Statement of Qualifications

Timothy J. O'Connor
Chief Nuclear Officer

Tim O'Connor is chief nuclear officer for Xcel Energy. He is responsible for all Xcel Energy nuclear activities in Minnesota at the Monticello and Prairie Island nuclear generating plants (operated by NSF-Minnesota and its parent company, Xcel Energy.)

Mr. O'Connor joined Xcel Energy in 2007 as the site vice president of the Monticello plant. Earlier this year, he was appointed vice president of engineering and nuclear regulatory compliance and licensing.

He has 30 years of commercial nuclear experience with both boiling and pressurized water reactors. His increasing responsibilities throughout his career have included site vice president at Constellation Energy Group's Nine Mile Point station in New York; vice presidential roles at the Public Service Enterprise Group (PSEG) Hope Creek and Salem plants; plant manager at LaSalle station; and operations manager at Dresden and Zion plants. He has also worked in management positions in maintenance, operations, and engineering. Mr. O'Connor also held a position with the Institute of Nuclear Power Operations (INPO) as an evaluation team manager on a reverse loaned assignment.

Mr. O'Connor received his mechanical engineering degree from Marquette University in Milwaukee.

List of Acronyms

Acronym	Meaning
10 CFR	Title 10 of the Code of Federal Regulations
2004 Resource Plan	*2004 Resource Plan*, Docket No. E002/RP-04-1752, Nov. 1, 2004
2007 Resource Plan	*2007 Resource Plan*, Docket No. E002/RP"-07-1572, Dec. 14, 2007
AACE, International	Association for the Advancement of Cost Engineering
ACRS	Advisory Committee on Reactor Safeguards
ADL	Affected Document List
AEA	U.S. Atomic Energy Act of 1954
AEC	Atomic Energy Commission
AEL	Affected Equipment Database List
ALARA	As low as reasonable achievable
AMR	Aging Management Rule
ANSI	American National Standards Institute
APA	Administrative Procedure Act
Areva	Areva NP
Bechtel	Bechtel Power Corporation
BOD	Board of Directors
BWR	Boiling water reactor
BWROG	Boiling Water Reactor Owners Group
BWRVIP	Boiling Water Reactor Vessel and Internals Project
CAA	Capital Asset Accounting
CAP	Containment Accident Pressure
CBS	Company's budgeting system
CDP	Condensate Demineralization Pump
CFD	Computational fluid dynamics
CFR	Code of Federal Regulations
CGCS	Cover Gas Cleanup System
CLB	Current Licensing Basis
CLTP	Current license thermal power
Commission	Nuclear Regulatory Commission
Company	Northern States Power Company, a wholly owned subsidiary of Xcel Energy Inc
CON	Certificate of Need

Acronym	Meaning
CST	Condensate Storage Tanks
Deloitte	Deloitte Touche Tohmatsu LLP
DIA	Design Interface Agreement
DIR	Design Information Request
DIR	Design Input Request
DRB	Design Review Board
DRM	Design Review Meetings
DSP	Dryer separate pool
DTR	Draft Task Reports
DZ	Day and Zimmerman
EC	Engineering change
ECCS	Emergency core cooling system
EDMG	Extensive Damage Mitigation Guidelines
EDO	Executive Director of Operations
EP	Emergency preparedness
EPRI	Electric Power Research Institute
EPU	Extended Power Uprate
FAT	Factory Acceptance Test
FFD	Fitness for duty
FLEX	Flexible approach
FPL	Florida Power and Light
GE	General Electric
GEH	GE Hitachi Nuclear Energy
GENE	General Electric Nuclear Energy
GEZIP	GE Passive Zinc Injection System
GSU	Generator Step-Up
Hot Shop	Work shop within the radiological control area
IAEA	International Atomic Energy Agency
INPO	Institute for Nuclear Power Operations
IPA	Integrated Plant Assessment
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
JDE	JD Edwards
LAR	License Amendment Request
LCM	Life Cycle Management
Licensee	Operator of a nuclear facility
LLW	Low-level radioactive waste

Acronym	Meaning
LTR	Licensing Topical Reports
LV	Low voltage
LWR	Light water reactor
MCC	Motor control center
MCO	Moisture carryover
MELLLA	Maximum extended load line limit analysis
MELLLA+	Maximum extended load line limit analysis plus
MG	Motor-generator
MNGP	Monticello Nuclear Generating Plant
Monticello	Monticello Nuclear Power Plant
Monticello LCM/EPU CON	Application for Certificate of Need, Docket No. E002/CN-08-185, Feb. 14, 2008
MSDT	Moisture Separator Drain Tank
MUR	Measurement Uncertainty Recapture
ND2	The ND2 Group, a consulting group
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NMC	Nuclear Management Company, Xcel Energy's prior contract operator
NPA	Nuclear Project Authorizations
NPAR	Nuclear Plant Aging Research
NPO	Nuclear Power Operations
NPSHa	Available Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSPM or NSP-M	Northern States Power Company Minnesota
NWL	Normal water level
O&M	Operating and Maintenance
OAG	Office of Attorney General
OEM	Original equipment manufacturer
OES	Minnesota Office of Energy Security
OLTP	Original license thermal power
Overheads	Plant Support/Administrative and General
P6	Primavera scheduling software
PCR	Project Change Request
Peterson Consulting	Peterson Consulting Limited Partnership
PIN	Project Impact Notification

Acronym	Meaning
PLC	Programmable Logic Controller
PMP	Program Management Plan
PNMR	Power Range Neutron Monitor
PORC	Plant Operating Review Committee
PRG	Project Review Group
PSEG	Public Servie Enterprise Group
PUSAR	Power Uprate Safety Analysis Report
PVRR	Present Value of Revenue Requirement
PVSC	Present Value of Societal Cost
RAI	Request for additional information
RAT	Reserve auxiliary transformer
Reg Guide	NRC's Regulatory Guide
RFO	Refueling outage
RFP	Reactor Fuel Pump
RIPD	Reaction internal pressure distance
RO	Reactor operator
RSDP	Replacement Steam Dryer
RWCU	Reactor Water Clean-Up
S&L	Sargent & Lundy
SAMG	Severe Accident Management Guidelines
SAR	Safety Analysis Report
SBO	Station blackout
SC	Scope change
SCD	Scope Change Description
SCR	Scope Change Request
Shaw	Shaw Group
SNF	Spent nuclear fuel
SOX	Sarbanes-Oxley Act of 2002
SPU	Stretch Power Uprate
SRO	Senior Reactor Operator
SS&W	(Shaw) Stone & Webster Construction, Inc.
SSCs	Structures, systems and components
Task Reports	Provide the analysis required for LCM/EPU programs
TSD	Task Scoping Document
TSI	Turbine Supervisory Instrumentation
Tucker Alan	Tucker Alan Inc.
USAR	Updated Safety Analysis Report

Acronym	Meaning
Westinghouse	Westinghouse electric Company
Xcel Energy	Northern States Power Company, doing business as Xcel Energy Inc

Monticello Nuclear Generating Plant

CONFIGURATION MANAGEMENT

Configuration Control Principles

- Things are functionally arranged for a reason
- All work activities are changes or challenges to the plant
- Nothing is different than what is expected
- Everything is formally managed

Configuration Control Behaviors

- Identify conditions that don't seem right
- Know how actions change things before starting
- Only change status using an approved process (permission, process, paper)
- Evaluate changes methodically
- Hold sacred: component positions, drawings, licensing basis, calculations, security barriers, procedures, radiological barriers

Xcel Energy®
RESPONSIBLE BY NATURE™

Monticello Nuclear Generating Plant

RISK MANAGEMENT IS CORE BUSINESS

Risk Management Principles

- Nothing is routine
- Take the time to challenge uncertainty
- Make risk significant activities visible
- Risk activities will be planned, challenged, and controlled
- No risk option is the first choice
- Prioritize to minimize operational challenges

Risk Management Behaviors

- Stop and engage when hearing justifications or the word "routine"
- Use methodical, fact-based decision making
- Risk activities are clearly identified and owned
- Verify commitments in detail
- Follow through and validate specifics

Xcel Energy®
RESPONSIBLE BY NATURE®


TRAITS OF A HEALTHY
NUCLEAR SAFETY CULTURE
Individual Commitment to Safety
Personal Accountability
Questioning Attitude
Effective Safety Communication
Management Commitment to Safety
Leadership Safety Values and Actions
Decision Making
Respectful Work Environment
Management Systems
Continuous Learning
Problem Identification and Resolution
Environment for Raising Concerns
Work Processes

Picture of **Xcellence**

Right Picture
Knowing what "xcellence" looks like

Right People
Knowledge, Skills, Experience, Attitudes

Nuclear Xcellence

Safe, Clean, Reliable—at a Competitive Cost for the Long Term

Organizational Xcellence

- Safety Culture
- Risk Management
- Involved and Accountable Team
- Aligned and Standardized

Operational Xcellence

- Safety
- Fundamentals
- Configuration Control
- Regulatory Compliance
- Environmental Leadership
- Decision Making

Learning Xcellence

- Training
- Problem Identification and Resolution
- Learning Organization
- Operating Experience

Equipment Xcellence

- System and Program Health
- Outage Performance
- Precision Maintenance
- Aging Equipment Management
- Zero Tolerance for Equipment Failures

Business Xcellence

- Strategic
- Process Improvements
- Long Range Business Planning
- Project Execution
- Asset Preservation
- Predictable Cost

Individual Xcellence

Accident Free	**C**ontrol Dose	**E**vent Free	**M**eet Commitments	**A**pply Training	**N**o Rework

Enablers of an Engaged, Thinking Organization

Qualified and Proficient Workers	Risk Assessment, Job Planning and Preparation	Procedures and Work Instructions	Verification and Validation	Supervisory Oversight	Work Practices

Right Process
Standardized, Effective, Efficient, Compliant

Right Leadership
Coaching, Mentoring, Observing, Leading

Xcel Energy® | RESPONSIBLE BY NATURE®

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

BACKGROUNDER

Office of Public Affairs
Phone: 301-415-8200
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Power Uprates for Nuclear Plants

Introduction

When the NRC issues a license for a commercial nuclear power plant, the agency sets limits on the maximum heat output, or power level, for the reactor core. This power level plays an important role in many of the analyses that demonstrate plant safety, so the NRC's permission is required before a plant can change its maximum power level. A "power uprate" only occurs after the NRC approves a commercial nuclear power plant's request to increase its power.

Background

Utilities have used power uprates since the 1970s as a way to generate more electricity from their nuclear plants. As of April 2011, the NRC has approved 139 uprates, resulting in a gain of approximately 18,063 MWt (megawatts thermal) or 6,020 MWe (megawatts electric) at existing plants. These uprates are listed in Table 1 at the end of this document. Collectively, these uprates have added generating capacity at existing plants that is equivalent to about six new reactors.

Discussion

To increase the power output of a reactor, typically a utility will refuel a reactor with either slightly more enriched uranium fuel or a higher percentage of new fuel. This enables the reactor to produce more thermal energy and therefore more steam, driving a turbine generator to produce electricity. In order to accomplish this, components such as pipes, valves, pumps, heat exchangers, electrical transformers and generators must be able to accommodate the conditions that would exist at the higher power level. For example, a higher power level usually involves higher steam and water flow through the systems used in converting the thermal power into electric power. These systems must be capable of accommodating the higher flows.

In some instances, licensees will modify and/or replace components in order to accommodate a higher power level. Depending on the desired increase in power level and original equipment design, this can involve major modifications to the plant such as the replacement of main turbines. All of these factors must be analyzed by the licensee as part of their request to amend their license for the uprate. The analyses must demonstrate that the proposed new configuration remains safe and that measures continue to be in place to protect the health and safety of the public. The NRC's technical and legal staffs review these analyses, which span many technical disciplines and may be complex, before approving a request for a power uprate.

Types of Power Uprates

The design of every U.S. commercial reactor has excess capacity needed to potentially allow for an uprate, which can fall into one of three categories: 1) measurement uncertainty recapture power uprates, 2) stretch power uprates, and 3) extended power uprates.

1) Measurement uncertainty recapture power uprates are power increases less than 2 percent of the licensed power level, and are achieved by implementing enhanced techniques for calculating reactor power. This involves the use of state-of-the-art devices to more precisely measure feedwater flow which is used to calculate reactor power. More precise measurements reduce the degree of uncertainty in the power level which is used by analysts to predict the ability of the reactor to be safely shut down under possible accident conditions.

2) Stretch power uprates are typically between 2 percent and 7 percent, with the actual increase in power depending on a plant design's specific operating margin. Stretch power uprates usually involve changes to instrumentation settings but do not involve major plant modifications.

3) Extended power uprates are greater than stretch power uprates and have been approved for increases as high as 20 percent. Extended power uprates usually require significant modifications to major pieces of non-nuclear equipment such as high-pressure turbines, condensate pumps and motors, main generators, and/or transformers.

Review Process

Since uprates affect a reactor's licensed power level, utilities apply for NRC permission to amend their operating license in order to implement a power uprate. The process for requesting and approving a change to a plant's power level is governed by 10 CFR 50.90-92. These regulations are available on the agency's Web site at: http://www.nrc.gov/reading-rm/doc-collections/cfr/part050/. The applications and reviews are complex and involve many areas of expertise in the NRC's Offices of Nuclear Reactor Regulation and General Counsel. Some reviews may also involve the Office of Nuclear Regulatory Research and the Advisory Committee on Reactor Safeguards (ACRS). In evaluating a power uprate request, NRC reviews data and accident analyses submitted by a licensee to confirm that the plant can operate safely at the higher power level. Reviews of power uprate requests are a high priority.

The NRC uses a review standard for extended power uprates (RS-001, December 2003), that has been endorsed by the ACRS. The standard provides a comprehensive process and technical guidance for reviews by the NRC staff, and provides useful information to licensees considering applying for an extended uprate.

After a licensee submits an uprate application, the NRC places a notice in the *Federal Register* to notify the public that the agency is considering the application. The public has 30 days to comment on the licensee's request and 60 days to request a hearing where the application could be contested. The NRC thoroughly reviews the application and any public comments, while the Atomic Safety and Licensing Board (ASLB) considers any requests for hearings. NRC technical staff complete their review while considering and addressing any public comments, issuing a safety evaluation and another *Federal Register* notice to inform the public.

If the ASLB determines a hearing is required, a separate legal process takes place, and NRC staff provides technical information, if needed. The safety evaluation and any hearing rulings form the basis for the NRC's final decision on the uprate request, although the staff can authorize an uprate while a hearing is underway. The NRC issues a press release for any approved uprate.

Uprates—Completed, Under Review, Expected

The NRC has approved 139 uprates and typically has several applications for power uprates under review at any given time. In addition, licensee responses to a December 2010 NRC survey indicate they plan to submit 35 power uprate applications in the next five years, including 12 extended uprates and 23 measurement uncertainty recapture uprates. If these applications are approved, the resulting uprates would add another 5,254 MWt (1,855 MWe) to the nation's generating capacity. Lists of uprate applications approved, under review, and anticipated can be found in the three tables at the end of this fact sheet, and on the NRC's website at: http://www.nrc.gov/reactors/operating/licensing/power-uprates/status-power-apps.html.

Public Involvement

The NRC welcomes public involvement in our activities as part of our strong, fair oversight of the nuclear industry. The public's opportunities to participate in the power uprate arena include:

- Pre-application meetings, where licensees discuss their uprate plans with NRC staff (some portions of these meetings may be closed to the public to discuss proprietary information).
- Comments related to an application and requests for a hearing on the application.
- Briefings to the ACRS on the results of the staff's review of the applications (some portions of these meetings may be closed to the public to discuss proprietary information). ACRS meeting schedules are available on the NRC's website at: http://www.nrc.gov/reading-rm/doc-collections/acrs/agenda.

For each extended power uprate, the NRC staff typically issues a draft environmental assessment for a 30-day public comment period. The NRC staff considers and addresses all comments before finalizing the draft environmental assessment.

Table 1 - Approved Power Uprates, April 2011
(TYPE – S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

No.	Plant	% Uprate	MWt	Year Approved	TYPE
1	Calvert Cliffs 1	5.5	140	1977	S
2	Calvert Cliffs 2	5.5	140	1977	S
3	Millstone 2	5	140	1979	S
4	H. B. Robinson	4.5	100	1979	S
5	Fort Calhoun	5.6	80	1980	S
6	Crystal River 3	3.8	92	1981	S
7	St. Lucie 1	5.5	140	1981	S
8	St. Lucie 2	5.5	140	1985	S
9	Duane Arnold	4.1	65	1985	S
10	Salem 1	2	73	1986	S
11	North Anna 1	4.2	118	1986	S
12	North Anna 2	4.2	118	1986	S
13	Callaway	4.5	154	1988	S
14	TMI-1	1.3	33	1988	S
15	Fermi 2	4	137	1992	S
16	Vogtle 1	4.5	154	1993	S
17	Vogtle 2	4.5	154	1993	S
18	Wolf Creek	4.5	154	1993	S
19	Susquehanna 2	4.5	148	1994	S
20	Peach Bottom 2	5	165	1994	S
21	Limerick 2	5	165	1995	S
22	Susquehanna 1	4.5	148	1995	S
23	Nine Mile Point 2	4.3	144	1995	S
24	WNP-2	4.9	163	1995	S
25	Peach Bottom 3	5	165	1995	S
26	Surry 1	4.3	105	1995	S
27	Surry 2	4.3	105	1995	S

No.	Plant	% Uprate	MWt	Year Approved	TYPE
28	Hatch 1	5	122	1995	S
29	Hatch 2	5	122	1995	S
30	Limerick 1	5	165	1996	S
31	V. C. Summer	4.5	125	1996	S
32	Palo Verde 1	2	76	1996	S
33	Palo Verde 2	2	76	1996	S
34	Palo Verde 3	2	76	1996	S
35	Turkey Point 3	4.5	100	1996	S
36	Turkey Point 4	4.5	100	1996	S
37	Brunswick 1	5	122	1996	S
38	Brunswick 2	5	122	1996	S
39	Fitzpatrick	4	100	1996	S
40	Farley 1	5	138	1998	S
41	Farley 2	5	138	1998	S
42	Browns Ferry 2	5	164	1998	S
43	Browns Ferry 3	5	164	1998	S
44	Monticello	6.3	105	1998	E
45	Hatch 1	8	205	1998	E
46	Hatch 2	8	205	1998	E
47	Comanche Peak 2	1	34	1999	MU
48	LaSalle 1	5	166	2000	S
49	LaSalle 2	5	166	2000	S
50	Perry	5	178	2000	S
51	River Bend	5	145	2000	S
52	Diablo Canyon 1	2	73	2000	S
53	Watts Bar	1.4	48	2001	MU
54	Byron 1	5	170	2001	S
55	Byron 2	5	170	2001	S
56	Braidwood 1	5	170	2001	S

No.	Plant	% Uprate	MWt	Year Approved	TYPE
57	Braidwood 2	5	170	2001	S
58	Salem 1	1.4	48	2001	MU
59	Salem 2	1.4	48	2001	MU
60	San Onofre 2	1.4	48	2001	MU
61	San Onofre 3	1.4	48	2001	MU
62	Susquehanna 1	1.4	48	2001	MU
63	Susquehanna 2	1.4	48	2001	MU
64	Hope Creek	1.4	46	2001	MU
65	Beaver Valley 1	1.4	37	2001	MU
66	Beaver Valley 2	1.4	37	2001	MU
67	Shearon Harris	4.5	138	2001	S
68	Comanche Peak 1	1.4	47	2001	MU
69	Comanche Peak 2	0.4	13	2001	MU
70	Duane Arnold	15.3	248	2001	E
71	Dresden 2	17	430	2001	E
72	Dresden 3	17	430	2001	E
73	Quad Cities 1	17.8	446	2001	E
74	Quad Cities 2	17.8	446	2001	E
75	Waterford 3	1.5	51	2002	MU
76	Clinton	20	579	2002	E
77	South Texas 1	1.4	53	2002	MU
78	South Texas 2	1.4	53	2002	MU
79	ANO-2	7.5	211	2002	E
80	Sequoyah 1	1.3	44	2002	MU
81	Sequoyah 2	1.3	44	2002	MU
82	Brunswick 1	15	365	2002	E
83	Brunswick 2	15	365	2002	E
84	Grand Gulf	1.7	65	2002	MU
85	H. B. Robinson	1.7	39	2002	MU

No.	Plant	% Uprate	MWt	Year Approved	TYPE
86	Peach Bottom 2	1.62	56	2002	MU
87	Peach Bottom 3	1.62	56	2002	MU
88	Indian Point 3	1.4	42.4	2002	MU
89	Point Beach 1	1.4	21.5	2002	MU
90	Point Beach 2	1.4	21.5	2002	MU
91	Crystal River 3	0.9	24	2002	S
92	D.C. Cook 1	1.66	54	2002	MU
93	River Bend	1.7	52	2003	MU
94	D.C. Cook 2	1.66	57	2003	MU
95	Pilgrim	1.5	30	2003	MU
96	Indian Point 2	1.4	43	2003	MU
97	Kewaunee	1.4	23	2003	MU
98	Hatch 1	1.5	41	2003	MU
99	Hatch 2	1.5	41	2003	MU
100	Palo Verde 2	2.9	114	2003	S
101	Kewaunee	6.0	99	2004	S
102	Palisades	1.4	35	2004	MU
103	Indian Point 2	3.2	101.6	2004	S
104	Seabrook	5.2	176	2005	S
105	Indian Point 3	4.85	148.6	2005	S
106	Waterford	8.0	275	2005	E
107	Palo Verde 1	2.9	114	2005	S
108	Palo Verde 3	2.9	114	2005	S
109	Vermont Yankee	20	319	2006	E
110	Seabrook	107	61	2006	MU
111	Ginna	16.8	255	2006	E
112	Beaver Valley 1	8	211	2006	E
113	Beaver Valley 2	8	211	2006	E
114	Browns Ferry 1	5	165	2007	S
115	Crystal River 3	1.6	41	2007	MU
116	Susquehanna 1	13	463	2008	E
117	Susquehanna 2	13	463	2008	E
118	Vogtle 1	1.7	60.6	2008	MU
119	Vogtle 2	1.7	60.6	2008	MU
120	Hope Creek	15	501	2008	E
121	Comanche Peak 1	4.5	154	2008	S

No.	Plant	% Uprate	MWt	Year Approved	TYPE
122	Comanche Peak 2	4.5	154	2008	S
123	Cooper	1.6	38	2008	MU
124	Davis-Besse	1.6	45	2008	MU
125	Millstone 3	7.0	239	2008	S
126	Calvert Cliffs 1	1.4	37	2009	MU
127	Calvert Cliffs 2	1.4	37	2009	MU
128	North Anna 1	1.6	47	2009	MU
129	North Anna 2	1.6	47	2009	MU
130	Prairie Island 1	1.6	27	2010	MU
131	Prairie Island 2	1.6	27	2010	MU
132	LaSalle 1	1.6	57	2010	MU
133	LaSalle 2	1.6	57	2010	MU
134	Surry 1	1.6	41	2010	MU
135	Surry 2	1.6	41	2010	MU
136	Limerick 1	1.6	57	2011	MU
137	Limerick 2	1.6	57	2011	MU
138	Point Beach 1	17	260	2011	S
139	Point Beach 2	17	260	2011	S
		TOTAL	**18,062.8**		
		TOTAL Mwe	**5,960.7**		

Table 2 - Power Uprates Under Review, April 2011

(TYPE -- S = Stretch; E = Extended; MU = Measurement Uncertainty Recapture)

No.	Plant	% Uprate	MWt	Submittal Date	Projected Completion Date	Type
1	Browns Ferry 2	15	494	06/25/2004	TBD	E
2	Browns Ferry 3	15	494	06/25/2004	TBD	E
3	Browns Ferry 1	15	494	06/28/2004	TBD	E
4	Monticello	12.9	229	11/05/2008	TBD	E
5	Nine Mile Pt.2	15	521	05/27/2009	Fall 2011	E
6	Grand Gulf 1	13.1	510	09/08/2010	Fall 2011	E
7	Turkey Point 3	15	344	10/21/2010	Fall 2011	E
8	Turkey Point 4	15	344	10/21/2010	Fall 2011	E
9	St. Lucie 1	11.9	320	11/22/2010	TBD	E

10	St. Lucie 2	11.9	320	02/25/2011	TBD	E
		TOTAL	**4,070**			
		TOTAL MWe	**1,355**			

Table 3 - Expected Future Submittals for Power Uprates, December 2010

Fiscal Year	Total Uprates Expected	Measurement Uncertainty Recapture Uprates	Stretch Power Uprates	Extended Power Uprates	Megawatts Thermal	Approximate Megawatts Electric
2011	11	9	0	2	1139	380
2012	15	9	0	6	2486	829
2013	0	0	0	0	0	0
2014	8	5	0	3	1504	501
2015	1	0	0	1	435	145
TOTAL	**35**	**23**	**0**	**12**	**5,564**	**1,855**

Additional Information

Additional information and guidance for power uprate license amendment request submittals can be found on the NRC's Power Uprate Web page at this address: http://www.nrc.gov/reactors/operating/licensing/power-uprates.html.

April 2011

LCM/EPU Modification In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
10435578	MNGP Extended Power Uprate	Common costs associated with the entire LCM/EPU project, rather than specific subprojects (listed below), consisting mainly of the contract with General Electric (GE) for services to support extended power uprate and life cycle management activities and internal Xcel Energy costs including site reviews, project engineering, project licensing and project management costs.	7/19/2013 (with allocations continuing until project close-out)	Common costs (net of those direct assigned to other projects) $103.1 Allocations out ($103.0) Unallocated costs remaining $0.1	GE services and Xcel common costs were necessary for license approval and design and engineering of LCM/EPU modifications. By the end of the current outage, these modifications (as described below) will have been installed and new and modified equipment will be supporting plant operation. Common costs are transferred to other JDE child work orders in order to properly assign a total cost to the physical assets placed in service. Such common costs are allocated to specific subproject child work orders proportionately as they are completed and placed in service.
10859413	MNGP EPU Steam Dryer Acoustic Monitoring	Engineering and analyses undertaken to examine the structural capabilities and moisture carryover of the steam dryer. Scope included installation of strain gages on Main Steam Lines for steam dryer acoustic monitoring.	6/1/08	Direct costs $5.0 Common allocations $2.3 Total $7.3	This scope of work was required for the company to make an informed decision regarding whether or not to replace the old steam dryer. This work was necessary to evaluate the old steam dryer for continued use and to ultimately decide upon the preferred option of replacing the steam dryer. As described in more detail below, the new steam dryer is installed and supporting plant operations at the current power level and is designed to also support operation at the uprated power level upon EPU approval. NRC required the instruments and they are in service monitoring real-time operations.
10884258	MNGP EPU Certificate of Need	Prepare certificate of need application and submit to the Minnesota Public Utilities Commission. Scope of work included all additional support necessary during the	N/A Moved to	Direct costs $0.0	The certificate of need was a necessary step for moving forward with the project and ultimately putting it into service.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		review and approval process.	another EPU workorder	Common Allocations $0.0 Total $0.0	Note: While certificate of need costs were initially recorded in this work order separately, they are common costs and were transferred to the MNGP Extended Power Uprate work order 10435578 in 2010 for consistent handling. Through the common cost allocation process used for that workorder, these costs are allocated to physical assets as they are completed and placed into service.
10942850	MNGP EPU-Power Range Neutron Monitor	Design, engineering and installation of a GE Nuclear Measurement Analysis & Control (NUMAC) Power Range Neutron Monitor (PRNM) system to replace the existing PRNM systems at MNGP in support of the LCM/EPU project. The replacement PRNM for Monticello includes four (4) NUMAC Average Power Range Monitor (APRM) instruments, two (2) Rod Block Monitor (RBM) instruments and a Two-out-of-Four logic interface to the Reactor Protection System (RPS) which consists of four (4) Two-out-of-Four Logic Modules, one Quad-low voltage power supply for each division, interface panels and modules to the plant or core monitoring computer, and necessary installation hardware. The NUMAC PRNM uses the same in-core detectors as the old system, but replaces all of the electronics and associated power	9/4/09	Direct costs $12.2 Common Allocations $5.3 Total $17.5	A PRNM is required to support plant operation at the currently authorized power level and at the EPU power level once approved. The PRNM employs in-core neutron detectors to monitor local reactivity for core monitoring purposes. The PRNM initiates a reactor scram or rod block depending on the monitored reactivity levels. The new PRNM is now installed and supporting current plant operation by providing additional stability functions and additional trip capability, among other functions and capabilities.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		supplies. This modification required demolition of existing internal components from the Main Control Room panel C-37 (5 bays) and some from the C-05 panel. The new PRNM equipment from GE was installed in the C-37 and C-05 panels as well as 4 new transmitters in the C-57 & C-58 instrument racks. Associated Plant Process Computer (PPC) interfaces were also installed and tested. New operating software was installed as well as existing Plant Process Computer (PPC) software changes. New fiber optic cables were installed between control room panel C-05 and panel C-37 and between panel C-37 and the plant computer system. New cables were also installed from the four existing and the four new Reactor Recirculation (REC) flow transmitters in the Reactor Building to panel C-37.			
10943007	MNGP EPU Main Power Transformer	Replace the Main Power (GSU) Transformer. This project also includes a new fire suppression system, a new gate in the security fencing system to facilitate transformer movements. A gas monitor was installed, and a temporary storage pad was constructed to store the new	5/25/11	Direct costs $19.0 Common	The Main Power Transformer is required for the plant to operate at the currently authorized power level and at the EPU power level once approved. The new Main Power Transformer is installed and stepping up the generator terminal voltage to the higher voltage necessary to provide station output to the transmission system.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		transformer until it was installed (and then to store the old transformer). The fire protection deluge system required removal, re-design, and replacement to accommodate the new transformer configuration and code requirements. Spill containment within the transformer area was also addressed as a technical issue for this modification. Removal and re-installation of the low-side isolated phase bus connections was included within this scope. A new bushing transformer for metering and protection circuits were connected to the new transformer. Fan control, foundation adequacy, and firewall modification as a result of tap bus removal were included in this modification.		Allocations $7.5 Total $26.5	
10943047	MNGP EPU GEZIP Installation	Design, engineering, analyses, and installation of a GE Passive Zinc Injection System (GEZIP). The GEZIP is mounted on a skid and contains a dissolution vessel, a manual flow control valve that controls the flow of water through the skid, a strainer on the discharge of the vessel, and block valves at the inlet and the outlet of the skid. Modification scope included replacing the old active Zinc Injection System with the new GEZIP, which	5/25/11	Direct costs $1.8 Common Allocations $0.8 Total $2.6	A GEZIP system is necessary to inject zinc into feedwater to reduce corrosion in the reactor cooling system in support of plant operation. The new GEZIP system is installed and is injecting zinc into the feedwater system. The new GEZIP piping and equipment has a higher design zinc injection capacity to accommodate the increased feedwater flow rate when EPU is approved. In addition, the new passive system design provides a simpler approach to operation and maintenance than the old active system design. This system has reduced

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		included removing the old zinc injection skid and installing a new zinc injection platform. The modification included installation of new Demineralized Water supply piping, GEZIP inlet from Feedwater piping, GEZIP outlet to Feedwater piping, and a drain line to the existing Clean Radwaste System. The modification also included installation of associated piping hangers and supports.			normal maintenance and operating costs compared to the previous system.
10943052	MNGP EPU Condensate Pump Impeller	Replace both condensate pumps and motors. Condensate pump replacement includes: removing the existing pumps P-1A and P-1B and installing new pumps, removing and replacing the condensate pump motors, providing grounding connections for the new motors, installing motor termination enclosures and associated supports, routing vibration and temperature instrumentation to the pumps and motors, routing and terminating new motor heater supply cables, and routing and connecting motor bearing cooling service water piping. The modification also included changes to condensate pump auxiliary equipment, including: the condenser recirculation sparger (providing larger diameter exhaust	7/19/13	Direct costs $19.8 Common Allocations $2.0 Total $21.8	The condensate and reactor feedwater systems provide feedwater to the reactor to maintain a constant reactor water level. The condensate system, with the new pumps and motors, is necessary for the plant to operate at the currently authorized power levels. The condensate pump and related equipment will have been installed by the end of the current outage and will be operating to maintain the constant reactor water level. The new pumps are sized to provide sufficient feedwater flow when the EPU is approved. The existing pumps and motors had reached their 40-year life. These replacements are an example of the LCM expectation under the NRC aging management license renewal.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		holes to increase flow); removing existing valve trim from flow control valves and installing new trim packages; replacing the flow transmitter; replacing the condensate flow indicator; replacing the condensate recirculation flow indicator; rescaling the recirculation flow controller; replacing flow indicators in the simulator; removing, rerouting, and replacing hotwell reject and makeup transmitters; and replacing hotwell level switches. The modification also includes replacement of condensate pump HVAC with higher capacity air handling units.			
11132414	MNGP EPU Expansion Joints	The extraction steam piping expansion joints were replaced based on aging issues and EPU-related increases in pressures and temperature conditions in the extraction steam piping. This WO involved the installation of fourteen (14) new expansion joints on the 8th, 10th, and 12th stage steam extraction lines in Condenser E-1A and E-1B.	5/8/09	Direct costs $4.9 Common Allocations $2.1 Total $7.0	Extraction steam is steam that is pulled from the main steam flow and is then supplied to feedwater heaters to preheat the feedwater prior to being returned to the reactor. Expansion joints are necessary to absorb changes in piping as it heats and cools. The new expansion joints are installed in the extraction steam lines and are functioning in support of plant operation at the currently authorized power levels. The new expansion joints are designed to accommodate plant operations at the EPU levels when approved. These replacements have resolved past leakage issues and are more robust for the next 20 years of operation improving plant efficiency for electrical generation.
11133668	MNGP EPU Turbine	Replaced High Pressure (HP) turbine steam path with a new rotor and diaphragms to accommodate increased steam flow under	5/8/09	Direct costs $37.6	The HP and LP turbines convert the energy in the steam to mechanical motion to spin the generator. The modified turbines are necessary for the plant to operate

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
	Replacement	EPU conditions. Replaced several diaphragm sets on one set of buckets in each low pressure turbine. Replacement of selected casing bolts. LP inner casing bolts (12) were upgraded to support expected stresses under EPU conditions. The modification also included new cams and camshafts. HP Turbine replacement or maintenance was considered probable during License Renewal Period. The replacement HP Turbine uses General Electric's latest high-efficiency technology known as the Advanced Design Steam Path (ADSP). The ADSP consists of a monoblock rotor with high-efficiency buckets (blades), a new 1st stage advanced design nozzle plate and new high-efficiency diaphragms. Detailed evaluation determined that replacement of LP diaphragms and buckets was necessary to achieve the desired bucket frequency margin. The LP Turbines have entirely new 7th and 8th stage diaphragms along with new rows of buckets for the 8th stage on the generator end of both LP rotors.		Common Allocations $16.4 Total $54.0	at the currently authorized power level. The turbines are installed and using high and low pressure steam to produce electric power from the generator. The modified turbines are designed to accommodate plant operations at the EPU levels when approved. The LP turbine modification scope restored turbine design margins and addressed a cracking issue at a plant with an identical turbine design (i.e., bucket cover "wear" at Vermont Yankee).

