Direct Testimony and Schedules
Darin W. Schottler

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

DARIN W. SCHOTTLER

On Behalf of

NORTHERN STATES POWER COMPANY

June 16, 2023

Exhibit___(DWS-1)

Restoration

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Darin W. Schottler. My business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

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

A. I am employed by Xcel Energy Services Inc. I am the Director of Regional Capital Projects. In this position, I am responsible for capital project planning and execution of capital projects in Energy Supply for Xcel Energy in the NSP MN and NSP WI operating companies. I lead a team of project managers, engineers, contractors, consultants and other various supporting resources to complete capital projects.

Q. FOR WHOM ARE YOU TESTIFYING?

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. In my current role role, I am responsible for the development and execution of all capital projects in Energy Supply for the Company. Prior to this assignment, I was the Project Manager responsible for the restoration of Sherco Unit 3, following a November 19, 2011 catastrophic failure at that facility (Event). My qualifications and experience are more fully described in Exhibit___(DWS-1), Schedule 1.

Q. PLEASE SPECIFICALLY DESCRIBE YOUR EXPERIENCE AT THE SHERCO PLANT AND WITH SHERCO UNIT 3.

A. I was the Project Manager responsible for the restoration of the Sherco Unit 3 (Unit 3) to service following the event of November 19, 2011 (Event). As the Project Manager, I led a team that performed a number of tasks necessary to return Unit 3 to service, including the following:

1. Conducted post-incident safe shutdown and layup of the affected portions of the unit[1];
2. Performed detailed assessments of the damage and condition of the unit;
3. Conducted forensic analysis of the root and contributing causes of the failure;
4. Prepared engineering recommendations, detailed design specifications and drawings for restoration of the unit;
5. Implemented the purchasing of equipment, parts, materials and services to effect the repairs; and
6. Coordinated the integrated commissioning, testing, and return to commercial operation following the completion of the restoration work.

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

A. My testimony focuses on the restoration efforts conducted on Sherco Unit 3, following the Event. I discuss the work performed to restore Unit 3 to commercial operational service status, the timing and scheduling of that work, and the cost of that work. I also discuss how the restoration work has benefited our customers in the years since Unit 3 returned to service beyond the benefits

[1] "Layup" refers to placing a plant or equipment in a state where it can remain un-used for a period of time while minimizing any degradation.

that would have been realized if the Event and subsequent restoration had not occurred.

II. RESTORATION WORK AND ASSOCIATED WORK AT UNIT 3

Q. FIRST, PLEASE PROVIDE AN OVERVIEW OF THE RESTORATION WORK REQUIRED AT UNIT 3 FOLLOWING THE EVENT.

A. The restoration work started the day the Event occurred, November 19, 2011, and continued through three phases briefly described below, concluding when the unit was returned to operation in September 2013 and fully released to the Midwest Independent System Operator (MISO) in October 2013.

The Event occurred at the end of a planned overhaul to install uprated components into the high pressure and low pressure steam turbine and auxiliary equipment on Unit 3. The uprate was completed as planned, and the plant staff were conducting post-uprate commissioning testing to confirm the equipment was ready to return to commercial operation at the uprated conditions. During one of the commissioning tests, a major failure occurred, which partially destroyed the steam turbine, generator, and many auxiliaries. The Event started in the "B" low pressure turbine section when a group of blades separated from the turbine rotor causing a major imbalance in the spinning mass of the turbine generator. The major imbalance shook the turbine generator set and the foundation to which it was attached to the point that the bearings, seals, and many securing components were torn loose from their attachments. The loss of seals resulted in lubricating oil leaving the bearing area and making contact with hot steam surfaces which erupted in a fire. The hydrogen seals were also damaged and large volumes of hydrogen escaped the generator and found a spark to ignite and burn. All of this occurred in a matter of seconds and workers near the machine had to flee the area to avoid the flying debris, fires, and tremendous noise. Fortunately, no significant injuries occurred, and the plant operators were able to isolate the source of the hydrogen and oil and shut off the steam supply quickly. The Event included a response from the local fire department to extinguish the fires, ventilate the smoke, and ensure all staff were accounted for and safe.

The first phase of the restoration effort started with isolation and layup of Unit 3 following the Event. Isolation is the physical shutdown and separation of live systems and equipment in Unit 3 from the remaining portions of the Sherco plant that were expected to remain in service to generate electricity for our customers while the Company and our partner, Southern Minnesota Municipal Power Agency (SMMPA), determined the plans for restoration of Unit 3. The layup work consisted of removing the remaining fuel, oil, chemicals, water, and other chemicals that had been loaded into the various systems and equipment on Unit 3 in anticipation of normal operation, and preparing the unit for remaining idle for an extended period of time, such that the unit and all systems would be preserved with the least amount of degradation when the time came to return the unit to operation. For example, the boiler was filled with nitrogen inside all the tubes and pressure parts to reduce corrosion.

The second phase of the restoration was the disassembly, inspection, and assessment of the damaged systems and components. This phase also included the investigation and determination of the root cause of the Event. The turbine, generator, and auxiliary systems were systematically and carefully disassembled and inspected. The turbine, which experienced the most damage, was taken apart piece by piece starting with the "normal" disassembly that occurs during a planned overhaul, but then the disassembly went much further into areas that are not typically removed. For example, all the bearing support housings and even the foundation attachment systems were removed for inspection and assessment. The identification of the root cause was paramount to the Company so that we understood what changes were required to ensure that the unit could be returned to service with confidence that another failure would not occur. Extreme care was taken to collect and preserve evidence for examination by multiple parties, experts, and laboratories through the use of approved "Protocols." Fracture surfaces were particularly valuable and were treated with the utmost care and control to preserve the information contained on them for forensic analysis. The Company retained a well respected failure analysis firm, Thielsch Engineering, to guide this portion of the work and to provide on-site oversight of the evidence collection and preservation. The experts reviewed the evidence, inspection reports, and laboratory analysis in addition to performing many other related activities to determine the root cause, a process detailed more fully in the testimony of Company witness Mr. Anthony A. Tipton.

The third and final phase of the restoration project was the actual repair, replacement, and return to service of the unit. This phase started at the completion of the turbine generator disassembly once the information needed for the root cause analysis was obtained in February of 2012 and continued until September 2013 when the unit was returned to operation. The turbine, generator, and many auxiliaries were completely disassembled, parts were shipped off site for repairs, and new parts were procured to replace items that could not effectively be repaired. For example, the two low pressure rotors were shipped to the General Electric (GE) facility in Chicago for removal of the damaged blades, complete inspection of all high stress areas, and ultimately for replacement of the root area that was found to be the root cause of the Event. GE then replaced many of the blades, performed a set of factory tests, including high speed balancing, and shipped the rotors back to the Sherco plant. Other large components shipped offsite for inspections and repairs included the generator rotor, high pressure and intermediate pressure rotors, all of the bearing standards, the boiler feed pumps and their turbine drives, in addition to numerous smaller components. The repairs for some components were performed on site due to size, shipping limitations, and other complexities; examples of onsite repairs include the turbine casings, generator stator, foundations, piping, wiring, and condensers.

In some cases, repair of existing components was not possible, and thus replacements were required. For example, the condenser tubes were damaged by flying debris and although only a few dozen tubes were damaged, all the tubes had to be replaced to gain access to the tight spaces between the tubes where smaller pieces of debris would "hide-out" and eventually wear through and cause tube leaks in the future. Tubes cannot be removed and reinstalled, and thus had to be replaced. Replacement of the tubes also presented an opportunity to make improvements in the condenser waterboxes where the tubes are terminated. For example, the tubesheets were replaced on 50 percent of the condenser outlet tubes. Other major replacements included the generator exciter, the generator core and windings, the turbine-generator condition monitoring system, the overspeed protection system, all the seals and packing (steam, oil, and hydrogen), bearings, and instrumentation. GE provided over 25,000 new parts to complete their portion of the work. Another example of the magnitude of this effort was the 80 truck loads of parts deliveries for the restoration. The restoration work required 191 contracts/purchase orders to complete the project.

During this third phase of the work, after complete disassembly of the unit, the extent of damage became fully known and the required repairs could be defined. This Event was unlike any other in the size, complexity, and efforts required to restore the unit. In some cases, repair techniques were invented at the jobsite. For example, the laser machining of the horizontal mating surfaces required large precision machines that were sensitive to even a few degrees of temperature difference, which required tight environmental controls while machining was in progress. The set up and operation of these machines had never been performed on a large unit like Sherco Unit 3.

Q. HOW MANY PEOPLE WERE REQUIRED TO COMPLETE THE RESTORATION WORK?

A. The restoration project was a large effort and required an average of approximately 200 people from the spring of 2012 through completion. This included craft workers and supervisors who were engaged full time in the on site work. Although this number is the average, at one point, the site workforce dedicated to this project reached 320 people which included a combination of Company employees, contract staff employees, and contractors. The team worked a total of 1,083,000 hours at the plant to restore the unit.

