Before The Public Service Commission
Of the State of Montana

DOCKET NOS. D2013.5.33/D2014.5.46

ELECTRIC TRACKER FILING

REBUTTAL
TESTIMONY AND EXHIBITS

JULY 2015

NorthWestern Energy
Delivering a Bright Future

July 24, 2015

Ms. Kate Whitney
Utility Division
Montana Public Service Commission
1701 Prospect Avenue
PO Box 2022601
Helena, Montana 59620-2601

Re: Docket Nos. D2013.5.33/D2014.5.46 Electric Tracker Rebuttal Testimony

Dear Ms. Whitney:

Please find enclosed NorthWestern Energy's Prefiled Rebuttal Testimony in Consolidated Docket Nos. D2013.5.33/D2014.5.46.

This filing includes two exhibits involving protected or confidential materials. First, Exhibit__(JHG-1) attached to the Prefiled Rebuttal Testimony of James H. Goetz consists of several pages from the General Agreement for Supply of Equipment, Field Services, Shop Repair Services and Technical Services between PPL Services Corporation and Siemens Power Generation, Inc. Please note that Talen Energy (formerly PPL Montana, LLC) considers the remainder of this document to be confidential.

Please also note that the protected version of Exhibit__(RAH-4) accompanying the Prefiled Rebuttal Testimony of Ronald A. Halpern has been provided on yellow paper in a separate, sealed envelope only to the Commission and those parties who have signed the appropriate non-disclosure agreement per Protective Order No. 7283c. This exhibit is the Root Cause Analysis Report on PPL Montana Colstrip 4 Core Failure Event.

Should you have questions please contact Joe Schwartzenberger at (406) 497-3362.

Sincerely,

Tracy Lowney Killoy

Tracy Lowney Killoy
Administrative Assistant

CERTIFICATE OF SERVICE

I hereby certify that a copy of NorthWestern Energy's Rebuttal Testimony and Exhibits in Docket Nos. D2013.5.33/D2014.5.46 has been hand delivered to the Montana Public Service Commission and to the Montana Consumer Counsel this date. It has been e-filed on the PSC website, emailed to counsel of record, and served on the most recent service list by mailing a copy thereof by first class mail, postage prepaid.

Date: July 24, 2015

Tracy Lowney Killoy

Tracy Lowney Killoy
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D2013.5.33/D2014.5.46
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Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF PATRICK R. CORCORAN

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is Patrick R. Corcoran, and my business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom and in what capacity are you employed?

A. I am employed by NorthWestern Energy ("NorthWestern") as the Vice President of Government and Regulatory Affairs.

Q. Please summarize your education and employment experience.

A. I attended the Montana College of Mineral Science and Technology, Butte Montana, receiving an Associate of Science degree and a Bachelor of Science degree in Computer Science. I have also attended the University of Idaho's Public Utilities Executive Course and many other courses, seminars and sessions on business, utility, and regulatory subjects.

I began work for the then Montana Power Company ("MPC") in January 1979. After progressing through a number of positions in the Regulatory Affairs Department, I became the MPC Vice President of Regulatory Affairs in September 2000 and a NorthWestern Vice President in 2002.

Q. What are your responsibilities as Vice President of Government and Regulatory Affairs?

A. I am the officer in charge of state and federal governmental and regulatory affairs for NorthWestern in Montana, South Dakota, Nebraska, and at the federal level. I have broad utility knowledge and experience, and I am familiar with many aspect of the utility business. I am an active participant in regulatory proceedings and forums before the state and federal regulatory commissions, and I have testified on various regulatory and utility-related business matters. I am also responsible for NorthWestern's energy conservation, Demand-Side Management ("DSM"), Universal System Benefits Programs, and other related

programs/activities. I have been actively involved in and guided these efforts for many years.

As part of my overall responsibilities, I play a key role in formulating, shaping, and guiding internal and external public policy matters for NorthWestern.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. First, I describe the general framework that has been in place since 1997 to recover the cost of purchased power, including replacement power. I explain why there is nothing unusual or unseemly about the fact that the electricity supply cost tracking adjustment in these dockets contains the cost of power needed when there was a forced outage at Colstrip Unit 4 on July 1, 2013. Second, I address the positions taken by Montana Consumer Counsel ("MCC") witness John W. Wilson, and the Montana Environmental Information Center ("MEIC")/Sierra Club witness David A. Schlissel, regarding the propriety of including, in these tracker dockets, the cost of power incurred by NorthWestern when there was a forced outage at Colstrip Unit 4. Third, I address the savings in labor expense from the employee furlough associated with the outage. Fourth, I address the advocacy of MCC witness Wilson that the Lost Revenue Adjustment

Mechanism ("LRAM") be removed from the electricity supply cost tracking adjustment.

Corcoran Rebuttal Testimony

Q. Mr. Corcoran, please describe the general framework that has been in place since 1997 to recover the cost of purchased power, including replacement power.

A. The Electric Utility Industry Restructuring and Customer Choice Act, §§ 69-8-101 et seq., was enacted into law in 1997. As part of that Act, beginning in 2002, purchased power costs have been recovered through Electricity Supply Cost Tracker Filings, such as the two before the Montana Public Service Commission ("Commission") in these dockets. Subsequently, the Commission has recognized that replacement power costs are part of electricity supply costs[1] to be reflected in rates through the tracking adjustment. Docket No. D2012.5.49, Order No. 7219h, ¶101.

Q. Is there anything improper about NorthWestern recovering in this proceeding its cost of replacement power during the Colstrip 4 outage?

A. No. In fact, NorthWestern is supposed to include its cost of purchased power, including replacement power for Colstrip Unit 4, in the electricity supply cost tracking adjustments currently before this Commission.

[1] § 69-8-210(1), MCA

Correspondingly, the Commission is required by statute to allow the full recovery of such costs, unless they were imprudently incurred. The Commission does not have the choice of deferring cost recovery to a later proceeding, as suggested by MCC witness Wilson, or MEIC/Sierra Club witness Schlissel, in their prefiled testimonies.

When a generating resource is out of production because of a planned or forced outage, NorthWestern is obligated to acquire sufficient replacement power to meet its customers' needs. Neither Dr. Wilson nor Mr. Schlissel contends that NorthWestern imprudently purchased replacement power, or imprudently paid too high a price for the power. They didn't make such assertions because they had no factual basis for making them. Instead, they assert that NorthWestern should first sue somebody before including its replacement power costs in the electricity supply cost tracking adjustment. Secondarily, they argue that NorthWestern should not be able to include the cost of replacement power in the electricity supply cost tracking adjustment because it should have had outage insurance that would have reimbursed NorthWestern for the cost of the replacement power. If outage insurance is an alternative to replacement power costs, as suggested by Wilson and Schlissel, the cost of such insurance would also have to be included in rates, as the coverage is not available for free.

Dr. Wilson and Mr. Schlissel are effectively suggesting that the Commission obliterate its statutory obligation to provide NorthWestern full recovery of its prudently incurred replacement power costs.

Q. Assume, hypothetically, that either Talen Energy Corporation or Siemens was potentially liable to NorthWestern for its replacement power costs from the Colstrip 4 outage. Under that assumption, would it be proper for the Commission to exclude from the electricity supply cost tracking adjustment the replacement power costs incurred by NorthWestern because of the Colstrip 4 outage, as advocated by Dr. Wilson and Mr. Schlissel?

A. No. The fact that NorthWestern might have a cause of action against another party to recover the costs of replacement power it incurred because of the forced outage at Colstrip Unit 4 does not magically transform those costs into something other than purchased power costs recoverable in an electricity supply cost tracker. The costs are real, they were incurred to provide needed power to NorthWestern's customers, and they need to be recovered through rates in accordance with the statutory mandate.

Q. Would including the replacement power costs in rates in these proceedings provide NorthWestern with an opportunity for a double recovery – once from its customers, once from alleged wrong doers?

A. No. Including the replacement power costs in rates in these proceedings vests in NorthWestern's customers the right to receive the full benefit of any later recovery from alleged wrong doers. If there is any doubt in the Commission's mind on that point, it should include in the final order in this docket an ordering paragraph that requires any subsequent recovery through court action to be reflected as a credit in the deferred account for the electricity supply cost tracking adjustment.

Q. Both MCC witness Wilson and MEIC/Sierra Club witness Schlissel testify that NorthWestern is unfairly trying to recover the costs associated with the outage at Colstrip Unit 4, while retaining the benefits, specifically the avoided labor costs associated with the 36 employees at Colstrip Unit 4 who were furloughed while the unit was being repaired. Is NorthWestern unfairly trying to recover the costs associated with the outage at Colstrip Unit 4, while retaining the benefits?

A. No. Both MCC witness Wilson and MEIC witness Schlissel are choosing to ignore the difference under Montana law and regulation between the recovery of purchased power expense and the recovery of general operating and maintenance expense. The dockets before the Commission in this case are annual proceedings to implement the electricity supply cost tracking adjustment statutorily mandated in § 69-8-210(1), MCA. The statutory procedure is for the recovery of electricity

supply costs, a defined term in the Act. I have set out below the statutory definition:

> (8) "Electricity supply costs" means the actual costs incurred in providing electricity supply service through power purchase agreements, demand-side management, and energy efficiency programs, including but not limited to:
> (a) capacity costs;
> (b) energy costs;
> (c) fuel costs;
> (d) ancillary service costs;
> (e) transmission costs, including congestion and losses;
> (f) planning and administrative costs; and
> (g) any other costs directly related to the purchase of electricity and the management and provision of power purchase agreements.

Section 69-8-103(8), MCA. A savings in labor expense is not an electricity supply cost as defined.

