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Investigation Report
Calpine Russell City Steam Turbine/Generator Event
May 27, 2021

Calpine Corporation - Russell City Energy Center

Prepared For:

[redacted]
Calpine Corporation
Walnut Creek, CA

C1070-2000000013

Prepared by:	[redacted]	**Date:**	11/16/21
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1 SUMMARY

The Russell City Energy Center steam turbine and generator (STG) experienced a mechanical failure as a result of an overspeed event late in the evening on May 27, 2021.

Calpine contracted with Structural Integrity Associates, Inc. (SI) to perform an independent investigation with a focus on determining the root cause of the event. SI performed an initial onsite investigation from May 30th to June 4th, which included reviewing the condition of the STG and its support auxiliaries, examining rotor train fracture surfaces and the reheat system piping, as well as performing an initial review of the unit's operating data. At the closure of the initial onsite investigation, SI indicated that an additional inspection would be planned to take place once the STG and valves were exposed. This second onsite investigation occurred on July 26th after the steam turbine and main steam system valves were exposed.

Through review of the STG operational data, it was determined that immediately prior to the mechanical failure, the STG reached speeds equal to or greater than 146% of its rated speed. These rotor speeds are far in excess of the controller's overspeed protection settings and component mechanical failure would be expected. The radial vibration levels, as the unit accelerated from 1,950 RPM to near the rotor's ultimate speed of greater than 5,250 RPM, remained at acceptable operation levels. This lack of elevated vibration levels indicates that the rotor and bearings were in mechanically sound condition even under excessive speeds. Consistent with this conclusion, the shaft fractures lacked indications of pre-existing flaws or fractures. Therefore, no additional effort was expended to determine the exact nature of how the rotor fractures occurred as this was not required to carry out the causal analysis of the overspeed event.

The overspeed was the final event in a cascade of events that led to the mechanical overload of the STG rotor. Prior to the overspeed, a water induction event resulted in thermal seizure of the intermediate pressure steam turbine #2 intercept and stop valves, preventing their closure. The water induction event also caused an increase in the rotor axial load and position, tripping the steam turbine. Leading up to the water induction event, heat recovery steam generator (HRSG) #1 was shut down (but available) for approximately two days while the plant operated in 1x1 configuration. During this time, HSRG #1 condensed an excessive volume of water at saturation temperature and was pressurized to near operating levels. This was an undetected, abnormal condition for an out-of-service HRSG.

As combustion turbine #2 was reducing load through its normal shutdown procedure, the two HRSGs equalized in pressure, initiating the induction of water from the out-of-service HRSG #1. As water passed through the #2 intercept and stop valves, the valve components were thermally distorted preventing their closure. The valve seizure was thermally induced and was not associated with a lack of periodic maintenance. Further, the valves operated as expected in the days preceding this event. The STG's primary and emergency overspeed protection triggered properly, however, were unable to prevent the overspeed due to the thermal seizure of the valves. Additionally, the water induction resulted in the trip command that led to the automated opening of the STG line breakers. With the line breakers no longer maintaining rotor speed, the continued flow through the seized valves provided the energy source to accelerate the STG into the overspeed event.

In the hours prior to the event, a small number of alarms re-occurred[1], all during operating load transition periods. These alarms provided no new event-related information to the operator and would not have prompted operator action based on the common occurrence of these alarms during transient conditions within normal operation. The first non-recurrent alarms related to the event were triggered starting at 29 seconds prior to the trip, documenting the rapid fall of the HRH steam temperature. Operator intervention at this point would not have prevented the event from occurring as the intercept valve seizure had occurred.

Based on the operation data, the accumulation of excessive quantities of water at near operating pressure within the out-of-service HRSG was primarily driven by flow and pressure supplied by the cold reheat piping across the HRSG #1 Cold Reheat stop valve. Investigation of this valve at a valve service center identified degradation of the gearbox that was observed once the gearbox was disconnected, fully disassembled, and cleaned. Testing at the service center revealed that the degradation reduced the valve stroke, which would not have been apparent during operation as the actuator attained its full stroke. With the actuator's full stroke, both open and closed actuator limit switch positions were met such that no alarms were triggered.

Since some steam valve leakage should be expected during the operation of a combined cycle plant, limited amounts of condensation within an out-of-serve HRSG are not uncommon. This water does not specifically put a unit at risk for a water induction event as HRSG heating and drain operation during a normal startup will boil off or purge a reasonable quantity of water.

Prior to the event on May 27th, the out-of-service HRSG #1 reheat system maintained elevated pressure levels and condensed excessive quantities of high temperature water within its harps. The reheat systems were not equipped by design to reliably detect the presence of water in all circumstances. Additionally, the distributed control system was not configured by design to mitigate the presence of excessive water under near operating pressure and elevated temperatures within an out-of-service HRSG. The systems' inability to detect and drain excess water under pressure and at high temperature within the reheater system is the root cause of the STG drivetrain event at Russell City Energy Center.

[1] The site recorded alarms during turning gear operation (07:30:00 5/23/21) up to the trip (23:45:03 5/27/21). The vast majority of these alarms occurred while on turning gear up through the shutdown (22:40:15 5/25/21) of block 1 (combustion turbine, generator and HRSG). The alarms that entered during this time period all occurred during normal, transient operating conditions and prior to the accumulation of water in the offline HRSG.

2 INTRODUCTION

The Calpine Russell City Energy Center is a natural gas-fired combined-cycle electric generating facility with two blocks, each comprised of one combustion turbine (CT) (nominally 200 MW each), one generator manufactured by Siemens Westinghouse, and one heat recovery steam generator (HRSG) manufactured by Nooter Eriksen, as well as a single condensing steam turbine and hydrogen cooled generator (combined drivetrain referred to as STG) manufactured by General Electric (nominally 235 MW). The net baseload rating for the facility is 572 MW and the nameplate capacity is 635 MW. The facility treats effluent water from the local sanitation district for use as cooling water and operates as a zero liquid discharge plant. The combined cycle site began commercial operation in August 2013.

At 11:47 pm PDT on May 27, 2021, a STG event occurred during a shutdown at the Russell City facility. At the time of the failure, the steam turbine had [redacted] operating hours and [redacted] starts. As a result of the event, extensive damage was incurred by the steam turbine (including both stationary and rotating members), bearings, seals, sensors, and casing components. Damage was also incurred by the generator, collector, hydrogen cooling system, and other peripheral and auxiliary systems. The common rotor between the steam turbine and generator was also fractured into multiple sections, at least two of which were found at ground level subsequent to the event.

Immediately following the event on May 27th, operators at the plant confirmed there were no injuries to on-site personnel and called emergency personnel to the site to extinguish the ensuing fire. After the fire was extinguished, and over the course of the next several days, the extent of damage was assessed by Calpine personnel. Structural Integrity Associates (SI) was contracted by Calpine to conduct an independent failure investigation and to perform a root cause assessment. SI initiated site work on May 30, 2021, and substantially completed site work on June 4, 2021. A follow-up site visit was completed on July 26, 2021. On-site personnel included:

[redacted]

Additional (remote) support for the investigation was provided by:

[redacted]

3 EVENT BACKGROUND

3.1 Steam Turbine Generator Description

An overall view of the Russell City Energy Center is provided in **Figure 3-1**; the STG is located to the west side of the two blocks. The General Electric (GE) model D11 steam turbine (ST) includes a high pressure (HP) section, an intermediate pressure (IP) section, and a low pressure (LP) section; the generator is a hydrogen-cooled, two-pole, 60 Hz machine that operates at 3,600 rpm. A schematic of the steam turbine is provided in **Figure 3-2**. The HP and IP sections share a common rotor arranged in a double-flow configuration in which the steam enters each section near the center of the rotor and flows outward towards each end (one flowing away from the generator end through the HP section and the other flowing towards the generator end through the IP section). The dual flow LP section of the steam turbine is similarly arranged, on a common shaft with steam flow from the center towards each end.

The overall design is such that main steam from the HRSGs flows into the north end of the HP turbine section and flows south, away from the generator (steam flows are shown as red arrows in **Figure 3-2**). Main steam design (nameplate) pressure and temperature are [redacted] psi and [redacted]F, respectively. The cold reheat (CRH) steam from the HP turbine exhaust flows back to the HRSGs' reheater (RH) systems, and hot reheat (HRH) steam flows back to the IP turbine section, where it flows towards the generator. Steam from the IP turbine casing (exhaust) flows through the crossover pipe and into the center of the LP turbine, where it is joined by LP steam from the HRSGs and flows in opposite directions through each set of LP blade rows, then down to the condenser (located beneath the LP turbine). When looking from the HP front standard towards the hydrogen-cooled generator, rotation of the turbine and generator rotors is counter-clockwise (also indicated in **Figure 3-2**).

3.2 May 27th Event Timeline

On the night of the event, the STG had been running in [redacted] at the time of the failure, block 2 was in operation and block 1 was offline. At approximately [redacted], the operator in the control room received a communication from PG&E Dispatch to [redacted]. At [redacted] pm, he initiated the process to shut down power production. Three additional personnel were on-site but were not in the control room at the time of the event. The operator in the control room reported spending several minutes going through a number of procedural steps that included reducing the combustion gas turbine load to [redacted] MW, changing the setpoints of the LP, HRH, and HP steam bypass systems, and verifying that the bypass valves were opening and beginning to control pressure. During the shutdown process and concurrent with the STG trip, the operator reportedly noticed that some settings and valve positions were already in the appropriate positions for shutting down. The operator stated that at this point he looked out of the [redacted] where he saw a fire emerging from the turbine deck.

[2] The facility has two combustion turbines blocks. Either or both blocks can provide steam to the STG. Based on this layout, 1x1 operating mode corresponds to one block providing steam to the STG, and 2x1 operating mode corresponds to generation with both blocks providing steam to the STG.

A separate operator was working on shutting down auxiliary systems and was located in the [redacted] area of the plant ([redacted] of the control room, and [redacted] of the turbine deck). This operator reported hearing a loud, persistent sound that resembled a small airplane. He stated that he heard two loud sounds that occurred close together, and for an instant thought that a small plane had struck the turbine deck.

Emergency personnel reportedly responded to the scene in a timely manner and executed fire suppression activities in areas near the generator. The operator located northwest of the turbine deck at the time of the event reported seeing what he believed was steam continue to emit from the turbine area for an extended period of time subsequent to suppression of the fire, but was not entirely sure whether he was observing steam or residual smoke. During and after the emergency response, other (offsite) Calpine personnel were contacted and notified of the event in order to initiate an investigation of the event as well as an assessment of the extent of damage.

3.3 Calpine's Initial Review of Operating Data

Following the event, Calpine personnel reportedly began to review operating data for the steam turbine and generator. When SI was retained, Calpine reported that their initial review of the operating data had found that a combined reheat valve (CRV)[3], which controls steam flow to the IP turbine inlet, appeared to have failed to close, and that during the attempted shutdown event, the STG rotational speed had initially decreased from [redacted] immediately prior to the failure. Calpine also reported that abnormal drops in HRH steam temperature(s) were identified in steam feeding the IP turbine. Based on Calpine's preliminary review of operating data, an important aspect of SI's failure investigation was to fully review a broader set of operating data in order to identify and evaluate potential causes of the event.