Q. HOW DID THE COMPANY MANAGE THE WORK AND PEOPLE NEEDED FOR THIS COMPLEX RESTORATION?

A. All work performed to complete the three phases of the restoration was planned and scheduled using a critical path scheduling tool known as Primavera (P6). The master schedule evolved as the project progressed and more work was identified and specific steps become known. The final version of the schedule had over 7,000 activities. The first five pages of the 215-page Total Project Schedule is included as Exhibit___(DWS-1), Schedule 2. Each activity is sequenced to optimize the most effective use of resources and time by linking activities to predecessors, successors and other constraints. The schedule identified the critical path to complete the restoration, which is the set of activities that pace the overall restoration project. Many activities do not impact the critical path, and it is imperative that the project manager knows which activities do, to ensure that the project is completed as expeditiously as possible.

Q. HOW LONG DID THIS WORK TAKE?

A. The incident occurred on November 19, 2011, taking Unit 3 out of service on that date. Following a short period of time to safely shutdown and isolate the unit, a full mapping and cataloging of the debris field was conducted to record the location of all debris liberated or created by the Event. Protocols for disassembly were created to protect and preserve evidence and give interested parties an opportunity to safely participate in the disassembly process which started on December 15, 2011. Disassembly was substantially complete by May 2012, however, additional disassembly would be required based on the results of engineering assessments from the results of the first disassembly to effect the required repairs and replacements. The investigation of the root cause started immediately after the Event and continued through all stages of disassembly and inspections and was substantially complete with the publication of Mr. Tipton's Root Cause Analysis on May 29, 2013. The repair work started in February 2012 and was completed in July 2013 allowing startup, testing, and commissioning to begin in August 2013, followed by full release to market dispatch in October 2013. For simplicity and consistency, in the rest of my testimony I refer to the entire time period from the date of the Event to Unit 3's return to service as the restoration period.

Q. DID THE COMPANY STRIVE TO COMPLETE THIS WORK EXPEDITIOUSLY, THEREBY MINIMIZING COSTS?

A. Yes. The Company acted reasonably throughout this time period and performed the work as expeditiously as we could, minimizing the costs of the Event. The restoration was approached and managed like other forced outages on our units, where returning the unit to service as quickly as possible without sacrificing safety and quality is paramount. For example, the labor crews worked a large amount of overtime. This overtime was mostly applied to the critical path work and generally was based on working six days per week and 10 hours per day and working every other Sunday. We considered working all Sundays, but the workers need a physical and mental break at least one day every two weeks on a long duration overhaul like the restoration of the unit. We also considered working more overtime (for example 12 hour days), but this is known to reduce productivity, increase labor and contractor costs, while also potentially increasing risk of injuries and poor quality through rushed work. The Company worked to optimize the schedule against the costs to return the unit to service as quickly and safely as practicable. In sum, for the Company to have reduced one cost center, such as labor costs, it would have needed to reduce overtime and thus perform the work more slowly, which in turn would have increased the Restoration Period and thereby increased replacement power costs. Alternatively, if the Company would have attempted to increase the speed of the restoration to reduce replacement power costs, it would have had increased overtime and expediting costs, scheduling conflicts, and potentially created safety risks.

Q. WHAT TOTAL COST DID THE COMPANY INCUR FOR THIS RESTORATION?

A. As discussed by Company witness Mr. Allen D. Krug, and in prior filings made by the Company in these dockets, the Company incurred approximately $104.3 million in restoration costs allocated to the Minnesota jurisdiction.

Q. WERE THESE COSTS COVERED IN FULL OR IN PART BY INSURANCE PROCEEDS?

A. Yes. As Company witness Mr. Robert L. Miller discusses, the Company worked closely with our insurers throughout this process, ultimately recovering nearly $99 million of these costs.

Q. DID THE COMPANY ALSO RECOVER FUNDS FROM GE, AS PART OF A SETTLEMENT (GE SETTLEMENT) RELATED TO LITIGATION THE COMPANY BROUGHT AGAINST GE DUE TO THE EVENT?

A. Yes. Mr. Krug provides further discussion of this matter. While the GE Settlement terms are confidential, it is my understanding that the GE Settlement did not describe these settlement proceeds as covering any particular costs. It is also my understanding that the Company returned these proceeds to customers through the monthly fuel adjustment clause.

III. DIRECT AND INDIRECT CUSTOMER BENEFITS OF RESTORATION AND RELATED WORK

Q. DID THE RESTORATION PROCESS PROVIDE ADDITIONAL BENEFITS TO THE COMPANY AND CUSTOMERS BEYOND RETURNING UNIT 3 TO SERVICE?

A. Yes. Several benefits – some measurable and others not readily measurable – were realized as a result of the restoration work and additional work performed during the restoration period. The restoration project, because of the magnitude of the Event and the extent of the damage to multiple components, requiring significant amounts of inspections, repairs and replacement parts, provided benefits that included: (1) the avoidance of costs for future work that was necessarily performed as part of the restoration and therefore no longer needed to be performed in the future; (2) the reduction of future planned outage time; (3) improved performance and efficiency of the unit; and (4) reduction of the future risk of failure events.

To explain these benefits, I will first discuss the types of work performed that benefited the customers beyond the restoration goal of returning Unit 3 to service, and then I will explain more fully each of the four benefits listed above, providing a reasonable estimated value of the benefit where feasible.

A. Defining the Types of Work During the Restoration Period that Benefited Customers

Q. WHAT DO YOU MEAN WHEN YOU SAY THAT RESTORATION WORK NECESSARY TO RETURN THE UNIT TO SERVICE PROVIDED ADDITIONAL BENEFIT THE CUSTOMERS?

A. The magnitude of the Event resulted in many components, auxiliaries, and systems being significantly damaged, at times beyond repair. At the time of the Event, Unit 3 had been in service for more than 22 years. Where equipment, or parts of equipment, were destroyed beyond repair, the restoration work necessarily required purchasing of new equipment and parts. For example, the twelve blade rows of each of the two low pressure turbines were significantly damaged. Many of those blades were original to the Unit, but as a result of the damage sustained, those blades had to be fully replaced with new blading. That work, while necessary to return Unit 3 to service, also provided additional measurable benefits to the Company and customers including the avoidance of costs and outage time associated with future planned blade replacement, the improved equipment efficiency and reliability of the unit, and the reduction of risk of a future failure event. The specific benefits of this example and others are discussed more fully below.

Q. In addition to the required restoration work, did the Company perform other work on Unit 3 during the time that it was out of service?

A. Yes, significant other work was performed during the restoration period which was not required to return the unit to service but was performed as an opportunity to take advantage of the extended time frame when the unit would be offline. A list of many of these "Opportunity Projects" is attached as Exhibit___(DWS-1), Schedule 3. One of the most significant projects was the replacement of the Unit 3 cooling tower. The cooling tower was planned for replacement during an extended future overhaul in 2014 due to its deteriorated condition. Once the Company realized the unit would be offline for enough time to complete the replacement without extending the restoration outage duration, the project was accelerated into 2012. The cooling tower replacement project provided several benefits, including: the replacement of the cooling tower without a future extended overhaul (outage), improvement of the efficiency of the tower which improves the performance of the unit, reducing the amount of coal burned and emissions released, and reducing the risk of a failure that could force the unit offline at an in-opportune time and for an extended period of time. The cooling tower direct capital replacement costs were lower in 2012 than would have occurred in if the replacement had been performed in 2014 since the restoration project provided an extended window to complete the work without significant overtime and the costs were lower since we saved two years of escalation.

Q. DID THESE "OPPORTUNITY PROJECTS" EXTEND THE TIME IT TOOK TO RETURN UNIT 3 TO IN-SERVICE STATUS?

No. The work performed beyond that which was necessary to return the unit to service did not extend the restoration period. Rather, these Opportunity Projects were performed to take advantage of the extended outage, reduce cost/duration of future overhauls, reduce risk or future outages, and/or improve the performance of the unit. The work was performed either concurrently with or "off" the critical path for the restoration project. The critical path for the restoration only involved work required to restore the unit to service as expeditiously as possible. Other upgrades and component/system replacements that were not required to return the unit to service were performed "off" the critical path and did not delay the return to service date. As just discussed, some of the work on the critical path as well as these additional Opportunity Projects benefited customers beyond returning the unit to service.

B. Additional Benefits to Customers from Restoration Work and Opportunity Projects

Q. CAN YOU MORE FULLY DISCUSS HOW CUSTOMERS BENEFITED FROM THE COMPANY PERFORMING BOTH THE NECESSARY RESTORATION WORK AND ADDITIONAL WORK DURING THE RESTORATION PERIOD?

A. Customers benefited in multiple ways, beyond simply restoring Unit 3 to in-service status. First, they received new and/or upgraded equipment for many of the impacted systems/equipment damaged during the Event. Secondly, they received the benefit of thorough inspections and repairs during the restoration. Thirdly, they received the performance benefits of the additional work and received the benefit of this work being completed without having to take a future outage (forced or planned), or allowing the duration of a future outage to be shortened. The customers also benefited from the increased performance of this new/upgrade equipment and from the reduction in risk that resulted from this work. Finally, customers benefited as the insurance proceeds covered many of the costs.