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
11133705	EPU Condensate Demineralizer System Replacement	The old condensate demineralizer vessels were replaced with larger vessels to accommodate the additional output of the condensate pumps under EPU conditions. Associated piping, valves, and support systems were also replaced as required and condensate demineralizer control panel C80 was replaced with a Programmable Logic Controller (PLC) control panel. The new condensate demineralizer system is comprised of five (5) demineralizer vessels, a precoat system mounted on a skid, holding pumps, associated piping with modifications, replacement valves, a PLC based control panel, and a new motor control center (MCC). To support the increased condensate flow, the filter elements in each new demineralizer vessel were replaced with longer (10" length increase) elements. The number of elements remains at 302 per vessel. In addition, a gantry crane was installed on the 951' level operating floor of the Turbine Building. The crane was used to support the removal of the existing demineralizer vessels and the installation of the new demineralizer vessels and appurtenances. After installation and startup, the crane will remain in place on the operating floor and will be used for	5/25/11	Direct costs $64.5 Common Allocations $15.3 Total $79.8	The condensate and reactor feedwater systems provide feedwater to the reactor to maintain a constant reactor water level. The demineralizer functions to remove minerals from the water to ensure flows remain unobstructed from mineral buildup. The demineralizer system has been replaced, and the new system is servicing this function in support of plant operation. The condensate demineralizer system, with the new demineralizer vessels, is necessary for the plant to operate at the currently authorized power levels. The new demineralizer vessels are sized to provide sufficient feedwater flow when the EPU is approved. Moreover, the new control panel has been installed and is controlling the sophisticated valve timing sequences necessary for condensate demineralizer system operation, backwashing, and precoating and providing improved reliability compared to the old system. The supplier of the new system (Graver Water Systems, LLC) guarantees the quality of condensate produced with the increased flow will match or exceed the existing system filtration. The new system has reduced feedwater iron and sulfate levels, which have direct long-term asset preservation of the internal reactor vessel components. The NRC has indicated a positive step in aging management decision-making.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		periodic maintenance activities associated with the demineralizers. The concrete plugs inserted in the floor at the 951' level were replaced with decking plates which allow access to the vessels, the vent piping, valves, and instrumentation attached to the vessel covers. The old control panel system had cam driven relays for controlling the sophisticated valve timing sequences necessary for condensate demineralizer system operation, backwashing, and precoating. The mechanical cams periodically misaligned and/or failed causing system mis-operation and necessitating "work-arounds" for the operators. This WO replaced the old control system with a solid state logic system for control of these timing sequences, comparable to the systems installed in many other nuclear plants.			
11133713	EPU Cross Around Relief Valves Replacement	Replace four (4) Cross Around Relief Valves (CARV) and 16" piping to provide increased relieving capacity under EPU conditions. The replacement valves have larger twenty-inch diameter outlet flanges and revised setpoints. The replacement valves have higher discharge pressure and higher	5/8/09	Direct costs $12.8 Common Allocations $5.6	The Cross Around Relief Valves are installed and are providing over pressure protection to the turbine by providing an alternate path for the steam to the condenser should the turbine not be able to accept the steam. The Cross Around Relief Valves are necessary to operate the plant at the currently authorized power level. The new Cross Around Relief Valves are sized to

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		discharge steam flow. As such, discharge piping was replaced with larger diameter piping to achieve sufficient discharge flow rates. New piping hangers and supports were also installed where required. The four discharge pipes originate in the turbine building, adjacent to the main turbine. The pipes terminate inside the main condenser, where they connect to the spargers. Four new spargers were also installed inside the main condenser.		Total $18.4	operate at EPU power levels when approved. These valves are in service providing over pressure protection of the turbine.
11133719	EPU Feedwater Heater Drain & Dump Valve Replacement	Replaces dump valves and drain valves for feedwater heaters and drain coolers. Scope included replacing 8 feedwater heater air operated valve (AOV) drain valves (4", 6", 8" and 12"; 2 of each) and replacing 10 feedwater heater AOV dump valves (2.5", 4", 6", 8" and 10"; 2 of each). Replacements included valves, air operators, positioners, and solenoids. Fourteen (14) of eighteen (18) were replaced during RF 24. The remaining four (4) valves were replaced during RF25. These valves were not installed in RF24 because the manufacturer could not produce them in time.	5/8/09	Direct costs $3.3 Common Allocations $1.4 Total $4.7	Feedwater heater drain and vent valves are installed and functioning to help maintain water level in the feedwater heaters. They are necessary to operate the plant at the current authorized power level. The new valves are sized to operate at EPU power levels when approved. The valves are in service providing improved efficiencies in heater performance for power generation as well as more control for the control room operators. This has a direct improvement with reducing safety risk to the plant.
11133731	EPU Main Steam Flow Transmitters	Replace the main steam flow transmitters to accommodate increased flows under	5/8/09	Direct	Main steam flow is a plant parameter that is necessary to be monitored during plant operation. The new main

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
	Replacement	EPU conditions. This modification replaced four main steam flow transmitters located in the reactor building and replaced the eight main steam flow indicators located in the control room on Panels C-05 and C-03. In addition, the main steam flow recorder was re-programmed.		costs $0.3 Common Allocations $0.2 Total $0.5	steam flow transmitters and indicators are installed and being used to measure steam flow in support of plant operation at the currently authorized power level. The new main steam flow transmitters are sized to operate at EPU power levels when approved.
11133856	EPU Feedwater Flow Transmitters/PC In	Replace the feedwater flow transmitters and pressure control instrumentation to maintain functionality with increased flows and pressure drops under EPU conditions. This modification involved rescaling four feedwater flow transmitters and replacing two feedwater flow indicators located in the control room. The four rescaled feedwater flow transmitters are located in the turbine building. The existing flow transmitters were removed, rescaled, recalibrated, and reinstalled in their original locations. The existing feedwater flow transmitters were manufactured by GE Nuclear and were located in the control room on Panel C-05. The replacement indicators are the same model, produced by Yokogawa, and use the same electrical connections and fit in the same control room panel as the	5/8/09	Direct costs $0.2 Common Allocations $0.1 Total $0.3	Feedwater flow is a plant parameter that is necessary to be monitored during plant operation. The new feedwater flow transmitters and pressure control instrumentation are installed and being used to measure feedwater flow in support of plant operation at the currently authorized power level. The new feedwater flow transmitters are sized to operate at EPU power levels when approved.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		existing indicators. The existing feedwater flow recorder was re-programmed as a result of the new EPU feedwater flow rate conditions.			
11133861	EPU Isophase Bus Cooling Replacement	Replace existing isophase cooling unit with a new one sized for increased EPU heat loads. Also add a new redundant cooling unit to increase reliability. This modification involved the removal of the old cooling unit and the installation of a new cooling unit and associated components, including: a fan coil air-handling unit, re-routing of supply and return cooling air ducting and water piping to conform to new equipment; and provision of a cooling unit support structure capable of supporting primary and redundant units while providing maintenance access. The redundant unit included a fan coil air-handling unit, new service water taps for supply and return from the redundant unit, automated startup and automated isolation valves and dampers, and new electrical cabling and conduit supplied from the new breaker on MCC 125.	5/8/09	Direct costs $3.8 Common Allocations $1.6 Total $5.4	A large amount of heat is generated when the electricity produced in the plant's generator is being transferred to the main transformer via the isolated bus ducts. This heat needs to be removed to avoid damaging the equipment. The new isolated phase bus cooling system has been installed and is being used to cool the bus ducts at the currently authorized plant power levels. The new isolated phase bus duct cooling system has been sized to operate at the EPU power levels when approved. Specifically, the isolated bus duct cooling system provides forced draft cooling to each (A, B, and C) isolated phase bus and accompanying concentric ductwork enclosing each bus from the turbine building out to the main transformer. The modified cooling system is removing up to 415,000 Btu/hr of the heat released from the isolated phase bus ducts and providing for dual redundancy in support of plant operation. This system provides more certainty of the reliability of plant operations for peak load demands in the summer.
11133865	EPU EQ Transmitters &	Replace transmitters and detectors (10) based on new Environmental Qualification (EQ) evaluations due to the new High	5/8/09	Direct costs $0.6	Under NRC regulations certain plant components are required to be qualified to operate in high temperature and radiation environments in the unlikely event of a

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
	Detectors	Energy Line Break (HELB) analyses.		Common Allocations $0.2 Total $0.8	plant accident. The higher EPU power level will change the conditions after an accident for which EQ-required components must be qualified. As an NRC requirement, the plant cannot operate without Environmentally Qualified equipment. These new qualified EQ transmitters and detectors are installed and supporting plant operation at the currently authorized power levels. The new EQ transmitters and detectors have been qualified to operate at the EPU power levels when approved.
11133871	EPU Main Steam Isolation Valve Solenoid Valve Replacement	Replace the solenoid valves on the inboard Main Steam Isolation Valve (MSIV) to increase the margin between maximum containment pressure and minimum nitrogen supply pressure. The old MSIV valves required 50 psi dp to actuate. Under EPU conditions approximately 48 dp will be available. The new poppet valves will require 25 psi dp.	5/8/09	Direct costs $0.2 Common Allocations $0.1 Total $0.3	In the event of a plant transient, the flow from the main steam line from the reactor to the turbine needs to be able to be isolated to prevent the loss of coolant from the reactor. The main steam isolation valves are installed and are required to during plant operation to provide this ability to isolate the steam flow. The new main steam isolation valves utilize a smaller solenoid valve to accomplish their intended function. The new solenoid valves installed on the inboard main steam isolation valves are being used at the currently authorized power levels. The new solenoid valves have been designed to perform their intended function at EPU power levels when approved.
11133877	EPU Removal of Drywell Bricks in	Removal of remaining drywell shield bricks from bioshield for High Energy Line Break	5/8/09	Direct costs $0.1	The NRC requires plants to analyze the effects of steam lines breaking in the plant that have a large amount of energy flowing through them, so that if they break, they

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
	Bioshield	(HELB)/EPU analyses requirements. In the event of a loss of coolant accident (LOCA), pressure could develop within the annulus between the biological shield wall and the reactor pressure vessel by failure of a nozzle or safe end. The resulting pressure would cause the missile energy of the biological shield to exceed its limit; therefore, the shielding bricks were postulated to be ejected and impact the containment. As such, this modification removed all shield bricks from three penetrations in the drywell bioshield. Also, dosimeters were installed near possibly affected EQ equipment to measure the doses in the drywell.		Common Allocations $0.0 Total $0.1	will not damage other critical plant equipment in the vicinity. Under NRC requirements, the plant cannot operate without being in compliance with the High Energy Line Break analysis. One of the required analyses is for the break of a large steam line inside of containment. It was determined that bricks that are stacked in penetrations through the biological shield wall to provide radiation shielding could become missiles and damage other equipment in the event of such a line break. Therefore, the drywell bricks in the bioshield were removed, thus meeting safety requirement necessary for ongoing plant operation at both the currently authorized power levels and the EPU power levels when approved. This complies with NRC rulemaking regardless of power operations and for long-term operations in the extended 20-year license period.
11133931	EPU Drywell Spray Flow Valve Replacement	Replace motor operated valve with a manual valve to provide capability to throttle drywell spray flow consistent with design bases analytical assumptions.	5/8/09	Direct costs $0.2 Common Allocations $0.0 Total $0.2	The drywell spray system is an NRC requirement for plant operation. The drywell spray flow valve has been replaced, and operation of the drywell spray system with the new manual valve is being used to support plant operation at the currently authorized power level. The new manual valve has been designed to ensure safe plant operation in keeping with design bases analytical assumptions under EPU conditions when approved. This system change now has proven to be a step-forward in reducing future impacts from Fukushima.
11194611	EPU Off Gas Dilution Fan	Life cycle management project to replace aging plant cable and allow extended	8/28/09	Direct costs $0.4	The old cable has been replaced, and the new cable is supporting the operation of the off gas dilution fan

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
	Cable	operation; cable replacement of original plant equipment. Scope: replace two continuous runs of 900 feet of cable and replace the cable with 1,200 feet.		Common Allocations $0.2 Total $0.6	with added reliability under the currently authorized plant power level and EPU plant power level when approved. This cable replacement is a LCM project that was also necessary under the new NRC license life of the facility.
11213813	EPU 1 AR Cable Replacement	Install new 4.16 kV feeder cables between the Number 1 Auxiliary Reserve (1AR) Transformer and safety related busses, numbers 15 and 16. The 1AR transformer is a reserve auxiliary transformer (RAT) located on a concrete slab south of the plant's condensate storage tanks (CST). The secondary side of the transformer is used to supply the essential busses (15 & 16) with 4.16 kV power when the normal power supply (1R & 2R) is unavailable. The primary side of this transformer is energized by a 13.8 kV feed via the MNGP switchyard. Due to its age, the 1AR transformer and cabling was replaced as part of the Life Cycle Management (LCM) modifications. The 1AR transformer was replaced under a separate WO. Under this WO, three conductors were installed for each bus feed (one conductor for each phase) for a total of six new	N/A Went to a non-EPU work order	Direct costs $0.0 Common Allocations $0.0 Total $0.0	The new feeder cables will be in place by the end of the current outage and available to supply the essential busses (15 & 16) with 4.16 kV power when the normal power supply (1R & 2R) is unavailable. The ability to supply the essential busses with 4.16 kV power when the normal power supply is unavailable is needed under plant operations at the currently authorized plant power level and EPU plant power level when approved. These cable replacements are an LCM requirement for long-term management as well as EPU support. Note: While some cable replacement costs were initially assigned and recorded in this LCM/EPU work order from 2009-2011, in 2012 they were transferred to a separate non-EPU work order at MNGP (#10735617) where all plant cable replacements (including those unrelated to EPU) are being handled.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		conductors. Each bus feed was installed in a new cable tray, routed along the CST containment walls and into the existing turbine building penetrations. The cabling was routed through existing conduit inside of the turbine building utilizing the existing pathways for the current cabling. The old cabling was removed from inside of these conduits and the new cabling was installed through the existing conduit. The cable size was raised from 750 MCM to 1000 MCM cable. This will allow the cable to support future expansion from installing forced air cooling on the 1AR transformer and raising the available output of the 1AR transformer from its current 750 MVA. By sizing the cabling on the forced air cooling of the transformer, the cabling will be able to support future expansion capability of the transformer. Grounding stirrups were installed on the 1 ARS primary feed and 1AR primary and secondary feed cables to improve safety during installation and maintenance activities. The grounding grid from the 1AR transformer was connected to the plant grounding system to eliminate potential differentials.			

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
11215274	EPU Steam Dryer Replacement	Installation of Replacement Steam Dryer (RSDP). RSDP is necessary to achieve the moisture carry over (MCO) targets for long term operations of Monticello. The new dryer is fully instrumented and designed to provide compatibility with the existing and uprated MNGP reactor environment. It has a frame structure ensuring robustness and structural integrity. The dryer panels are designed for the power uprated operating conditions. The steam dryer is designed with maximum panel surface area to provide the lowest dryer MCO possible. The scope of work included replacement of the steam dryer, installation of instrumentation on the stream dryer, and installation of cabling to support the new instrumentation system.	5/25/11	Direct costs $30.4 Common Allocations $0.0 Total $30.4	The replacement steam dryer is installed and supporting plant operations at the currently authorized power levels and is designed to operate at the EPU power levels when approved. The steam dryer acts as the final stage of moisture removal for steam produced by the reactor and provides high-quality steam to the turbine. The new steam dryer is reducing moisture carryover to ≤ 0.1%. This reduction in moisture carryover helps minimize corrosion products in the reactor coolant loop. The reduced corrosion products minimize high pressure turbine wear, reduce the production and transportation of activated corrosion products, and reduce the volume of radioactive wastes (from condensate demineralizer and reactor water cleanup (RWCU) filtering material replacements). These reductions help minimize worker doses.
11225964	EPU Acoustic Monitoring Instrumentation	Replace 20 strain gauges (vibration monitoring instruments) during refueling outage.	5/8/09	Direct costs $0.3 Common Allocations $0.1 Total $0.4	Acoustic monitoring equipment is installed and providing data on vibration. These vibration monitoring instruments provide critical information regarding how plant equipment is performing. Such data are required by the NRC for operation at the EPU power level. However, the data also provide beneficial information regarding how plant equipment is performing at the currently authorized plant power levels. As such, the plant made a decision to install it regardless of whether or not EPU was pursued. It is part of long term equipment management for the

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
					license renewal period.
11257804	MNGP EPU 13.8 kV Distribution System	The project scope included the following items: • Replacement of 1R and 2R transformers. • Two new 13.8 kV switchgear line ups. • Two new 480 V unit substation transformers and switchgear line ups. • HVAC equipment for the new switchgear rooms. • Elevator for the new switchgear building. • Erection of new 13.8 kV switchgear rooms, including new elevator and installation of shielding between the turbine building and the work areas in the new building. • New foundation and firewalls (including verification of compliance with NFPA codes and NEIL insurance standards) for transformer 1R and 2R. Note that an oil retention barrier was provided around the final location of transformers 1R and 2R. • Installation of new transformer 2R including new 34.5 kV feed, new 34.5 kV disconnect structure, and removal of CLIP fuse and reactors in switchyard and new 4.16 kV and 13.8 kV bus work.	7/19/13	Direct costs $108.3 Common Allocations $11.2 Total $119.5	The new 13.8 kV system will have been installed by the end of the current outage and will provide electric power to operation plant equipment and system. Over the years as plant loads were added, the available safety margins of the old 4.16 kV system to support plant operation had been reduced. As such, the upgrade to 13.8 kV is not only necessary to provide adequate operation and margin for the MNGP electrical system while using the new equipment sized for EPU power levels but also provides more safety margin at the plant under current power levels. Specifically, the new 13.8 kV system allows for the separation of large loads in loss of power scenarios and more versatility for transient situations. Moreover, the upgrade provides strategic safety benefits in light of emerging Fukushima requirements. As such, the new 13.8 kV system will support the extended period of plant operation with or without EPU.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		• Installation of new 13.8 kV power cables to the Reactor Feed Pumps (RFPs), Condensate Pumps and Reactor Recirculation Motor-Generator (RRMG) drive motors. • Installation of new 4.16 kV power cables from the 13 and 14 switchgear to the new 480 V unit substation transformer primaries. Installation of new manual transfer switches and 480 power cables from the new unit substations to existing MCCs 131 and 141. • Installation of fire detection system in the 1R and 2R transformer bays including any modified hydraulic calculations for sprinkler piping. • Installation of a fire detection system in the 13.8kV switchgear facility without any automatic fire suppression equipment. • Demolition of Secondary Containment at the Recirc MG Set Room to facilitate demolition and installation of the motors. • Removal and installation of the RRMG Drive motors, including applicable lifting rigging.			
11284286	MNGP EPU Replacement 4 Feedwater Drain	Replaces dump valves and drain valves for feedwater heaters and drain coolers. Scope included replacing 8 feedwater heater	5/25/11	Direct costs $12.6	The feedwater heater drain and vent valves are installed and helping to maintain water level in the feedwater heaters. They are necessary to operate the plant at the

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
	& Dump Valves	air operated valve (AOV) drain valves (4", 6", 8" and 12"; 2 of each) and replacing 10 feedwater heater AOV dump valves (2.5", 4", 6", 8" and 10"; 2 of each). Replacements included valves, air operators, positioners, and solenoids. Fourteen (14) of eighteen (18) were replaced during RF 24. The remaining four (4) valves were replaced during RF25. These valves were not installed in RF24 because the manufacturer could not produce them in time.		Common Allocations $5.0 Total $17.6	current authorized power level. The new valves are sized to operate at EPU power levels when approved. These valves are in service providing improved heater efficiency for power operations.
11286955	MNGP EPU Replacement of Reactor Feedwater Pumps and Motors	Replace Reactor Feed Pumps and control valves to allow EPU full flow operation. Evaluate the system piping and hangers between the numbers 13 and 14 feedwater heaters. The scope of this modification included (inter alia): removing and replacing pumps and motors; rerouting drains and support for drains; installing a new 480-208/120 transformer, 480VAC and 120VAC distribution panels, termination blocks, control relays, cables and conduits to provide 120VAC power to the motor and main termination box space heaters and the new motor cooler leak detectors; routing vibration and temperature element leads to pump and motor instrumentation	7/19/13	Direct costs $83.5 Common Allocations $8.7 Total $92.2	By the end of the current outage, the new reactor feedwater pumps and motors will be installed and operating to provide feedwater to the reactor to maintain a constant reactor water level. The feedwater system, with the new pumps and motors, is necessary for the plant to operate at the currently authorized power levels. The new pumps are sized to provide sufficient feedwater flow when the EPU is approved. The new pumps and control valves support plant operation by helping to provide a regulated supply of de-aerated, pre-heated, demineralized water to the reactor to maintain a constant reactor water level. The existing equipment had reached the end of life and was required to be replaced as part of aging management under the new license for operations.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		enclosures; installing pump and motor foundation and anchorage; installing two new monorails to facilitate maintenance of the rotor and coupling for each reactor feedwater pump; installing lube oil skid pads; rerouting portions of the reactor feedwater pump suction and discharge piping between the 13 and 14 feedwater heaters; rerouting portions of the reactor feedwater pump recirculation piping between the reactor feedwater pumps and the condenser; rerouting emergency service water (ESW) piping; and redesigning, fabricating, and installing new hydrogen water chemistry platform, supports, and instrument rack.			
11286961 & 11757884	MNGP EPU Replacement of 14 and 15 A/B Feedwater Heaters	Replace the 14 and 15 A/B Feedwater Heaters. The project involved the procurement, manufacture, delivery, installation, and pre-operational and post-installation testing of the new heaters. It also involved the removal and disposal of the old feedwater heaters. Interferences were removed to facilitate the removal of the existing heaters and the installation of the new heaters. The removed interferences were reinstalled after the new feedwater heaters were installed. Attached piping was evaluated and certified to be adequate for EPU. In addition, the	5/25/11	Direct costs $15.4 Common Allocations $9.4 Total $24.8	The feedwater system, with the new feedwater heaters, is necessary for the plant to operate at the currently authorized power levels. The new feedwater heaters are installed and are using steam extracted from the main steam flow to pre-heat water before it goes into the reactor to be boiled to steam. The new feedwater heaters are raising condensate temperature above the hotwell temperature in order to provide feedwater to the reactor to maintain a constant reactor water level in support of plant operation. As part of EPU the flow of water through the reactor will be increased and as such the capacity of the feedwater heater to pre-heat that water requires a higher

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		instrumentation for the heaters was replaced. These instruments included the current level instruments that are routinely overhauled every cycle. This modification also involved the qualification of the floors under the heavier load of the new feedwater heaters. Stiffening cover plates were installed on 14 of the existing floor structural beam members under the E-14 and E-15 heaters, one beam seat for a connection as well as bearing plates under the wheels, and bearing plates under the middle wheels of the E-13 heaters.			feedwater heater capacity than the plant had at the current power level. The new feedwater heaters are sized to provide sufficient feedwater flow when the EPU is approved. The heaters had reached their end of service life and were necessary to be replaced for continued operations and to meet license expectations for assuring proper water temperatures were obtained flowing to the reactor. The plant has seen performance improvement with more consistent temperature control.
11286966	MNGP EPU Generator Field Rewind	Rewind the Monticello Main Generator for EPU rating. In order to meet EPU electrical output requirements as well as to manage plant life-cycle maintenance issues, the Monticello Main Generator had to be rewound. This project involved replacement of new upper and lower stator bars along with the field winding of the main generator. In addition, a flux probe fix was installed. All thermocouples were replaced in kind and existing resistance temperature detectors (RTDs) were replaced with dual element RTDs. A new class F epoxy insulation	5/25/11	Direct costs $5.8 Common Allocations $0.9 Total $6.7	The generator field winding is a mass of copper wires that spins within the magnetic field to produce the alternating current (AC) power. As the generator capacity is increased the number of copper wires that make up the generator winding are increased. The plant cannot produce electricity without the generator winding. The new generator field winding is installed and is supporting plant operation at the currently authorized power level. The new generator field winding has been sized to support plant operation at the EPU power level when approved.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		system was installed.			
11286973	MNGP EPU Generator Exciter Replacement	The scope of this project was to replace the old Alterex rotating exciter like-for-like. As an in-kind replacement, the new exciter incorporated modifications made to the existing exciter since it was installed. Additionally, some upgrades and changes were made due to technological improvements and obsolescence issues over the last 20+ years (RTDs, vibration monitoring, etc.). Components replaced include the box frame stator, stator coils, stator core, collector rings, rotor assembly, oil inlet assembly, bracket bearings, and exciter cooler.	9/12/11	Direct costs $0.1 Common Allocations $0.0 Total $0.1	The generator exciter sets up the magnetic field that allows alternating current to be induced. The plant cannot produce electricity without the exciter setting up this magnetic field. The new generator exciter is installed and is supporting plant operation at the currently authorized power level. The new generator excite has been sized to support plant operation at the EPU power level when approved.
11286981	MNGP EPU Main Steam Drain Tank Modifications	Resolve two issues (two phase flow) with the moisture separator drain tanks (MSDT). The station had a long history of control problems due to the water in the drain tanks flashing to steam in the vent piping and the drain to the 14A/B feedwater heaters as it is pushed up in elevation. With increased velocities and pressure drops the existing MS/MSDT level control problems would have been amplified under the EPU conditions. Resolution of the MSDT drain problem required a solution to two design problems: (1) insufficient venting of the B	N/A Moved to another EPU workorder	Direct costs $0.0 Common Allocations $0.0 Total $0.0	Moisture Separator Drain Tanks (MSDTs) collect the liquid separated from the steam by the moisture separators in support of plant operation. The new MSDTs resolve the aforementioned performance issues under the current power level (those issues would have been amplified under EPU conditions absent this modification). By the end of the current outage, the new MSDTs will be installed and supporting plant operation at the currently authorized power level and the EPU power level when approved. Note: Steam drain tank costs were initially recorded

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		& C MSDT through the 3" vent line to the moisture separator; and (2) unsteady two phase drain flow from the MSDTs to the level control valves (LCVs). Condensate injection was chosen as the method to solve the two phase flow problem. Condensate injection required the diversion of condensate from the condensate pump discharge to the MSDT drain lines at elevation 911'. This modification added the condensate injection lines, flow control valves, manual valves, and injection sparger/nozzle. This modification also changed 3" vent lines to 6" vent lines on the B and C MSDT to solve the venting problem.			separately in this work order from 2009-2011, but in 2011 they were transferred to another LCM/EPU workorder for the feedwater heater (11286961) and managed as part of that project from then on.
11286985	MNGP EPU Stator Water Cooler Replacement	At EPU power, the old heat exchangers would not have provided adequate heat removal due to their degraded state. Therefore, these heat exchangers were replaced with a similar design, containing more corrosive resistant stainless steel tubes. This similar design will allow for simpler installation due to minor modifications to the existing piping and skid, and it will decrease the impact to current operation and maintenance procedures for the system. The old YST-1 stator cooling strainer was a	5/24/11	Direct costs $1.7 Common Allocations $0.7 Total $2.4	The stator is the stationary portion of the generator and is made up of a series of cooling coils and windings. As the generator produces electricity, heat is generated. The stator has a water cooling system to remove the heat generated as electricity is produced. This heat needs to be removed or the generator would be damaged. As such the plant cannot operate without stator cooling. The new stator water cooling system is installed and supporting plant operation at the currently authorized power level. The new stator water cooling system is sized to support plant operation at the EPU power level when approved.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		single point of failure for the main generator stator cooling system. To mitigate this risk, the single YST-1 strainer was replaced. The old Y -strainer was replaced with pipe. The new strainer was relocated to the stator skid close to the ground for easy maintenance. Also, a mount was needed to secure the strainer to the skid. The old stator cooling filters for demin makeup water (YFI-2) and for rectifier cooling (YRFI-1) were susceptible to leaks at the gasket ends of the housing due to a single point of contact exhibited by a single bolt design. Therefore, these two filter housings were replaced with an improved design that will provide a better seal for both filters. Most new designs required minor piping and mounting modification.			The plant equipment has more margin for increased river temperatures experienced thus minimizing the need for plant derates in power operations.
11286992	MNGP EPU Reactor Water Clean Up Capacity Improvement	The RWCU pumps were replaced with higher capacity pumps to meet guidelines for EPU flow rates. Replacement of the pumps (rather than modification) was pursued due to the old equipment's inefficiencies and maintenance problems. This modification also included engineering and installation of proper mounting for the new pumps and motors as well as necessary changes to other	12/21/12	Direct costs $5.1 Common Allocations $0.6 Total $5.7	The reactor water clean-up (RWCU) system supports plant operation by filtering undesired particles out of reactor water and preventing them from being circulated through the reactor. The particles are removed so that they are not deposited on the surface of the fuel, which would diminish heat transfer, and to prevent the particles from becoming activated when they pass through the reactor core, which would increase radiation levels in the plant. Reactor water clean-up is necessary to support efficient plant operation and low radiation levels.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		RWCU components, piping, and hangers. This WO included: removing the RWCU recirculation pumps and motors and locating and install new pumps and motors; rerouting and supporting a new supply cable to the motor; providing ground connections for the motors; installing and supporting new pump vent and drain piping; installing new, rescaled flow indicators; installing new transmitters; and changing setpoints.			The new RWCU pumps are installed and functioning to support plant operations at the currently authorized power levels and the EPU power level when approved. The existing pumps had reached their end of life requiring large amounts of maintenance putting workers in radiation dose fields routinely. The new equipment has less future maintenance requirements.
11335729	MNGP EPU Turbine Generator Vibration	The Bently Nevada Vibration Monitoring System is intended to replace certain monitoring functions of the old Turbine Supervisory Instrumentation (TSI). These include thrust bearing wear detection, vibration, eccentricity, case expansion, differential expansion, rotor expansion and keyphasor. The project was divided into two phases. During the March, 2009 outage, EC13578 (Phase I) installed Bently Nevada 3500 equipment necessary to provide a Thrust Bearing Wear Detection System compatible with the new high pressure (HP) turbine. This equipment included a seismic II/I cabinet (C-49) in the cable spreading room to house the Bently Nevada Vibration Monitoring System, transducers, and	5/25/11	Direct costs $2.6 Common Allocations $0.9 Total $3.5	The Bently Nevada Vibration Monitoring System is installed and monitoring turbine vibration to ensure reliable operation by identifying problems that might lead to failures or maintenance needs. The new Vibration Monitoring System supports plant operation at the currently authorized power levels and will support plant operation at the EPU authorized power level when approved. The new system provides better diagnostic capabilities to monitor the larger components of the turbine giving early warning to prevent failures of these larger assets.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		proximitors. The new system was wired to existing thrust bearing wear detector interfaces including the existing annunciators, indicator, and turbine trip relay. In addition to the thrust transducers, additional transducers were installed to support a portion of Phase II. EC13808 was phase II of the vibration monitoring system modification and installed the remainder of the transducers on bearings 7 through 10 during the 2011 RFO. This EC also installed the proximitors and route associated instrumentation cabling to the C-49 cabinet in the cable spreading room. After completion of this modification, all of the turbine vibration, eccentricity, expansion and keyphasor monitoring is now via the C-49 Bently Nevada System. In addition to the Bently Nevada System, a System 1 Server was connected to the C-49 cabinet to provide real-time and archived vibration data.			
11376086	MNGP Drain Cooler Piping Modification	This project replaced the drain piping from the #11 and #12 feedwater heaters with larger piping to support increased flow rates at EPU operation. The drain line for feedwater heater E-12A was modified by replacing the 12” heater	1/6/12	Direct costs $0.0 Common Allocations $0.0	This drain piping is an integral part of the feedwater heater system and is necessary to support plant operation. The new drain cooler piping is installed and supporting plant operation at the currently authorized power level. The new drain cooler piping has been sized to support

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		drain nozzle with a 16" drain nozzle. The 12" pipe from E-12A to drain tank T-52A was replaced with a 16" pipe. Also, drain tank T-52A was removed and replaced with a 16" x 12" reducer and 12" pipe. The drain line for feedwater heater E-12B was modified by replacing the existing 12" piping from E-12B to drain tank T-52B with a 16" pipe. Also, drain tank T-52B was removed and replaced with a 16" x 12" reducer and 12" pipe. The drain lines for feedwater heaters E-11A and B were modified by replacing the 14" drain nozzles with a 16" drain nozzles. Also, the 14" piping from heaters E-11A/B to the E-DC-11A/B drain cooler inlet loop seal was replaced with 16" piping. The drain lines from drain coolers E-DC-11A and B to the condenser E-1A penetration were modified by replacing the 14" piping with 16" piping. Penetration E-1A was enlarged from 14" to 16".		Total $0.0	plant operation at the EPU power level when approved. The piping replacement resolved a code aging issue with pipe wall thinning for LCM aging management concerns. Note: Drain cooler piping costs were initially recorded separately in this work order in 2011, but that year they were transferred to another LCM/EPU workorder for the feedwater heater (11286961) and considered part of that project from then on.
11376103	MNGP Turbine Building Elevation 951' Reinforcement Project	This WO involved adding steel stiffeners to the beams supporting the 951' elevation floor. In addition, it included adding two jib cranes on the 930' elevation.	1/6/12	Direct costs $0.0 Common Allocations $0.0	When installing the new 14 and 15 Feedwater Heaters, the Turbine Building Floor at the 951' elevation needed to be reinforced due to the increase in size and weight of the new feedwater heaters. In addition, to complete the work on the new condensate demineralizers on the 930' elevation, two new jib cranes were added under this work order.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
				Total $0.0	This work has been completed and was needed to install the 14 and 15 feedwater heaters and condensate demineralizers described above. Operation of the new 14 and 15 feedwater heaters and new condensate demineralizers support plant operation at the currently authorized power level and will support plant operation at the EPU power level when approved. Note: These costs were initially recorded separately in this work order in 2011, but that year they were transferred to another LCM/EPU workorder for the feedwater heater (11286961) and considered part of that project from then on.
11398720	Engineering & Supervision for EPU	General engineering and supervision that was across the entire project was charged here in 2011 under FERC and company procedures, related to engineering and supervision assignable to project activity.	N/A Moved to another EPU workorder	Direct costs $0.0 Common Allocations $0.0 Total $0.0	These costs represent engineering and supervisory support required to design and install the new and modified equipment and systems described in this table that are installed and functioning to support plant operation. Note: While these overhead costs were initially recorded separately in this work order, they are common costs and were transferred to the MNGP Extended Power Uprate work order 10435578 for consistent handling. Through the common cost allocation process used for that workorder, these costs are allocated to physical assets as they are completed and placed into service.
11410738	MNGP EPU PCT Vent & Purge Valves	At EPU conditions, the old Primary Containment Vent and Purge Valves could not open or close against containment	7/19/13	Direct costs $0.4	Primary Containment Vent & Purge Valves are used to control hydrogen and oxygen concentrations inside the primary containment following the unlikely event of an accident. The new Vent & Purge valves are sized to