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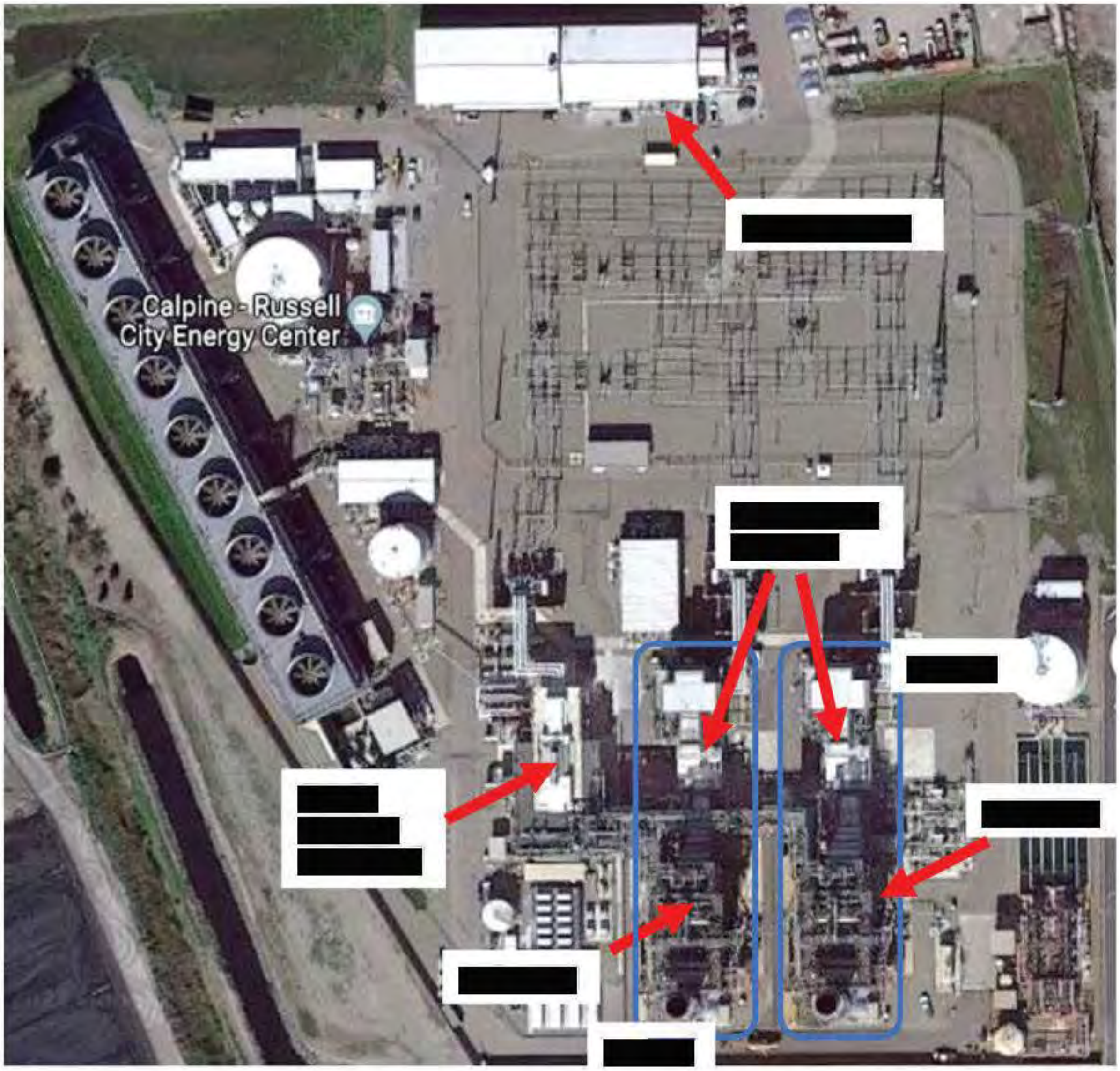
[3] The CRVs are located [redacted] These are used to control HRH steam flow to the IP turbine. When standing at the [redacted] the CRV #1 is located on the [redacted] and the CRV #2 is located on the [redacted]. Note that the CRV #'s do *not* correspond to the reheat piping lines feeding the valves from the HRSGs #1 and #2. Within this document, CRV # will be used to refer to both valves and the common body and RSV # or IV # will be used to refer to specific valves.



[redacted]

Figure 3-1. Satellite Image Showing the General Layout of the Russell City Generating Station

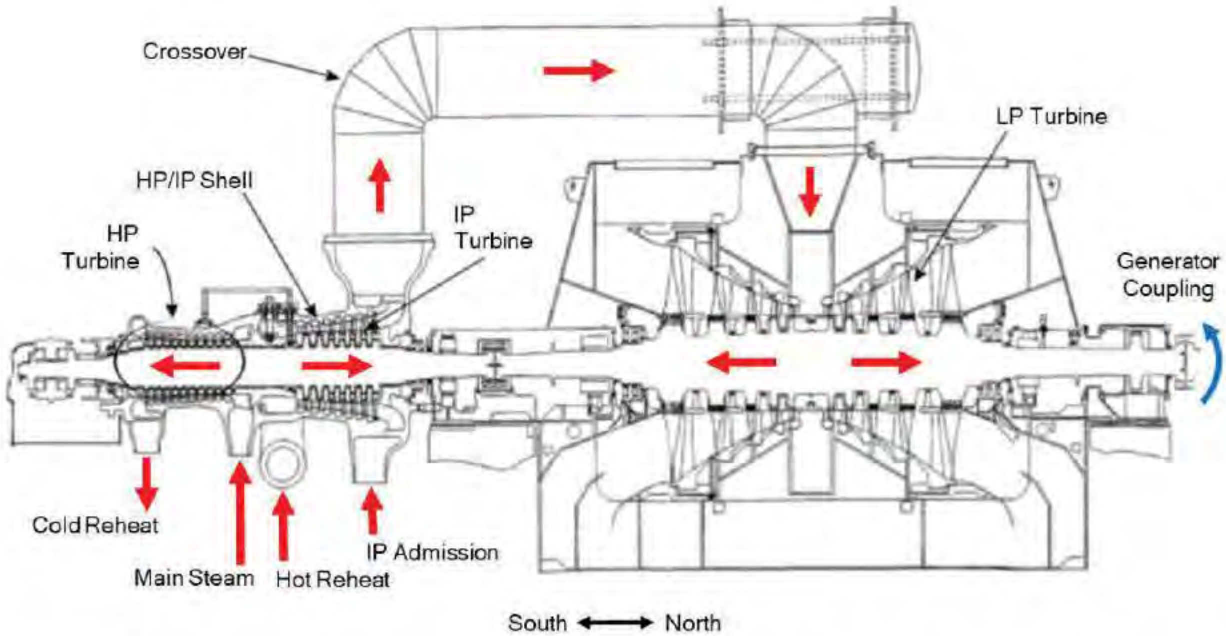


Figure 3-2. Schematic of the General Electric D11 Steam Turbine (Steam Flow Indicated in Red, Rotation in Blue)

4 POST-EVENT SITE ACTIVITIES

SI's investigation of the event was initiated at the plant site, and during the on-site effort, a number of preliminary tasks were accomplished. As discussed in the following sections, the onsite activities were partially directed by preliminary reviews of operating data and observations of visible damage and components in the initial days of the investigation.

4.1 Visual Examinations and Documentation of Damage

During the course of the event, extensive damage was incurred by the steam turbine stationary and rotating components, bearings, seals, sensors, couplings, etc. Damage also occurred to the hydrogen cooling system, the generator, the condenser, localized regions of the turbine support footing and bolting, and other peripheral and auxiliary systems. Photographs of the turbine, generator, and surrounding areas are provided in Attachment A. The turbine and generator rotor assembly fractured into multiple pieces, and several pieces, including the collector shaft, were found at ground level at various locations within the plant. Visual examination of exposed fracture surfaces on rotor sections revealed no indications of pre-existing cracks. Initial disassembly and removal of turbine components occurred while SI was on-site, but most of the deconstruction process was undertaken after SI had departed the plant site.

4.2 Preliminary Review of Operating Data

Concomitant with examinations performed prior to initiating the steam turbine and generator disassembly process, a review of operating data and the [redacted] trip log from the shutdown and event was initiated. Data related to turbine rotational speed, valve positions, bearing conditions, lube oil conditions, vibration levels, hydrogen cooling, and numerous other variables were reviewed. Collectively, the available operating data showed that during initial shutdown steps, after decreasing load on the operating CT 2 and while the plant shutdown checklist was being implemented by the control room operator, the steam turbine tripped due to the failure of the axial thrust bearing probes. This steam turbine trip initiated an automatic response of the control system that was taking place as the operator was following the standard shutdown process.

During the steam turbine trip, the IV #2 and RSV #2 failed to fully close, and as a result, the IP turbine continued to receive high pressure steam thru the partially open valves. During the initial stages of the event, the generator breaker stayed in a closed position, maintaining synchronization between the STG and the power grid ([redacted]). However, approximately [redacted] after the steam turbine trip was initiated, and with the IV #2 and RSV #2 in a partially open position, the STG line breakers opened. When the line breakers

[4] When the STG is synchronized to the power grid, the steam turbine rotor must continue to rotate at 3,600 rpm. If there is insufficient torque from the steam turbine to drive the generator and produce power, power from the grid will be consumed by the generator (reverse power or "motoring") in order to maintain the synchronized rotational speed. Note that this is an undesirable operating condition for more than a relatively short period of time.

opened, the turbine immediately began to slow at a faster than normal rate. After approximately one additional minute, the turbine rotational speed began to increase. The turbine rotational speed increased for approximately [redacted], passing the overspeed trip value setting of 3,960 rpm[5] and [redacted]; shortly thereafter the STG mechanical failure occurred.

4.2.1 *Indications of Water Induction into the Steam Turbine*

Preliminary review of the operation data identified multiple indicators that a water induction event, wherein water entered through one or both CRVs at the IP turbine inlet, had occurred. The first indicator, rapid reduction in HRH steam temperature below the normal operating temperature of approximately [redacted], indicated the presence of water in the HRH piping as it entered the IP steam turbine. Accompanying this, the second key indicator, the rapid reduction in rotor speed upon opening of the STG line breakers, provided a consistent indication that water had been inducted into the HRH steam flow path resulting in rotor deceleration much faster than during a typical shutdown. Additional indications of water in the flow path [redacted] in conjunction with a step change in the rotor axial position. Failure of the IV #2 and RSV #2 to close upon command and later closing as HRH steam temperature returned to near normal operating temperatures indicated that temporary valve thermal seizure resulted from the water induction. Review of [redacted] alarm logs also indicated alarms[6] were present indicating water detection in the RH bowl feeding the IP steam turbine based on bowl thermocouple temperature spreads.

4.2.2 *Nature of Steam Turbine Overspeed*

Steam turbine overspeed events occur for a variety of reasons and require specific investigations to determine the nature of the event. Many of these events such as a load rejection, failure of steam stop valves to close, or steam over pressure events have specific precursors visible in the operating data prior to the overspeed of the turbine. Review of the operating data in this case showed key observations that directed the nature of the forensic inspection on site:

- HRH IV #2 and RSV #2 remained partially open following the steam turbine trip while HRSG #1 and #2 RH sections were supplying pressure to the IP steam turbine after the generator breaker was opened.

- Radial vibrations remained low, even as the rotor speed exceeded overspeed (110% speed) condition. This indicated that the rotor had not experienced any significant losses of material.

As a result of these key observations, the event investigation was focused on IV #2 and RSV #2 failure to close, the source of water inducted into the IP turbine, and control logic leading to the STG line breakers opening while pressurized HRH steam was accessible to the turbine. The

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[5] At the time which the rotor speed began accelerating and passed the overspeed trip setting, the unit was already in a tripped condition.
[6] The initial [redacted] alarm indirectly indicating the presence of water, based on differential temperatures, within the ST occurred approximately [redacted] prior to the trip command. The [redacted] corresponds approximately to [redacted] as the [redacted] clock is approximately [redacted] off in synchronization to site local time.

on-site operating data review provided substantial evidence that any mechanical failures within the STG drivetrain were a result of the overspeed event and not contributors to the overspeed event.

4.3 Onsite Examination of Hot Reheat Piping

Based on the initial reviews of control system alarms and associated operating data that suggested water induction into the IP steam turbine, the HRH piping providing steam to the IP turbine (through the CRVs located on each side of the IP turbine inlet) was examined during multiple walkdowns. A schematic of the HRH piping near the STG is provided in **Figure 4-1**. Each of the two HRSGs has a HRH pipe that carries steam from the RH section of each HRSG to the IP steam turbine. For discussion purposes, the HRH piping from HRSG #1 is referred to as the HRH #1, and the HRH piping from HRSG #2 is the HRH #2. Because HRSG #2 was online and operating normally prior to the shutdown and failure event, HRH #1 was of interest as a potential source of water.

As the two HRH pipes approach the IP steam turbine, the pipes run essentially [redacted]. Near the downstream end of each HRH pipe there is a manually operated combined stop valve/check valve with a drain located just upstream of each stop/check valve. The outlet from each stop/check valve flows to a HRH header (or balancing pipe) that connects both HRH pipes, and from the header are parallel pipes that flow to the two CRVs.

While at the plant site, SI personnel requested that the drains on each HRH pipe upstream of the stop/check valves be opened to check for residual water in the system. The drain valve on HRH #2 was opened and a few drops of water emitted from the drain. The drain valve on HRH #1 was opened and flowed water steadily for approximately [redacted] minutes. Based on this observation, an additional drain located at a low point in HRH #1 pipe (situated in a [redacted] of HRSG #1 and HRSG #2) was opened; this drain emitted a strong flow of water (through a 1 inch opening) for approximately [redacted] minutes.