These benefits can be grouped into four categories: (1) the avoidance of direct cost of future planned work that was instead performed as part of the necessary restoration work, (2) the reduction of future outage time; (3) improved performance and efficiency of the unit; and (4) reduction of the future risk of significant failure events. I provide a summary chart of these benefits in Exhibit___(DWS-1), Schedule 4.

Q. WHAT DIRECT COSTS OF FUTURE WORK WERE AVOIDED BECAUSE OF THE RESTORATION WORK AND ADDITIONAL OPPORTUNITY PROJECTS?

A. Direct costs for future work were avoided in cases where the insurance proceeds covered the cost of planned future work, including inspections, repairs, replacements, and/or upgrades. For example, insurance proceeds were used to replace the L-0 blades on both ends of both low pressure turbines, because the existing blades were damaged beyond repair during the Event. This replacement was planned to occur in 2020 before the Event occurred, and would have cost approximately $5,500,000 in capital expense to complete (approximately $2,400,000 of which would have been allocated to the Xcel Energy Minnesota jurisdiction). This capital cost was completely avoided in this case since insurance covered the full cost of the blade replacement work. Even more, the completion of this work during the restoration period avoided an extended outage in 2020 that would have required one to two weeks of additional outage time to complete. As shown in Exhibit___(DWS-1), Schedule 4, the total avoided future costs associated with this and similar projects is approximately $16,900,000 (approximately $7,400,000 of which would have been allocated to the Xcel Energy Minnesota jurisdiction).

Q. DID THE COMPANY PERFORM WORK DURING THE RESTORATION PROJECT TIMELINE THAT REDUCED OR ELIMINATED THE DURATION OF FUTURE PLANNED OUTAGES OR OTHER POTENTIAL FORCED OUTAGES?

A. Yes, many work activities performed as part of the restoration project reset maintenance intervals. Significant examples include replacement of the L-0 turbine blades (mentioned above), replacement of the cooling towers, the boiler feedpump turbines inspections and overhauls, the main steam turbine valve inspections and overhauls, and the generator rotor and stator rewinds. The generator rotor rewind also included an upgrade to correct a design deficiency that significantly reduced the risk of a future failure. All this work was performed as part of the restoration project.

Q. ARE YOU ABLE TO ESTIMATE THE AMOUNT OF FUTURE PLANNED OUTAGE TIME AVOIDED BECAUSE OF WORK PERFORMED DURING THE RESTORATION PROJECT, AND IF SO, WHAT IS THAT AMOUNT?

A. Yes. As shown in Exhibit___(DWS-1), Schedule 4, the total duration of avoided planned overhauls and extensions to planned overhauls is estimated at 10 to 11 weeks. Company witness Mr. Nicholas J. Detmer estimates the value of the replacement power costs saved from these future events at approximately

$5,800,000 to $6,400,000 on a Total Company basis (or $4,300,000 to $4,800,000 for the Minnesota jurisdiction).

Q. DID THE COMPANY PERFORM WORK DURING THE RESTORATION PROJECT TIMELINE THAT IMPROVED THE PERFORMANCE AND EFFICIENCY OF THE UNIT?

A. Yes, many of the repairs, replacements, and upgrades performed as part of the restoration improved the performance and efficiency of the unit. For example, the new components installed in the low pressure steam turbine are estimated to have reduced the fuel consumption by 0.25 to 1.0% for the same output levels which is estimated to have saved our customers $4,500,000 in fuel costs on a Total Company basis (approximately $3,300,000 for the Minnesota jurisdiction) from the time of the Restoration until the new components would have been installed at a future planned outage.

Q. DID THE COMPANY PERFORM WORK DURING THE RESTORATION PROJECT TIMELINE THAT REDUCED THE RISK OF FUTURE FORCED OUTAGES?

A. Yes. Thousands of components, parts, systems, and subsystems that comprise Sherco Unit 3 were inspected, assessed, and repaired/replaced to the extent that risks of future forced outages, or even discovery (with risk of outage extensions) during planned outages were greatly reduced. Examples include new turbine blades, generator rewind/restack, turbine upgrades and component/system replacements, generator upgrades and component/system replacements, and balance of plant upgrades and component/system replacements.

Q. IS IT POSSIBLE TO QUANTIFY ALL OF THE ADDED VALUE TO CUSTOMERS OF THE COMPANY COMPLETING THE FULL SCOPE OF WORK PERFORMED DURING THE RESTORATION PERIOD?

A. Some of the customer benefits can be calculated, such as the avoidance of direct cost of planned future work that was ultimately performed as part of the restoration and covered by insurance proceeds. Other benefits can be estimated, such as the replacement power costs for avoided downtime due to shorter outages and avoided forced outages. Yet other benefits cannot reasonably be measured. For example, while the avoidance of a future failure event similar to the Event certainly has benefit to customers, it would be speculative to assign a value.

IV. UNIT 3 PERFORMANCE

Q. HOW HAS UNIT 3 PERFORMED SINCE BEING RETURNED TO SERVICE FOLLOWING RESTORATION?

A. Sherco Unit 3 has performed exceptionally well in the years since returning to service in 2013. The reliability of the steam turbine, the electric generator, and the other auxiliary equipment most impacted by the Event have exceeded expectations every year since the Event. The overall Sherco Unit 3 Equivalent Availability Factor (EAF) has averaged 85% from 2014 through 2022 compared to just over 82% in the seven years preceding the Event. The primary cause of less than perfect EAF in recent years is related to unit systems that are not related to those damaged during the Event or repaired during restoration. In addition to reliability, the efficiency of the unit has improved compared to before the Event. Some of this efficiency improvement is related to the turbine upgrades that were planned before the Event. The total impact of this improved performance is estimated at approximately $3,300,000 of annual fuel cost reduction (or approximately $2,400,000 for the Minnesota jurisdiction). This reduction in fuel cost also has benefits in reduced CO_2 emissions, reduced NOx emissions and savings of lime consumption to remove the sulfur emissions associated with burning coal. However, I have not included these benefits in the summary chart I present, below. I provide this estimate solely to demonstrate the improvement in performance of Unit 3 after restoration.

Q. TO WHAT DO YOU ATTRIBUTE UNIT 3'S IMPROVED PERFORMANCE AFTER THE RESTORATION PERIOD?

A. The turbine, generator, and auxiliaries were thoroughly inspected, analyzed, repaired, or replaced with new, or in many cases modern day equivalent new components, which were better than the original components. The turbine and generator set, including equipment that was physically connected, functionally connected, or simply in reasonably close proximity, was examined to a level of detail that would not normally be performed for a power plant and these examinations revealed conditions, including likely weaknesses from original installation that were corrected and thereby reduced the risk of future forced outages. In some cases, equipment that would have been inspected and repaired in future overhauls was inspected and repaired during the restoration period, which reduces the risk of equipment failures. For example, the steam turbine mounting system had deteriorated under the baseplates of the machine and were hidden from view, however, the baseplates were completely restored to new condition using improved construction tools and materials that were not available in 1987 when the unit was initially installed. The rotating equipment condition monitoring system was replaced with its modern equivalent which greatly enhances the operations capability of the unit.

V. LABOR AND MATERIAL SAVINGS DURING RESTORATION PERIOD

Q. WERE THERE ANY ADDITIONAL SAVINGS THAT BENEFITED CUSTOMERS DURING THE RESTORATION PERIOD NOT ACCOUNTED FOR IN THE TESTIMONY ABOVE?

A. Yes. There were beneficial savings for the customers due to the reallocation of staffing resources and a reduction in material costs.

Q. PLEASE EXPLAIN THE CUSTOMER SAVINGS DUE TO THE REALLOCATION OF STAFFING RESOURCES.

A. While Unit 3 was not operating during the restoration period, some plant operators and maintenance staff were not required. The Company nevertheless retained the resources and reassigned them to Units 1 and 2 for the duration of the restoration. Because of this reallocation of resources, the Sherco plant on whole had a reduction in overtime expenses in the amount of $705,382 on a Total Company basis (approximately $525,000 on a Minnesota jurisdictional basis) and is discussed further in the report by the Kenrich Group at pages 30 and 31. This report is included in Company witness Nicholas J. Detmer's testimony as Exhibit___(NJD-1), Schedule 5.

Q. PLEASE EXPLAIN THE MATERIAL COSTS SAVINGS THAT BENEFITED CUSTOMERS.

A. While Unit 3 was out of service during the restoration period, the Company – and therefore the customers – did not incur the costs of materials typically used to operate the unit. When material expenditures for the restoration period were compared to the material expenditures for a normal operating year, 2010, the material costs savings for the restoration period was $990,836 on a Total Company basis (approximately $735,000 on a Minnesota jurisdictional basis).