A utility's labor expense is generally considered to be a component of a general rate case. (Labor expense is an Operation & Maintenance expense reflected in Statement G for a utility governed by the Uniform

System of Accounts. See ARM 38.5.156.) MEIC/Sierra Club witness Schlissel acknowledges that labor expense is part of a general rate case, not an electricity supply cost tracking adjustment. Schlissel Direct at p. 22.

In fact, in Docket No. D2005.5.88, NorthWestern proposed to include labor costs for the DSM Program Coordinator arguing that it was an incremental position added subsequent to rates being set in the previous general case specifically to support NorthWestern's revived DSM efforts. MCC opposed and the Commission rejected the proposal on the grounds that these types of costs are not part of electricity supply costs and belong in general rate filings.

Q. Mr. Corcoran, please address MCC witness Wilson's advocacy in these dockets that the LRAM be removed from these two dockets and addressed in NorthWestern's next general rate case.

A. At page 28 of Dr. Wilson's testimony, and again at page 33, he advocates that the Commission remove the LRAM from these two tracker dockets and address the impact of lost revenues from investments in conservation and DSM programs in NorthWestern's next general rate case. His proposal is completely at odds with the decision of this Commission establishing the LRAM in 2005. Docket No. D2004.6.90, Order No. 6674e. His prefiled testimony in these dockets is a repetition of his

prefiled testimony in Docket No. D2014.6.53, the docket instituted by the Commission to review the policies and procedures behind the LRAM.

The advocacy of the MCC on the LRAM was initially rejected by the Commission in Order No. 6674e in 2005. Yet the MCC continues to take the position that the LRAM should not be included in the electricity supply cost tracking adjustment, but should instead be addressed as part of a general rate case filing. At least to date, the Commission has been as consistent in rejecting the MCC's LRAM advocacy as the MCC has been in forwarding it.

These tracker dockets are not the correct forum to reconsider, yet again, the MCC's familiar refrain on the LRAM. The Commission opened Docket No. D2014.6.53 for that purpose. These tracker dockets are the implementation of the Commission's express determination, in Docket No. D2004.6.90, that the LRAM <u>would</u> be included in the electricity supply cost tracking adjustment. While the Commission may have the power to reverse that decision prospectively in Docket No. D2014.6.53, it would be wholly inappropriate for it to attempt to do so retroactively in these tracker dockets. If the Commission decides in Docket No. D2014.6.53 to remove the LRAM from the electricity supply cost tracking adjustment, it will need to provide a reasonable transition for such a dramatic change in policy. As part of that reasonable transition, these two tracker dockets, which now

go back two years, have to be processed under the Commission policy in effect at the time of their preparation and filing. NorthWestern has been acting in reliance upon Order No. 6674e ever since it was issued.

Q. Does this complete your testimony?

A. Yes, it does.

Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF JAMES H. GOETZ

ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. My name is James H. Goetz. I am affiliated with the law firm of Goetz, Baldwin and Geddes, located at 35 N. Grand Street, Bozeman, Montana 59715.

Q. Please outline your educational background.

A. I received an undergraduate degree in history in 1965 from Montana State University. I received my law degree from Yale Law School in 1968.

Q. How have you been employed since that time?

A. Beginning in the fall of 1968, I engaged in a full-time teaching position as an assistant professor in what was then called the Department of History, Government and Philosophy at Montana State University. My teaching responsibilities included survey courses in American and state and local government and upper-level courses in American constitutional law and administrative law. I pioneered a course in environmental law. I taught full-time until 1972, at which time I took a part-time teaching position as an adjunct with course responsibilities in constitutional law and environmental law, which continued to 1988. I was admitted to the Montana Bar in 1969 and maintained a part-time, largely pro bono, law practice until 1972 when I formed my own law firm. That firm has since evolved into what is now called Goetz, Baldwin and Geddes, an eight-lawyer firm.

Q. Please describe your law practice, emphasizing particularly any experience that may bear upon the present matter.

A. My law practice is devoted almost solely to litigation. I have had extensive appellate experience, and in the last three to four years, I have concentrated my litigation activities primarily on handling appeals. I have argued probably over 100 cases in the Montana Supreme Court, a number in the Federal 9th Circuit Court of Appeals, and have argued two cases in the US Supreme Court.

Of particular relevance to the contract issues I have been asked to analyze in this case is my experience in several major contract cases. The most recent is an appeal of a $52 million verdict against Comerica Bank which was reversed by the Montana Supreme Court just this month. Masters Group International, Inc., v. Comerica Bank, 2015 MT 192 ___ Mont. ___ P.2d ___ (July 1, 2015). I represented Edwards Jet Center in Corporate Air v. Edwards Jet Center, 2008 MT 283, 345 Mont. 336, 190 P.3d 1111, a major contract action involving sale of a fixed based fueling station and several commercial aircraft, and the Textana Company in Textana Inc. v. Klabzuba Oil & Gas Company, 2009 MT 401, 353 Mont. 442, 222 P.3d 580, a major oil and gas and contract/lease case. I also represented Simmons Oil Corporation in two cases involving a squeeze-out of a joint interest in an oil refinery in Great Falls. Simmons Oil Corp.

v. Holly Corp. 244 Mont. 75, 796 P.2d 189 (1990), and Simmons Oil Corp. v. Holly Corp. 258 Mont. 79, 852 P.2d 523 (1993).

Q. Please describe any special awards or recognitions received.

A. I am a member of the American Law Institute, Fellow of the American College of Trial Lawyers, an associate in the American Board of Trial Advocates, a member of the American Academy of Appellate Lawyers, and a member of the International Society of Barristers. I have been listed in Corporation Counsel as one of the top lawyers in the "Bet-The-Company" litigation category. I am listed in Woodward & White's The Best Lawyers in America in a number of Montana categories, including appellate practice, Bet-The-Company litigation, and commercial litigation. I have been listed in Chambers USA America's Leading Business Lawyers as one of the "four" leading individuals in Montana in the category of general commercial litigation. I have recently been listed in Super Lawyers' top 100 mountain states lawyers.

I served, by appointment by the Montana Supreme Court, on the Montana Commission for Civil and Appellate Rules for approximately twenty years, the last ten of which I served as chairperson.

In 2013 I received the Jeanette Rankin award from the Montana Chapter of the American Civil Liberties Union. In the late 1970's, I received (along

with my partner Bill Madden) the Resource Defense Award from the National Wildlife Federation.

Purpose of Testimony

Q. On whose behalf are you testifying in this proceeding?

A. NorthWestern Energy ("NorthWestern").

Q. What questions have you been asked to address?

A. The primary question is whether NorthWestern has acted prudently in declining to pursue a claim for damages against Siemens Power Generation, Inc. ("Siemens") for allegedly defective work done by Siemens in the first six months of 2013 during a planned power outage on Colstrip Unit 4 ("CU No. 4"). I have also been requested to look at whether NorthWestern should have pursued a damage claim against PPL Montana, LLC ("PPLM") as Operator of CU No. 4.

Q. What have you done to address these questions?

A. I reviewed a number of documents, including the "General Agreement for Supply of Equipment, Field Services, Shop Repair Services and Technical Services" between PPL Services Corporation and Siemens Power Generation, Inc., dated January 1, 2006 ("General Agreement"), excerpts of which are my Exhibit__(JHG-1), the "Duplicate Contract No. 570202-C", dated January 31, 2013 between PPL and Siemens Energy, the

"Ownership and Operation Agreement" for Colstrip Units 3 and 4, dated May 6, 1981 between Montana Power Company and four other participants, excerpts of which are my Exhibit__(JHG-2), the Pre-Filed Direct Testimony of John W. Wilson on behalf of the Montana Consumer Counsel dated May 8, 2015, the Pre-filed Direct Testimony of David A. Schlissel on behalf of Montana Environmental Information Center and Sierra Club, the "Root Cause Analysis Report on PPL, Montana Colstrip 4 Core Failure Event" ("Root Cause Analysis") by Halpern and Ward, November 18, 2013, and other documents, including discovery responses. I have also reviewed a document indicating a declination by the insurer to pursue litigation on potential subrogation interests and have reviewed information on general industry practice regarding limitation of consequential damages in contracts such as the PPL/Siemens contract involved here. In addition, I have undertaken my own research on the enforceability of contractual provisions which limit recovery of consequential damages. I have discussed the issue of waiver of consequential damages, and particularly waiver of damages based on the cost of replacement power, with Fred Lyon, who has been retained by NorthWestern Energy to offer testimony in this matter. Mr. Lyon has extensive experience in the case area of utility-construction contracts (over 35 years of practice). He represents mostly utilities but sometimes vendors for utilities and frequently serves as a mediator in utility-construction related matters.

Opinions

Q. What is your opinion on whether NorthWestern should file a damage action against Siemens seeking recovery for the costs of replacement power resulting from Siemens' work on CU No. 4?

A. It is my opinion that no such case should be filed and, if filed, it would be unsuccessful. First, NorthWestern is not a party to the contract with Siemens for Siemens' work in 2013 on CU No. 4. Siemens' contract was with PPL. There is no privity between NorthWestern and Siemens. Lacking any direct contractual relationship, it is doubtful NorthWestern was owed any duties by Siemens, contractual or otherwise. It would not have been prudent for NorthWestern to sue Siemens.

Even if we overlook the problem of a lack of contractual relationship between NorthWestern and Siemens and, instead, look at the potential viability of a lawsuit by PPLM, my opinion is the same.

The General Agreement applies to the work done by Siemens under Contract No. 570202-C, dated January 31, 2013, which is the work Siemens performed at issue in this matter. The General Agreement limits liability under any theory of recovery. It provides that Siemens will not be liable for any indirect, special, incidental or consequential damage. Article 81. Article 81 explicitly precludes a damage recovery for any cost of purchased or replacement power.