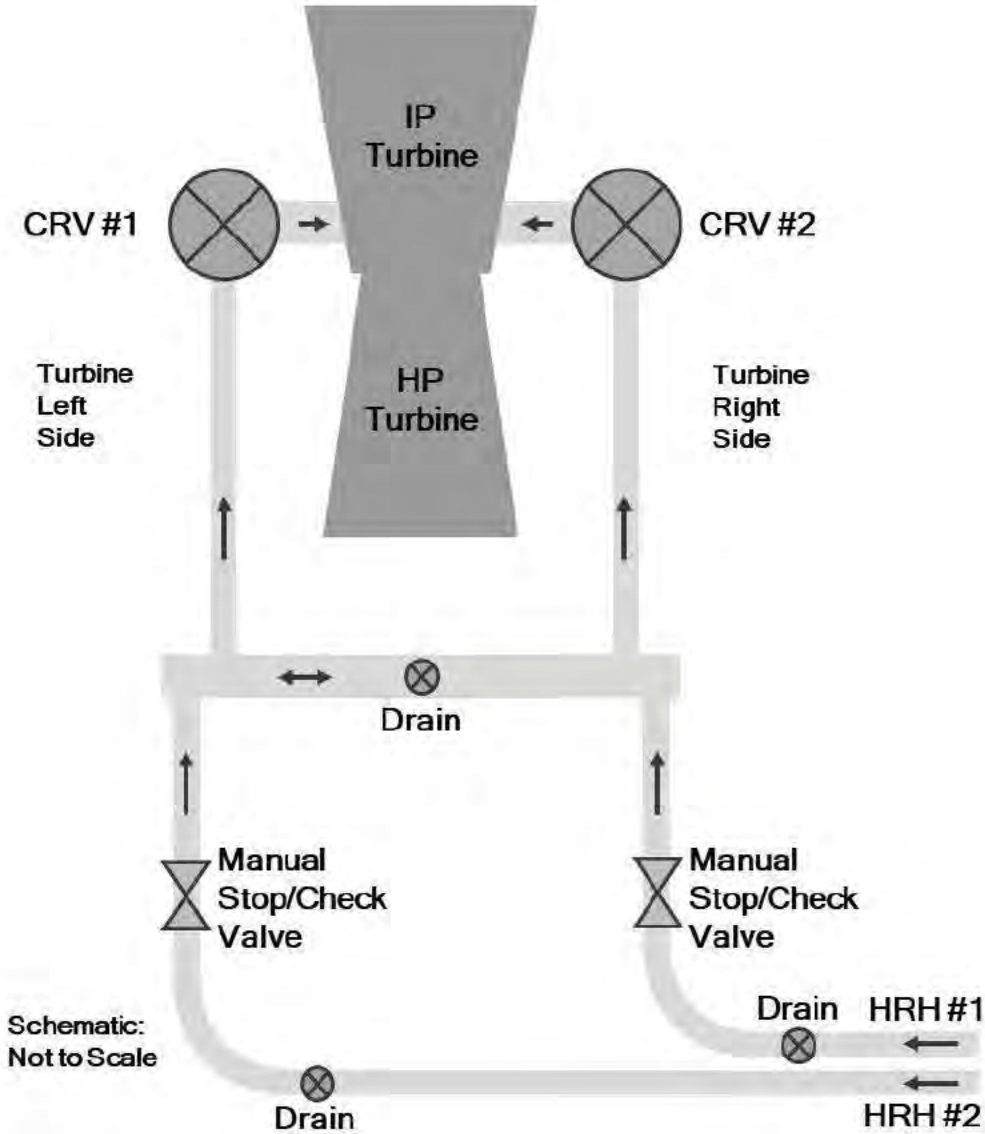

Figure 4-1. Arrangement of HRH Piping and Valves Upstream from the IP Turbine

These drain valve tests confirmed that a significant amount of water remained in the HRH #1 piping after the event. The possibility of checking for water in the HRSG #1 RH harps was discussed with plant personnel, but an appropriate drain was not present and testing was not feasible without destructively cutting into the system.

Further evaluation of water in HRH #1 was performed based on a detailed review of additional operating data obtained subsequent to the site visit. The analysis of this data is discussed later in this report.

4.4 Onsite Investigation of Steam Turbine CRVs

Operation data indicated that IV #2 and RSV #2 failed to fully close prior to the STG line breakers opening, thus allowing steam to continue to flow and resulting in the overspeed event. The CRVs were not readily accessible while the investigation team was onsite in early June. However, limited inspections were performed to support the overall investigation.

According to operation data, the IV #2 initially began throttling steam flow in coordination with IV #1. Both valves were commanded by the [redacted] controller to re-open to [redacted], IV #1 responded where IV #2 held at [redacted] open. The IVs were signaled to throttle flow a second time; IV #1 followed the command, however, IV #2 held at [redacted] open. Approximately [redacted] later the ST trip command (Axial Probe Failure) was issued from the [redacted] controller and all steam inlet valves (HP, IP and LP) closed with the exception of IV #2, which remained at [redacted] open, and RSV #2 which responded but failed to fully close, only reaching [redacted] open and remaining at that position through the event. RSV #2 and IV #2 closed on their own approximately [redacted], respectively, after the overspeed event.

While SI was at the plant site, an independent vendor performed a borescope inspection of the horizontal HRH pipe sections below the CRVs and the inlet of the CRVs, to the extent possible, via the upstream piping. The goal was to determine if foreign material was present that could have prevented IV #2 and RSV #2 from closing. No notable findings were made with the exception that the CRV #2 valve body showed indication of a greater degree of interior surface oxide exfoliation than CRV #1.

Multiple factors previously discussed suggest quenching of CRV #2's components during the water induction led to transient thermal distortion and resulted in the failure of both valves to close upon command. Therefore, further valve inspection was planned when the internal components could be exposed.

4.5 Onsite Investigation of Exposed Valves

SI completed a walk-down inspection of the exposed steam valves listed below on a return trip to site on July 26, 2021.

- Combined Reheat Valves:
  - CRV #1 (CRV-1)
  - CRV #2 (CRV-2)
- Cold Reheat Stop Valve:
  - HRSG #1 ([redacted])
- Cold Reheat Balance Valves:
  - HRSG #1 ([redacted])
  - HRSG #2 ([redacted])

Additionally, inspection reports were reviewed for the following valves:

- Combined Reheat Valves:
  - CRV #2 (CRV-2)
- HRH Manual Stop/Check Valves
  - HRSG #1 ([redacted])
  - HRSG #2 ([redacted])

Inspection pictures are included in **Appendix A**.

4.5.1 CRV Inspection

Visual inspection of RSV #2 stem documented scoring and the vendor inspection report documented excessive runout values in the IV #2 and RSV #2 stems. Run out check markings on the RSV #1 shaft were noted on the shaft as shown in **Table 5-1** and were not excessive. The RSV #2 disk and pressure seal head, as well as the IV body and basket showed signs of surface oxide exfoliation greater than that of CRV #1.

Table 5-1: Comparison of CRV Stem Runout Values

Maximum Identified CRV Stem Runout Values		
	CRV #1	CRV #2
Intercept Valve	[redacted]	[redacted]
Stop Valve	[redacted]	[redacted]

Findings from the inspection of both CRVs are consistent with those anticipated from operational data review where IV #2 began throttling after [redacted] steam temperature drop as measured in the upstream right steam pipe and the RSV action occurring after a greater than [redacted] steam temperature drop. All IV #1 and RSV #1 operation occurred while exposed to [redacted] temperature drops, respectively, as measured in the upstream [redacted] steam pipe. Temperature measurements downstream of CRV #1 and CRV #2 indicate operation of the valves occurred with up to [redacted] temperature reductions respectively.

The scoring on RSV #2 stem, exfoliation of multiple components, as well as the stem plastic deformation (measured as runout) in both portions of CRV #2 are consistent with a steam valve having experienced a large thermal transient and resulting distortion while both stems were in transient position. CRV #1 experienced a far less significant thermal transient and corresponding distortion when in operation and post event inspections had no notable findings.

4.5.2 CRH Stop Valve Inspection

Visual inspection of the HRSG #1 CRH stop valve was performed with the valve removed from the CRH pipe, in the closed position, and with the actuator removed. Visual inspection was performed as best as possible with the valve in the closed position. No significant deficiencies were observed. It appeared to be seated and no visual signs of seat or butterfly-disc damage could be observed in the as-examined position. The only item of potential significance was the appearance of a horizontal (in the installed orientation) line possibly indicating there had been an accumulation of liquid on the discharge side of the valve disk.

4.5.3 CRH Balance Valve Inspection

No notable findings were observed during visual inspection of the CRH balance valve.

5 DISCUSSION

Subsequent to the on-site work activities, the ongoing investigation involved requesting and reviewing more detailed operational data related to the failure event and prior shutdown events, and analysis of HRSG #1 operating data associated with the potential for water condensation during 1x1 operations. These are discussed in detail in the following sections.

Section 5.1 through **Section 5.8** include detailed evaluation of the site's operating data to characterize the events through documentation of their predecessors and causes. Each figure identifies points of interest within the operating data as a # and corresponding discussion for that item is identified with a corresponding (#) within the section.

5.1 Shutdown and Event Characterization

A review of basic operating parameters was performed to characterize the type and nature of the event and better direct further investigation efforts. **Figure 5-1** characterizes basic operation data prior to and during the failure event.

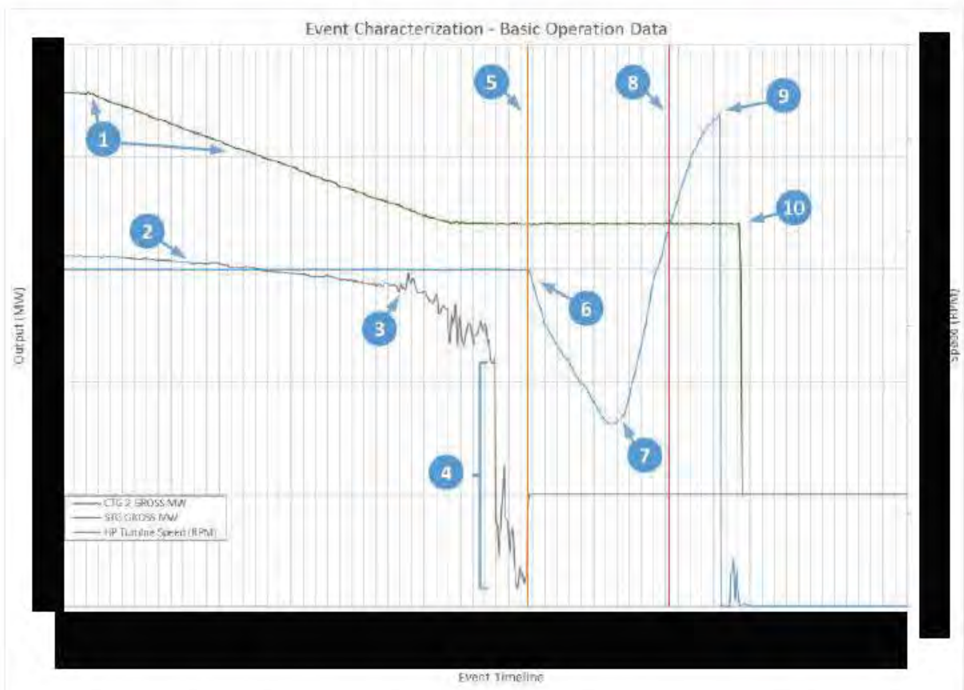

Figure 5-1 - Event Characterization - Basic Operation Data

Prior to the event and as part of the shutdown procedure, the operator initiated a (1) load reduction for CT 2 load to [redacted] MW at approximately [redacted]. As the reduction in CT output occurred, the (2) output of the STG began to decline accordingly. Both the CT and STG load reductions were smooth until approximately [redacted] when the (3) STG load began to fluctuate in an inconsistent manner with respect to the CT load reduction. At [redacted]

[redacted]
Throughout this operating period, the STG rotor speed remained at 3,600 RPM.

At approximately [redacted], the (5) STG line breakers [redacted]) opened, de-synchronizing the STG from the grid (indicated by the vertical orange line in this and future figures). The rotor speed immediately responded to the loss of synchronization by (6) dropping at a very high rate. The speed fell from [redacted] RPM to slightly below [redacted] as compared to a normal shutdown deceleration of approximately [redacted] per minute. After this rapid deceleration, the rotor began (7) accelerating rapidly, crossing the (8) overspeed limit of [redacted] (indicated by the vertical red line in this and future figures). The rotational speed registered a maximum of [redacted]. This acceleration of [redacted], which greatly exceeds typical controlled rotor acceleration of less than [redacted] per minute. The rotor speed (9) dropped to [redacted] and shortly after this, the control room operator (10) tripped CT 2 from load.

The (3) STG load fluctuation and subsequent (5) rapid rotor deceleration is indicative of a substantial change within the STG, and based on the steady load of CT 2, suggests the cause was not related to the running CT. [redacted]. This is also evident in the (6) rapid deceleration of the rotor upon (5) breaker opening. Based on this operating data, there is no indication of the cause or nature of the event, but it would indicate a significant driving force change associated with the rotating hardware within the STG.

Figure 5-2 overlays additional operating data to that presented in **Figure 5-1**. Further analysis of basic operating data adds vibration sensors to the trend to further characterize the nature of the event. It is common to review both radial and axial vibrations in the diagnosis of a turbine event as trends in this data provide primary indicators of physical changes to the rotating components. Some signals in **Figure 5-2** were multiplied as noted in the legend to enhance the visibility of changes.

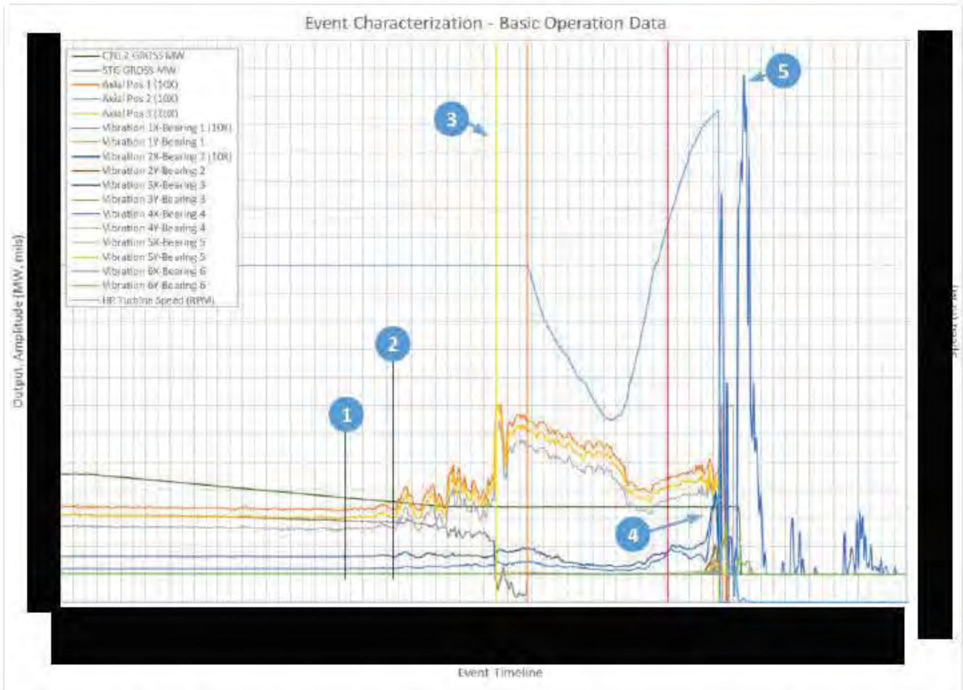

Figure 5-2 - Event Characterization - Basic Operation Data (Continued)

Minor trends (1) are visible beginning at [redacted] in **Figure 5-2** with the axial position probes and radial bearing 1X and 2X appearing inconsistent with prior operation, although these would likely not raise concern until a more significant (2) step change occurs at [redacted] within the axial position probes. The second (2) step change is consistent with STG load fluctuations identified in **Figure 5-1**.