This is also discussed in the Kenrich Group report at pages 30 and 31. *See* Exhibit___(NJD-1), Schedule 5.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My testimony summarizes the significant work performed by the Company to restore Unit 3 to service. I also document the significant collateral benefits realized and the risks reduced from the extended restoration period which go beyond simply returning the unit to service in the condition that existed before the Event. Moreover, other benefits, such as the reduced risk of future incidents, cannot be quantified but have benefited customers nonetheless. Consequently, I can say that based on my evaluation of the work performed during the restoration process, the customer benefits were no less than (and likely in excess of) approximately $16,260,000, broken down in Table 1 below:

Table 1

Estimated MN Customer Benefit

Category	Estimated MN Customer Benefit
Avoided future costs	$7,400,000
Avoided replacement power needs	$4,300,000 - $4,800,000
Improved performance (fuel savings)	$3,300,000
Other labor and material savings	$1,260,000
TOTAL	$16,260,000 - $16,760,000

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications
Darin W. Schottler

I have been employed by Xcel Energy since 2003, in various engineering areas. In my current role as Director of Regional Capital Projects, I am responsible for strategy, budgeting, development, and execution representing over $2.5B in capital investments. These projects include extensive experience with wind, solar, hydro, and traditional technologies. In my previous roles, I was responsible for development, deployment, and implementation of the new Operational Model for providing engineering services at Energy Supply facilities. At Sherco I was responsible for management of the Sherco plant engineers and technicians, consisting of training, development, workforce planning, and performance. I was a key member of the plant management team responsible for safety, reliability, financial, and environmental performance objectives. I was the project manager for the Sherco Unit 3 Restoration Project. I was the project manager for the Riverside Repowering Project (MERP). I was also the project manager for multiple other significant projects including analysis of experimental gasification technologies and evaluating future energy supply alternatives.

EMPLOYMENT

Xcel Energy

2020-present	Director – Regional Capital Projects
2019-2020	Director – Reliability Engineering; Coal, Gas and RDF
2013-2019	Manager – Plant Engineering and Technical Services
2003-2013	Project Manager – Engineering and Construction

Black and Veatch

1990-2003	Various Engineering Positions – Engineering and Construction

EDUCATION

Bachelor of Science Mechanical Engineering
North Dakota State University

Activity ID	Activity Name	Resp	Dur Hrs	Rem Dur Hrs	Act Dur Hrs	% Comp	Start	Finish
SHERCO U-3: Restoration Project Schedule			5872.0h	752.0h	4120.0h		10-Sep-11 A	22-Jan-14
PHASE I The Event			200.0h	0.0h	132.0h		19-Nov-11 A	13-Dec-11 A
Event & Lay-Up			80.0h	0.0h	72.0h		19-Nov-11 A	02-Dec-11 A
A13480	Initial Observations & Visual Inspections		90.0h	0.0h	90.0h	100%	19-Nov-11 A	28-Nov-11 A
A13470	Turb / Gen / Exciter Event		0.0h	0.0h	0.0h	100%	19-Nov-11 A	
A14100	Empty Coal Bunkers		110.0h	0.0h	100.0h	100%	21-Nov-11 A	02-Dec-11 A
Document & Plan			134.0h	0.0h	116.0h		23-Nov-11 A	13-Dec-11 A
A13500	Formulate Disassembly Plan for Turb/Gen/Exc		168.0h	0.0h	138.0h	100%	23-Nov-11 A	12-Dec-11 A
A13490	Photo Documentation of Turb / Gen / Exc		80.0h	0.0h	80.0h	100%	29-Nov-11 A	07-Dec-11 A
A13510	Team Review / Update Disassembly Plan		56.0h	0.0h	50.0h	100%	06-Dec-11 A	13-Dec-11 A
Clean-Up			120.0h	0.0h	120.0h		21-Nov-11 A	06-Dec-11 A
Mezzanine Floor & Below			80.0h	0.0h	80.0h		21-Nov-11 A	30-Nov-11 A
A14130	Mezzanine Floor Clean-Up		40.0h	0.0h	40.0h	100%	21-Nov-11 A	24-Nov-11 A
A14140	Below Mezzanine Floor Clean-Up		40.0h	0.0h	40.0h	100%	25-Nov-11 A	30-Nov-11 A
Turbine Building Area			120.0h	0.0h	120.0h		21-Nov-11 A	06-Dec-11 A
A14150	Turbine Building Ceiling Clean-Up		40.0h	0.0h	40.0h	100%	21-Nov-11 A	24-Nov-11 A
A14160	Other Turbine Building Ceiling Clean-Up Activities		80.0h	0.0h	80.0h	100%	25-Nov-11 A	06-Dec-11 A
PHASE II Inspect Affected Areas			3800.0h	80.0h	4120.0h		10-Sep-11 A	26-Sep-13
Milestones			0.0h	0.0h	0.0h		05-Dec-11 A	05-Dec-11 A
MS15371	Start Phase II (Project Kickoff)		0.0h	0.0h	0.0h	100%	05-Dec-11 A	
System Inspections			3680.0h	80.0h	3720.0h		19-Nov-11 A	26-Sep-13
BCB-01 - Control Equipment Building Inspection			1072.0h	0.0h	1328.0h		05-Jan-12 A	24-Aug-12 A
BCB01-15668	Prepare Plan - Control Equipment Building Inspection	B. Morrison	40.0h	0.0h	40.0h	100%	05-Jan-12 A	12-Jan-12 A
BCB01-15669	Review Plan - Control Equipment Building Inspection	B. Morrison	520.0h	0.0h	120.0h	100%	25-Jan-12 A	15-Feb-12 A
BCB01-15670	Approve Plan - Control Equipment Building Inspection	B. Morrison	0.0h	0.0h	0.0h	100%		22-Feb-12 A
BCB01-15672	Inspect - Control Equipment Building	B. Morrison	24.0h	0.0h	64.0h	100%	10-Jul-12 A	20-Jul-12 A
BCB01-15673	Prepare Report & ID Follow Up Work - Control Equipment Building Inspection	B. Morrison	40.0h	0.0h	200.0h	100%	20-Jul-12 A	24-Aug-12 A
BCG-01 - Compressed Gas Building Inspection			1016.0h	0.0h	1336.0h		05-Jan-12 A	24-Aug-12 A
BCG01-15675	Prepare Plan - Compressed Gas Building Inspection	B. Morrison	40.0h	0.0h	40.0h	100%	05-Jan-12 A	12-Jan-12 A
BCG01-15676	Review Plan - Compressed Gas Building Inspection	B. Morrison	40.0h	0.0h	143.0h	100%	30-Jan-12 A	22-Feb-12 A
BCG01-15677	Approve Plan - Compressed Gas Building Inspection	B. Morrison	0.0h	0.0h	0.0h	100%		22-Feb-12 A
BCG01-15679	Inspect - Compressed Gas Building	B. Morrison	24.0h	0.0h	24.0h	100%	03-Jul-12 A	05-Jul-12 A
BCG01-15680	Prepare Report & ID Follow Up Work - Compressed Gas Building Inspection Report	B. Morrison	64.0h	0.0h	288.0h	100%	06-Jul-12 A	24-Aug-12 A
BPH-01 - Turbine/Generator Foundation Inspection			1136.0h	0.0h	1280.0h		13-Jan-12 A	24-Aug-12 A
BPH01-15682	Prepare Plan - Turbine/Generator Foundation Inspection	B. Morrison	168.0h	0.0h	170.0h	100%	13-Jan-12 A	07-Feb-12 A
BPH01-15683	Review Plan - Turbine/Generator Foundation Inspection	B. Morrison	80.0h	0.0h	109.0h	100%	08-Feb-12 A	22-Feb-12 A
BPH01-15688	Visually Inspect STG Grout / Create Report	B. Morrison	112.0h	0.0h	940.0h	100%	20-Feb-12 A	28-Jun-12 A
BPH01-15684	Approve Plan - Turbine/Generator Foundation Inspection	B. Morrison	0.0h	0.0h	0.0h	100%		22-Feb-12 A

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Northern States Power Company
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Total Project Schedule Layout
Docket No. E002/GR-13-868
Exhibit___(RLB-1), Schedule 6

