DESIGN AND PERFORMANCE OF BWC REPLACEMENT STEAM GENERATORS FOR PWR SYSTEMS

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ABSTRACT

In recent years, Babcock & Wilcox Canada (BWC) has provided a number of PWR Replacement Steam Generators (RSGs) to replace units that had experienced extensive Alloy 600 tube degradation. BWC RSG units are in operation at Northeast Utilities' Millstone Unit 2, Rochester Gas and Electric's Ginna Station, Duke Energy's Catawba Unit 1, McGuire Unit 1 & 2, Florida Power and Light's St. Lucie Unit 1 and Commonwealth Edison's Byron 1 Station. Extensive start-up performance characteristics have been obtained for Millstone 2, Ginna, McGuire 1, and Catawba 1 RSGs. The Millstone 2, Ginna and Catawba 1 RSGs have also undergone extensive inspections following their first cycle of operation. The design and start-up performance characteristics of these RSGs are presented.

The BWC Replacement Steam generators were designed to fit the existing envelope of pressure boundary dimensions to ensure licensability and integration into the Nuclear Steam Supply System. The RSGs were provided with a tube bundle of Alloy 690TT tubing, sized to match or exceed the original steam generator (OSG) thermal performance including provision for the reduced thermal conductivity of Alloy 690 relative to Alloy 600. The RSG tube bundle configurations provide a higher circulation design relative to the OSG, and feature corrosion resistant lattice grid and U-bend tube supports which provide effective anti-vibration support. The tube bundle supports accommodate relatively unobstructed flow and allow un-restrained structural interactions during thermal transients. Efficient steam separators assure low moisture carryover as well as high circulation.

Performance measurements obtained during start-up verify that the BWC RSGs meet or exceed the specified thermal and moisture carryover performance requirements. RSG water level stability results at normal operation and during plant transients have been excellent. Visual and ECT inspections have confirmed minimal deposition and 100% tube integrity following the first fuel cycles.

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INTRODUCTION

BWC Recirculating U-tube Steam Generators (SGs) have operated up to 27 years with very high availability and few in-service tube failures. There are presently 126 BWC CANDU SGs in service, following the shutdown of 32 SGs at Bruce A and 48 SGs at Pickering A. In total an additional 8 BWC CANDU SGs have been installed with reactors not yet critical at Cernavoda Unit 2 and Wolsong 4. Another 8 SGs are being fabricated for Qinshan 1 and 2. This CANDU experience represents over 620,000 tubes in service. Out-of-service tube plugging rates of 1.0 tubes per 10,000 tube years of service have been experienced by the 12 early CANDU 6 SGs which have been operating for a cumulative total of 192 SG-years.

In January of 1993 the first two BWC Replacement Steam Generators for a PWR unit went into operation at the Millstone Unit 2 station. Presently there are 22 RSGs in operation in 7 PWR units with another 4 delivered with startup imminent. The operational BWC RSGs include two for Northeast Utilities' Millstone Unit 2, two for Rochester Gas and Electric's Ginna Station, twelve for Duke Energy's Catawba Unit 1 and McGuire Unit 1 and 2 Stations, two for Florida Power and Light's St. Lucie Unit 1 Station and four for Commonwealth Edison's Byron Unit 1 Station. An additional four RSGs have been delivered to ComEd's Braidwood Unit 1. Presently four RSGs for American Electric Power's D. C. Cook Unit 1 Station are being fabricated and four RSGs for Baltimore Gas and Electric's Calvert Cliffs Unit 1 and 2.

The BWC RSGs currently in operation have replaced three models of original steam generators all of which were fabricated using Alloy 600 tubing in the mill annealed condition with either broached plate, drilled plate or 'egg-crate' carbon steel tube support structures.

The need for replacement of the original equipment was primarily driven by tube degradation in the form of pitting at tube support locations and primary and secondary side circumferential stress corrosion cracking (SCC) near the tubesheet face. In addition some units exhibited severely corroded carbon steel tube supports resulting in denting and loose parts due to disintegration of components. Extensive tube plugging, up to 10%, and threatened derating with continual degradation, motivated the replacement projects.

Development of requirements and specifications for the replacement steam generator projects was a major undertaking for the utilities. In 1991, ten PWR utilities including RGE pooled resources to form the Joint Procurement Corporation to issue a common tendering specification. Some of the key requirements in the equipment specifications common to all replacements were that:

- the RSGs must be designed such that the licensing basis of the NSSS system remains valid;
- the RSG design must be qualified for a 40 year design life;
- the preferred tubing material was Alloy 690 although other optional materials could be offered with in-depth justification;
- the geometric envelope of the replacement vessels must duplicate the original equipment; and
- the design must incorporate proven technology.

Replacement of Ginna steam generators under 10CFR50.59 was desirable to avoid the cost and potentially critical path schedule time of the NRC review and approval process. 10CFR50.59 allows plant modification without prior NRC review provided no changes to the plant Technical Specifications are required and no Unreviewed Safety Questions are created.

The RSGs for Duke Energy's Catawba 1 and McGuire 1 and 2 Stations were an exception to the 10CFR50.59 licensing approach. For these stations the original units, which had integral preheaters, were replaced with RSGs having significantly larger tube bundles and upper feedring feedwater distribution headers. Since Duke Energy desired to optimize the operation of the station considering the replacement steam generator features and required the associated update to the licensing basis, they opted for extensive reanalysis and resubmission of Safety Analysis and modified Technical Specifications to the NRC as required under 10CFR50.90. Unlike other utilities, Duke Energy also specified a 60 year design life for the RSGs which required confirmation by fatigue analysis of extended operating cycles, extensive material testing, wear assessment and structural analysis. The design incorporates a 60 year corrosion allowance considering general corrosion, chemical cleaning cycles and flow accelerated corrosion.

Undoubtedly the unmatched performance of the BWC CANDU steam generators and the earlier success of Millstone Unit 2 RSGs contributed towards BWC capturing the majority of the U.S. replacement market since 1992.

DESIGN DESCRIPTIONS

The BWC RSGs presently in service have replaced three models of OSGs and correspondingly have three different general designs: Millstone and St.Lucie RSGs replace System 67 OSGs; Ginna RSGs replace Series 44 OSGs; and Catawba, McGuire, Byron and Braidwood RSGs replace Model D OSGs. In all cases the OSG shell envelopes were replicated to simplify changeout and minimize licensing impact. For the Millstone replacement, the original steam drum shell was retained since it could not pass through the equipment hatch. The moisture separators at Millstone were replaced within containment with high efficiency BWC separators. Figure 1 illustrates general arrangements for the three BWC RSG designs.

Depending upon utility requirements, the RSGs were designed to thermally match or significantly exceed the performance of the original equipment. The primary factors affecting the thermal design requirements were driven by licensing considerations, potential future power uprate, and economic evaluation of benefits associated with lower Reactor Coolant System (RCS) temperatures and/or higher steam outlet pressures. Thermal sizing requirements were expressed by combinations of maximum RCS T_{hot} temperatures, minimum steam pressures, fouling and plugging margins or simply, as requested by Duke Energy, the largest practical heat transfer surface area consistent with licensing and outer envelope constraints. The arrangement of the heat transfer surface area must also consider the RCS hydraulic resistance of the replacement bundle and the change in conductivity of the tube material. To prevent a reduction in fuel Departure from Nucleate Boiling (DNB) ratio and an increase in peak fuel clad temperatures during design basis accidents, the tube bundle arrangement must not have increased hydraulic resistance relative to the OSG which would result in a reduced RCS flow. Conversely the reduction in hydraulic resistance must not result in an increase in RCS flow of, typically, more than 5% to prevent fuel lifting within the reactor core.

The conductivity of Alloy 690 is approximately 9% less than that of Alloy 600 and accounts for approximately one half of the total resistance to heat transfer. Due to this reduced conductivity, a 3% increase in heat transfer surface area and reduction in tube wall thickness from 0.048 inches to 0.045 inches was implemented for the Millstone and St. Lucie RSGs in order to maintain equivalent heat transfer performance. For other BWC RSGs significant increases in plugging and fouling margins were required resulting in large changes in tube bundle arrangements including tube size. Table 1 provides a description of significant RSG parameters for the various replacements and a comparison to the original equipment.

Although the RSG designs vary in shape and size they all share common features such as enhanced Alloy 690 Thermally Treated (TT) tubing, high efficiency centrifugal moisture separators, corrosion resistant Flatbar U-bend Restraints (FURs), lattice grid tube supports and high circulation ratio design. These features provide for increased reliability and optimized operability as discussed below.

Tube Material

Selection of the tube material was the most critical decision of the replacement program since tube material properties are fundamental to most steam generator reliability issues.

The development of Alloy 690 steam generator tubing, during the 1970's and 1980's, was driven by both primary side and secondary side in-service Stress Corrosion Cracking (SCC) of Alloy 600 Mill Annealed (MA) SG tubes. Alloy 690 has significantly more chromium (27 - 31% Cr) than Alloy 600 (14 - 17% Cr).