Because of this explicit provision, bargained for between two sophisticated parties, PPLM and/or its affiliated companies have no viable damage claim against Siemens for the cost of purchased or replacement power. Accordingly, it is not prudent for PPL to pursue such claim against Siemens.

Additionally, any complex commercial lawsuit of this nature is very expensive and time-consuming. Given the bleak prospects for success, it would not have been prudent for either NorthWestern or PPLM to pursue litigation against Siemens regarding CU No. 4.

Q. Do you have an opinion as to whether NorthWestern should have, prior to making its filing with the PSC, analyzed more carefully the question of whether it had a viable claim against Siemens?

A. I am not privy to precisely what NorthWestern did internally to analyze this question. I have seen the pre-filed testimony of the objectors which, in referring to certain discovery answers, suggests that NorthWestern did little, if anything, to analyze the viability of a claim against Siemens. Any such analysis, even a cursory one, would have resulted in the same conclusion I reach here. Namely, there is no direct contractual relationship between NorthWestern and Siemens. Also, the PPL/Siemens contract precludes recovery for consequential damages and precludes recovery for any costs of purchased or replacement power. Thus, the

question of whether, and to what extent, NorthWestern previously looked at seeking a recovery from Siemens is hardly material. There is (and was) no viable claim.

Q. Do you perceive that any party to these proceedings asserts that NorthWestern should make a claim against PPLM for any of the costs incurred by the outage and, if so, what is your response?

A. John W. Wilson, on behalf of the Montana Consumer Counsel, states that NorthWestern is requesting the rate increase "despite the fact" that it:

> "(3) has made no determination whether it can pursue any actions to recover all or part of the costs incurred by the outage from Siemens, **PPLM**, their insurers, or from any other party;"

John W. Wilson pre-filed testimony p.31 (emphasis added). This suggests that Dr. Wilson may be asserting that NorthWestern should have pursued an action against PPLM.

It is my opinion that any such claim by NorthWestern directed against PPLM would be fruitless and imprudent. First, the "Ownership and Operation Agreement" for Colstrip Units 3 and 4 between the Montana Power Company and four other participants dated May 6, 1981 provides in paragraph 20 "liabilities" that:

> Each of the Owners and Project Users releases all other Owners and Project Users and their respective directors, officers, employees and agents, from any consequential damages (including

> but not limited to, any loss of use, revenue or profit and any replacement power costs except as otherwise provided by Section 6(d) of the Transmission Agreement) arising out of the Construction or the operation, maintenance, or repair of the Project.

Thus, even if PPLM, which, I am informed, is the successor to Montana Power Company as the "Operator" were somehow culpable concerning the unplanned power outage, the Ownership and Operating Agreement releases it from any potential damages relating to replacement power costs.

More important, it is my understanding that the Root Cause Analysis does not find PPLM at fault concerning the unplanned power outage. Nor does it appear that either the Montana Consumer Counsel or the other intervening party claims that PPLM is culpable. Thus, it does not appear that there is any basis for a suit by NorthWestern against PPLM.

In addition, complex commercial litigation, such as this case, would be expensive and time-consuming, and any suit for recovery by NorthWestern against PPLM would not be prudent or advisable.

Q. Does this conclude your testimony?

A. Yes, it does.

ORIGINAL

GENERAL AGREEMENT

FOR

SUPPLY OF EQUIPMENT, FIELD SERVICES, SHOP REPAIR SERVICES AND TECHNICAL SERVICES

BETWEEN

PPL SERVICES CORPORATION
AND
SIEMENS POWER GENERATION, INC.

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Attachments:

Exhibit A - Supplemental Terms & Conditions for PPL Susquehanna, LLC
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Exhibit F – Release
Exhibit G – PPL Affiliates
Exhibit H – Proprietary Information Agreement
Exhibit I – Contractor's Major Competitors

[redacted]

Article 81 – Limitation of Liability

BOTH PARTIES EXPRESSLY AGREE THAT NEITHER PARTY NOR ITS SUPPLIERS WILL UNDER ANY CIRCUMSTANCES BE LIABLE UNDER ANY THEORY OF RECOVERY, WHETHER BASED IN CONTRACT, IN TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY), UNDER WARRANTY, OR OTHERWISE, FOR: ANY INDIRECT, SPECIAL, INCIDENTAL OR CONSEQUENTIAL LOSS OR DAMAGE WHATSOEVER; LOSS OF ANTICIPATED PROFITS OR REVENUE (EXCLUDING ANY PROFIT THAT MAY BE DUE CONTRACTOR FOR WORK PERFORMED); LOSS OF USE OF MATERIAL, EQUIPMENT OR POWER SYSTEM; INCLUDING BUT NOT LIMITED TO CAPITAL COST, FUEL COST AND COST OF PURCHASED OR REPLACEMENT POWER; OR LOSS OF USE OR CLAIMS OF CUSTOMERS. THIS PARAGRAPH SHALL NOT BE DEEMED TO LIMIT OR RESTRICT: (A) EITHER PARTY'S LIABILITY AND OBLIGATIONS ARISING UNDER ARTICLE 33 (INDEMNITY) AND EXHIBIT A, ARTICLE 5 (NUCLEAR INSURANCE) OR (B) PPL'S LIABILITY AND OBLIGATIONS TO INDEMNIFY CONTRACTOR FOR ANY CONSEQUENTIAL DAMAGES ACTUALLY PAID BY CONTRACTOR TO A THIRD PARTY PURSUANT TO THE LAST SENTENCE OF ARTICLE 82.]

BOTH PARTIES EXPRESSLY AGREE THAT UNDER NO CIRCUMSTANCES SHALL THE TOTAL AGGREGATE LIABILITY OF EITHER PARTY UNDER ANY THEORY OF RECOVERY, WHETHER BASED IN CONTRACT, IN TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY), UNDER WARRANTY, OR OTHERWISE, EXCEED THE TOTAL AGREEMENT COMPENSATION UNDER THE APPLICABLE CONTRACT, EXCLUDING ONLY OBLIGATIONS AND LIABILITY PURSUANT TO (A) ARTICLE 33 (INDEMNITY), (B) ARTICLE 34 (PATENT, COPYRIGHT AND TRADEMARK INDEMNITY), (C) ARTICLE 50 (CONFIDENTIAL INFORMATION), (D) ARTICLE 80 (DAMAGE TO PPL PROPERTY), (E) FINES OR PENALTIES FOR FAILURE TO COMPLY WITH ARTICLE 85 (ENVIRONMENTAL COMPLIANCE), AND, IF APPLICABLE, (F) EXHIBIT A, ARTICLE 5 (NUCLEAR INSURANCE); PROVIDED, THAT ANY AMOUNTS PAID OR PAYABLE BY PPL HEREUNDER SHALL NOT BE INCLUDED IN APPLYING THE LIMTATION OF LIABILITY OF PPL SET FORTH IN THIS PARAGRAPH. WHERE LIQUIDATED DAMAGES ARE PROVIDED IN THE CONTRACT, THEY SHALL BE, TO THE EXTENT APPLICABLE TO THE CONDITION FOR WHICH THEY APPLY, THE EXCLUSIVE REMEDY OF PPL FOR THE TYPES OF DEFAULTS FOR WHICH THEY ARE DESIGNATED AS EXCLUSIVE IN THE CONTRACT.

THE PROVISIONS OF THIS ARTICLE SHALL PREVAIL OVER ANY CONFLICTING OR INCONSISTENT PROVISIONS SET FORTH ELSEWHERE IN THIS CONTRACT.

THE MONTANA POWER COMPANY

AND

PUGET SOUND POWER & LIGHT COMPANY

AND

THE WASHINGTON WATER POWER COMPANY

AND

PORTLAND GENERAL ELECTRIC COMPANY

AND

PACIFIC POWER & LIGHT COMPANY

OWNERSHIP AND OPERATION AGREEMENT

Colstrip Units #3 & #4

OWNERSHIP AND OPERATION AGREEMENT

COLSTRIP UNITS #3 & #4

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At the same time, the amount of such reduction shall be added to the Project Shares of the Project Users giving such notice in the proportion that their respective Project Share bears to the total of the Project Shares of all Project Users giving such notice. Each of the Project Users shall pay or cause to be paid that part of the total cost of repair in the proportion that its Project Share bears to the total of the Project Shares of all Project Users giving such notice. Upon completion of repair, a second adjustment of the Project Share of each Project User will be made by substituting the actual expenditures for repair for the estimated expenditures in the above formula and adjusting the Project Share of each Project User to compensate for any increase or reduction of Project Share.

(c) Solely for the purposes of this Section 19, the depreciated value of the Project at any time shall be based on the original Costs of Construction of the Project (excluding allowance for funds used during construction), including additions and less retirements, depreciated on a straight-line basis using a composite life of 35 years.

20. Liabilities

Each of the Owners and Project Users releases all other Owners and Project Users and their respective directors, officers, employees and agents, from any consequential damages (including, but not limited to, any loss of use, revenue or profit and any replacement power costs except as otherwise provided by Section 6(d) of the Transmission Agreement) arising out of the Construction or the operation, maintenance, or repair of the Project.

21. Default

(a) Upon failure of a Project User to make or cause to be made any payment when due, or to perform or cause to be performed any other obligation to be performed by it pursuant to the terms, covenants and conditions contained in the Project Agreements, any other Project User may make written demand upon said Project User for such payment or performance. Any Project User making such a demand shall concurrently deliver copies of the demand to all other Project Users and Owners.

(b) If the failure of a Project User is to make a payment when due and such failure is not cured within five (5) days from the date of a demand made pursuant to Section 21(a), it shall constitute a default at the expiration of such period.

