PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEM EXCISED

Direct Testimony and Schedules
David G. Daniels

BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION STATE OF MINNESOTA

In the Matter of an Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota	MPUC Docket Nos. E002/GR-12-961 E002/GR-13-868
In the Matter of the Review of the Annual Automatic Adjustment Reports for All Electric Utilities	E999/AA-13-599 E999/AA-14-579 E999/AA-16-523 E999/AA-17-492 E999/AA-18-373
	OAH Docket No. 65-2500-38476

DIRECT TESTIMONY OF

DAVID G. DANIELS

On Behalf of

NORTHERN STATES POWER COMPANY

June 16, 2023

Exhibit___(DGD-1)

Steam Chemistry

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Table of Contents

Schedules

Resume	Schedule 1
Report on Sherco Unit 3 Water and Steam Chemistry	Schedule 2
Steam Path Diagram	Schedule 3
GEK-25407c Steam Chemistry Guidance	Schedule 4

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David G. Daniels. My business address is 1815 S. Highway 183, Suite 100, Leander, Texas 78641.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Senior Principal Scientist with Acuren Inspection, Inc. I am a recognized expert with 42 years of experience in steam and water treatment to electric utilities, pulp and paper mills, and industrial steam generators. I also have expertise in water purification equipment such as demineralizers and reverse osmosis, as well as cooling water treatment. My roles include evaluation, inspection, and training on water and steam chemistry and water-related corrosion issues.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of the Northern States Power Company, d/b/a Xcel Energy (Xcel Energy or Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. For two and a half decades, I have worked primarily with electric utilities providing independent consulting in the areas of evaluation, inspection of equipment, training, and investigation of water and steam chemistry corrosion events and failures. During my career I have visited close to 100 different power plants across the U.S. and internationally including power plants in Canada, Mexico, Saudi Arabia, Philippines, Morocco, Trinadad, Dominican Republic, and Ghana. My initial visit and often subsequent visits to many of these sites has been to perform an independent evaluation of the boiler and steam cycle chemistry at the plant and make recommendations regarding improving the water and steam chemistry program. I have published over two dozen articles as a contributing editor on water and steam chemistry topics for Power magazine. I have also authored and edited technical documents for the Electric Power Research Institute (EPRI) on water treatment equipment, steam cycle inspection, treating boiler chemical cleaning wastes, steam cycle lay-up and start up, and anime use and degradation in the steam cycle. Prior to this work, I had seven years' experience working directly in the steam cycle chemistry of a coal-fired power plant - first as a laboratory technician, and later as the plant chemist and laboratory supervisor. My qualifications and experience are more fully described on Exhibit___(DGD-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. On November 19, 2011, a failure occurred in a low pressure turbine (the Event) on the third unit (Unit 3) of the Sherburne County Generating Plant (Plant). Subsequent metallurgical analysis determined that the failure was caused by stress corrosion cracking of the rotor metal, as explained by Company witness Mr. Anthony A. Tipton. One factor that can contribute to the formation of stress corrosion cracking is the chemistry of the steam that passes through the turbine. Therefore, understanding the chemistry practices at Unit 3 is important to understanding the Event and the Company's operations leading up to the Event. My testimony will demonstrate that I have researched the plant chemistry practices, analyzed the data, and interviewed plant personnel to develop a thorough understanding of the Plant's chemistry practices specific to Unit 3. It will establish that those practices generally complied with, and occasionally exceeded, industry best practices; the Company's water and steam chemistry practices reflect that as an operator, the Company proactively took measures to ensure the proper monitoring of steam chemistry and responded swiftly and thoroughly whenever a chemical upset (water or steam chemistry analyses that were outside of the normal range) occurred. It will also establish that my thorough review of the chemistry data found that Sherco Unit 3 did not experience any significant acute or chronic contamination events that produced contaminated steam triggering a full inspection of the low pressure (LP) turbine finger-dovetail rotors between 2001 and the steam turbine failure on November 19, 2011.

Q. DESCRIBE YOUR PROCESS FOR LEARNING ABOUT, INVESTIGATING, AND ULTIMATELY REACHING YOUR OPINIONS REGARDING THE SHERCO UNIT 3 FAILURE EVENT?

A. As part of the root cause investigation following the Event, I made an extensive review of the water and steam chemistry data between the years 2000 and 2011, which the plant provided to me. Although the plant was commissioned in 1987, my data evaluation started in 2000 as this was the date of the last major LP turbine outage where the LP turbine blades were removed for inspection and then cleaned and reassembled. The data reviewed included: data on the steam purity to the turbine from the continuous on-line analyzers, test results that the laboratory performed, as well as other sources including the lab logbooks. I also had the opportunity to visit and tour the plant on at least three occasions. During these visits I spoke with Duane Wold, other lab personnel, and the control room operators about the water and steam chemistry at the plant. They were all very helpful and cooperative and answered my many questions. They also provided access to any information I requested. Details regarding my investigation, process, and opinions reached in 2016 can be found in

Exhibit___(DGD-1), Schedule 2. My opinions reached in that report continue to hold true today.

II. SHERCO UNIT 3 STEAM CHEMISTRY PROGRAM

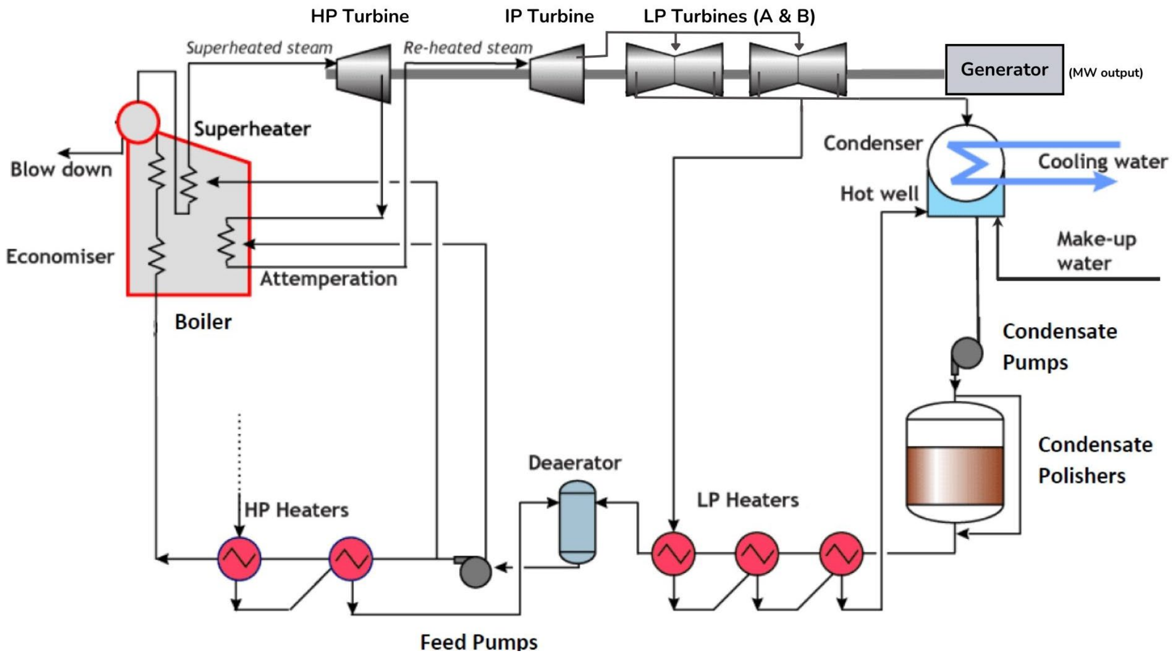
A. Steam Path

Q. WHAT IS A TURBINE STEAM PATH?

A. In a fossil fuel fired power plant, electricity is generated by using fossil fuel to heat water into steam, then sending that steam through a steam turbine which turns a generator. The generator sends electricity to transformers that send it out on the power lines that eventually reach individual homes and businesses. An illustrative diagram of Unit 3's steam cycle can be found in Figure 1 below, as well as in Exhibit___(DGD-1), Schedule 3, which provides a visual reference to assist in understanding the following testimony.

Figure 1

Diagram of Unit 3's Steam Cycle



The steam is generated in large specially designed boilers. Fossil fuel boilers operate on natural gas or coal. Sherco Unit 3 has a coal-fired boiler that generates 6.35 million pounds of steam per hour at pressures up to 2980 psi and at a temperature of 1000° Fahrenheit. The steam turbine on Unit 3, is a very large 930 MW General Electric (GE) turbine. It consists of one high pressure turbine (HP), one intermediate pressure (IP) turbine, and two low pressure (LP) turbines. These all operate together to drive the generator and produce electricity according to the requirements of the grid. The steam turbine is a very complex and high precision piece of equipment that rotates at 3600 revolutions per minute (RPM) or 60 cycles per second (Hz). There are tremendous mechanical forces and operating stresses on the turbine. Pressure, temperature, and speed are all continuously and carefully monitored.

In addition, steam chemistry parameters are continuously monitored to ensure the purity of the steam. Otherwise, impurities could collect on the steam turbine, reduce the turbine efficiency or cause corrosion that could lead to failure of the turbine. Generation of steam in the boiler and use of steam by the turbine creates a cycle where greater than 99 percent of the water sent to the boiler is reused over and over again. Once the steam has left the LP turbine it must be converted from a gas to liquid water so that it can be pumped back to the boiler where steam is generated.

In order to convert or condense the steam to water, the steam that leaves the turbine must be cooled. This is the job of the condenser. Cooling water that has a lower temperature than the steam, is sent through the inside of thousands of stainless-steel tubes. Heat transfer across the tubing causes the steam, confined to the outside of the tubes, to be condensed to extremely high purity water. As steam condenses, it shrinks in volume and creates nearly a perfect vacuum on the steam side of the condenser.

The cooling water is pumped through the condenser tubes at a rate of 335,000 gallons per minute. At this rate, you could fill an Olympic size swimming pool in about 2 minutes. With a perfect vacuum on the condenser side and pressure on the cooling water side sufficient to move the water through the tubes, there is always the potential for contamination of the high purity condensate caused by a leak in a condenser tube. Chemical monitoring is continuously performed by online instrumentation to detect even the smallest amount of cooling water contamination in the condensed steam (condensate). Additionally, at this plant, there are condensate polishers that remove trace amounts of contamination from condensate before it goes to the boiler. Should contamination be detected, alarms are set to sound in the control room to make the operators aware so that proper action can be taken to prevent amounts of contamination from reaching the steam turbine. Additional chemical monitoring is performed as the water is heated before it enters the boiler (feedwater), as well as while it is in the boiler, and as the steam leaves the boiler and before it reaches the steam turbine.

Q. WHAT EQUIPMENT IS IN THE STEAM CYCLE AND HOW DOES IT FUNCTION?

A. When it leaves the condenser, the water (condensate) is pumped through a number of heat exchangers that heat the water to about 300° Fahrenheit. This water is sent through a Deaerator that removes any dissolved oxygen or other non-condensable gases that may have been trapped in the water. After the Deaerator, the water pressure is boosted to pressures close to 3000 psi by special boiler feedwater pumps. The water is now called feedwater. The feedwater is heated further through more heat exchangers until it is close to the boiling temperature at boiler pressure. The boiling temperature of water at 2980 psi is 695° Fahrenheit. In the boiler, the burning coal provides the energy to boil the water, creating a water steam mixture in the boiler tubes. This mixture is sent to the steam drum which separates the water from the steam.

After the steam leaves the boiler, it is heated yet again, until the temperature reaches the specified temperature to enter the steam turbine of 1000° Fahrenheit. Steam that has been heated after it leaves the steam drum is called superheated steam or main steam. As the superheated or main steam passes through the turbine, the energy stored in the steam in the forms of temperature and pressure, is converted into mechanical (rotational) energy to make the turbine spin. The spinning turbine turns the generator that produces the electricity. After nearly all the usable energy has been removed from the steam by passing through the steam turbine, the steam is condensed back to water in the condenser to start the cycle again.

Q. HOW IS MAKEUP WATER INTRODUCED INTO THE STEAM CYCLE?

A. While nearly all the water that is used to generate steam is condensed and sent back to the boiler, some small amounts of water are lost through the vents, blowdowns, and sampling. This water needs to be replaced ("made up") with high purity water that was generated at the site's water treatment area. This high purity water is produced by specialized water treatment equipment that removes all of the dissolved solids or minerals from the water. Once these minerals have been removed, the water is referred to as demineralized water. A small amount of demineralized water is added to the steam cycle as needed, to maintain the required constant steam drum level. To produce this high purity water at the Sherco plant, well water first passes through a demineralizer that consists of three groups of vessels: primary, secondary, and polisher vessels. Different types of ion exchange resins (similar to the resins in a home water softener) remove minerals from the water. The produced demineralized water goes into one of three demineralized water storage tanks which are all tied together. Each tank holds approximately 260,000 gallons of water.

Q. AFTER STEAM LEAVES THE TURBINE HOW DOES IT BECOME WATER AGAIN?

A. As discussed above in the section on the steam path, once all the mechanically useful energy has been removed from the steam, it must be converted back into water to be reused. This is the job of the condenser. The condenser consists of thousands of stainless steel tubes through which cooling water is rapidly pumped. When the cooler metal surface of the outside of a condenser tube comes in contact with the hotter steam, the steam condenses into water. This is the same principle as the condensate that forms on a glass with a cold drink that is sitting outside on a hot humid day. To maintain the purity of the water in the steam cycle, it is critical that the cooling water and condensed steam stay separated.