Alloy 690 derives its improved general and localized corrosion resistance from the stability of its passive film, which is influenced by increased chromium concentration. Corrosion resistance may also be influenced by microstructure which is a function of processing, mill anneal temperature, and thermal treatment.

Alloy 690TT SG tubing used by BWC requires a material microstructure exhibiting continuous chromium carbide decoration along the grain boundaries in addition to minimal chromium carbide precipitation within the grain interiors. This morphology, considered optimum in terms of intergranular SCC resistance, is largely due to attaining complete carbide solution during mill anneal which results in enhanced grain boundary carbide precipitation during the subsequent thermal treatment step. The critical parameter influencing carbon solution is the final mill anneal temperature.

The BWC Alloy 690TT tubing was qualified for the specified service conditions by extensive corrosion testing in secondary water environments, wear testing, residual stress measurements and tube-to-tubesheet joint qualification. Corrosion qualification included a review of open literature which confirmed that Alloy 690 is not susceptible to primary water stress corrosion cracking. Even in 680°F primary water which cracked both Alloys 600 and 800 within 2,900 hours, Alloy 690 tensile specimens exhibited no PWSCC after 7000 hours [1]. Due to the corrosion resistance of Alloy 690 in primary environments BWC focused research towards corrosion testing in aggressive secondary environments. Comparative autoclave tests in 0.5 M (approximately 2%) sodium hydroxide ($NaOH$) contaminated with 5000 ppm (0.02 M) lead oxide (PbO) at 575°F for 1000 - 2000 hours resulted in no evidence of SCC. Tested Alloy 690TT specimens included the tubesheet weld, secondary face expansion transition and U-bend regions.

Alloy 690 and Alloy 600 C-ring control specimens, pre-stressed to approximately three times room temperature yield strength, were similarly tested in an autoclave environment and examined microscopically. None of the Alloy 690 C-ring specimens failed while the Alloy 600 control specimens cracked. It was noted that Alloy 690 C-ring specimens will crack in extremely aggressive caustic plus lead environments such as 10% $NaOH$ with 0.1 M PbO.

Steam Separators

Efficient and reliable operation also requires efficient steam separation. Separators must be capable of achieving very low moisture carryover. High carryover will result in turbine efficiency losses as well as the potential for turbine blade erosion. Based on secondary side calormetric heat duty calculations, where only feedwater flow rates are measured with no steam flow measurement, an increase in carryover results in reduced thermal power. A given percentage increase in carryover translates into the same percentage reduction in station electric output, if moisture carryover is omitted from the secondary side calormetric heat balance.

Efficient steam separator design also requires that the primary separation stage have low pressure drop and low steam carryunder in the downcomer flow in order to support efficient recirculation through the tube bundle. Furthermore, to allow flexibility in water level operation, the separators must be able to operate over a wide range of water levels.

The BWC moisture separation system consists of Curved Arm Primary (CAP) separators matched with centrifugal secondary separators arranged within the steam drum. Both the CAP and secondary separators (illustrated in Figure 2) are laboratory tested at full-scale pressure, temperature and overload flow conditions. There can be no confidence in the performance of the steam/moisture separation equipment without such testing of prototype and production units. The primary separators are of a curved arm, falling film type which provide the inherent separation efficiency and level range capabilities. The secondary cyclone separators are matched one-for-one with the primary separators, and have a skimmer action which removes the separated moisture from the main flow. Qualification of separators for RSG applications also included three-dimensional thermal hydraulic simulation of inlet fluid conditions to assure that the tested conditions bound the flow maldistribution anticipated during service.

Circulation Ratio

One of the most important thermal hydraulic design criteria for RSGs is the Circulation Ratio (CR). Circulation ratio is defined as the ratio of mass flow rate through the tube bundle versus the steam outlet mass flow rate. A steam generator with a high circulation ratio maintains a large quantity of liquid flowing through the tube bundle relative to steam, hence, with a high circulation ratio, the mass content of steam within the tube bundle is small. By maximizing the circulation ratio, problems attributable to tube dry out, tube degradation, poor heat transfer, corrosion product transport, sludge management, and water level controllability, all of which combined or individually contribute to poor performance and premature failure, can be alleviated. A high circulation ratio also maximizes the available fluid mass and fluid velocity in the region above the tubesheet. By maximizing circulation ratio, the velocity of liquid across the secondary face of the tubesheet is increased, thereby reducing areas of low velocity and resulting sludge deposition. Worldwide operating experience has shown that steam generators with low circulation ratios routinely experience large levels of sludge deposition and sludge pile formations on the top face of the tubesheet.

Experience from the Palo Verde Nuclear Generating Station confirms that observed tube degradation and deposition have a direct correlation with regions of high quality zones. Computer simulations by BWC of the System 80 design, which are known to have low circulation ratio, show that zones of high quality correspond to regions where observed deposits and tube failures have occurred [2].

A high circulation ratio also has numerous benefits with regard to corrosion and corrosion product transport. By maintaining a high circulation ratio, high velocities help maintain corrosion product contaminants in suspension thereby maximizing blowdown contaminant removal efficiency. Further, a high circulation ratio promotes more effective blowdown by maximizing the recirculated water content in the downcomer fluid, with only a small proportion being feedwater (for a CR = 5, feedwater makes up 20%). This means that the crud-bearing recirculated water sees less dilution by "clean" feedwater, and therefore blowdown removes fluid with a corrosion product concentration closer to the steam generator bulk fluid concentration.

A high circulation ratio benefits the controllability of the steam generator. The resultant high liquid-to-steam mass ratio within the riser region provides for a steam generator design that experiences less water level swell and shrink during transient operation. Swell is the phenomenon of rapid steam creation during power increases or pressure decreases which causes the overall water level to rapidly rise with a relatively constant secondary side mass. Shrink is the opposite phenomenon where steam is rapidly condensed or compressed (i.e. as with cold feedwater injection or pressure increase) and the water level within the steam generator rapidly falls. By minimizing the amount of vapour phase within the steam generator with a high circulation ratio design, the magnitude of the swell and shrink effects can be minimized.

Stability of recirculation is also a critical consideration for an operating steam generator. Even during steady state with no changes in pressure, power, or feedwater conditions, steam generators may experience two-phase boiling instability which causes large oscillatory changes in water level. This instability can be attributed to a low pressure drop in the downcomer and bundle entrance area and a high two-phase pressure drop in the tube bundle. By maximizing circulation the margin to the onset of instability is increased. Boiling instability occurred at Surry and Bruce A due to blocked tube support plates, resulting in operational water level oscillations, and ultimately leading to power reductions.

Flatbar U-bend Restraints

The U-bend tube support assembly consists of 410S stainless steel flat bars, 316L stainless steel J-tabs and carbon steel structural support components such as arch bars, clamping bars and tie tubes illustrated in Figure 3. All materials are qualified for the specified design life of the replacement equipment for operation in accordance with the customer specifications. Qualification includes identifying corrosion allowances for structural analysis including the effects of general corrosion, flow assisted corrosion and chemical cleaning allowance. Fretting wear behaviour of 410S stainless steel supports and Alloy 690 tubing has been quantified at typical PWR temperatures, pressures and chemistries. The wear behaviour was confirmed by testing, to be equivalent or better than other typical material combinations used for U-bend support applications.

Type 410S stainless steel flat bars provide a corrosion resistant material with high mechanical strength required to provide adequate structural support during seismic events. Type 410S material is compatible with the autogenous welding process which is used to join the fan bar fingers to a lower collector bar across the bottom of the fan assemblies. The 410S welded joints are qualified in an aggressive PWR secondary side environment by Constant Elongation Rate Tests (CERT) and long term immersion tests on highly stressed bend specimens. Prototypical welded joint specimens in as-welded and post weld heat treated conditions were tested. Based on these qualification tests BWC has conservatively implemented a Post Weld Heat Treatment (PWHT) procedure which includes a forced draft cooling operation to rapidly cool the welded 410S assemblies to prevent tempered martensite embrittlement.

U-bend assembly support is provided by 316L J-tabs (earlier designs utilized carbon steel J-tabs) which transfer the weight of the flat bar U-bend support structure to the peripheral tubes. The fabrication of J-tabs involves bending flat strips into 'J' shaped tabs followed by a solution-anneal heat treatment. This thermal treatment effectively relieves residual cold work in the bent tabs, which are specified as low carbon grade. ASTM sensitization tests are performed on the bent, thermally treated components to assure that the J-tabs are in the unsensitized condition.

High circulation is promoted in the U-bend region by designing a tube support structure which has low hydraulic resistance. The flat bars are staggered between successive tube layers and the fan fingers are oriented radially in the direction of the flow. All components and contact surfaces are upwardly vented to prevent formation of steam pockets and dryout regions. To reduce the resistance of the tube pattern, the tube pitch is stretched in the vertical direction at the apex locations of tubes within the tube bundle. This is accomplished by incrementally increasing the tube tangent point height for successively larger bend radii.