Date & Time Printed:18-Sep-13 13:45
Status Date: 13-Sep-13

Activity ID	Activity Name	Resp	Dur Hrs	Rem Dur Hrs	Act Dur Hrs	% Comp	Start	Finish
BPH01-15686	Inspect Turbine/Generator Foundation	B. Morrison	160.0h	0.0h	890.0h	100%	19-Mar-12 A	19-Jul-12 A
BPH01-15690	Test LP A Anchor Bolts	B. Morrison	16.0h	0.0h	19.0h	100%	20-Mar-12 A	21-Mar-12 A
BPH01-15691	Test Generator Anchor Bolts	B. Morrison	8.0h	0.0h	9.0h	100%	20-Mar-12 A	20-Mar-12 A
BPH01-15692	Test LP B Anchor Bolts	B. Morrison	16.0h	0.0h	224.0h	100%	21-Mar-12 A	21-Apr-12 A
BPH01-15689	Test Front Standard Anchor Bolts	B. Morrison	8.0h	0.0h	9.0h	100%	22-Mar-12 A	22-Mar-12 A
BPH01-15693	Test Mid Standard Anchor Bolts	B. Morrison	8.0h	0.0h	219.0h	100%	22-Mar-12 A	21-Apr-12 A
BPH01-15685	Preparations (Scaffolding) For - Turbine/Generator Foundation Inspection	B. Morrison	130.0h	0.0h	300.0h	100%	30-Apr-12 A	11-Jun-12 A
BPH01-15687	Prepare Report & ID Follow Up Work - Turbine/Generator Foundation Inspection	B. Morrison	50.0h	0.0h	400.0h	100%	29-Jun-12 A	24-Aug-12 A
BPH-02 - Building Structure Inspection			708.0h	0.0h	952.0h		12-Mar-12 A	24-Aug-12 A
BPH02-15689	Prepare Plan - Building Structure Inspection	B. Morrison	40.0h	0.0h	40.0h	100%	12-Mar-12 A	16-Mar-12 A
BPH02-15690	Review Plan - Building Structure Inspection	B. Morrison	40.0h	0.0h	40.0h	100%	19-Mar-12 A	23-Mar-12 A
BPH02-15691	Approve Plan - Building Structure Inspection	B. Morrison	0.0h	0.0h	0.0h	100%		23-Mar-12 A
BPH02-15693	Inspect - Building Structure	B. Morrison	40.0h	0.0h	336.0h	100%	25-Jun-12 A	21-Aug-12 A
BPH02-15694	Prepare Report & ID Follow Up Work - Building Structure Inspection	B. Morrison	100.0h	0.0h	344.0h	100%	26-Jun-12 A	24-Aug-12 A
BPH-03 - Turbine Roof Inspection			519.0h	0.0h	639.0h		20-Nov-11 A	09-Mar-12 A
BPH03-15700	Inspect - Turbine Roof	B. Morrison	40.0h	0.0h	32.0h	100%	20-Nov-11 A	25-Nov-11 A
BPH03-14240	Turbine Building Membrane Roof Inspection	B. Morrison	86.0h	0.0h	88.0h	100%	01-Dec-11 A	16-Dec-11 A
BPH03-15696	Prepare Plan - Turbine Roof Inspection	B. Morrison	80.0h	0.0h	80.0h	100%	11-Jan-12 A	25-Jan-12 A
BPH03-15697	Review Plan - Turbine Roof Inspection	B. Morrison	120.0h	0.0h	103.0h	100%	06-Feb-12 A	22-Feb-12 A
BPH03-15698	Approve Plan - Turbine Roof Inspection	B. Morrison	0.0h	0.0h	0.0h	100%		22-Feb-12 A
BPH03-15701	Prepare Report & ID Follow Up Work - Turbine Roof Inspection	B. Morrison	96.0h	0.0h	95.0h	100%	23-Feb-12 A	09-Mar-12 A
BTB-01 - Transition Building Inspection			1040.0h	0.0h	1328.0h		05-Jan-12 A	24-Aug-12 A
BTB01-15703	Prepare Plan - Transition Building Inspection	B. Morrison	80.0h	0.0h	40.0h	100%	05-Jan-12 A	12-Jan-12 A
BTB01-15704	Review Plan - Transition Building Inspection	B. Morrison	224.0h	0.0h	160.0h	100%	25-Jan-12 A	21-Feb-12 A
BTB01-15705	Approve Plan - Transition Building Inspection	B. Morrison	0.0h	0.0h	0.0h	100%		22-Feb-12 A
BTB01-15707	Inspect - Transition Building	B. Morrison	0.0h	0.0h	120.0h	100%	16-Jul-12 A	03-Aug-12 A
BTB01-15708	Prepare Report & ID Follow Up Work - Transition Building Inspection	B. Morrison	40.0h	0.0h	192.0h	100%	23-Jul-12 A	24-Aug-12 A
EEB-01 - Aux Power - 6.9 & 4.16 kv System Inspection			2696.0h	0.0h	2664.0h		07-May-12 A	26-Aug-13 A
EEB01-15780	Prepare Plan - Aux Power - 6.9 & 4.16 kv System Inspection	M. Danberg	40.0h	0.0h	40.0h	100%	07-May-12 A	11-May-12 A
EEB01-15781	Review Plan - Aux Power - 6.9 & 4.16 kv System Inspection	M. Danberg	40.0h	0.0h	40.0h	100%	14-May-12 A	18-May-12 A
EEB01-15782	Approve Plan - Aux Power - 6.9 & 4.16 kv System Inspection	M. Danberg	0.0h	0.0h	0.0h	100%		25-May-12 A
EEB01-15784	Inspect Aux Power - 6.9 & 4.16 kv System	M. Danberg	608.0h	0.0h	2288.0h	100%	15-Jun-12 A	01-Aug-13 A
EEB01-15785	Prepare Report & ID Follow Up Work - Aux Power - 6.9 & 4.16 kv System Inspection	M. Danberg	40.0h	0.0h	8.0h	100%	26-Aug-13 A	26-Aug-13 A
ETR-01 - Raceway, Conduit and Cable Tray Inspection			1160.0h	0.0h	1536.0h		30-Jan-12 A	23-Oct-12 A
ETR01-15815	Prepare Plan - Raceway, Conduit and Cable Tray Inspection	M. Danberg	40.0h	0.0h	24.0h	100%	30-Jan-12 A	02-Feb-12 A
ETR01-15819	Inspect - Raceway, Conduit and Cable Tray	M. Danberg	400.0h	0.0h	1376.0h	100%	01-Feb-12 A	28-Sep-12 A
ETR01-15816	Review Plan - Raceway, Conduit and Cable Tray Inspection	M. Danberg	40.0h	0.0h	48.0h	100%	02-Feb-12 A	10-Feb-12 A
ETR01-15817	Approve Plan - Raceway, Conduit and Cable Tray Inspection	M. Danberg	0.0h	0.0h	0.0h	100%		18-May-12 A
ETR01-15820	Prepare Report & ID Follow Up Work - Raceway, Conduit and Cable Tray Inspection	M. Danberg	32.0h	0.0h	144.0h	100%	28-Sep-12 A	23-Oct-12 A