(c) If the failure of a Project User is to perform any obligation contained in the Project Agreements other than to make payments when due and such failure is not cured within 30 days from the date of a demand made pursuant to Section 21(a) or, if it could not be cured within said 30 days, within a reasonable period

Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF FRED LYON

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Fred Lyon Resume	Exhibit__(FL-1)
Article on EPC Contracting	Exhibit__(FL-2)
Sample Agreements	Exhibits (FL-3) - (FL-9)

Witness Information

Q. Please state your name and business address.

A. My name is Fred Lyon. My business address is 941 W. Morse Boulevard, Suite 100, Winter Park, Florida 32789.

Q. By whom are you employed and in what capacity?

A. I am employed as the sole partner of the Lyon Firm, P.A., a law firm which specializes in construction law and contracts, with emphasis on the electric utility industry. I also am the managing director of TriCon Power Group, a construction contracts consulting group which provides training and recommendations to utilities regarding project management and delivery, risk allocation, and the proper utilization of commercial terms and conditions.

Q. What is your educational background?

A. I am a 1970 graduate of Duke University with a Bachelor of Arts degree in History. I graduated from the University of Virginia School of Law with a Juris Doctor in 1976. In 2009, I received a Master's degree in Liberal Studies from Rollins College. I also am a mediator with previous certification in North Carolina and training at Duke University and the Harvard Law School Program on Negotiation.

Q. Did you file prefiled direct testimony in this docket?

A. No, I did not.

Purpose of Testimony

Q. What is the purpose of your prefiled rebuttal testimony in this docket?

A. NorthWestern Corporation d/b/a NorthWestern Energy ("NorthWestern") has retained me as an expert witness to testify regarding whether a waiver of consequential damages clause is a standard industry clause in contracts between turbine manufacturers and utilities. In addition, NorthWestern has retained me as an expert to testify regarding whether utilities typically obtain business interruption (outage insurance) in connection with the construction, maintenance, or repair of fossil fuel power plants.

Q. What are your general qualifications to testify as an expert on this issue?

A. Since 1977, I have worked as an attorney and consultant with offices in Washington, D.C. and Florida. I have specialized in construction law and contracts with a focus since 1977 on the electric utility industry and its procurement practices. In that capacity, I have drafted and negotiated numerous contracts involving equipment supply, construction, and design in connection with the construction of power projects. Included among these contracts are agreements between utilities and turbine manufacturers. I routinely am a member of a utility's project team which decides upon the particular risk profile for a project which includes, without limitation, real time decisions on the most appropriate contract language

and the related insurance risk profile. These decisions are made considering the utility's particular needs and consistent with standard risk and insurance practices in the industry at large. I am very familiar with the language of construction agreements, the clauses which are considered to be industry standard, and typical insurance profiles. In addition to having worked with a number of utilities on these issues, as outlined below, I have written, spoken, and taught frequently regarding procurement practices in the energy construction arena. I have attached as Exhibit__(FL-1) a resume which describes my experience in greater detail.

Q. Describe the types of utility projects on which you have worked.

A. I have worked on nuclear, coal, integrated gasification combined cycle, hydropower, and natural gas (combined and simple cycle) contracts and projects, including baseload generation and peaking capacity. I have also worked on environmental contracts, including related equipment supply, for brownfield and greenfield projects and contracts for the construction of transmission systems. Brownfield projects typically are coordinated with scheduled outages and require careful planning. I have also worked on projects involving unplanned outages and the repair of defective equipment, including turbine blades.

Q. Identify power industry clients for whom you have provided contract drafting, review, and negotiation services.

A. I have provided such services to several of the largest regulated utilities in the United States, including American Electric Power and its various subsidiaries (AEP Ohio, AEP Texas, Appalachian Power, Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, Southwestern Electric Power Company), Duke Energy, Progress Energy and its predecessor, Florida Power. I have also provided such services to Tampa Electric, the Orlando Utilities Commission, Sierra Pacific, PNMR Resources, International Power, EcoElectrica, and the Florida Municipal Power Association. In addition, I have provided workshops to Alliant Energy. Although I primarily work with utilities, I have also represented industry vendors and contractors such as Areva, Toshiba, J.A. Jones Construction, Victory Energy, and Barton Malow.

Q. Are you currently working with some of these entities on such services?

A. Yes. I am currently working with American Electric Power, Duke Power, Toshiba, and Victory Energy in drafting, reviewing, and negotiating contracts for equipment supply and construction of environmental and baseload facilities.

Q. Identify representative industry-related writings which you have authored.

A. "Improved Construction Contracting for the 1990s," Power Engineering, June 1991.

"Controlling Dispute from Start to Finish – Partnering, Project Neutrals, Mini-trials, Design Review Boards, Mediation," Construction Law Handbook, 1998.

"EPC Contracting in a Seller's Market – Should It Still be the Project Delivery System of Choice?" World Generation, 2001. A copy of this article is attached as Exhibit__(FL-2).

"Controlling Dispute by Controlling the Forum: Forum Selection Clauses in Construction Contracts," The Construction Lawyer, American Bar Association, 2002.

"Force Majeure and Power Plant Construction Delays: Too Much Terror Not Enough Labor," World Generation, 2005.

"Mediation," Construction Law Handbook, 2008.

"Contracting Strategies," Florida Construction Users, 2010.

"Collaborative Contracting," Southeastern Construction Owners, 2012.

"Engineer-Procure-Construct Contracting in a Changing Climate," World Generation, 2013.

In addition, in 2009, Pennwell Publishing retained me to provide the peer-review of a proposed industry standard textbook on utility contracting strategies and contracts.

Q. Identify representative industry-related speaking engagements which you have had.

A. "Construction Claims on the Project-financed Job," Forbes conference, 1992.

"Dispute Avoidance in the Construction of Power Plants," Florida Business Roundtable, 1992.

"OSHA Enforcement and the Power Industry," Southeastern Electric Exchange, 1992.

"Industry Legislative Updates," Edison Electric Institute, 1994.

"Contracting in the Power Industry," EXNET, 1996.

"Contracting for the Next Generation of Coal-fired Power Plants," CoalGen 2001.

"EPC Contracting in a Seller's Market," PowerGen 2001.

"EPC Contracts in the International Market," Forbes conference, London, 2002.

"Managing Construction Risk in an Uncertain World," PowerGen 2002.

"Energy, Politics, and Risk," Association of Edison Illuminating Companies, 2003.

"Lessons Learned in Energy Construction," Electric Power, 2003 and 2007.

"Good Jobs Gone Bad," PowerGen 2003.

Series of presentations at PowerGen from 2004 until present on contracting strategies and typical, industry standard contract language.

Series of presentations from 2009 until present to American Boiler Manufacturers Association on contract clauses and commercial language.

Since 1994, I have also provided utilities project management training on commercial terms and conditions. These workshops usually last one to two days and familiarize utility personnel with industry standard terms and conditions.

Q. Describe any industry honors or recognition which you have received.

A. Outstanding Energy Leader, World Generation, 2003.

Duke University Founders Society.

Outstanding Lawyer, Chambers.

Super Lawyers and Best Lawyers in America.

AV rated, Martindale Hubbell.

Consequential Damages

Q. Article 81 of the January 1, 2006 Agreement between Siemens Power Generation, Inc. ("Siemens") and PPL Services Corporation ("PPL"), which is attached as Exhibit__(JHG-1) to the Prefiled Rebuttal Testimony of James H. Goetz, provides for a mutual waiver of consequential damages between the parties. In your opinion, is such language typical of a contract between an Original Equipment Manufacturer ("OEM") such as Siemens and a utility?

A. Yes. As described below, it is my experience that such waivers of consequential damages are the industry standard, included routinely in major equipment (including but not limited to turbines and generators) repair and construction contracts utilized in the power construction industry. That experience is reflected on page 9 of my article, "EPC Contracting in a Seller's Market – Should it Still be the Project Delivery System of Choice?" that is attached as Exhibit__(FL-2). In addition, I have negotiated and reviewed numerous such contracts between utilities and Siemens (including its predecessor companies). A mutual waiver of consequential damages has been included in every Siemens contract that I have negotiated or reviewed.

Q. Please discuss the various types of damage clauses associated with major equipment contracts and warranties.

A. Damages that result from a breach of contract or breach of warranty are of two types – direct and consequential. Direct damages such as the costs of repair, re-design, or equipment replacement are the immediate result of the breach. Consequential damages, while they must be reasonably foreseeable, are more incidental and remote from the actual breach. Consequential damages are beyond the contract itself; they implicate damages that do not directly involve, for example, the product itself but foreseeable losses that the non-breaching party may experience as a result of the failure of the product. Examples of consequential damages include loss of use, loss of goodwill, cost of substitute facilities, and the

cost of replacement power. In the power industry, the customary waiver of consequential damage clauses used in the typical equipment supply or construction contract will usually enumerate examples of consequential damages. Such enumerations frequently will identify the "cost of replacement power" (or include words to that effect) as one type of consequential damage which a utility agrees to waive.

Q. Describe how consequential damages are treated in the Siemens – PPL agreement.

A. Article 81 of that agreement contains a waiver of consequential damages which is customary and typical of such clauses in the power industry and in connection with the purchase of major equipment such as turbines and generators. The section also specifically provides that the "cost of purchased or replacement power" is within the scope of the waiver. Again, such a waiver with respect to the recovery of replacement power from a vendor is typical and well within customary industry practices and has been included in every Siemens – utility contract that I have negotiated or reviewed.

Q. Are you able to provide copies of other agreements which contain a waiver of consequential damages?

A. Yes. Attached hereto as Exhibit__(FL-3) through Exhibit__(FL-8) are the recital pages and relevant language from Sample Agreements as found in the legal database Westlaw/Construction Law Section/Sample Contracts.