Based on the above, high velocities, low mixture qualities and high circulation are desirable design characteristics, however care must be taken to assure acceptable flow induced vibration response. FIV is the primary design consideration influencing the quantity and positioning of Flatbar U-bend Restraints within the U-tube bundle.

Lattice Grid Tube Supports

The design of the tube support system is critical to the reliability of the tube bundle and the steam generator. The design requirements for reliable effective tube supports must:

a) preclude excessive Flow-Induced Vibration (FIV),
b) minimize pressure loss in order to promote a high circulation ratio,
c) provide line support contact to reduce the potential for deposition of corrosion-causing impurities and localized dryout,
d) provide sufficient tube contact length to lower contact stress and hence minimize fretting wear of tubes,
e) provide a strong tube support design to withstand lateral seismic loads, loads caused by LOCA and burst pipe events, and handling and shipping loads,
f) accommodate tube-support motions during heatup/startup operation without risk of lockup and without the need for tie rods,
g) resist corrosion and stress corrosion cracking due to normal operation and chemical cleaning.

Figure 4 shows the details of a typical lattice grid arrangement. The lattice grid is made up of two intersecting arrays of 410S stainless steel high bars (3.15 inches high) oriented at 30° and 150° to the tube free lane and located every four to eight pitches, depending on the size of the bundle and the particular steam generator loading conditions. 410S stainless steel low bars (approximately 1 inch wide) are located at every pitch location between the high bars. All low bars flush to the top of the high bars are oriented at 30° to the tube free lane and all low bars flush to the bottom plane of the high bars are oriented at 150° to the tube free lane. The bar ends are fitted into precise slots on a peripheral support ring, which is then clamped by two outer retainer rings that are bolted together. The assembly is positioned by welded blocks and wedges within the shroud.

All of the lattice supports are similar except that the lowermost lattice incorporates a differential resistance feature which is used to encourage bundle flow penetration above the tubesheet. The construction of the differential resistance lattice grid resembles that of a regular grid, however, the low bars located towards the bundle periphery are replaced by medium bars (approximately 2½ inches high). As a result, the flow passages through these regions offer more resistance to flow and the fluid is preferentially directed to penetrate into the central region of the tube bundle. A drilled flow distribution baffle which may accumulate deposits become plugged and cause tube wear or denting is not used.

Lattice grids provide low flow resistance to the two-phase fluid flowing and promote high circulation.

Lattice grid bars provide line support contact with the tubes minimizing the crevice potential in the tube support. This together with a higher circulation ratio prevent stagnant regions and dry-out.

Full-scale modeling of a section of tube bundle for tube vibration has confirmed the effectiveness of lattice grids in suppressing vibration by providing a 'pinned' support condition. Lattice grids are extremely strong in the vertical and lateral directions and are capable of withstanding all operational and accidental loads without the need for tie rods. Despite the strength of the structure, low bar spans allow for inherent flexibility which accommodate thermally induced rotations between the tube and tube support.

BWC has fabricated a considerable number of steam generators using both lattice grids and broached plates and is the only supplier with operating experience with both designs. As a result of many years of design and operating experience, BWC concluded that the lattice grid tube support system was the best choice to ensure reliable operation of replacement steam generators.

RSG OPERATIONAL PERFORMANCE

Millstone Unit 2 Performance

The Millstone 2 RSGs went into service in January 1993 at which time a variety of performance measurements were made by Northeast Utilities.

Heat transfer performance of the RSGs was reported as fully satisfying the requirement that the RSG should provide the same or better heat transfer capacity than the original unit. Thermal performance was demonstrated by field measurements of feedwater flows and temperatures, steam pressure and RCS hot leg and cold leg temperatures. RCS hot leg temperatures were corrected for thermal streaming. The secondary side calorimetric heat duty was balanced with the primary side and used to determine primary flow in accordance with Northeast Utilities' procedures. The BWC heat transfer program CIRC was used to predict RCS temperatures using the same methodology as that used to size the RSGs.

Table 2 presents results from CIRC startup simulations. These simulations used primary flow, feedwater flow, feedwater temperature and steam pressure from field measurements as inputs to predict RCS temperatures. For both SG-1 and SG-2, the CIRC predictions for RCS hot leg temperatures are slightly higher than the actual measured values when using the traditional startup fouling value of 0.00002 $hr \times ft^2 \times {}^{\circ}F/Btu$. Since the actual RCS operating temperatures are less than those predicted the bundle is thermally more efficient thus fulfilling the specified requirements.

Low moisture carryover is vital in avoiding turbine blade erosion, maintaining turbine efficiency, and maximizing station electric output. Moisture carryover in the steam was measured as 0.022% - an order of magnitude below the guaranteed value of 0.20%. The moisture carryover measurements were made using Sodium-24 radiotracer in accordance with the IST 92-74 Test Procedures. Test results for both RSGs are provided in Table 3. These test results correlate with the predicted carryover of 0.025% determined from full scale, full power testing of an individual primary and secondary separator set.

Water level stability is observable by the absence of level fluctuations during steady-state operation at power and by rapid stabilization after a change in operating conditions. Level stability is a measure of controllability and is enhanced by an appropriate distribution of circulating flow pressure losses, efficient separator operation and by a high circulation ratio. Based on steadiness and responsiveness, level stability was observed to be excellent.

Millstone 2 RSG inspections were performed in October 1994 at the end of the first post-replacement fuel cycle. The inspection of each RSG included eddy current inspections (bobbin coil) of approximately 30% of the tubing, and fibreoptic/video probe inspection of the tubesheet tube-free-lane and outer perimeter. Inspection also included visual and video inspection of the U-bends and drum internals. These inspections confirmed that the RSGs are in excellent condition.

Tube bundle ECT inspections confirmed no reportable tube indications. One 22% bobbin coil signal, with only a 0.3 volt amplitude, was detected but re-examination using MRPC concluded that the bobbin coil indication was likely a spurious signal or a nonquantifiable anomaly.

Secondary side examination of the U-bend tubes and tube supports showed all structures to be in place in their correct as-designed positions. U-bend inspection included J-tabs, arch bar assemblies, tie tubes and anti-rotation bars. No excessive tube displacements were observed at the J-tab interfaces with the outer U-tubes. Examination of the U-bend tubes showed a thin general deposition in the tube U-bend region, with preferential deposition on the hot leg side. The feedwater header for Millstone was fabricated using Schedule 80 carbon steel pipe sections unlike later RSG feedwater systems which used 2 ¼% Chrome - 1% Molybdenum material. A surface discoloration on the header and shroud was observed in the J-tube flow impingement region but no erosion was evident. Also, no evidence of erosion or degradation of the primary or secondary separators was observed.

Examination of tube-to-support bar contact points at peripheral U-bend support locations and peripheral upper lattice support locations showed no signs of deposition blockage or tube-to-bar bridging or filleting. This confirms the ability of the fully rounded support bar configuration to resist preferential deposition and blockage at the supports.

Although there was no visible sludge during the tubesheet inspection (other than a ¼" to ½" diameter 'sludge rock') a sludge lancing was performed. The lancing effort resulted in removing approximately 40 lbs of deposition from each of the RSGs. Based on both the visual inspections and sludge removal results it was concluded that both generators were very clean. The foreign object inspection program found a weld wire, weld rod and a thin metal strip, 1/16" thick x ¼" wide x 3 ½" long, all of which were retrieved.

The Millstone 2 replacement program has resulted in steam generators which have been successfully operated and have met all performance expectations. Heat transfer, moisture carryover and controllability objectives are being met. To date the Millstone 2 RSGs have accumulated 24 months of full power operating experience. Presently however, Millstone 2 continues to be shutdown pending conclusions from a configuration management program in response to NRC 10CFR50.54f requirements to show compliance with the plant license basis. Millstone 2 is expected to restart late in 1998.

Ginna Performance

Ginna Station reached full power with BWC RSGs on June 15, 1996. Thermal performance and moisture carryover were measured as part of the startup program. The thermal performance warranty for the Ginna RSGs was in the form of a minimum steam pressure, downstream of the outlet nozzle flow restrictor, as a function of the reactor average temperature at full power. The guaranteed minimum steam pressure is given by the equation:

Pstm (psia) = 7.822 Tavg (°F) - 3618.5

Note that the irrecoverable loss in the steam lines between the instrument tap and the generator nozzle must be accounted for when comparing measured and guaranteed pressures.

Unlike the earlier Millstone 2 RSG the heat transfer area for Ginna was designed to significantly outperform the OSG thereby allowing for an increase in steam pressure and/or reduction in RCS temperature.

Verification of thermal performance at Ginna was done as part of the thermal calorimetric calculation. The calorimetric results for the two RSGs show that the measured steam pressure downstream in the main steam line was 733 psig at a reactor average temperature of 560.1°F. Since the pressure drop in the steam line is 15 psi, the nozzle pressure was calculated to be 748 psig, which satisfies the warranty value without inclusion of corrections (see Table 4).