Q. WHERE DOES THE COOLING WATER COME FROM THAT HELPS CONDENSE THE STEAM?

A. The original source of the cooling water is the Mississippi River, which flows close by the plant. The water is stored on the plant site until it is needed by the cooling tower. As the cooling water passes through the inside of the condenser tubes, it absorbs the heat of the steam on the outside of the tubes. After leaving the condenser, the warmer (approximately 10-15° Fahrenheit) water is sent to the cooling tower where it is sprayed across the cooling tower while huge fans pull air into the sides of the tower and send water vapor out the top and into the atmosphere. The most visible plume coming from the plant is the water vapor cloud generated by the cooling tower. As water vapor evaporates, salts concentrate in the cooling water. To prevent scale formation or corrosion, some of the cooling water is continuously discharged (blown down). Both the cooling water that has been lost due to evaporation and water that is blown down, are replaced by the river water that has been stored on the site.

Q. WHICH CHEMICAL SPECIES ARE MONITORED IN STEAM?

A. Because of the very large volumes of steam going through the turbine (often over 6 million pounds per hour for many years between turbine outages) steam purity it critical. For turbine metallurgy, the most critical impurities include caustic, chloride, and sulfate. The plant uses a parameter called cation conductivity to indirectly monitor for chloride and sulfate and an on-line sodium monitor for determining the potential presence of sodium hydroxide (caustic) in the steam. Cation conductivity analyzers can detect the presence of low part per billion (ppb) levels of chloride and sulfate dissolved in the steam. Sodium analyzers accurately measure sub-ppb levels of sodium in the steam. However, they cannot differentiate between different kinds of sodium salts. For example, the sodium monitor cannot differentiate between sodium chloride and sodium hydroxide.

Q. HOW CAN THE ULTRAPURE WATER IN THE STEAM CYCLE BECOME CONTAMINATED?

A. As discussed above, the condenser, with condensing steam on the outside of the tubes and cooling tower water on the inside of the tubes, is the area with the largest risk of contamination. The plant is continuously monitoring the condensate water for any contamination. Another potential source of contamination would be from contaminated makeup water should the water treatment equipment malfunction. If this equipment does not operate properly, it could contaminate all the demineralized water at the site and eventually the boiler and steam turbine. Therefore, continuous monitoring for contamination is also performed in the water treatment area that produces the demineralized water. This monitoring will shut down the water treatment equipment if contamination is detected. Since the makeup water is added to the condenser, chemical monitoring of the condensate also would detect if there were any contaminated makeup water.

Q. WHY IS CONTINUOUS MONITORING OF THE ENTIRE STEAM CYCLE SO CRITICAL TO EQUIPMENT RELIABILITY?

A. It is critical to understand that the steam cycle is just that – a cycle. When contamination enters at one location of the steam cycle, it will cause chemistry-related changes in other areas of the cycle. The same parameter, measured at a variety of sample points, will respond in a predictable way. Similarly, other parameters on the various sample points will likewise be predictably affected. When troubleshooting a high value from one or more analyzers, it is important to see if the other analyzers in the cycle are also responding in the expected manner. If not – for example, if only one instrument in the cycle is showing a higher-than-normal level – the cause is almost always because the instrument itself is malfunctioning and needs maintenance (as opposed to actual contamination). In contrast, when multiple instruments measuring the same and different parameters at various points in the cycle indicate contamination, it is almost always because there is actual contamination in the cycle. As I reviewed the historical data for Sherco Unit 3, there were periods when one parameter appeared to be out of range. When this occurred, I carefully reviewed the other parameters in the cycle. If there was only one reading out of limits at that time, it could be safely concluded that there was a problem with the instrument and not real contamination. This process – separating real contamination events from instrument problems – requires experience with the steam chemistry cycle in a power plant. I have summarized some of the changes to be expected with real contamination. *See* Exhibit___(DGD-1), Schedule 2, Table 3.

Q. EARLIER YOU MENTIONED CONDENSATE POLISHERS AT THE PLANT. WHAT PURPOSE DO THEY SERVE IN HELPING PREVENT CONTAMINATION FROM REACHING THE TURBINE?

A. As discussed previously, due to the large number of tubes in the condenser and the difference between the cooling water and the ultrapure condensate, there is always the potential for some minute amounts of cooling water to leak into the condenser. While a major condenser tube leak would contaminate the steam cycle and quickly cause an operator to shut down the plant, very small amounts of contamination can be removed by the condensate polishers until the plant can come off line and address the leak. It can be very advantageous to plant operations to have a method to remove contamination before it causes harm, while also avoiding an immediate forced outage. The polishers use a similar technology to the demineralizer. However, the polishers are actually treating the very high purity condensate and are designed specifically to remove traces of contamination. Also, once depleted, the ion exchange resins on these specific types of polishers are disposed of and replaced with new ion exchange material.

Q. WHAT IS THE PURPOSE OF BOILER BLOWDOWN?

A. In a sub-critical boiler (operating pressure less than 3200 psig) there is a steam drum. The drum contains mechanical devices that separate the boiler water from the steam. The steam generation and separation process acts like a distillation process, where soluble contaminants concentrate in the water instead of leaving with the steam. After a period of time, and depending on the amount of contamination that is reaching the boiler, any dissolved salts concentrate to the point where it is prudent to remove them from the system using a blowdown line. This line sends very small amounts of the boiler water out of the boiler and to waste. Any water discharged out the blowdown is replaced by makeup water, so that the water level in the steam drum remains constant. Makeup, in turn, comes from the demineralized water storage tanks and is added to the condenser.

Q. HOW CAN THE OPERATING PRESSURE OF THE BOILER AFFECT STEAM PURITY?

A. Sherco Unit 3's boiler is designed to operate at 2980 psig. At this pressure and with the appropriate amount of fuel being burned in the boiler, the boiler can generate sufficient steam to achieve the 930 MW of designed power output. However, electrical demand on the grid does not always require 930 MW. The power requirements of the electrical grid are changing constantly, depending on the time of day, weather, and the availability of other sources of power generation, including wind and solar generation. In cases where less load (fewer MWs) is required, the plant may reduce load by lowering the operating pressure of the boiler. The lower the operating pressure of the boiler, the greater the difference in density between the water and the steam in the steam drum. This density difference increases the effectiveness of the steam separation equipment in the steam drum, further reducing the potential for droplets of boiler water to be entrained in the steam (termed mechanical carryover). Reducing the boiler pressure also reduces the solubility of the various chemical species in the steam (termed volatile carryover). So, although sliding pressure operation of the boiler is done to control the amount of generation, it also reduces the potential for chemical contamination to enter the steam in two separate ways. EPRI has published research showing the potential for sodium hydroxide (caustic) to enter the steam is very low when the operating pressure of the boiler is less than 2500 psig. During the time between 2000 and 2011, the Unit 3 boiler often operated below 2500 psig. This would have significantly reduced the potential for any caustic in the boiler to carry over into the steam, had there been any present in the boiler.

Q. HOW CAN STEAM CHEMISTRY AFFECT STRESS CORROSION CRACKING IN TURBINES?

A. Stress Corrosion Cracking (SCC) in a steam turbine rotor occurs from a combination of the following factors: defects in the metallurgy of the rotor, the stresses that the turbine is exposed to (this includes manufacturing/design stresses and operational stresses), a corrosive environment, and time. For the GE rotor alloy, the corrosive environment that would cause SCC would be the presence of caustic (sodium hydroxide) on the rotor. The caustic would have to be present in the steam and precipitate out on the turbine blades, eventually concentrating in the highly stressed areas of the fingers of the turbine blade root. While it has been shown time and again that elevated concentrations of sodium hydroxide in steam have contributed to turbine rotor failures by SCC, the literature also states that, in the presence of sufficiently high stresses, SCC can occur in "pure water" – in other words, water (or steam) where the concentration of sodium hydroxide is so small that it could not be measured.

In a chemistry guidance document specific to the risks of stress corrosion cracking (GEK-25407c), GE admits that they do not know of a concentration of caustic in steam that can be considered safe for their tubines. *See* Exhibit___(DGD-1), Schedule 4.

B. Plant Laboratory Background and Expertise

Q. WHO WAS THE SHERCO UNIT 3 CHEMISTRY MANAGER AND WHAT WERE HIS CREDENTIALS?

A. The plant chemist during the period of 2001 through 2011 was Duane Wold. Mr. Wold worked in water and steam chemistry at the plant site since Unit 3 was started in 1987. He was very experienced in the area of water and steam chemistry and an expert in the operation of all the water treatment equipment and cooling tower operation. He was assisted by a group of chemical technicians who performed chemical testing, and chemically treated the various systems to ensure that they remained within the plant-established water and steam chemistry limits.

Q. WHAT RESOURCES, INTERNAL AND EXTERNAL, WERE AVAILABLE TO THE SHERCO UNIT 3 CHEMISTRY TEAM?

A. Should Mr. Wold have a question or need additional expertise or analytical capabilities not found at the plant, he could turn to the resources of the Company's central chemistry lab located on Chestnut Street in Minneapolis. This lab had specialized analytical equipment and expertise. Additionally, for many years, Xcel Energy had been a member of EPRI and participated in the steam cycle chemistry target providing the results of the most current research to member utilities. Mr. Wold was up to date on industry trends and research performed by EPRI. After understanding and evaluating the EPRI guidance, Mr. Wold would institute what he felt were appropriate changes to the chemistry program on Unit 3, consistent with EPRI guidance. For example, in

2000, the plant discontinued the use of a chemical in their treatment regime, consistent recent EPRI recommendations at the time.

Q. BASED ON YOUR INDUSTRY EXPERIENCE, HOW DID MR. WOLD'S EXPERIENCE COMPARE TO THAT OF OTHER OPERATORS OF COAL-FIRED RECIRCULATING BOILER UNITS?

A. In my interviews and ongoing discussion with Mr. Wold, I found him to be very knowledgeable about industry guidelines and best practices. He was extremely knowledgeable about the plant equipment, in particular the water treatment equipment, polishers and sample analyzers.

Q. WHAT ARE YOUR OPINIONS ON THE DILIGENCE AND EFFORTS OF THE UNIT 3 CHEMISTRY TEAM WITH REGARD TO MONITORING AND ADDRESSING STEAM CHEMISTRY FOR UNIT 3?

A. Both operations and the lab personnel were very diligent about monitoring the chemistry via on-line analyzers and addressing any contamination problems when they occurred. Their commitment to close monitoring of the steam cycle chemistry is demonstrated by the following: (1) every startup was manned with a lab technician until the unit was released to full operating pressure during which the technician closely monitored steam chemistry and watched for signs of any contamination, and the unit did not go to full operating pressure until the chemistry was within normal operating limits; (2) on-line analyzers were regularly confirmed by separate bench testing, including cation conductivity, specific conductivity, pH, and sodium (by atomic adsorption spectroscopy (AA)); and (3) the lab developed an ingenious method for looking for the presence of extremely small condenser tube leaks using cation conductivity resis. This testing took advantage of an aspect of the specific chemistry of the cooling water at Sherco. This demonstrated the chemistry team's eagerness to use their capabilities creatively to best serve their units. Though this particular method was ultimately discontinued, the efforts showed the chemistry team's commitment to go above and beyond typical industry practice to identify even trace levels of contamination, so as to keep them out of the steam cycle. These are all practices that demonstrate diligence and dedication by plant staff to monitoring steam chemistry.

Q. BASED ON YOUR INDUSTRY EXPERIENCE, HOW DID THE SHERCO UNIT 3 CHEMISTRY RESOURCES AND THE BROADER RESOURCES OF XCEL ENERGY COMPARE TO THAT OF OTHER OPERATORS OF COAL-FIRED RECIRCULATING BOILER UNITS?

A. The Sherco plant laboratory was well staffed by knowledgeable individuals who were dedicated to maintaining plant chemistry limits. In addition, the Company provided the Xcel Energy power plants with access to a laboratory (Chestnut Street) with advanced analytical capabilities. It is very unusual to have such a corporate laboratory with the capacity to do specialized testing of the high purity water and condensate samples collected by the plant and served as an excellent resource for the Sherco chemistry tream.

C. Industry Standards

Q. WHAT IS EPRI?

A. EPRI is an industry group made up of member utilities that pay annual dues to participate in and direct research important to their members. EPRI is not a regulatory body. It is an industry research organization. It has no legal or regulatory authority to require that member or non-member utilities act in a certain way, perform specific analyses, or take specific actions, including – for example – based on steam or water chemistry testing at a given plant.

One of the research areas (targets) is water and steam chemistry. Starting in 1986, EPRI provided its members with best-practice guidelines on water and steam chemistry. These included chemical limits on the level of impurities allowed in the steam going to a steam turbine. These limits were consistent with (or stricter than) the chemistry limits produced by the turbine manufacturers at the time. However, once established, member utilities (including the Company, with respect to Sherco and other plants) quickly worked toward applying the chemistry guidelinesat their sites. At Sherco, the Company applied many of the EPRI recommended limits in the plant specific chemistry limits.

EPRI revised and updated its chemistry guidance from time to time according to increasing industry knowledge, available instrumentation, and best industry practice. It is important to understand, however, that while EPRI's guidance in water and steam chemistry incorporates chemical and metallurgical research (some of which EPRI sponsored), the EPRI limits balance their research findings against the limitations of the instrumentation and equipment commonly used in the industry. Their goal was to encourage member power plants to improve their practices. Moreover, because (1) the damage mechanisms that cause failures in large equipment such as turbines can take many years to develop, (2) the damage mechanisms may be affected by a number of operating factors (such as the number of starts and stops), and (3) there are many various manufacturers and types of equipment (i.e., turbine size), EPRI limits are not guarantees. EPRI never states that staying within their chemistry limits guarantees that the equipment will not fail. Conversely, operating above the limits for hours or even days, does not guarantee equipment failure or corrosion. EPRI only states that operation outside of their limits is not optimum and the risk of failure is higher under non-optimum conditions, without further quantifying that risk.