Each of these agreements, including contracts which provide for turbines and those for engineering and construction, contains a waiver of consequential damages as I have described in my testimony and consistent with industry practices and standards. The agreements include:

Engineering, Procurement and Construction Agreement between Georgia Power Company/Oglethorpe Power Corporation and Stone & Webster/Westinghouse Electric Company LLC, Section 17.1 (April 8, 2008) available in Westlaw/ Construction Law Section/Sample Contracts. Construction of nuclear power plant, including turbines.

Engineering, Procurement and Construction Agreement between Florida Power Corporation, d/b/a Progress Energy Florida, Inc. and Westinghouse Electric Company LLC/Stone & Webster, Section 17.1 (Dec. 31, 2008) available in Westlaw/ Construction Law Section/Sample Contracts. Construction of nuclear power plant, including turbines.

Engineering, Procurement and Construction Agreement between South Carolina Electric & Gas Company and Westinghouse Electric Company LLC, et al., Section 17.1 (May 23, 2008) available in Westlaw/ Construction Law Section/Sample Contracts. Construction of nuclear power plant, including turbines.

Development and Construction Services Agreement between Grant County Wind, LLC and Juhl Energy Development, Inc., et al., Section 11.b (Nov. 6, 2009) available in Westlaw/ Construction Law Section/Sample Contracts. Wind turbines supplied by Owner under separate contract.

Contract for Engineering, Procurement and Construction Services New Plymouth Power Plant between Idaho Power Company and Boise Power Partners Joint Venture, Section 26.2 (April 2009) available in Westlaw/ Construction Law Section/Sample Contracts. Turbine supplied by Owner under separate contract.

Engineering and Construction Agreement between Duke Energy Carolinas, LLC and Shaw North Carolina, LLC, Section 17.1 (May 5, 2008) available in Westlaw/ Construction Law Section/Sample Contracts. Turbines supplied by Owner under separate contract.

Also attached hereto as Exhibit__(FL-9) is an agreement for the sale of goods – Equipment – Turbine Generator from 18 American Jurisprudence Legal Forms 2d which provides for a mutual waiver of consequential damages in Section 10.M. Again, this clause is typical of such clauses standard in the power industry and in connection with the sale of turbines to utilities.

Q. What is the rationale for such consequential damage waivers?

A. Equipment supply, repair, and construction contracts in the power industry are risk allocation documents. Vendors and contractors are unwilling to take on the potentially unlimited risk of such consequential damages. Potentially, a plant may be shut down for a long period as a result of a repair or warranty issue. Such shutdowns can be for many months or even years and could potentially require the construction of a whole new replacement facility. Consequential damages in those instances could be billions of dollars. A turbine manufacturer is not willing to absorb that risk. If vendors and contractors were required to take the risk of consequential damages, they would include a substantial contingency in their price to protect their significant risk exposure. In that instance, the contract price would be higher and the utility would pay for the contingency even in the event consequential damages were never actually incurred. By incorporating a waiver of consequential damages, the utility reduces the cost of the original contract and provides the potential to deliver the project at a significantly reduced price.

Q. Is it reasonable for NorthWestern's customers to pay the consequential costs (i.e. replacement power) of the 2013 Colstrip Unit 4 forced outage?

A. The agreement and attendant waiver of consequential damages (including replacement power costs) that PPL entered into with Siemens was typical of the industry and of such agreements with turbine suppliers. By agreeing to a clause which is customary and consistent with what was

available in the market, PPL acted reasonably and prudently, and to the extent that NorthWestern paid a portion of these replacement power costs at Colstrip, it also acted reasonably and prudently.

Q. In your experience negotiating contracts and assisting in insurance risk profiles for fossil fuel plants and in light of the waiver of consequential damages, is it typical for utilities to obtain business interruption (outage) insurance as an alternative for the cost of replacement power?

A. No. Such insurance policies are expensive and may incorporate a large deductible with exclusions, policy limits, and restrictions on recovery based on market fluctuations. In light of the expense and the policy terms, utilities typically do not consider such policies to be cost effective and thus elect not to obtain such coverage in connection with equipment, construction or repair contracts for fossil fuel plants.

Q. In your experience in the power industry, are there situations when owners of plants elect to purchase business interruption (outage) insurance?

A. Yes. Independent power producers ("IPPs") are more likely to purchase such insurance. Unlike investor-owned utilities, IPPs are more likely to be thinly capitalized and also with less access to replacement power sources. Moreover, because they are unregulated, IPPs can incorporate the cost of insurance into their rates depending upon market conditions.

Consequently, such IPPs may purchase such insurance as a hedge against the need to purchase replacement power and as a condition of their financial arrangements with their lenders. Also in the case of investor-owned utilities that own nuclear plants, it is more common for the utility to purchase outage insurance. There are several reasons for this difference. The nuclear industry typically strives for greater redundancy in its entire risk profile, from safety to quality assurance/quality control to insurance. Because nuclear outages can be extensive, expensive, and the repairs can be difficult, utilities may opt for outage insurance. Because of these factors, the industry has formed a mutual insurance company, the Nuclear Electric Insurance Limited, as an alternative to the commercial market to sell outage insurance which, subject to deductibles and exclusions, covers, inter alia, the cost of replacement power in the event of an outage at a nuclear facility. There is no similar company servicing the fossil industry.

Q. In his Pre-Filed Direct Testimony on behalf of the Montana Environmental Information Center and the Sierra Club, Mr. David Schlissel has offered his opinion that prior to June 2013, it was imprudent for NorthWestern not to have evaluated or considered whether to procure business interruption insurance in connection with the scheduled Colstrip outage. Do you agree?

A. No. It is well known in the industry that such insurance is expensive and, because of its costs, limits, restrictions, and terms, not a cost effective

option. A telephone call or similar inquiry to obtain information already known to discuss insurance not usually purchased would have been elevating form over substance. NorthWestern's decision not to purchase such insurance (and not to make an inquiry to substantiate such a decision prior to the 2013 outage) was reasonable and prudent. Requiring the inquiry as a condition of a prudency determination would be a mechanistic solution to the complex determinations of risk made when a contract is being negotiated and finalized.

Q. Does this complete your rebuttal testimony in this matter?

A. Yes.

V. Frederic Lyon

An attorney for 38 years, Fred Lyon has practiced energy and power plant construction law and litigation on a national basis with offices in Washington D.C., Virginia, and Florida. He is experienced in engineering-procure-construct (EPC) power plant contracts and has worked with many of the industry's largest owners and utilities (including two of the three largest utilities in the United States), vendors, architect/engineers, and contractors. He has prepared and negotiated power industry contracts whose total values is between $15 and $20 billion. He has worked on greenfield, brownfield, and outage based projects. A long time proponent of alternative dispute resolution, he has substantial experience in its various forms, including arbitration, mediation, and nonbinding mini-trials. He has practiced as an advocate in a significant number of energy construction mediations and arbitration and has provided alternative dispute resolution services as a neutral, both as a mediator and arbitrator. He writes and speaks frequently on these issues to members of the bar and to energy trade associations and construction industry groups interested in reducing the costs of dispute resolution. Mr. Lyon currently practices with The Lyon Firm, P.A., with offices in Florida. He is also of counsel to Shields Mott, a New Orleans . firm specializing in construction and commercial law. Mr. Lyon is also a principal in TriCon Power Group which provides project delivery recommendations and training to the power industry.

Areas of Special Interest

- Construction Law; Energy Law; Power Plant Construction; EPC contracts; Mediation and Arbitration

Education

- Duke University A.B. 1970
- University of Virginia School of Law, J.D. 1976
- Rollins College, Masters of Liberal Studies, 2009

Mediation Training

- Harvard Law School Negotiating Project
- Duke University Law School, Private Adjudication Center, Certified Mediator Training
- Advanced Mediation Training, Center for Dispute Settlement, Washington D.C.
- American Arbitration Association, Mediator and Arbitrator Training

ADR Certifications and Memberships

- Panel of Neutrals, Construction Panel, American Arbitration Association
- Certified Civil Mediator, North Carolina
- Member, American Bar Association Section on Dispute Resolution

Experience

- Former U.S. Naval officer
- Judicial clerkship, U.S. Claims Court, Washington D.C.
- 20 years experience in D.C. in private practice as senior partner in own firm prior to relocating to Florida in 1995 where he has continued to practice as senior partner in his own firm
- Practice primarily related to energy representing utilities, independent power producers (IPPs), A/E's, contractors, and original equipment manufacturers (OEMs). Project delivery

review, including EPC and alternative contracting systems. Involved in resolution of over $500 million in claims involving power plants and negotiation of numerous energy construction contracts totaling $15 to $20 billion in value. Structured project contracts and related insurance provisions.

- Principal, TriCon Power Group, a project management and delivery consulting company for the power industry

Representative Resolution/Transactional Experience in the Energy Industry

Types of Projects

- Nuclear plants in Washington, Florida, and Louisiana
- Coal plants in Florida, Arkansas, Oklahoma, New York, Massachusetts, Tennessee, Kentucky, Ohio, West Virginia, and Indiana
- Gas turbine plants, including simple and combined cycle in Florida, Louisiana, Texas, North Carolina, Virginia, Georgia, Wisconsin, Iowa, Puerto Rico, Canada, and New Mexico
- Clean coal plants in Indiana, West Virginia, Florida and Nevada
- Environmental retrofits in Florida, Arkansas, West Virginia, Georgia, Kentucky, Oklahoma, Texas, North Carolina, New Mexico, Iowa, Indiana, and Wisconsin
- Oil plant in Egypt
- Nuclear waste facilities in South Carolina and Washington
- Co-generation facilities in Florida, South Carolina, and New York
- Hydro-electric facility in Michigan
- Refinery in Michigan
- Fertilizer plant in Morocco

Types of Claims/Issues

- Bankruptcy
- Limitations of liability
- Delay, disruption and acceleration
- Performance guarantees and liquidated damages
- Safety, personal and property damage issues
- Demineralized water provisions
- Insurance coverage and subrogation
- Cost audits
- Environmental contamination and indemnification
- Differing site conditions
- Construction defects and warranty
- Professional malpractice
- Contract interpretation
- Terminations, default and convenience

Representative Mediation Experience

As an advocate and now as a mediator, Mr. Lyon has substantial experience in the mediation process for over twenty years. He has advocated numerous times throughout the United States on behalf of clients in energy construction mediations involving subjects as diverse as delay claims, safety issues, acceleration and power plant tort claims. As a mediator, he has handled energy construction disputes, delay claims, insurance coverage, construction defects, and performance guarantees. His experience in all aspects of power plant construction, his long-time familiarity with mediation, his firm commitment to its goals, and his creativity make Mr. Lyon an effective and capable construction mediator.