While the warranty performance is satisfied, the CIRC predicted nozzle pressure at T_{ave} = 560.1°F is 762 psig, 14 psi higher than the measured pressure. Further analysis of the data indicates that thermal streaming is occurring in the RCS hot legs. The measured T_{hot} in Loop B is 2.6°F higher than in Loop A. This difference is difficult to explain since the Ginna NSSS is symmetric, and the core power distribution was symmetric during the test and hot leg temperatures should not exhibit this wide spread. At Ginna, one of the four hot-leg RTDs in Loop A is located on the opposite side of the other three in the 27" ID RCS pipe. On Loop B, all four RTDs are localized on one side of the RCS pipe. As a result, the average temperature from Loop A measurements can be expected to give a better representation of true bulk temperature than the Loop B average.

Using measured hot leg and cold leg temperatures in conjunction with secondary side calormetric heat duty, the calculated Loop A and Loop B RCS flows differ by 3%. Since the Loops are symmetric this large difference can only be attributed to RCS temperature uncertainty. Since there is no absolute flow measurements in the RCS Loops, the degree of streaming cannot be definitely determined and a correction to T_{hot} cannot be easily calculated. However, assuming the measured value in Loop A is more reliable, as supported by RTD positions and independently calculated best estimate RCS flows, the warranty nozzle pressure is calculated to be 742 psig and the CIRC predicted pressure is 756 psig, compared to the measured pressure of 748 psig.

The remaining 8 psi difference between the measured and the predicted values can be attributed to the variance in tube wall thickness. Ginna RSG tubing has a specified thickness of 0.043 ±.004" and thermal analysis assumed an average thickness of 0.043". The actual wall thickness was 0.0445"; the resulting increased tube wall thermal resistance would be expected to reduce steam pressure by approximately 6 psi thereby effectively matching the predicted performance.

Data collected following the initial performance testing has confirmed a linear increase in steam pressure even though RCS temperatures and thermal power were held constant. This represents an improvement in the overall heat transfer coefficient, likely resulting from an improved boiling heat transfer coefficient due to improved nucleation on the tube outer surface. Similar trends were reported at San Onofre Unit 2 and Callaway during the first cycle of operation [3]. During the first 18 month Ginna operating cycle, a steam pressure increase of approximately 8 psi was observed. This pressure increase trend as illustrated in Figure 5 continues beyond the first refuelling outage. This results in both warranted and predicted performance being met (after inclusion of streaming correction but without correction for wall thickness).

Moisture carryover tests were performed by RGE under the direction of NWT Corporation using Sodium-24 radiotracer. Based on sampling reheater drain activity, the estimated ± 1σ uncertainty band for the Ginna steam carryover measurement was ±20% using a Sodium-24 radiotracer and assuming a mean carryover concentration of 0.01%. The estimated uncertainty of using non-radioactive potassium concentrations for determination of carryover is significantly larger. Based on sampling reheater drain flow a mean carryover of 0.07%, the potassium technique would have an uncertainty of ±50%.

The Sodium-24 test procedure involved injecting the tracer into the feedwater system and allowing the system concentration (radioactivity) to equilibrate. Moisture carryover was determined by two sampling techniques. The first used feedwater sampling, blowdown sampling and circulation ratio for determining steam drum concentration, while the second used heater drain tank and blowdown sampling and circulation ratio. Both methods, as reported in Table 5, confirm moisture carryover values of 0.015%, more than 6 times lower than the warranty value of 0.1%.

Startup testing at Ginna also included water level stability tests to assess the adequacy of the wide-range level feed-forward signal at low power and the responsiveness of the Advanced Digital Feedwater Control System (ADFCS). The Ginna ADFCS uses the wide-range level at low power as a feed-forward signal to control feedwater valve setting in response to increases or decreases in steam load at low power. The original Ginna feedwater level control system increased level from 39% of span at 0% power to 52% of span at 20% power and then maintained a constant level of 52% up to 100% power. The OSG wide range signal as a function of power had a negative slope despite increasing water level. The negative slope can be attributed to higher velocities in the narrower Westinghouse Series 44 downcomer which resulted in a larger dynamic pressure drop at the low wide range tap. The RSG, however, has a wider downcomer and lower downcomer velocity which results in a relatively constant wide range signal versus power. Due to the reduced slope of this signal, the effectiveness as a feed-forward controller was questioned. To resolve this concern the water level control program was altered to a constant level of 52% of the 143 inch span for all powers. This change produced a more negatively sloped signal for the feed-forward element. Startup testing confirmed water level stability using ADFCS control at low powers.

The automatic feedwater control system was also tested at 25% and 75% power by imposing a 5% step change increase in feedwater flow to force an increase in water level and then note the level recovery responsiveness. Tests confirmed a smooth recovery to the water level setpoint with little or no undershoot.

An unplanned turbine trip at 25% power, due to loss of condenser vacuum, confirmed excellent water level controllability. Immediately following the trip, a 45 psi pressure rise resulted in only a 9" water level collapse before condenser steam dump valves opened and effectively returned the level to the controlled setpoint.

Following the first cycle of operation both secondary and primary side inspections were carried out. Primary side Eddy Current Testing (ECT) of 100% of the tube bundle confirmed no reportable indications. In addition to this bobbin coil inspection, 20% of the tube expansion transitions at the secondary face of the tubesheet were tested on the hot leg side, again confirming no reportable indications.

Secondary side internals inspection was undertaken to verify that there were no unknown degradation mechanisms occurring in the RSGs and to assist with the response to Nuclear Regulatory Commission Generic Letter 97-06 on secondary internals degradation. In addition the inspection helped determine if the RSGs were experiencing tubes in close proximity to each other.

Secondary side inspections included the steam dome, primary and secondary separators, feedwater header, U-bend region and lower internals near the top of the tubesheet. No degradation of any items in any regions were observed, and tube deposits were light.

Two foreign objects, a hex-head bolt and matching nut were found near the center of the no-tube lane and removed. No tube damage was observed by ECT. Subsequent investigations revealed that the bolt and nut were not native to the steam generator.

Five tube gaps with less than 0.100" of vertical clearance were identified by ECT in both SG A and SG B. Visual inspections of some of these tubes confirmed the ECT results. The condition of tube proximity is an acceptable condition based on extensive analysis by BWC including thermal hydraulic, structural and wear analysis.

Catawba Unit 1 Performance

Catawba Unit 1 RSGs, the first of three sets installed in Duke Energy units, reached full-power operation in October, 1996.

For the Duke Energy heat transfer warranty, a minimum overall heat transfer capacity, UA, of 9.29×10^7 Btu/hr°F was specified for full-power operation rather than a steam pressure versus RCS temperature curve as at Ginna. The heat transfer capacity is calculated by dividing the measured heat duty as determined from a secondary side calormetric by the Log Mean Temperature Difference (LMTD) based on RCS hot leg, RCS cold leg and steam outlet temperatures. UA has the advantage of remaining nearly constant for relatively wide ranges of full-power conditions thereby providing greater flexibility for startup conditions during heat transfer testing.

To account for measurement uncertainty, the UA guarantee value included a 3.3% margin to account for instrument inaccuracy and known RCS hot leg thermal streaming.

Based on analysis of raw uncorrected data obtained at the time of the test, BWC calculated the average overall heat transfer capacity for all four steam generators to be 9.68×10^7 BTU/hr·°F, which is 4.2% above the guaranteed value. Table 6 summarizes the data used to obtain these values.

Babcock & Wilcox has further analyzed the startup data in order to verify that the steam generators are performing as predicted. Catawba has a relatively accurate absolute RCS flow measurement which can be used to calculate RCS hot leg temperatures. Using the measured RCS flow to correct for streaming, adjusting the cold leg temperature to account for pump heat input, and accounting for steam line pressure losses, BWC has calculated an average corrected UA of 1.00×10^8 BTU/hr·°F, which is marginally above the BWC best estimate value of 9.98×10^7 BTU/hr·°F. The corrected data is shown in Table 7.

Following initial startup, moisture carryover testing was performed by NWT Corporation using the potassium chemical tracer method. Duke Energy opted for the chemical tracer method rather than a Na-24 radio tracer due to considerations related to handling a small but highly radioactive Sodium-24 sample. A potassium tracer was selected because of the unknown corrosion behaviour of the other alternate chemical tracers, sodium and lithium nitrate.

Accuracies of chemical tracer techniques are less than those associated with Na-24 radio tracer due to chemical tracer detection limits and the small concentrations of tracer chemicals downstream of the RSGs. For example the RSG steam drum liquid concentrations were approximately 10 ppb and the feedwater concentration resulting from carryover is only 1.5 ppt. Chemical tracer moisture carryover accuracy was maximized by using forward pumped heater drain (FPHD) and moisture separator reheater (MSR) drains where typical concentrations increased to approximately .015 and .025 ppb respectively. Moisture carryover based on feedwater concentrations and second stage reheater drains were attempted; however the observed concentrations were at, or near, the NWT detection limit for potassium and the concentration increases were only approximately 10% of the background level. Because of the large associated uncertainty, feedwater and second stage reheater drain measurements were not considered valid.