The limitations that EPRI has placed on certain parameters (cation conductivity in particular) have created long-running debates in the industry, with some research showing that the limits are too strict or not sufficiently specific to the actual causes of corrosion to be helpful. However, since the EPRI limits were published 1986, failures from specific corrosion mechanisms in the boiler and on steam turbines has been reduced. This indicates that the EPRI chemistry limits are having a general positive effect in the industry.

Q. PLEASE DESCRIBE THE STEAM CHEMISTRY GUIDANCE SET BY EPRI.

A. EPRI's steam chemistry guidance was a consensus of various equipment manufacturers guidance (turbines, boilers, etc.) and EPRI-member experience with what could actually be achieved in an operating power plant using state of the art analyzers. For steam going to the turbine, the guidance recommended a concentration of less than 2 ppb of sodium and a cation conductivity of less than 0.2 μS/cm. Once established by EPRI, GE started to use the EPRI chemistry guidance limits in producing their own steam purity limits. Versions of the GE chemistry guidance that appear after the year 2000 closely mirror the EPRI guidance values during that same period.

Q. WHAT ARE GE'S STEAM GUIDELINES AND HOW DO THEY COMPARE WITH THE EPRI STANDARDS?

A. GE, like other turbine manufacturers, produces steam chemistry guidance consistent with scientific understanding regarding chemicals in steam, metallurgy, and industry experience. The GE Steam Chemistry guidelines are specific to their steam turbines, whereas the EPRI chemistry guidance documents cover the entire steam cycle – boiler, feedwater heaters, deaerator, condenser and the turbine. From time to time, GE has updated or expanded their guidance based on changes to the science or industry experience.

In 1979, GE published its first steam purity document that specifically discussed prevention of stress corrosion cracking of its turbine rotors. It was labeled GEK-72281. The recommendation was only for once-through boilers; drum boilers like Sherco Unit 3 were not mentioned. Limits were given for sodium and cation conductivity in the steam. These guidelines were periodically updated by GE as industry knowledge changed and other bodies, like EPRI, updated their recommendations. While the most recent GE chemistry limits would have been supplied to those purchasing new turbines, GE did not dissemintate updated guidelines to existing steam turbine owners. By the early 2000s, the GEK guidance on steam chemistry was generally consistent with the recommendations made by EPRI and other groups such as the International Association for the Properties of Water and Steam (IAPWS). By the time of the Event, GE was on its sixth version of the GEK (GEK 72281f). As noted above, the combination of metallurgy, stresses, steam chemistry, and time that produces an SCC crack can vary widely in a steam turbine that has been in service. As a result, it is essentially impossible to ascertain a “safe” level of caustic in the steam, whereby the risk of SCC failure would be essentially zero for any turbine, of any age. Both EPRI and GE have admitted as much in their documents. The best that any steam chemistry guidance can do is to recommend levels of sodium in steam that are a) achievable in an operating plant and b) have been shown historically to result in a low risk of a failure due to SCC.

Q. HOW DID XCEL ENERGY'S WATER CHEMISTRY MONITORING PRACTICES AND NORMAL OPERATING LIMITS FOR UNIT 3 COMPARE TO THE GUIDELINES PROVIDED BY EPRI?

A. The chemical limits established by Mr. Wold for the Sherco station were consistent with the EPRI guidelines for the treatment regime under which that plant was operating. The plant limit on steam sodium was <2 ppb, which is the same as the EPRI limit.

Q. HOW DID XCEL ENERGY'S WATER CHEMISTRY PRACTICES AND THRESHOLDS FOR UNIT 3 COMPARE TO THE CHEMISTRY GUIDANCE PROVIDED BY GE?

A. The plant had been monitoring sodium in the condensate and in the boiler water continuously since startup. Sherco Unit 3's chemistry limit for sodium in the boiler water was based on the EPRI-produced curve for sodium in boilers using All Volatile Treatment. The EPRI recommended limits on boiler sodium, in turn, were calculated to produce less than 2 ppb sodium in the steam considering mechanical and volatile carryover. The Unit 3 boiler sodium data produced by the various data sources shows that the boiler sodium was consistenly below the EPRI recommended limit. The plant added the direct monitoring of Main Steam for sodium in 2008 and the sodium limit for steam at <2 ppb. Once installed, the Main Steam sodium monitor confirmed that the sodium value in the steam was much lower than 2 ppb. In all their publications except one, the GE limit for sodium in steam to their turbine was <3 ppb. The last GEK limits that apply to this case were issued in 2009. In that document, the limit for sodium in steam was <3 ppb. *See* Exhibit___(DGD-1), Schedule 2, Table 5.

Q. HOW AND WHERE DID THE PLANT MONITOR FOR SODIUM HYDROXIDE IN THE STEAM CYCLE?

A. Sherco Unit 3 had been monitoring sodium continuously on a sample point just after the condenser and in the boiler water since the plant started operation in 1989. Starting in 2008, the plant installed a sodium monitor directly on the main steam sample. Sodium hydroxide (caustic) is the chemical species associated with SCC in turbine rotors. While it is impossible to measure sodium hydroxide at very low (ppb) levels, the sodium ion itself can be detected. The most conservative assumption, then, is that if the sodium is present, it could be in the form of sodium hydroxide and the chemical limits for sodium are set with this assumption. The chemical process required for detecting sodium at levels below 1 ppb has been established for many years and this instrumentation has been common in power plants at a variety of sample points in the steam cycle. As discussed previously, any contamination entering the steam cycle must enter at the condenser (whether from a condenser tube leak or from the water treatment area). The first point of detection then would be the first sampling point downstreasm of the condenser. Furthermore, any contamination in the steam cycle such as sodium hydroxide would concentrate in the boiler. Again, the boiler acts like a large water distillation plant, concentrating impurities in the boiler water while the steam remains pure. By measuring sodium in the boiler water, the plant put its analytical capability for sodium at the most sensitive point in the steam cycle to detect that contamination.

D. Sherco Unit 3 Steam Cycle Chemistry History

1. Unit 3's Monitoring Practices

Q. IN YOUR EXPERT OPINION AND BASED ON YOUR INDUSTRY KNOWLEDGE OF OTHER COAL-FIRED POWER PLANTS, HOW DID XCEL ENERGY'S WATER CHEMISTRY PRACTICES AND NORMAL CHEMISTRY LIMITS FOR UNIT 3 COMPARE TO OTHER OPERATORS?

A. The Sherco Unit 3 chemistry limits, sampling points and monitored parameters were closely aligned with the EPRI guidance documents, with minor differences. Most power plants I have visited try to follow the EPRI guidance for the sampling locations and instruments that their plant has. My experience has been that very few plants have all the EPRI-recommended analyzers at each EPRI recommended sample point. Sherco Unit 3 had more of these sample points and chemical parameters than most power plants. From my review of the Unit 3 chemistry data between 2000 and 2011, I can say that Xcel Energy was very successful at operating at or below the chemistry limits that they established, which were guided by the EPRI recommendations.

Q. IN YOUR EXPERTISE, HOW DOES SHERCO UNIT 3'S MONITORING AND MANAGEMENT OF THE CRITICAL STEAM CHEMISTRY AND STEAM PATH COMPARE TO OTHER OPERATORS OF COAL-FIRED RECIRCULATING BOILER UNITS?

A. In my interviews with plant personnel, I found that Sherco Unit 3 control room operators, supervisors, and laboratory personnel were very experienced and understood the importance of steam cycle chemistry to the health and reliability of the plant, and particularly the steam turbine. This level of operator knowledge regarding chemistry is a combination of experience and training by the lab supervisor. In my experience, this level of understanding among operators is well above average. The laboratory was dedicated to maintaining continuous monitoring equipment and performing routine testing to confirm steam cycle conditions. They also established a system so that one of the lab personnel was always on call. Operators understood if there were any questions about the water and steam chemistry or unusual readings, they could call on the lab at any time, and someone would answer. If the concerns could not be resolved over the phone, the lab technician or lab supervisor would come out to the plant, day or night, and troubleshoot the issue. Laboratory personnel were always present during the unit startup, when on-line chemistry analyzers are generally not representative of actual steam cycle conditions. Having laboratory technicians on call and the practice of staffing startups is well above average compared to most power plants, where lab personnel only find out a unit was started overnight when they arrive the next day.

Q. BESIDES THE CHEMISTRY DATA RECORDS, WHAT OTHER EVIDENCE INFLUENCED YOUR OPINION OF THE PLANT'S CONTROL OF THE WATER AND STEAM CHEMISTRY ON UNIT 3 BETWEEN 2000 AND 2011?

A. In association with regularly scheduled outages, the plant inspected the LP turbine in 2005. The inspection found that the turbine rotor and blades were clean. There is no mention of significant deposits or pitting in this inspection report. In November 2011, the plant was returning from a planned outage where work was performed on the HP and IP turbine; when, during an overspeed test, the LP-B turbine failed (the Event). The photographs taken of the LP-B turbine after the Event found no significant deposits on the turbine blades and only minor pitting. Poor control of water and steam chemistry leaves its mark on the turbine in the form of pitting and deposits. The lack of these in 2005 and 2011 confirms that the chemistry control had been very successful.

2. *Historical Data Records*

Q. WERE YOU ABLE TO REVIEW DATA ASSOCIATED WITH EACH OF THE KEY MONITORING POINTS FOR SHERCO UNIT 3'S STEAM CHEMISTRY?

A. Yes. The plant kept records of the steam chemistry data in various formats and through several different systems. A summary of the historical data sources I reviewed are explained on pages 5-6 of Exhibit___(DGD-1), Schedule 2 and include lab generated data (Mapper), plant historian or Plant Information (PI) Database, and main steam sodium (Yokogawa Data). The data from these sources are reflected on Tables 1 and 2 of Schedule 2 (Exhibit___(DGD-1), Schedule 2). However, it is critical to remember that the plant continuously monitored the steam cycle chemistry through on-line monitors located at multiple sample points around the cycle which were testing various chemical parameters. This monitoring was active any time the unit was operating. An alarm would notify the control room when any analyzer was in an alarm condition and the operator (or lab staff, when present) would respond to the alarm, assess the situation and determine a course of action. During weekdays and on all unit startups, when lab personnel were on-site, they were also monitoring the on-line analyzers as well as performing additional testing to ensure that the steam chemistry was within limits. From my interviews with the control room operators and laboratory personnel, together with my review of the available data, I concluded that the plant chemistry was closely monitored and the unit was prudently operated consistent with industry steam cycle chemistry standards. During the period I reviewed, I could find no evidence that the plant was operated in a condition that would have sent contaminated steam to the steam turbine.

Q. WERE THERE GAPS OR ANOMALIES IN THE HISTORICAL DATA, AND IF SO, HOW DID YOU ADDRESS THOSE WHEN EVALUATING UNIT 3'S HISTORICAL STEAM CHEMISTRY OPERATIONS?

A. Yes, there are often gaps in historical data records, especially when the electronic database is queried for records going back more than a decade. However, the combination of all record sources reviewed allowed me to be confident about my conclusions. The plant has a data collection system, also referred to as a plant historian, that generally goes by the acronym PI. The PI system tracks literally hundreds of data points in the power plant including temperatures, pressures, flows, equipment condition etc. Steam cycle chemistry information from the continuous analyzers on the unit is also collected in PI. PI data is gathered for historical purposes only. It is not generally visible to the laboratory or control room operators, unless they are specifically looking for historical information. Even then, the trends are often of very recent data (hours or days). The operator's primary focus is on the current operating conditions of the plant. Therefore, the plant's data collection system is assumed to be working, but is not closely monitored in the same manner as the current plant data would be. In my experience, data collection and retrieval issues from PI systems are not uncommon. Even if the data were collected properly and stored at the time, with older records there is always the potential for data corruption issues that are only discovered when the records are retrieved. However, when data collection is working properly, the PI system contains a wealth of minute-by-minute data about the operating conditions of the plant and the water and steam chemistry. So, it is always valuable to query this data and see what can be retrieved.

When the historical data was requested for my analysis, going back more than 10 years, the plant realized that there were times when data points had not been recorded properly, or the data accuracy was questionable. Because the data collection and storage are running in the background, a gap or anomaly in the collection process might go undetected for months before being identified and corrected. Additionally, the PI system is recording data even when Unit 3 is shut down or just starting up – times when the data would be irrelevant or at best inaccurate, and therefore unhelpful for determining true steam-contamination events. Consequently, any historical data must be scrutinized for accuracy and reasonableness when compared with the other data collected at the time. The laboratory kept a spreadsheet containing the analytical data from the laboratory testing that they did. They also recorded the data displayed on the on-line analyzers at the moment that they were collecting samples for their laboratory testing. This data was recorded at least once a week when the unit was operating. However, the data shows more frequent records, often daily or every other day. This record was complete, containing data for all the days on which the lab personnel did testing. Although this is only a snapshot, it can be compared with the PI data being recorded at the same time for reasonableness. This was the most complete record I reviewed. An additional sodium analyzer was established on the Main Steam sample in January 2008. However, the data was not recorded on the PI system. Instead, it was recorded on a separate data logger manufactured by the Yokogawa company. Memory cards collected and recorded the data. I reviewed this data for the period between 2008 and 2011. There were also gaps here and periods for which the data had not been stored correctly (negative values). However, the majority of the recorded data that is actual instrument output shows the sodium values generally below 1 ppb sodium in the Main Steam. During startups, the laboratory kept a written log of the many tests that they would perform, sometimes retesting every few minutes. This data was also referred to in my evaluation.