Xcel Energy

TASK filter: All Activities

Activity ID	Activity Name	Resp	Dur Hrs	Rem Dur Hrs	Act Dur Hrs	% Comp	Start	Finish
FBF-01 - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection			1944.0h	0.0h	1912.0h		13-Jan-12 A	17-Dec-12 A
FBF01-15710	Prepare Plan - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection (Plan 1)	A. Hiebner	208.0h	0.0h	303.0h	100%	13-Jan-12 A	06-Mar-12 A
FBF01-15711	Review Plan - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection (Plan 1)	B. Jackson	40.0h	0.0h	72.0h	100%	12-Mar-12 A	22-Mar-12 A
FBF01-15712	Approve Plan - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection (Plan 1)	B. Jackson	0.0h	0.0h	0.0h	100%		22-Mar-12 A
FBF01-15716	Prepare Plan - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection (Plan 2)	B. Jackson	8.0h	0.0h	8.0h	100%	30-Apr-12 A	30-Apr-12 A
FBF01-15717	Review Plan - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection (Plan 2)	B. Jackson	24.0h	0.0h	56.0h	100%	30-Apr-12 A	09-May-12 A
FBF01-15718	Approve Plan - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection (Plan 2)	B. Jackson	0.0h	0.0h	0.0h	100%		11-May-12 A
FBF01-15713	Preparations for Inspection - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection	B. Jackson	16.0h	0.0h	16.0h	100%	28-May-12 A	29-May-12 A
FBF01-15714	Inspect - BFPT #33	B. Jackson	280.0h	0.0h	879.0h	100%	04-Jun-12 A	14-Sep-12 A
FBF01-15719	Inspect - BFPT #32	B. Jackson	320.0h	0.0h	879.0h	100%	04-Jun-12 A	14-Sep-12 A
FBF01-15721	Inspect - BFP #32 (Offsite - RER)	B. Jackson	40.0h	0.0h	520.0h	100%	14-Aug-12 A	12-Oct-12 A
FBF01-15720	Inspect - BFP #33 (Offsite - RER)	B. Jackson	40.0h	0.0h	460.0h	100%	21-Aug-12 A	12-Oct-12 A
FBF01-15715	Prepare Report & ID Follow Up Work - Boiler Feed Pump & Boiler Feed Pump Turbines Inspection	A. Hiebner	120.0h	0.0h	520.0h	100%	15-Oct-12 A	17-Dec-12 A
FBF-02 - Feedwater Heaters Inspection - LP 31-1, 31-2			600.0h	0.0h	888.0h		10-Feb-12 A	13-Jul-12 A
FBF02-15717	Prepare Plan - Feedwater Heaters Inspection	M. Aasen	120.0h	0.0h	207.0h	100%	10-Feb-12 A	16-Mar-12 A
FBF02-15718	Review Plan - Feedwater Heaters Inspection	M. Aasen	40.0h	0.0h	39.0h	100%	19-Mar-12 A	23-Mar-12 A
FBF02-15723	Eddy Current Testing	M. Aasen	40.0h	0.0h	33.0h	100%	30-Apr-12 A	04-May-12 A
FBF02-15720	Preparations (Scaffolding) For - Feedwater Heaters Inspection	M. Aasen	8.0h	0.0h	8.0h	100%	04-May-12 A	04-May-12 A
FBF02-15719	Approve Plan - Feedwater Heaters Inspection	M. Aasen	0.0h	0.0h	0.0h	100%		04-May-12 A
FBF02-15721	Inspect - Feedwater Heaters	M. Aasen	16.0h	0.0h	16.0h	100%	10-May-12 A	11-May-12 A
FBF02-15722	Prepare Report & ID Follow Up Work - Feedwater Heaters Inspection	M. Aasen	40.0h	0.0h	280.0h	100%	28-May-12 A	13-Jul-12 A
FBF-03 - SU Boiler Feed Pump Inspection			48.0h	0.0h	48.0h		20-Dec-12 A	02-Jan-13 A
FBF03-15728	Prepare Plan - SU Boiler Feed Pump	D. Lien	0.0h	0.0h	0.0h	100%	20-Dec-12 A	20-Dec-12 A
FBF03-15729	Review Plan - SU Boiler Feed Pump	D. Lien	8.0h	0.0h	8.0h	100%	21-Dec-12 A	21-Dec-12 A
FBF03-15730	Approve Plan - SU Boiler Feed Pump	D. Lien	0.0h	0.0h	0.0h	100%		21-Dec-12 A
FBF03-15726	Inspect - SU Boiler Feed Pump	D. Lien	40.0h	0.0h	40.0h	100%	26-Dec-12 A	29-Dec-12 A
FBF03-15727	Prepare Report & ID Follow Up Work - SU Boiler Feed Pump	D. Lien	8.0h	0.0h	8.0h	100%	02-Jan-13 A	02-Jan-13 A
FBF-04 - DA Internal Inspection			230.0h	0.0h	400.0h		13-Nov-12 A	04-Jan-13 A
FBF04-16136	Prepare Plan - DA Internal Inspection	M. Aasen	40.0h	0.0h	40.0h	100%	13-Nov-12 A	16-Nov-12 A
FBF04-16137	Review Plan - DA Internal Inspection	M. Aasen	20.0h	0.0h	20.0h	100%	20-Nov-12 A	21-Nov-12 A
FBF04-16138	Approve Plan - DA Internal Inspection	M. Aasen	0.0h	0.0h	0.0h	100%		21-Nov-12 A
FBF04-16134	Inspect - DA Internal Inspection	M. Aasen	0.0h	0.0h	0.0h	100%	05-Dec-12 A	05-Dec-12 A
FBF04-16135	Prepare Report & ID Follow Up Work - DA Internal Inspection	M. Aasen	60.0h	0.0h	230.0h	100%	05-Dec-12 A	04-Jan-13 A
GPH-01 - Fire Protection System Inspection			32.0h	0.0h	40.0h		10-Jul-12 A	17-Jul-12 A
GPH01-15855	Prepare Report & ID Follow Up Work - Fire Protection System Inspection	M. Aasen	32.0h	0.0h	40.0h	100%	10-Jul-12 A	17-Jul-12 A
HPH-01 - HVAC Generation			80.0h	0.0h	512.0h		04-Feb-13 A	03-May-13 A
HPH01-15954	Draft / Approve Plan	M. Aasen	40.0h	0.0h	512.0h	100%	04-Feb-13 A	03-May-13 A
HPH01-15955	Final Report	M. Aasen	40.0h	0.0h	472.0h	100%	11-Feb-13 A	03-May-13 A
KVV-01 - Instrumentation Inspection			872.0h	0.0h	912.0h		01-Feb-12 A	10-Jul-12 A

Activity ID	Activity Name	Resp	Dur Hrs	Rem Dur Hrs	Act Dur Hrs	% Comp	Start	Finish
KVV01-15822	Prepare Instrumentation Inspection Plan	M. Danberg	40.0h	0.0h	8.0h	100%	01-Feb-12 A	02-Feb-12 A
KVV01-15823	Review Instrumentation Inspection Plan	M. Danberg	40.0h	0.0h	32.0h	100%	03-Feb-12 A	09-Feb-12 A
KVV01-15826	Inspect Instrumentation	M. Danberg	576.0h	0.0h	720.0h	100%	06-Feb-12 A	08-Jun-12 A
KVV01-15824	Approve Instrumentation Inspection Plan	M. Danberg	0.0h	0.0h	0.0h	100%		24-Feb-12 A
KVV01-15827	Prepare Instrumentation Inspection Report & ID Follow Up Work	M. Danberg	40.0h	0.0h	80.0h	100%	26-Jun-12 A	10-Jul-12 A
LVV-01 - Lighting Inspection			520.0h	0.0h	760.0h		09-Jan-12 A	18-May-12 A
LVV01-15735	Inspect - Lighting	M.Aasen	40.0h	0.0h	32.0h	100%	09-Jan-12 A	13-Jan-12 A
LVV01-15731	Prepare Plan - Lighting Inspection	M.Aasen	80.0h	0.0h	151.0h	100%	06-Feb-12 A	01-Mar-12 A
LVV01-15732	Review Plan - Lighting Inspection	M.Aasen	40.0h	0.0h	456.0h	100%	01-Mar-12 A	18-May-12 A
LVV01-15733	Approve Plan - Lighting Inspection	M.Aasen	0.0h	0.0h	0.0h	100%		18-May-12 A
LPH-02 - Lighting Inspection			360.0h	0.0h	328.0h		21-May-12 A	16-Jul-12 A
LPH02-15734	Prepare Plan - Lighting Inspection	M. Danberg	40.0h	0.0h	40.0h	100%	21-May-12 A	25-May-12 A
LPH02-15736	Review Plan - Lighting Inspection	M. Danberg	40.0h	0.0h	40.0h	100%	28-May-12 A	01-Jun-12 A
LPH02-15737	Approve Plan - Lighting Inspection	M. Danberg	0.0h	0.0h	0.0h	100%		01-Jun-12 A
LPH02-15738	Inspect - Lighting Inspection	M. Danberg	80.0h	0.0h	8.0h	100%	09-Jul-12 A	10-Jul-12 A
LPH02-15739	Prepare Lighting Inspection Report & ID Follow Up Work	M. Danberg	32.0h	0.0h	32.0h	100%	11-Jul-12 A	16-Jul-12 A
MGC-01 - H2 Seal Oil Inspection			776.0h	0.0h	776.0h		01-Jun-12 A	15-Oct-12 A
MGC01-15920	Prepare Plan - H2 Seal Oil Inspection	B. Jackson	40.0h	0.0h	120.0h	100%	01-Jun-12 A	22-Jun-12 A
MGC01-15921	Review Plan - H2 Seal Oil Inspection	B. Jackson	32.0h	0.0h	152.0h	100%	25-Jun-12 A	20-Jul-12 A
MGC01-15924	Inspect - H2 Seal Oil	B. Jackson	40.0h	0.0h	232.0h	100%	04-Sep-12 A	12-Oct-12 A
MGC01-15922	Approve Plan - H2 Seal Oil Pumps Inspection	B. Jackson	0.0h	0.0h	0.0h	100%		04-Sep-12 A
MGC01-15925	Prepare Report & ID Follow Up Work - H2 Seal Oil Pumps Inspection	B. Jackson	8.0h	0.0h	8.0h	100%	15-Oct-12 A	15-Oct-12 A
MGC-02 - Stator Cooling Water Inspection			648.0h	0.0h	648.0h		25-Jun-12 A	15-Oct-12 A
MGC02-15906	Prepare Plan - Stator Cooling Water Inspection	B. Jackson	32.0h	0.0h	32.0h	100%	25-Jun-12 A	29-Jun-12 A
MGC02-15907	Review Plan - Stator Cooling Water Inspection	B. Jackson	32.0h	0.0h	112.0h	100%	02-Jul-12 A	20-Jul-12 A
MGC02-15910	Inspect - Stator Cooling Water	B. Jackson	40.0h	0.0h	440.0h	100%	30-Jul-12 A	12-Oct-12 A
MGC02-15908	Approve Plan - Stator Cooling Water Pumps Inspection	B. Jackson	0.0h	0.0h	0.0h	100%		17-Aug-12 A
MGC02-15911	Prepare Report & ID Follow Up Work - Stator Cooling Water Pumps Inspection	B. Jackson	8.0h	0.0h	8.0h	100%	15-Oct-12 A	15-Oct-12 A
MGC-03 - Cooling & Purge (H2/CO2) Inspection			2640.0h	80.0h	2176.0h		11-Jun-12 A	26-Sep-13
MGC03-15948	Prepare Plan - Cooling & Purge Inspection	B. Jackson	40.0h	0.0h	112.0h	100%	11-Jun-12 A	29-Jun-12 A
MGC03-15949	Review Plan - Cooling & Purge Inspection	B. Jackson	32.0h	0.0h	112.0h	100%	02-Jul-12 A	20-Jul-12 A
MGC03-15950	Approve Plan - Cooling & Purge Inspection	B. Jackson	0.0h	0.0h	0.0h	100%		31-Jul-12 A
MGC03-15952	Inspect - Cooling & Purge	M. Aasen	96.0h	0.0h	744.0h	100%	25-Feb-13 A	08-Jul-13 A
MGC03-15953	Prepare Report & ID Follow Up Work - Cooling & Purge Inspection	M. Aasen	80.0h	80.0h	0.0h	0%	13-Sep-13	26-Sep-13
MGN-01- Pressure Vessel From Stator Coil Integrity Detector Inspection			519.0h	0.0h	504.0h		01-Feb-12 A	30-Apr-12 A
MGN01-15878	Prepare Plan - Pressure Vessel From Stator Coil Integrity Detector Inspection	M.Aasen	96.0h	0.0h	111.0h	100%	01-Feb-12 A	20-Feb-12 A
MGN01-15881	Preparations For - Pressure Vessel From Stator Coil Integrity Detector Inspection	M.Aasen	40.0h	0.0h	32.0h	100%	06-Feb-12 A	10-Feb-12 A
MGN01-15879	Review Plan - Pressure Vessel From Stator Coil Integrity Detector Inspection	M.Aasen	40.0h	0.0h	279.0h	100%	13-Feb-12 A	30-Mar-12 A
MGN01-15882	Inspect - Pressure Vessel From Stator Coil Integrity Detector	M.Aasen	256.0h	0.0h	15.0h	100%	19-Mar-12 A	20-Mar-12 A