Table 8 provides the summary of the FPHD and MSR drain tank moisture carryover analysis from two tests. The results varied from .039% to .057% moisture carryover which, despite reduced accuracy relative to Na-24 was about 20% of the 0.25% limit.

Secondary side visual inspections and ECT inspections of the tube bundle were completed during the first refueling outage in 1997. Visual inspections included secondary and primary deck steam drum components, top of tube bundle, tube bundle U-bend restraint system, feedwater header, downcomer and tubesheet region. All inspections were performed by personnel access through the steam drum manway or remote inspections using a PTZ camera through a transition cone handhole. Varying amounts of corrosion products were observed on different components. Generally the deposition observed on the primary separator deck was loose granular particulate matter and a pasty deposit was observed on the primary separator flow arm surfaces. A thin fouling layer was observed on the tube bundle with no evidence of deposit bridging at support locations. It was observed that some J-tabs were not contacting tubes which can be expected and is indicative of J-tab support redundancy. ECT inspection of the tube bundle found no reportable indications.

McGuire Unit 1 Performance

The McGuire Unit 1 RSGs reached full power in June 1997. Heat transfer capacity and moisture carryover testing similar to the Catawba Unit 1 tests were completed shortly following startup.

Like Catawba the heat transfer capacity UA was calculated from secondary side heat balance and measured terminal point temperatures for comparison with the guaranteed minimum value of 9.29 x 10^7 Btu/hr/ft^2. Results from testing each of the flow loops are provided in Tables 9 and 10 showing that the guaranteed minimum UA was easily satisfied. The corrected UA which considers hot leg steaming and steam line pressure losses is negligibly less than the best estimate value.

Like Catawba Unit 1 the moisture carryover was determined by NWT Corporation utilizing the potassium tracer method for comparison to the guaranteed maximum of 0.25%. During the measurement programs, the SG sampling system valves were configured to obtain samples from the upper shell, however, since it is possible dilution of this sample with blowdown liquid occurred as a result of sampling system valve leakage, two sets of MCO values were calculated, i.e., one assuming that the source was the upper shell tap and the other that the source was the blowdown tap sample. Since the RSG recirculation ratio is 5.74 at 100% power, the calculated MCO values differ by $\leq$ 0.01%. Table 11 provides results of the moisture carryover testing. The overall average of the eight values is 0.047% which is approximately 20% of the 0.25% guaranteed.

Catawba 1 water level responses were stable at all power levels. During the McGuire 1 start-up the RSGs experienced both low power and full load water level oscillations. Catawba 1 utilizes a digital feedwater control system and McGuire 1 has an analogue feedwater control system. McGuire 1 did experience water level swings at less than 10% power which required constant attention by operators. After analyzing McGuire 1 control system data and comparing with Catawba 1 control system responses, control system tuning and operator experience have improved level control stability for McGuire 1 at low power levels.

At full load for all 4 RSGs one of four narrow range water level instrumentation loops experienced a 3% of range oscillation at approximately 1 Hz. Due to the lack of correlation between the unstable loops and internal steam generator features and due to the excellent stability of Catawba the oscillations are not attributed to the RSG design or thermal hydraulic characteristics.

CONCLUSION

Replacement steam generators supplied by BWC to Northeast Utilities, Rochester Gas and Electric, Duke Power and Florida Power and Light have been designed for maximum reliability and operability. Start-up performance testing at Millstone Unit 2, Ginna, Catawba Unit 1 and McGuire Unit 1 have confirmed that the RSGs are meeting all expectations of performance. Heat transfer, moisture carryover and controllability objectives have been met. First outage visual and ECT inspections of the Millstone Unit 2, Ginna and Catawba Unit 1 RSGs confirms that the steam generators are in excellent condition.

REFERENCES

[1] T. Yonzewa, et al., "Evaluation of the Corrosion Resistance of Alloy 690", EPRI NP-4665S-SR Proceedings: Workshop on Thermally Treated Alloy 690 Tubes for Nuclear Steam Generators, Pittsburgh, Pennsylvania, June 26-28, 1986, paper no. 11.

[2] Jiang, et al., "Identification of Potential Fouling Regions in Steam Generators Using ATHOSBWI, International Conference on Nuclear Engineering, Volume 5, 1996.

[3] White, et al., "Causes of PWR Steam Generator Thermal Performance Degradation", *Sixth EPRI PSE Nuclear Plant Performance Improvement Seminar*, *Sept. 3-4, 1996*, Asherville, NC.

Table 1
Steam Generator Parameters

		Millstone Unit 2		FPL, St. Lucie Unit 1		RG&E, Ginna Station		Duke Power, Catawba Unit 1 & McGuire Unit 1 & 2	
		OSG	**RSG**	**OSG**	**RSG**	**OSG**	**RSG**	**OSG**	**RSG**
Steam Generator Model		CE - Series 67	B&W – Series 67 Replacement	CE - Series 67	B&W - Series 67 Replacement	W- Model 44	B&W - Model 44 Replacement	W - Model D2/D3	B&W - Model D Replacement
No. Steam Generators/Unit		2	2	2	2	2	2	4	4
NSSS Thermal Power Rating	MWt	2715	2715	2710	2710	1528	1528	3430	3430
Unit Electric Power Rating	MWe	862	862	900/839	900/839	516/470	516/470	1129	1129
In Service Date	year	12/75	1/93	12/76	1/98	7/70	6/96	6/85 12/81 3/84	10/96 5/97 12/97
Design Life	years	40	40	40	40	40	40	40	60
Dry Weight	lbm	1,009,089	1,070,400	1,024,317	1,086,000	610,000	632,400	736,000	795,800
Weight of Lower assembly	lbm		676,800						
Tube Support Structure		6 - Egg-Crate 2 - Partial Egg Crate 2 - Partial Support Plates	7 – Lattice Grids	6 - Egg-Crate 2 - Partial Egg Crate 2-Partial Support Plates	7 - Lattice Grids	6 - Drilled Plates	8 - Lattice Grids	8 - Broached Plates	9 - Lattice Grids
U-bend Support Structure		5 - Bat-Wing Supports	12 – Flat-bar Supports	5 - Bat-Wing Supports	12-Flat-bar Supports	4-Anti-Vibration Bars	10 - Flat-Bar Supports	4 - Anti-Vibration Bars	10-Flat-Bar Supports
Tube Support Material		Carbon Steel	SS Type 410S	Carbon Steel	SS Type 410S	Carbon Steel	SS Type 410S	Ferritic Stainless	SS Type 410S
Heat Transfer Area	ft^2	90,674	93,500	90,109	93,707	44,430	54,000	48,300	79,800
Tube Material - Alloy		Alloy 600 MA	Alloy 690 TT	Alloy 600 MA	Alloy 690 TT	Alloy 600 MA	Alloy 690 TT	Alloy 600 MA	Alloy 690 TT
Number of Tubes		8519	8523	8519	8523	3260	4765	4568	6633
Tube Nominal O.D.	in.	0.750	0.750	0.750	0.750	0.875	0.75	0.750	0.685
Tube Nominal Wall Thickness	in.	0.048	0.045	0.048	0.045	0.05	0.043	0.043	0.040
Tube pitch	in.	1	1	1	1	1.234	1.019	1.0625	0.93
Full Power RCS T-hot (Design/Startup)	°F	594	594/592.7	606	597.6/594.8	603.9	603/601.7		624.4/614.2
Full Power TCS T-cold (Design/Startup)	°F	548	545.7/544.2	548	548	543.1	544/545.4		564.8/556.3
RCS Loop Flow/SG	lbm/hr	74 x 10^6	74 x 10^6	70 x 10^6	71.05/75.57 x 10^6	32.95 x 10^6	33.36/34.95 x 10^6		34.7/37 x 10^6
Full Load Steam Flow (Design)	lbm/hr	5.9 x 10^6	5.9 x 10^6	5.9 x 10^6	5.9 x 10^6	3.3 x 10^6	3.25/3.26 x 10^6		3.78 x 10^6
Full Load Steam Outlet Nozzle Pressure	psia	880	880	885	823/868	755	787/877	1020	1020
Full Load Steam Temperature	°F	529.3	529.3	530	521.5/527.7	514	516.3/528.9	547	547
Full Load Feedwater Temperature (Design)	°F	435	435	435	435	425	425	440	440
Design Fouling Margin	hr-ft²-°F/Btu	0	0	0.0003624	0.00005/0.00002	0	0.00015/0.00002		0.000196/0.00002
Design Plugging Margin	%	0.0%	7.4%/0%	0%	18%/0%	15%	20%/0%		20%/0%
Circulation Ratio		4.0	4.4	4.1	4.3	3.4	5.3		5.7
ASME Secondary Side Design Pressure	psia	1015	1015	1000	1000	1100	1100	1200	1200
ASME Secondary Side Design Temperature	°F	550	550	550	550	556	556	600	600
ASME Primary Side Design Pressure	psia	2500	2500	2500	2500	2500	2500	2500	2500
ASME Primary Side Design Temperature	°F	650	650	650	650	650	650	650	650