Consistent with the load swing to reverse power, the most significant (3) axial position change occurs. At this point, a trip was initiated (indicated by the vertical yellow line in this and future figures) by the [redacted] controller. While there were minor trends within the radial vibration at this time, the magnitude of the axial change far exceeded the radial fluctuations. Pairing this axial position change with the load swing provides a strong indication that water was present within the flow path. The axial thrust of the rotor increased substantially due to the dramatic increase in the density of the ST operating fluid, [redacted]. The minimal changes in radial vibrations indicate that mass loss within the rotor train did not contribute to the event.

The first significant (4) radial vibration step change occurred after the STG exceeded 110% overspeed and (5) bearing 1X peaked approximately [redacted] after the rotor speed fell to [redacted]

[redacted]. The latter indicates that the speed sensors were likely damaged prior to recording the rotor's ultimate speed.

Review of STG basic operating data provided conclusive evidence that mechanical failures within the steam turbine and generator drivetrain are a result of and not contributors to the overspeed event. Further investigation of the sources and causes of the water induction and the rotor overspeed are discussed in subsequent sections.

5.2 Event Investigation - Vibration Predecessors

Figure 5-3 overlays key steam turbine temperature data to that presented in **Figure 5-1** and **Figure 5-2**.

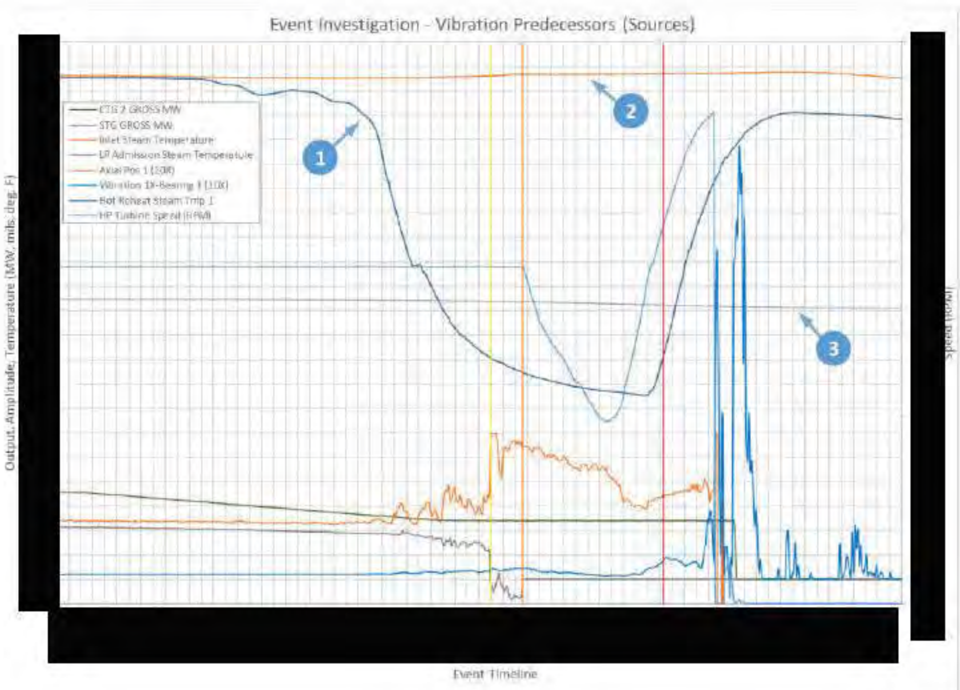

Figure 5-3 - Event Investigation - Vibration Predecessors

Based on the operational data review of STG speed, power output and vibrations, it has been identified that the overspeed event was substantially initiated by a water induction event. Review of HP, IP and LP inlet temperatures was utilized to isolate the turbine section that initially experienced this water induction. The IP section showed a significant reduction in temperature prior to the event and corresponding with the initial minor vibration trends identified in **Figure 5-2**. As shown in **Figure 5-3**, HP steam (2) inlet temperature and (3) LP admission steam temperature remained steady throughout the event, however, the (1) HRH steam entering through the right of the IP turbine showed a rapid reduction in temperature consistent with the induction of liquid water vs. steam.

5.3 Event Investigation - Overspeed Investigation

Sections 5.2 and **5.3** identified that the steam turbine trip, followed by reverse power and rapid rotor deceleration, was initiated by rotor axial position change due to a water induction event within the IP turbine section. This water induction event resulted in the rapid speed reduction of the rotor once the STG line breakers opened, however, cannot explain the following rapid acceleration and eventual overspeed of the rotor. **Figure 5.4** presents additional IP steam turbine temperatures prior to and during the failure event.

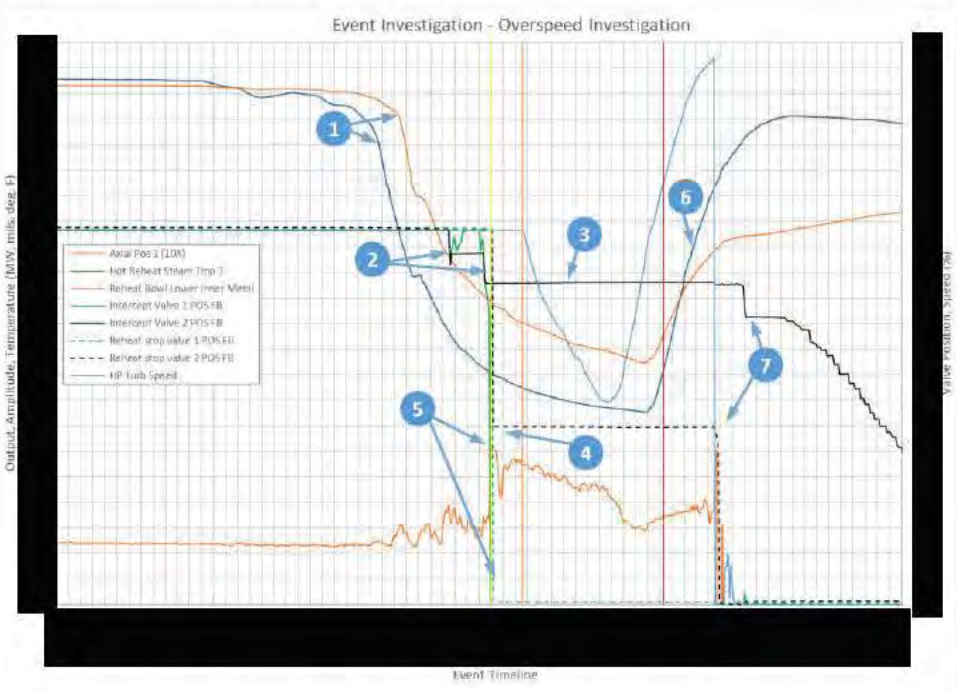

Figure 5-4 - Event Investigation - Overspeed Investigation

Figure 5-4 shows that (1) both the right HRH pipe beneath the STG and the right IP lower bowl temperatures were rapidly reduced from operating temperatures of approximately [redacted] to less than [redacted] when (2) both CRV IVs began to throttle in response to shutdown activities as described in **Section 4.4**. At this time, the right HRH pipe and IP lower bowl showed the presence of water versus the left HRH pipe and IP lower bowl, providing explanation as to why the IV #2 was (3) unable to close in response to flow throttling and RSV #2 in response to the trip command to (4) close all stop valves. At the time of the steam turbine trip, the left IP lower bowl temperature had begun to drop below [redacted] indicating a much smaller volume of water had entered through the left HRH pipe, allowing (5) IV #1 and RSV #1 to throttle and close as commanded.

As the unit over sped, the (6) steam flowing through CRV #2 returned to approximately [redacted] allowing the IV #2 and RSV #2 to close.

5.4 Event Investigation - HRH Investigation

Data from HRH thermocouples downstream of the pair of HRH stop/check valves is presented in **Figure 5-5**.

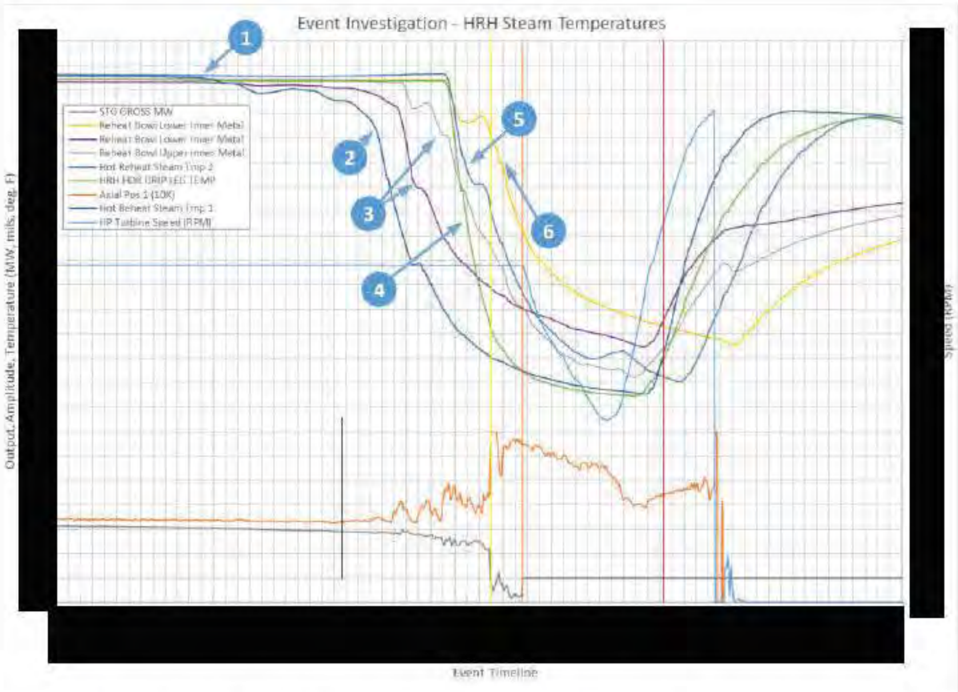

Figure 5-5 - Event Investigation - HRH Steam Temperatures

An (1) initial temperature disturbance occurred in the right HRH pipe beneath the STG prior to the initial vibration changes as previously highlighted in **Figure 5-2.** This disturbance was followed by a (2) significant drop in temperature in the same HRH pipe. Next, (3) the right, lower IP reheat bowl thermocouple, followed by the upper IP reheat bowl thermocouple, showed a sharp reduction in temperature, indicating that water was churning in the ST flow path. These significant temperature disturbances precede the axial vibration shift and the reverse power occurrence by less than one minute.

As of approximately [redacted], all noticeable activity occurred in the right side of the STG feeding up through the vertical piping leg and through CRV #2 into the IP steam bowls. The next indication of water within the steam piping is in the (4) HRH header drain between the right and left vertical CRV inlet piping. The drain temperature drop is followed quickly by a rapid temperature reduction in the (5) left vertical pipe leading to CRV #1. After there is an indication in both vertical pipes, (6) the left lower IP bowl thermocouple at CRV #1 sees a drop in temperature, indicating water mixing with steam at this location.

The HRH steam temperatures in **Figure 5-5** and the schematic in **Figure 4-1** indicate that initially water entered the right side of the HRH header and the IP turbine through the right vertical pipe and passed through CRV #2. As the right steam temperature dropped to saturation temperature (based on the HRH pressure), the header drain data showed that water spread from the right HRH pipe across the header and into the left HRH pipe. The schematic shows that HRH pipe

#1 from HRSG #1 aligns closely with the right vertical pipe leg leading to CRV #2 and that this side of the header would naturally pass water first if the HRH pipe #1 was the source of water. Further investigation of the HRH pipe #1 and #2 and HRSG #1 and #2 temperatures follow in subsequent sections to document the source of water involved in the induction event.