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Activity ID	Activity Name	Resp	Dur Hrs	Rem Dur Hrs	Act Dur Hrs	% Comp	Start	Finish
MGN01-15883	Prepare Report & ID Follow Up Work - Pressure Vessel From Stator Coil Integrity Detector Inspection	M.Aasen	8.0h	0.0h	7.0h	100%	30-Mar-12 A	30-Mar-12 A
MGN01-15880	Approve Plan - Pressure Vessel From Stator Coil Integrity Detector Inspection	M.Aasen	0.0h	0.0h	0.0h	100%		30-Apr-12 A
MISC-01 - Piping - Inspection (External)			1384.0h	0.0h	2888.0h		06-Feb-12 A	05-Jul-13 A
MISC01-15885	Prepare Plan - Piping Inspection	M.Aasen	80.0h	0.0h	159.0h	100%	06-Feb-12 A	02-Mar-12 A
MISC01-15886	Review Plan - Piping Inspection	M.Aasen	40.0h	0.0h	39.0h	100%	02-Mar-12 A	08-Mar-12 A
MISC01-15887	Approve Plan - Piping Inspection	M.Aasen	0.0h	0.0h	0.0h	100%		09-Mar-12 A
MISC01-15888	Preperation for Inspection - Piping Inspection	M.Aasen	40.0h	0.0h	472.0h	100%	12-Mar-12 A	01-Jun-12 A
MISC01-15889	Visual Inspection - Piping Inspection	M.Aasen	40.0h	0.0h	480.0h	100%	04-Jun-12 A	24-Aug-12 A
MISC01-15890	Phased Array Inspection - Piping Inpsection	M.Aasen	112.0h	0.0h	208.0h	100%	04-Jun-12 A	10-Jul-12 A
MISC01-15892	Condition Inspection & Repair Recommendations - CRVs	M.Aasen	80.0h	0.0h	1392.0h	100%	27-Sep-12 A	07-Jun-13 A
MISC01-15891	Prepare Inspection Report & ID Follow Up Work - Piping Inspection	M.Aasen	40.0h	0.0h	1536.0h	100%	28-Sep-12 A	05-Jul-13 A
MISC-02 - Internal Piping Inspection (D800)			2864.0h	30.0h	3280.0h		06-Feb-12 A	18-Sep-13
MISC02-15885	Prepare Plan - Internal Piping Inspection	M. Aasen	120.0h	0.0h	488.0h	100%	06-Feb-12 A	30-Apr-12 A
MISC02-15886	Review Plan - Internal Piping Inspection	M. Aasen	32.0h	0.0h	32.0h	100%	01-May-12 A	04-May-12 A
MISC02-15888	Preparations (Scaffolding) For - Internal Piping Inspection	M. Aasen	8.0h	0.0h	8.0h	100%	04-May-12 A	04-May-12 A
MISC02-15889	Inspect - Internal Piping (Non-N2 blanket)	M. Aasen	80.0h	0.0h	720.0h	100%	07-May-12 A	07-Sep-12 A
MISC02-15887	Approve Plan - Internal Piping Inspection	M. Aasen	0.0h	0.0h	0.0h	100%		11-May-12 A
MISC02-15890	Prepare Report & ID Follow Up Work - Internal Piping Inspection	M. Aasen	80.0h	30.0h	2432.0h	50%	03-Jul-12 A	18-Sep-13
MISC02-15891	Inspect - Internal Piping (Post-N2 blanket)	M. Aasen	136.0h	0.0h	1336.0h	100%	26-Nov-12 A	25-Jul-13 A
MISC02-15893	Inspect MTD Piping	M. Aasen	56.0h	0.0h	56.0h	100%	11-Mar-13 A	20-Mar-13 A
MISC02-15894	Inspect MTS Piping	M. Aasen	40.0h	0.0h	16.0h	100%	30-May-13 A	31-May-13 A
MISC02-15896	Inspect SRS Piping	M. Aasen	32.0h	0.0h	16.0h	100%	04-Jun-13 A	05-Jun-13 A
MISC02-15892	Inspect RET Piping	M. Aasen	0.0h	0.0h	8.0h	100%	05-Jul-13 A	08-Jul-13 A
MISC02-15895	Inspect SMS Piping	M. Aasen	40.0h	0.0h	8.0h	100%	05-Jul-13 A	08-Jul-13 A
MISC-03 - Strainers Inspection & In-Line Components			744.0h	0.0h	1064.0h		01-Feb-12 A	03-Aug-12 A
MISC03-15899	Prepare Plan - Strainers Inspection	M. Aasen	80.0h	0.0h	416.0h	100%	01-Feb-12 A	13-Apr-12 A
MISC03-15900	Review Plan - Strainers Inspection	M. Aasen	40.0h	0.0h	120.0h	100%	16-Apr-12 A	04-May-12 A
MISC03-15902	Preparations For - Strainers Inspection	M. Aasen	80.0h	0.0h	200.0h	100%	14-May-12 A	15-Jun-12 A
MISC03-15901	Approve Plan - Strainers Inspection	M. Aasen	0.0h	0.0h	0.0h	100%		14-May-12 A
MISC03-15903	Inspect - Strainers	M. Aasen	40.0h	0.0h	112.0h	100%	18-Jun-12 A	06-Jul-12 A
MISC03-15904	Prepare Report & ID Follow Up Work - Strainers Inspection	M. Aasen	40.0h	0.0h	256.0h	100%	21-Jun-12 A	03-Aug-12 A
MISC-04 - Valves Inspection			2512.0h	0.0h	3160.0h		01-Feb-12 A	18-Aug-13 A
MISC04-15892	Prepare Plan - Valves Inspection	M. Aasen	80.0h	0.0h	416.0h	100%	01-Feb-12 A	13-Apr-12 A
MISC04-15893	Review Plan - Valves Inspection	M. Aasen	40.0h	0.0h	120.0h	100%	16-Apr-12 A	04-May-12 A
MISC04-15895	Preparations (Scaffolding) For - Valves Inspection	M. Aasen	8.0h	0.0h	8.0h	100%	04-May-12 A	04-May-12 A
MISC04-15896	Inspect - Valves	M. Aasen	0.0h	0.0h	40.0h	100%	14-May-12 A	18-May-12 A
MISC04-15894	Approve Plan - Valves Inspection	M. Aasen	0.0h	0.0h	0.0h	100%		14-May-12 A
MISC04-15897	Prepare Report & ID Follow Up Work - Valve Inspection	M. Aasen	40.0h	0.0h	408.0h	100%	04-Jun-12 A	13-Aug-12 A
MISC04-15898	MISC-04 Inspections	M. Aasen	112.0h	0.0h	656.0h	100%	23-Apr-13 A	18-Aug-13 A

Xcel Energy

TASK filter: All Activities

Opportunity Projects

The following activities were initiated or completed during the Sherco Unit 3 Restoration period (November 2011 – October 2013). These projects were identified and prioritized based on reliability and Equivalent Forced Outage Rate (EUOR) improvement goals.