Representative Writings/Speeches on Dispute Resolution

- "Your Lawyer as a Project Team Member," Partnering in Design and Construction, 1996
- "Mediation – How it Works," Florida Business Roundtable, 1997
- "Effective Partnering," Construction Law Superconference, 1996
- "Controlling the Dispute from Start to Finish – Partnering, Project Neutrals, Mini-Trials, Design Review Boards, Mediation," The Aspen Law Construction Law Handbook, 1998
- "Advantages of Business Mediation," Florida Business Roundtable, 2000
- "Lawyers and Mediation," American Arbitration Association, 2003
- "Anything but Litigation," World Generation, Spring 2004
- "Practicing Mediation," American Arbitration Association, 2004
- "Partnering and Dispute Avoidance in Power Plant Construction," Florida Business Roundtable
- "Mediation," Construction Law Handbook, 2007 to present

Honors

- Honored as member of Class of 2003, Outstanding Energy Industry Leaders, World Generation
- Charter Member, American College of Construction Lawyers
- Duke University Founders Society
- AV rating, Martindale Hubbell
- Chambers Outstanding Lawyers
- Super Lawyers and Best Lawyers in America
- Outstanding Instructor, Turner Construction Company Minority Contracting Course

Memberships

- Member D.C., Virginia, Maryland, Florida bars
- Member, American Bar Association Forum Committee on the Construction Industry; Sections on Dispute Resolution, Litigation, Public Contracts, Public Utility, Environment and Energy
- Admitted: 1976, U.S. Court of Federal Claims; 1978, U.S. District Court, District of Columbia; 1982, U.S. Court of Appeals, Fourth Circuit; 1983, U.S. District Court, Eastern District of Virginia; 1985, U.S. Court of Appeals, Federal Circuit; 1986, U.S. District Court of Maryland; 1989, U.S. Court of Appeals, District of Columbia Circuit; 1998, U.S. District Court, Middle District of Florida; and U.S. Court of Appeals, Eleventh Circuit

Representative Writings/Speeches

- "Improved Construction Contracting for the 1990's," Power Engineering, June 1991
- "Construction Claims on the Project Financed Job," Forbes Conference on Project Financing, 1992
- "Partnering and Dispute Avoidance in the Construction of Power Plants," Florida Business Roundtable, 1992
- "OSHA Enforcement and the Power Industry," Southeastern Electric Exchange, 1992
- "Legislative Updates," Edison Electric Exchange, 1994
- "Contracting in the Power Industry," EXNET, 1996
- "Controlling the Dispute from Start to Finish – Partnering, Project Neutrals, Mini-Trials, Design Review Boards, Mediation," The Aspen Law Construction Law Handbook, 1998
- "From CoGen to Coal Gen: EPC Contracting" World Generation, 2001
- "EPC Contracting in a Seller's Market," PowerGen 2001
- "Contracting for the Next Generation of Coal Fired Power Plants," Coal-Gen, 2001
- "Controlling Disputes by Controlling the Forum: Forum Selection Clauses in Construction Contracts," V. Frederic Lyon and Douglas W. Ackerman, The Construction Lawyer, American Bar Association, October 2002
- "Force Majeure and Power Plant Construction Delays, Too Much Terror, Not Enough Labor," World Generation, 2002
- "EPC Contracts in an International Power Market," London Forbes Conference, 2002
- "Managing Construction Risk in an Uncertain World," PowerGen 2002
- "Energy, Politics and Risk," Association of Edison Illuminating Companies Annual Meeting, 2003
- "Lessons Learned in Energy Construction," Electric Power 2003 and 2007
- "Good Jobs Gone Bad," PowerGen 2003
- Series of presentations at PowerGen 2004 until 2010 on power industry contracting strategies
- 2009 to present, speaker on contracting issues to American Boiler Manufacturers Association
- "Collaborative Contracting," Florida Construction Users magazine, 2012
- "EPC Contracting in a Changing Climate," World Generation 2013
- "Contracting Trends in a Changing Market," PowerGen 2013
- "Legal Issues in Boiler Leasing," American Boiler Manufacturers Association, 2014
- "International Contracting and Licensing: Risk Factors," American Boiler Manufacturers Association, 2015
- Frequent speaker to construction and industry groups, including Southeastern Electric Exchange, Forbes Magazine, Edison Electric Institute, Florida Business Roundtable, Coal-Gen, Power-Gen, American Boiler Manufacturers Association, Association of Edison Illuminating Companies

Community Service/Interests

- Member, Hannibal Square Community Land Trust, Committee, City of Winter Park, Florida
  Elder, Presbyterian Church U.S.A.
- Co-Founder, Corunthians®, a marathon and distance running organization
- Co-Chair, Duke University Leadership Gift Committee, Class of 1970
- Chairman, Parents Fund Council, Choate Rosemary Hall, 2009-2011
- Habitat for Humanity
- Volunteer coach, youth basketball and baseball
- Author, "When Not Performing: New Orleans Musicians," a book on New Orleans music published in 2012 by Pelican Press

E. P.C. CONTRACTING IN A SELLER'S MARKET - SHOULD IT STILL BE THE PROJECT DELIVERY SYSTEM OF CHOICE ?

Fred Lyon, The Lyon Firm, P.A.
Energy Construction Law

In the 1990s, owners, contractors, and vendors frequently utilized an engineer/procure/construct (EPC) approach to project delivery of new power plants ("turnkey" contracting). This system of project delivery evolved in the context of the independent power market and developing technology. The advantage was sole source responsibility and consolidation of risk, in theory to control and limit dispute. Now that the market is changing, with more balance sheet construction, an overheated market with contractors and vendors less willing to assume risk that they cannot control, and the need for rapid delivery, the question must be asked when and even whether EPC construction still makes sense. This presentation will address:

*Types of projects most and least appropriate for EPC contracting
*Which owners are best served by the turnkey approach
*How should the EPC team be configured
*Has EPC contracting actually resulted in less disputes and more timely, cost effective contracting?

Within this context, the important EPC contract clauses will be evaluated and recommendations for their use will be made, including:

*Wrap-around performance guarantees
*Liquidated damages
*Assurances of payment
*Dispute control
*Partnering and teambuilding

As the industry undergoes rapid evolution, old models of doing business need to be constantly re-evaluated. Even EPC contracting, a creature of the 1990s, needs to be scrutinized to see if it remains a preferred business model.

It is a truism that energy construction will remain a hot market for at least a decade. The most pessimistic observers forecast the need for one new power plant a week; those less gloomy nevertheless predict that a plant every other week will be required to avoid shortages and rolling blackouts (New York Times, May 2001). Under any circumstances, major environmental infrastructure will be mandated; attention is also only now being paid to the need for major investment in the too long-ignored transmission grid. In this context, builders of plants, environmental controls, and the grid will look to the most recent past to guide their decision regarding project delivery, risk allocation, and contracting. The attention will inevitably be captured by the EPC contracts which have dominated energy construction during the last decade.

Much has changed during that decade. Technology, environmental issues, and efficient project management have taken on new importance. Contracting techniques which worked in the days of a regulated environment where costs were almost always rolled without question into the rate base are no longer appropriate in an uncertain, deregulating, competitive environment. Project management, which is defined by the commercial terms of a contract and the attendant risk allocation, has especially been recognized as critical to a project's success.

Plants built in the 1990's were almost exclusively gas-fired, frequently constructed by thinly capitalized IPPs. The market has been sensitive to this reality in structuring contracts leading to the emphasis on EPC agreements. Moreover, the first to market often will determine the profitability of a project. One month improvement in a schedule can provide a generator critical access to a peaking season, generating millions of dollars in potential profits. Generators no longer simply manage tightly regulated assets; they sell electricity. Within this context, efficient and timely construction of new facilities directly bears on the short and long term profitability of the selling entity. As outlined below, the allocation of risk in connection with a construction contract no longer can be viewed as simply a boilerplate activity - one way or another, such allocation will always go directly to a project's bottom line - for either the contractor or owner.

Technology and environmental issues will be an important part of the construction equation, influencing the decision whether to use an EPC approach. Both the owner and contractor must manage risk within a changing technological and environmentally sensitive arena. In any construction context, change is the primary risk and danger which will extend schedule and increase costs. Continued uncertainty about environmental regulations (and shifting political allegiances) will impact the construction of new energy facilities and must be factored into the equation of project delivery and EPC contracting. Blindly using an EPC approach, which while effective has nevertheless not been without its problems, will insure problems during the next round of construction. Continued cautious calibration of the risk equation should determine whether an EPC approach is appropriate.