In evaluating the PI data, I collected corresponding boiler operating pressure data and generator megawatts at the same frequency in order to filter out periods when the boiler was not operating or just staring up. Based on my experience with power plants and on-line analyzers, I chose a value of 100 MW as the point below which I deemed the on-line analyzer data was not reliable due to startup anomalies. For this unit, the time between when steam was admitted to the turbine and when the unit reached 100 MW of generation, was short. Besides simply graphing and comparing the historical data against the plant's normal chemistry limits, the data presented times when an additional level of analysis was required. There are times when any analyzer can malfunction and produce erroneous data. This erroneous data would also be recorded by the PI system. When there is actual contamination of the steam cycle, many chemical parameters are affected at multiple sample points. If one analyzer reads high, and if there is really contamination in the cycle, there should be multiple confirmatory readings on numerous other analyzers in the cycle. For example, if the sodium analyzer on the boiler is reading high, then other analyzers, including the other sodium analyzer and the multiple cation conductivity analyzers should also indicate contamination. If not, the problem is not real contamination, but an issue with a single analyzer. In every case, were any analyzer was significantly out of limits, I always compared it against what the other analyzers at the time were reading. In nearly all cases, this analysis showed that the issues were with the analyzers. Cases where the analyzers pointed to actual contaminiation are discussed in more detail below – and, as I note, were promptly and appropriately addressed.

Q. DO GAPS IN HISTORICAL PI DATA SUGGEST THAT STEAM CHEMISTRY WAS NOT MONITORED OR TRACKED DURING THAT TIME PERIOD?

A. No. The PI data is a historical record that does not necessarily reflect the data being displayed to and relied upon by the control room operators and the laboratory staff. The primary monitoring of the water and steam cycle chemistry at the plant was done by the on-line analyzers which operated continuously. The control room operators and the laboratory staff were attentive to any analyzer that was in alarm. Interviews with control room operators and other plant personnel confirmed that they understood that steam cycle chemistry was important to the plant. If the operators had any questions or concerns, lab personnel were on call at all times to provide advice or come into the plant to deal with the situation. The laboratory also monitored the steam cycle chemistry and kept a record of their test results. This record (Mapper) confirms steam cycle chemistry was in control during this period.

3. Excursions, Upsets, or Other Notable Steam Chemistry Events

Q. IN SHERCO UNIT 3'S OPERATIONS, WERE THERE ANY EXCURSIONS, UPSETS, OR OTHER NOTABLE EVENTS WITH REGARD TO STEAM PATH CHEMISTRY, AND IF SO, HOW WERE THE EVENTS HANDLED?

A. Any operating plant is expected to experience times when the steam chemistry is not within normal limits. The critical consideration is how the plant reponds to such an event. In my investigation, I analyzed the data and records to determine when excursions or updates occurred and assessed whether the chemistry team and operations staff took quick and responsive action to address any such events. In every case I found, any excursions, upsets, or other chemistry events that occurred were promptly observed and addressed.

An example of the response of operations and laboratory personnel to contamination in the steam cycle can be seen in the following incident. At 13:30 on June 23, 2003, the lab noted an increase in the cation conductivity at the condensate pump discharge from the normal level of about 0.13 μS/cm to over 0.7 μS/cm by 16:00 when the unit tripped for an unrelated reason.

The unit returned to service between 18:00 and 19:00. At the request of the lab, at that time, operators had already isolated the inside loop of the condenser and the chemistry improved. This indicated that the location of the condenser tube leak was in the area that was isolated. During the startup, the boiler blowdown was opened to reduce the accumulation of contaminants, water was not returned from the hotwell to the working tank, and the boiler operating pressure was limited per the lab to 2000 psig (Operations maintained 1900 psig through this period). All of these severely limited the potential for any contamination to reach the steam. The laboratory was staffed with a lab technician throughout the night to closely monitor chemistry on the unit. During this entire time, all three of the condensate polishers were in service.

By early the next morning, with the contamination source isolated and the polishers continuing to remove any residual contamination in the cycle, the chemistry had improved considerably. At 01:30 on June 24, the boiler sodium was 181 ppb. It had dropped back to 137 ppb by 04:30 that same morning. The record shows that the boiler remained at a restricted pressure until June 25th at 22:00. By that time, the boiler water chemistry had long since returned to normal. During this entire event, the boiler sodium concentration never approached the top of the EPRI Normal recommendation of 700 ppb (at 1900 psig). No boiler sodium measurements were recorded that would have produced a steam sodium (per EPRI's worst case assumption) of greater than 2 ppb.

This is the only clearly documented condenser tube leak that occurred during operation throughout the 11 year period that was reviewed. Lab books, operations logs, reports, emails and other sources have been thoroughly reviewed for any reference to condenser tube leaks found during an operating condition. Some references were found to condenser leaks, but these were determined later to refer to air leaking into the condenser and not cooling water contaminating the steam cycle. There were times when, because of the special test the lab was doing to try and find very small condenser tube leaks, they thought that a small tube leak existed (such as January 2010), but the general boiler chemistry did not indicate there was a leak. These "false alarms" were determined to be caused by problems with the test itself and therefore, the test was discontinued. As discussed elsewhere in this document, both the plant operators and laboratory technicians were watching for any signs of contamination. Had there been any such cases, they would have been well documented like the one that occurred in 2003.

If there was any condition where chemistry parameters were not normal or were in alarm, the laboratory had primary responsibility to determine what the problem was and address/correct the issue. If a problem with the boiler or steam chemistry occurred when the lab was not at the plant site, the Operators would call one of the lab personnel or Duane Wold notify them and get advice from them in how to address the issue. The laboratory staff were very dediciated and supported by plant management. If they needed to come out in the middle of the night or on a weekend to address a chemistry question, plant management would support the overtime.

Q. DID ANY OF THOSE EVENTS INDIVIDUALLY OR COLLECTIVELY PUT THE TURBINE AT RISK OF CAUSTIC CONTAMINATION?

A. A thorough review of the historical data found no instance during the evaluated period where the records show that the chemistry of the feedwater, boiler, or steam were sufficiently contaminated to put the turbine at risk of caustic contamination.

Q. WERE THERE ANY CHRONIC, OR UNTREATED, STEAM PATH EVENTS FOR SHERCO UNIT 3 THAT WOULD CAUSE CAUSTIC TO ACCUMULATE IN THE LOW PRESSURE TURBINES?

A. It is my opinion that, neither the laboratory nor the operators would have knowingly operated the plant with condition that would have caused contaminated steam to enter the turbine.

E. Final Opinions

Q. IN YOUR EXPERT OPINION, BASED ON YOUR INDUSTRY EXPERIENCE AND SPECIFIC INVESTIGATION INTO THE SHERCO UNIT 3'S PRACTICES, DID THE COMPANY PRUDENTLY MONITOR AND MAINTAIN UNIT 3'S STEAM CHEMISTRY?

A. Yes. Throughout the history of the unit, the data shows that the steam cycle chemistry was controlled and that the plant was diligent in monitoring and maintaining the steam chemistry on the unit.

Q. IN YOUR EXPERT OPINION, BASED ON YOUR INDUSTRY EXPERIENCE AND SPECIFIC INVESTIGATION INTO THE SHERCO UNIT 3'S PRACTICES, DID THE

COMPANY PRUDENTLY RESPOND TO ANY EXCURSIONS, UPSETS, OR OTHER NOTABLE STEAM CHEMISTRY EVENTS?

A. Yes. The plant consistently monitored the chemistry parameters, identified any issues early, and addressed any condensate contamination quickly to ensure that the steam reaching the turbines was not contaminated. The response to the condenser tube leak on June 23, 2003 is a good example.

Q. WERE THE COMPANY'S STEAM CHEMISTRY MONITORING PRACTICES REASONABLE BASED ON INDUSTRY STANDARDS?

A. Yes. In my experience they were better than many of the power plants that I have visited. They certainly took the chemistry of the steam cycle seriously and were diligent in monitoring for contamination.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. Xcel Energy's Sherco Unit 3 personnel were diligent in monitoring the steam cycle chemistry between the year 2000 and 2011, up to the point of the turbine failure. If any contamination was suspected, they would take steps immediately to minimize the potential for the steam going to the turbine to become contaminated while finding and isolating the contamination source. In summary, they acted in every way like prudent operators of the power plant with regards to water and steam chemistry.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

David G Daniels

Senior Principal Scientist

Education

B.S. Chemistry, University of Utah, 1980

Relevant Work Experience

M & M Engineering, Leander, Texas, 1998-Present

Mr. Daniels is an internationally recognized expert in steam and water treatment to electric utilities, pulp and paper mills, and industrial boilers. This includes inspection, evaluation, and training on water and steam chemistry and water-related corrosion issues.

He also has experience with corrosion in chemical processes in a variety of industries and with insurance-related claims and litigation.

In 1998, Radian's Mechanical and Materials group became a separate division of the Hartford Steam Boiler called Mechanical & Materials Engineering. In 2008, employees purchased the firm from Hartford Steam Boiler and changed the name to M&M Engineering Associates, Inc. On January 1, 2017 the company was acquired by Acuren Inspection, Inc.

Radian International LLC Austin, Texas, 1988-1998

Hired as the Laboratory Supervisor for Radian's Inorganic Chemistry Laboratories. While in this area, he also supported the Hartford Steam Boiler Inspection and Insurance Company (Radian's parent company) and Radian's Mechanical and Materials Group in the area of boiler and steam chemistry. This included consulting internationally with industries generating steam regarding water and steam chemistry corrosion issues.

Utah Power & Light, Utah, 1981-1988

Hired on as a lab technician at the Huntington plant and was shortly thereafter promoted to environmental engineering at the Hunter plant, and then to chemical supervisor also at the Hunter Plant. The Hunter plant consists of three 400 MW 2600 psig units. As plant chemist, he supervised twenty technicians that provided around-the-clock chemistry support to the units including all on-line and grab analyses for water and steam chemistry parameters and the clarifiers, softeners, and demineralizers that supplied boiler makeup and cooling water to the plant.

Professional Committees and Affiliations

Mr. Daniels is the former chairman of the ASME Research and Technology Committee on Water and Steam in Thermal Power Systems. As a member of this committee, Mr. Daniels participated in establishing guidelines for water and steam chemistry for industrial and utility steam generating equipment. He chaired a task group that published ASME committees' recommendations for chemistry in heat recovery steam generators at combined cycle power plants.

Publications

From 1999 to 2016, Mr. Daniels was the contributing editor on water and steam chemistry for Power magazine and has written and edited numerous articles on water and steam chemistry for the magazine. He has authored and edited technical documents for the Electric Power Research Institute (EPRI) on water treatment equipment, treating boiler chemical cleaning wastes, steam cycle lay-up and start up and amine use and degradation in the steam cycle. He has also presented papers at numerous professional conferences. He provides training on boiler water chemistry at the International Water Conference every year. A list of publications and papers that he has authored or contributed to is listed below.

1. *Monitoring and Treatment of Closed-Loop Cooling Water Systems,* Power, March 2016
2. *Winning the Cooling Tower Trifecta: Controlling Corrosion, Scale, and Microbiological Fouling*, Power September 2015
3. *Feedwater Chemistry Meets Stainless Steel, Copper, and Iron*, Power March 2015
4. *Boiler Chemistry: Doing It Correctly*, Power September 2014
5. *Consensus on Operating Practices for Control of Water and Steam Chemistry in Combined Cycle and Cogeneration*, ASME, 2012
6. *Water and Power: Will Your Next Power Plant Make Both*, Power September 2012
7. *Taming Condenser Tube Leaks*—Part 2, Power, October 2010
8. *Taming Condenser Tube Leaks*—Part 1, Power, September 2010
9. *Focus on O&M—Avoid these 10 Mistakes When Selecting Your New Water Treatment System,* Power September 2009
10. *Focus on Organics in Steam*, Power Magazine, June 2009
11. *Cycling, Startup, Shutdown, and Lay-up Fossil Plant Cycle Chemistry Guidelines for Operators and Chemists, (co-author)* 1015657, January 2009 EPRI, Palo Alto, CA
12. *Cation conductivity monitoring: a reality check,* Power Magazine May 2008
13. *Biofouling control options for cooling systems,* Power Magazine, September 2007
14. *Water chemistry an important factor to consider for cycling HRSGs,* Power Magazine, May 2007

15. *Organics in the boiler and steam: Good or bad?,* Power Magazine, September 2006
16. *New Membrane Technologies Bring Any Water Up To Plant Quality*, Power Magazine, September, 2005
17. *How to Identify, Prevent Waterside Failure Mechanisms in Your HRSGs*, 2006 Outage Handbook, Combined Cycle Journal, 3Q, 2005
18. *Boiler and Feedwater Treatment: Do the Right Thing(s)*, Power Magazine, September 2004
19. *New Precomissioning Options for Controlling Corrosion in HRSGs*", Power Magazine, September 2003
20. *Cooling for a Hot and Thirsty Industry*, Power Magazine, September 2002
21. *HRSG Waterside Failure Mechanisms*, Journal of Power Plant Chemistry (PPChem), 2002 4(9)
22. *Consensus for the Lay-up of Boilers, Turbines, Turbine Condensers, and Auxiliary Equipment*, CRTD-66., ASME, 2002
23. *The TOC Debate- Between a Rock and a Hard Spot*, Power Magazine, March 2002
24. *Power plants learn to reuse, recycle*, Power Magazine, September 2001
25. *Oxidation Reduction Potential (ORP)—A new tool or another gadget?*, Power Magazine, July 1999
26. *A Copper-Plated Thief—Copper Deposits on HP Turbines Steal MWs*, Power Magazine, April/May 1999
27. *Follow Good Lay-up Practice to Prevent Cycle Corrosion*, Power, March/April 1998
28. *Good Lay-up Practice Produces Significant Benefits*, Proceedings of the International Water Conference, Vol. 59, 1998
29. *Consensus on Operating Practices for the Control of Feedwater and Boiler Water Chemistry in Modern Industrial Boilers*, CRTD-Vol-34, ASME, 1994

Expert Report of David G. Daniels

Vice President & Senior Principal Scientist
M&M Engineering Associates, Inc.