- *Replacement of the Unit 3 Cooling Towers.* These cooling towers were at the end of their predicted life and replacement eliminated the risk of collapse. This project was originally planned for the 2014 Unit 3 overhaul outage. However, we accelerated the project and completed it during the restoration period to facilitate shortening the future outage.

- *Unit 3 Boiler Feed Pumps and Boiler Feed Pump Turbines.* Both pumps and pump turbines were overhauled during the Restoration. These overhauls were originally planned to be conducted during the 2014 Unit 3 overhaul outage. However, it was unclear if these components sustained damage during the Unit 3 turbine failure event so to ensure their reliability when the unit returned to service, we accelerated these projects.

- *Unit 3 Baghouse Replacement.* We replaced the filter bags in the Unit 3 baghouse. There are 3 baghouse with 16 compartments each; each compartment has 378 bags for a total 18,144 bags. Replacement includes removal of the old bag, replacement of the bag support hardware, and installation of the new bags. The baghouse is part of the air quality control system (AQCS) and the bags are used to remove particulate from the boiler flue gas. The baghouse bags had reached the end of life, and the individual bag failure rate was accelerating.

- *33 Feed Water Heater Repair.* At the time of the Event, the heater walls were at their minimum wall thickness. The decision to move forward with this necessary repair work was based on the availability of boilermakers (skilled craft) who were available to work during this usual 'down time' for them.

- *Attemperator Nozzle Replacement* - This small nozzle is located within the steam line and sprays water to control the steam temperature. We took the opportunity to inspect this part while the unit was offline and as a result, decided to replace it. If this nozzle failed during operation, the Unit would need to be shutdown to replace it.

- *Circulation Water Pump Rewind.* This project required taking the motor off the circulation water pump and sending it offsite to be rewound. The repair shop needs a long lead time (more than 30 weeks) to order parts to perform the rewind. This pump has a high impact on performance and reliability as if it needed to be rewound while the plant was online the circulating water would be reduced which would in turn reduce the plant's output.

- *31 Boiler Feed Pump Discharge Check Valve replacement.* This discharge valve is located on the start up pump and keeps water that is supposed to be going to the boiler from going backwards. This valve was leaking and without this replacement, its failure could have caused the plant to shutdown. This part cannot be repaired while the plant is online and requires a long lead time (more than 30 weeks) to order the parts

- *#3 Fire Pump.* This pump provides fire protection water to the plant. The failure of this pump could cause a lot of damage to a coal fired power plant. We replaced the pump because of the long lead time for ordering and the resulting improved safety and fire protection.

Customer Benefits of Work Performed during Restoration Period

The following list identifies work performed during the restoration period that provided additional customer benefits ($$ presented on Total Company basis; Avoided Future Costs includes SMMPA share):

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
Turbine-Related Work						
1.	Complete Overhaul (inspections and standard repairs)	A major outage (overhaul) planned for 2014 was avoided due to the restoration.	$3,000,000	Reduced the planned eight week outage in 2014 to four weeks of planned outage for a warranty inspection.		
2.	L-0 blade replacement for both low pressure turbines	Four rows of L-0 blades were scheduled to be replaced in 2020. These blades were replaced during the restoration, the cost of which was covered by the insurance recovery. Replacement during restoration reduced the planned outage time for 2020 by one to two weeks.	$5,500,000	7 to 14 days. This work would have required a nine to ten week outage to complete in 2020. This is one to two weeks longer than the planned outage, which saves 7 to 14 days.	Earlier blade replacement resulted in an estimated 0.25% improvement in unit heat rate from 2013 to 2020 (when the replacement would have otherwise occurred).	

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
3.	Replacement and restoration of L-2/L-3, and other LP blade/diaphragm for both low pressure turbines	Latent, non-SCC cracks were discovered and repaired on the L-2 and L-3 rotor sections.		No effect on future planned outages	The performance improvement of this work is reflected above in Item #2.	Avoids risk of future failure event and outages.
4.	Cross over pipe bellows replacement	Cross over pipe bellows were replaced during the restoration. This resulted in savings of the cost for future replacement.	$500,000	No effect on future planned outages		Potentially avoids a 4-week forced outage due to failure.
5.	Digital Overspeed Protection System Replacement	The new digital overspeed protection system avoids requiring the unit being taken out of service to perform annual overspeed tests. The new system also allows testing without operating turbine at 110% overspeed. This new system saves 1 outage per year from 2013 to 2030.		17 days		Reduction of risk of damage or failure during testing due to reduced overspeed conditions.

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
6.	Turbine Supervisory Instrumentation Vibration Monitoring System	This system would have been replaced at a future outage and substantial cost, however the time would have fit within existing planned outages. The customer benefit is the cost avoided on the future work.	$925,000	No effect on future planned outages		This equipment provides real time machine condition information to allow more effective and safe operations, including faster diagnostics and troubleshooting during operation. This equipment reduces unplanned forced outages.
7.	MSV/MCV/CRV Inspections, Repairs		$250,000	No effect on future planned outages		
8.	EHC Valve Actuator internal inspections and repairs		$200,000	No effect on future planned outages		

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
9.	Main turbine/generator bearings, seals, oil deflectors service life reset		$300,000	No effect on future planned outages	1% heat rate improvement results in $3,700,000 million in fuel savings from 2013 to the 2020 outage when this work would have occurred.	New equipment reduces the risk of failures and improves reliability.
10.	Boiler feed pump turbines service life reset		$500,000	No effect on future planned outages		
11.	Lube oil and hydraulic oil replacement and system cleaning/flushing		$100,000	No effect on future planned outages		New equipment reduces the risk of failures and improves reliability.
12.	Coupling bolt upgrade to hydraulic bolts	This modification saves two days per major outage for each of the five outages between 2013 and 2030.	$410,000	10 days		

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
Generator-Related Work						
13.	Stator rewind and rewedge, including restack	The generator stator would have required a rewind one more time before retirement. This work would have been performed as a planned capital budget concurrent with a future outage.	$1,900,000	No effect on future planned outages		New equipment reduces the risk of failures and improves reliability.
14.	Rotor rewind, including Retaining Ring inspections/replacements	The generator rotor would have required a rewind one more time before retirement. This work would have been performed as a planned capital budget concurrent with a future outage.	$2,650,000	No effect on future planned outages		New equipment reduces the risk of failures and improves reliability.

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
15.	Generator field collector ring replacement	The generator field collector would have required major machining or replacement one more time before retirement. This work would have been performed as a planned capital budget concurrent with a future outage.	$40,000	No effect on future planned outages		New equipment reduces the risk of failures and improves reliability.
16.	Gen Core monitor replacement	This equipment would have required replacement once more before retirement of the unit.	$40,000	No effect on future planned outages		New equipment reduces the risk of failures and improves reliability.

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
Boiler-Related Work						
17.	Chemical Cleaning	The boiler chemical cleaning removes debris and deposits from the internal water surfaces in the boiler. Since the boiler had been cleaned less than one year before the failure, there is limited incremental value, but this is some.		No effect on future planned outages		Slight reduction of debris/deposit accumulations were removed which reduced the risk of tube leaks/failures.
Building-Related Work						
18.	Roof replacement	The western portion of the steam turbine/generator roof was replaced due to fire damage. This enabled this section of roof to last until end of life.	$153,000	No effect on future planned outages		

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
19.	Lighting replacements	The lights over the steam turbine/generator were replaced with LED lights.	12,000	No effect on future planned outages		
20.	Cleaning and fire hazard reduction	The entire steam turbine/generator building was hand cleaned to remove residual oil, soot, grease and other contaminants from walls, ceilings, cables, pipes, and other surfaces		No effect on future planned outages		Deep cleaning of these areas reduces the risk of future fires

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
Balance-of-Plant Work						
21.	Cooling tower replacement			Performing the capital project to replace the cooling tower during the restoration period reduced the 2014 outage from 10 weeks if we replaced the tower to just 4 weeks saving 6 weeks	The replacement of the cooling tower increased the efficiency of the unit (at least from 2013 until it's planned replacement in 2014. The value of the avoided fuel consumption is estimated at $177,000.	New equipment reduces the risk of failures and improves reliability.
22.	Condenser tubes, tubesheets, dogbone expansion joint and waterbox upgrades					New equipment reduces the risk of failures and improves reliability.
23.	Condensate polisher elements and refurbishment	Replacement would have been required once more but-for the restoration in either the 2017 or 2020 outage	$230,000			New equipment reduces the risk of failures and improves reliability.

Customer Benefits of Work Performed during Restoration Period

	Work Scope	Details	Avoided Future Costs	Reduction in Planned Outage Time	Performance Improvements	Reliability Improvements
24.	Boiler feed pump, reduction gearset, and booster pump service life reset	Both pumps, reduction gearsets, and booster pumps were overhauled during the restoration project, and therefore were not needed in the planned 2014 outage.	$210,000			