Historical context. Anticipating where the EPC construction market is heading requires an understanding of its historical roots. Prior to the 1990s, plants were typically built by investor-owner utilities utilizing tried and true technology with very conservative project delivery systems. They were typically constructed using the traditional approach to construction - design/bid/build with the utility contracting first with any one of several established Architect/Engineer design firms to engineer the facility and then with a general contractor who built the plant. Frequently these contracts were on a cost-plus basis with few incentives to control costs. During the 1980s, as rate commissions became more cost sensitive, the industry moved away from a single general contractor to experimenting with a lump sum, multiple-prime approach which required greater coordination and occasionally led to cost overruns. However, because the market remained non-competitive, few problems resulted with prudency reviews still typically allowing the recovery of most, if not all, costs associated with the construction of new coal-fired capacity.

Everything changed in the 1990s - including who was building, what they were building, and how they were contracting. Instead of IOUs, the owners were IPPs and the emerging national energy companies; instead of coal and nuclear plants, the project of choice was typically gas fired, both base load and peaking; instead of cost plus traditional contracting, the delivery system of choice became engineer-procure-construct (EPC) or some variation thereof. A host of evolving regulatory and statutory incentives encouraged first the IPPs and then the national energy companies to build new gas facilities. These comparatively new players in the market had different incentives and agendas than the IOUs which directly impacted how they chose to contract for the construction of their new power plants.

In the case of the IPPs, the financing of project was obviously critical. Their projects were not funded off a healthy balance sheet with equity to back-stop the risk in a deal. They were more typically project-financed by any one of several international or domestic lenders notoriously unenthusiastic about risk. These risk-averse lenders demanded that their thinly capitalized borrowers, the IPPs, proceed on a non-recourse basis with a contractor to whom as much (ideally all) risk should be shifted.

Performance - schedule - environmental issues - the lenders for a typical gas project insisted that the EPC contractor assume the risk for virtually all contingencies. Sole source responsibility was intended to obviate problems and reassure skittish lenders. The construction contracts reflected this harsh, often inequitable risk shifting approach (by way of full disclosure, the author believes that the best way to insure successful contracting is for risk to be borne by the party best able to control it, hence risk sharing; risk-shifting contracts, which often serve other agendas, are more likely to result in dispute and contention by the end of the project). The EPC contracts were heavily laden with onerous liquidated damage clauses and associated schedule and performance guarantees, often with no limitation of potential EPC liabilities.

The national energy companies were perhaps more equipped to finance these gas projects off their balance sheets. But as aggressive competitors in a volatile and potentially enormously profitable market, they had their own important construction considerations with a particular emphasis on the premium of being first to market. Consequently, they contracted for speed, with incentives for timely and even early completion and reliance on management techniques like partnering to avoid time-consuming and divisive dispute. Again EPC approaches were favored.

In the case of both the IOUs and national energy companies, environmental considerations dictated the construction of gas-turbine projects. The market reflected increasingly reliable and clean technology with a period at least through the end of the decade into 2000 of comparatively stable fuel prices. Both the IOUs and national companies relied extensively on the EPC model for which they were willing to pay as much as an 8 to 15% premium (for the assumption of risk by the contractor) - emphasis was placed upon the use of performance specifications rather than the detailed design specification approach typically used by the traditional IOU. Performance, not design, was the key. The emphasis was on schedule and performance; the EPC construction contracts reflected these realties of the marketplace.

The contracting industry which serviced this market consisted of the AE firms and the large contractors experienced in the construction of generating facilities. There was consolidation and innovation within this industry - with both the designers and contractors reacting to the use of the EPC model by reaching across the old bright line of responsibilities to begin doing work which they traditionally had left to others. In their enthusiasm to service and support this gas market, these E&C firms initially were too willing or enthusiastic in assuming risk that they often could not control during the construction process - a prescription for financial problems if not disaster.

These E&C contractors would take performance wraps on equipment which they had not purchased or specified; they too often agreed to unrealistic schedules, with either non-existent or relatively narrow limitation of liabilities. The consequence was a number of financial disasters for large E&C contractors. This experience, together with the recent surge in demand, creating a seller's market, has led these contractors to take a more aggressive stance in limiting their risk - walking away from jobs where they are being asked to assume risks that they cannot control, especially with regard to performance and schedule. These E&C contractors are including greater contingencies in their prices (driving up capital costs generally), insisting upon extensive limitation of liabilities, and even demanding a return to cost-plus contracting with incentives.

These realities of the 1990's market will impact the next round of construction and how the projects are constructed. Technology, performance, and schedule will dominate this market in ways completely different from the construction of these plants 20 to 50 years ago. Moreover, the enormous need for new plants, grid capacity will put a tremendous strain on the delivery systems being used. In the gas turbine market, equipment availability is the driving force of construction - but any delays in this process has a ripple effect throughout the entire construction phase. Even more importantly to construction generally is the developing labor shortage, in both engineering and construction. Some estimate a labor shortage of 20-30%, exacerbated by the lack of experienced engineers and project managers. This shortage of skilled designers and craftsmen to build new plants is a fast developing problem that will slow down construction and again go right to the bottom line. A critical factor of the construction risk allocation process will be who will bear the risk of the shortage of labor and engineers.

Within this environment, owners considering the construction of new facilities of whatever type will need to determine what kind of project delivery system best serves their interests - traditional v. EPC, single contractor v. multiple primes, lump sum v. cost plus. As the 1990's market has demonstrated, different owners have different agendas and different risk parameters. Lenders may continue to dictate that project-financed jobs shift all risk to the contractors, suggesting continued reliance on the EPC model with its 8-15% premium. Large IOUs and national energy companies may have sufficient in house construction expertise to parcel out the different construction tasks and to avoid payment of the premium. Builders of all facilities will face the same areas of concern, however, as the IPPs and national energy companies, including:

*Performance risk - with guarantees and warranties
*Schedule risk - with allocation of the risk of delay, liquidated damages, and

force majeure (with labor shortages as a component).
*Limitation of liabilities - the appropriate level of caps and consequential damages.
*Environmental risks- changing political environment
*Dispute control - partnering and techniques to avoid litigation, including disputes review boards, structured negotiations, and mediation.

How the industry addresses these concerns in their construction contracts will translate directly to the bottom line - profits, not traditional prudency, will dictate the appropriate allocation of risk. Every project is different; careful consideration of risk and the appropriateness of the EPC approach will determine profitably.

Project delivery systems. Not all project delivery systems are created equal; not all are right for every type of power plant construction. As outlined, the types most frequently encountered include traditional (Design-bid-build), design build or EPC, construction management, and multiple prime. Pricing can be structured in a variety of ways, including lump sum or fixed price, cost plus on a Not-to exceed basis, straight cost - plus, or cost plus with an incentivized fee structure.

IPPs in the gas market relied heavily on the EPC approach with a fixed price, often paying an 8 to 15% premium for the single source assumption of responsibility of virtually all risk by the EPC contractor. The EPC contractor could come in a variety of forms, including a large AE, contractor, or vendor who would then subcontract its engineering/procure/construct responsibilities as appropriate. The lead EPC role varies - each element of the industry will contend that they are best equipped to serve this responsibility. Increasingly, however, there appears to be reliance on a joint venture as the EPC contractor with appropriate allocation of responsibility in accordance with expertise and financial investment. In that context, joint venture partners who have worked together previously are generally most successful. If a single entity is to be selected, some give less preference to a large contractor with AEs and OEMs less favored

National energy companies also have relied upon the EPC approach. These companies have often locked up large number of turbine contracts with any one of the several OEM vendors. They will then assign these contracts to the successful balance of plant EPC contractor. Under these circumstances, it is especially important for the parties to agree on how the risk of non-performance of the assigned vendor's equipment will be allocated. The balance of plant contractor should be certain that its risk is co-extensive ("back to back" or "flagged up") with or less than that of the vendor who should bear the risk of the non-performance of its equipment. EPC contracts in the 1990's have too often involved assumption of risk of immature technology, with the contractor left holding a very large bag.

Given the recent experience of the energy construction industry with the EPC project delivery system, it is likely that the initial approach to construction of facilities will inevitably focus on the EPC approach. Certainly owners will consider this system in opposition to the traditional approach ("design-bid-serve") they used in the past. In that context, the IOU owners and experienced national energy companies should avoid rushing blindly down the EPC road which carries with it a toll of 8

to 15%. This premium can be avoided if the Owner assumes some risk itself and focuses instead on an aggressively managed construction program relying upon its own in-house staff (lenders may not permit this in the context if a project-financed job). In this context, even a multiple prime approach may be more cost effective. Not only can construction packages be broken down into the traditional trades such as mechanical, electrical, or construction, innovative utilities should consider dividing the construction by facility - even considering transferring the construction and ownership interest of parts of the plant to other, profit-making entities (e.g. the SCRs or other environmental control systems which generate marketable byproduct). It would be a mistake for owners to assume that the EPC project delivery system relied upon in the gas industry is always and necessarily the best approach. Before deciding upon this approach, all the various alternatives should be realistically priced. In a competitive market, an 8 to 15% capitol premium may spell the difference in profitability.

Pricing. The need for certainty and profits would seem to suggest that the best way to price the next round of construction would be on a lump sum or fixed price basis. Unfortunately, the market appears likely to make that approach problematic (again lenders complicate this analysis on project-financed jobs). As discussed, E&C contractors, once burned, are not going to agree to lump sum these contracts, especially in the light of the serious craft and design labor shortage. Already prominent AEs are retreating from the wholesale assumption of uncontrollable risk. The largest component of risk dictating schedule is labor; E&C contractors are reluctant to lump sum this risk given the developing shortages.