Submitted to:

Tim Thornton
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402

January 29, 2016

David G. Daniels

EDUCATION B.S. Chemistry, University of Utah, 1980

RELEVANT WORK EXPERIENCE:

M&M Engineering Assoc. Inc, Austin, TX — 1998-present

Provides steam and water treatment consulting services to electric utilities, pulp and paper mills, and industrial boilers. This includes inspection, evaluation, and training on water and steam chemistry issues. In February 1998, Radian's Mechanical and Materials group became a separate division of the Hartford Steam Boiler called Mechanical & Materials Engineering. In 2008, Mechanical & Materials Engineering bought itself away from HSB and became M&M Engineering Associates, Inc. Mr. Daniels serves as a Vice President and Senior Principal Scientist.

Radian International LLC Austin, TX — 1988-1998

Hired as the Laboratory Supervisor for Radian's the Inorganic Chemistry Laboratories. In 1990 he transferred to Radian's process chemistry area. There he worked with electric utilities in the areas of asbestos, waste management, and pollution prevention. He also supported the Hartford Steam Boiler Inspection and Insurance Company (Radian's parent company) and Radian's Mechanical and Materials Group in the area of boiler and steam chemistry. This included consulting through the country and internationally with industries generating steam regarding water and steam chemistry.

Utah Power & Light Castle Dale, UT — 1981-1988

Hired on as a lab technician at the Huntington plant and was shortly thereafter promoted to environmental engineering at the Hunter plant, then to chemical supervisor also at the Hunter Plant. The Hunter plant consists of three 400 MW 2600 psig units. As plant chemist, he supervised 20 technicians that provided around the clock chemistry support to the units including all on-line and grab analyses for water and steam chemistry parameters and the clarifiers, softeners, and demineralizers that supplied boiler makeup and cooling water to the plant.

Professional Committees and Affiliations

Mr. Daniels is the chairman of the ASME Research and Technology Committee on Water and Steam in Thermal Power Systems. As a member of this committee, Mr. Daniels participates in establishing guidelines for water and steam chemistry for industrial and utility steam generating equipment. He was the Task Group Leader in establishing the ASME committees' recommendations for chemistry limits in HRSGs published in 2012.

Publications of David G. Daniels

Since 1999, Mr. Daniels has been the contributing editor on water and steam chemistry for Power magazine and has written and edited numerous articles on water and steam chemistry for the magazine. He has authored and edited technical documents for the Electric Power Research Institute (EPRI) on steam cycle lay-up and start up, amine use and degradation in the steam cycle, handling of boiler chemical cleaning wastes, and an inspection guide for boilers and HRSGs. He has also presented papers at numerous professional conferences.

A list of publications is listed below.

1. *Feedwater Chemistry Meets Stainless Steel, Copper, and Iron*, Power March 2015
2. *Winning the Cooling Tower Trifecta: Controlling Corrosion, Scale, and Microbiological Fouling*, Power, Sept 2015
3. *Boiler Chemical Cleaning: Doing It Correctly*, Power September 2014
4. *Consensus on Operating Practices for Control of Water and Steam Chemistry in Combined Cycle and Cogeneration*, ASME, 2012
5. *Water and Power: Will Your Next Power Plant Make Both*, Power September 2012
6. *Taming Condenser Tube Leaks*—Part 2 Power , October 2010
7. *Taming Condenser Tube Leaks*—Part 1 Power September 2010
8. *Focus on O&M—Avoid these 10 Mistakes When Selecting Your New Water Treatment System*, Power September 2009
9. *Focus on Organics in Steam*, Power Magazine, June 2009
10. *Cycling, Startup, Shutdown, and Lay-up Fossil Plant Cycle Chemistry Guidelines for Operators and Chemists, (co-author)* 1015657, January 2009 EPRI, Palo Alto, CA
11. *Cation conductivity monitoring: a reality check*, Power Magazine May 2008
12. *Biofouling control options for cooling systems*, Power Magazine, September 2007
13. *Water chemistry an important factor to consider for cycling HRSGs*, Power Magazine, May 2007
14. *Organics in the boiler and steam: Good or bad?*, Power Magazine, September 2006
15. *New Membrane Technologies Bring Any Water Up To Plant Quality*, Power Magazine, September, 2005
16. *How to Identify, Prevent Waterside Failure Mechanisms in Your HRSGs*, 2006 Outage Handbook, Combined Cycle Journal, 3Q, 2005

Depositions/Testimony since 2011

TransAlta v TransCanada: Regarding the removal of Sundance Units 1 and 2 from Service, July 2013

I. Expert Opinion

I have made a thorough review of the steam cycle chemistry for Sherco Unit #3, particularly between the years 2000 and 2011 when the incident occurred, and have reached the following conclusions:

1. Throughout the history of the unit, the data shows that the steam cycle chemistry was controlled and that NSP was neither negligent nor careless in maintaining the steam chemistry on the unit as claimed by GE. The evidence is clear that the plant monitored the chemistry parameters that they had and addressed minor contamination issues as they arose to ensure that the steam was not contaminated.
2. We found no evidence of "abnormal events or operational anomalies" between 2000 and 2011 that sent contaminated steam to the turbine.
3. There was a condenser tube leak detected on June 23, 2003 during operation. As soon as it was detected, the actions were taken to prevent contamination of the steam. The portion of the condenser that had the leaking tube was isolated, repaired and chemistry monitored closely during the subsequent startup before the unit was released to a pressure that could contaminate the steam with sodium.
4. Both operations and the lab personnel were very diligent about monitoring the chemistry via the on-line analyzers and addressing any contamination problems when they occurred. Their commitment to close monitoring of the steam cycle chemistry can be seen by the following:
    a. Every startup was manned with a lab technician until the unit was released to full operating pressure. The lab technician checked for iron particulate in the feedwater, silica, cation conductivity, and sodium. If these were not within normal operating limits, the unit did not go to full operating pressure.
    b. On-line analyzers were regularly confirmed by separate bench testing. This included cation conductivity, specific conductivity, pH, and sodium (by Flame-AAS).
    c. The plant had and utilized full-flow condensate polishers. Although the design was that two of the three polishers would handle 100% of the condensate flow, the plant routinely maintained all three polishers in service when operating at full pressure and only removed one when it needed to be recoated. This continuously polished the condensate guarding against contamination.

5. The plant did not have direct monitoring of the Main Steam sodium until 2008. However, they did have sodium monitoring on the boiler and at the condensate pump discharge throughout the history of the unit. Although direct measurement of the Main or Reheat Steam sodium is best practice, the sodium monitoring that the plant had, in conjunction with other continuously monitored parameters, provided sufficient continuous monitoring information to determine if any contamination existed in the steam.
6. The GEK guidance on steam chemistry for turbines was and is consistent with the general recommendations issued by EPRI and other international groups such as IAPWS. All these parties understand that the guidelines represent levels that are normally achievable in conventional power plants, not levels below which damage cannot occur, as damage mechanisms such as SCC are dependent on material and design stresses, not just the chemical purity of the steam.

II. Data Sources Used

Chemistry data was assembled from a variety of data sources provided by the plant. (Tables 1 and 2). A combination of these sources was used to determine that the boiler and steam chemistry were within limits during the period between 2000 and the incident. In reviewing the data, if a parameter such as cation conductivity or sodium in the PI data indicated an anomaly, or if data was lacking, the other data sources including the lab data (mapper) and the Yokogawa data (Main Steam sodium) were referenced.

Mapper Database

The only data source over which the laboratory had full control was the Mapper database which consisted of data that the laboratory entered based on their weekly testing. During the scheduled weekly testing, the laboratory technicians verified the online instrumentation with their bench testing. Besides the typical pH and specific conductivity checks, the laboratory also tested cation conductivity and sodium by independent analyses. In addition to verifying the online analyzers, the laboratory performed a number of additional tests on various sample points that did not have online analyzers.

Plant Historian (PI) Database

The plant historian or PI database was in place for water and steam chemistry parameters in November 2001. The data is stored along with many other data points including pressures, and temperatures, flows, etc. Once the PI data collection is turned on, it continues to collect data regardless of whether the unit is operating or not. Therefore in our evaluation of this data, I also collected the boiler operating pressure and generator megawatts at the same frequency and filtered out periods when the boiler was not operating or just starting up (generally less than 100 MW of generation.

This PI data is not normally visible to the laboratory or even to the control room operators. It resides in the database until the specific points are queried. For this reason there may be accuracy issues or even data points that are not being collected due to problems with the data conversion and storage hardware. These problems in the plant historian often go on for many months without being detected, as it is the DCS and not the plant historian (PI) information that is used to operate the unit. Furthermore, adding or repairing a data point to the plant historian system may require hardware installation or repair, or some additional programming. Often the resources to perform this work are not at the plant and must be contracted out, and so changes may not be timely.

An on-line analyzer for the Main Steam sample was added in 2008. It appears that a data point was set up on PI to collect data from this analyzer, but it only collected meaningful data between January 24, 2008 and October 2, 2008. There is no other data on PI for Main Steam sodium until after the incident.

Yokogawa Data

In 2006 the plant purchased and installed two electronic strip chart recorders made by Yokogawa. These had the capacity to record data from 10 data points each. These strip chart recorders were located in the laboratory and data was collected directly from the on-line analyzers. After the Main Steam sodium analyzer was installed in 2008, one channel on one of the recorders was set to collect Main Steam sodium data. We reviewed Main Steam sodium data from January 24, 2008 through September 2011 from this data source.

Table 1. Data Sources Reviewed

Data Source	Date Ranges Reviewed	Parameters	Comments
Mapper Data – Laboratory chemistry data	Reviewed from 2000 to incident. Database starts with commercial operation of Unit 3 and continues through the incident	See Table	Instruments were compared with bench testing weekly.
Plant Historian (PI) Data	Chemistry Data Starts- 11/16/00 11:00 thru Incident	Most on-line (continuous) chemistry analyzers. See Table for details.	Hourly averages were used to review the data. .
Yokogawa Data	Starts 1/24/08 2:00 to 9/15/11	MS Sodium	Other data points are available, but not reviewed for this opinion.
Startup Log	2000 to incident	Sodium, cation conductivity, and silica	Chemistry parameters were monitored closely during each startup and recorded in the log.

Table 2. Records of Chemistry Data Points by Source

Sample	Parameter	PI	Mapper	
			lab	meter
Condensate Pump Discharge	Sodium	x	x	x
	Cation Conductivity	x	x	x
	pH		x	
	Silica	x	x	x
	Specific Conductivity		x	x
	Dissolved Oxygen		x	
	Ammonia		x	
	Iron		x	
Polisher Effluent (31,32,33)	Cation Conductivity	x	x	x
	Dissolved Oxygen		x	
	pH		x	
	Silica		x	
	Sodium		x	
Condensate after chemical addition	Specific Conductivity	x		
Deaerator Outlet	Dissolved Oxygen		x	
Economizer Inlet	Cation Conductivity	x	x	x
	Specific Conductivity	x	x	x
	pH	x	x	x
	Dissolved Oxygen		X	
	Sodium		x	
	Ammonia		x	
	Silica		x	
	Hydrazine (before discontinued)		x	
	Iron		x	
Boiler	Sodium	x	x	x
	Cation Conductivity	x	x	x
	Specific Conductivity	x	x	x
	Dissolved Oxygen (for OT)		X	
	Silica	x	x	x
	pH	x	x	x
Main Steam	Cation Conductivity	x	x	x
	Sodium	x	x	x
	Ammonia		x	
	pH		x	
	Silica		X	
	Specific Conductivity		x	

Other Data Sources

Other data relied on in this opinion include:

- Sherco Startup Log Books
- Sherco Water Quality Panel Maintenance Logbooks
- Cycle Chemistry Guidelines for Fossil Plants: All-Volatile Treatment Revision 1 1004187, 2002 EPRI, Palo Alto, CA
- GEK 25407c Stress Corrosion Cracking , Revised, September 2001, Last Reviewed, October 2003(GE-NSP00265894)
- GEK72281 Steam Purity--Stress Corrosion Cracking, 1979 (GE-NSP00476318)
- GEK 72281c Steam Purity Recommendations for Utility Steam Turbines, Revised April, 2004 (XCEL_Sherco_07_0167757 thru –772)
- GEK 72281d Steam Purity Recommendations for Utility Steam Turbines, Revised November, 2009 (GE-NSP00000976 thru 989)
- GEK 72281e Steam Purity Recommendations for Utility Steam Turbines, Revised Jan 2011 (GE-NSP00051771 thru -784)
- GEK 72281f Steam Purity Recommendations for Utility Steam Turbines, Revised May 2012 (GE-NSP00465236 thru -251)
- IAPWS Technical Guidance Document: Volatile treatments for the steam-water circuits of fossil and combined cycle/HRSG power plants, 2010
- L. Carvalho, et. Al., “Cation Conductivity and Power Plant Reliability: A 20-Plant Survey” PPChem 2002, 4(5)

Depositions and other documents reviewed prior to preparing this report include:

- Deposition of Timothy Murray, with related exhibits
- Deposition of David Heisick, with related exhibits
- Deposition of Duane Wold, with related exhibits
- Deposition of Steve Breitenbach, with related exhibits
- Deposition of Eloy Emeterio, with related exhibits
- Deposition of Thomas Farineau, with related exhibits

- Deposition of Andrew Witney, with related exhibits
- Root Cause Analysis, Steam Turbine Generator Event of November 19, 2011, Unit No. 3 Sherburne County, Report No. 14439, Thielsch Engineering, Inc., dated May 29, 2013
- Complaint, *Northern States Power Co. et al v. General Electric Co. et al*, Court File No. 71-cv-13-1472

In addition to my review of documents and data, I visited the Sherburne County facility on at least three occasions and interviewed various engineers, operators, chemists, and other NSP/Xcel staff while onsite.