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		pressures. This modification was an equivalency to upgrade the valves (actuators, springs, etc.) to have more robust capabilities and recover margin for EPU conditions. The equivalency enhanced the Air Regulators or Actuator Springs for sixteen PCT Vent and Purge AOVs to ensure appropriate operating margin at EPU conditions		Common Allocations $0.0 Total $0.4	open and close against containment pressures that would be experienced in an accident at EPU power levels. By the end of the current outage, the new Purge & Vent Valves will be installed and functioning to support plant operation at the currently authorized power levels and the EPU power levels when approved. These valve actuator changes isolate containment faster and in support of new NRC rulemaking regarding the Fukushima event.
11536446 11636097 11636101 11636105 11636109 11636114 11775097	MNGP EPU License Development (various)	This WO covers EPU license amendment request (LAR) submittal and interface with the NRC to resolve Steam Dryer RAI's and the Containment Accident Pressure issues. This WO also includes EPU Implementation EC-13638 whose purpose is to provide the engineering basis for an increase in reactor thermal power up to 2004 MWt (EPU) and to assure plant design documentation is updated accordingly. This EC provides the results of evaluations performed that justify uprating the licensed thermal power at the MNGP and makes required changes to site records systems to support the change. The purpose of this EC is to evaluate plant piping, equipment, programs, systems, electrical margins, materials, chemical, instrumentation and controls, habitability,	10/31/13 (EPU license) and 1/31/14 (MELLLA + license) 10/31/2012 (license related but related to specific equipment)	Direct costs $59.4 Common Allocations $1.1 Total $60.5	This WO scope of work was necessary to prepare the plant for and to obtain approval for operation at the uprated power level. These charges were initially included in the initial Extended Power Uprate WO #10435578, and in 2011 were split out to track licensing costs separately in this WO. During 2012 and 2013, several separate licensing-related workorders were created to track various licensing efforts, but all are combined here.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		source term, health physics, human performance, testing and risk to assure all aspects continue to meet the intended design basis when considering the effects of an increase in Reactor thermal power up to 2004 MWt.			
11638897	MNGP EPU 13 A/B Feedwater Heater Replacements	Replace the 13 A/B Feedwater Heaters. The project involved the procurement, manufacture, delivery, installation, and pre-operational and post-installation testing of the new heaters. It also involved the removal and disposal of the old feedwater heaters. Interferences were removed to facilitate the removal of the existing heaters and the installation of the new heaters. The removed interferences were reinstalled after the new feedwater heaters were installed. Attached piping was evaluated and certified to be adequate for EPU. In addition, the instrumentation for the heaters was replaced. These instruments included the current level instruments that are routinely overhauled every cycle. Turbine Building Hatch No. 2 was enlarged to accommodate both removal and installation of the E-13 Heaters. This modification also involved the qualification of the floors under the heavier load of the new feedwater heaters. Stiffening cover plates were installed on 14	7/19/13	Direct costs $44.7 Common Allocations $4.4 Total $49.1	The feedwater system, with the new feedwater heaters, is necessary for the plant to operate at the currently authorized power levels. By the end of the current outage, the new feedwater heaters will be installed and using steam extracted from the main steam flow to pre-heat water before it goes into the reactor to be boiled to steam. The new feedwater heaters will raise condensate temperature above the hotwell temperature in order to provide feedwater to the reactor to maintain a constant reactor water level in support of plant operation. As part of EPU the flow of water through the reactor will be increased and as such the capacity of the feedwater heater to pre-heat that water requires a higher feedwater heater capacity than the plant had at the current power level. The new feedwater heaters are sized to provide sufficient feedwater flow when the EPU is approved. Note: Costs for 13 A/B feedwater heaters initially commenced under the 14 A/B feedwater workorder (11286961) but in 2012 they were transferred to this workorder for separate project management since the

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		of the existing floor structural beam members under the E-14 and E-15 heaters, one beam seat for a connection as well as bearing plates under the wheels, and bearing plates under the middle wheels of the E-13 heaters.			14 A/B work was completed in 2011.
10735617	MNGP EPU 1AR Transformer Replacement	Replace the Number 1 Auxiliary Reserve (1AR) transformer. The 1AR Transformer was replaced as an LCM project due to obsolescence. This modification replaced the 1AR Transformer due to reliability issues. Scope included the replacement with a new 13.8kV- 4.16kV transformer, equipped with an auto load tap changer transformer on the high voltage side. The old voltage regulator was removed. The new transformer is rated 7500kV A ONAN. The new transformer required a new structural foundation with oil containment and concrete pad to facilitate the new transformer physical arrangement, as well as accommodate the requirement for potential oil medium leakage retention. A SorbWeb Plus oil containment system was installed.	9/20/09	Direct costs $2.4 Common Allocations $1.0 Total $3.4	The 1AR transformer is a reserve auxiliary transformer (RAT) used to supply the essential busses (15 & 16) with 4.16 kV power when the normal power supply (1R & 2R) is unavailable. The new 1AR transformer is installed and available to supply the essential busses (15 & 16) with 4.16 kV power when the normal power supply (1R & 2R) is unavailable, as is necessary for safe plant operation at the currently authorized power levels. Moreover, the replacement 1AR transformer is providing reliability benefits compared to the old equipment. The new 1AR transformer is sized to support plant operation at the EPU power levels when approved. This transformer replacement improves the safety margin of the plant given the loss of power impacts from the Fukushima event. The replacement also addressed the aging management issue since the existing transformer was at its end of life.
11776513	EPU Steam Dryer Instrumentation Removal	The Steam Dryer Instrumentation was installed to measure stresses throughout the dryer during its first cycle of operation. The information was used to validate the	7/19/13	Direct costs $1.1	All Steam Dryer instrumentation was removed during the 2013 refueling outage. The validation process was complete and submitted to the NRC. They reviewed

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		assumptions used within the Power Uprate Analysis, which in-turn was submitted to the NRC in support of our new licensed condition. - The instrumentation had to be removed to allow reactor disassembly and refueling activities. The instrumentation was no longer needed, since good data was obtained during the previous run cycle.		Common Allocations $0.1 Total $1.2	the data and accepted the results.
11842626	EPU 13A & 13B Feedwater Heater Repair	There was a gasket leak on both Feedwater Heaters that was identified during the post modification testing of the system. It was discovered that the vendor installed the wrong gaskets for the application, which caused the leak. Both Feedwater Heater Gaskets were replaced and retested. No leaks were found. Tracking work orders for disputes. The dollars will be transferred back to the original work order and these workorders will not go into service.	N/A Will be moved to original work order	Direct costs $0.1 Common Allocations $0.0 Total $0.1	The Feedwater Heaters were placed back in-service as described under the Feedwater Heater Replacement Project. The new gaskets did not leak and allowed the plant to declare the system operable and proceed with Reactor Start-Up.
11845189	EPU Condensate Repair	The vibrations measured/experienced on the Condensate Minimum Flow Lines, following the initial start-up of the condensate pumps, was unacceptable. Additional piping supports had to be designed, procured, and installed. The new support(s) dampen the flow effects and reduce the line vibration to an acceptable level. Note: The line vibration resulted in valve damage. Both Min Flow Valves required repairs prior to placing them back	N/A Will be moved to original work order	Direct costs $0.1 Common Allocations $0.0 Total $0.1	The Condensate System was placed in-service and the vibration levels seen at the Min Flow Valves was reduced to a level that would support plant start-up and not damage equipment.

LCM/EPU Modifications In-Service Table

Child Work Order Number	Modification	Description	In-Service Date	Actual Costs 8/31/13 ($ million)	In-Service Justification
		in-service. Tracking work order			
9	Contingencies - Later assigned to individual child work orders	Contingencies are a common project management tool used in construction activities to allow for unexpected, emergent issues arising during a project.	7/19/13	$0.0	Contingencies are forecasted future spend that are eventually used up by assignment to the other WOs above to fund unanticipated, emergent issues that typically arise during implementation of project work. Given the conclusion of the project in July 2013, all of the previously forecasted contingency was used up through actual costs incurred in other workorders. Any remaining amount forecasted will be zeroed out prior to project close-out.
Total Forecasted Project Cost – September 2013				$664.9	

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Turbine Replacement						
Turbine Replacement	11133668	The existing turbine would have required extensive maintenance or replacement to run through the end of the operating license. Replacing with like or larger was comparable cost. Turbine vibration monitoring equipment required replacement to ensure continued station operation but was more complicated due to EPU.	2009	54.0	GE-HITACHI NUCLEAR DAY & ZIMMERMAN NPS SARGENT & LUNDY LLC STUDSVIK INC. ENERGY SOLUTIONS LLC	• Scope changes • Schedule delays
Turbine Generator Vibration	11335729	Though the former system was able to support operation at pre-EPU power levels, the new Bently Nevada Vibration Monitoring system was put in place to support plant operation at EPU levels.	2011	3.5	DAY & ZIMMERMAN NPS SARGENT & LUNDY LLC BENTLY NEVADA LLC EXCEL SERVICES CORP	• Delay in work order approval

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Power Range Neutron Monitoring System						
Power Range Neutron Monitor	10942850	The power range neutron monitor is an upgraded, digital replacement for the old neutron monitoring system which was aged and presented obsolescence and spare parts issues. The system is expected to improve reliability and has alleviated the need to continually test and monitor the average power neutron monitor system.	2009	17.5	GE-HITACHI NUCLEAR; DAY & ZIMMERMAN NPS; C3-ILEX AUTOMATED ENGINEERING SERVICES CORP; EXITECH CORPORATION; MGP INSTRUMENTS INC; INTERNATIONAL QUALITY CONSULTANTS, INC; SARGENT & LUNDY, LLC.; J.D. STEVENSON & ASSOCIATES	• Few difficulties encountered
Major Modification: Steam Dryer Replacement						
Steam Dryer Acoustic Monitoring	10859413	The steam dryer required replacement to ensure continued operation through the operating license term. Steam dryer acoustic monitoring was an EPU requirement.	2008	7.3	NUCLEAR MANAGEMENT CO LLC CONTINUUM DYNAMICS INC. STRUCTURAL INTEGRITY ASSOCIATES, INC. DAY & ZIMMERMAN NPS	• Scope Expansion

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Steam Dryer Replacement	11215274	The steam dryer required replacement to ensure continued operation through the operating license term. Replacing the steam dryer with a new design that is expecting higher moisture inlet and producing lower output was the best way to improve equipment reliability and satisfy NRC requirements.	2011	30.4	WESTINGHOUSE DAY & ZIMMERMAN NPS SARGENT & LUNDY LLC STRUCTURAL INTEGRITY ASSOCIATES, INC. TRIVIS STAFFING, INC.	• NRC regulations required steam dryer replacement rather than modification • Five cracks found on existing steam dryer

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Condensate Demineralizer System Replacement						
Condensate Demineralizer System Replacement	11133705	The condensate demineralizer removes minerals from the feedwater to prevent mineral buildup. The condensate demineralizer system, with the new demineralizer vessels and controls, was necessary for continued operation of the station. The new demineralizer vessels were sized to provide sufficient feedwater flow when the EPU is approved.	2011	79.8	BECHTEL POWER CORP; GE-HITACHI NUCLEAR ENERGY AMERICAS LLC; DAY & ZIMMERMAN NPS; GE-HITACHI NUCLEAR ENERGY AMERICAS LLC; DELTA ENERGY SERVICES, LLC; INTERNATIONAL QUALITY CONSULTANTS, INC; TRI TOOL INC; AUTOMATED ENGINEERING SERVICES CORP; BECHTEL POWER CORP; ENERGY SOLUTIONS, LLC; WILLOUGHBY & DE CHANT, INC; GRAVER WATER SYSTEMS LLC; COLLINS ELECTRICAL; EXCEL SERVICES CORP.	• Scope Expansion • Modification Complexity • Space Limitations

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Main Power Transformer						
Main Power Transformer	10943007	Replacement of main power transformer necessary due to equipment obsolescence, but equipment is larger for EPU.	2011	26.5	GE-HITACHI NUCLEAR DAY & ZIMMERMAN NPS SARGENT & LUNDY LLC TRIVIS STAFFING INC. NEXUS TECHNICAL SERVICES CORP	• Degradation issues with LV bushings • Had to accelerate replacement • Vendor issues led to schedule delays • Problems in welds caused leaking • Transportation plan needed revisions
1AR Emergency Transformer	10735617	Transformer 1AR provides essential power for the plant auxiliary power system. Due to its age, the 1AR transformer needed to be replaced as part of LCM modifications.	2009	3.4	DAY & ZIMMERMAN NPS NUCLEAR MANAGEMENT CO LLC ENGINEERING & MANAGEMENT SPECIALISTS, INC GE-HITACHI NUCLEAR ENERGY AMERICAS LLC	• Installation delayed due to conflicting work items in plant schedule prior to outage

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Feedwater Heater Systems Replacement						
Feedwater Heater Drain & Dump Valves Replacement	11133719 & 11284286	Feedwater heaters, valves, and piping required replacement to support continued operation of the station. Modification to drain tank all EPU. Increased size of heaters, piping, and valves attributed to EPU.	2009 and 2011[1]	22.3	DAY & ZIMMERMAN NPS; BECHTEL POWER CORP; GE-HITACHI NUCLEAR ENERGY AMERICAS LLC; AUTOMATED ENGINEERING SERVICES CORP; BARTLETT NUCLEAR INC; API INC. DBA API INSULATION INC; TRI TOOL INC; INTERNATIONAL QUALITY CONSULTANTS, INC; DELTA ENERGY SERVICES, LLC; THERMAL ENGINEERING INTERNATIONAL, INC.; ENERGY SOLUTIONS, LLC; SUPERHEAT FGH SERVICES INC; STUDSVIK, INC.; SARGENT & LUNDY, LLC.; COLLINS ELECTRICAL; EMPYREAN SERVICES LLC; SUN TECHNICAL SERVICES INC.	• Scope Expansion • Space Limitations • Interference Removal • Equipment Complications
Feedwater Heater 14 & 15 A/B Replacement	11286961	Feedwater heaters, valves, and piping required replacement to support continued operation of the station. Modification to drain tank all EPU. Increased size of heaters, piping, and valves attributed to EPU.	2011	24.8		
Feedwater Heater 13A/B Replacement	11638897 & 11842626	The feedwater heaters 13A/B were replaced based on life cycle management. Replacing the heaters will ensure continued plant reliability.	2013	49.2		

[1] 14 of the 18 valves installed in 2009 and the remaining 4 installed in 2011

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Feedwater Flow Transmitters/Programmable Control In	11133856	Feedwater flow is a plant parameter that needs to be monitored during plant operation. Due to the increased feedwater flow rate resulting from EPU, this modification re-spanned four feedwater flow transmitters and replaced two feedwater flow indicators	2009	0.3		
EPU Cross Around Relief Valves (CARVs) Replacement	11133713	The CARVs provide over pressure protection to the turbine by providing an alternate path for the steam to the condenser should the turbine not be able to accept the steam. The new CARVs were sized to operate at EPU power levels. These valves were installed in 2009, but could not be set to the EPU set point until the feedwater heaters were installed.	2009[2]	18.4		

[2] The valves were installed in 2009, but could not be set to the needed EPU set point until the heaters were replaced. The reset occurred during RFO26.

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Feedwater Heater Drain & Dump Valves Replacement	11133719 & 11284286	Feedwater heaters, valves, and piping required replacement to support continued operation of the station. Modification to drain tank all EPU. Increased size of heaters, piping, and valves attributed to EPU.	2009 and 2011[3]	22.3		

[3] 14 of the 18 valves installed in 2009 and the remaining 4 installed in 2011

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Reactor Feedwater Pump Replacement						
Reactor Feedwater Pump & Associated Equipment Replacement	11286955	Equipment required replacement to support continued operation of the station. Larger equipment costs attributed to EPU.	2013	92.1	BECHTEL POWER CORP; SARGENT & LUNDY, LLC.; AUTOMATED ENGINEERING SERVICES CORP; DAY & ZIMMERMAN NPS; GE-HITACHI NUCLEAR ENERGY AMERICAS LLC; J.D. STEVENSON & ASSOCIATES (DBA STEVENSON & ASSOC; BARTLETT NUCLEAR INC; J. GIVOO CONSULTANTS, INC.; DELTA ENERGY SERVICES, LLC; INTERNATIONAL QUALITY CONSULTANTS, INC; TRIVIS STAFFING INC.; ADVENT ENGINEERING SERVICES INC.; WILLOUGHBY & DE CHANT, INC; CONTROL COMPONENTS INC; FLOWSERVE US INC; ENGINEERING & MANAGEMENT SPECIALISTS, INC; EMPYREAN SERVICES LLC; CRANE NUCLEAR, INC.	• Scope Expansion • Tight Plant Confines • Equipment Complications

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Condensate Pump and Motor Replacement						
Condensate Pump and Motor Replacement	10943052 & 11845189	The condensate and reactor feedwater systems provide feedwater to the reactor to maintain a constant reactor water level. The condensate system, with the new pumps and motors, was necessary for the plant to operate at the currently authorized power levels. The new pumps were sized to provide sufficient feedwater flow.	2013	21.8	BECHTEL POWER CORP; GE-HITACHI NUCLEAR ENERGY AMERICAS LLC; AUTOMATED ENGINEERING SERVICES CORP; PREFERRED METAL TECHNOLOGIES INC; EMPYREAN SERVICES LLC; TRIVIS STAFFING INC.	• Scope Expansion • Modification Complexity • Equipment Complications

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: 13.8 kV Distribution System Upgrade						
13.8 kV Distribution System Upgrade	11257804	Electrical system upgrades required to support ongoing operation at the station. The margins associated with the 4.16 kV electrical distribution system was only marginally acceptable and needed supplementation. With the addition of larger Feedwater and Condensate pumps and motors, a larger electrical system was required to enhance the margin and prevent plant transients and/or breaker actuations. Existing 4 kV system breakers are no longer manufactured. Cost of 13.8 kV comparable to required 4 kV system modifications.	2013	119.5	BECHTEL POWER CORP; J.D. STEVENSON & ASSOCIATES (DBA STEVENSON & ASSOC; DAY & ZIMMERMAN NPS; SARGENT & LUNDY, LLC.; DELTA STAR INC.; DELTA ENERGY SERVICES, LLC; PERFORMANCE POWER SERVICES PC; ELECTRIC MACHINERY CO INC; GE-HITACHI NUCLEAR ENERGY AMERICAS LLC; POWELL ELECTRICAL SYSTEMS, INC.; AUTOMATED ENGINEERING SERVICES CORP; COLLINS ELECTRICAL; TRIVIS STAFFING INC.; INTERNATIONAL QUALITY CONSULTANTS, INC; SUN TECHNICAL SERVICES INC; VEIT & CO INC; TSSD SERVICES INC.; BCP TECHNICAL SERVICES INC; VIC'S CRANE SERVICE; JOHNSON CONTROLS INC; CALVERT CO INC; EMPYREAN SERVICES LLC.	• Scope Expansion • Modification Complexity

Modification	WO Number	Justification for the Modification	In-Service Year	Final Actual Cost ($ million)*	Applicable Vendors	Applicable Challenges
Major Modification: Licensing						
EPU License Development	11536446 11636097 11636101 11636105 11636109 11636114 11775097	This scope of work was necessary to prepare the plant for and to obtain approval for operation at the uprated power level and with a new fuel configuration pursuant to MELLA+.	2013 / 2014	59.6	GE-HITACHI NUCLEAR; WESTINGHOUSE; AUTOMATED ENGINEERING SERVICES CORP; GLOBAL NUCLEAR FUEL; SUN TECHNICAL SERVICES INC; INNOTECH ENGINEERING SOLUTIONS, LLC; NWI CONSULTING; EMPYREAN SERVICES LLC	• Extended NRC suspension of licensing review • Extensive additional analysis required by NRC for steam dryer and containment accident pressure issue

* With common costs allocated.

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EPU Project

By Year / w Child WO

August 2013

10245258 MNGP Extended Power Uprate

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
10435578	MNGP Extended Power Uprate	796,294	158	6,879,598	11,725,050	69,040,875	14,680,962	48,784,723	(129,606,009)	(4,363,314)	(17,849,896)	88,442
10859413	MNGP EPU Steam Dryer Acoustic			40,060	3,461,044	1,025,454			2,757,939			7,284,497
10884258	MNGP EPU Certificate of Need					149,871	28,418	(178,289)				
10942850	MNGP EPU-Power Range/Neutron				525,833	2,032,779	9,975,282	(321,824)	5,324,261			17,536,332
10943007	MNGP EPU Main Power Transform				50,770	760,457	10,870,277	3,419,403	11,343,807	46,285		26,491,000
10943047	MNGP EPU GEZIP Installation					20,948	1,147,423	623,758	845,715			2,637,845
10943052	MNGP EPU Condensate Impeller/P					310	842,422	2,651,616	3,379,522	2,402,367	12,529,271	21,805,509
11132414	MNGP EPU Expansion Joints					273,044	4,618,737		2,127,077			7,018,858
11133668	MNGP EPU Turbine Replacement					18,342	37,641,129	(40,574)	16,357,704			53,976,601
11133705	EPU Condensate Demin Sys Repl					6,224	3,035,588	2,176,857	74,117,821	438,084		79,774,573
11133713	EPU CARV Replacement					135,920	8,689,051	623	9,548,855			18,374,449
11133719	EPU FW Heater Drain & Dump Vlv					2,252	3,273,546	4,070	1,426,869			4,706,737
11133731	EPU MS Flow Transmitters Repl						219,505		237,493			456,998
11133856	EPU FW Flow Transmitters/PC In					116	163,395		176,911			340,421
11133861	EPU Isophase Bus Cooling					9,790	2,593,160	7,655	2,827,992			5,438,597
11133865	EPU EQ Transmitters & Detector						585,886		254,759			840,645
11133871	EPU MSIV Solenoid Valve Repl						237,734		103,373			341,107
11133877	EPU Remove DW Bricks in Bioshi					4,795	141,176					145,971
11133931	EPU Drywell Spray Flow Valve R					202	105,864		114,758			220,824
11194611	EPU Off Gas Dilution Fan Cable						439,017	136	190,955			630,108
11213813	EPU 1AR Cable Replacement						180,586	721,787	239,434	(1,141,807)		
11215274	EPU Steam Dryer Replacement						12,974,136	4,864,717	12,437,027	98,937		30,374,817
11225964	EPU Acoustic Monitoring Instr						312,652		135,949			448,601
11257804	MNGP EPU 13.8 KV Distribution						3,725,653	11,979,995	19,596,852	15,787,949	68,450,052	119,540,502
11284286	MNGP EPU Rpl 4 FW Drain & Dum						117,160	685,742	16,757,538	12,027		17,572,466
11286955	MNGP EPU Replace Reactor FW P						87,573	5,660,992	21,788,780	12,297,241	52,328,329	92,162,915
11286961	MNGP EPU Rpl 14&15 A/B FW He						117,427	(3,010,772)	33,320,358	(15,053,882)	9,397,128	24,770,259
11286966	MNGP EPU Rewind Generator						11,466	(4,566,954)	11,220,145	(549)		6,664,108
11286973	MNGP EPU Replace Exciter						44,556	14,153	59,688			118,397
11286981	MNGP EPU MSD Tank Mods						48,861	580,361	(664,954)	33,790		(1,941)
11286985	MNGP EPU Stator Water Cooler R						90,948	428,774	1,909,285	1,086		2,430,092
11286992	MNGP EPU RWCU Capacity Impro						201,111	677,809	1,013,508	3,204,380	570,842	5,667,650
11335729	MNGP EPU Turbine Generator Vib							802,970	2,671,806	1,299		3,476,075
11376086	MNGP Drain Cooler Piping Mod P							8,590	(8,590)			

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EPU Project

By Year / w Child WO

August 2013

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total
10245258	**MNGP Extended Power Uprate**											
11376103	MNGP Turbine Bldg Elev 951' Rp							11,956	(11,956)			
11398720	E & S for EPU								(375)			(375)
11410738	MNGP EPU PCT Vent & Purge Valv							63,977	100,329	1,688	254,191	420,184
11536446	MNGP EPU License Development								50,015,888	(11,322,217)	4,560,561	43,254,231
11636097	EPU Lic-HELB Design Basis Docu									4,906,024	(127,515)	4,778,509
11636101	EPU Lic-Envir Qual DBD									2,558,596	(36,360)	2,522,236
11636105	EPU Lic-HELB & Inst Srv DBD									2,175,334	(30,892)	2,144,441
11636109	EPU Lic- Motor & Air Op Vlv Sys De									2,619,272	(36,835)	2,582,437
11636114	EPU Lic- Piping Stress Design Basi									4,111,340	(58,610)	4,052,730
11638897	MNGP EPU 13A&B Feed Wtr Heate									18,865,216	30,263,470	49,128,685
11757884	MNGP Rplc 14/15 FW									9,362,294	(9,362,294)	
11775097	EPU MELLA+											
11776513	EPU Steam Dryer Instr Removal										1,181,841	1,181,841
11842626	EPU 13A & 13B Feed Water Heater										53,963	53,963
11845189	MNGP EPU Condensate Impeller R										53,156	53,156
		796,294	158	6,919,658	15,762,697	73,481,379	117,200,701	76,052,252	172,110,512	47,041,440	152,140,401	661,505,492
10245381	**EPU-1AR Transformer Repl**											
10735617	MNGP EPU-1AR Transformer Repl		13,599	67,153	(57,755)	78,418	1,508,613	26,613	1,776,338			3,412,979
			13,599	67,153	(57,755)	78,418	1,508,613	26,613	1,776,338			3,412,979
	TOTAL EPU \ LCM	796,294	13,757	6,986,812	15,704,942	73,559,796	118,709,314	76,078,865	173,886,850	47,041,440	152,140,401	664,918,471
	Life to Date		810,052	7,796,863	23,501,805	97,061,602	215,770,916	291,849,780	465,736,630	512,778,070		

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☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002/GR-12-961
Response To: Department of Commerce   Information Request No. 160
Requestor: Nancy Campbell, Dale Lusti & Angela Byrne
Date Received: December 26, 2012   **Supplemental Response**

Question:

Subject: Certificate of Need Projects
Reference: No specific reference

Please provide a brief description of the Monticello LCM/EPU project, the proposed in-service date, the actual in-service date, the proposed costs for the project, the actual total costs of the project by in-service date. Please provide an explanation for why cost recovery should be allowed for any project costs that exceed the certification of need proposed costs. Please provide where costs are included in the 2013 test year.

[*Supplemental*] Response:

I. DOC-160 Update Schedule

This schedule provides an update to the LCM/EPU Project cost information the Company provided in response to the Department of Commerce Information Request Number 160 ("DOC-160") in the Company's 2012 rate case, Docket No. E002/GR-12-961. Our original response to DOC 160 is included below.

Table 1 below provides a summary of the cost changes since the 2008 initial certificate of need for the ten largest subprojects and all other subprojects combined, but updated to include our final Project costs. Table 1 was prepared and supplemented by Company Witness Mr. Scott Weatherby and is attached to his prefiled testimony in Docket E002/CI-13-754 as Exhibit ___ (SLW-1), Schedule 5.

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Table 1: – Monticello LCM/EPU Costs Estimates from 2008 to 2013 – Before Allocations of Common Costs

	Subproject ($ in millions)	Work order number	Jan. 2008 Estimate	Dec. 2010 Estimate	Oct. 2012 Estimate	Jan. 2013 Estimate	August 31, 2013 Actuals	Increase (Decrease) Aug. 2013 vs. 2008
1a	Engineering, Licensing and Project Support (Common)	10435578	$90.0	$140.6	$162.5	$163.7	$163.7	$73.7
1b	License Development	11536446	included in 1a above	included in 1a above	included in 1a above	Included in 1a above	$59.3 included in 1a above	included in 1a above
2	13.8 kV Distribution System	11257804	not in scope	28.2	64.1	96.8	*108.3*	108
3	Replace Reactor Feedwater Pump	11286955	9.8	17.3	65.8	66.2	83.5	73.7
4	Replace 14 & 15 Feedwater Heater (and 13 prior to 2011)	11286961 and 11757884	2.9	13.5	15.1	15.1	15.4	12.5
5	Replace 13A&B Feedwater Heater (split out in 2011)	11638897	included in 4 above	included in 4 above	37.5	37.6	44.7	44.7
6	Condensate Demineralization System Replacement	11133705	9.0	42.9	62.8	62.8	64.4	*55.4*
7	Condensate Impeller	10943052	0.7	5.1	14.6	14.9	19.8	19.1
8	Steam Dryer Replacement	11215274	30.0	28.1	30.4	30.4	30.4	0.1
9	Turbine Replacement	11133668	44.3	37.7	37.7	37.7	37.7	(6.6)
10	Main Power Transformer	10943007	13.1	15.1	18.9	18.9	18.9	5.8
	Subtotal – Largest 10 Subprojects		**$199.8**	**$328.5**	**$509.4**	**$544.1**	**$586.8**	**$386.7**
	All Other Subprojects	various	120.2	70.6	77.3	75.8	78.1	(42.1)
	Contingency	--	--	--	--	20.0	--	--
	Total – All		**$320.0**	**$399.1**	**$586.7**	**$639.9**	**$664.9**	**$344.6**

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	Subprojects							

II. Revised Analysis of Initial LCM/EPU Cost Estimate by Major Modification

For the purposes of this proceeding, Docket No. E002/CI-13-754, the Company performed a revised analysis of initially estimated costs by major modification. Table 2 presents a comparison of the revised analysis of initially estimated costs by major modification to the final Program costs.

The Company's original DOC-160 response also included a description of the primary factors behind the difference between total forecasted Program costs and the initial cost estimate. This schedule updates the analysis of major cost drivers that explain the difference between the Program's $320 million initial cost estimate and the final Program costs. The cost drivers are analyzed more fully in the Direct Testimony of Company Witness Mr. Timothy J. O'Connor.

While the cost driver analysis in the original DOC-160 response represented the Company's best estimates and judgment at the time, that analysis was prepared prior to the completion of the project and immediately prior to the start of the Program's final implementation outage. At the time, the Program and Nuclear personnel were fully engaged in preparation for the outage. The explanation of cost drivers in this schedule benefits from the Company's hindsight, having now completed the final implementation outage, and from more extensive engagement from key Program and Nuclear personnel.

Table 2 shows the results of a revised analysis that identifies the costs attributed to specific major modifications in the LCM/EPU Program's initial $320 million cost estimate using a refined methodology. Table 2 compares the revised initial cost estimates by major modification to the final actual costs incurred as of August 31, 2013.

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Table 2: Revised Analysis Comparing 2008 Estimate to Final LCM/EPU Program Costs

Subproject		Work order number(s)	Million $		
			2008 Estimate with Common Cost	2013 Actuals through August with Common Cost	Increase (Decrease) 2013 vs. 2008
1	License Development	11536446*	28.6	59.3	30.7
2	13.8 kV Distribution System	11257804	20.9	119.5	98.6
3	Replace Reactor Feedwater Pump	11286955	27.8	92.2	64.4
4	Feedwater Heaters	11286961**	37.0	114.9	77.9
5	Power Range Neutron Monitoring System	10942850	15.7	17.5	1.9
6	Condensate Demineralization System Replacement	11133705	18.0	79.8	61.8
7	Condensate Impeller	10943052 & 11845189	3.2	21.9	18.7
8	Steam Dryer Replacement and Acoustic Monitoring	11215274 & 10859413	35.9	37.7	1.8
9	Turbine Replacement	11133668 & 11335729	60.2	57.5	(2.7)
10	Main Power and 1AR Transformers	10735617 & 10943007	16.9	29.9	13.0
Subtotal – Largest 10 Subprojects			**264.1**	**630.2**	**366.1**
All Other Subprojects		various	55.9	34.7	(21.2)
Total – All Subprojects			**320.0**	**664.9**	**344.9**

*Licensing includes the following WOs: 11536446, 11636097, 11636101, 11636105, 11636109, 11636114, 11775097
**Feedwater Heaters includes the following WOs: 11133713, 11133719, 11133856, 11284286, 11286961, 11286981, 11376086, 11376103, 11638897, 11757884, 11842626

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A. Cost Driver Analysis

There are three main drivers of the cost changes illustrated in the tables above, and these cost drivers are summarized in Table 3. The cost impacts discussed below are the Company's best estimates, and the Company believes they represent reasonable estimates of the impacts of the items. These cost drivers are discussed more fully in the Direct Testimony of Company Witness O'Connor.

Table 3: Cost Driver Summary

	Cost Drivers	**Increase 2013 vs. 2008 (million$)**
1	*Scope Changes - Total*	*85.7*
	13.8 kV Distribution System	25.3
	Condensate Demineralization System Replacement	27.3
	Feedwater Heaters	13.5
	Replace Reactor Feedwater Pump	19.6
2	*Licensing*	*30.7*
3	*Installation - Total*	*228.5*
	13.8 kV Distribution System	73.4
	Condensate Demineralization System Replacement	34.5
	Feedwater Heaters	64.5
	Replace Reactor Feedwater Pump	44.7
	All Other Modifications	11.5
Total		*344.9*

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As discussed in the initial DOC-160 response, there are several overlapping reasons that help to explain the Program's cost increases. The Company believes there are three important cost drivers: major scope changes; licensing delays; and implementation costs. The scope changes and implementation costs clearly have overlapping components. The Company has broken down the costs by assuming that the ultimate design and engineering, materials and other non-installation costs were the key identifiable changes associated with our scope changes. However, some of our design work was associated with implementation challenges. Also, there are implementation costs that drove the ultimate cost of each scope change. As explained in the Direct Testimony of Company Witness O'Connor, many of the reasons for the higher implementation costs are ones that even had the Company done a better job of forecasting, the Company certainly would not have anticipated early in the project. This view helps to explain the different aspects of the project that changed, but these explanations should not be viewed in isolation.

1. Major Scope Changes (Previously referred to as Project Design Changes)

There were four key scope changes that account for nearly $86 million of incremental engineering and design, materials, and other non-installation costs compared to the initial project estimate of $320 million. These four key scope change decisions were: (i) replacement of the feedwater heaters and associated equipment; (ii) replacement of the reactor feed pumps and motors; (iii) replacement of the entire condensate demineralizer system; and (iv) upgrade of the 4 kV electric distribution system to a 13.8 kV system.

i. Feedwater Heaters – The original scope called for rerating six feedwater heaters and replacing or modifying other related plant equipment. During the design phase of the Program, however, it was determined that the six feedwater heaters all required replacement. Other scope additions included the need for structural analysis and turbine floor reinforcement to support the new feedwater heaters and extensive replacement of drain and dump piping. In total, the added scope related to the feedwater heater system accounted for more than $13 million in incremental costs.