Table 2
MILLSTONE UNIT 2 START-UP DATA

Parameter	SG-1		SG-2	
	Site Data	CIRC	Site Data	CIRC
Primary Flow (lbm/hr)	69.59×10^6	69.59×10^6	70.74×10^6	70.74×10^6
T_{hot} (°F)	598.0	598.3	597.0	597.1
T_{cold} (°F)	547.5	547.9	547.0	547.1
Feedwater Flow (lbm/hr)	5.92×10^6	5.92×10^6	5.94×10^6	5.94×10^6
Steam Pressure (psia)	887.5	887.5	880.3	880.3
Heat Duty (Btu/hr)	4.618×10^9	4.618×10^9	4.638×10^9	4.638×10^9
Fouling ($hr\cdot ft^2\cdot °F/Btu$)	-	0.00002	-	0.00002

Table 3
Moisture Carryover Testing

	Moisture Carryover
Steam Generator No. 1	0.016%±0.003%
Steam Generator No. 2	0.028%±0.002%
System Avg.	0.022%

Table 4
Ginna Startup Performance Measurement Results

Parameter	Loop A	Loop B	Average
T_{hot} (°F)	587.9	590.5	589.2
T_{cold} (°F)	530.6	531.5	531.1
T_{ave} (°F)	559.3	561.0	560.1
ΔT (°F)	57.3	59.0	58.1
W_{pri} (lbm/hr)	35.39×10^6	34.25×10^6	34.82×10^6
P (psig)	748.0	748.0	748.0

Table 5
Moisture Carryover Test Results for Ginna

Parameters	Units	Sample #1	Sample #2	Sample #3	Sample #4	ample #5
SG Power	%	100	100	100	100	100
Main FD Water Activity	µci/ml	1.23E-06	1.22E-06	1.27E-06	1.13E-06	1.49E-06
Average SG Blowdown Activity	µci/ml	6.76E-03	6.69E-03	6.72E-03	6.67E-03	6.60E-03
(CR-1)/CR		0.81	0.81	0.81	0.81	0.81
MCO Based on Main Feedwater Sample	%	0.015	0.015	0.015	0.014	0.018
Heater Drain Tank Flow	klbm/hr	2002	2000	2002	2007	2008
SG Total Feedwater Flow	klbm/hr	6473	6471	6474	6475	6477
Heater Drain Tank Activity	µci/ml	3.90E-06	4.11E-06	4.15E-06	3.99E-06	3.86E-06
MCO Based on Heater Drain Tank Sample	%	0.015	0.015	0.015	0.015	0.015

Table 6
Uncorrected Data and UA Calculations for Comparison to Guarantee for Catawba Unit 1

Parameter	Loop A	Loop B	Loop C	Loop D
Hot Leg Temperature (°F)	614.02	609.69	613.98	612.84
Cold Leg Temperature (°F)	553.88	553.37	553.42	554.28
Calculated RCS Flow Rate (lbm/hr)	3.690×10^7	3.667×10^7	3.584×10^7	3.660×10^7
Feedwater Temperature (°F)	439.29	439.09	439.43	438.48
Feedwater Pressure (psig)	1018.67	1020.58	1030.45	1016.97
Feedwater Flow (lbm/hr)	3.90×10^6	3.60×10^6	3.81×10^6	3.76×10^6
Steam Pressure (psig)	979.88	980.97	981.31	980.77
Calculated Steam Temperature (°F)	543.92	544.05	544.09	544.03
Blowdown Flow (lbm/hr)	0	0	0	0
Heat Duty (Btu/hr)	3.023×10^9	2.785×10^9	2.953×10^9	2.912×10^9
Log Mean Temperature Difference (°F)	30.82	28.84	30.07	30.76
UA (BTU/hr·°F)	9.80×10^7	9.66×10^7	9.82×10^7	9.47×10^7
Guaranteed UA (Btu/hr°F)	9.29×10^7	9.29×10^7	9.29×10^7	9.29×10^7

Table 7
Corrected Data and UA Calculation for
Comparison to Best Estimate Performance for Catawba Unit 1

Parameter	Loop A	Loop B	Loop C	Loop D
Corrected Hot Leg Temperature (°F)	613.24	608.56	611.79	611.87
Corrected Cold Leg Temperature (°F)	553.58	553.07	553.12	553.98
Measured RCS Flow Rate (lbm/hr)	3.729×10^7	4.046×10^7	3.804×10^7	3.851×10^7
Feedwater Temperature (°F)	439.29	439.09	439.43	438.48
Feedwater Pressure (psig)	1018.67	1020.58	1030.45	1016.97
Feedwater Flow (lbm/hr)	3.90×10^6	3.60×10^6	3.81×10^6	3.76×10^6
Corrected Steam Pressure (psig)	987.68	988.77	989.11	988.57
Calculated Corrected Steam Temperature (°F)	544.87	545.00	545.04	544.98
Blowdown Flow (lbm/hr)	0	0	0	0
Corrected Heat Duty (Btu/hr)	3.021×10^9	2.784×10^9	2.952×10^9	2.911×10^9
Corrected LMTD (°F)	29.91	27.89	28.76	29.79
Corrected UA (BTU/hr·°F)	1.01×10^8	9.98×10^7	1.03×10^8	9.77×10^7
Best Estimate UA (BTU/hr°F)	9.98×10^7	9.98×10^7	9.98×10^7	9.98×10^7

Table 8
Summary of Moisture Carryover Measurement at Catawba Unit-1

MCO Based on	**Test No.**	**MCO, %**
FPHD	2	0.057
	1	0.045
MSR Dr. Tk.	2	0.045
	1	0.039

Table 9
Uncorrected Data and UA Calculations for Comparisons to Guarantee for McGuire Unit 1

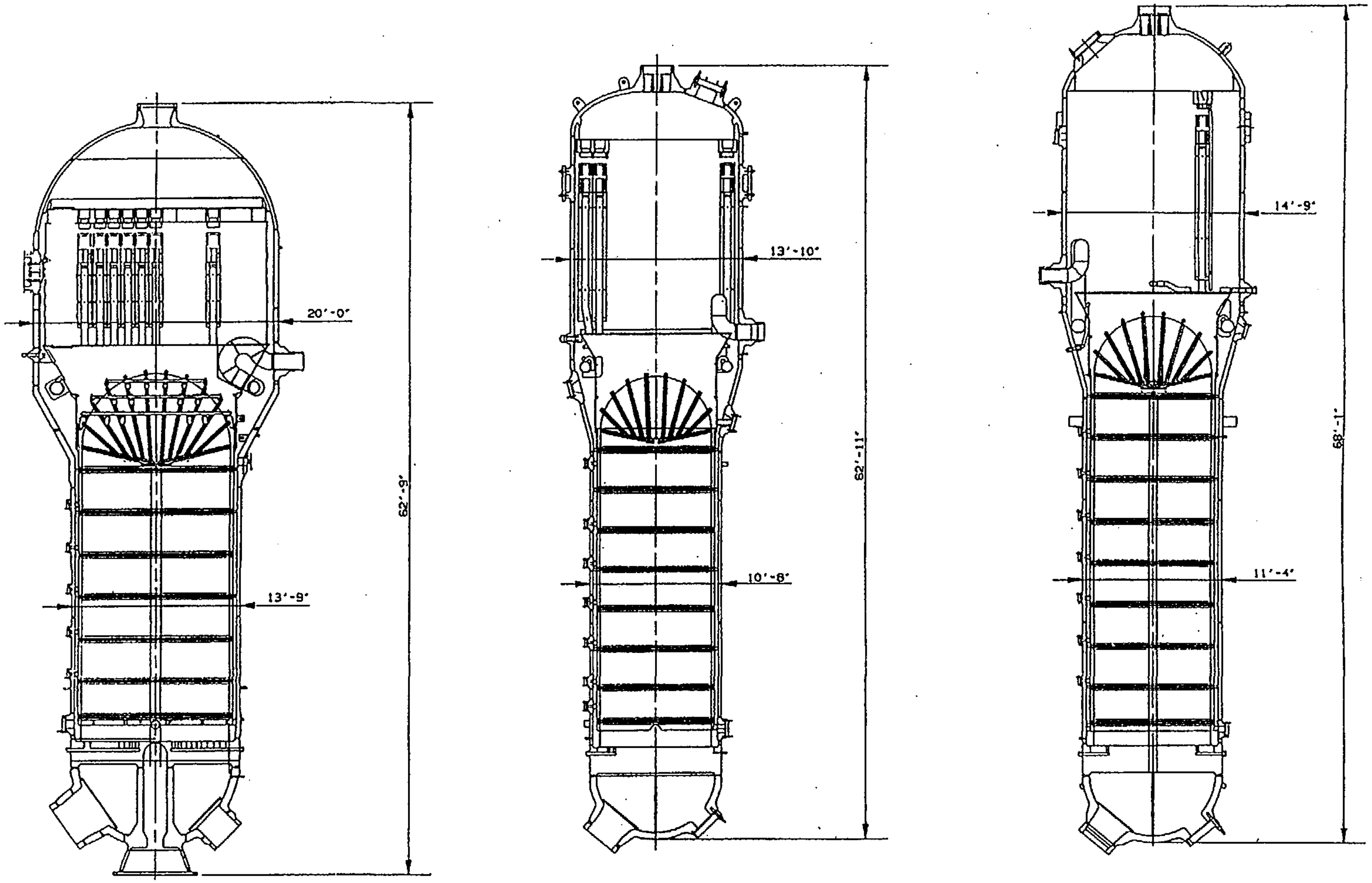
Parameter	Loop A	Loop B	Loop C	Loop D
Hot Leg Temperature (°F)	613.376	613.149	613.984	612.154
Cold Leg Temperature (°F)	555.152	555.517	555.576	555.537
Feedwater Temperature (°F)	437.65	437.22	437.28	437.32
Feedwater Enthalpy (Btu/lbm)	416.696	416.425	416.491	416.545
Feedwater Flow (lbm/hr)	3.7163×10^6	3.7773×10^6	3.7743×10^6	3.7523×10^6
Steam Pressure (psig)	1009.821	1010.633	1011.27	1010.157
Calculated Steam Temperature (°F)	545.768	545.865	545.935	545.808
Steam Enthalpy @ 0.047% MCO	1192.269	1192.238	1192.217	1192.256
Blowdown Flow (lbm/hr)	0	0	0	0
Thermal Load (10^9 Btu/hr)	2.8823	2.9305	2.9278	2.9107
RCS Calorimetric Flow (10^6 lbm/hr)	36.397	37.383	36.793	37.753
Log Mean Temperature Difference (°F)	29.485	29.680	29.888	29.300
UA (Btu/hr-°F)	9.78×10^7	9.87×10^7	9.80×10^7	9.93×10^7
Guaranteed UA (Btu/hr°F)	9.29×10^7	9.29×10^7	9.29×10^7	9.29×10^7