5.5 Event Investigation - Water Source Investigation

Figure 5-6 compares the HRSG outlet temperatures to thermocouples downstream of the pair of HRH stop/check valves shown in **Figure 5-5.**

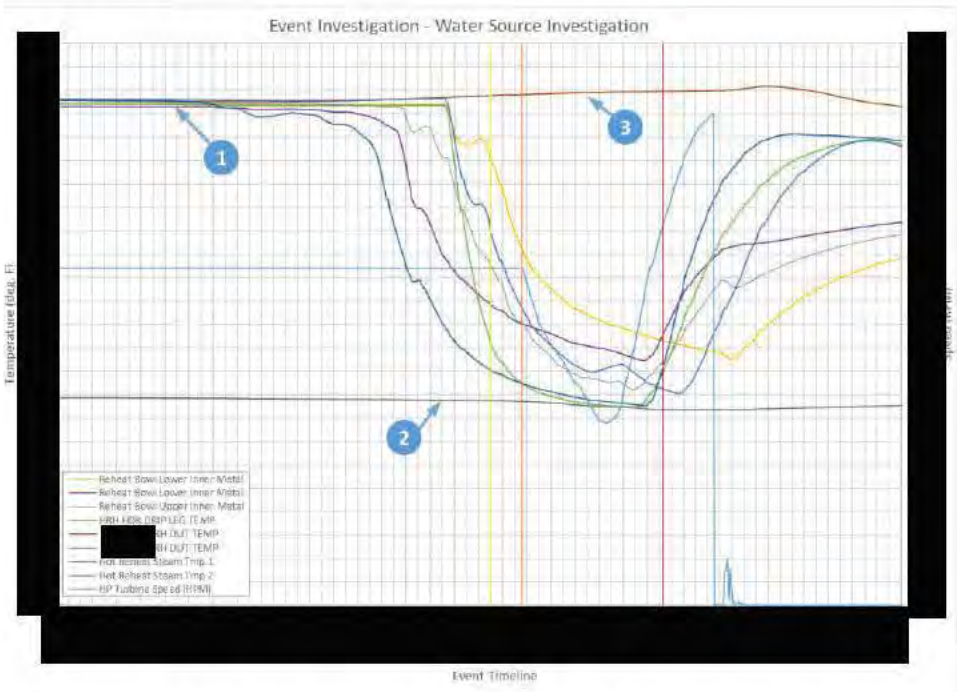

Figure 5-6 - Event Investigation - Water Source Investigation

During the initial shutdown of CT 2, (1) all left and right HRH pipe and reheat bowl thermocouple temperatures are aligned with the (3) output temperature of HRSG #2 RH, which was in service at the time. As the temperatures of the HRH pipe and IP bowls dropped, those temperatures became consistent with the (2) output temperature of HRSG #1 RH, which was out of service at the time. The HRSG #2 HRH outlet temperature remained at a (3) relatively consistent temperature throughout the event and only began to fall once CT 2 was tripped by the control room operator. This data gives a clear indication of the source of water in the water induction event is HRSG #1 RH and associated piping.

Since HRSG #1 was out of service at the time of the event, additional investigation into why water was present in HRSG #1, and what caused the induction of water into the active steam path, is detailed in the following sections.

5.6 Event Investigation - Water Induction Investigation

Figure 5-7 compares the inlet and outlet pressures HRSG #1 and #2 operating data as block 1 was reducing load.

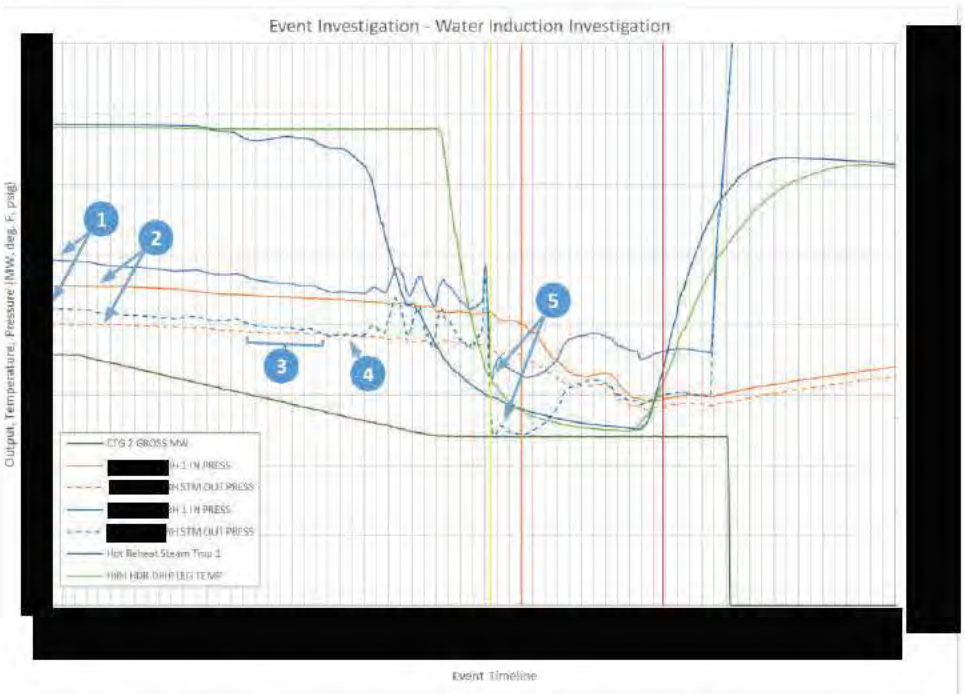

Figure 5-7 - Event Investigation - Water Induction Investigation

During normal operation prior to the event, (1) the inlet and exit pressures of HRSG #2 RH were greater than the (2) corresponding pressures of HRSG #1 which was out of service. As CT 2 load was reduced as part of the normal shutdown sequence, both (3) HRSG #2 RH inlet and outlet pressures declined with reduced CT output / exhaust temperatures, as expected. Later in the shutdown, the (4) outlet pressure of HRSG #2 RH drops below the outlet pressure of HRSG #1 RH, and the timing of this is consistent with the HRH #1 pipe showing the rapid temperature reduction. Immediately prior to the steam turbine trip, (5) both the inlet and outlet pressures of HRSG #2 RH drop below the corresponding pressures from HRSG #1 and remain below for approximately 1 minute.

As the HRSG RH outlet pressures close in (3) on each other and equalize (4), water is inducted into the IP ST. As the pressure of HRSG #1 is maintained above that of HRSG #2, flow from the out-of-service HRSG was permitted into the IP ST.

5.7 Event Investigation - Water Accumulation Investigation

To understand how water accumulated in HRSG #1 prior to the event, historical data for the plant was reviewed. Operating data is presented in **Figure 5-8** representing the 5 days prior to the event.

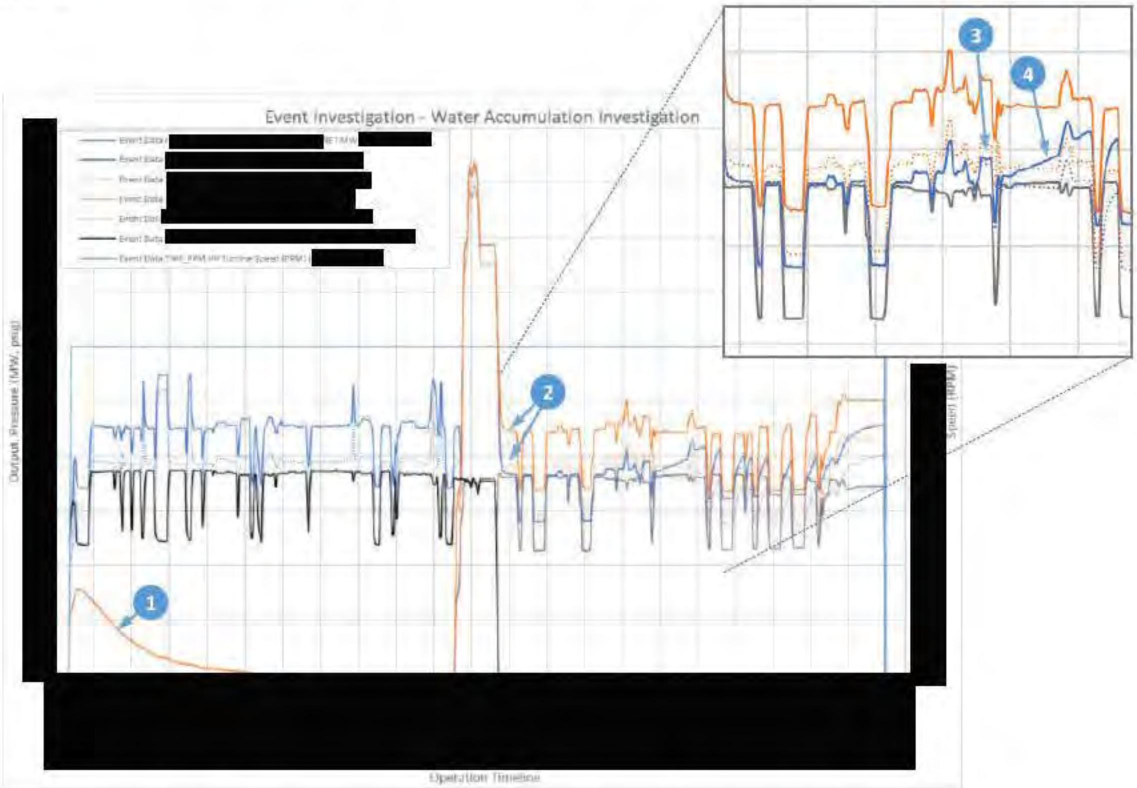

Figure 5-8 - Event Investigation - Water Accumulation Investigation

The plant operated in a [redacted]. During this time, block 1 provided [redacted] ranged between approximately [redacted] Also, during this time, HRSG #1 RH inlet pressure followed CRH outlet pressure with typical losses through piping and valves. HRSG #1 RH outlet pressure shows an average differential relative to inlet pressure of approximately [redacted], consistent with pressure losses through the reheat cycle.

Notable to the investigation, at the start of the 1x1 operation with block 1, (1) HRSG #2 RH inlet and outlet pressures increase upon startup of the STG to approximately [redacted], but this pressure decays off over the [redacted] Both HRSG #2 RH inlet and outlet pressures were equivalent throughout this time period, indicating that the RH circuit was pressurized and free of obstructions from inlet to exit.

The plant then operated a short time in 2x1 configuration with both block 1 and 2 in service for approximately [redacted]. At approximately [redacted], block 1 shut down while block 2 remained in operation until the event.

Unlike how HRSG #2 RH pressure levels decayed as HRSG #1 came online on 5/23/21, (2) HRSG #1 RH held pressure throughout the remaining operation of block 2. Initially, with block 1 offline, the differential pressure across HRSG #1 RH inlet and outlet locations remained very low [redacted], which indicates unobstructed flow of steam through the reheater circuit. However, at approximately [redacted], the (3) HRSG #1 RH inlet pressure began to rise, holding an increased level of pressure over the HRSG #1 RH exit. The (4) HRSG #1 RH inlet pressure continued to increase, driving towards the CRH pipe pressure through the remaining operation, with the exception of CT 2 load reductions, which also dropped the CRH pressure.

The RH sections of the HRSGs are comprised of 3 harps as depicted in the Nooter Eriksen P&ID drawing excerpt provided in **Figure 5-9**. While not in service, meaning no heat input to the HRSG, the inlet and outlet of the RH circuit should have no obstructions that could cause a differential pressure to develop across the circuit. When in operation, the temperature of steam flowing through the RH circuit increases from the inlet to the outlet as depicted in **Figure 5-9**, with the inlet pressure corresponding to the CRH pressure (HP turbine exhaust) and outlet pressure set by the CRV and IP turbine load. For a differential pressure to exist across the HRSG #1 RH circuit with block 1 out of service, there would have to be a source of pressure and a flow obstruction to prevent free flow through the harps.

[redacted]

Figure 5-9 - Nooter/Eriksen RH P&ID (Ref: [redacted])

Review of the same timeline with HRSG #1 RH temperatures, **Figure 5-10** provides the necessary details to identify how obstructions within the RH harps were created.

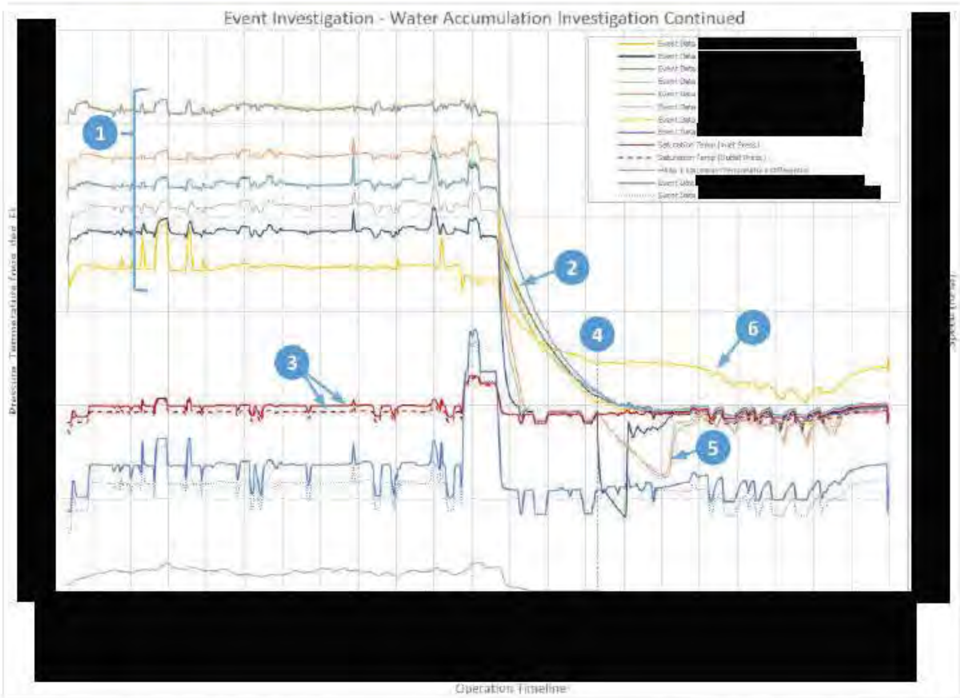

Figure 5-10 - Water Accumulation Investigation Temperature Plot

Temperature traces (1) show representative temperatures through the RH circuit including the inlet, 3 harps, and outlet; these traces show that the RH steam was steadily increasing in temperature when HRSG #1 was in service. These temperatures (2) decline after HRSG #1 is taken out of service. RH harp 1 drain ([redacted]) temperatures, followed by harp 3 drain ([redacted]) temperatures, decline first, followed by drops in temperature at the upper region thermocouples.