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ii. Reactor Feed Pumps and Motors – The initial estimate for this major modification was based on General Electric's recommendation to add a smaller capacity supplemental reactor feed pump and motor. However, the Company determined that the third pump design was not workable due to size limitations and operating procedures. The Company elected to replace the existing pumps and motors with larger capacity equipment to support uprated power conditions and to ameliorate repair issues with the legacy pumps and motors. The increased scope for this major modification led to incremental engineering and design, materials and other costs of nearly $31 million.

iii. Condensate Demineralizer System Replacement – The initial estimate of the condensate demineralizer modification included replacing the five vessels, upgrading the pre-coat pumps, making small modifications to the existing analog control system and testing. However, the Company identified the need to replace the entirety of the condensate demineralizer system and control panel because the existing system would not support long-term operations or the increased flow requirements at EPU levels. This represented a substantial increase in scope that necessitated unanticipated engineering and design, materials and other costs that amounted to roughly $27 million.

iv. 13.8 kV Distribution System - The initial LCM/EPU Program cost estimate included limited modifications to the plant's existing 4 kV electrical distribution system. However, as the Program's detailed design and engineering phase advanced, the Company decided to replace the reactor feed pumps and motors with larger capacity equipment to meet the operational and uprate needs of Monticello. The Company determined that upgrading the plant's non-safety-related equipment to a new 13.8 kV electrical distribution system was the preferred option for meeting the electrical needs of this new equipment. The 13.8 kV upgrade led to incremental engineering and design, materials and other non-installation costs of about $25 million.

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2. Delays in the Licensing Process

One of the significant cost drivers for the LCM/EPU Program was the Nuclear Regulatory Commission's ("NRC") approval process for the EPU license amendment request ("LAR"). The LCM/EPU Program's actual licensing costs exceeded the initial estimate by nearly $31 million.

The Company originally submitted the EPU LAR to the NRC in 2008. At that time, the Company projected that the license approval would be received no later than year-end 2009. This projection was based on the typical NRC approval process as well as the NRC's published review schedule.

As the Direct Testimony of Company Witness O'Connor explains, the LCM/EPU Program was confronted with unprecedented regulatory delays before the NRC. Those delays included an 18-month suspension of all review activities related to a specific portion of the LAR. That suspension was beyond the Company's control and related to the NRC's desire to develop a consensus position on containment accident pressure ("CAP") requirements. The NRC's review also became more stringent after the events at the Fukushima Dai-ichi Nuclear Power Plant in March 2011. As a result, the Company's actual licensing costs substantially exceeded the initial estimate as the LCM/EPU Program incurred costs to meet the increasingly rigorous NRC standards and to provide new information in response to NRC concerns.

The initial DOC-160 attributed substantial cost increases to LCM/EPU Program schedule reconfigurations that were made at the time in part due to the delay in the NRC's LAR review. However, having now completed the final implementation outage for the Program, it is clear that the extensive scope of work and complex installation could not have been accomplished cost-effectively in two outages and would have ultimately required three implementation outages irrespective of the NRC delays.

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3. Installation

Higher than anticipated costs related to installation and pre-outage design and engineering and work planning account for the largest difference between the initial 2008 cost estimate and the final Program costs—more than $228 million. Several factors led to higher than initially estimated installation costs. First, the Company's initial LCM/EPU Program installation cost estimate was based on an installation cost estimate from General Electric, but this estimate was not based on detailed planning or analysis of the complexity of the ultimate installation activities required. Moreover, as Table 3 shows, the vast majority of the incremental installation costs were attributable to the four major modifications that constituted the Program's most substantial scope additions, and the Company's initial cost estimate did not reflect the ultimate scale or complexity of the installation activities required for those major modifications. For example, the 13.8 kV electrical distribution system upgrade, which involved the installation of more than 14 miles of five-inch cable in raceways throughout the station, illustrates the unforeseen magnitude of the installation activities undertaken as part of the LCM/EPU Program.

Second, the Company encountered additional pre-outage design and engineering and work planning efforts required to address issues discovered as the Program advanced closer to its three implementation outages. For example, in the case of the condensate demineralizer system replacement, the discovery of a backwash receiving tank design issue required expedited design changes in the months before the 2011 outage. Also, to meet the design specifications for the condensate pumps and motors, the vendor had to modify the motors resulting in an increased heat load. This required further analysis of the area cooling systems and resulting duct design and installation for area cooling.

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Actual in-outage installation efforts and costs also proved to be substantially greater than estimated as the Company encountered in-plant conditions that required added work (this was referred to as emergent work in the DOC-160 response) and as modifications required complex construction activities that had to be completed under more challenging conditions than anticipated. For example, as part of the feedwater heater system modification, the Company replaced the drain and dump piping. The Company relied primarily on as-builts for design of the piping, but once the 2009 outage began, several in-outage design modifications were required because of in-plant conditions. As another example, while preparing to install new digital controls for the condensate demineralizer system, the Company found that existing wiring for the controls was degraded and required replacement. This forced the Company to quickly plan for and replace this wiring before proceeding with the rest of the installation work. The Company also discovered plumbing and construction interferences for the modification during the outage. The condensate demineralizer system replacement also illustrates the challenging working conditions encountered during the outages. The condensate demineralizer vessels are highly radiological and are located in concrete vaults that severely limit access. The space limitations and radiological work restrictions led to substantially higher installation costs for the vessels than initially anticipated.

Third, the Company found that construction labor productivity (i.e., the number of person-hours required to complete defined installation tasks) during the implementation outages was substantially lower than predicted by the Company's installation vendors. The Company attributes this productivity challenge to several factors, including the challenging work conditions, difficulties hiring experienced craft labor due to the competitive nuclear labor market, and restrictions on work schedules imposed by the NRC's fatigue rule.

Finally, challenges that the Company faced with vendor performance also contributed to higher Program implementation costs. The Company incurred internal project support cost to bolster vendor oversight when quality issues arose with equipment fabrication, construction management or other activities. The Company faced both design and performance issues in 2010 and 2011 with its primary contractors for these functions. The Company needed to shift certain design work to other firms; and ultimately changed implementation vendors during the course of the construction. Moreover, the Company had some concerns over the management of certain installation tasks and is currently attempting to resolve those concerns with its contractors.

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B. Revised Analysis of Initial Cost Estimates for Major Modifications

The differences between the initial cost estimates in Table 1and the revised analysis of the Company's initial cost estimates by major modification presented in Table 2 above are explained in detail below. A primary difference is the approach to allocating estimated common costs (including installation costs) among the major modifications.

This revised analysis in Table 2 incorporates several changes from the approach used in the Company's response to DOC-160 and updated in Table 1 above.

For purposes of describing the difference between initial estimates and final costs by modification, Xcel Energy performed a more detailed review to allocate costs that were considered "common" during the original estimate's creation. These common costs were ultimately charged to the detailed child work orders, so the revised analysis includes the common costs in the specific estimates for each major modification. In the revised analysis, cost items such as Xcel Energy overheads, escalation, General Electric management costs, and balance of plant installation costs were allocated more precisely to the major modifications.

Also of note, for the 13.8 kV distribution system upgrade, the revised analysis in Table 2 takes into account that, while the 13.8 kV upgrade was not included in the LCM/EPU Program scope corresponding to the 2008 cost estimate, $11.6 million in direct costs were included in the 2008 cost estimate related to electrical distribution system modifications. These electrical distribution system modifications were replaced by or incorporated into the ultimate scope of the 13.8 kV upgrade. This analysis used the $11.6 million as a starting point and then allocated additional common costs to arrive at an original estimated cost of $20.9 million for electrical distribution system modifications.

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Title: Chief Nuclear Officer
Department: Nuclear
Telephone: (612) 330-5500
Date: October 18, 2013

<u>[*Original*] Question:</u>

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Subject: Certificate of Need Projects
Reference: No specific reference

Please provide a list of all NSP-MN certificates of need since 2005, a brief description of the project, the proposed in-service date, the actual in-service date, the proposed costs for the project, the actual total costs of the project by in-service date. Please provide an explanation for why cost recovery should be allowed for any project costs that exceed the certification of need proposed costs. Please provide where costs are included in the 2013 test year.

[*Original*] Response:

A. Certificates of Need Project Details

[*Not Updated*]

B. Monticello LCM/EPU Project Costs

Our cost estimates for the Monticello Life Cycle Management and Extended Power Uprate (LCM/EPU) project have increased in the five years since our original cost estimate was provided in our January 2008 Certificate of Need (CON) filing. Table 1 provides a summary of the cost changes since the CON for the 10 largest subprojects and all other projects combined as has been previously provided (see our response to OAG-9), but updated to include our most recent cost estimate for the project. We note that although our current estimate has increased from our October 2012 estimate of $586.7 million, we are not asking for recovery of any of those additional costs at this time. We are only noting that we have updated our estimates and expect these costs will be evaluated in their entirety during the course of the prudence review which will be conducted after the LCM/EPU is completed.

Table 1
Monticello LCM/EPU Cost Estimates from 2008 to 2013

	Subproject ($ in millions)	**Work order number**	**Jan. 2008 Estimate**	**Dec. 2010 Estimate**	**Oct. 2012 Estimate**	**Jan. 2013 Estimate *[Trade Secret Begins***	**Increase (Decrease) 2013 vs 2008**
1a	Engineering, Licensing and Project Support (Common)	10435578	$90.0	$140.6	$162.5		
1b	License Development	11536446	included in 1a above	included in 1a	included in 1a above		

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	Subproject ($ in millions)	Work order number	Jan. 2008 Estimate	Dec. 2010 Estimate	Oct. 2012 Estimate	Jan. 2013 Estimate *[Trade Secret Begins*	Increase (Decrease) 2013 vs 2008
				above			
2	13.8 KV Distribution System	11257804	not in scope	28.2	64.1		
3	Replace Reactor Feedwater Pump	11286955	9.8	17.3	65.8		
4	Replace 14 & 15 Feedwater Heater (and 13 prior to 2011)	11286961 and 11757884	2.9	13.5	15.1		
5	Replace 13A&B Feedwater Heater (split out in 2011)	11638897	included in 4 above	included in 4 above	37.5		
6	Condensate Demineralization System Replacement	11133705	9.0	42.9	62.8		
7	Condensate Impeller	10943052	0.7	5.1	14.6		
8	Steam Dryer Replacement	11215274	30.0	28.1	30.1		
9	Turbine Replacement	11133668	44.3	37.7	37.7		
10	Main Power Transformer	10943007	13.1	15.1	18.9		
	Subtotal – Largest 10 Subprojects		199.8	328.5	509.1		
	All Other Subprojects	various	120.2	70.6	77.6		
	Contingency	--	0.0	0.0	0.0		
	Total – All Subprojects		**$320.0**	**$399.1**	**$586.7**		*Trade Secret Ends]*

As discussed in our response to OAG-9, we present these 10 largest subprojects of Monticello's LCM/EPU on a pre-allocation basis, to maintain consistent comparability for all periods shown. Common project costs in Item 1a are those not directly assignable to a specific subproject – mainly up-front engineering, license application preparation and related studies, and overall project support – and are allocated proportionately to subprojects after they are completed. This pre-allocation view helps identify the impact of licensing delays and additional engineering, which are discussed below as drivers of project cost increases.

We note that in the project cost summary included in Schedule 4 of Mr. O'Connor's Direct Testimony, a significant portion of the common costs were allocated to individual subprojects, based on equipment installations completed to date. Such allocations account for any differences between Schedule 4 amounts and the corresponding amounts shown in the table above under the Oct. 2012 Estimate column.

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There are three main drivers of the cost changes summarized in the table above. Each is discussed below using the October 2012 cost estimates that have been included in our 2012 rate case. The cost impacts discussed below are the Company's best estimates, based on review of relevant historical records and reference documents and the judgment of knowledgeable personnel involved with the projects. Although they are not directly based on specific transactions in our accounting records, we believe they represent reasonable estimates of the impacts of the items discussed.

1. *Delays in the Licensing Process*

One of the significant drivers of the cost and schedule changes in the LCM/EPU project has been the Nuclear Regulatory Commission's (NRC) approval process for our license amendment application. Our license must be approved before the final phase of the LCM/EPU can be completed.

We originally submitted our license amendment application to the NRC in 2008. At that time, we projected that our license approval would be received no later than year-end 2009. Our projection was based on the typical NRC approval process as well as the NRC's published review schedule. We built the project's schedule and implementation plan around that 2009 projection.

The NRC's extension of Monticello's license approval process stems from many causes, including the NRC's evolving oversight due to developments at other plants that have undergone EPUs, as well as the events at Fukushima. As a result of these delays, the costs of the license application process have increased significantly, and as of October 2012 we estimate a $73 million increase in licensing and engineering costs compared to our original cost expectations in 2008. In addition to licensing costs, the extension of the license approval process has led to a series of reconfigurations of the project's schedule which will likely add $40 to $70 million to the project's final cost.

We are hopeful we will receive our license approval this summer. However, we continue to receive information requests from the NRC and do not yet know the impact those may have on the process. We will keep the parties informed.

2. *Project Design Changes*

A second major cost driver for the LCM/EPU project is the expansion of the project scope that occurred as more detailed engineering and design took place. The Monticello LCM/EPU project began with a high-level, conceptual work scope, which

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then naturally progressed as more detailed design and engineering plans were developed. To comply with the Commission's order to file a CON by a date certain as well as our desire to maximize our benefits of the LCM/EPU, we filed the CON with our initial cost estimate that relied on a generic estimate from our vendor – that is, the vendor's estimate did not yet account for plant-specific requirements or configurations. As that work proceeded and over the course of the four-year license delay, we determined that more extensive upgrades to certain pieces of equipment would be required to support the needs of the plant to ensure reliable and safe conditions during the uprate and license extension period. Likewise, we identified equipment that would need to be replaced over the course of the plant's extended life that made sense to implement in conjunction with the EPU to gain the maximum benefit. As noted in Mr. O'Connor's Direct Testimony, our experience is consistent with others in our industry.

Below we discuss some examples the project's scope changes.

- *13.8 kV Distribution System Upgrades.* This 13.8 kV distribution system was not included in the conceptual scope of work for the LCM/EPU project; rather more limited modifications to the plant's electrical distribution system were originally contemplated. We later chose the 13.8 kV system upgrade to meet additional feedwater needs of the plant under EPU conditions and to alleviate the existing margin concerns (that is, to provide more operating capacity to ensure we have sufficient electrical coverage over a variety of scenarios). Our October 2012 cost estimate reflected in this rate case includes a $64 million increase in the project's costs above the CON estimate due to this portion of the project.

- *Steam Dryer.* Our original cost estimates even prior to the CON application assumed that we would modify the plant's steam dryer instead of replacing it. In 2008, after evaluating another utility's EPU license request, the NRC made changes to their steam dryer evaluation process. Based on that experience, we concluded that installing the new steam dryer would likely be required and that expanding our project scope to include replacement would help speed the approval of our license. As a result, we increased our cost estimate to reflect this change; the $320 million cost estimate in our January 2008 estimate used in the CON includes a $30 million estimate for steam dryer replacement. While our cost estimate for this portion of the project has not varied significantly since that time, it does account for a $30 million cost change since the project was originally conceived.

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- *Feedwater System*. In the original estimate provided by GE, it was anticipated that certain major components of the feedwater system, including the feedwater pumps and motors, would not be replaced as part of the LCM/EPU project. As the project proceeded, it became clear it was necessary to replace these components to both support EPU operations and the additional 20 years of operations. The impact of the feedwater pump design changes as of October 2012 was estimated to be approximately $106 million over the original CON amount.

- *Concurrent or Accelerated Projects*. The scope of the LCM/EPU project was also influenced by the decision to accelerate certain projects to be conducted concurrently with the LCM/EPU project. In many cases, these replacements were necessary because the components were nearing the end of their useful lives and would have likely needed to be replaced in the near future; we thus decided it was most cost-effective to implement with the LCM/EPU. Specific examples of this scope expansion include portions of the 13.8 kV distribution system, including motors and the motor transformers, and the condensate demineralizer control panel and wiring.

3. Emergent Work due to Specific Plant Conditions

The last major driver of the cost changes for the LCM/EPU project relates to emergent work that arose due to plant conditions or that we discovered once the planned work had progressed into the construction phase. For example:

- *Condensate Demineralizer System*. In addition to a scope change that involved a more thorough replacement of the condensate demineralizer vessels, there were also some additional steps necessary once the work began on the condensate system. As the project progressed into construction for the plant's condensate system, we discovered the work exposed workers to a higher radiation dose than originally anticipated and steps had to be taken to protect the workers installing the modification in the plant. Similarly, once under construction it was discovered that the existing wiring for the condensate system was degraded and would require replacement to safely operate for the next 20 years. In aggregate, the scope changes to the condensate demineralization system are expected to add approximately $68 million to the final cost of the project.

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To further assist in understanding the specific cost changes within the Monticello LCM/EPU, we provide a more technical discussion of the following four largest scope additions in Attachment B, including:

- 13.8 kV Distribution System Upgrades
- Steam Dryer
- Feedwater System
- Condensate Demineralizer System

Finally, we note that the Monticello LCM/EPU is a large, complex project with a detailed history and many complex components. As with any large project, there have been a variety of factors resulting in increased costs, such as scheduling changes, vendor issues, evolving regulations, and emergent work. While we have provided a general discussion of those issues here and sought to quantify their impacts, the issues are multi-faceted and additional detail is needed to understand both how the project unfolded and the convergence of factors affecting various parts of the project. We will continue to carefully manage this project and will present additional supporting information more thoroughly in the upcoming prudence review.

C. Other CON Projects

[*Not Updated*]

D. Recovery of Costs Over CON Estimates

[*Not Updated*]

E. Trade Secret Justification

Table 1 includes information the Company considers trade secret under Minn. Stat. §13.37(1)(b). The information presented includes a contingency amount we included with our January 2013 cost estimate to provide for possible delays from the critical path assumed in the project schedule, based on recent industry experience with uprate projects. Contractual incentives for a major vendor used in an upcoming outage are affected by the vendor's ability to manage to their cost estimates and our project schedule, and disclosure of our provision for contingency could adversely impact the vendor's project management.

This data includes confidential terms, and this information has independent economic value from not being generally known to, and not being readily ascertainable by, other

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parties who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy maintains this information as a trade secret.

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Date:	February 1, 2013

General Electric and General Electric Hitachi Nuclear

	2006	2007	2008	2009	2010	2011	2012
Total Revenue (in millions)	$ 151,843	$ 172,738	$ 182,515	$ 154,438	$ 149,593	$ 147,300	$ 147,150
Market Cap (in billions)	$ 302.1	$ 300.3	$ 107.5	$ 157.6	$ 203.9	$ 194.8	$ 218.4
S&P Credit Rating				AA+			

*Period ending December 31

General Electric ("GE") is a multinational technology and financial services company whose business activities span from power generation to consumer financing and household appliances. The Energy Infrastructure segment engages in the development, implementation and improvement of energy technologies. Its services include equipment upgrades, long-term maintenance, repairs, monitoring, equipment installation, and performance optimization.[1] In the 1950s, GE developed and patented a reactor design known as the boiling water reactor ('BWR'); the company remains the sole designer and manufacturer of BWRs in the United States today.

In 2007, GE and Japanese company Hitachi Ltd. formed GE Hitachi Nuclear Energy ("GEH"), a global strategic alliance that offers nuclear services and advanced reactor design. The company's headquarters are located in Wilmington, NC. Prior to the partnership, GE and Hitachi had worked together in developing advanced boiling water reactor (ABWR) technology. The company now develops advanced light water reactors ('LWR') and offers equipment and services used by operators of ABWRs and pressurized water reactors ('PWRs').[2] Products and services provided by GEH include: steam turbines, refurbished parts, nuclear fuel, inspection and reactor modifications and modernization, plant performance software, and instrumentation such as in-core/ex-core sensors, gamma thermometers, probes, and radiation monitors. GEH provided support and assistance to the Fukushima Nuclear Power Stations in the aftermath of the earthquake/tsunami that damaged the structure in 2011.[3]

GEH's most recent projects include a $150 million integrated outage contract awarded by Illinois-based Exelon Nuclear, the nation's largest nuclear utility, to help ensure the continued, safe performance of the utility's entire fleet of BWR nuclear power plants in Illinois, Pennsylvania, and New Jersey. As per the August 2011 agreement, GEH will provide services related to the refuel floor activities and the under-vessel inspection services. It will also continue to deploy new technologies outage projects to reduce worker dosage, enhance safety and improve plant performance.[4]

On September 25, 2012 GEH received a license from the NRC enabling Global Laser Enrichment to build a uranium enrichment facility using lasers. [5]

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[1] "GE-Hitachi Nuclear Energy, Inc.", BusinessWeek Company Report, <http://investing.businessweek.com/research/stocks/snapshot/snapshot.asp?ticker=GE:US>

[2] "First Half of GE, Hitachi alliance begins operations," World Nuclear News, 6/5/2007 <http://www.world-nuclear-news.org/newsarticle.aspx?id=13512&terms=hitachi>

[3] "GE-Hitachi Nuclear Energy, Inc.," Hoovers Company Report <http://www.hoovers.com/company/GE-Hitachi_Nuclear_Energy_Inc/ryjtjti-1.html>

[4] "Exelon Nuclear and GE Hitachi Nuclear Energy Sign Services Contract," Company Press Release, 8/29/11 <http://www.genewscenter.com/content/Detail.aspx?ReleaseID=13050&NewsAreaID=2>

[5] "GE Hitachi Nuclear Energy Continues to Build Nuclear Infrastructure in Poland," Company Press Release, 10/4/12 <http://www.genewscenter.com/Press-Releases/GE-Hitachi-Nuclear-Energy-Continues-to-Build-Nuclear-Infrastructure-in-Poland-3b8d.aspx>

Plant Name	**% Uprate**	**MWt**	**Date LAR Approved**	**Nuclear Steam Supply System (NSSS) Designer**	**Role of NSSS Designer in Uprate**
Monticello	6.3	105	9/16/1998	GE	Monticello and Hatch were the first U.S. plants in GE's "extended" power uprate program. GE developed general guidance and generic evaluations for licensee use.
Hatch 1 Hatch 2	8	205	10/22/1998	GE	Monticello and Hatch were the first U.S. plants in GE's "extended" power uprate program.
Duane Arnold	15.3	248	11/6/2001	GE	GE provided safety analysis.
Clinton	20	579	4/5/2002	GE	CPS contracted GE to perform the engineering analysis for the NRC license. The development and analysis of each of the task reports was performed either by GE, Sargent and Lundy, or a subcontractor. GE prepared the safety analysis.
Brunswick 1 Brunswick 2	15	365	5/31/2002	GE	GE provided equipment and other services for the power uprate projects in addition to fuel engineering services and licensing support
Vermont Yankee	20	319	3/2/2006	GE	GE assisted with NSSS engineering; Stone & Webster did the balance-of-plant engineering work.
Susquehanna 1	13	463	1/30/2008	GE	GE supported implementation.. GE performed the engineering analysis and provided documentation support for the uprate as well as the generator scope of work. A combination of GE, PPL Susquehanna, and other subcontractors hired by PPL performed the balance of the

Plant Name	**% Uprate**	**MWt**	**Date LAR Approved**	**Nuclear Steam Supply System (NSSS) Designer**	**Role of NSSS Designer in Uprate**
Susquehanna 2					plant work.
Hope Creek	15	501	5/14/2008	GE	GE provided the turbine and implemented the EPU.
Nine Mile Point 2	15	521	12/22/2011	GE	GE provided equipment and services in support of the EPU.
Grand Gulf 1	13.1	510	7/18/2012	GE	GE was in charge of work related to the steam dryer, including design, manufacture, delivery and installation. GE also performed analyses and engineering studies to satisfy regulatory requirements for the uprate and worked with Entergy to prepare the licensing submittal for the NRC.
Turkey Point 3 Turkey Point 4	15	344	6/15/2012	Westinghouse	Major EPU contractors included: Bechtel, Siemens, Westinghouse, Shaw/SWEC and Areva.
St. Lucie 1 St. Lucie 2	11.9	320	7/9/2012	Combustion Engineering (now Westinghouse)	Major EPU contractors included: Bechtel, Siemens, Westinghouse, Shaw/SWEC and Areva.
Crystal River 3	15.5		Retirement announced 2/2013	B&W (now AREVA)	Progress Energy partnered with AREVA and WorleyParsons, the original OEMs for the Nuclear Steam Supply System, Fuel, Safety Analyses and Turbine Plant Systems.

The Shaw Group (CB&I Shaw)

	2006	2007	2008	2009	2010	2011	2012
Total Revenue (in millions)	$ 4,775.6	5,723.7	$ 6,998.0	$ 7,276.3	$ 6,984.0	$ 5,937.7	$6,008.4
Market Cap (in billions)	$ 2.0	$ 4.7	$ 2.5	$ 2.6	$ 2.8	$ 1.6	n/a
S&P Credit Rating					BBB-		

*Period ending August 31

The Shaw Group ("Shaw") is a leading provider of plant construction and nuclear services in the United States. Since its formation in 1986, the company has grown from a pipe fabrication shop to a world leader in the power generation industry, servicing over a third of the U.S. nuclear fleet. Shaw has performed more than 60 uprate projects and studies on boiling water reactors ('BWRs') and pressurized water reactors ('PWR'). The company provides engineering, procurement, construction, project management, and technology services to independent and merchant power producers, government agencies and industrial corporations.[1]

Shaw's Power Generation segment includes a wide range of technical services to the nuclear industry. Most recently, the company was awarded contracts for the engineering, procurement and construction ('EPC') of four Westinghouse AP1000 nuclear units in the United States. These include Units 3 and 4 of Vogtle Electric Power Plant, and Units 2 and 3 of V.C. Summer Nuclear Station.[2]

On May 13, 2010, Shaw announced that it had been awarded a $197 million dollar contract by Entergy Operation, Inc. to provide extended power uprate ('EPU') plant modifications to its Grand Gulf Nuclear Station in Mississippi. Shaw will provide engineering, procurement and construction services under the terms of the contract, adding approximately 178-MW of power generation.[3]

The Shaw Group was awarded a contract in January 2010 by American Electric Power ("AEP") for a feasibility study in support of a power uprate to AEP's Cook Nuclear Plant in Michigan. The study will define the scope of the project as well as estimate the cost of uprating the plant. Under the terms of the agreement, Shaw will add approximately 400-MW of electricity.[4]

In addition to plant construction, the Shaw Group is one of the largest providers of power and industrial plant services in the United States. It offers nuclear services for existing plants to improve their reliability, efficiency and capacity output. These services include plant maintenance, modifications, off-site modularization, and full-service plant engineering, other specialties.

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1 "Business Units" Company Website, Accessed 7/16/2012 <http://www.shawgrp.com/about/org>

2 "Shaw and Westinghouse Receive Final Notice to Proceed on V.C. Summer Nuclear Power Plant" Company Press Release, 4/19/12, <http://www.shawgrp.com/industries/power/nuclear>

3 Shaw Awarded Extended Power Uprate Contract for Entergy's Grand Gulf Nuclear Station, Company Press Release, 5/13/10, <http://ir.shawgrp.com/phoenix.zhtml?c=61066&p=irol-newsArticle&ID=1426444&highlight=>

4 "Shaw Awarded Power Uprate Study for American Electric Power's Cook Nuclear Plant", Company Press Release, 1/14/10, <http://ir.shawgrp.com/phoenix.zhtml?c=61066&p=irol-newsArticle&ID=1375118&highlight=>

Shaw has also provided decontamination and decommissioning services for commercial nuclear reactors, research reactors and government facilities. Its maintenance and modification services support approximately 39% of nuclear power reactors in the United States.[5]

On February 13, 2013 Chicago Bridge & Iron Company ("CB&I") acquired the Shaw Group for $3 billion. The company now operates as a separate business unit under the name CB&I Shaw. Following the merger, Shaw moved its headquarters from Baton Rouge, LA to CB&I administrative headquarters in The Woodlands, Texas. CB&I plans to operate Shaw as a separate business unit. [6]

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5 The Shaw Group 10-K Filing, August 2011, <http://investing.businessweek.com/research/stocks/financials/drawFiling.asp?formType=10-K>

6 "CB&I closes $3B Shaw Group acquisition," Accessed 9/5/2013, <http://www.bizjournals.com/houston/news/2013/02/13/cbi-closes-3b-shaw-group-acquisition.html>

Day & Zimmermann Group

The Day & Zimmermann Group ("Day & Zimmerman") is a privately-held global contractor providing engineering, procurement, construction, maintenance and other specialty services for industrial and government customers worldwide. The company was founded in 1901 and is based in Philadelphia, PA.

Day & Zimmermann NPS ('DZNPS') operates as the power maintenance unit of the company, providing comprehensive plant life-cycle solutions to the nuclear and fossil power generating markets. The unit maintains nearly half of the U.S. nuclear fleet, with a focus on safety, quality, continuous improvement and cost reduction. Its service offerings include: plant maintenance, engineering, construction, modifications, turnkey scaffolding, repairs and nuclear facility decommissioning.[1]

In September 2009 DZNPS was awarded a $50 million dollar contract by the Tennessee Valley Authority (TVA) to provide services for completion of TVA/s Watts Bar Unit 2 Nuclear Plant in Spring City, TN. DZNPS will oversee project management, maintenance and modification, refurbishment services and installation of major plants components in support of TVA. Completion of the project is expected by 2015.[2] TVA awarded the company another five-year contract in April 2010 valued at $700 million for modification, outage, technical and maintenance support at its nuclear and fossil generating plants in the region.

In October 2009, AREVA DZ, a nuclear alliance between AREVA and Day & Zimmermann, announced an exclusive contract with TVA to provide refueling services, outage optimization, steam generator services and other specialized services to TVA's fleet of boiling water reactors (BWRs) and pressured water reactors (PWRs).[3]

DZNPS was recently granted multi-year contracts with PSEG Nuclear and FirstEnergy Nuclear Operating Company ("FENOC"). In November 2012, PSEG renewed its five-year contract for DZNPS to provide full-service outage management, power plant maintenance, and modifications to their Salem and Hope Creek nuclear stations in Hancock's Bridge, NJ.[4] Most recently, in August 2013, the company renewed its multi-year contract with FENOC to provide full-service maintenance and modifications for refueling outages, online operations and capital projects at FENOC's three nuclear power facilities, as well as Valve and Radiological Protection services.[5]

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1 "Day & Zimmermann NPS", Company Website, Accessed 7/17/2012, <http://dayzim.com/Services_and_Products/ECM/Maintenance/Day_Zimmermann_NPS>

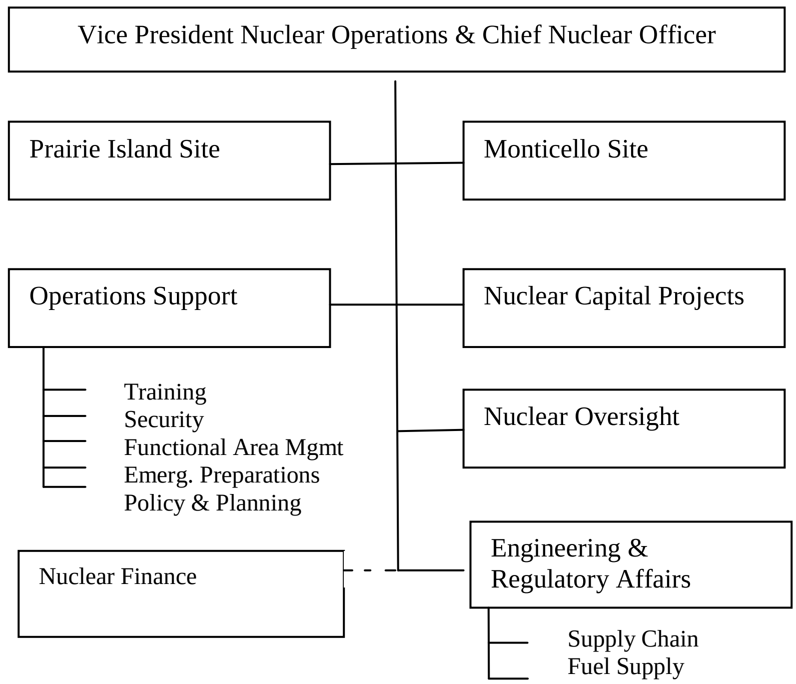
2 "Day & Zimmermann NPS Awarded Contract for Completion of Nation's First New Nuclear Plant in Two Decades" Company Press Release, 09/14/09, <http://dayzim.com/About_DZ/News/NewsItem?id={13D8307A-A3F3-458D-B945-90AD25869980}>

3 "AREVA DZ Announces Alliance Agreement with TVA", Company Press Release, 10/12/09, <http://dayzim.com/About_DZ/News/NewsItem?id={51347FE4-E009-4B6D-83B7-6928DC5206FA}>

4 "Day & Zimmermann Granted Multi-Year Contract Renewal with PSEG Nuclear", Company Press Release, 11/12/2012, <http://dayzim.com/About_DZ/News/NewsItem?id={157F9BDD-818E-49BE-A046-483A727CB61C}>

5 "Day & Zimmermann Granted Multi-Year Contract Renewal with First Energy Nuclear", Company Press Release, 8/7/2013, <http://dayzim.com/About_DZ/News/NewsItem?id={1B62335E-25E7-4F7A-85EF-2F976298E444}>

Nuclear Generation
Operations – Support Functions – Activities



Major Functions

The Nuclear Generation Operations and Support organization oversees Xcel Energy's nuclear plant operations and the required services to support those operations. The leaders of the areas listed below collaborate as a Nuclear executive team for the oversight of business planning, project prioritization and funding, regulatory compliance, and other matters.

Key Organizations and Activities:

- **Monticello and Prairie Island Sites —** The Site Operations organization at each plant oversees the safe day-to-day operation of the generating plant and the strategic implementation of all functions performed at/for the site. These functions, which include regulatory/environmental compliance, security, emergency planning, capital projects, training and financial management, have the common objective of assuring the collective operations of the site to meet Nuclear and Company expectations.

- **Nuclear Capital Projects** oversees the planning and execution of capital projects for nuclear generating units. Nuclear's capital projects include initiatives mandated by regulators, upgrades to equipment to maintain reliability, efforts to improve operating performance, storage of spent nuclear fuel, and facilities.

- **Operations Support** provides support to plant production and maintenance, staff training, safety oversight, and radiological protection through the following areas:
  - *Training* — Responsible for overall coordination of fleet training programs to assure delivery of effective training that meets regulatory commitments and business needs.
  - *Security* — Responsible for maintaining and implementing effective security measures for nuclear generating sites to meet applicable regulatory requirements. This includes programs for access authorization, fitness for duty, and physical protection of the facilities.
  - *Functional Area Management* — Responsible for oversight and fleet support activities in Operations, Maintenance, Production Management, Radiation Protection/Chemistry, Performance Assessment, Human Performance and Safety.
  - *Emergency Preparedness* — Directs fleet strategic emergency preparedness activities.
  - *Policy & Planning* — Provides support for strategic business and regulatory planning.