Table 10
Corrected Data and UA Calculations for Comparisons to Best Estimate Performance for McGuire Unit 1

Parameter	Loop A	Loop B	Loop C	Loop D
Corrected Hot Leg Temperature (°F)	613.28	612.026	612.639	612.281
Cold Leg Temperature (°F)	555.152	555.517	555.576	555.537
Feedwater Temperature (°F)	437.65	437.22	437.28	437.32
Feedwater Enthalpy (Btu/lbm)	416.696	416.425	416.491	416.545
Feedwater Flow (lbm/hr)	3.7163×10^6	3.7773×10^6	3.7743×10^6	3.7523×10^6
Steam Pressure (psig)	1009.821	1010.633	1011.27	1010.157
Calculated Steam Temperature (°F)	545.768	545.865	545.935	545.808
Steam Enthalpy @ 0.047% MCO	1192.269	1192.238	1192.217	1192.256
Blowdown Flow (lbm/hr)	0	0	0	0
Thermal Load (10^9 Btu/hr)	2.8823	2.9305	2.9278	2.9107
Measured RCS Flow (10^6 lbm/hr)	36.48	38.13	37.66	37.67
Log Mean Temperature Difference (°F)	29.457	29.356	29.502	29.337
UA (Btu/hr-°F)	9.7848×10^7	9.9826×10^7	9.9241×10^7	9.9216×10^7
Best Estimate UA (Btu/hr°F)	9.98×10^7	9.98×10^7	9.98×10^7	9.98×10^7

Table 11
Summary of Moisture Carryover Measurements at McGuire Unit 1

Calculation Basis	Test No.	SG Upper Shell Sample Source	SG Blowdown Sample Source
Forward Pumped Heater Drains	1	0.057	0.047
Forward Pumped Heater Drains	2	0.041	0.034
Moisture Separator Drains	1	0.053	0.044
Moisture Separator Drains	2	0.056	0.046
	Average	0.052	0.043



MILLSTONE UNIT 2
ST.LUCIE UNIT 1
(APPROX.540 TON DRY WEIGHT)

GINNA
(315 TON DRY WEIGHT)

CATAWBA UNIT 1, McGUIRE UNITS 1 & 2
BYRON UNIT 1, & BRAIDWOOD UNIT 1
(APPROX.400 TON DRY WEIGHT)