To aid in the investigation (3) the steam saturation temperature was calculated based on the HRSG #1 RH inlet and outlet pressures and trended through the operation period. The 3 drains identified above quickly dropped in temperature to the saturation temperature after the unit shut down. Approximately [redacted] after block 1 shut down, (4) RH harp 1 drain temperature dropped below the steam saturation temperature, quickly followed by the (5) RH harp 3 drains. This indicates that steam condensed within the HRSG. Approximately [redacted] later, the HRSG #1 RH inlet and outlet pressures began to separate, indicating that a sufficient amount of water had accumulated in the lower turns of the harps to form loop seals, as depicted in **Figure 5-11,** and was preventing free flow through the circuit.

The presence of small amounts of water within an offline HRSG is not necessarily intended, but on its own, is not capable of resulting in a significant water induction event. The warming through CT startup and startup drain will typically boil off and purge small levels of residual water within the HRSG. The HRSG #1 RH condensed water within the harps for greater than [redacted] prior to the event, as shown in **Figure 5-10**. The RH also maintained approximately [redacted] of its typical operating pressure prior to the formation of the loop seals, and the inlet pressure reached [redacted] of typical operating pressure early on the morning of 5/27, followed by meeting typical operating pressures hours before the event.

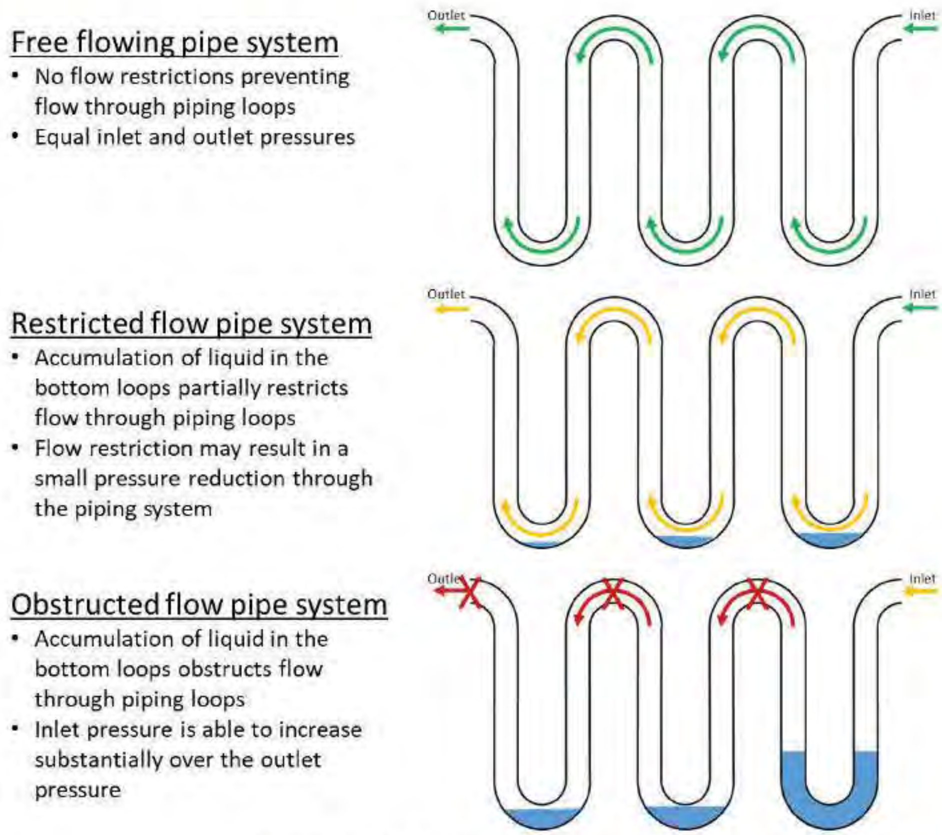

Figure 5-11 - Loop Seal Depiction

Along with this maintained pressure, the temperatures within the RH system were at or near saturation temperature. The maintained pressure acted as one force driving accumulated water into the IP ST via the HRH pipe when the exit pressure of HRSG #2 dropped. The second driving force was the additional pressure created as portions of the high temperature water boiled off (flashed) and expanded as the HRH header pressure dropped.

A significant source of steam was required to condense enough water within the RH harps to form loop seals. Additionally, this source maintained near operating levels of pressure within the out-of-service HRSG and near boiling temperatures at that eleveted pressure. Potential sources of steam are discussed in the next section.

5.8 Event Investigation - Water Accumulation Steam Source Investigation

Review of Russell City Energy Center Main Steam P&ID drawings [redacted] through [redacted] and the HRSG P&ID drawing [redacted] through [redacted] for sources of steam flow to HRSG #1 RH identified the following potential sources (•) and flow monitoring devices(○) (listed in the order of steam flow from the HP ST):

- Flow from the CRH piping through HRSG #1 CRH SV
- Flow into CRH piping from the HP Bypass
- ○ CRH Flow Balance Flowmeter
- Flow from the HRSG #1 CRH Blowdown Tank[7]
- Flow into HRSG #1 RH from the IP Superheater
  - ○ IP Superheater to CRH Flowmeter
- Drain piping and vents within HRSG #1[7]
- Reverse flow into HRH pipe from HRSG #1 Bypass to Condenser[7]
- Reverse flow into HRH pipe from HRSG #1 Vent Stack[7]
- Reverse flow into HRH pipe from HRSG #1 Blowdown Tank[7]
- Reverse flow from the HRH header through the HRH stop/check valve

5.8.1 Forward flow into HRSG #1 RH

Figure 5-12 provides a view of flow into both HRSGs during the operation time period prior to the event.

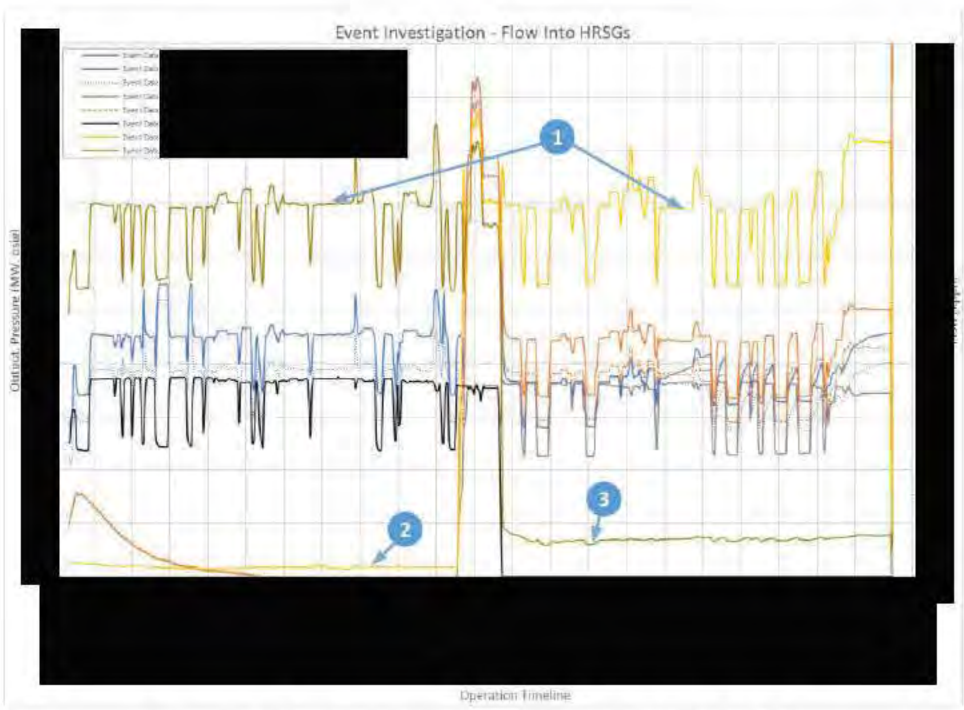

Figure 5-12 - Event Investigation Flow into HRSGs

The CRH Flow Balance Flowmeter is in-line downstream of the HRSG CRH SV, CRH flow balance valve and HP bypass piping. As shown in **Figure 5-12**, (1) both HRSG #1 and HRSG

[7] Vent stacks, drains, condenser and blowdown tanks were reviewed and excluded due to an inability to support pressure and temperature documented in **Figure 5-8** and **Figure 5-10**.

#2 recorded approximately [redacted] of steam flow during steady, full load operation. While low levels of flow through the flowmeters are unlikely to provide accurate readings, a relative comparison can be drawn between the offline CRH flow into the HRSGs. While offline, (2) HRSG #2 showed approximately [redacted] where (3) HRSG #1 recorded [redacted].

Plotted in **Figure 5-13**, the pressures upstream of HRSG #1 are shown for the (1) CRH pipe upstream of the CRH SV, (2) HP bypass system (plotted on the secondary Y scale), (3) CRH flow meter, (4) IP superheater, and both the (5) RH inlet and outlet. Initially, after the shutdown of block 1, the HP bypass system remained at approximately [redacted]. However, after approximately [redacted], the (6) pressure bleeds off to less than [redacted]. Throughout the majority of block 2's operation, both CRH pipes remain at approximately [redacted]sig with the exception of the [redacted] prior to the event where the pressure (7) increases to approximately [redacted] without a load increase on CT 2.

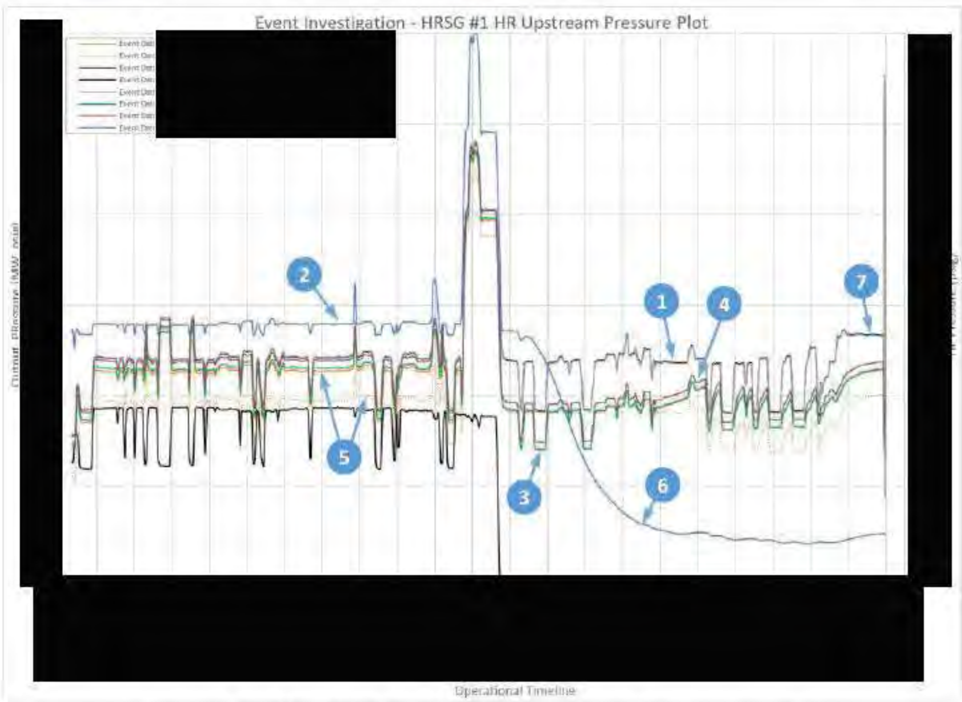

Figure 5-13 - HRSG #1 HR Upstream Pressure Plot

Flow into HRSG #1 RH from the CRH pipe was documented to remain at approximately [redacted] greater than flow into HRSG #2 when similarly offline. The 3 potential sources were assessed as follows:

- Flow from the CRH piping through HRSG #1 CRH SV
  - The (1) CRH pipe upstream of the CRH SV remains at a higher pressure than the (3) CRH pipe leading to the RH system throughout the duration of operation.
  - The CRH upstream pressure fluctuates with operation of block 2 and pressures downstream of the CRH SV follow these fluctuations. This pressure association appears to indicate flow across the CRH SV.