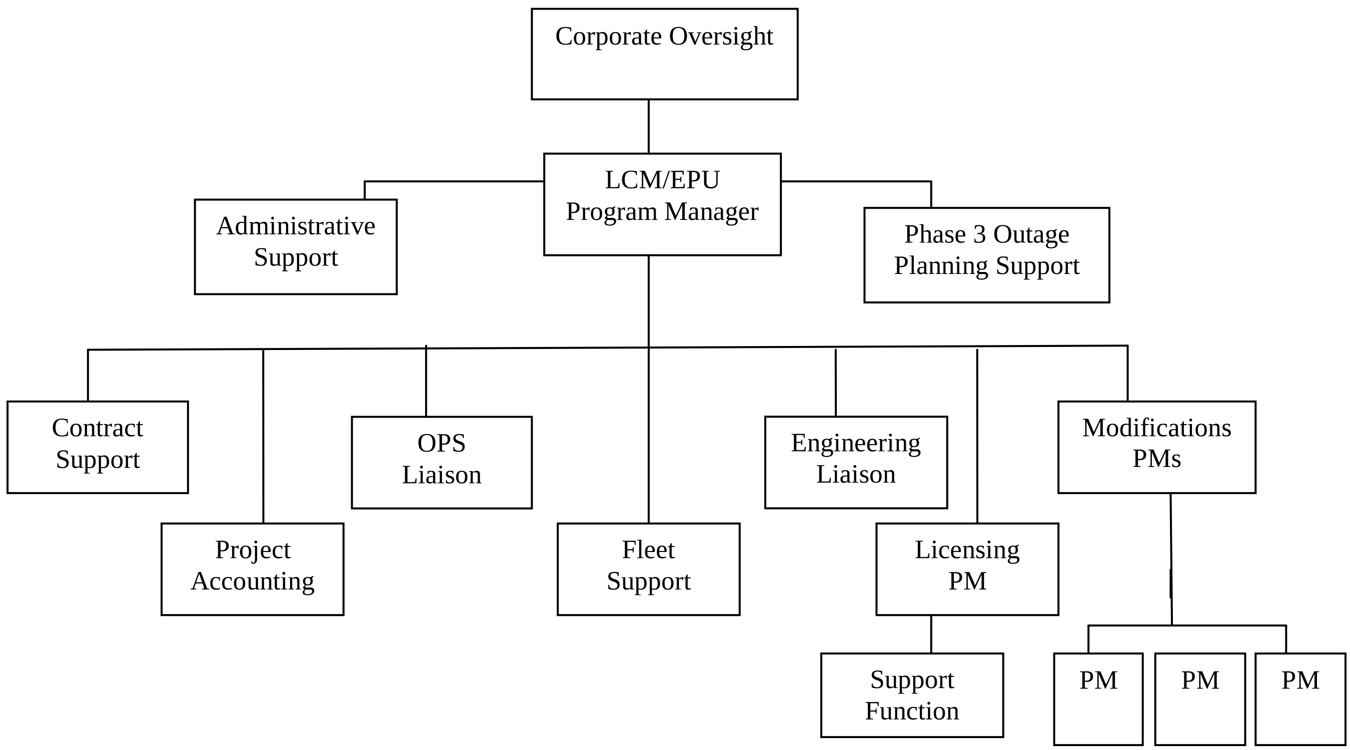
- **Nuclear Oversight** is responsible for Nuclear's quality assurance and corrective action programs. This area is responsible for establishing, maintaining, and interpreting Xcel Energy's quality assurance policies and procedures; establishing the requirements for assessor and inspector certification; managing the overall independent assessment process and establishing quality control practices and policies for quality verification activities. Additionally Nuclear Oversight provides for supplier evaluation; the conduct of supplier assessments or surveys (including their sub-tier suppliers); and verification that supplier quality assurance programs comply with Xcel Energy requirements. This organization has the authority to stop work at the sites and headquarter offices.

- **Engineering & Regulatory Affairs** provides support in several areas.
  - *Engineering* is a core competency of Nuclear in its operation, maintenance and construction activities. Engineering is responsible for program engineering, nuclear analysis and design, and day-to-day engineering support at the sites.
  - *Regulatory Affairs* supports compliance and licensing, which are also significant responsibilities for maintaining safe and reliable nuclear operations. This area manages the NRC regulatory interfaces, responding to NRC regulatory inspections and requests, developing licensing action requests for NRC regulatory approval.
  - *Supply Chain* is responsible for procurement of commodities, equipment, parts, components and services, including warehouse operations at the generating sites.
  - *Nuclear Fuel Supply* provides planning and procurement for nuclear fuel, including the long-term storage of spent fuel.

- **Nuclear Finance** provides accounting, budgeting and reporting support for Nuclear operations, including governance oversight for capital projects.

- **LCM/EPU Program** provides project management services in connection with implementation of the LCM/EPU Program.

Monticello LCM/EPU Organization (2007)



Monticello LCM/EPU Modification	Planned Timing of Outage Installation at Time of CON	Actual/Currently Planned Timing of Outage Installation	Discussion of Timing or Scope Changes
HP Turbine Modification or Replacement	2009	Replaced in 2009	Current condition of equipment required replacement rather than modification of the existing HP turbine.
LP Turbine Modifications	2009	2009	
Power Range Neutron Monitoring Installation	2009	2009	
GE Zinc Injection Platform (GEZIP) Installation	2009	2009	
Main Steam, Feedwater Piping Mods and New Instrumentation	2009	2009	
1AR Transformer	2009	2009	
Condensate Demineralizer Replacement	2009	2011	System needed to be replaced to support long-term plant operations. Added design complexity led to deferral.

Monticello LCM/EPU Modification	Planned Timing of Outage Installation at Time of CON	Actual/Currently Planned Timing of Outage Installation	Discussion of Timing or Scope Changes
Condensate Pump Replacement	2009	2013	The condensate pump and motor needed to be upgraded to support EPU. Installation coordinated with 13.8 kV.
NobleChem Installation	2009	N/A – no longer in LCM/EPU	This modification was removed from the LCM/EPU Project and is being pursued by the Plant as a routine capital project.
Steam Dryer Modifications	2009	Replaced Steam Dryer in 2011	Due to evolving NRC licensing requirements and expectations, elected to replace, rather than modify, the steam dryer.
IsoPhase Cooler Modifications	2009	2009	
Cross Around Relief Valve and Piping Replacement	2009	2009	
Feed Water Heater Dump and Drain Valve Replacement	2011	4 of 18 replaced in 2009 14 of 18 completed in 2011	Due to equipment condition, the replacement of four valves was accelerated to 2009.
MISV Solenoid	N/A – not in CON	2009	Required after Power Uprate Safety Analysis Report testing.
Drywell Brick Removal	N/A – not in CON	2009	Required after Power Uprate Safety Analysis Report testing.

Monticello LCM/EPU Modification	Planned Timing of Outage Installation at Time of CON	Actual/Currently Planned Timing of Outage Installation	Discussion of Timing or Scope Changes
Drywell Spray Mods	N/A – not in CON	2009	Required after Power Uprate Safety Analysis Report testing.
Main Generator Rewind	2011	2011	
Main Transformer Replacement	2009	2011	The main transformer was originally projected for installation in 2011, but due to the aging condition of the existing main transformer, it was assumed to be accelerated to 2009. After fabrication and shipping challenges, the installation was moved to 2011.
#13 A/B, #14 A/B, and #15 A/B Feedwater Heater (FWH) Replacement	2011	14 A/B & 15 A/B FWHs were installed in 2011 13 A/B FWHs were installed in 2013	#13 FWHs replacement was deferred to optimize outage schedule by minimizing simultaneous outage work activities in the same area.
Moisture Separator Drain Tank Injection	2011	Partially completed in 2011, completed in 2013	Priority of this item did not require full completion in 2011, and completed in 2013.
Stator Winding	2011	2011	
Exciter Replacement	2011	2011	
Steam Dryer Replacement	2011	2011	

Monticello LCM/EPU Modification	Planned Timing of Outage Installation at Time of CON	Actual/Currently Planned Timing of Outage Installation	Discussion of Timing or Scope Changes
Stator Water Cooler and Hydrogen Cooler Replacement	N/A – not in CON	2011	Not a major item anticipated in certificate of need.
#11 and #12 Feed Water Heater Drain Line Replacement	2011	Partially installed in 2011, completed in 2013	Installation is spread over two outages to minimize impact on outage schedule and labor requirements.
Turbine Vibration Monitoring System	2009	Partially installed in 2009; completed in 2011	Installed during 2009 and 2011 outages in tandem with turbine upgrades.
Replacement of the 13.8kV Switchgear Bus #11 and #12	2011	2013	The 13.8 kV switchgear coordinated with upgraded pump motors as combined initiative.
Replacement of the 1R and 2R Transformers	2011	2013	The 13.8 kV/4.16 kV Transformers coordinated with upgraded pump motors as combined initiative.
Replacement of the Feed Water Pumps and Motors	2011	2013	New pumps and motors designed to use 13.8 kV and installation coordinated as combined initiative.

Monticello LCM/EPU Modification	Planned Timing of Outage Installation at Time of CON	Actual/Currently Planned Timing of Outage Installation	Discussion of Timing or Scope Changes
Replacement of the Reactor Recirculation Pump Motor Generator Set Motors	N/A – not in CON	2013	Not anticipated in certificate of need. The motors are being upgraded to 13.8 kV and will be installed when the 13.8 kV switchgear is installed in the plant.

The Bechtel Corporation

The Bechtel Corporation ("Bechtel") is a privately-held global contractor providing engineering, construction and project management services for the energy, transportation, communications, mining and government services sectors. The company was founded in 1898 and has headquarters in San Francisco, CA. In 2011, it reported $32.9 billion in revenues.

Bechtel's nuclear power division offers a wide range of construction and operating services, including plant recovery support, plant license renewal, steam generator replacement, and new nuclear generation. The company has built and/or designed over 85% of the U.S. nuclear fleet.[1]

Some of Bechtel's nuclear projects include performing extended power uprates for NextEra Energy at the St. Lucie nuclear plant in Florida as well as at two of its other nuclear facilities. In 2007, the company was awarded a $4.2 billion contract for construction of a pressurized water reactor ("PWR") for TVA at Watts Bar Station in Spring City, TN. The project is expected to go on line in 2015 and add nearly 1,200 megawatts to TVA's power system. Bechtel also completed construction for TVA's Browns Ferry Unit 1 in Athens, Alabama in 2007. The $1.8 billion restart project required engineering, systems testing and technical services. [2]

On July 14, 2010 Bechtel Power Corporation announced an alliance—known as Generation mPower—with Babcock & Wilcox Nuclear Energy to design, license and deploy the world's first commercial Generation III+ small modular nuclear reactors („SMRs‟).[3] The company received additional funding from the U.S. Energy Department in August 2013 to support the design, licensing, and commercialization of SMRs in the United States.[4]

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[1] "Nuclear Power", Company Website, Accessed 8/29/12, <http://www.bechtel.com/nuclear.html>
[2] "Power: Business Review," The Bechtel Report 2012, <http://www.bechtel.com/assets/annual_report2012/power.htm>
[3] "B&W and Bechtel Form Alliance to Commercialize World's First Generation III++ SMR Nuclear Plant," Company Press Release, July 14, 2010, <http://www.bechtel.com/2010-07-14.html>
[4] "Small Modular Reactor Project Gets Additional Funding," Company Press Release, 8/27/13, <http://www.bechtel.com/5193.html>

Modification: Licensing

Initial Scope and Estimate	• Estimates only prepared for minimal vendor involvement for EPU and MELLLA+ licensing • **$28.6 million**

Final Scope	• License Amendment Request for EPU and MELLLA+ – $47.9 million
	  o GE Cost based on issuance of final contract
	  o Internal costs
	  o NRC Fees for Review

Milestones	• September 2006: Licensing Agreement to use Licensing Topical Reports. • 2007-2008: License Amendment Request preparations and meetings with NRC. • March 31, 2008: EPU License Amendment Request submitted to the NRC. • April 2008: Advisory Committee on Reactor Safeguards ("ACRS") requested increase in level of scrutiny for steam dryer structural analysis. • June 26, 2008: NRC Letter indicating License Amendment Request for EPU inadequate. • June 2008: Xcel Energy withdrew EPU License Amendment Request. • October 2008: Xcel Energy met with NRC to discuss License Amendment Request resubmission. • November 5, 2008: EPU License Amendment Request submitted to the NRC. • March 2009: NRC sent letter to ACRS recommending industry-wide changes to practice of including containment accident pressure ("CAP") credit in licenses until resolution of NRC staff and ACRS could resolve disagreement. • October 2009: EPU application put on hold by NRC until CAP credit issue resolved. • January 2010: MELLLA+ License Amendment Request submitted to the NRC. • January 2011: NRC staff issued options for consideration of the use of CAP and recommended commissioners approve resuming reviews of EPU applications. • March 2011: NRC commissioners voted to approve staff's recommendation on CAP analysis. • March 2011: Fukushima event and followup impact availability of NRC reviewers to support EPU. • March 2011: NRC increased expected hours for review of License Amendment Request from 5,040 hours to 7,500 hours. • April 2011: NRC reactivated review of the EPU License Amendment Request. • April 2011 – 2012: Xcel Energy worked to develop CAP analysis to satisfy new requirements. • September and November 2012: Xcel Energy submitted CAP analyses to the NRC. • February and March 2013: Xcel Energy responded to additional containment accident pressure RAIs. • September 2013: ACRS voted to approve approach to containment accident pressure – first success under the new NRC CAP review requirements. • September 2013: ACRS voted to approve company EPU steam dryer proposal, final NRC approval anticipated November 2013 (timing dependant on Federal Government shutdown). • 2013: MELLLA+ in NRC review, approval anticipated early 2014.

Modification: Licensing

Costs Incurred	• *2006-2008 First EPU License Amendment Request:* Estimate increases to $47.86 million, primarily due to costs recognized with final issuance of contract for Phase 1 and Phase 2 that covered this work. Cost increase was also associated with recognition of additional scope required for onsite resources to complete EPU scope added at this time. • Cost increases from August to December 2006 o Original August 2006 GE cost o Revised in December 2006 • Company costs for Licensing (2006 estimate): o Internal cost – $19.6 million o NRC Fees for Review – $1.4 million • Cost Increases After December 2006: o *Repairs to main steam line strain gauges and piping vibration accelerometers*: $1.2 million o *Re-analysis of steam dryer and second EPU LAR submittal*: $4.5 million o *Removal of steam dryer instrumentation*: $1 million o *Additional calculations required by NRC including CAP analysis*: $7.5 million • August 31, 2013: **$59.5 million**
WOs	11536446; 11636097; 11636101; 11636105; 11636109; 11636114; and 11775097

	Work Order	2011	2012	2013	Total
11536446	MNGP EPU License Development	50,015,888	(11,323,392)	4,658,214	43,350,710
11636097	EPU Lic-HELB Design Basis Documents	-	4,906,024	(127,515)	4,778,509
11636101	EPU Lic-Envir Qual DBD	-	2,558,596	(36,360)	2,522,236
11636105	EPU Lic-HELB & Inst Srv DBD	-	2,175,334	(30,892)	2,144,441
11636109	EPU Lic- Motor & Air Op Vlv Sys Design Basis Docs	-	2,619,272	(36,835)	2,582,437
11636114	EPU Lic- Piping Stress Design Basis Documents	-	4,111,340	(58,610)	4,052,730
11775097	EPU MELLA+	-	-	52,028	52,028
	Total:	**$ 50,015,888**	**$ 5,047,175**	**$ 4,420,030**	**$ 59,483,092**

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

September 16, 2013

The Honorable Allison M. Macfarlane
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: MONTICELLO NUCLEAR GENERATING PLANT EXTENDED POWER UPRATE LICENSE AMENDMENT REQUEST

Dear Chairman Macfarlane:

During the 607th meeting of the Advisory Committee on Reactor Safeguards, September 5-7, 2013, we completed our review of the extended power uprate (EPU) license amendment request (LAR) for Monticello Nuclear Generating Plant (MNGP) and the associated NRC staff's draft final safety evaluation. Our Subcommittee on Power Uprates also reviewed this matter on July 25 and 26, 2013. During these reviews, we had the benefit of discussions with representatives of the NRC staff and the Northern States Power Company Minnesota (NSPM or the licensee). We also had the benefit of the documents referenced.

RECOMMENDATION AND CONCLUSIONS

1. The NSPM application for the MNGP EPU should be approved subject to the conditions and commitments identified in the staff's draft final safety evaluation.

2. The license condition for monitoring during power ascension testing provides reasonable assurance that unanticipated vibration modes induced in the steam dryer will be detected and addressed.

3. Application of the guidance in SECY-11-0014 for containment accident pressure (CAP) credit and the required analyses in this LAR provide reasonable assurance related to pump survivability and the availability of required net positive suction head (NPSH). Including the evaluation of the potential for circuit issues associated with an Appendix R fire helps to identify actions that may be necessary to reduce the likelihood of inadvertent containment venting that could result in a loss of CAP.

4. The requirement for CAP may limit the capability to implement future venting actions that may be proposed in response to the Near Term Task Force recommendations.

BACKGROUND

MNGP is a boiling water reactor (BWR) plant of the BWR/3 design with a Mark I containment. The plant began operation in 1970. Although not licensed to Appendix A General Design Criteria, evaluations show that MNGP conforms with the intent of the 1967 Atomic Energy Commission draft General Design Criteria. In November 2006, the NRC granted MNGP an extension to operate until 2030.

The current licensed thermal power (CLTP) of 1,775 MWt (with a gross electrical output of 600 MWe) is approximately 6.3% higher than the original licensed thermal power (OLTP) of 1,670 MWt. NSPM applied for an EPU of approximately 13% from the CLTP, which would result in a total uprate of 20% from the OLTP to 2,004 MWt. NSPM plans to begin implementing this EPU during 2013.

DISCUSSION

The Constant Pressure Power Uprate (CPPU) for MNGP is primarily accomplished by generating and supplying higher steam mass flow to the turbine-generator. As-designed equipment and system capabilities, along with improvements in analytical methods, improved fuel and core designs, and newly installed or modified equipment accommodate the higher steam mass flow rate and the resultant power increase. EPU operation does not involve increasing the maximum normal operating reactor vessel dome pressure because the plant's modified non-safety power generation equipment has sufficient pressure control and turbine flow capability to control turbine inlet pressure conditions.

The licensee proposes that a higher steam mass flow be achieved by increasing the reactor power along specified control rod and core flow lines. This also requires that a limited number of operating parameters be changed, some set points be adjusted, and some instruments be recalibrated. Plant procedures will be revised, and tests similar to some of the original startup tests will be performed. The MNGP power ascension test plan does not include performing large transient tests at full EPU power. The licensee and the staff state that such tests can be omitted because relevant experience at other BWR 3/4 units similar in design to the MNGP exists, because transients had previously occurred at MNGP, and because of prior large transient tests that were completed at MNGP. We concur.

The initial power ascension test plan is focused on assessing steam dryer and selected piping system performance. MNGP modifications that have already been implemented (or will be implemented prior to ascending to EPU power) include: a replacement steam dryer (RSD), addition of vibration monitoring accelerometers on main steam and feedwater piping, a new digital power range neutron monitoring system, a new high pressure turbine, new feedwater pumps and motors, new feedwater heaters, new condensate pumps and motors, and revised instrumentation setpoints. Power transmission system upgrades include new main and auxiliary transformers, new external busses, new internal busses and switchgear, and installation of the required controls and cooling features to operate the new equipment. No changes to the type of fuel will be made for the EPU. The MNGP core has been comprised entirely of GE14 fuel assemblies since Cycle 24 (the plant is currently in Cycle 27), and this will continue to be the case during EPU implementation.

MNGP currently operates in the Maximum Extended Load Line Limit Analysis (MELLLA) operating domain. Due to core flow limitations at MNGP, ascension to full EPU power is planned after NRC approval of a separate LAR for operation in the MELLLA Plus (MELLLA+) operating domain.

The Safety Analysis Report for the Monticello Constant Pressure Power Uprate follows the guidelines in the NRC-endorsed General Electric (GE) licensing topical reports for BWR CPPUs. The staff's evaluation of the application follows the methodology prescribed in the EPU review standard (RS-001). In addition, the staff used applicable rules, regulatory guides, Standard Review Plan (SRP) sections, and staff positions on applicable topics.

The MNGP EPU application was not submitted as a risk-informed license application. Nevertheless, NSPM submitted assessments of risk metrics associated with operation at EPU conditions. The staff considered this risk information and determined that the MNGP EPU would not create any special circumstances that could potentially invalidate the presumption of adequate protection justified by compliance of MNGP EPU operation with deterministic requirements and regulations.

The licensee evaluated the effects of EPU conditions on relevant materials degradation mechanisms including intergranular stress corrosion cracking, irradiation assisted stress corrosion cracking, flow-accelerated corrosion, fatigue, radiation embrittlement, and flow-induced vibration and concluded that they would be adequately managed. The staff accepted their approach, which includes additional measures for monitoring the RSD during power ascension to full EPU power. We concur with this conclusion.

Containment Accident Pressure (CAP)

The current MNGP licensing basis includes design basis accident calculations that take credit for CAP in assessing the available net positive suction head (NPSHa) for core spray (CS) and residual heat removal (RHR) pumps to avoid excessive cavitation [e.g., for the limiting design basis loss of coolant accident (DBLOCA), CAP credit of up to 6.1 psig for approximately four days is currently allowed]. EPU implementation at MNGP increases the heat transferred to the suppression pool, which will increase the pool water temperature, reduce NPSHa at the suction inlet of the RHR and CS pumps, and reduce NPSH margin.

This application is the first EPU request using SECY-11-0014 CAP guidance, as well as the BWR Owners Group (BWROG) guidance. NSPM evaluated NPSH margin using conservative assumptions for the limiting DBLOCA, and realistic assumptions for non-design basis events, such as Appendix R fire, anticipated transient without scram (ATWS), and station blackout (SBO) events. The licensee's analyses for each event consisted of the following steps: (a) containment analysis using the Super HEX (SHEX) computer code to calculate the transient wetwell pressure and the corresponding transient suppression pool temperature, (b) calculation of the NPSHa at the inlet of the RHR and CS pumps using the transient suppression pool temperature with varying transient wetwell pressure as inputs, and (c) evaluation of NPSH margin. These deterministic calculations were performed using conservative assumptions consistent with Regulatory Guide 1.82, Revision 3.

The deterministic analysis with conservative inputs showed more limiting results in NPSH margin than a statistical analysis performed by the BWROG for MNGP. In accordance with SECY-11-0014 guidance, NSPM also demonstrated that results obtained from the deterministic analyses were conservative by providing comparisons with a best estimate analysis using the GOTHIC code. Application of SECY-11-0014 guidance indicates that the maximum CAP credit will need to increase for MNGP at EPU conditions; however, it is less than 10 psig for 5 days for the limiting DBLOCA.

Consistent with SECY-11-0014 guidance, evaluations were also performed to provide assurance that operator actions to control CAP are acceptable and documented in appropriate plant procedures. As part of the BWROG program to address the use of CAP, the pump manufacturer completed tests at the flow rate and NPSH margin that causes the maximum erosion of the pump impeller. Results indicate that cavitation erosion will not challenge the ability of the pumps to operate.

To address SECY-11-0014 guidance that circuit issues associated with an Appendix R fire should not result in a loss of required CAP, NSPM considered multiple spurious operation (MSO) scenarios in accordance with the guidance in NEI 00-01, Revision 2 and Regulatory Guide 1.189, Revision 2. MSO scenarios that could challenge Appendix R fire-required CAP were precluded from occurring through modifications and configuration changes.

NSPM performed GOTHIC calculations to demonstrate that the leakage rate to lose all NPSH margin is greater than 228 standard cubic feet per minute (scfm), which is approximately 30 times the MNGP technical specification limit (10 CFR 50 Appendix J). In addition to the Appendix J testing program, this margin is ensured through on-line monitoring of nitrogen makeup to the containment and NSPM implementation of a one-time test each startup that will demonstrate leakage will be less than 150 scfm.

In summary, the licensee adequately addressed the effects of the proposed EPU on containment heat removal. The licensee implemented new SECY-11-0014 guidance for using CAP credit. Analyses indicate that under EPU conditions, the emergency core cooling system and containment heat removal systems will continue to meet General Design Criterion-38, with respect to rapidly reducing the containment pressure and temperature following the design basis and non-design basis events and maintaining these parameters at acceptably low levels.

However, the magnitude and duration of CAP credit has increased due to EPU conditions. This may further limit the capability to implement future venting actions that may be proposed in response to the Near Term Task Force recommendations. We look forward to interacting with the staff to ensure that such actions can be performed reliably without adversely affecting plant risk.

Replacement Steam Dryer (RSD)

The proposed EPU will increase flow induced vibration in certain components that could lead to high-cycle fatigue failure. EPU operating experience has revealed that the steam dryer is the most likely component to be affected. Although the steam dryer does not perform a safety function, it must retain its structural integrity to avoid generating loose parts that may adversely affect the capability of other plant equipment. The main steam line (MSL) velocity at MNGP will be 179 feet per second (fps) at EPU conditions. This is higher than steam line velocities at Susquehanna (153 fps), similar to that at Nine Mile Point Unit 2 (177 fps), and lower than that at Quad Cities Unit 2 (202 fps).

The licensee replaced the original steam dryer during the Spring 2011 refueling outage. The RSD is a Westinghouse-designed “Nordic” steam dryer. It is octagonal in shape and contains three concentric rings of dryer panels. This provides symmetry of fluid flow paths through the dryer and results in an overall robustness and integrity with regard to structural loads. The shape of the structure and its fabrication details (nearly all welds are full-penetration) are also well-suited to withstand dynamic loads. Similar steam dryers installed in BWRs in Sweden and Finland have operated successfully for more than 25 years at temperatures and MSL flow velocities equal to or significantly greater than those planned for MNGP at EPU conditions.

The RSD was instrumented and operated with accelerometers, pressure transducers, and strain gauges. In addition, strain gauges were installed on the four MSLs. In 2011, during the Cycle 26 power ascension to CLTP levels, these instruments provided time history data to support benchmarking of the Acoustic Circuit Enhanced (ACE) Version 2.0 methodology that was used, in conjunction with multiple structural analyses and scale model testing, to qualify the steam dryer for acoustic loads at EPU operating conditions. Measurements of pressure pulsations in the MSL are used with the ACE acoustic model to calculate pressure pulsations on the MNGP steam dryer, and a structural finite element model of the dryer is used to determine peak stress. The ACE acoustic methodology was benchmarked against direct strain gauge measurements in the RSD to establish applicable bias errors and uncertainties in the stress. The loads at CLTP conditions inferred from MSL signals are projected to EPU conditions using frequency based scaling factors. These scaling factors are based on small-scale testing on models of the steam system and account for increases in steam velocity and more importantly, the safety relief valve acoustic resonances that may take place during power ascension from CLTP to EPU conditions. The estimated loads at EPU conditions and the bias errors and uncertainties determined from benchmarking at the CLTP levels are used to determine the peak stress. The scaling factors used to estimate the loads will be verified during the power ascension testing.

Based on these calculations, NSPM concluded that the peak stress in the RSD at EPU conditions meets ASME design criteria. However, no strain gauge or pressure measurements were made on the steam dryer skirt. Direct application of the acoustic model to Quad Cities data showed that the model underpredicted pressures on the skirt in the low frequency range. To address this, a separate acoustic model was developed and benchmarked solely to Quad Cities measurements of pressure on the skirt. The skirt model shows good agreement with the Quad Cities data and was used to estimate stresses on the skirt for the MNGP dryer.

To provide assurance against fatigue cracking, the staff generally expects that the ratio of the ASME allowable cyclic stress to the maximum cyclic stress predicted for the dryer be greater than unity for dryers with full benchmarking and greater than two for uninstrumented components. For the upper dryer (hood) portion, which was instrumented, the minimum alternating stress ratio was well above unity at projected EPU conditions. For the lower dryer (skirt) portion, which was not instrumented, the minimum alternating stress ratio including safety relief valve resonance was slightly below two at projected EPU conditions. Because of the good agreement between end-to-end strain simulations and because the dryer was partially instrumented, the staff found this small non-adherence to the factor of two for skirt stresses required for completely uninstrumented dryers acceptable. We concur with the staff's conclusion.

After installation of the RSD, the licensee began implementing a slow and deliberate program for power ascension, with defined hold points. As of August 2011, sections of this test plan were implemented that allowed steam dryer data to be gathered to support operation under CLTP conditions. Power ascension to EPU conditions will occur over a period of time with small (equal to or less than 5% power) gradual increases in power and hold periods. In addition, the power ascension plan includes monitoring and analysis to trend the steam dryer performance and a long-term inspection program to verify performance of the steam dryer and piping system. Limit curves that define the maximum allowable MSL pressure (or strain) as a function of frequency have been developed based on finite element analysis to ensure that steam dryer allowable stresses aren't exceeded. During power ascension testing, the licensee will monitor MSL strain gauge signals. If the MSL pressure or strain limit curves at any frequency are exceeded, power will be immediately reduced to the previous power level pending further evaluation. Steam dryer loads and stresses will be re-evaluated based on the MSL pressure measurements, and the stresses so determined will be compared to the ASME code fatigue endurance limit to confirm dryer integrity. The power level will be increased to the next hold point only after confirmation that the maximum expected stress at the next hold point will be below the ASME code endurance limit.

The licensee will transmit relevant data and evaluations to the NRC staff during the power ascension. The MNGP limit curve approach is similar to that used by other licensees during power ascension to monitor steam dryer structural integrity. The power ascension program, coupled with the large margin in predicted stress and confirmatory inspections, provides reasonable assurance that unexpected vibration modes will be detected and analyzed before further increases in power.

SUMMARY

In summary, we agree with the staff's reasonable assurance determination that the health and safety of the public will not be endangered by the licensee's operation at the proposed EPU power level and that such activities will be conducted in compliance with the Commission's regulations. The NSPM application for the MNGP EPU should be approved subject to the remaining regulatory conditions and commitments identified in the staff's draft final safety evaluation. We commend the licensee on the quality of this application and the staff for their thorough review.

Sincerely,

/RA/

J. Sam Armijo
Chairman

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3. Letter from Timothy J. O'Connor (NSPM) to Document Control Desk (NRC), "License Amendment Request: Maximum Extended Load Line Limit Analysis Plus," L-MT-10-003, January 21, 2010 (ML100280558).

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5. GE Nuclear Energy, “Constant Pressure Power Uprate,” Licensing Topical Report NEDC-33004P-A, Revision 4, Class III (Proprietary), July 2003 (ML032170343).

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10. SECY-11-0014, Enclosure 1, “The Use of Containment Accident Pressure in Reactor Safety Analysis,” January 31, 2011 (ML102110167).

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13. NEI 00-01, “Guidance for Post-Fire Safe-Shutdown Circuit Analysis,” Revision 2, June 5, 2009 (ML091770265).

14. Regulatory Guide 1.189, “Fire Protection for Nuclear Power Plants,” Revision 2, October 2009 (ML092580550).

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6. GE Nuclear Energy, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate,” Licensing Topical Report NEDC-32424P-A, Class III (Proprietary), February 1999 (ML081690229).

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9. SECY-11-0014, “Use of Containment Accident Pressure in Analyzing Emergency Core Cooling System and Containment Heat Removal System Pump Performance in Postulated Accidents,” January 31, 2011 (ML102590196).

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13. NEI 00-01, “Guidance for Post-Fire Safe-Shutdown Circuit Analysis,” Revision 2, June 5, 2009 (ML091770265).

14. Regulatory Guide 1.189, “Fire Protection for Nuclear Power Plants,” Revision 2, October 2009 (ML092580550).

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Modification: Turbine

Initial Scope and Estimate	• Replacement of high-pressure turbine; • Stage 8 and 10 replacement of low-pressure turbine; • Replace cams in camshafts; • Turbine generator Bentley Nevada Vibration Monitoring system; and • Testing • **$60.2 million**
Final Scope	• Replacement of high-pressure turbine. • Stage 8 and 10 replacement of low-pressure turbine. • Replace cams in camshafts. • Turbine generator Bentley Nevada Vibration Monitoring system. • Complete testing.
Milestones	• December 2006: Phase II GE contract finalized. • August 2007: Scope of modification finalized. • July 2008: High-pressure rotor inspection. • November 2008: Low-pressure diaphragm fabrication. • November 2008: High-pressure diaphragms delivered to site. • December 2008: High-pressure rotor delivered to Monticello. • 2009 Outage: Turbine installation modification completed. • May 2010: Final vibration monitoring engineering change approved. • 2011 Outage: Phase II Bentley Nevada Vibration Monitoring system installation completed.