I also attended the deposition of Duane Wold.

III. Background

Sherco #3 has a coal-fired drum boiler with the capacity to generate 6350 klbs/hour of steam at approximately 2980 psig at the steam drum and 1005°F turbine inlet temperature. This steam can produce up to 930 MW. Changes to the burners to reduce NOx in 2008 caused a slight increase in the amount of attemporation spray water used. Most of the spray water is applied to the superheater, very little to the reheater.

From startup, up to the time of the incident, high purity water was supplied to the boiler by well water that had first passed through a demineralizer that consists of three groups of vessels: primary, secondary, and a polisher. The primary strong acid cation is followed by degasifier which is followed by a weak base anion. A secondary train consists of a secondary strong acid cation and a secondary strong base anion. This water is then polished through separate strong acid cation and strong base anion beds. The finished water purity has an approximate conductivity of 0.06 µS/cm. The demineralized water goes into one of three demin storage tanks which are all tied together. Each tank holds proximally 260,000 gallons of water.

All of the feedwater heaters on Unit #3 are and always have been tubed with stainless steel. There are four low-pressure feedwater heaters followed by the deaerator. The high pressure feedwater heaters are in two parallel circuits with two HP heaters in each circuit. The combined flow from the four HP heaters goes to the economizer and the boiler.

The main condenser was tubed with 304 stainless steel and was not re-tubed prior to the incident. There is an inner and outer circulation loop in this very large condenser. This design allowed the unit to continue to operate at a reduced load with either the inner or outer loop isolated and drained. This was done if the Lab or Operations suspected a condenser tube leak.

The Unit #3 GE turbine consists of a single HP turbine, and IP turbine and dual LP turbines. The failure occurred on the L-1 stage of LP turbine B.

From commissioning in 1987 the plant used all volatile treatment with hydrazine (AVT (R)). In 2000, the use of hydrazine was discontinued in accordance with EPRI recommendations to reduce the potential for flow accelerated corrosion (FAC). Unit #3 later attempted to move to oxygenated treatment (OT) for the same reason. They had trouble getting reliable oxygen feed due to problems with the oxygen mass sensors and returned to all volatile treatment without hydrazine, AVT(O). This was the chemistry regime they were working under at the time of the incident.

All of the condensate is polished at all times when the unit is operating. There are three 50% powdered resin (Powdex) polisher vessels. During startup, when the feedwater flow rate is lower, two polisher vessels will often be used. When recoating is required, one vessel is removed from service to be recoated while the other two remain in service. Therefore, even during the recoating, 100% of the condensate is polished. Generally the polishers are recoated about every six weeks. The polisher cation conductivity is continuously monitored and alarmed. The polisher resins are 1.75:1 Anion (Epicor PD-1): Cation (Epicor PD-2). The cation resin is already in the ammoniated form.

The plant uses river water for cooling tower makeup and generally operates between 8 to 10 cycles of concentration. The river water has a high level of magnesium. For a time, the laboratory used magnesium (analyzed by AAS) to try to find very small condenser tube leaks.

A plant historian (PI) system that also monitored the on-line chemistry analyzers was started in 2001.

IV. Monitoring Steam Cycle Chemistry at Sherco #3

The laboratory was in charge of the chemistry of all three units, performing bench testing, and maintaining the online analyzers. This included general maintenance and troubleshooting of this instrumentation. Bench testing was performed routinely (generally every week), and the results compared with the online analyzers. A log book exists for all of the calibration and maintenance work performed on the sample panels for all three units. The log book record is quite detailed and shows regular maintenance not only of the sodium analyzers, but replacement of the cation resin cartridges on the cation conductivity meters and maintenance of the silica analyzers.

Initially, Unit #3 was designed with two online sodium analyzers from Orion. These analyzers were on the boiler water sample and at the condensate pump discharge, and were the SLeD type of analyzer sold by Orion at the time. Either late in 1998 or very early 1999, the analyzer log book shows that the original SLeD sodium analyzers were replaced with sodium analyzers from Honeywell (L&N) on Unit #3 and that there was a new Orion 1811 EL sodium analyzer at the demineralizer effluent. It appears that Unit #3 received the new sodium analyzers first (January 1999). There is a notation in the log regarding a new Orion 2111LL sodium analyzer for the Main Steam sample on Unit #3. It was installed and calibrated on January 28, 2008. Similar new sodium analyzers were installed on the Main Steam sample of the other two units later the same year.

If any of the on-line analyzers went into alarm, a Water Treatment Panel Trouble alarm sounded in the control room. Additional details on which alarm had come in were displayed on the sample panel in the laboratory, which was down the hall from the control room. If the laboratory was not staffed at the time, an operator would go to this panel and determine which parameter was in alarm and how to address the issue.

The laboratory also performed a number of tests that are not commonly done in the utility industry. For example, most power plants in the US and Canada do not have the capacity to test for sodium with atomic absorption spectroscopy (AAS). The fact that the plant purchased this equipment and used it to confirm the on-line steam cycle sodium concentrations is exemplary. The detection limit that the plant used for their analysis of sodium by of flame AAS was 5 ppb. Therefore, the primary function of the sodium analyzer was as a check for the online boiler sodium analyzer where sodium values are generally greater than 5 ppb.

Another interesting test that the laboratory performed was a check on the condenser to determine the presence of extremely small leaks that would not be otherwise detected by either the cation conductivity or sodium analyzer. To do this, the laboratory ran a large volume of condensate through a dedicated cation resin column. The column was then eluted with a small volume of hydrochloric acid. This created a concentrated acidic sample that could be analyzed for magnesium by AAS. The cooling water at this power plant has a high concentration of magnesium relative to other cations. At the same time, a cooling water sample was collected, diluted, and analyzed for magnesium. The amount of magnesium in the eluted sample and the cooling water was then used to back-calculate a theoretical leak rate of cooling water into the hotwell.

The test results were recorded in Mapper which shows regular testing from Unit #3 startup in 1987 to 1995, and occasional testing thereafter. There was a slightly higher reading on this test on November 4, 2002 that caused the laboratory to think that it had detected an incipient condenser tube leak[1]; however, cation conductivity at the Condensate Pump Discharge was 0.12 µS/cm, and the polisher effluent cation conductivity was about 0.1 µS/cm during this same time. If there were actually a leak, it certainly never reached a level where it was detected by these instruments or was exhausting the capacity of the online polishers to remove the contamination. Subsequent testing using this specialized test was lower than the value tested on November 4.

Both of these tests show the level of concern for the steam chemistry and ingenuity of the laboratory staff at Sherco; particularly that they developed a method to find and isolate condenser tube leaks that were too small to produce conditions that would generate an above normal reading for sodium or cation conductivity, on which the rest of the industry relies.

---

[1] XCEL_Sherco_05_0170458

What happens when actual contamination occurs?

It is critical to understand that the steam cycle is just that – a cycle. When contamination enters at one location of the steam cycle, it will cause chemistry-related changes in other areas of the cycle. The same parameter, measured at a variety of sample points, should respond in a predictable way. Other parameters will likewise be predictably affected.

When only one instrument in the cycle is showing higher than normal levels, it is almost always because the instrument is malfunctioning and needs maintenance. However, when multiple instruments measuring the same and different parameters at various points in the cycle act together to indicate contamination, it is almost sure that there is actual contamination in the unit.

If contamination is caused by a condenser tube leak there are many parameters that will respond. These are detailed in Table 3.

Table 3. How cycle chemistry is affected by a condenser tube leak.

Sample Point	Parameter	How it is affected?
Condensate Pump Discharge	Sodium	There is a sharp increase in sodium. This is generally the first and most sensitive response.
	Cation Conductivity	Increases along with sodium, but is not as sensitive as sodium to very low levels of contamination.
	Specific Conductivity	May increase, but the increase may be hidden by changes in the ammonia concentration of the condensate.
Polisher Effluent	Cation Conductivity	Polishers will remove contamination until they become exhausted, at which time the effluent cation conductivity will increase sharply.
Economizer Inlet	Cation Conductivity	Will only increase after the polishers are exhausted and allow contamination to pass through.
	Specific Conductivity	Will increase, but not as markedly as cation conductivity
Boiler	Cation Conductivity	Will increase sharply when any inorganic contamination accumulates in the boiler.
	Sodium	Boiler sodium will increase sharply as contamination accumulates sodium in the boiler water.
	Specific Conductivity	Specific conductivity of the boiler will also increase when contamination enters, though not as quickly as cation conductivity.
	pH	In some cases, pH is affected by contamination though this is less commonly seen in a boiler on AVT.
	Silica	Depending on the cooling water source, an increase in silica in the boiler water is a following-indicator of contamination.
Main steam	Cation Conductivity	Main steam cation conductivity will increase proportional to the amount of contamination that is carried over into the steam. In a drum boiler, the steam will be purer than the boiler water.
	Sodium	Main steam sodium will increase if the boiler is operating at pressures that cause the sodium salts to be volatile in the steam. This is added to any increase in contamination from the attemporation sprays, and any increase due to mechanical carryover.

The first sample point after the condenser where the contamination is entering the system is the condensate pump discharge. There are three parameters that are monitored at this point: sodium, cation conductivity, and specific conductivity. In the case of contamination, the first analyzer to respond is the sodium analyzer, as it is the most sensitive. Following shortly after will be an increase in cation conductivity. Specific conductivity includes contributions from cations, particularly ammonium ion. Therefore, any change due to contamination may be hidden by an unrelated change in the ammonium ion concentration. Since the condensate pump discharge is before the polishers, the analyzers at the sample point allow operators and the laboratory time to detect contamination before it actually affects the boiler and steam chemistry.

Cation conductivity detects not only chloride and sulfate, but other anions such as bicarbonate (HCO_3^-) and organic acids. Under boiler operating conditions, bicarbonate forms carbon dioxide in the steam which passes through the steam turbine without affecting any metallurgy. Therefore, cation conductivity may be slightly elevated with no risk to the turbine, if the reason for the elevated reading is carbon dioxide. Carbon dioxide can enter the cycle via air inleakage in the condenser (air contains carbon dioxide). Small levels of organic chemicals that breakdown into organic acids also raise the cation conductivity. These chemicals also eventually breakdown to carbon dioxide. Also, as the cation resin becomes exhausted, the cation conductivity increases until it approaches the higher specific conductivity reading. After replacing the old resin with a new cation resin, the column will produce high readings for a few hours until the column is rinsed down. For these reasons, the more reliable analyzer for detecting condenser tube leaks is the sodium monitor.

Cation conductivity is next monitored at the polisher effluent. Each polisher vessel has a cation conductivity monitor associated with it. The powdered resins in the polisher have a limited capacity to remove contamination. As the polisher resins become exhausted, that vessel must be removed from service and recoated with fresh powdered ion exchange resin. The plant practice was to recoat the vessels on a set schedule, if they did not first show an increase of cation conductivity at the effluent. The cation conductivity of the polisher effluent was monitored continuously and alarmed in the control room when the reading exceeded 0.25µS/cm.

The Economizer Inlet sample represents the feedwater as it enters the boiler and after it has been purified by the polishers. Cation conductivity and specific conductivity were both monitored at the sample point. As with the condensate pump discharge sample, cation conductivity would increase sharply, if there were contamination, and that contamination exhausted the capacity of the polishers to remove it.

A sample from the boiler was continuously monitored for cation conductivity, sodium, specific conductivity, silica, and pH. The boiler concentrates any non-volatile chemistry in the feedwater, generally 100 times or more, depending on the setting of the boiler blowdown. Therefore, if there is contamination of the feedwater, its effect will be multiplied many times in the boiler and both cation and specific conductivity of the boiler will increase with the cation conductivity. Similarly, any sodium from the cooling water that gets through exhausted polishers will cause the boiler sodium to sharply increase. Cooling water typically also has high silica levels and silica is monitored on the boiler water sample. However, due to its chemistry, silica is generally the following and not a leading indicator of contamination. Gradual increases in the boiler cation conductivity are normal and remedied by opening the boiler blowdown temporarily.

Unlike a once-through boiler, any trace contamination that enters with the feedwater will be reduced by the boiling water interface in the steam drum. Inorganic contaminants, in particular, are not very volatile in the steam at lower steam pressures, but increase as the boiler operating pressure approaches the critical pressure.

In order for a contamination event to be of concern in this particular case, it must affect the steam chemistry. Any contamination that is removed by the polisher or reduced by the boiler blowdown to the point where the steam chemistry is within the normal operating limits specified by GE is not relevant.

With the exception of a minor contribution from feedwater attemporation, (discussed in more detail below) the chemistry of the steam is determined by the chemistry of the boiler. Furthermore, the amount of contamination that is carried over in the steam can be limited by reducing the operating pressure of the boiler.

The final arbiter of steam purity is the monitoring of cation conductivity and sodium in the main steam or reheat steam sample. In the case of contamination on a subcritical (drum) boiler, any contamination will have been detected at the condensate pump discharge, economizer inlet, and the boiler, before it is detected in the steam, providing the plant with advance warning of a problem. Once contamination has been shown to have affected the steam, prompt action must be taken to prevent it from accumulating on the turbine.

The reheat steam sample is generally preferred in the literature because it is at a lower pressure and is easier to condition the sample to the pressure and ambient temperature required for the online analyzers.

