulls. The thickness of pulled tube along the length should be recorded.

Brass tube pulling examination results to date are summarized below.

Year	Tube ID	What was found	Reference
1987	NS-A-3-1	Pit at 8.6% of wall no crack.	[3]
1987	SN-D-74-1	80% through wall crack eminating from OD Pitt.	[3]
1987	SS-A-81-1	No Damage found in Section Examined	[3]
1999	NS-D-63-26	70% through wall crack eminating from OD Pitt or depression.	[2]

Tube OD Corrosion

Longview Inspection [1] indicates they are concerned about the external brass corrosion *on the steam side on the inlet end. They indicates this is 360 degrees and about 20%* wall. This may have been caused from the long shutdown period like the ECCS outage *when the condenser was wet all outage and with oxygen present. We may be seeing this* in the 1/3 eddy current samples over three cycles so it appears this is an ongoing.

Longview indicates this is possibly due to improper venting at least In the area of the inlet tube sheet. Performance does not indicate we have a lot of non-condensables present It could be that poor performance on the NN vent is being compensated by the NS vent and resulting in pockets on non-condensibles. This outage we will scope a Temp Mod to measure vent system effectiveness. This would allow us to ascertain whether there is good vent flow in all four tube bundles.

UT Exam of Water Boxes

The 1999 condenser evaluation report [2] indicates that Inside of the Y2" thick carbon steel water-box shell has significant corrosion and pitting. As in past inspection Kuester has recommended VY perform UT exam of selected areas of the water-boxes to measure the corrosion depth. This is standard procedure throughout the plant to monitor corrosion and stay ahead of failures. This should be done this coming outage.

- Inspect inside, and identify areas for exterior UT inspection.
- Remove insulation at these locations.
- Draw a Grid and ID (map) Locations.
- Obtain UT data.

If corrosion rates are projected to be problem, the interior of the water-boxes could be epoxy coated in conjunction with the tube sheet and tube ends.

Condenser Long Term Plan

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