Costs Incurred	• *Design/Engineering*: $3.5 million
	  o All design and engineering handled by GE through their general design and planning group.
	• *Materials*: $31.9 million
	  o Fabricated and procured through the standard GE procurement train.
	• *Installation*: $4.4 million
	  o High-pressure turbine balance issue resulted in three-day delay of start up.
	  o Delay of startup from failure to achieve clean oil test.
	  o Turbine/generator centerline alignment vibration issue that had to be resolved in outage – extended outage by seven days.
	  o Testing of equipment including construction testing, pre-operational testing, and operational testing.
	• August 31, 2013: **$57.5 million**

WOs	11133668; 11335729

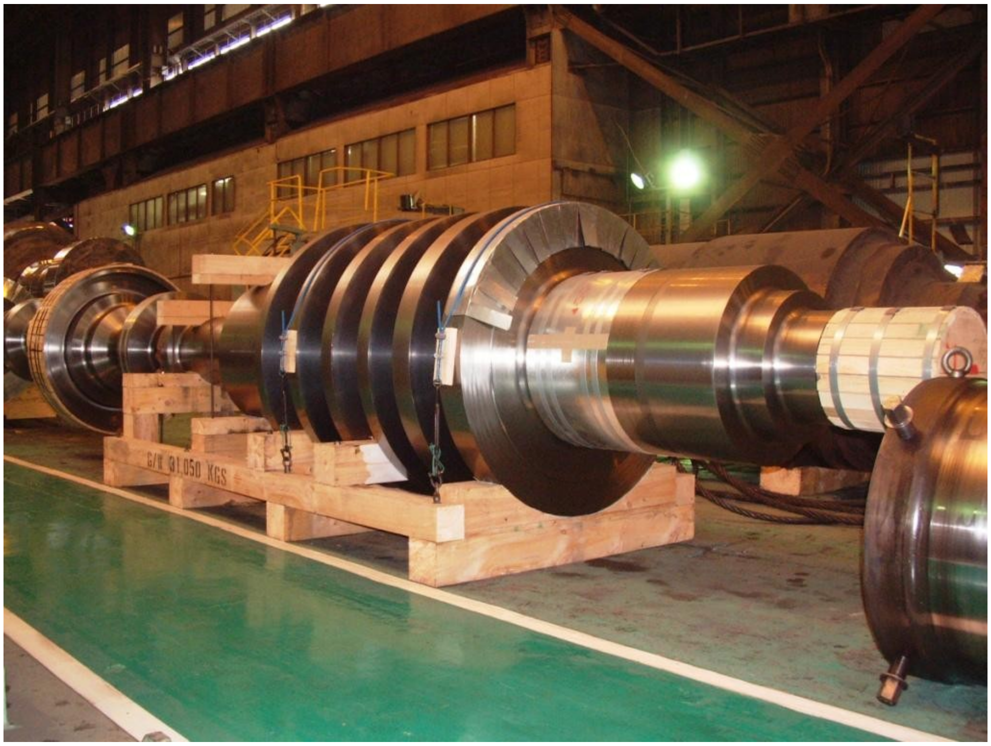
Modification: Turbine

Turbine Replacement	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$ -	$ -	$ 5,215	$ 89,720	$ -	$ -	$ 94,935
Design/Engineering	$ 18,330	$ 3,052,077	$ 350,391	$ 125,980	$ -	$ -	$ 3,546,778
Materials/Components	$ -	$ 31,611,678	$ 260,618	$ 9,308	$ -	$ -	$ 31,881,605
Installation	$ -	$ 2,773,654	$ 133,403	$ 1,530,337	$ 1,285	$ -	$ 4,438,679
Common**	$ -	$ -	$ -	$ 17,171,378	$ -	$ -	$ 17,171,378
Xcel General Costs	$ 12	$ 203,720	$ 12,768	$ 102,788	$ 14	$ -	$ 319,302
Total	**$ 18,342**	**$ 37,641,129**	**$ 762,395**	**$ 19,029,510**	**$ 1,299**	**$ -**	**$ 57,452,676**

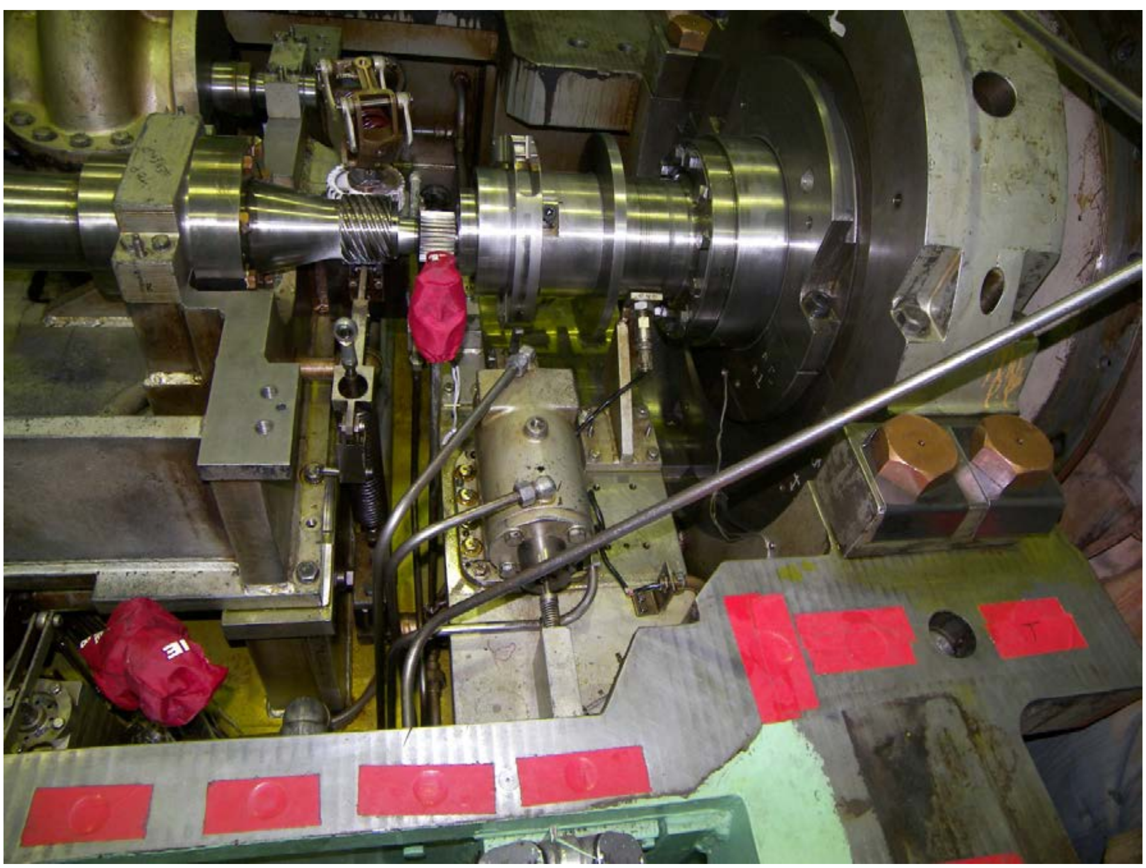
* Child Work Orders - 11133668 - MNGP EPU Turbine Replacement, 11335729 - MNGP EPU Turbine Generator Vibration

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Turbine



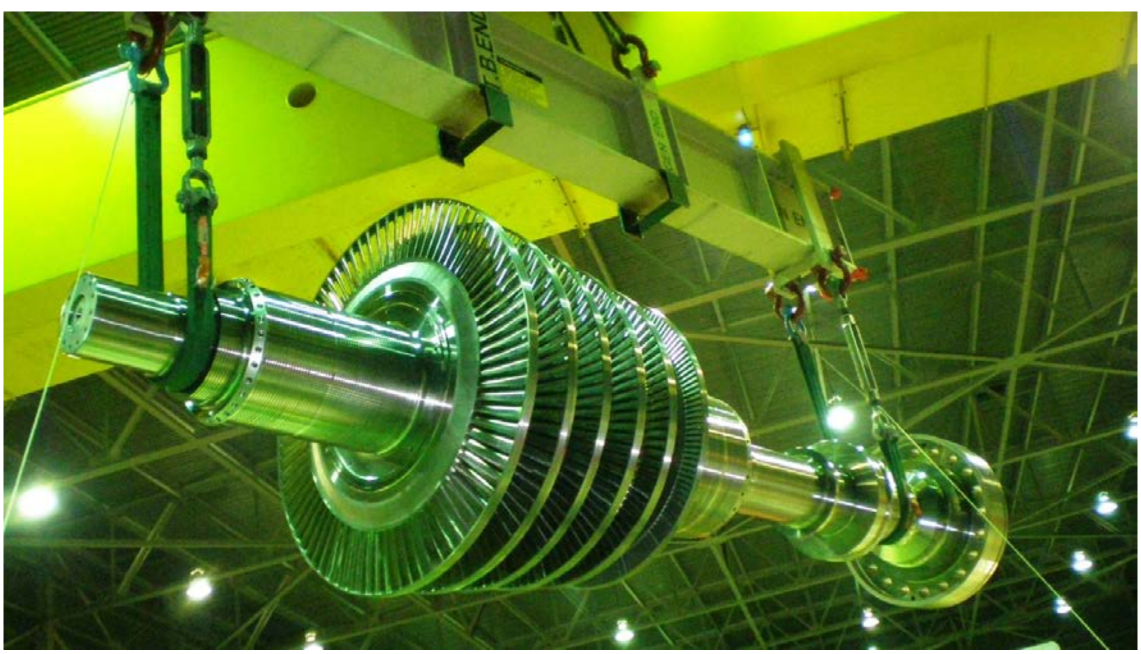
High-Pressure Turbine Delivery



Turbine Installation

Modification: Turbine

High-Pressure Turbine Rotor



High-Pressure Turbine Installation

Country	Operator	Facility	Type of Reactor	Capacity (MWe net)	Start Year	Type of Project	Contract Awarded & Signed	Contract Amount	Project Scope	Comments
Canada	Hydro-Quebec	Gentilly-2	CANDU	635	Cancelled	Refurbishment	GE Energy (2/12/13)[1]	$120 million	Under the contract, GE Energy will replace the generator rotor windings and the moisture separator-reheaters. In addition, the two low pressure steam turbine rotors and diaphragms must be replaced and adjustments made to the turbine base plate. A new control system will also be installed.	• The project was cancelled in October 2012 due to rising project costs and falling market prices. The plant will stop producing electricity in December 2012 and begin decommissioning. • GE Energy was the OEM.
Canada	New Brunswick Power	Point Lepreau	CANDU	635	2008	Refurbishment	Siemens Canada (9/1/06)	$65 million	Siemens contracted to provide to NBPNC three Low Pressure Modules ("LP Modules") for incorporation into Point Lepreau. Each LP Module is comprised of an outer LP Casing and an internal LP Turbine Rotor. The LP Module converts energy contained within the steam flow into a rotational force which is then transmitted to the generator to produce electrical power. The LP Casing contains the LP Turbine Rotor and directs steam through it, causing it to rotate and thereby drive the generator rotor. In addition, Siemens contracted with NBPNC to refurbish and upgrade the Generator Rotor. This required that the Generator Rotor be transported from Point Lepreau, to Saint John and then back to Point Lepreau after the refurbishing and upgrading was completed in Newcastle UK.	• AECL was the general contractor for the project responsible for managing and executing all of the fieldwork as part of a turnkey, fixed price contract. • Expenditures as of March 2012 were $68 million. • In October 2008, 2 of the 3 rotors fell off a barge during transportation. The rotors were repaired at a cost of $10 million. In addition, the life of the rotors has been reduced to 6 years instead of the anticipated 30 years. Thus, at the end of the 6 years, Siemens must produce and deliver 2 new rotors for a cost of $20 million. • Parsons Turbine Generators Canada Limited was the OEM.
Canada	Bruce Power	Bruce A Units 1 & 2	CANDU	750 (each)	2006	Refurbishment	Siemens Canada (10/31/05)	$60 million	Change out the first rows of spindle blades on all of the low-pressure turbines and on the high pressure turbines, Conduct a full electrical test and inspection on the generators in both units, Completely replace the generator stator in Unit 2, Improve the generator rotor in Unit 2 by installing new magnetic end caps, and Replace the excitation and governor systems in both units.	• The return to service of the refurbished unit 2 was delayed due to damage that had occurred to the electric generator. Siemens Canada was responsible for the repair work. • The problem was traced to an error in the original design drawings used to manufacture a component in the generator. Therefore, the problem was deemed beyond the control of Bruce Power by the OPA. • Parsons Turbine Generators Canada Limited was the OEM.

1 The date of the first press release to announce the contract was awarded.

Country	Operator	Facility	Type of Reactor	Capacity (MWe net)	Start Year	Type of Project	Contract Awarded & Signed	Contract Amount	Project Scope	Comments
Argentina	Nucleo-electrica Argentina SA	Embalse	CANDU	600	2013	Refurbishment	Ansaldo Nucleare (5/28/12)[1]	EUR 104 million	Upgrade and improve the efficiency of the thermal cycle and the turbogenerator under the project to extend the life of the Embalse nuclear power station, in Argentina.	• Ansaldo Nucleare was the OEM.
South Africa	Eskom	Koeberg	PWR	1,800	2009	Turbine Retrofit	Alstom (3/13/09) [1]	EUR 125 ($162m) million	Retrofit the low pressure turbines to increase the station's power output by more than 65 MW.	• The retrofit was carried out during a planned refueling outage in 2009. • Alstom was the OEM
USA	Nextra Energy Resources (FPL Energy)	Point Beach	PWR	1,023	2011	2 PWR SPUs	Siemens Energy (Jun. 2008) [1]	$90 million	Siemens will provide the HP turbine upgrade; complete upgrade of the generator, including a RIGI-FLEX™ rewind of the stator; a new generator rotor; refurbished exciters and certain field installation services for both units. The upgrades are expected to add up to 85 MWe to the installed capacity of each Point Beach unit.	• On June 27, 2012, Point Beach Unit 2 stopped operating after a problem developed with the plant's turbine. • A failure investigation process (FIP) was entered. Based on troubleshooting, NextEra determined that the loss of turbine load was due to a failure of the speed channel 'A' card in the EH system. Speed channel cards in the EH system were replaced with spares and calibrated. This was done as a conservative measure since only the 'A' card had failed. The calibration was completed satisfactory and the EH system was subsequently returned-to-service. This event is not reported as a safety system functional failure.[2] • Westinghouse Electric Corporation was the OEM.

[2] "Licensee Event Report 3011201 2-001 -00; Unit 2 Manual Reactor Trip," Company Report Filed with the NRC

Country	Operator	Facility	Type of Reactor	Capacity (MWe net)	Start Year	Type of Project	Contract Awarded & Signed	Contract Amount	Project Scope	Comments
USA	Florida Power and Light (FPL)	Turkey Point 3 & 4 and Saint Lucie 1 & 2	PWR	3,080[3]	2008	4 PWR EPUs	Siemens Energy (11/12/08)[4]	$250 million	**Turkey Point**: For both units, Siemens will supply a new HP turbine; complete modernization of the generator, including a RIGI-FLEX™ rewind of the stator; new generator rotors; refurbished exciters and certain field installation services. The upgrades at Turkey Point are expected to result in approximately 100 MWe of new generation capacity for each Turkey Point unit.[5] **St. Lucie**: The Siemens scope of supply for both units includes a new high-pressure (HP) turbine; two new low-pressure (LP) turbines; complete modernization of the generator, including a RIGI-FLEX™ rewind of the stator; generator rotor rewind; refurbished exciter and certain field installation services. The capacity increase for St. Lucie is expected to be approximately 100 MWe for each St. Lucie unit.[5]	• The estimated cost of the work to be completed by Siemens is now close $450 million.[6] • Two work stoppages related to Siemens have occurred: one at Turkey Point Unit 3 and the other at St. Lucie Unit 2. • The Projects is expected to be completed in 2013. • Westinghouse Electric Corporation was the OEM.
USA	Exelon	Quad Cities 1+2	BWR	1,824	2010	Retrofit	Alstom (6/19/08)[1]	$140 million[7][8]	LP Retrofit – The project entails the replacement of three low pressure turbine rotors and casings on each of two units (Unit 1 and Unit 2).	• The turbine retrofit project was completed at Quad Cities 2 and 1 in March 2010 and May 2011 respectively. • The retrofit projects is estimated to give each unit an additional 40 MWe • GE Energy was the OEM.
USA	Exelon	Dresden 2+3	BWR	1,734	2011	Retrofit	Alstom (6/19/08)[1]	$140 million	LP Retrofit – The project entails the replacement of three low pressure turbine rotors and casings on each of two units (Unit 2 and Unit 3).	• During its 2011 fall outage, Dresden replaced all three of its Unit 2 low-pressure turbine rotors and casings. • The same turbine retrofit project will be completed on Dresden 3 during 2012's upcoming refueling outage in November. • The retrofit projects is estimated to give each unit an additional 40 MWe • GE Energy was the OEM

3 FPL Order No. PSC-08-0021-FOF-EI
4 Contract was approved by the Florida PSC in ORDER NO. PSC-08-0749-FOF-EI on 11/12/2008.
5 "Siemens to upgrade the turbine-generator units of two nuclear power plants in the U.S. Combined order value approximately USD250 million," Company Press Release
6 Direct Testimony of Terry Jones filed in Dockets 120009-EI and 110009-EI.
7 $420 million is the estimated value of the contract signed with Excelon for all three nuclear plants (Quad Cities, Dresdan and Peach Bottom).
8 "Alstom sign agreement with Exelon to supply nuclear steam turbine retrofit equipment" Company Press Release

Country	Operator	Facility	Type of Reactor	Capacity (MWe net)	Start Year	Type of Project	Contract Awarded & Signed	Contract Amount	Project Scope	Comments
USA	Exelon	Peach Bottom 2+3	BWR	2,224	2011	Retrofit	Alstom (6/19/08)[1]	$140 million	LP Retrofit – The project entails the replacement of three low pressure turbine rotors and casings on each of two units (Unit 2 and Unit 3).	• The turbine retrofit project was completed at Peach Bottom 3 and 2 in September 2011 and September 2012 respectively. • The retrofit projects is estimated to give each unit an additional 40 MWe • GE Energy was the OEM.
USA	Tennessee Valley Authority (TVA)	Watts Bar 2	PWR	1,270	2008	Completion of partially constructed PWR	Siemens Energy (12/5/07)[1]	$172 million	The Siemens scope of supply for Unit 2 includes one new high-pressure (HP) turbine; three new low-pressure (LP) turbines; complete modernization of the generator, including a RIGI-FLEX rewind of the stator and new retaining rings; exciter rotor refurbishment; six new moisture separator reheaters; plus multiple other components and more than 40,000 individual replacement parts. The HP turbine is planned for delivery in August 2009 and the three LP turbines in June 2010.[9]	• TVA has selected Siemens as the most cost effective solution for completing the work needed to maximize electric output and provide a reliable and efficient turbine generator for Watts Bar 2.[9] • Due to inaccurate time and cost estimates and flawed project management, the cost of the project is now estimated to be $4.2 billion instead of the original $2.5 billion. In addition, the plant was expected to be online in the fall of 2012; however, that date has been pushed back until the fall of 2015.[10] • Westinghouse Electric Corporation was the OEM.
USA	Indiana Michigan Power Company	DC Cook Unit 1	PWR	1,009	2006	Retrofit	Siemens Energy (2/23/05)[1]	$45 million	Replace the three low pressure turbine rotors on Cook Nuclear Plant Unit 1 during the fall 2006 refueling outage. The aerodynamic design of the new rotors is expected to increase the electrical output by an estimated 41 megawatts (MW) as well as prevent blade cracking, which has been a problem at some facilities.[11]	• On September 20, 2008, the unit was forced to go off line when the main turbine and generator were damaged by severe turbine vibrations caused by broken low pressure turbine blades. • Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process.[12] • GE Energy was the OEM.

9 "Siemens to refurbish and upgrade turbine island for the Watts Bar 2 Nuclear Power Plant" Energy Central News Article
10 "Watts Bar reactor delayed again" Times Daily News Article
11 "Turbine rotor replacement at AEP's Cook Nuclear Plant to improve performance and increase electrical output" Company News Release
12 Indiana Michigan Power Company 2010 10-K

Country	Operator	Facility	Type of Reactor	Capacity (MWe net)	Start Year	Type of Project	Contract Awarded & Signed	Contract Amount	Project Scope	Comments
USA	PPL	Susquehanna 1 & 2	BWR	1,176	2003 & 2008	Turbine Upgrade (2003) 2 BWR EPUs (2008)	Siemens Energy (5/1/2001)	The value of the 2001 contract was not released.	**Siemens Energy (2003):** The project is a turnkey installation of one high- pressure and three low-pressure rotors on each of two steam turbine generators at the two 1130-MW nuclear units. The eight rotors will be designed and manufactured in Siemens' plant in Mulheim, Germany. **Siemens Energy (2008):** Replace the high pressure (HP) turbine in units 1 & 2 which will add 67 MWE to Unit 1 and 60 MWE to Unit 2.	• In April of 2011 during a scheduled biennial refueling and maintenance outage for Unit 2, cracks were discovered on the blades during inspections of the low pressure turbines. • In response to the cracks found at Unit 2, Unit 1 was shut down on May 16th for a similar inspection during which comparable blade cracks were found in the low pressure turbines. • The estimate of the after-tax financial impact, including energy-sales margins and repair costs for both units, is $50 million to $60 million. • Unit 1 will undergo additional turbine inspections in October 2012. • Pending the outcome of the Unit 1 inspection, PPL will determine whether a similar inspection of the Unit 2 turbine is warranted. • GE Energy was the OEM.
USA	Nextra Energy Resources (FPL Energy)	Seabrook Unit 1	PWR	1,244	2009					• Seabrook replaced a low pressure rotor in the fall of 2009 when they shut down for refueling but they detected a torsional vibration issue when the plant went back online.[13] • The plant was shut down for repair in December 2009 and workers replaced the low-pressure turbine that was experiencing vibrations with another one on site.[14] • We believe that Siemens was responsible for the low pressure turbine retrofit which resulted in the reinstalling of the original GE (OEM) low pressure turbine.

13 "Seabrook nuke plant shuts down for repairs" Newburyport News
14 "Seabrook nuclear plant shut down for repair" Professional Reactor Operator Society

Modification: Power Range Neutron Monitoring System

Initial Scope and Estimate	• Nuclear Measurement Analysis and Control ("NUMAC") Power Range Neutron Monitor ("PRNM") installation and testing. • **$15.7 million**
Final Scope	• Fabrication and installation of PRNM System. • Upgrade of the plant process computer to a state of the art processing system. • Testing.
Milestones	• September 2007: MELLLA+ stability solution safety evaluation issued. • January 2008: Initiate procedure development. • February 2008: LAR Submittal. • May 2008: Installation of listening device to validate 30-year-old protocols. • July 2008: PRNM system fabrication completed. • August 2008: Successfully completed factory acceptance testing for both the PRNM system and the new plant process computer. • December 2008: Components delivered onsite. • 2009 Outage: Installation and preoperational testing complete.
Costs Incurred	• *Materials*: $4.7 million o Four NUMAC Average Power Range Monitor ("APRM") instruments o Two Rod Block Monitor ("RBM") instruments and a Two-out-of-Four logic interface to the Reactor Protection System ("RPS") • *Installation*: $3.5 million o Demolition of existing internal components from the Main Control Room panel C-37 (5 bays) and some from the C-05 panel. o Associated plant process computer interfaces installed and tested. o Installation of new fiber optic cables between control room panel C-05 and panel C-37, and between panel C-37 and the plant computer system. o Installation of new cables from the four existing and the four new Reactor Recirculation ("REC") flow transmitters in the Reactor Building to panel C-37. • *Design/Engineering*: $3.8 million o Design and engineering of new NUMAC PRNM, using the same in-core detectors as the old system, but replacing all of the electronics and associated power supplies. o Design of instrument rack. o Setpoint calculations. o New operating software installed as well as existing PPC software changes. • *Licensing-Related*: $0.2 million o PRNM required a separate License Amendment Request ("LAR"). • August 31, 2013: **$17.5 million**
WOs	10942850

Modification: Power Range Neutron Monitoring System

PRNM	2007	2008	2009	2010	2011	2013	Total
Licensing-Related	$ -	$ 261,188	$ (82,554)	$ -	$ -	$ -	$ 178,634
Design/Engineering	$ 525,547	$ 1,637,051	$ 1,660,699	$ (20,740)	$ 9,736	$ -	$ 3,812,293
Materials/Components	$ -	$ 130,933	$ 4,855,922	$ (296,648)	$ -	$ -	$ 4,690,207
Installation	$ -	$ 1,361	$ 3,505,546	$ -	$ -	$ -	$ 3,506,907
Common**	$ -	$ -	$ -	$ -	$ 5,287,956	$ -	$ 5,287,956
Xcel General Costs	$ 287	$ 2,246	$ 35,670	$ (4,437)	$ 26,569	$ -	$ 60,334
Total		**$ 2,032,779**	**$ 9,975,282**	**$ (321,824)**	**$ 5,324,261**	**$ -**	**$ 17,536,332**

* Child Work Orders - 10942850 - MNGP EPU-Power Range/Neutron Monitoring System

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Steam Dryer

Initial Scope and Estimate	• Equipment cost to replace steam dryer, replace instrumentation, and testing, excluding installation. • **$35.9 million**
Final Scope	• Replacement of steam dryer, excluding removal costs of existing steam dryer. • Installation of dryer instrumentation, excluding removal costs of existing instrumentation. • Evaluation of contingency modifications and evaluations. • Installation of cabling to support the new instrumentation system. • Testing.
Milestones	• January 2007: Initiated procurement of long lead items. • October 2007: Resolution of vibration data noise and implementation of contracts for load and finite element analysis. • 2007-2008: Evaluation of vibration data to determine if modification would be sufficient for plant operation. • Early 2008: Competitive solicitation for replacement of the steam dryer initiated. • August 2008: Replacement Steam Dryer estimated at $28 million. • April 2009: Westinghouse procurement agreement. • October 2009: Initial NPA including $28 million for (design work, detailed cost estimates, and manufacture and fabrication). • 2009-2010: Planning for removal and replacement of the steam dryer. • January 2011: Received steam dryer. • January 2011: Final steam dryer modification engineering change approved. • 2011 Outage: Third of four acoustic monitoring replacement test fit ups failed. • 2011 Outage: Installation of steam dryer and acoustic monitoring completed.

Costs Incurred	• *Installation*: $5.0 million
	  o Specialized craft labor for reinstallation of equipment.
	  o Steam dryer acoustic monitoring instrumentation.
	  o Testing of equipment including construction testing, pre-operational testing, and operational testing.
	• *Design/Engineering*: $10.7 million
	  o Design of steam dryer acoustic monitoring instrumentation.
	  o Vessel dimensional verification was time intensive.
	• *Equipment*: $20.1 million
	  o Equipment procured as planned.
	  o Added steam dryer instrumentation.
	• August 31, 2013: **$37.7 million**

WOs	10859413 (Steam Dryer Acoustic Monitoring); 11215274 (Steam Dryer Replacement)

Modification: Steam Dryer

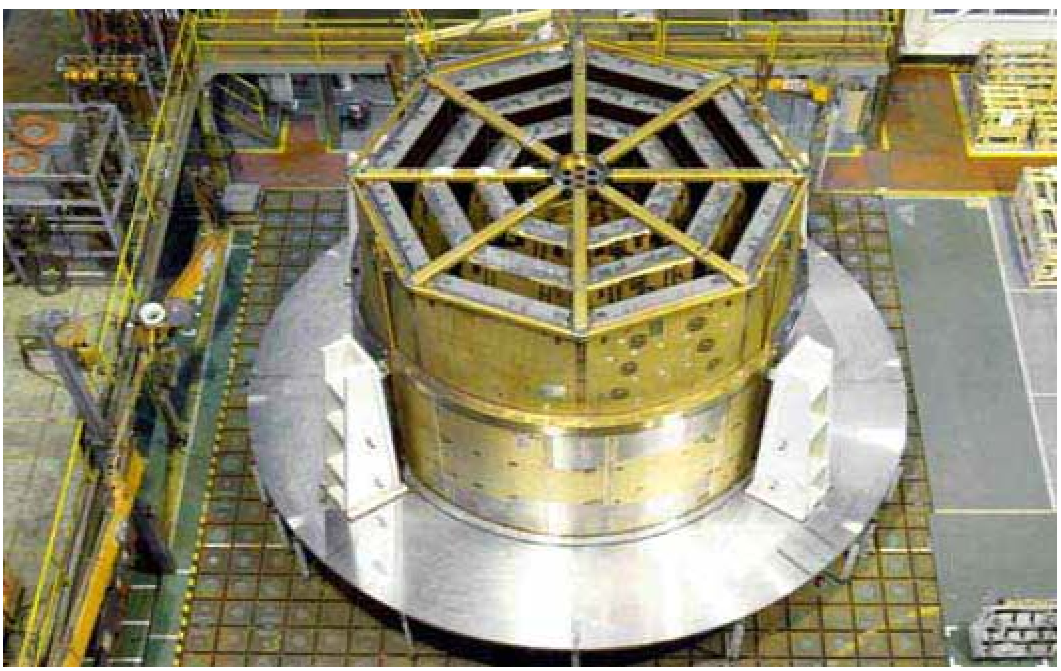
Steam Dryer	2006	2007	2008	2009	2010	2011	2012	Total
Licensing-Related	$ -	$ -	$ -	$ 752	$ 4,669	$ -	$ -	$ 5,421
Design/Engineering	$40,060	$3,461,044	$1,023,699	$ 4,092,816	$ 904,836	$ 1,052,519	$ 94,612	$ 10,669,588
Materials/Components	$ -	$ -	$ 1,754	$ 8,482,842	$3,305,022	$ 8,343,828	$(17,760)	$ 20,115,687
Installation	$ -	$ -	$ -	$ 397,726	$ 650,189	$ 3,908,510	$ 22,085	$ 4,978,510
Common**	$ -	$ -	$ -	$ -	$ -	$ 2,196,588	$ -	$ 2,196,588
Xcel General Costs	$ -	$ -	$ -	$ -	$ -	$ (306,481)	$ -	$ (306,481)
Total	**$40,060**	**$ 3,461,044**	**$ 1,025,454**	**$12,974,136**	**$ 4,864,717**	**$15,194,966**	**$ 98,937**	**$ 37,659,313**

* Child Work Orders 10859413 - MNGP EPU Steam Dryer Acoustic Monitoring, 11215274 - EPU Steam Dryer Replacement

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Steam Dryer

New Steam Dryer Installation



New Steam Dryer – Top View

Modification: Steam Dryer

New Steam Dryer Being Set Into Reactor Vessel

Modification: Condensate Demineralizer

Initial Scope and Estimate	• Replace five vessels with 78-inch diameter vessels designed for 70-inch elements (removal and installation costs – not including costs for floor shield plugs); • Upgrade pre-coat pumps; • Modify analog control system; • Vessel disposal to be done by Company; and • Testing. • **$18.0 million**
Final Scope	• Replace five vessels with 78-inch diameter vessels designed for 70-inch elements. • Relocate pre-coat skid. • Modify the tank vent system (T-33). • Add new air surge piping and larger capacity air surge tanks. • Modify holding pump design and backwash system. • Replace control panel with a digital, redundant, PLC system and add local motor control center. • Replace wiring and piping. • Install larger capacity holding pumps. • Install larger capacity resin traps. • Install larger capacity air surge and vent system. • Install air-operated valves. • Replace actuator for the condensate demineralizer bypass valve. • Testing.
Milestones	• September 2007: Decision to design complete system replacement not just vessel replacement. • March 2008: Identified replacement of control panel with digital system. • October 2008: Decision to move project to 2011 outage. • June 2009: Equipment received from vendor. • Early 2011: Final design turned over to another vendor for completion. • April 2011: Final condensate demineralizer modification engineering change approved. • 2011 Outage: Interferences previously unidentified due to limitations in access to the vaults. • 2011 Outage: T-33 backwash receiving tank and air surge tanks required in-outage design modifications. • 2011 Outage: Existing wiring as-found condition when covering removed during outage required replacement and repair. • 2011 Outage: Condensate demineralizer modification complete.

Costs Incurred	• *Design/Engineering*: $28.2 million
	  o Initial scope did not account for preexisting concerns related to operation of the system as well as chemistry – required to design new scope for modification.
	  o Design process consumed three years due to changes in scope of project, plant-specific information for design purposes, and plant engineering resources.
	  o Early 2011: Backwash receiving tank design issue identified in plans issued and work turned over to another vendor.
	  o In-outage design work necessary to address various piping and instrumentation

Modification: Condensate Demineralizer

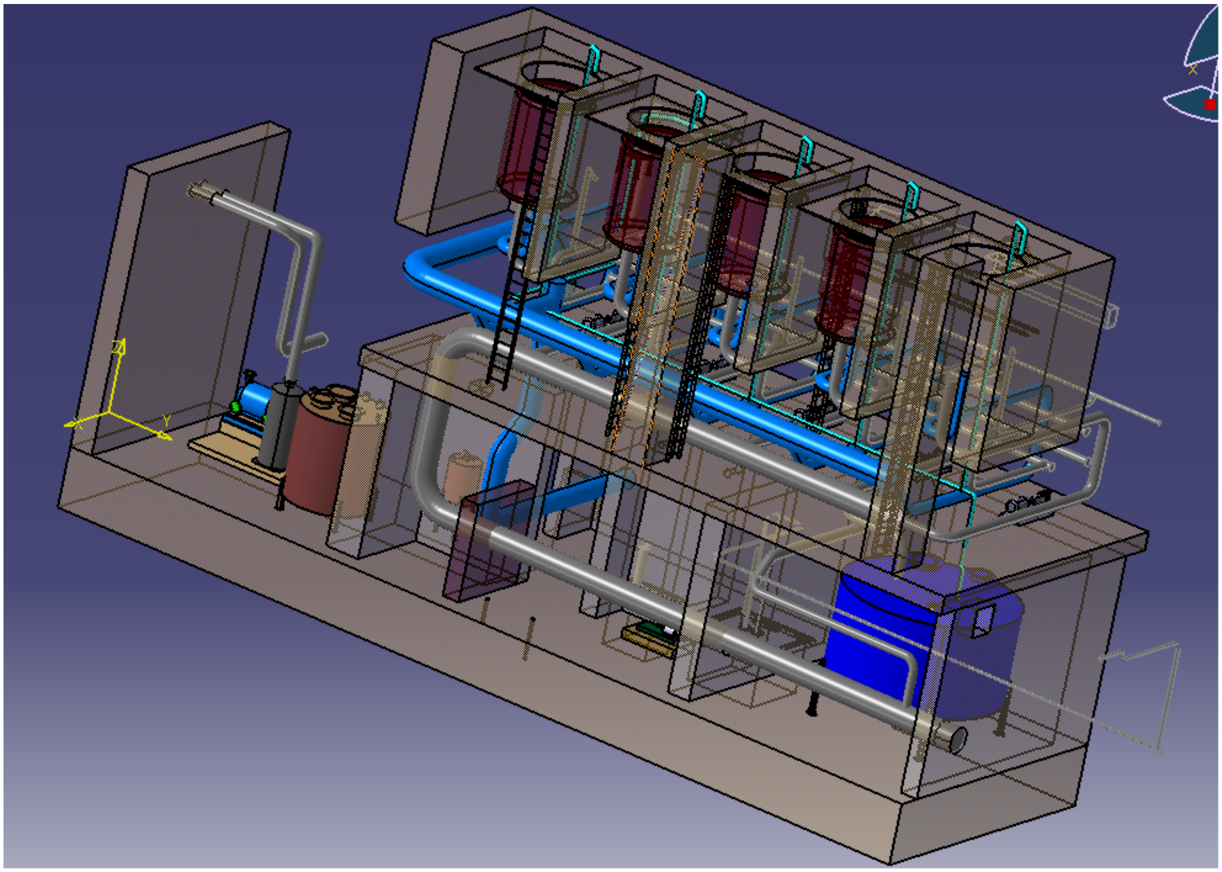
	challenges encountered after the tanks and vaults were exposed (drawings were not entirely accurate in final piping placements in the plant – these could not be verified until this outage and until this equipment was accessed). o Replacement of analog control panel ($96,000) with a digital redundant PLC system ($1,000,000). • *Materials*: $3.7 million o Piping, wiring, and control panel were all not included in the initial scope. o Majority of materials cost in common category. • *Installation*: $32.1 million o Underestimated installation costs associated with modification. o Interferences identified during installation due to lack of access availability. o Engineering and design not far enough along to allow meaningful inspection of area for interferences during 2009 outage. o Space limitations and radiological environment limited both the quantity of craft that could be in place at any one time and the amount of time labor could be in place. o Rewiring control panel and other wiring replacement. o Challenges during installation related to physical locations of equipment slightly different than drawings used for engineering. o Labor and time for replacement of air surge system lines from 2" to 3". o Testing method changed during outage to shorten overall installation/testing time frame – 10 day reduction in modification timeframe. o Testing of equipment including construction testing, pre-operational testing, and operational testing. • August 31, 2013: **$79.8 million**
WOs	11133705

Condensate Demineralizer	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$ -	$ -	$ -	$ 11,751	$ -	$ -	$ 11,751
Design/Engineering	$ 6,221	$ 970,311	$ 676,721	$ 26,481,894	$ 32,185	$ -	$ 28,167,332
Materials/Components	$ -	$ 1,839,896	$ 255,163	$ 1,564,319	$ 7,869	$ -	$ 3,667,248
Installation	$ -	$ 216,879	$ 1,207,334	$ 30,278,445	$ 391,270	$ -	$ 32,093,929
Common**	$ -	$ -	$ -	$ 15,358,744	$ -	$ -	$ 15,358,744
Xcel General Costs	$ 3	$ 8,501	$ 37,638	$ 422,668	$ 6,759	$ -	$ 475,570
Total	**$ 6,224**	**$ 3,035,588**	**$ 2,176,857**	**$ 74,117,821**	**$ 438,084**	**$ -**	**$ 79,774,573**