- The CRH SV supplies both the needed pressure and temperature to condense water in HRSG #1 RH and maintain the pressurization and temperature {**Figure 5-14** (1) and (2)} from the inlet side of the RH.

- Flow from the CRH piping from the HP Bypass
  - Initial equalization of the (2) HP bypass system is likely to have provided flow into the CRH piping upstream of the CRH valve for up to approximately 16 hours through the HP bypass control valve or its warming line.
  - After this timeframe, however, the system (6) pressure dropped below the CRH pipe pressure, at which point the direction of flow would have reversed back into the HP bypass system.
  - The HP bypass flow enters downstream of the CRH SV but upstream of the CRH balance flow meter. The temperatures of the HP bypass {**Figure 5-14** (4)} are cooler than both of these temperature readings for the majority of the block 2 operation. This indicates the HP bypass is not contributing significant flow for the duration HRSG #1 is out of service, otherwise, the CRH balance flow meter would have recorded a temperature at or below the HP bypass temperature.
  - While the HP bypass initially provides steam flow and pressure to the CRH pipe, that flow reverses backwards into the HP bypass system early in the HRSG #1 offline period.
  - It should be noted that the bypass warmup lines are expected to be similar for both units, and operation of HRSG #1 with HRSG #2 offline did not result in a significant pressurization of the HRSG #2 RH.

- Flow into the HRSG #1 RH from the IP Superheater
  - The IP superheater feeds into the CRH pipe downstream of the CRH flowmeter and has a flowmeter of its own.
  - The (4) pressure within the IP superheater (measured upstream of the flow meter) remains slightly above the CRH pipe pressure, however, the pressure of the IP superheater itself is approximately 150 psig lower than CRH pressure.
  - Based on the low supply pressure from the IP superheater and the {**Figure 5-14** (3)} temperatures within the IP superheater piping, it is unlikely that this contributes any significant steam flow or pressurization of the HRSG #1 RH.

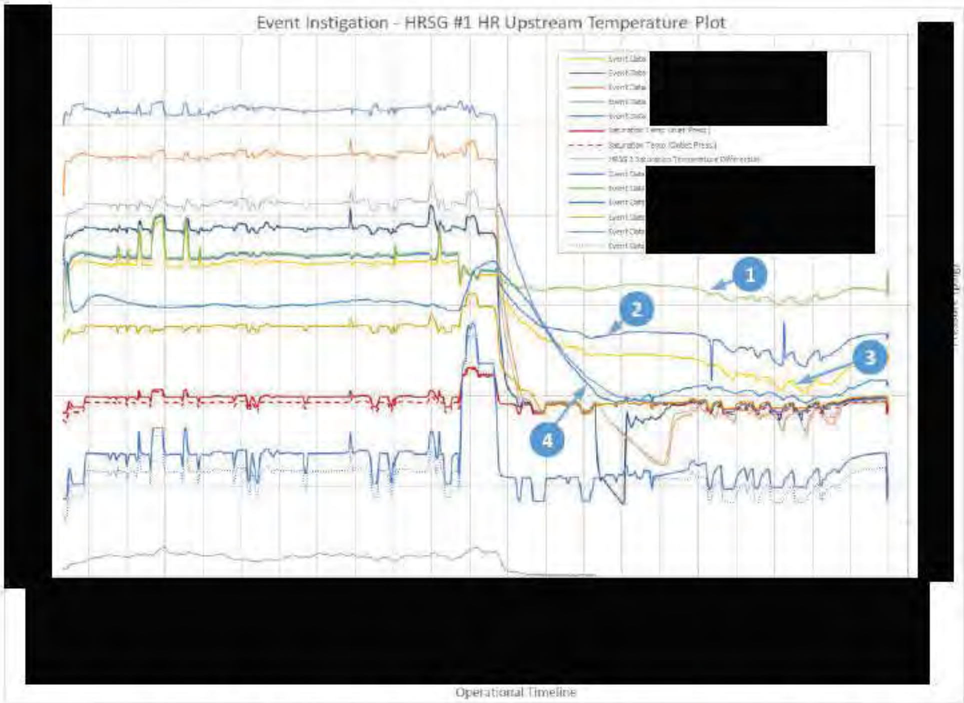

Figure 5-14 - HRSG #1 HR Upstream Temperature Plot

5.8.2 **Reverse flow into HRSG #1 RH**

Pressures within the HRH and CRH piping, as presented in **Figure 5-15**, further document steam flow direction within these systems.

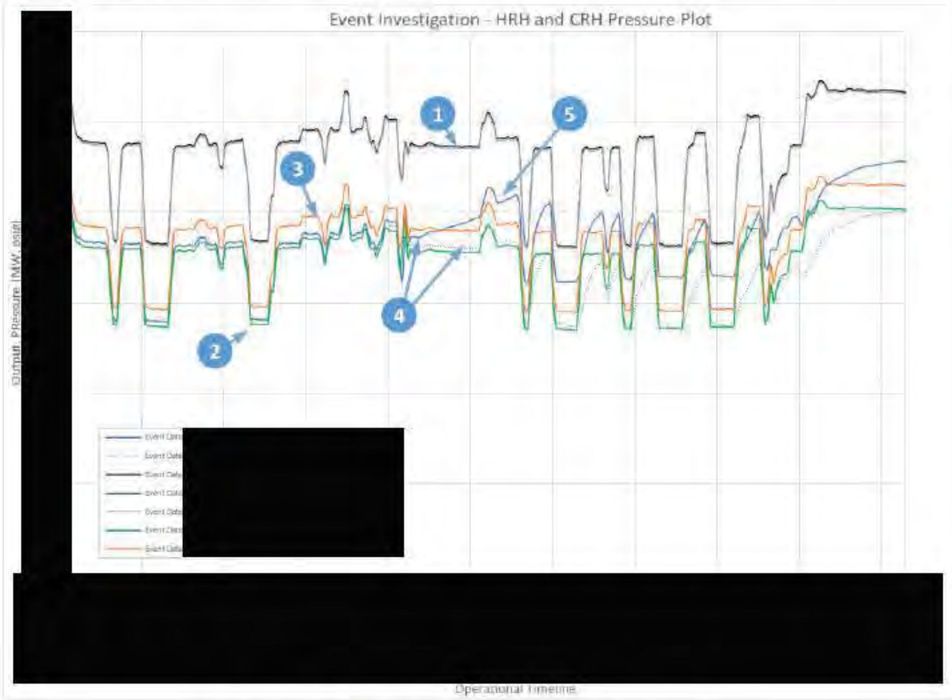

Figure 5-15- CHR and HRH Pressure

The (1) CRH pipes to HRSG #1 and #2 remain the highest pressure within the CRH and HRH piping systems throughout the approximately [redacted] of operation prior to the event. Due to flow losses in the piping and valves, (2) the inlet pressure of the IP ST downstream of the CRVs is the lowest pressure. The (3) outlet pressure of HRSG #2 RH, which is in service, is initially greater than both the (4) inlet and outlet pressure of HRSG #1 RH. However, as the loop seals form within HRSG #1, (5) the inlet pressure of the HRSG #1 RH begins to exceed the outlet pressure of the HRSG #2 RH.

Both HRSGs meet at the HRH header downstream of the HRH stop/check valves. In the event that HRH #1 stop/check valve was providing significant reverse steam flow to HRSG #1, the outlet pressure of the RH would exceed in the inlet pressure. Additionally, the inlet temperature of HRSG #1 exceeds the outlet temperature, which indicates the source of steam flow to the out-of-service HRSG is on the inlet side of the RH. This is consistent with flow recorded through the HRSG #1 CRH flowmeter as well. For these reasons, reverse flow through the HRH #1 stop/check valve was not considered as a substantial source of steam for the water accumulation within the HRSG #1 RH.

5.9 Cold Reheat Stop Valve Investigation

The HRSG #1 CRH stop valve [redacted] was removed for investigation based on continued supply of steam to the offline HRSG #1. The valve, gearbox and actuator were tested, disassembled, and inspected at a local valve service center.

5.9.1 *Cold Reheat Stop Valve Shop Investigation*

The HRSG #1 CRH stop valve [redacted]) was removed from the CRH piping for investigation and the actuator was separated while on site. Initially, the valve and gearbox were sent to Bay Valve Service center; subsequently the actuator was shipped to the service center for a complete system evaluation. Bay Valve performed inspection and testing under SI's direction.

Initial observations from the shop confirmed that the valve was capable of manual actuation from the fully opened to fully closed position. Additionally, the valve was noted to hold water in an atmospheric pressure, static water test. Externally, the valve and gearbox had no significant findings.

Upon arrival of the actuator to the shop, a visual inspection was completed with no notable findings. The actuator's controller was configured to open and close based on limit switch positions. The actuator was stroked in the stand alone configuration. During this test, the electrical current draw slightly exceeded the typical operating range.

The actuator, gear box and valve were reassembled for testing purposes. When attempting to align the three components, it was identified that the configuration prior to removal could not be recreated. When assembled, only [redacted] of stroke was achieved by the valve through the full stroke of the actuator. Due to this limited valve stroke, the assembly could be internally aligned such that the valve either fully closed, fully opened or partially stroked achieving neither full opening nor closure. Depiction of an ideal alignment as well as the former two potential alignments are shown in **Figure 5-16**.

Both the actuator and valve were disassembled with no notable findings impacting the stroke of the valve. The valve stem and yoke bearing were identified with galling damage which was noted to potentially increase actuator load but would not significantly impact the range of stroke. Disassembly of the gearbox identified a heavily damaged gear box shaft roller bearing. The bearing components had been trapped within the worm and quarter gear further damaging the gearbox. This damage increased the gearbox backlash and resulted in reduced valve stroke.

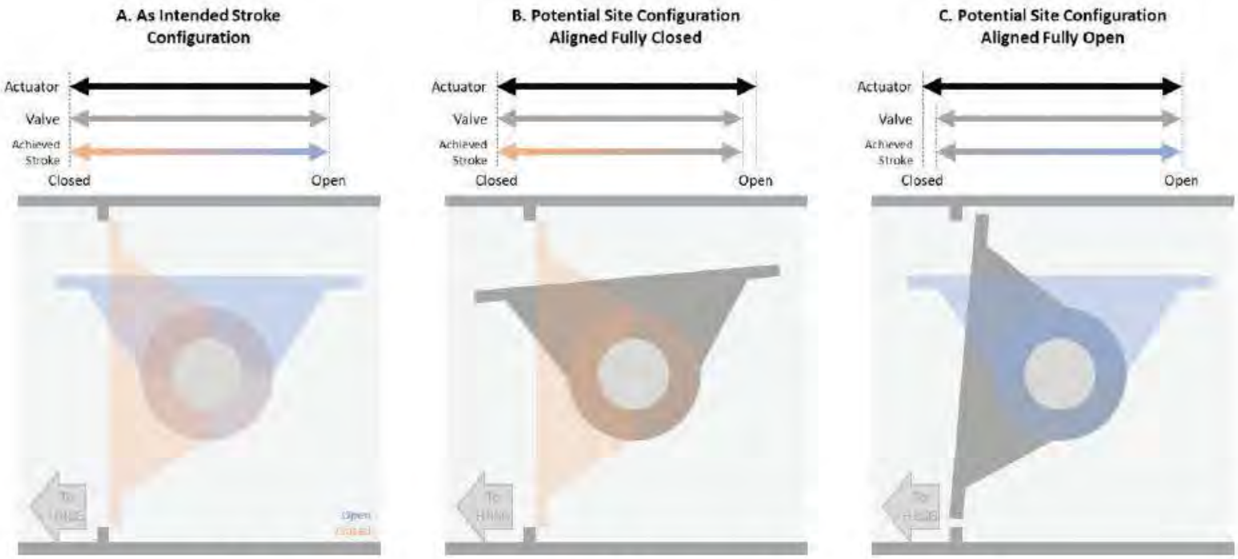

Figure 5-16 - CRH Stop Valve Component Stroke Depiction

Had the gearbox been able to efficiently translate the full actuator motion to the valve, both positions in **Figure 5-16**A. could have been achieved. The fully opened position is depicted in blue and the fully closed position is shown in orange. Intermediate positions are shown as grey in depictions B and C.

As the gearbox was unable to efficiently translate the actuator motion to the valve, Figure 5-15 depictions B and C represent possible alignments of the valve while in service. If the three components were aligned based off a fully closed position, the resulting partially opened position would have been as depicted in **Figure 5-16B**. If the three components were aligned based off a fully open position, the resulting partially closed position would have been as depicted in **Figure 5-16C**. More likely, the valve was unable to reach either the fully opened or fully closed position through the full stroke of the actuator.

The assembly actuation was tested both at shop temperatures and heated to [redacted] to simulate operating conditions. The valve was found to move smoothly throughout the actuator stroke in both tests. When configured to fully close, as shown in **Figure 5-16B**, the valve passed a graphite seat contact test and feeler gage inspection.

To perform a static pressure test, the valve was manually actuated to the closed position and tested at 250 PSI. The valve experienced significant leakage (8 oz. / minute) at 250 PSI and was unable to achieve pressurization to 500 PSI due to the leakage level. Per American Petroleum Institute (API) Standard 598 - Valve Inspection and Testing, the maximum allowable leakage for this size valve is 28 drops per minute (0.06 oz. per min) at 1,625 PSI. The test leakage equates to approximately 135 times the acceptable leakage at 15% of the API Standard test pressure.