FIGURE 1
RSG GENERAL ARRANGEMENTS

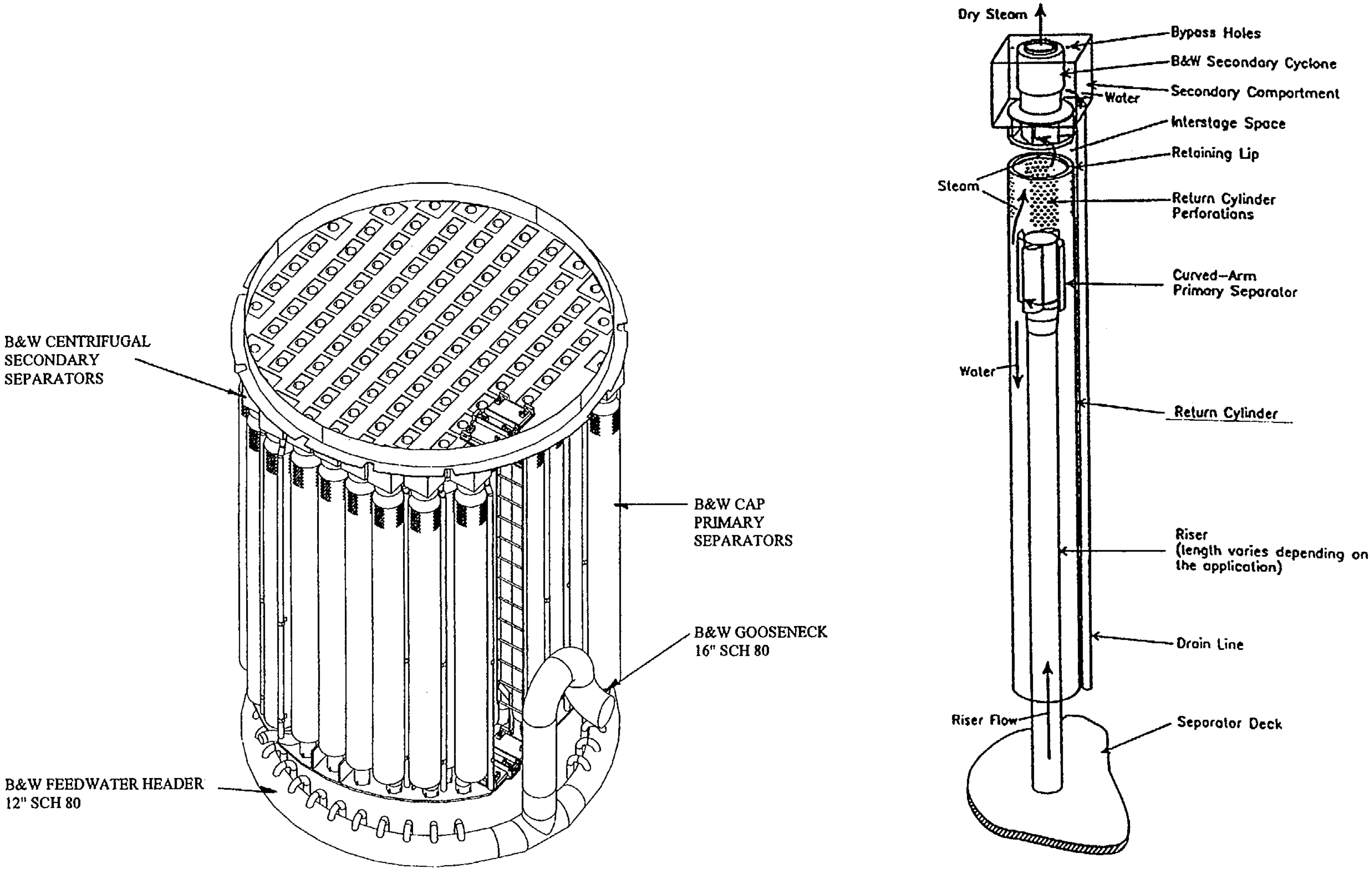


Figure 2 - Primary and Secondary Steam Moisture Separator Arrangement

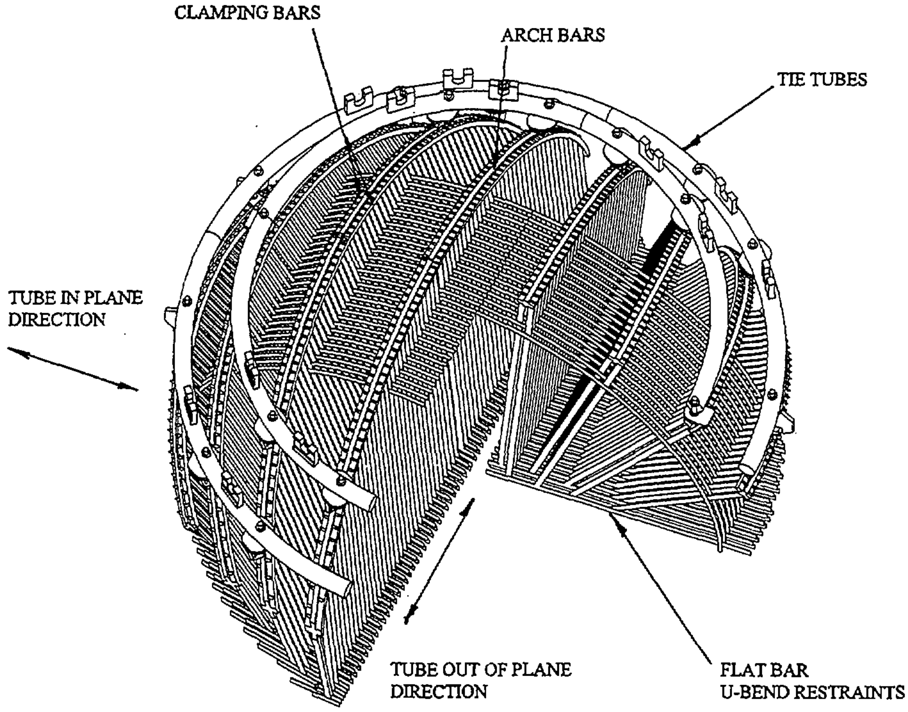


Figure 3 - Flatbar U-bend Restraint System Arrangement

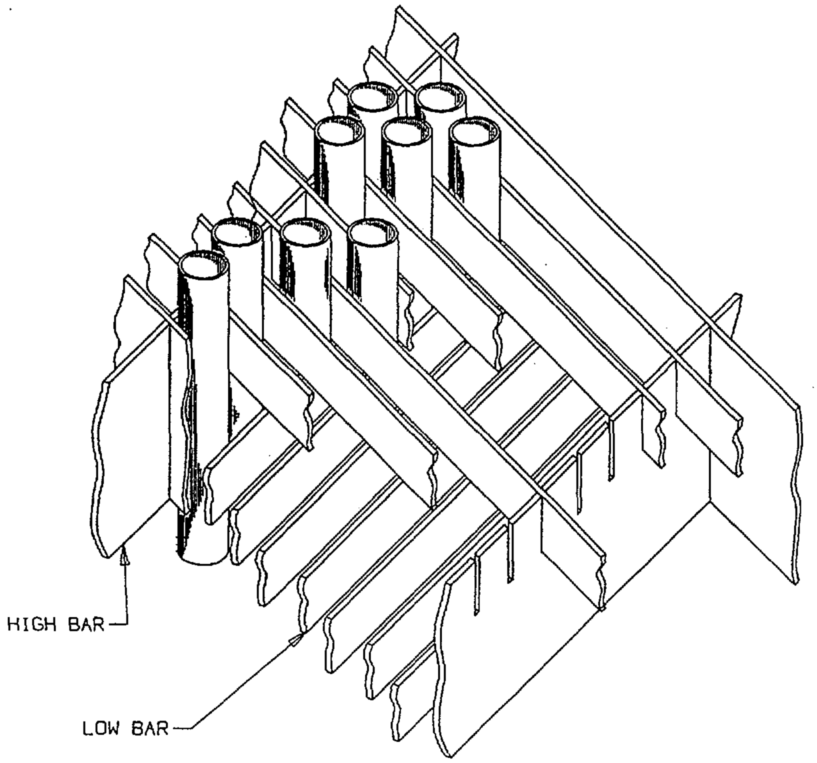


Figure 4 - Lattice Grid High Bar/Low Bar Detail

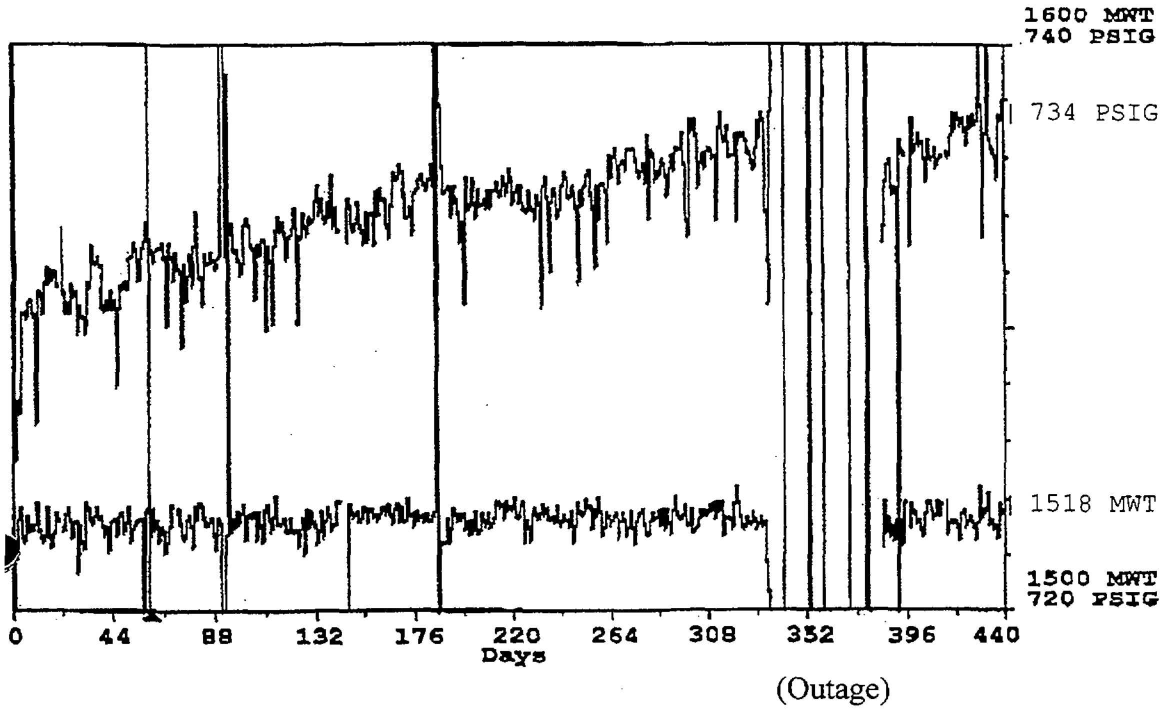


Figure 5 - Ginna RSG Steam Pressure and Core Thermal Power Trending
From 11/26/96 to 01/26/98

DISCUSSIONS

Authors: R. Klarner, F. Steinmoeller, J. Millman, W. Schneider, Babcock & Wilcox

Paper: Design and Performance of BWC Replacement Steam Generators for PWR Systems

Questioner: C. Turner, AECL

Question/Comment:

The design steam quality on the hot leg upper tube bundle is 40%, and inspection results indicate deposits are heaviest in regions where steam quality exceeds 30%. Are you expecting heavy tube deposits in the 40% steam quality region of your replacement SG's?

Response:

For a recirculating steam generator design with a circulation ratio of approximately 5.5, the maximum quality is approximately 40% and occurs in the hot leg of the U-bend region. This region is most susceptible to tube deposition and should be inspected. Simulations by BWC of the Palo Verde steam generators showed that the upper bundle region which experienced significant deposition correlates well with the region having more than 30% quality. Experimental results have also shown significant increases in deposition rates with increases in steam quality beyond approximately 30%. See Turner et al. "Reducing Tube Bundle Deposition with Alternative Amines" (Session 3).

Questioner: B. Bussy, EDF

Question/Comment:

How do you explain the increase of pressure during the first cycle?

Response:

Increases in pressure have been observed in other stations and is the result of increased nucleation sites relative to clean tubes. See Kreider et al. "A Global Fouling Factor Methodology for Analyzing Steam Generator Thermal Performance Degradation" (Session 3) for a discussion of other stations with similar results.

Questioner: S. Buhay, Ontario Hydro

Question/Comment:

For the B&W RSG "D" Style design with the "U-bend Flat Bar Support System", what stabilizer approach is recommended when a primary side tube removal is performed?

Response:

The question is understood to relate to the need for vertical restraint where a tube section has been removed and may require stabilization. Firstly, if a section of tubing is removed, the need for stabilization if any should be determined. For a situation where the remaining tube is well supported laterally, no stabilizer may be needed. Regarding vertical restraint, where a lower section of tube is removed, the remaining U-bend "cane" may remain at its nominal location or it may be left in contact with a vertically adjacent neighbour. Restoring the U-bend cane to position, verifying position and securing it is a complex and tedious activity. Allowing the cane to remain in contact with its in-service neighbour is considered to be an acceptable condition and precludes the need for vertical stabilization (W. Schneider, Babcock & Wilcox).

Questioner: K. Bagli, OH/SESD

Question/Comment:

For the Millstone Inspection Results, you mentioned sludge particles ¼" by ¼". I would not refer to these as particles. Do you know the nature and origin of these particles?

Response:

Millstone inspection reports referred to the ¼" x ¼" particles as sludge 'rocks'; however, the report noted that they disintegrated under light pressure during retrieval attempts. No detailed information on the nature or origins of these particles was available.