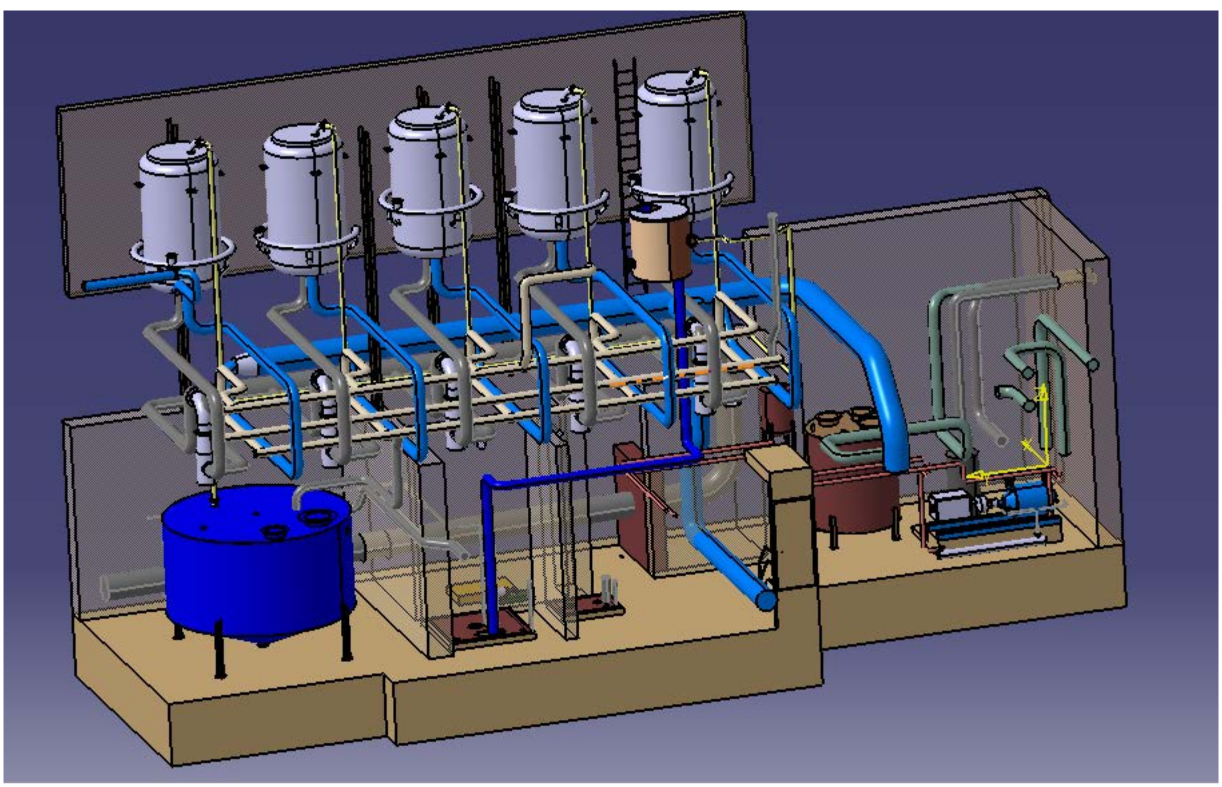
* Child Work Order - 11133705 - EPU Condensate Demin System Replacement

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Condensate Demineralizer

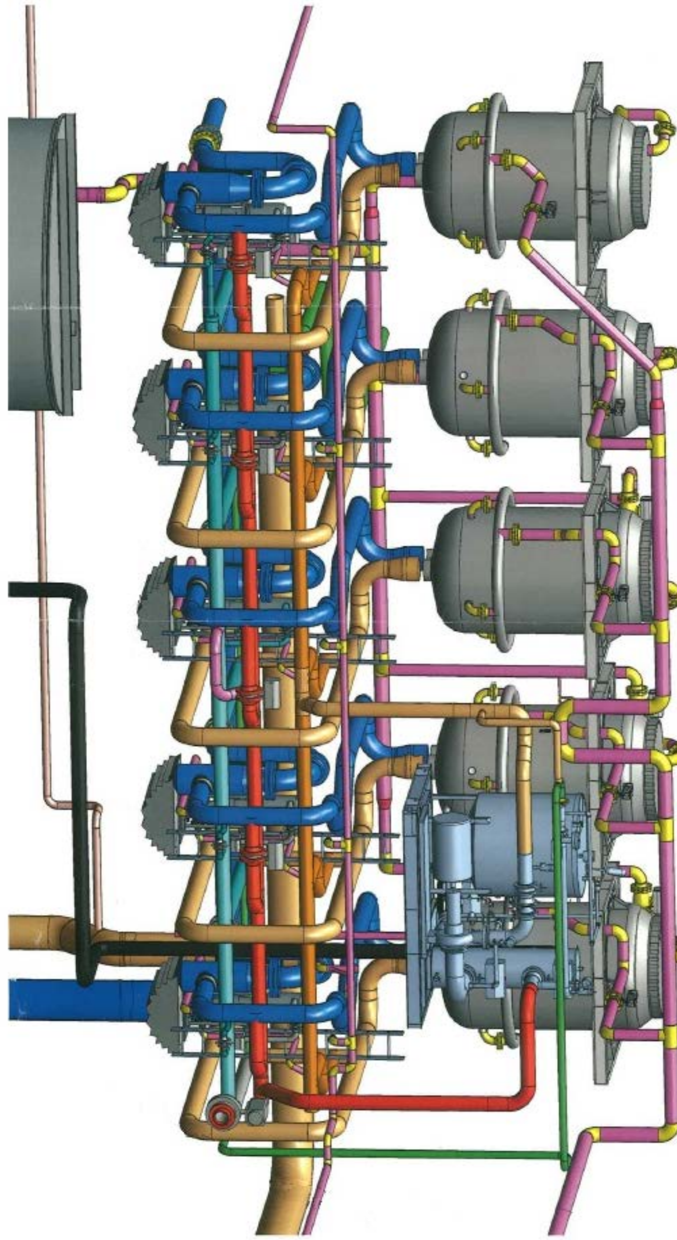


Condensate Demineralizer System View with Vaults in Place



Condensate Demineralizer System View with Vaults Removed for Illustrative Purposes Only

Modification: Condensate Demineralizer



Condensate Demineralizer Vessels
Piping Detail

Modification: Condensate Demineralizer

Welding Inside Condensate Demineralizer Vault

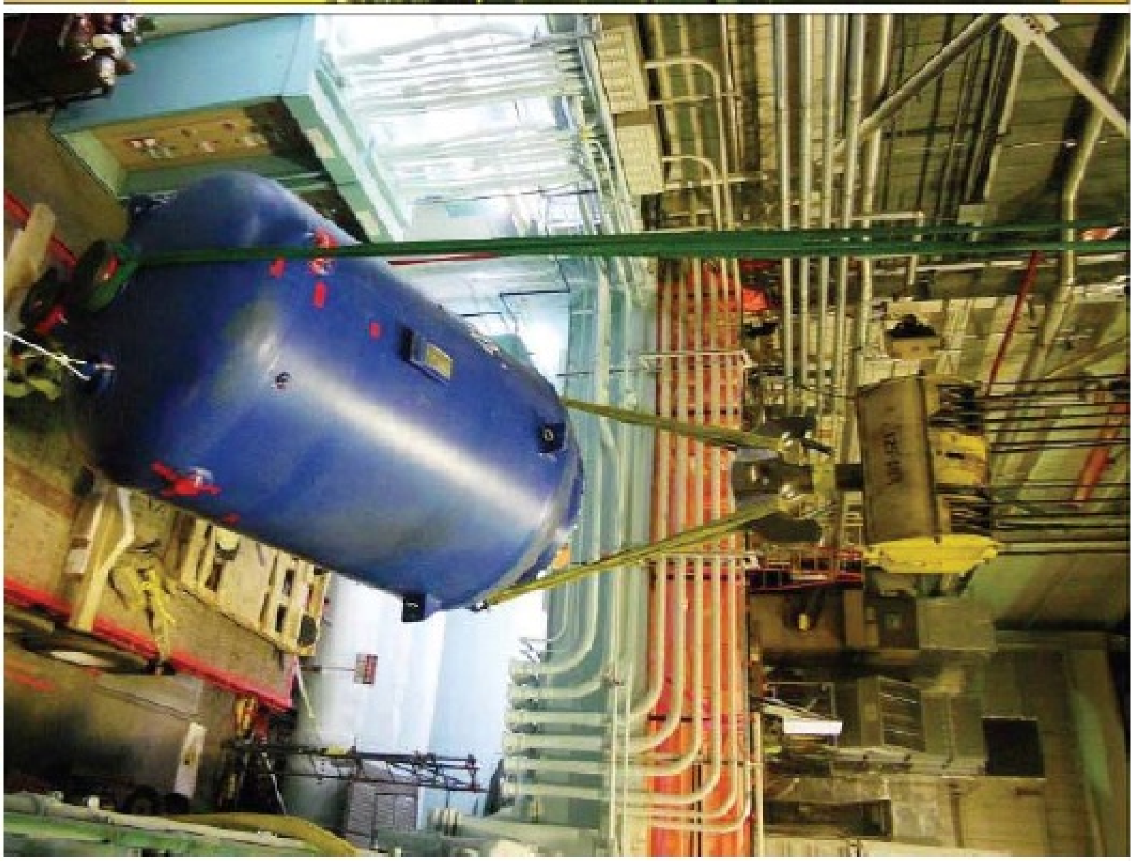
Welding of Condensate Demineralizer Vessel No. 4

Welding Inside Condensate Demineralizer Vault

Welding Condensate Demineralizer Piping
(Welder is Laying in Vault – Photo Taken from Above)

Modification: Condensate Demineralizer

Old Condensate Demineralizer Vessels Being Removed From Vault



New Condensate Demineralizer Vessel Being Prepared For Installation

Modification: Main Transformers

Initial Scope and Estimate	• Replacement of main transformer and testing. ($4.5 million) • Replacement of 1AR Transformer ($3.5 million) • **$16.9 million**
Final Scope	• Replacement of main power transformer. • Replacement of 1AR transformer. • Installation of main transformer fire detection and suppression. • Preparation of existing main power transformer as spare transformer. • Testing.
Milestones	• 2006: Transformer recommended but not required for EPU. • December 2006: Decision to replace main transformer. • April 2007: Tested main transformer and accelerated replacement to 2009 outage. • September 2007: Meeting to discuss electrical solutions, including 1AR transformer. • January 2008: Copper procurement issues for main power transformer – 2 month delay. • January 2008: Selected 1AR transformer vendor. • March 2008: 1AR purchase order issued. • 2008: Quality assurance identified vendor not performing welding according to approved welding plan and stop work order issued. • November 2008: Main power transformer weld defects identified during hydrostatic test. • December 2008: Main power transformer oil fails factory acceptance testing for particle presence and fails the induced voltage test. • December 2008: Decision to move main power transformer to 2011 due to failed induced voltage test. • 2009 Outage: Installation of 1AR modification completed. • May 2010: Main power transformer encountered en-route transportation issues. • May 2010: Main power transformer arrives onsite. • July 2010: Main power transformer repairs and testing complete. • April 2011: Final main power transformer modification engineering change approved. • 2011 Outage: Main power transformer installed and main transformer modification completed.

Costs Incurred	• *Materials*: $12.1 million
	  o Advanced materials from 2011 to 2009 outage.
	  o 2009: Failed factory acceptance testing and did not pass hydrostatic test, requiring refabrication.
	  o Added 1AR transformer to scope.
	  o Main transformer encountered en-route transportation issues that required Company oversight to repair.
	• *Installation*: $4.5 million
	  o Transformers were designed and fabricated to existing equipment footprint.
	  o Special hauling and transportation precautions to deliver main transformer to

Modification: Main Transformers

	pad including modifications to security fence. o Construction of temporary storage pad. o Refurbishment of existing main transformer for use as spare. o GE warranted cooling fan replacement. o Testing of equipment including construction testing, pre-operational testing, and operational testing. • *Design/Engineering*: $4.3 million o Evaluation of heavy haul route not initially anticipated. o 1AR addition to the scope of the modification. • August 31, 2013: **$29.9 million**
WOs	10735617; 10943007

Transformer	2005	2006	2007	2008	2009	2010	2011	2012	Total
Licensing-Related	$ -	$ -	$ -	$ -	$ -	$ 20,692	$ 79,523	$ 6,240	$ 106,456
Design/Engineering	$ -	$ 26,890	$ 14,775	$ 803,641	$ 1,711,213	$ 300,660	$ 1,418,625	$ 44,538	$ 4,320,341
Materials/Components	$ -	$ -	$ (21,569)	$ 34,226	$ 9,304,208	$ 2,561,594	$ 188,850	$ 541	$ 12,067,850
Installation	$ -	$ -	$ -	$ -	$ 1,300,783	$ 494,537	$ 2,709,516	$ 1,147	$ 4,505,983
Common**	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,643,173	$ -	$ 8,643,173
Xcel General Costs	$ 13,599	$ 40,264	$ (191)	$ 1,008	$ 62,687	$ 68,533	$ 80,458	$ (6,182)	$ 260,176
Total	**$ 13,599**	**$ 67,153**	**$ (6,985)**	**$ 838,875**	**$ 12,378,890**	**$ 3,446,016**	**$ 13,120,145**	**$ 46,285**	**$ 29,903,979**

* Child Work Orders - 10943007 - MNGP EPU Main Power Transformer, 10735617 - MNGP EPU-1AR Transformer Replacement

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Main Transformers

New Main Power Transformer (790,000 lbs)

Main Power Transformer Arrival Onsite

Modification: Main Transformers

Existing 1AR Transformer Before Removal

New 1AR Transformer

Modification: Feedwater Heaters

Initial Scope and Estimate	• Feedwater heaters:
	  o Rerate 12, 14, and 15 feedwater heaters,
	  o Rerate dump and drain piping, and
	  o Rerate drain coolers and install bypass;
	• Replace Cross-Around Relief Valves ("CARV") – piping and setpoints;
	• Modify navy nipples;
	• Modify Moisture Separator Drain Tank ("MSDT") with condensate injection; and
	• Testing.
	• **$37.0 million**

Final Scope	• Replace and rerate feedwater heaters:
	  o Replace six feedwater heaters (13 A/B, 14 A/B, 15 A/B);
	  o Replace discharge nozzles on three of four low pressure feedwater heaters (11 A/B, 12 A) with larger diameter nozzles;
	  o Replace 400 feet of dump and drain insulated piping and remove asbestos insulation from existing piping;
	  o Install two four ton jib cranes;
	  o Replace dump and drain venting and valves; and
	  o Replace drain coolers.
	• Replace CARV piping and establish new setpoints.
	• Enlarge Turbine Floor #2 Hatch.
	• Reinforcement of Turbine Floor 951'.
	• Remove and cap main steam thermowell.
	• Modify main steam Navy Nipples.
	• Modify MSDT.
	• Replace Feedwater Flow Transmitters.
	• Testing.

Milestones	• 2007: Decision to replace six feedwater heaters instead of rerates. • 2009 Outage: 14 of 18 dump and drain valves replaced, CARV piping replaced. • June 2009: Fabrication (13 A/B, 14 A/B, and 15 A/B) awarded. • October 2010: Stop Work order issued (tube denting). • November 2010: Stop Work order lifted. • End of 2010: Deferral of 13 A/B replacement to 2013 Outage. • March 2011: Feedwater heaters delivered (14 A/B and 15 A/B arrived but 13 A/B delivered post-outage). • March 2011: Final feedwater heater, moisture separator drain tank, turbine floor, and jib crane modification engineering changes approved. • April 2011: Final dump and drain piping and valve modification engineering changes approved. • 2011 Outage: Replacement of 14 A/B and 15 A/B feedwater heaters, CARV (except for setpoints), MSDT condensate injection (partial), 180 feet of low pressure heating drain piping, and remaining control valves; reinforcement of turbine floor 951'. • August 2011: Main steam thermowell modification engineering change approved. • 2013 Outage: Removal and cap of main steam thermowell, CARV setpoints, enlarge turbine deck hatch #2, modify main steam navy nipples, replacement of 13 A/B

Modification: Feedwater Heaters

	feedwater heaters, 11 A/B and 12 A nozzle installation, and complete replacement of remaining piping.
Costs Incurred	• *Materials*: \$3.0 million o 2007: \$10 million increase in equipment for decision to replace heaters 13 A/B, 14 A/B, and 15 A/B series heaters instead of rerating four feedwater heaters. (does not include removal or installation costs). o 2008: Decision to replace CARV piping in addition to valves. o 2010-2011: Fabrication and delivery challenges. Vendor, during fabrication, dropped and damaged baskets for which there were insufficient spares on hand and new baskets had to be fabricated. Issues with bundle insertion (13 A, October 29, 2010-Stop Work Order). o March 2011: 14 A/B and 15 A/B heaters arrived on site with defects (welding slag and moisture) that required time and effort to correct and extended the outage. o 2011-March 2013: Storage of 13 A/B heaters onsite. • *Installation:* \$59.5 million o 2011 & 2013: \$30 million for replacement of 400 feet of dump and drain piping (asbestos abatement of existing piping to be removed). o 2011 & 2013: Turbine floor hatch enlargement and reinforcement of turbine floor (approximately \$6 million in installation and analysis). o 2011 & 2013: Non-Destructive Evaluation of welds. On-site required x-ray radiograph necessitating removal of all personnel from building during testing and time for film to develop. o 2013: 12 A drain nozzle installed at wrong orientation requiring follow-on modification. o 2013: \$1.1 million in underestimated electrical work. o 2013: \$2.9 million in scope changes identified during the outage for unanticipated and unpredictable engineering modifications needed to accommodate replacement of feedwater heaters. o 2013: Space limitations affected removal and installation of the 13 A/B feedwater heaters, including 22 interferences encountered during removal. o Testing of equipment including construction testing, pre-operational testing, and operational testing. • *Design/Engineering*: \$26.1 million o Multiple contractors for engineering and design of feedwater heaters, piping, loading and support. o New piping design for CARVs. o Design changes to feedwater heater piping to avoid interferences requiring additional analysis for strain and supports. o Reinforcement of turbine floor loading with increased 14 A/B and 15 A/B weight and enlargement of turbine floor hatch to 13 A/B. o Design revisions to account for facility specifications (generic piping as-built model vs. MNGP-specific model). • August 31, 2013: **\$114.9 million**
WOs	11133719 (D&D Valves); 11133713 (CARV); 11284286 (D&D Piping);

Modification: Feedwater Heaters

	11286961; 11638897; 11757884; 11842626 (FWHs, Cranes; Navy Nipple, and MS Thermowell); 11286981 (MSDT); 11376086 (Drain Coolers); 11133856 (Feedwater Flow Transmitters); 11376103 (Turbine Floor)

Feedwater Heater	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$ -	$ 3,100	$ -	$ 3,850	$ -	$ -	$ 6,950
Design/Engineering	$ 111,266	$ 2,398,605	$ 1,840,595	$ 19,742,184	$ 451,533	$ 1,561,561	$ 26,105,744
Materials/Components	$ 26,855	$ 1,124,177	$ (4,274,838)	$ 3,854,511	$ 1,532,069	$ 750,736	$ 3,013,511
Installation	$ -	$ 8,861,196	$ 719,803	$ 24,492,226	$ 1,864,078	$ 23,531,639	$ 59,468,942
Common**	$ -	$ -	$ -	$ 12,016,229	$ 9,362,294	$ 4,433,901	$ 25,812,425
Xcel General Costs	$ 167	$ 22,362	$ (4,989)	$ 436,028	$ 9,470	$ 74,430	537,468
Total	**$ 138,288**	**$ 12,409,440**	**$ (1,719,429)**	**$ 60,545,029**	**$ 13,219,445**	**$ 30,352,267**	**$ 114,945,040**

* Child Work Order - 11638897 - MNGP EPU 13 A&B Feed Wtr Heater, 11842626 - EPU 13 A & 13B Feed Water Heater Repair, 11133719 - EPU FW Heater Drain & Dump Valve, 11284286 - MNGP EPU Rpl 4 FW Drain & Dump, 11757884 - MNGP Replc 14/15 FW, 11286961 - MNGP EPU Rpl 14&15 A/B FW Heater, 11133856 - EPU FW Flow Transmitters/PC In, 11133713 - EPU CARV Replacement, 11286981 - Moisture Separator Drain Tank, 11376086 - Drain Coolers, 11376103 - Turbine Floor 951'

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Feedwater Heaters

Arrival of Feedwater Heater 15A for Installation

Feedwater Heater 15A on Turbine Deck

Modification: Reactor Feed Pumps and Motors

Initial Scope and Estimate	• Supplemental reactor feed pump; • Reactor feed pump motor; and • Testing. • **$27.8 million**
Final Scope	• Replace two pumps and motors, including new foundations. • Replace discharge piping with larger diameter piping. • Install four five ton jib cranes. • Replace feedwater regulating valves and controls. • Relocating emergency service water lines. • Replace minimum flow valves. • Replace auxiliary instrumentation. • Demolition of existing equipment in reactor feed pump and motor room. • Relocation of area cooling. • Modifications and replacements to vent, drain, bypass, hydrogen injection, pump warm-up, and service water piping. • Testing.
Milestones	• April 2007: Company notifies GE of its decision to replace reactor feed pumps instead of adding supplemental pump. • February 2008: Decision to move to 2011 outage. • August 2010: Decision to move replacement to mid-2011 outage. • October 2010: One motor failed motor vendor factory voltage specification test. Motor vendor identified solution to add iron to stator. • December 2010: Pump fails first test at pump vendor. • August 2011: Decision to move replacement to mid-cycle 2012 outage. • November 2011: Decision to move replacement to 2013 outage. • December 2011: Final engineering change for modification approved. • Mid-2012: Motor shipped to pump vendor's facility for testing. • 2012: Motor heating load increased with added iron – HVAC system capable of handling. • Fall-2012: Second pump test at pump vendor fails, requiring further pump modifications. • 2013: Pump and motor shipped from pump vendor to MNGP. • 2013 Outage: Reactor feed pumps and motors replaced.
Costs Incurred	• *Design/Engineering*: $25.2 million o Evolution of regulatory expectations and industry experience resulted in escalation of testing standards. o Replumbing and identification of new piping paths and connection schemes. o Independent review of piping changes supports during the design process. o Personnel presence required at motor and pump fabricators to verify modifications to ensure factory acceptance testing complied with specifications.

Modification: Reactor Feed Pumps and Motors

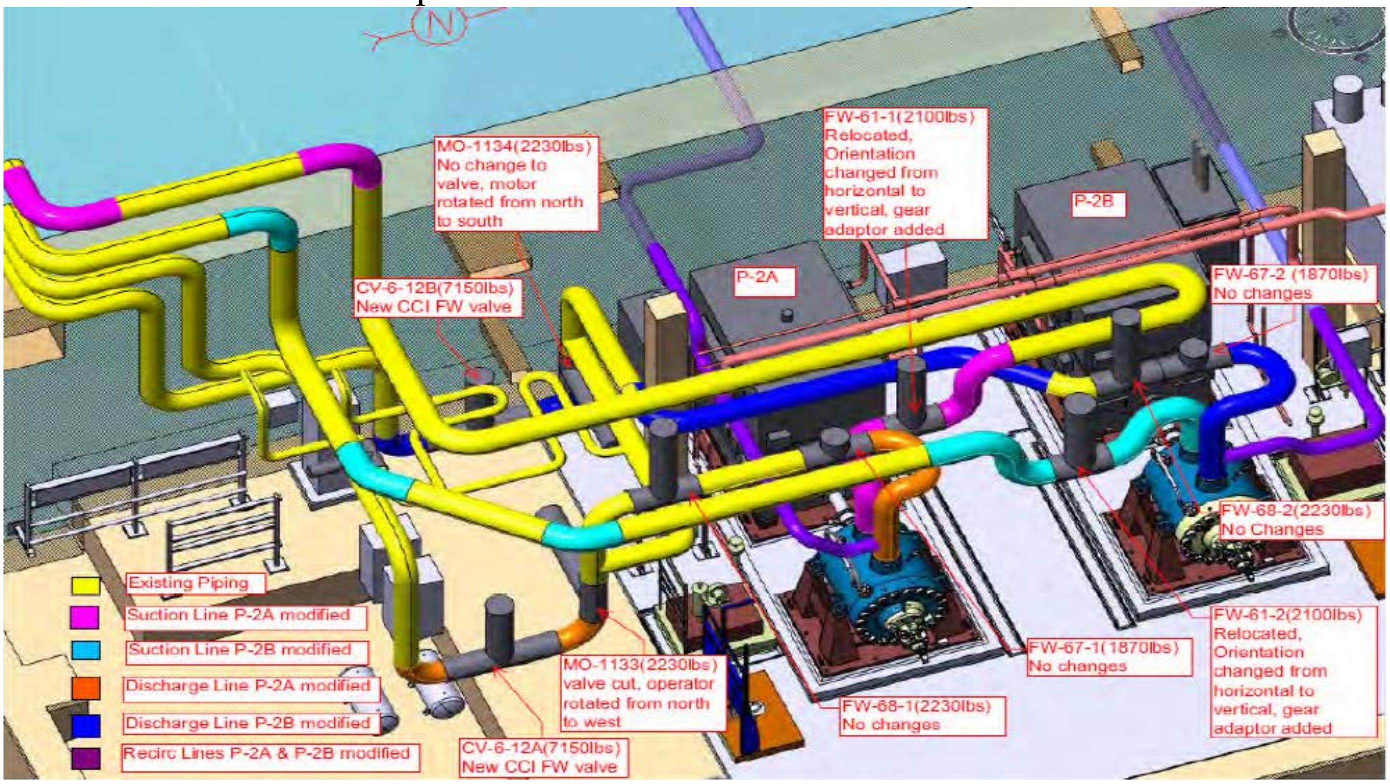
	• *Installation*: $54.2 million o Space limitations affected ability to perform replacement work in the time allotted during the outage. Craft labor costs increased (Underestimated labor required at 35,000 hours). o Installation timeline exceeded estimates by approximately 40 days. o Mylar remaining in motor after shipment from the motor manufacturer to the pump manufacturer damaged the motor bearings and required personnel monitoring of additional testing prior to pump testing at pump manufacturer. o Significant replumbing of the piping feeding to and discharging from pumps, some of which was not discoverable until demolition of existing surrounding equipment. o New foundations required to support equipment. o Demolition of pump foundations, existing piping, pumps, and instrument racks. o Testing of equipment including construction testing, pre-operational testing, and operational testing. • *Materials*: $3.7 million o Cost of two new pumps and motors to operate on 13.8 kV. o Associated piping, instrumentation, valves, and controls. • August 31, 2013: **$92.2 million**
WOs	11286955

Reactor Feed Pumps & Motors	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Design/Engineering	$ -	$ 79,334	$ 4,137,932	$ 12,687,338	$ 3,390,334	$ 4,925,807	$ 25,220,745
Materials/Components	$ -	$ -	$ 370,213	$ 747,618	$ 641,635	$ 1,966,609	$ 3,726,075
Installation	$ -	$ 8,017	$ 1,037,213	$ 8,116,451	$ 8,226,721	$ 36,773,035	$ 54,161,437
Common	$ -	$ -	$ -	$ -	$ -	$ 8,636,856	$ 8,636,856
Xcel General Costs	$ -	$ 222	$ 115,634	$ 237,372	$ 38,552	$ 26,021	$ 417,801
Total	**$ -**	**$ 87,573**	**$ 5,660,992**	**$ 21,788,780**	**$ 12,297,241**	**$ 52,328,329**	**$ 92,162,915**

* Child Work Order 11286955 MNGP EPU Replacement FW Pump

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: Reactor Feed Pumps and Motors



Reactor Feed Pump Modification

Modification: Condensate Pumps and Motors

Initial Scope and Estimate	• Replace condensate pump internals; • Replace condensate pump motors; and • Testing. • **$3.2 million**
Final Scope	• Replace condensate pump and motor (not just internals of pump). • Replace condensate pump and motor auxiliaries. • Replace area HVAC for condensate pump motors. • Increase condenser hotwell level. • Testing.
Milestones	• Late 2007: Decision to further analyze replacing condensate pumps and motors in response to overall analysis and decision to replace reactor feed pumps. • February 2008: Decision to move to 2011 outage. • 2009: Determined that Net Positive Suction Head ("NPSH") required was higher than the NPSH available. • May 2010: Initial HVAC evaluation for motors. • August 2010: Decision to move replacement to mid-2011 outage. • October 2010: One motor failed factory voltage specification test. Vendor identified solution to add iron to stator. • December 2010: Pump failed first test. • January 2011: Final pump and motor engineering change approved. • August 2011: Pump re-test satisfactory result. Condensate pump motor damaged by motor vendor – repair estimated to take 10 weeks. • August 2011: Decision to move replacement to mid-cycle 2012 outage. • November 2011: Decision to move replacement to 2013 outage. • September 2011: Motor heating load increased with added iron – required further design and engineering of HVAC cooling system. • Fall-2012: Second pump test at pump vendor failed, requiring further pump modifications. • 2013: Pump and motor shipped from pump vendor to MNGP. • February 2013: Final HVAC engineering change approved. • 2013 Outage: Condensate pumps and motors replaced.
Costs Incurred	• *Installation*: $11.1 million o Personnel presence required at motor and pump fabricators to verify modifications to equipment to meet specifications. o Labor to raise level instrumentation to achieve NPSH. o Vibrations experienced on condensate minimum flow line after installation resulted in redesign of the valve actuators and required repairs. o Additional work necessary to install the HVAC cooling equipment to resolve the motor heating load concerns. o Testing of equipment including construction testing, pre-operational testing,

Modification: Condensate Pumps and Motors

	and operational testing.
	• *Design/Engineering*: $5.7 million
	  o Decision to replace reactor feed pumps drove the scope of condensate pumps from replacement of pump internals to replacement of the pump.
	  o Change in design vendor related to HVAC cooling design.
	  o Redesign of pipe supports after identification of vibrations.
	  o Design and engineering to resolve concerns with NPSH.
	  o Equipment is primarily standard and like-for-like with exception of changing power source delivery from 4.16 kV to 13.8 kV.
	  o Overall equipment and instrumentation configuration was predictable.
	• *Materials*: $2.9 million
	  o Cost of two new pumps and motors to operate on 13.8 kV.
	  o HVAC air handling units and ductwork.
	• 2007: Added approximately $10 million to replace pump instead of internals only
	• August 31, 2013: **$21.9 million**

WOs	10943052; 11845189

Condensate Pumps & Motors	2008	2009	2010	2011	2012	2013	Total
Licensing-Related	$ -	$ -	$ 3,463	$ -	$ -	$ 2,206	$ 5,669
Design/Engineering	$ 310	$ 299,746	$ 750,704	$ 2,225,993	$ 646,802	$ 1,822,771	$ 5,746,325
Materials/Components	$ -	$ 535,229	$ 1,641,006	$ 20,821	$ 55,553	$ 615,802	$ 2,868,410
Installation	$ -	$ 7,447	$ 190,611	$ 1,100,697	$ 1,689,147	$ 8,128,314	$ 11,116,216
Common**	$ -	$ -	$ -	$ -	$ -	$ 2,025,947	$ 2,025,947
Xcel General Costs	$ -	$ -	$ 65,833	$ 32,011	$ 10,866	$ (12,614)	$ 96,096
Total	**$ 310**	**$ 842,422**	**$ 2,651,616**	**$ 3,379,522**	**$ 2,402,367**	**$ 12,582,426**	**$ 21,858,664**

* Child Work Orders - 10943052 - MNGP EPU Condensate Impeller/P, 11845189 - MNGP EPU Condensate Impeller Repair

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Modification: 13.8 kV System

Initial Scope and Estimate	• Replacement of 1R and 2R transformers; • Installation of switchgear busses & load centers; • Installation of cabling and bus duct; • Removal and installation of reactor recirculation motor-generator ("RRMG"); • Replacement of breaker maintenance facility; • Program management and engineering support; and • Testing. • **$20.9 million**
Final Scope	• Replacement of existing 1R and 2R transformers. • Installation of fire detection and suppression systems in the 1R and 2R transformer bays. • Installation of new 15 kV power cables and raceways with associated supports from the 1R and 2R transformers to busses 11 and 12. • Demolition of 4 kV busses 11 and 12. • Installation of new control cable and raceways with associated supports. • Demolition and decontamination of existing Hot Shop. • Erection of new 13.8 kV switchgear rooms in previous Hot Shop room. • Installation of two new 13.8 kV switchgear lineups. • Installation of HVAC for the new switchgear rooms. • Installation of fire detection system in switchgear rooms. • Installation of vertical lift from 911' to 931' in turbine building. • Installation of new Hot Shop in Radwaste shipping building (including HVAC). • Relocation of rigging storage cages to Reactor Building 985' elevation. • Removal and installation of the RRMG drive motors. • Installation of new 15 kV power cables to reactor feed pumps, condensate pumps, and reactor recirculation motor-generator drive motors. • Demolition of secondary containment at RRMG set room to facilitate removal and installation of motors. • Installation of digital process computer system and associated system points for six new associated equipment systems, 1R and 2R transformers, and new 13.8 kV busses 11 & 12. • Removal of the switchyard current limiting protector and associated disconnects. • Removal of breaker 3N5. • Automatic tap changers were installed on 1R and 2R transformers (old 1R had fixed tap changers). • Modify cable feeder from 2RS to 2R. • Testing.
Milestones	• August 2007: Determination that 4 kV system upgrades may not be feasible as planned (given larger replacement reactor feed pumps). • September 2007: Electrical Summit to evaluate options for accommodating pumps and other equipment. • December 2007: Decision made to construct 13.8 kV. • December 2007: Decision made to add larger condensate pump motors to 13.8 kV. • 2009: Award modification to vendors. • 2009: Hot Shop identified as location for 13.8 kV room and final transformer

Modification: 13.8 kV System

	configuration identified. • May 2010: MG Motor modification approved. • August 2010: Decision to push to mid-cycle 2011. • Mid 2011: Decision to push to fall 2012. • September 2011: Final engineering change for 13.8 kV modification approved. • Late 2011: Decision to push to 2013 outage. • 2011 Outage: Installed some raceway supports and switchgear to prepare for 2013 conduit install. • Fall 2011: Hot Shop construction completed. • June 2013: 13.8 kV supply breaker 152-107 electrical fault to bus 11. • 2013 Outage: Installation of remaining 13.8 kV project modification work including installation of over 14 miles of cable, nearly three miles of raceways, and over 6,800 cable terminations.