5.9.2 *Cold Reheat Stop Valve Operation Investigation*

The HRSG CRH SV is positioned upstream of the CRH balance valve ([redacted]), the HP bypass tie-in, and the CRH Flow Balance flowmeter, all of which feed the HRSG RH. The CRH SV is intended to isolate the offline HRSG from the common CRH piping, which is active when either block is operational.

The CRH SV is configured to operate either fully opened or fully closed. The valve is configured to report to the distributed control system (DCS) when in the open limit position, closed limit position, in-motion, or when the actuator fails to actuate properly. As identified in the shop inspection, the actuator was able to stroke throughout its entire range and reach both limit positions. Therefore, prior to the event, the actuator reported to the DCS that it successfully reached both the fully opened and fully closed positions during operation. Based on the degradation of the gearbox, while the actuator reached both positions it was commanded to reach, the valve likely never fully reached either position. Since the actuator reached its limit position, no valve alarms were triggered.

5.10 [redacted] Controller Alarm Log Review

SI completed a review of the complete, historical process alarm log from the [redacted] controller including turning gear operation[8] prior to the startup on 5/23/21 through the event on the evening of 5/27/21. From the time the STG began turning gear operation to the event trip, the [redacted] controller registered 5,391 alarms. Review of operational data indicated that 39 of these alarms were raised after the accumulation of water within the offline HRSG. Relevant alarms are discussed relative to the plant operation and plotted on the operation timeline within **Figure 5-17**.

Of the 5,391 alarms experienced from turning gear operation (beginning [redacted]) up to the trip ([redacted]), the first non-recurrent alarms relevant to the event entered 29 seconds prior to the trip documenting the rapid fall of the HRH steam temperature. Operator intervention at this point would not have prevented the event from occurring.

Based on the configuration of the STG HRH #1 and #2 pipes feeding the HRH header, shown in **Figure 4-1**, flow, temperature, and pressure changes from either HRSG will affect both CRVs and the STG. However, since the individual HRH pipes are closely aligned to the right and left vertical pipe legs, temperature and pressure differences downstream of the header would be expected during transient[9] conditions as flow balances through the header. During review of the alarm log, it was not uncommon for transient conditions to result in temperature differences that triggered alarms.

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[8] STG are put on turning gear operation when offline to aid in cooling the turbine after shutdown, prevent rotor bowing when offline or on standby, and to evenly heat the rotor during startup warming. It is common for STGs with cyclic or peaker operating profiles to operate on turning gear to reduce the start time unless the unit is not planned to start for longer durations of time (typically weeks or longer). Turning gear is an electric motor rotating the STG rotor at low RPMs typically in the 4-20 RPM range, and RCEC operates at 6-7 RPM.

[9] Transient conditions are conditions where parameters (pressure, temperature and flow) within the STG, HRSG and steam piping are changing. These conditions typically occur during start-up or shutdown and load changes.

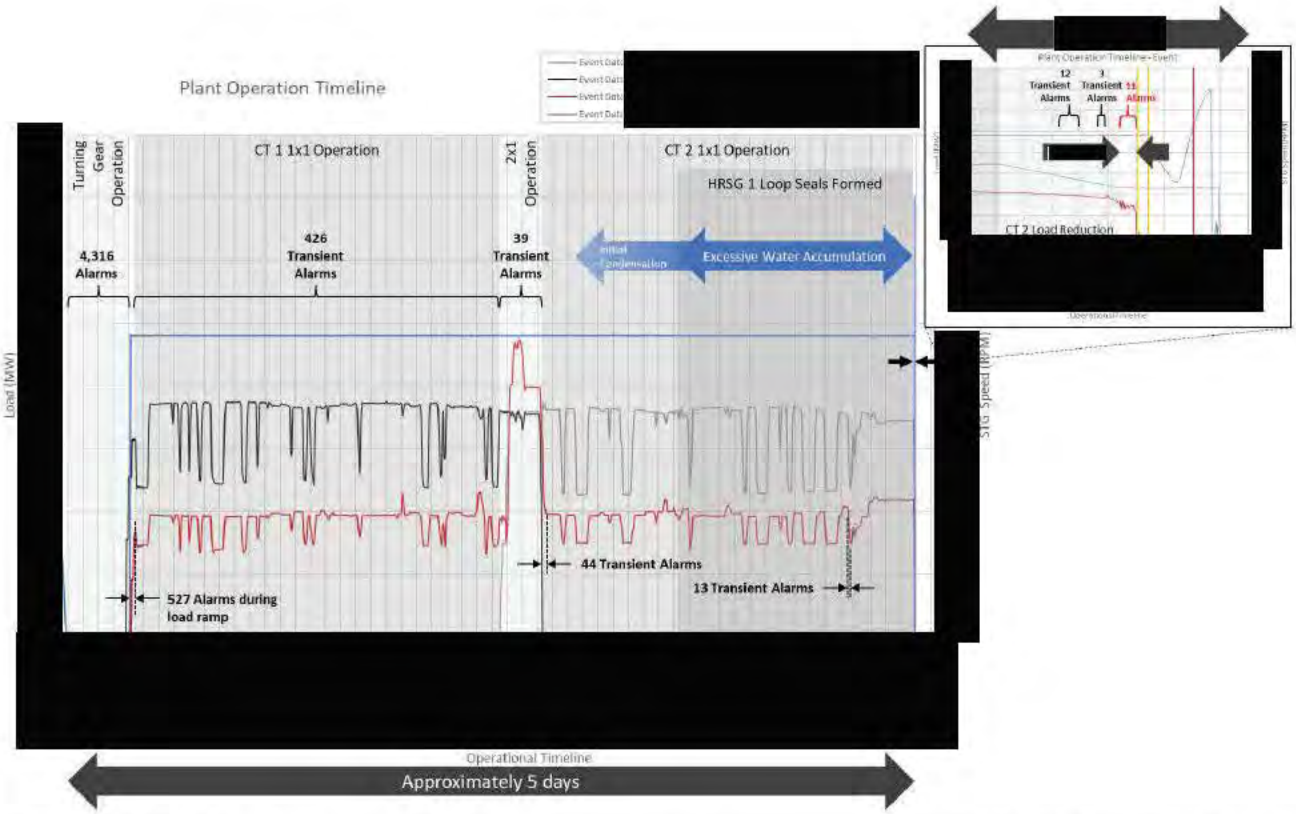

Figure 5-17 - Plant Operation Timeline ([redacted]) with [redacted] Alarm Overlay

Of the 5,391 alarms, 5,352 occurred from the start of turning gear operation up to [redacted] prior [redacted]) to the event. The 5,352 alarms occurred prior to water accumulation in offline and transient conditions and do not present abnormal operating conditions. Of these alarms, 5,308 occurred on turning gear or with HRSG 1 online in conditions that would not condense or accumulate water within the HRSG. The remaining 44 alarms occurred in 1x1 operation as block 1 was shutting down with HRSG 1 still at operating temperature. Based on the CT and HRSG operation time periods, these alarms would not have been associated with large amounts of water accumulating within the offline HRSG. These alarms are not related to the event or its precursors.

The remaining 39 alarms of the 5,391 occurred later in the 1x1 block 2 operation and after water was forensically determined as part of this investigation to have accumulated in HRSG 1. 13 of these occurred during transient operation between [redacted] hours prior to the trip. These "REHEAT STEAM TC PROBLEM" alarms indicate a temperature spread was identified in the HRH pipes downstream of the HRH header. This alarm had been experienced 304 times previously while on turning gear and in both 2x1 and 1x1 transient operation. Providing no new information to the operator on the afternoon of 5/25/21, these alarms would not have prompted operator action.

After the operator initiated the load reduction of CT 2, the same alarm repeated 12 times between [redacted] minutes prior to the trip. 3 additional alarms (1 - REHEAT BOWL LOWER TC

PROBLEM, 2 - WATER DETECT RH BOWL TEMP SPREAD EXCEEDED[10]) entered between [redacted] minutes prior to the trip. Combined, these three alarms occurred 969 times since the unit was on turning gear, and when triggered within [redacted] minutes of the event, did not present new information to the operator. Based on the transient operation and the repetitive nature of the alarms, they would not have prompted operator action.

A total of 11 non-recurrent alarms triggered within 29 seconds of the trip, including the HRH steam temperature downward trend, IV failure to respond, and axial position alarms. The HRH steam temperature alarms entered at [redacted] documenting the rapid HRH temperature fall. The next relevant alarms occurred at approximately [redacted] and were related to failure of the IV #2 to respond appropriately and the axial position trip command from the [redacted]. The axial probes failed trip alarm occurred at [redacted] Operator intervention was no longer possible to impact the event during this timeframe. IV #2 and SV #2 were seized, allowing continued flow into the IP ST, the manual HRH #1 stop / check could not have been closed, and no operator interaction could have maintained the STG line breakers in a closed position.

[10] "Water detect" alarms are based off differential temperature measurements between thermocouple pairs verses a physical detection of the presence of water. These alarms typically trigger based off differential temperature between thermocouples in the upper and lower halves of the turbine shell.

5.11 Root Cause and Contributing Factors

The Russell City Energy Center STG experienced an overspeed event including liberation of portions of the drivetrain shaft, on the evening of May 27, 2021. This mechanical failure of the STG has been determined to be a result of a rotor overspeed event where the rotor exceeded [redacted] or [redacted] of rated speed, when the speed sensors were destroyed. Review of the rotor fracture surfaces and operation data indicate, as noted in **Sections 4.1** and **5.1**, that the failure occurred as a result of the overspeed event with no indication of pre-existing flaws or mass loss prior to the overspeed event. Therefore, no additional effort was expended to determine the exact nature of how the rotor fractures occurred as understanding this failure sequence was not required to carry out the causal analysis of the overspeed event.

The rotor overspeed event occurred due to the continued flow of pressurized operating fluid to the IP ST and subsequently the LP from both the in- and out-of-service HRSGs after the control system initiated a trip and commanded all steam valves to close. The IP ST continued to receive flow due to the failure of the IV #2 and RSV #2 to close, which has been attributed to the binding of the valves' components. [redacted] Contributing to the overspeed event, the STG line breakers opened prior to the closure of IV #2 and RSV #2 based on delay logic within the protection system. With the generator no longer maintaining rotor speed of 3,600 RPM, the fluid pressure from both HRSGs could freely accelerate the rotor beyond its intended operating speed and into the uncontrolled overspeed condition. Based on feedback from Calpine, there is no indication that the STG control system failed to execute commands per the existing protection logic.

The IV #2 and RSV #2 binding occurred as a result of thermal distortion due to a water induction event from pressurized, high temperature water condensed in the out-of-service HRSG #1. HRSG #1 RH was charged to near operation pressures and maintained elevated temperatures while out of service for approximately [redacted]. Water was inducted from HRSG #1 as the RH outlet pressure of HRSG #2 decreased to a level below that of HRSG #1 RH during the normal shutdown of CT 2. Identified as a secondary factor impacting this RCA, Russell City Energy Center's main steam system was not designed with an effective means of isolating the out-of-service HRSG during routine operation[11].

The RH circuit within HRSG #1 maintained an elevated pressure and condensed high temperature water within RH harps as a result of continued flow of steam into the circuit when offline. Initially, HRSG #1 RH was supplied with steam from both the HP Bypass and the CRH SV as verified by the CRH Bypass flow meter. After the decay of the HP bypass pressure below the HRSG #1 RH inlet pressure, the CRH SV continued to supply steam to the HRSG #1 RH and maintain its pressurization. The pressures and temperatures of the CRH pipe downstream of the CRH SV remained above corresponding values at the inlet to the first RH harp. HRSG #1 condensed and accumulated water within the RH harps for approximately [redacted] while offline. Typical 1x1 operation prior to the event was less than [redacted], which is less than the duration in which the harp loop seals formed prior to the event.

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[11] Manual operation of the HRH stop/check valve to isolate either out-of-service HRSG is not practical for a plant that operates in cyclic and peaking operation. Manual operation of the HRH stop/check valve could not be performed in timely manner to prevent the event from occurring upon [redacted] alarms identifying the presence of water within the IP ST.

Investigation of the HRSG #1 CRH SV at a valve service center identified degradation of the gearbox, which resulted in increased gear backlash. This increased backlash reduced the valve's effective stroke to approximately [redacted], where a [redacted] stroke is required to move from the fully opened to fully closed position. It is likely that the increased backlash within the gearbox resulted in the valve failing to meet either position while the actuator's stroke met its programmed range indicating to the DCS the limits were met.

Due to the potential for steam valves to leak, this causal analysis focused primarily on detecting and mitigating the consequences of valve leaks that increased the site's risk of a water induction event. The HRSGs are equipped to monitor temperatures and pressures within the RH system but are not equipped by design to reliably detect the presence of water within the RH harps in all circumstances. The presence of water was forensically determined through the evaluation of historian data from multiple sensors, however there is no direct indication of the presence of water (e.g. via liquid level switch) within the DCS. In addition to the lack of capability to detect water, the DCS was not configured to mitigate, through actuation of the RH drains, the presence of excessive water under near operating pressure and elevated temperatures within an out-of-service HRSG. Respectively, the design and configuration of the HRSG and DCS failed to adequately detect and mitigate the presence of excess water under pressure and temperature within the RH system; this is the root cause of the STG drivetrain event at Russell City Energy Center.