A reheat sample also contains any attemporation spray added to the reheater, and so gives the most complete picture of the total steam purity going to the IP and LP turbines where deposits are more likely to form. In some power plants, boiler designs and fuels require a considerable amount of attemporation of the reheater piping to control the hot reheat temperature going to the IP turbine. Specifying the use of a reheat steam sample, covers these cases.

However, in the case of Sherco #3, the amount of reheater attemporation spray used was very small (about 1% of the feedwater flow) and therefore, the main steam sample would be essentially equivalent to the reheat steam sample. The most recent EPRI and IAPWS guidance indicates that testing either the Main Steam or Reheat Steam samples are acceptable.

Once contamination does occur, the most important thing is to locate and isolate the contamination. In the case of a condenser tube leak, this means isolating that half of the condenser that contains the leak. This requires that the unit load and operating pressure be reduced to accommodate the reduction in steam condensing capacity. The plant has a number of ways of removing contamination from the steam cycle. These include not returning any water from the hotwell back to the condensate storage tanks and instead sending it to drain; opening the boiler blowdown; and recoating the polishers as they become exhausted. When all of these methods were applied, the boiler chemistry would quickly be returned to normal operating limits.

V. How Sherco Responded to Out-of-limit Conditions

In the course of its operating history, every unit will experience some condition where the condensate is contaminated. The primary purpose of monitoring the steam chemistry on a continuous basis is to identify any abnormal condition early on and take action so that the equipment is not damaged.

The plant had very experienced Operations personnel on each shift including the Shift Supervisor, Lead Operator, Plant Equipment Operator (Control Room Operator), and Assistant Operator. The laboratory was manned five days per week during the day shift. Operators were very responsive to any chemistry-related alarms at all times and understood to take action appropriate to the alarm condition. If the contamination occurred while the laboratory was staffed, the Laboratory and Operations personnel worked together to address any concerns. On nights and weekends, operators understood that they had to be the first responders to any chemistry alarms. If contamination was suspected, common and immediate responses performed by the operators included opening the boiler blowdown, and precoating any polishers that exhibited elevated cation conductivity. The Shift Superviors were never hesitant about contacting the plant chemist or lab technicians if there were any unusual chemistry conditions. The Laboratory made sure that there was always at least one person from the lab who would answer Operations' call and be available to come to the plant, if needed to address the situation.

The largest potential for contamination at any water cooled power plant is from the condenser, where tens of thousands of condenser tubes are the only barrier between ultrapure condensate and the high conductivity cooling water. The best chemistry tools for monitoring for this contamination are sodium and cation conductivity. Is important to remember that, this plant had a second line of defense to protect the unit in case of contamination—the condensate polishers. In order for contamination to make its way into the boiler and eventually to the steam, the condensate polishers first had to become exhausted.

In the case of Sherco Unit #3, chemistry alarms were set up in the DCS, and the control room operator and shift supervisor were very aware of the importance of these parameters and took prompt action when any contamination was suspected. A good example of this is the case of a condenser tube leak that occurred in July 2003.

At 13:30 on July 23rd, the lab noted an increase in the cation conductivity at the condensate pump discharge. The unit tripped for an unrelated reason at approximately 16:00 and was back on-line sometime between 18:00 and 19:00. At the request of the lab, operators isolated the inside loop of the condenser and the chemistry improved. The boiler blowdown was opened, water was not returned from the hotwell to the working tank, and the boiler operating pressure was limited per the lab to 2000 psig (Operations maintained 1900 psig through this period). The laboratory was covered with a lab technician throughout the night. By early the next morning, with the source isolated and the polishers continuing to remove contamination, the chemistry had improved considerably. The record shows that the boiler remained at this restricted pressure until June 25th at 22:00. By that time, the boiler water chemistry had long since returned to normal. During this entire event, the boiler sodium concentration never approached the top of the EPRI Normal recommendation of 700 ppb (at 1900 psig).

In summary, Sherco responded to this condenser tube leak quickly, and took steps to minimize the amount of contamination that went to the boiler. This action limited the potential for sodium carryover in the steam so that it did not exceed EPRI guidance.

A. What Factors Control Steam Purity in the Steam Cycle?

The steam purity is primarily a function of what goes on in the boiler drum where water is separated from steam. The steam drum is responsible for the separation of boiler water from steam vapor.

Mechanical carryover is a measurement of the amount of water droplets that leave the boiler and are carried out into the steam. Steam drums are carefully designed to remove as many of the water droplets as possible; however, there is always some mechanical carryover from the steam drum into the superheated steam piping. Mechanical carryover increases with operating pressure as the difference in density between the water and the vapor decreases. This makes all mechanical separation more inefficient. Therefore, as the operating pressure of the boiler increases, the demands on water purity in the steam cycle increases accordingly to minimize the effect of any mechanical carryover on the steam purity.

The amount of volatile carryover is governed by the operating pressure of the boiler and by the concentration of chemical contaminants in the boiler water. Of particular interest in this case is the volatility of sodium hydroxide or caustic in boiler water. It is important to note that Sherco did not add any caustic to their feedwater or boiler water on any of the units. The only chemical used to increase the pH of the feedwater or boiler water was ammonia. Since the unit used pre-rinsed powdered resins, with the cation resins already in an ammoniated form, they did not even have the potential for the trace amounts of caustic to contaminate the feedwater, as often occurs in units that have deep bed polishers.

EPRI's research showed that sodium hydroxide is not particularly volatile in steam, and only becomes measurably volatile when the drum pressure exceeds 2500 psig[2]. The Sherco #3 unit is designed to operate up to 2950 psig. So, when the unit is operating under full pressure, if caustic were present in the boiler water, it could be carried over into the steam. However, this also means that, anytime that the boiler was operating at a pressure of less than 2500 psig, the potential for sodium hydroxide to be carried over into the steam was limited to the amount in the mechanical carryover.

EPRI's recommended normal chemistry limits take the design mechanical carryover into account when establishing boiler chemistry limits and ensure that there will be less than the normal limit of that chemical in the steam. For example, the EPRI-recommended chloride level for a boiler operating at 2800 psig on AVT is approximately 30 ppb. This takes into account the volatility of commons chloride salts in steam, plus the design contribution from mechanical carryover at this pressure, and ensures that if the boiler chloride is less than 30 ppb, the steam chloride will be less than EPRI's recommended 2 ppb.

The third source of chemicals in the steam is the attemporation sprays used to control the final temperature of the superheated and reheated steam entering the high pressure (HP) and intermediate pressure (IP) turbines, respectively. The amount of attemporation water used on the Sherco #3 is discussed in more detail below.

---

[2] EPRI AVT Guidelines pg 3-21

B. The Effect of Attemporation Spray Water on Steam Chemistry

The amount of attemporation spray water used can be expressed as a percentage of the feedwater flow, which is equivalent to the steam flow. It is a function first and foremost of the boiler design. Some boilers have more superheater surface area than others and therefore need more or less cooling of the steam via attemporation. Another major factor is the fuel used. The ash content of the fuel changes depending on the source. Also, subtle changes in the fuel chemistry can affect the "stickiness" of the ash, which in turn affects how much of the ash accumulates on the superheater and reheater pendants. Ash acts as an insulator and inhibits heat transfer. Small changes in the coal chemistry have significant affects on the unit's ability to remove the ash. Change in the ash content affects how often the ash will need to be removed from these surfaces.

The plant routinely uses sootblowers to remove the ash and restore the heat transfer properties across the superheater and reheater. Depending on which sootblowers are being used and how often they are used affects the amount of attemporation required. The load on the unit affects the amount of coal being burned and ash being generated. Suffice it to say that the amount of attemporation spray water is constantly changing within a range that is determined by the design and operation of the boiler.

I examined the records of the attemporation spray flows for the years 2003 to 2011. The average spray flow per year is listed in the table below.

Table 4. Attemporation Flows for Sherco #3

Year	SH	RH	Combined	Dil Factor
2003	5.69%	1.44%	7.13%	14.03
2004	5.56%	0.94%	6.50%	15.38
2005	5.56%	0.94%	6.50%	15.38
2006	3.48%	0.63%	4.11%	24.34
2007	3.85%	1.15%	5.00%	19.98
2008	5.23%	1.05%	6.28%	15.92
2009	8.07%	0.88%	8.95%	11.17
2010	8.02%	0.61%	8.64%	11.58
2011	7.27%	0.59%	7.86%	12.72
8 yr average	5.86%	0.92%	6.77%	
Dilution Factor	17.07	109.23	14.76	

For Sherco #3, the superheater attemporation spray is between 3.5 and 8% of the feedwater flow rate. This boiler has far less need for reheater attemporation and it is normally less than 1% of the feedwater flow rate. There was an increase in the amount of superheater attemporation spray flow after Low NOx burners were installed in 2008, as these changed firing patterns in the boiler.

The inverse of the percent attemporation produces a dilution factor for any chemicals that might be in the feedwater, and how they would affect the steam purity. For example, if there were 5 ppb of a sodium salt in the feedwater (this would only occur during a severe contamination event), and the main steam attemporation flow was 5.86% of the feedwater flow, the attemporation spray water would be diluted by 94% of the main steam flow. This means that a feedwater with 5 ppb sodium would contribute approximately 0.29 ppb sodium to the steam via the superheater attemporation sprays. If the superheated steam contained 1 ppb of a sodium salt from the combined volatile and mechanical carryover of the boiler, the total sodium in the steam with the contribution from main steam attemporation, would be 1.29 ppb. The same contaminated feedwater would only contribute 0.05 ppb sodium via the reheat sprays, for a combined sodium going to the turbine of 1.34 ppb.

The example above is an extreme case and never occurred in the period for which we examined the chemistry data. A contamination event that would produce a level of 5 ppb sodium in the feedwater, downsteam of the polisher would have been severe. It would have required first, that there was a contamination source, such as a condenser tube leak, and second that the polishers were either out of service or exhausted. During normal operation, the sodium in the feedwater is already less than 1 ppb, making the contribution of attemporation spray water not detectable.

VI. Review of Plant Chemistry Data

To review the plant chemistry data, I examined data from all three sources. The primary source was the plant historian (PI) data. However, there were times when, unbeknownst to the plant, the data for one or more parameters was not being properly recorded. In these cases, I examined the laboratory data put into the Mapper database, and the Yokogawa data during the period for which that was available. In keeping with the explanation above, I looked first and foremost at sodium and cation conductivity data before and after the polishers. If there were any data that were suspect, other parameters including specific conductivity were examined, to see if any other information substantiated or refuted the suspect data.

A thorough review of the data between the year 2000 and the date of the incident found only one clear case of a condenser tube leak. However, actions taken by the Lab and Operations ensured that it did not contaminate the steam during this event. This was discussed in more detail above in Section V.

Online analyzers often see a spike as the unit is returned to service. Spikes in cation conductivity occur due to carbon dioxide contamination in the sample line. Similarly, the accuracy of sodium analyzers can be affected by a number of factors during startup and not reflect what is actually in the steam cycle. Therefore in reviewing the data, I filtered out data points that were generated when the unit was operating at less than 100 MW as unreliable. Even with this removed there were some higher than normal readings for the first few hours, while the pressure on the unit was increasing, particularly after a cold start. Any time when the unit was starting after the boiler had been drained, the laboratory was staffed around the clock to monitor the startup. Prior to filling the boiler, the water was circulated between the Hotwell and the Deaerator Storage Tank, repeatedly cycling through the polishers to remove any contaminants. When the laboratory had tested the water and deemed it to meet their limits, they allowed Operations to fill the boiler with this water that was already treated with ammonia for pH. Once the boiler started generating steam, the laboratory valved in sample points as the unit came up on pressure and load and tested parameters with bench methods until the on-line analyzers were operating accurately. The boiler was not allowed to reach full operating pressure until the chemistry was under control.

As was discussed above, both chemical carryover and mechanical carryover increase with pressure. Operating at lower pressures limited the carryover of any contaminants in the steam to levels consistent with EPRI and GEK guidelines for startups.

VII. EPRI and GEK Guidance Documents and Their Relationship to Stress Corrosion Cracking

In 1979 GE published its first steam purity document regarding stress corrosion cracking of which we are aware. It was labeled GEK–72281. There is a recommendation for once through boilers, that contaminants not exceed 3ppb of sodium and 0.2 µS/cm of cation conductivity during normal operation. In this document GE states that the once-through guidelines should be easily met by those drum units operating on AVT, but no specific guidance for drum boilers on AVT is given.

There is also guidance for operating with steam chemistry above normal levels. This includes operation at 6 ppb sodium 0.5 µS/cm for less than 100 hours per incident and 500 hours annually. It also lists limits for “emergency conditions” for periods of less than 24 hours equal to

10 ppb of sodium and cation conductivity less than 1.0 µS/cm. GE recommends steam monitoring, but understands that it is often not possible and cautions that it is difficult to get a representative saturated steam sample.

The next revision of this document, GEK–72281 a, appears to have been published in July 1996. This would have been 10 years after the initial iteration of EPRI steam chemistry guidance. In this version, GE published limits for cation conductivity and sodium as well as specific limits for chloride, sulfate, and total organic carbon.

GEK–72281c was published in 2004 and was generally consistent with the EPRI documentation in form and substance, with minor changes in cation conductivity and sodium. By GEK-72281f, (2012) the GE document is precisely the same as the EPRI document.

A comparison of the limits between EPRI AVT Guidelines, and GEK-72281c and f are shown in Table 5. The most recent EPRI Chemistry Guidelines (2011) for steam are the same as in 2002 for drum units on AVT.