Costs Incurred	• December 2011: Additional $35.7 million for 13.8 kV for work through 2013.
	• December 2012: NPA for $105.2 million for total work
	• *Design/Engineering*: $23.9 million
	  o 4 kV system to remain intact for service to other equipment in plant/13.8 kV to be installed to certain equipment
	  o Original engineering design flaw of switchgear room location resulted in seeking new designer.
	  o Design given to Sargent & Lundy
	  o 2011: Relocate Hot Shop and modify Hot Shop location to accommodate 13.8 kV busses.
	  o Design HVAC to support clean room conditions for two, independently housed, 13.8 kV breaker busses.
	  o Significant lead times required budget approvals before design and engineering work was completed.
	  o Engineer placement of five miles of conduit, including concrete boring from busses to motors.
	• *Materials*: $10.3 million
	  o July 28, 2009: Stop work order to transformer welding vendor.
	  o October 27, 2009: Stop work order lifted.
	  o December 17, 2009: Brought in fabricator as direct vendor to streamline transformer fabrication oversight.
	• *Installation*: $73.2 million
	  o Severely underestimated scope and difficulty of installation work scope. Final scope and design plans not complete until December 2012.
	  o Cable tension limits reached during pulling; devised central pulling in both transformer and breaker bus directions.
	  o December 2012: Revised installation estimate to over 59,000 hours (2,491 equivalent days) for pre-outage and outage 13.8 kV installation (90 days of pre-outage and 62 days of outage were identified).
	  o Bus ducts and cable trays to carry conductor from transformers to 13.8 kV room and to pump motors and equipment.
	  o Demolition and decontamination of existing Hot Shop and relocation/construction of new Hot Shop in radwaste building.
	  o Construction of clean room in former Hot Shop location along with fire wall

Modification: 13.8 kV System

	between busses. o Installation of over 14 miles of cable, nearly three miles of raceways, and over 6,800 cable terminations. Cable was pulled in segments of approximately 20 feet to minimize risk of overtension, which could damage the cable. o Extensive testing (three weeks) of transformers, switchgear, and electrical connections includes construction testing, pre-operational testing, and operational testing. • August 31, 2013: **$119.5 million**
WOs	11257804

13.8 kV Distribution	2009	2010	2011	2012	2013	Total
Licensing-Related	$ -	$ 28,695	$ 5,403	$ 17,028	$ 162,852	$ 213,978
Design/Engineering	$ 3,193,526	$ 5,923,429	$ 5,861,220	$ 2,490,157	$ 6,420,101	$ 23,888,434
Materials/Components	$ 503,464	$ 3,552,936	$ 3,457,875	$ 359,637	$ 2,463,486	$ 10,337,397
Installation	$ 21,590	$ 2,186,276	$ 10,044,742	$ 12,869,076	$ 48,080,556	$ 73,202,240
Common	$ -	$ -	$ (0)	$ -	$ 11,189,453	$ 11,189,453
Xcel General Costs	$ 7,073	$ 288,660	$ 227,613	$ 52,050	$ 133,603	$ 708,999
Total	**$ 3,725,653**	**$ 11,979,995**	**$ 19,596,852**	**$ 15,787,949**	**$ 68,450,052**	**$ 119,540,502**

* Child Work Order - 11257804 - MNGP EPU 13.8kV Distribution

** "Common" represents the allocated portion of the $103 million of Work Order 10435578. See Exhibit __ (SLW-1), Schedule 3.

Existing 1R Transformer Removal

Modification: 13.8 kV System

Disconnecting 1R Transformer

Loading Existing 1R Transformer

Modification: 13.8 kV System

Hauling Existing 1R Transformer

New 1R and 2R Transformers Onsite

Modification: 13.8 kV System

Installation of New 1R Transformer

1R Transformer Oil Filling

Modification: 13.8 kV System

Scaffolding for 13.8 kV Raceway Installation in Turbine Building

13.8 kV Power and Control Cables in Conduits and Raceways

Modification: 13.8 kV System

Scaffolding to Area Above 4 kV Equipment for 13.8 kV Conduit Installation

Modification: 13.8 kV System

Scaffolding to Protect 4 kV Equipment During 13.8 kV Installation

Unavoidable LCM and Avoidable EPU Costs

This Schedule provides a narrative description of the process used to determine the unavoidable LCM costs and the avoidable EPU costs. This narrative description, along with the next schedule which provides the outcomes of the analysis, constitute Xcel Energy's effort to provide the Commission with information to separate the LCM and EPU costs..

We evaluated each LCM/EPU modification (at the child work order level) to assess whether that modification was required in the absence of pursuing an EPU at Monticello. Based on the information available today, this evaluation determined what work was needed on existing equipment to ensure the plant would operate reliably through 2030. We also considered whether unique equipment or implementation was specifically required to support EPU conditions. If we determined different equipment was required, we estimated the incremental cost of such equipment using the the ratio of the uprate capacity (71 MWe) to the pre-EPU output of the plant (585 MWe) or 12.1 percent.

These evaluations identified the costs that were either unavoidable LCM (that were required absent an uprate), or avoidable EPU (those only needed to support an uprate). For those items with a combination of LCM and EPU costs, we relied on the judgment of the Monticello engineering to apportion the costs between unavoidable LCM and avoidable EPU based on the nature of the vendor services necessary to complete each modification. Finally, we allocated the Project's common costs on a pro rata basis to the two LCM and EPU cost categories.

This analysis provides a reasonable basis to segregate the LCM and EPU costs based on our best engineering judgment and information that we know today. This analysis is similar to the analysis we conducted in connection with the cancelation of the EPU program at our Prairie Island nuclear plant. That analysis was performed in a very similar manner in that we sought to determine what work was required to move forward to operate through the remaining life of the plant. However, several key distinctions exist between the two analyses. The principle distinctions between the analyses performed for the cancellation of the Prairie Island EPU program and the Monticello LCM/EPU Program are:

- <u>Timing of the analyses</u>
    - The analysis in this Docket was undertaken after the work was completed and based on information we knew following completion of the work, including the condition of components found during the project.

- The Prairie Island LCM/EPU analysis was completed prior to conducting the physical work, and thus, without the specific knowledge of potential as-found conditions that may be discovered as we complete the work.

- <u>As-Found Conditions</u>
  - The Monticello plant was found to have more systems that needed work than we expected. This plant was originally constructed in the 1960s and the age and condition of many of its components contributed to the assessment of the level of LCM work that was needed.
  - Some significant LCM activities have already occurred at Prairie Island, with the replacement of the steam generator work was done with one unit and is ongoing with the other.

- <u>Type of facility</u>
  - Prairie Island and Monticello are different types of reactors. The Prairie Island units are both pressurized water reactors and the Monticello unit is a boiling water reactor.
  - The differences in the design of these facilities require different investments at different points in time.

Based on the analysis that we conducted, we are providing the following total amounts for the unavoidable LCM and avoidable EPU costs and the amounts associated with each of the the major modifications. The Table also shows the costs associated with the LCM/EPU Program using the split that was used in the 2008 certificate of need proceeding.

LCM/EPU Split

LCM/EPU Split	LCM Capital $million	EPU Capital $million	Total Capital $million
Avoidable EPU Scenario	$518.9 (78.0%)	$146 (22.0%)	$665 (100%)

Unavoidable LCM/Avoidable EPU by Major Modification

Modification	Aggregate Cost	Unavoidable LCM (78.0%)	Avoidable EPU (22.0%)
HP Turbine	$57.3 million	$37.9 million	$2.3 million
	The existing turbine required extensive maintenance or replacement to run through the end of the operating license. Replacing with like or larger was comparable cost. Turbine vibration monitoring equipment required replacement to ensure continued station operation but was more complicated and aportion was allocated to EPU.		
PRNM	$17.5 million	$12.2 million	--
	The PRNM system would have eventually been needed due to aging and lack of spare parts and did not require any additional equipment or analysis related to the EPU.		
Steam Dryer	$37.7 million	$30.4 million	$5.1 million
	The steam dryer required replacement to ensure continued operation through the operating license term. Steam dryer acoustic monitoring was an EPU requirement.		
Condensate Demineralizer	$79.8 million	$48.3 million	$16.1 million
	Replacement of the five vessels necessary to support continued plant operation but 25 percent of the cost was attributed to EPU for larger equipment. Control system, valves, wiring, and piping required replacement to support continued plant operation.		
Transformer	$29.9 million	$19.4 million	$1.9 million

Modification	**Aggregate Cost**	**Unavoidable LCM (78.0%)**	**Avoidable EPU (22.0%)**
	Replacement of 1AR transformer necessary due to equipment obsolescence and continued plant operation. Replacement of main power transformer necessary due to equipment obsolescence, but equipment is larger for EPU.		
Feedwater Heaters	$114.9 million	$79.6 million	$9.3 million
	Feedwater heaters, valves, and piping required replacement to support continued operation of the station. Modification to drain tank all EPU. Increased size of heaters, piping, and valves attributed to EPU.		
Reactor Feed Pumps and Motors	$92.2 million	$77.8 million	$5.7 million
	Equipment required replacement to support continued operation of the station. Larger equipment costs attributed to EPU.		
Condensate Pump and Motor	$21.9 million	$5.0 million	$14.8 million
	Pump replacement was an EPU requirement. Replacement of the motors was necessary to ensure operation of the station through the current operating license term.		
13.8 kV System	$119.5 million	$108.0 million	--
	Existing 4 kV system breakers are no longer manufactured. Cost of 13.8 kV comparable to required 4 kV system modifications.		
Licensing	$59.5 million	--	$59.3 million
	Licensing work all allocated to EPU.		
Other Modifications	$34.7 million	$21.9 million	$5.7 million
	Other Modifications. See Exhibit ___ (TJO-1), Schedule 30.		
Common Cost	n/a	$78.6 million	$25.8 million

Modification	**Aggregate Cost**	**Unavoidable LCM (78.0%)**	**Avoidable EPU (22.0%)**
Allocation	Although most costs were directly assigned, some costs were considered common in nature (i.e., not readily attributable to either LCM or EPU) or were smaller costs remaining after the larger cost items were reviewed and assigned. These remaining common and other costs were then allocated pro rata to costs that were directly assigned to unavoidable LCM or avoidable EPU under the process described above.		
Totals	**$664.9 million**	**$518.9 million Unavoidable LCM**	**$146.0 million Avoidable EPU**

Monticello LCM/EPU Work Orders - LCM vs EPU Split ($ in millions)

	Child W O No.	Modification	Aug '13 Actuals with allocations	Direct Charge to WO(incl GE)	GE Equipmt Direct Assign	GE Licensing Direct Assign	GE Other Direct Assign	Othr Licensing Direct Assign	GE Common Allocation	Othr Common Allocation	Remove Allocations Included	Aug '13 Actuals w/o allocations	Materials/ Equipmt Incl v	Equipment needed without EPU? (See page 2)	Addtl equipment (Eq) or implementation needed for EPU?	EPU: Est. incremental / avoidable EPU cost ($M)	LCM: Unavoidable LCM / Other Costs ($M)
		LCM-only work - not avoidable in the absence of an uprate															
1	10942850	MNGP EPU-Power Range Neutron Monitor	$17.5	$ 7.4	$ 4.8				$ 0.9	$ 4.4	(5.3)	12.2		Yes	No	$ -	$ 12.2
2	10943047	MNGP EPU GEZIP Installation (Zinc Injection Passivization)	$2.6	$ 1.5	$ 0.4				$ 0.1	$ 0.7	(0.8)	1.8		Yes	No	$ -	$ 1.8
3	11132414	MNGP EPU Expansion Joints	$7.0	$ 4.9					$ 0.4	$ 1.8	(2.1)	4.9		Yes	No	$ -	$ 4.9
4	11133668	MNGP EPU Turbine Replacement	$54.0	$ 5.3	$ 32.4				$ 2.8	$ 13.5	(16.3)	37.7		Yes	Yes Eq , but comparable cost	$ -	$ 37.7
5	11133719	EPU Feedwater Heater Drain & Dump Valve Replacement	$4.7	$ 3.3					$ 0.2	$ 1.2	(1.4)	3.3		Yes	No	$ -	$ 3.3
6	11133731	EPU Main Steam Flow Transmitters Replacement	$0.5	$ 0.2			$ 0.1		$ 0.0	$ 0.1	(0.1)	0.3		Yes	No	$ -	$ 0.3
7	11133861	EPU Isophase Bus Cooling Replacement	$5.4	$ 2.4	$ 0.2		$ 1.2		$ 0.3	$ 1.4	(1.6)	3.8		Yes	No	$ -	$ 3.8
8	11133865	EPU EQ Transmitters & Detectors	$0.8	$ 0.6					$ 0.0	$ 0.2	(0.3)	0.6		Yes	No	$ -	$ 0.6
9	11194611	EPU Off Gas Dilution Fan Cable	$0.6	$ 0.4					$ 0.0	$ 0.2	(0.2)	0.4		Yes	No	$ -	$ 0.4
10	11215274	EPU Steam Dryer Replacement	$30.4	$ 30.4					$ -	$ 0.0	(0.0)	30.4		Yes	No	$ -	$ 30.4
11	11225964	EPU Acoustic Monitoring Instrumentation	$0.4	$ 0.3					$ 0.0	$ 0.1	(0.1)	0.3		Yes	No	$ -	$ 0.3
12	11257804	MNGP EPU 13.8 kV Distribution System	$119.5	$ 107.9	$ 0.4				$ 0.1	$ 11.1	(11.2)	108.4		Yes	Yes Eq , but comparable cost	$ -	$ 108.4
13	11284286	MNGP EPU Replacement 4 Feedwater Drain & Dump Valves	$17.6	$ 6.9	$ 0.9		$ 4.8		$ 0.8	$ 4.1	(5.0)	12.6		Yes	No	$ -	$ 12.6
14	11286966	MNGP EPU Generator Field Rewind	$6.7	$ 5.7					$ 0.2	$ 0.8	(0.9)	5.7		Yes	No	$ -	$ 5.7
15	11286973	MNGP EPU Generator Exciter Replacement	$0.1	$ 0.0					$ 0.0	$ 0.1	(0.1)	0.0		Yes	No	$ -	$ 0.0
16	11286985	MNGP EPU Stator Water Cooler Replacement	$2.4	$ 1.7					$ 0.1	$ 0.6	(0.7)	1.7		Yes	No	$ -	$ 1.7
17	10735617	MNGP EPU 1AR Transformer Replacement	$3.4	$ 1.6	$ 0.0		$ 0.7		$ 0.2	$ 0.9	(1.0)	2.4		Yes	No	$ -	$ 2.4
	9	Contingencies - Later assigned to individual child work orders	$0.0	$ -						$ -	-	-		Yes	No	$ -	$ -
		Subtotal - Items fully Unavoidable regardless of EPU	$273.8	$ 180.6	$ 39.2	$ -	$ 6.8	$ -	$ 6.2	$ 41.0	(47.2)	226.6				$ -	$ 226.6
		EPU-only work - Could have been avoided in the absence of an uprate														EPU	LCM
18	10859413	MNGP EPU Steam Dryer Acoustic Monitoring	$7.3	$ 5.1					$ 0.4	$ 1.8	(2.2)	5.1		No	Yes	$ 5.1	$ -
19	11133877	EPU Removal of Drywell Bricks in Bioshield	$0.1	$ 0.1						$ -	-	0.1		No	Yes	$ 0.1	$ -
20	11133856	EPU Feedwater Flow Transmitters/Programmable Control In	$0.3	$ 0.2			$ 0.1		$ 0.0	$ 0.1	(0.1)	0.2		No	Yes	$ 0.2	$ -
21	11133931	EPU Drywell Spray Flow Valve Replacement	$0.2	$ 0.1			$ 0.0		$ 0.0	$ 0.1	(0.1)	0.2		No	Yes	$ 0.2	$ -
22	11286981	MNGP EPU Main Steam Drain Tank Modifications	($0.0)	$ (1.6)			$ 1.6		$ -	$ -	-	(0.0)		No	Yes - see line 36 below	$ (0.0)	$ -
23	11398720	Engineering & Supervision for EPU	($0.0)	$ (0.0)						$ -	-	(0.0)		No	Yes	$ (0.0)	$ -
24	11776513	EPU Steam Dryer Instrumentation Removal	$1.2	$ 1.1					$ -	$ 0.1	(0.1)	1.1		No -driven by EPU	Yes	$ 1.1	$ -
25	11536446 / +5 11636xxx wo's + 11775097	MNGP EPU License Development	$59.3	$ 10.3	$ -	$ 25.3		$ 23.7	$ 0.0	$ 0.0	(0.1)	59.3		No	Yes	$ 59.3	$ -
		Subtotal - Items fully related to EPU, which would have been avoidable were an EPU not completed	$68.5	$ 15.3	$ -	$ 25.3	$ 1.7	$ 23.7	$ 0.4	$ 2.1	(2.5)	66.0				$ 66.0	$ -
		LCM Work with some incremental EPU costs (e.g. equipment changes)											Materials/ Equipmt Incl v	Assumed upsize for EPU = this % of equipmt cost>>		EPU 12.1%	LCM
26	10943007	MNGP EPU Main Power Transformer	$26.5	$ 9.2	$ 9.7				$ 1.3	$ 6.3	(7.6)	18.9	$ 15.5	Yes	Yes - Eq larger	$ 1.9	$ 17.0
27	10943052 & 11845189	MNGP EPU Condensate Impeller/Pumps/Motors	$21.9	$ 17.9	$ 0.2		$ 1.7		$ 0.0	$ 2.0	(2.0)	19.8	$ 3.4	Motors - Yes (LCM) Pumps - No	Motors - No ($5M LCM) Pumps -Yes (all remainder)	$ 14.8	$ 5.0
28	11133705	EPU Condensate Demineralizer System Replacement	$79.8	$ 41.5	$ 1.0		$ 21.9		$ 2.6	$ 12.7	(15.4)	64.4	$ 10.9	See below	See below	See below	See below
28a		Replace 5 vessels & related piping									-	-		No	Yes:estimate@ 25% of modification cost	$ 16.1	
28b		Control systems & valves w/h needed replacemt									-	-		Yes - remainder	No		$ 48.3
29	11133713	EPU Cross Around Relief Valves (CARV) Replacement	$18.4	$ 8.6	$ 0.3		$ 4.0		$ 0.9	$ 4.6	(5.5)	12.8	$ 3.2	Yes	Special tests - est@ $250k	$ 0.3	$ 12.6
30	11133871	EPU Main Steam Isolation Valve Solenoid Valve Replacement	$0.3	$ 0.2					$ 0.0	$ 0.1	(0.1)	0.2	$ 0.2	Yes	Yes - Eq larger	$ 0.0	$ 0.2
31	11286955	MNGP EPU Replacement of Reactor Feedwater Pumps/Motors	$92.2	$ 78.2			$ 5.3		$ 0.1	$ 8.5	(8.6)	83.5	$ 6.1	Yes	Yes - Eq larger plus more installation (est @ $5M)	$ 5.7	$ 77.8
32	11286961 & 11757884	MNGP EPU Replacement of 14 and 15 A/B Feedwater Heaters	$24.8	$ 8.4			$ 7.0		$ -	$ 9.4	(9.4)	15.4	$ 4.6	Yes	Yes - Eq larger and $6M for floor replacement	$ 6.6	$ 8.9
33	11286992	MNGP EPU Reactor Water Clean Up Capacity Improvement	$5.7	$ 5.1					$ 0.0	$ 0.5	(0.5)	5.1	$ 0.9	Yes	Yes - Eq larger	$ 0.1	$ 5.0
34	11335729	MNGP EPU Turbine Generator Vibration	$3.5	$ 2.6					$ 0.2	$ 0.7	(0.9)	2.6	$ 0.5	Yes	Yes-Eq 50% more complex	$ 0.2	$ 2.3
35	11410738	MNGP EPU PCT Vent & Purge Valves	$0.4	$ 0.4					$ 0.0	$ 0.0	(0.0)	0.4	$ 0.0	Yes	Yes-AppR cable only	$ 0.0	$ 0.4
36	11638897 & 11842626	MNGP EPU 13 A/B Feedwater Heater Replacements	$49.2	$ 44.7					$ 0.0	$ 4.4	(4.4)	44.7	$ 4.3	Yes	Yes - $8M in Tank drain is EPU, plus other Eq larger	$ 8.5	$ 36.2
		Subtotal - Items that are mainly unavoidable LCM costs, but also with incrementally avoidable EPU costs	$322.5	$ 216.9	$ 11.1	$ -	$ 40.0	$ -	$ 5.2	$ 49.3	(54.5)	268.0				$ 54.3	$ 213.7
		COMMON COSTS															
37	10435578	MNGP Extended Power Uprate - **COMMON COSTS**	$0.1	$ 252.1	$ (50.3)	$ (25.3)	$ (48.5)	$ (23.7)	$ (11.8)	$ (92.5)	104.3	104.4	N/A	N/A - see Common workorder worksheet		$ 25.8	$ 78.6
		Total Monticello LCM/EPU Project	$664.9	$664.9	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$664.9		Estimated Split of Avoidable EPU vs. LCM		EPU $146.0	LCM $518.9
																22.0%	78.0%

Total Direct Assigned	EPU	LCM		
Child WO's	$ 120.2	$ 440.3		
Common	$ 11.1	$ 21.1		
Total	$ 131.4	$ 461.4	89.1%	$ 592.8
	22.2%	*77.8%*		

	Total	EPU	LCM
Direct Assigned child WO	$ 560.6	$ 120.2	$ 440.3
Ratio of direct assigned child WO costs		21.45%	78.55%
% of total project costs	*84.3%*		

Monticello LCM/EPU Work Orders - Description of why work was unavoidable LCM vs. avoidable EPU

			Equipment needed without EPU?	Reason for unavoidable LCM work, if not avoidable EPU work
	LCM-only work - not avoidable in the absence of an uprate			
1	10942850	MNGP EPU-Power Range Neutron Monitor	Yes	Obsolesence. Power range neutron monitoring system had been in service for over 40 years and the analog system was scheduled for replacement in support of life extension.
2	10943047	MNGP EPU GEZIP Installation (Zinc Injection Passivization)	Yes	Obsolescence. Necessary to replace at some point to ensure safe operation to end of plant life. One expansion joint had developed a hole and required replacement. Because we had to do one, it was prudent to do all to avoid duplicate mobilization charges.
3	11132414	MNGP EPU Expansion Joints	Yes	Obsolescence
4	11133668	MNGP EPU Turbine Replacement	Yes	The previously installed turbine rotor would have to have extensive maintenance or replacement to run through the end of plant life.
5	11133719	EPU Feedwater Heater Drain & Dump Valve Replacement	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant life. Appropriate to combine tasks.
6	11133731	EPU Main Steam Flow Transmitters Replacement	Yes	Obsolescence. Necessary to replace at some point to ensure safe operation to end of plant life. Appropriate to combine tasks.
7	11133861	EPU Isophase Bus Cooling Replacement	Yes	Necessary to replace as scheduled to ensure safe operation of plant - end of life issue.
8	11133865	EPU EQ Transmitters & Detectors	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue.
9	11194611	EPU Off Gas Dilution Fan Cable	Yes	Necessary to replace as scheduled to ensure safe operation of plant - end of life issue.
10	11215274	EPU Steam Dryer Replacement	Yes	Necessary to replace at some point to ensure safe operation to end of plant life. Old steam dryer would not have lasted through 2030.
11	11225964	EPU Acoustic Monitoring Instrumentation	Yes	Would be required by NRC for any dryer replacement due to end of life issues with existing dryer.
12	11257804	MNGP EPU 13.8 kV Distribution System	Yes	Obsolescence. Necessary to replace 4kv bus and breakers at scheduled to ensure safe operation of plant - end of life issue. The 4kv breakers are horizontal magnablast breakers that are no longer manufactured by GE.
13	11284286	MNGP EPU Replacement 4 Feedwater Drain & Dump Valves	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue.
14	11286966	MNGP EPU Generator Field Rewind	Yes	Necessary to rewind at some point sooner as opposed to later to ensure continued operation of plant to end of life.
15	11286973	MNGP EPU Generator Exciter Replacement	Yes	Obsolescence. Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue.
16	11286985	MNGP EPU Stator Water Cooler Replacement	Yes	Obsolescence. Necessary to provide second heat exchanger as scheduled to ensure safe operation of plant - single point vulnerability issue. Also, existing heat exchanger was approaching end of life.
17	10735617	MNGP EPU 1AR Transformer Replacement	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue.
	EPU-only work - Could have been avoided in the absence of an uprate			
18	10859413	MNGP EPU Steam Dryer Acoustic Monitoring	No	Only related to EPU
19	11133877	EPU Removal of Drywell Bricks in Bioshield	No	Only related to EPU
20	11133856	EPU Feedwater Flow Transmitters/Programmable Control In	No	Only related to EPU
21	11133931	EPU Drywell Spray Flow Valve Replacement	No	Only related to EPU
22	11286981	MNGP EPU Main Steam Drain Tank Modifications	No	Only related to EPU
23	11398720	Engineering & Supervision for EPU	No	Only related to EPU
24	11776513	EPU Steam Dryer Instrumentation Removal	No	Only related to EPU
25	11536446 / +5 11636xxx wo's + 11775097	MNGP EPU License Development	No	Only related to EPU
	LCM Work with some incremental EPU costs (e.g. equipment changes)			
26	10943007	MNGP EPU Main Power Transformer	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue. Equipment larger for EPU.
27	10943052 & 11845189	MNGP EPU Condensate Impeller/Pumps/Motors	See below	
27a		EPU only - pumps	Pumps - no	Only related to EPU. Not end of life; possible that pumps would not need to be replaced during plant life.
27b		LCM only - motors	Motors - Yes	Obsolescence. Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue.
28	11133705	EPU Condensate Demineralizer System Replacement	See below	
28a		Replace 5 vessels & related piping	No	25% of the modification cost related to the larger equipment.
28b		Control systems & valves w/h needed replacemt	Yes - remainder	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue.
29	11133713	EPU Cross Around Relief Valves Replacement	Yes	Obsolescence. Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. Special testing needed.
30	11133871	EPU Main Steam Isolation Valve Solenoid Valve Replacement	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue. Larger equipment needed for EPU.
31	11286955	MNGP EPU Replacement of Reactor Feedwater Pumps/Motors	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue. Larger equipment and difficult installation related to EPU.
32	11286961 & 11757884	MNGP EPU Replacement of 14 and 15 A/B Feedwater Heaters	Yes	Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. Tube failures had already occurred to the extent that further plugging would have affected generation if not put plant operation in jeapordy. Larger equipment needed for EPU; $6 million in costs related to reinforced floor relates solely to EPU.
33	11286992	MNGP EPU Reactor Water Clean Up Capacity Improvement	Yes	Obsolescence. Necessary to replace as scheduled to ensure safe operation of plant - end of life issue. Larger equipment for EPU.
34	11335729	MNGP EPU Turbine Generator Vibration	Yes	Obsolescence. Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. Equipment 50% more complex for EPU.
35	11410738	MNGP EPU PCT Vent & Purge Valves	Yes	Obsolescence. Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. AR cable additional for EPU.
36	11638897 & 11842626	MNGP EPU 13 A/B Feedwater Heater Replacements	Yes	Necessary to replace as scheduled to ensure reliable operation of plant - end of life issue. Equipement larger and $8 million for tank drains due to EPU.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002/GR-12-961
Response To: Office of Attorney General Information Request No. 0048
Requestor: Ron Giteck
Date Received: January 4, 2013 **Second Supplemental Response**

Question:

For all responses show amounts for Total Company and the Minnesota jurisdictional electric company unless indicated otherwise. Total Company is meant to include costs incurred by Xcel Energy Services and NSP Minnesota, both regulated and non-regulated operations.

Reference Heuer Direct pg. 46.

(a) Provide an explanation with the associated costs incurred for the Monticello LCM/EPU that were identified as unusable due to changes in scope, NRC requirements or changes in design or other reasons.

(b) Provide a list of all vendors who have provided services, equipment or materials and show the total amounts paid to each vendor for each year 2008 through the test year 2013. Show only amounts for vendors who were paid more than $300,000 in any single year. Also show the amount in total for each year for all vendors that were paid less than $300,000.

Response:

(a) We have not identified any costs incurred for the Monticello LCM/EPU project that we consider unusable due to changes in scope, NRC requirements, changes in design, or other reasons.

(b) Attachment A to this response provides the requested information.

Attachment A has been marked Non-Public in its entirety as it contains information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b).

This data includes confidential contract terms and this information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. The disclosure of this information could adversely impact contract negotiations, potentially increasing costs for these services for our customers. Thus, Xcel Energy/NSPM maintains this information as a trade secret.

Supplemental Response:

A. As we began responding to information request DOC 160, we determined that there is additional information responsive to this request. While we are still reviewing the project costs, the work and associated costs listed in the table below may be classified as potentially unusable. For purposes of this response, NSPM interpreted the term of "unusable" to mean work that was ultimately not fit for its intended project purpose because of scope changes, changes in NRC requirements, changes in design, or other items. This work may have had other purposes or been a part of a necessary process to optimize the final design of LCM/EPU modifications.

NSPM is continuing to review its project costs in anticipation of filing a prudence review at the conclusion of the Monticello LCM/EPU Project. We expect the final prudence report will include a review of project documentation to identify any work that was ultimately unusable. This review will further quantify the cost of such work and discuss why the work, changes, and decisions were consistent with those that are part of any large construction project at a nuclear facility.

The cost impacts listed in the table below are the Company's best estimates based on available documentation and professional knowledge. While we believe they represent reasonable estimates of the impacts of the items discussed, NSPM is in the process of working with its vendors to develop definitive cost estimates for each piece of work.

Item #	Description	Estimated Cost	Discussion
1	The portions of the initial License Amendment Request (LAR) submittal were redone following additional questions from the NRC regarding the existing Steam Dryer.	$ 2,391,940	NSPM submitted the initial LAR based on the then existing NRC requirements for steam dryer analyses. Over time the NRC requirements evolved to require a more rigorous analysis of the structural integrity of the steam dryer. That evolution required NSP to withdraw its initial LAR submittal in order to re-perform the steam dryer analysis in a manner that would meet the NRC's revised requirements.
2	The original GE contract scope included analysis and modification of the existing steam dryer. The analysis of the existing steam dryer and potential modifications was abandoned in favor of a replacement steam dryer from Westinghouse.	$ 1,849,995	Due to continuing evolution of the NRC requirements for the steam dryer analysis, NSP made the determination that it was in the best interest of the project to replace the existing steam dryer with a new, more efficient design from Westinghouse. This new steam dryer alleviated the NRC's concerns with respect to the structural integrity of the existing steam dryer at uprated conditions, as well as more efficiently removed excess moisture from the steam that is transferred from the reactor the turbines. That efficiency improvement is expected to lower ongoing maintenance costs and reduce dose to plant personnel.
3	Design work on the 13.8 kV distribution replacement project.	$ 1,800,000	Design work on the 13.8 kV distribution replacement project amounting to $1,800,000 proved unusable due to issues of quality and timing.

Item #	Description	Estimated Cost	Discussion
4	The initial design and location of the 13.8 kV distribution replacement project would have prevented installation of this modification as designed by GE/Shaw.	$ 1,259,685	GE/Shaw's initial design for the 13.8kV system placed the switchgear over plant piping. This would have prevented installation of this modification in the plant do to the inability to access this piping following installation of the switchgear.
5	GEH/ Shaw completed the Torus and Attached Piping analysis to a 208 degree Torus temperature. Upon plant review of the completed calculations, the plant requested 4 degrees of additional margin. GEH issued a Project Change Request to complete this re-analysis. NSP, instead, contracted with another vendor to complete the new analysis and associated summary reports.	$ 352,842	The plant's request was necessary to have acceptable margins of safety.
6	The Equipment Qualification (EQ) program files EQ Part A and B as well as the calculation/file conversions were updated as part of the LCM/EPU Project. Following the completion this work, Monticello chose to perform changes to its HELB analysis and the EQ work was redone to reflect these changes. This is the cost of the contractor work to perform the file conversions (2 years of effort).	$ 302,738	The revisions to the HELB calculations to incorporate conservative assumptions had a downstream impact on the EQ analysis.

Item #	Description	Estimated Cost	Discussion
7	Plant procedures were marked up to reflect changes following implementation of the LAR. Licensing delays resulted in re-performing procedure for those mark-ups to maintain configuration control.	$ 192,449	The plant procedures were revised to prepare the procedures for EPU operations. This is a necessary and required part of performing the uprate. When the NRC was unable to meet its LAR review schedule due to changes to its requirements related to Containment Accident Pressure (CAP) and the steam dryer analysis, NSP was forced to delay implementation of the EPU. It was then necessary to revise the plant procedures to reflect the new equipment installed in the plant, but not yet operating at EPU conditions.
8	As a result of the decision to select Westinghouse for the replacement steam dryer, GE was required to revise two task reports to reflect changes due to the replacement steam dryer.	$ 68,476	Westinghouse's replacement steam dryer was selected due to its better design and anticipated more efficient moisture removal. In addition, Westinghouse provided better terms and conditions under which to procure the replacement steam dryer.
9	Design work on the reactor feed water pumps.	$ 3,000,000	Design work on the reactor feed water pumps work amounting to approximately $3,000,000 proved unusable due to issues of quality and timing.
10	WEC Replacement Steam Dryer Requests for additional information responses	$ 1,400,000	About two-thirds of the WEC replacement steam dryer responses to NRC request's for additional information constituted re-work due to the NRC changing requirements for the analyses.

Item #	Description	Estimated Cost	Discussion
11	13.8kV Incorrect Cable Procurement	$700,000 (initial value)	Cable for the 13.8kV system was ordered correctly by the field engineer and then changed to the incorrect cable by the procurement engineer. The incorrect cable could not be used because the sheathing had a chemical composition that would give off noxious fumes in a fire. It was identified that it was incorrect after the first portion of cable was installed. The correct cable was then ordered. The unusable cable was given back to the warehouse and it will be auctioned off under the recovery program.

B. Attachment A to the original response provided the requested information for the years 2008-2012. We are unable to provide a list of expected payments to vendors for the budgeted test year 2013 as we do not budget at the vendor payment level.

Second Supplemental Response:

A. The Company has now completed the LCM/EPU Program. In preparation of making its filing to the Minnesota Public Utilities Commission in Docket No. E-002/CI-13-754, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, the Company revisited the response to this Information Request. Through that review, we added two additional items to the chart above.

Further, as described above, for purposes of this response, NSPM interpreted the term of "unusable" to mean work that was ultimately not fit for its intended project purpose because of scope changes, changes in NRC requirements, changes in design, or other items. The work, however, may have had other purposes or been a part of a necessary process to optimize the final design and/or engineering of LCM/EPU modifications. Including an item in this response does not equate to the work being valueless, imprudently performed, or required to be excluded from capital. Rather, changes in scope and rework resulting from inspections, testing, and changes in NRC requirements in order to place the property in service is included in capital. These types of changes are normal in the context of a large scale construction project at a nuclear facility.

After further review, items 1-10 listed on the above chart are work that was necessary to bring the LCM/EPU Project to close. Much of the work listed above relates to preliminary design work that was the groundwork for subsequent design and engineering. Those items can be classified into work related to (1) the NRC Changes/Delays and (2) Scope Changes.

(1) NRC Changes/Delays
Items 1, 2, 7, and 10 listed above relate to work that was preliminarily performed and then had to be changed due to evolving or changing NRC requirements and NRC delay. As the NRC requirements change, the Company must adjust the analyses and scope of work related to various projects to comply with the new requirements.

(2) Construction Scope Changes
Items 3, 4, 5, 6, 8, and 9 listed above relate to scope changes that were necessary to place the property in service. These changes are part of the normal course of business in a construction project. The baseline work and evaluations were necessary in order to determine the appropriate course of action in moving the project forward.

Item 11, on the other hand, relates to incorrect material being procured and new material having to be purchased as replacement. The incorrect cable was transferred to inventory, which removed the cost from the project.

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Supplemented: February 4, 2013
Second Supplemental: October 18, 2013