Table 5. Comparision of EPRI and GEK Chemistry Limits

Parameter	**EPRI AVT Guidelines (2002)**	**GEK–72281c (2004)**	**GEK–72281f (2012)**
Sodium, ppb	≤ 2	≤ 3	≤ 2
Cation conductivity, µS/cm	≤ 0.2	≤ 0.15	≤ 0.2
Silica, ppb	≤ 10	≤ 10	≤ 10
Chloride, ppb	≤ 2	≤ 3	≤ 2
Sulfate, ppb	≤ 2	≤ 3	≤ 2
TOC, ppb as C	≤ 100		≤ 100

EPRI's initial chemistry guidelines had borrowed a concept of three Action Levels from earlier VGB Guidance documents. Action levels that are found in GEK–72281c repeated the VGB/EPRI Action Levels, including the convention of doubling the limits between action levels for most of the parameters, which was significantly more stringent than GE's 1979 document.

Prior to the publication of GEK–72281c, GE had published a document specific to stress corrosion cracking in GE turbines. A copy of GEK–25407c notes that it was revised in September 2001 and reviewed in October 2003, both of these dates preceding the issue of GEK–

72281c. It is not clear when this document was first issued. Unlike other GEK documents, there is nothing in this document that indicates whether GE intended this to be issued to fossil or nuclear turbine owners, or both.

In the last paragraph of this document, GE states that the steam should be as pure as possible and that the sodium concentration of the steam should not exceed 1 ppb, and the cation conductivity not exceed 0.2 µS/cm. The document actually states 0.2 mmhos/cm, which is the equivalent of 200 µS/cm, but this is an obvious typographical error that Andy Witney would later correct). There is no reconciliation, or discussion, of GEK–25407c and the acceptable sodium limit of ≤ 3 ppb that was published in GEK–72281c, a year after GEK–25407c was last reviewed.

Certainly if GE felt that steam contamination should never exceed 1 ppb sodium for its turbines, then GEK–72281c is in error and there can be no operation in excess of this limit. Therefore the Action Levels and maximum annual exposure limits at the various action levels that are listed in theGEK–72281c document are also misleading. Obviously, such a stance would put GE turbines at a sales disadvantage when competing against other steam turbine manufacturers whose limits are consistent with the EPRI documentation.

In the paragraph just prior to this very strict sodium limit, GE freely admits that the current state of knowledge at that time did not allow them to specifically prescribe the maximum allowable concentration of impurities in the steam that would eliminate the possibility of stress corrosion cracking.

By defining the steam purity limit so tightly, it would be impossible in actual practice to commission and consistently operate in accordance with this guidance, and then stating that "*The GE Company assumes no responsibility for the difficulties resulting from corrosive contamination of the unit*". (Emphasis in the original) GE appears to be attempting to distance itself from stress corrosion cracking issues in its turbines by focusing the blame solely on steam purity.

GE and EPRI have stated that for the case of sodium hydroxide in steam and its relationship to caustic stress corrosion cracking, there is no data that establishes a "safe" level of caustic in steam. However, this manufacturer (and the industry in general) has found that modern power steam cycles can routinely achieve sodium concentrations of <1 ppb in steam. Therefore, operating at a level greater than 3 ppb (or later greater than 2 ppb) must be an indication of an abnormal condition, which must be investigated and addressed before it becomes a corrosion issue to the equipment.

By establishing a "normal" operating limit for any parameter, including sodium, GE (or EPRI) is also establishing the level below which history has shown that there is little risk of a chemistry-related failure. Certainly, for most turbines in the industry, operating within the EPRI guidelines has minimized the potential for corrosion fatigue or stress corrosion cracking.

The three-tier Action Level system that was developed by the VGB and appropriated by EPRI in their first set of consensus guidelines has been copied by others and was incorporated into the GEKs as early as 2004.

As noted above, for linear parameters, the Actions Levels conveniently double for each increasing level. For example, if the normal sodium level for steam is listed as <2 ppb, the top of Action Level I is 4 ppb, the top of the Action Level II limit is 8 ppb and Action Level III is any value >8 ppb.

In establishing these alarm levels, VGB and EPRI chose the simple doubling regime as a way to indicate increasing risk of damage to the equipment, and an increasing sense of urgency that should be placed on finding and correcting the problem.

There is no data that the industry has that shows that operating with, for example, cation conductivity in an Action Level I alarm condition for 8 days, 16 days, or even 80 days will definitively cause corrosion or damage in any particular piece of equipment. Nor is there any data showing that the potential for corrosion for operating the unit in an Action Level II condition is precisely, or even approximately, seven times greater than for Action Level I (allowance of 1 day versus one week).

A few studies have even shown the contrary, in particular regarding the parameter of cation conductivity. Many steam turbines that have an extensive history of operating with cation conductivities significantly higher than 0.2 µS/cm have been shown to have no greater failure rate than those that operate with the cation conductivity less than the recommended limit[3].

The arbitrary nature of the Action Levels is clearly pointed out in the most recent worldwide chemistry guidelines produced by IAPWS[4]. In their guideline for All Volatile and Oxygenated Treatment, they establish only normal operating chemistry and decline to add any type of "Action Levels".

The IAPWS committee, which includes the former head of the EPRI target group over water and steam chemistry in fossil boilers, states that it will leave it to the individual plant operator whether to establish two or three Action Levels, and what actions are to be taken when

---

[3] L. Carvalho, et. Al., "Cation Conductivity and Power Plant Reliability: A 20-Plant Survey" PPChem 2002, 4(5)
[4] IAPWS—International Association for the Properties of Water and Steam, www.iapws.org

these are reached. They freely admit that "adequate research has not been conducted" into the levels of risk of corrosion or damage associated with each parameter; and that the doubling of the limits between what has been termed Action Level 1, Action Level 2, and Action Level 3 is simply industry convention. Similarly, they also state that the annual accumulation limits are simply a guide to determine when some overall action such as retubing a condenser or performing a chemical cleaning would be prudent. Here again, they clearly do not call out any specific corrosion risk to equipment based on the cumulative annual time a single parameter in the steam cycle is operating in an arbitrarily set "Action Level".

They are even somewhat circumspect about the establishment of the normal operating limits, indicating that these are simply "considered as the normal operating limits under stable operations" and not that they are limits that have been proven to pose no risk to the equipment. In fact, as risks are identified, the "normal limits" issued by organizations such as IAPWS and ERPI are changed to reduce those risks. This has already been the case with feedwater pH levels and flow accelerated corrosion.

In summary, the GEK–72281 guidance through its various iterations had relied on the EPRI limits, including ERPI's Action Level structure. These limits are also generally consistent with the steam purity limits of other turbine manufacturers, which would mean that GE is not disadvantaged when competing against other manufacturers for new business.

There are mechanical and chemical limitations on the purity of the steam that can be achieved in the normal daily operation of the plant. Presuming these limits are achieved by the plant, it is the responsibility of the turbine manufacturer to design and build a turbine with appropriate stresses and materials to handle the normally achievable steam purity.

What GE knew about L-1 failures in their turbines, how they notified their clients regarding required inspection intervals, and how they were responding internally to their history of failures is covered in more detail in the Expert Opinion of Karen Fuentes.

Date:__________January 29, 2016___________

Prepared by:______________________________

David G. Daniels
Vice President & Senior Principal Scientist
M&M Engineering Associates, Inc.

2012 TIME AND MATERIALS
SCHEDULE OF FEES

Direct Labor Category	**Straight Time Per Hour**
Senior Principal Engineer/Scientist/Specialist	$285.00
Principal Engineer/Scientist/Specialist	$275.00
Senior Consulting Engineer/Scientist/Specialist	$240.00
Consulting Engineer/Scientist/Specialist	$215.00
Senior Engineer/Scientist/Specialist	$190.00
Engineer/Scientist/Specialist	$165.00
Engineering Specialist/Accounting Specialist	$125.00
Senior Metallurgical Technician	$105.00*†
Metallurgical Technician	$95.00*†
Administrative Services	$70.00*

Relevant Policies: Deposition and court testimony will be billed at two times the published rate. Based on client pre-approved overtime, an additional 50% premium will be billed for each hour these non-exempt (*) categories are required to work (including travel) in excess of 40 hours per week where M&M Engineering Associates, Inc. holidays (9) are not involved. For required holiday work or travel, the premium for these category rates (*) will be 150%.

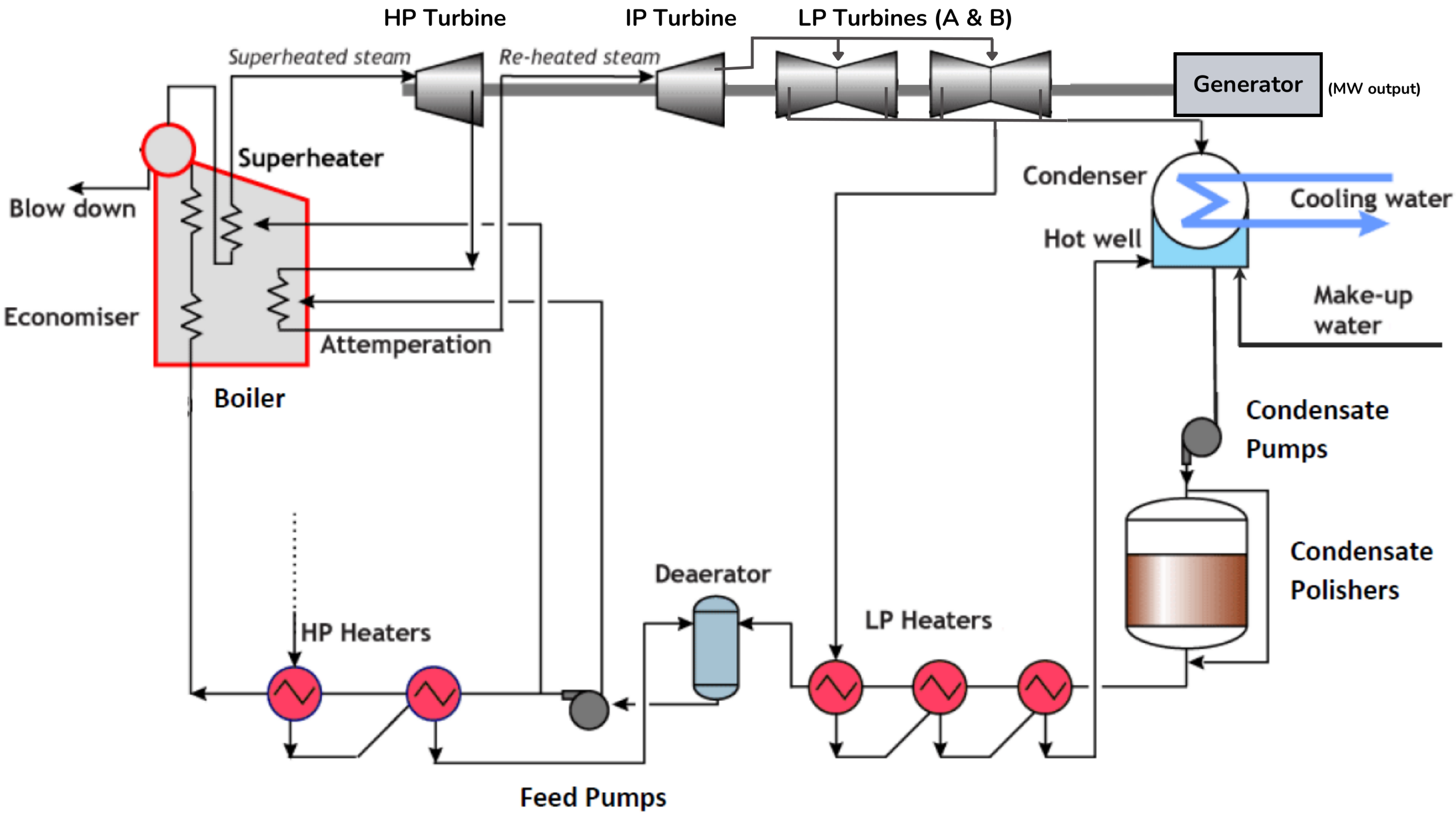
A minimum charge of $750 may apply.

Other Direct Costs (ODC)

ODC are billed at 10% over costs and include other non-labor costs incurred for the direct benefit of our client's work. These costs may include such items as:

Travel & Subsistence	Ordinary and necessary expenses including most economical available air fare and/or surface travel.
Scanning Electron Microscope (SEM) Use Fee	$125.00 per SEM hour, plus operator labor.
Laboratory Use Fee	A $15.00 per hour lab expendables charge will be added to the labor rates for Technicians in this labor category. †
Outside Services	Alloy confirmation, consultants, others as required.
Freight	Shipment of parts to M&M Engineering or return of parts to client if client so requests. Report transmittal.
Storage	Appropriate portions of the hardware received on a given project will be stored at M&M Engineering for one year following the completion of the project. The hardware will then be discarded, unless the client wishes for M&M Engineering to continue storage, in which case a nominal storage fee will be assessed to the client. Special situations will be addressed on an individual basis.

All amounts shown are in $US.


HP Turbine
IP Turbine
LP Turbines (A & B)
Superheated steam
Re-heated steam
Generator
(MW output)
Superheater
Blow down
Condenser
Cooling water
Hot well
Economiser
Attemperation
Make-up water
Boiler
Condensate Pumps
Condensate Polishers
Deaerator
LP Heaters
HP Heaters
Feed Pumps

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Schedule 4

Exhibit___(DGD-1), Schedule 4 has been marked Not-Public in its entirety. This Schedule was provided by General Electric (GE) subject to a confidentiality agreement and GE consider it to include confidential and proprietary information to GE. Therefore, the Company considers this Schedule to be trade secret data as defined by Minn. Stat. §13.37(1)(b) and Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** GEK 25407c Steam Chemistry Guidance
2. **Authors:** General Electric Company
3. **Importance:** Confidential and proprietary information of GE and subject to a confidentiality agreement between the Company and GE.
4. **Date the Information was Prepared:** October 2003