Rather than hard money , the preferred approach now is a variation of cost plus, with the owner and contractor agreeing to certain target incentive involving labor and safety and other measurable indicia of efficient performance. The contractor will agree to put part of its fee at risk, depending on how well the various incentives are achieved, but under no circumstances does the contractor assume the risk of cost overruns. Alternatively, the parties will agree on target manhours and productivity rates, with the owner to gain the benefit of any improvements on these targets, but also assuming the risk of any overruns. The E&C community will either shift or share the risk of these marketplace labor realities to the owner which will need to pay a greater construction cost to reflect these conditions.

Risk allocation. A construction contract does nothing but allocate risk. EPC contracts are no different, with most risk by definition allocated to the contractor. Whoever assumes an allocated risk ideally is compensated accordingly. <u>The best contracts are ones where a party assumes only those risks which it is in the position to control</u>. However that is not always the risk philosophy of either an owner or contractor, depending on the exigencies of the market and the financing of a particular project. Regardless, the primary areas of risk allocation and the related construction clauses will involve performance, schedule, force majeure, limitation of liability, payment, and dispute control and resolution. Although EPC contracts endeavor to shift most of these risks to the contractor, hybrid approaches insure theses issues will remain part of every negotiation.

Performance risk. The energy construction industry of the 1990's, with its emphasis on technology and balance sheet financing, has placed special emphasis on performance. EPC contracts

are intended to implement sole source responsibility for performance. Lending and environmental constraints require no less. Therefore these EPC contracts are replete with performance guarantees and associated liquidated damages for failure to comply with performance specifications. The resulting contracts will delineate very specific performance demands or requirements, like the gas contracts, in the context of Net Heat Rate, Net Electrical Output, and availability. Enforcement of these guarantees is achieved by liquidated damages, subject to a negotiated cap (10 to 35%). These LDs must be reasonable (not a penalty) and bear an approximation to actual damage when forecast. Within the EPC environment and increasingly aggressive contractors and vendors, typical market LDs are as follows:

Schedule - $10,000 to $100,000 daily (with sliding scale)
NEO - $350 to $1,000 kwh (95%)
NHR - $10,000 to $100,000 btu/kwh (105%)

With respect to the various emission and environmental guarantees, the industry has proceeded on a must-fix basis to bring the unit into compliance with its various permitting obligations. Environmental constraints will remain critically important in coming years; must fix remedies will continue to characterize EPC contracts.

Scope of warranty. An unresolved issue in some EPC contracts is the scope of the warranty provided by the vendor. The confusion involves the liability of the vendor for downstream or collateral damage if its product proves defective. Owners prefer to contract for "bumper to bumper" coverage which imposes upon the vendor the obligation to repair all damage done by its defective part, at least within the confines of the supplied equipment. Vendors, not surprisingly, see the scope of this warranty much more narrowly, arguing that their obligation is only to repair a defective part and not collateral damage, even if it is within the configuration of the equipment provided by the vendor. This allocation of risk is directly dependent upon the wording of the warranty clause itself.

Unfortunately, within the as industry, these clauses frequently have not proven clear on this point, leading to dispute on the scope of warranty obligation if and when damage does occur. The parties should devote special attention to this issue as part of contractual negotiations; if addressed up front, any gaps can be covered by insurance. The worst result is if the parties do not squarely address the issue, each have a different interpretation, and then end up in an expensive dispute if and when damage does occur. Like all risk, it is best allocated by the parties prior to a dispute rather than by a third party like a judge after the problem arises. If not directly addressed, confusion will result, especially in the EPC environment.

Schedule risk. In an increasingly competitive market, one month can make all the difference - in access to a peak season, in fuel supply and prices, in increasingly sophisticated and risky trading. Gas turbine construction is relatively short time-framed in comparison to other facilities. Consequently, the EPC gas turbine contracts have placed a special premium on timely construction with associated liquidated damages and even incentives for early completion. This emphasis on speed has sometimes meant that construction begins before complete design, which can be a prescription for problems since a changed design can lead directly to cost overruns.

If the coal market re-energizes, schedule risks in the EPC contract are likely to be allocated somewhat differently. The three year construction of a coal plant provides the comparative luxury that there is simply more time to overcome the impact of a change or a mistake. The more time there is to finish a plant, the more float which is available to bring the project back onto schedule. Moreover, coal is priced more stably than the gas market which will vitiate the need for speed and allow the constructors of new coal facilities to focus on accuracy. Nevertheless, liquidated damage clauses tied to likely losses (and not a Penalty) will be included in coal construction contracts to properly incentive the contractor. Early completion bonuses are less likely since the market is simply less volatile than gas.

Classically risk of delay is also addressed by the inclusion in contracts of clauses which either allow or disallow the contractor's right to recover delay damages for owner-caused delays. These "no damage for delay" clauses are narrowly construed by most courts, but nevertheless can be drafted in such a way that they are enforceable. However, this is a risk shifting device which can be easily abused. To ask a contractor to pay for delay caused by an owner is potentially inequitable. The gas market has recognized this and moved away from these clauses. However, they can still be utilitized if narrowly crafted to delineate the specific types of damages which a contractor can recover in the event of delay. If approached on that basis, they are far less likely to give rise to contractor -inflated claims for extended offsite overhead. These clauses are more typical in the project financed EPC environment where the lender wants to avoid the risk of delays.

Labor shortages. The single most important issue in energy construction for the foreseeable future will be the labor shortage in both design and craft personnel. Given the lack of design on non-gas arenas over the last 20 years, design shortages in these sectors will be particularly acute. Coal plants will require even more skilled craftsmen than the comparative cookie cutter gas facilities. The result is that some observers think that all energy construction schedules should and will be extended by 20 to 40%.

The impact of this critical issue is already being felt. Recent market developments demonstrate that E&C contractors are insisting on pricing their contracts so that the risk of labor shortages are recognized and shared or shifted to the owner. If that does not occur, and a shortage results, E&C contractors are endeavoring to justify late performance by arguing that a labor shortage is a force majeure delay that not only entitles them to more time, but additional money.

While creative, this argument is simply not in accord with most, if not all, force majeure clauses. These clauses are intended to provide time only (not dollars) to a party whose schedules are impacted by an unanticipated risk outside its control. Such a risk would not include the availability of design or craft labor which is a risk a contractor or designer should have been able to anticipate when it signed the contract. It is a risk which, without further risk allocation, is uniquely within a contractor's control. Similarly, to argue that craft unavailability is the basis of an impossibility of impracticability excuse is also unjustified since economic hardship should and does not provide the basis for non-performance (see,e.g. the Westinghouse uranium cases form the 1970s and 1980s).

Again this is an issue, like warranty, that should be dealt with by the parties up-front. Pricing of the contract is the most appropriate place. But the parties should mutually address their expectations with regard to the availability of labor and its impact on the schedule. Schedules should be realistic in light of these expectations. E&C contractors should not oversell; owners should not over demand. Like the other risks associated with construction, this is one which should be considered as part of the contacting process. Under the circumstances, as a practical matter, it would also argue strongly in favor of contracting with an E&C contractor who has access to a skilled labor pool in the area within which the project is going to be located.

Limitations of liability. During recent years, increasingly risk averse E&C contractors who have significantly limited their liabilities in order to avoid financial catastrophe. These limitation of liabilities extend beyond the usual mutual waiver of consequential damages which have been and must continue to be part and parcel of energy construction contracts. Beyond that, however, the E&C contractors have been increasingly aggressive in limiting the scope of their liability for liquidated damages with respect to performance guarantees, schedule, and liquidated damages.

Typically, these Lds are limited separately for both performance (usually in the 10-20% of total contract value) and schedule (increasingly only 10-15% as a cap). Then overall Lds will be limited to 20-30% of the contract value. An overall cap on liability for any reason whatsoever is then attached to the contract - usually 100%, but in view of the LD cap and the consequential damage waiver, this risk in is considered minimal. These limits are far more aggressive than even 2 or 3 years ago, reflecting the reality of a once burned, risk averse marketplace. Such limits are likely to be pursued aggressively in the contractor-oriented markets place. They are simply too well-entrenched to be negotiated out of the industry approach to complex construction.

Payment and performance risk. The payment cycle, its timing and security, is also a significant component of the risk allocation. The owner must be certain that it is dealing with a financially viable entity. Typically, they have sought security of performance with either a letter of credit or corporate/parent guarantee, with surety bonds (and their premium of 1%) somewhat less common. Again the market is changing this reality as contractors shy away from corporate or parent guarantees. Contractors conversely need their own security of payment. In the case of gas contracts, payment risk has occasionally been addressed by aggressive from-end loading of payment to avoid the risk of later problems. This may be especially true in the case of contracts with limited liability companies on a non-recourse basis. However, in that context, it is important for both contractor and owner to pay attention to the payment process to insure that as it proceeds, both parties execute the necessary partial affidavits and waiver of liens to insure that the owner's interest in payment is protected while recognizing the contractor's right to lien in accordance with governing law. Contractors also should insist upon quick payment cycles to insure that they do not get too deeply into the job. Thirty days is typical with non-payment constituting a material breach. This reality is not altered by the EPC context.

Indemnification. Indemnifying or holding harmless another party to the contract for injury to a third party can take a variety of forms. A broad indemnity clause will provide that the contractor indemnifies the owner even for owner's sole negligence. An intermediate clause provides indemnity

if the contractor bears any responsibility for the incident; a narrow clause provides for proportional indemnity based on percent of responsibility. As the industry has matured, more and more contracts have moved away from disfavored broad or even intermediate indemnity clauses in the direction of a more equitable proportional indemnity. In this context, environmental indemnity also looms large. Owners typically take this risk. Contractors should insure that there is adequate owner financial stability since this exposure can be significant. Again the EPC environment does not change this risk allocation reality.

Dispute control. Dispute on a major construction process is inevitable. No contract, no project delivery system can change that reality of business and human relationships. However inevitable it may be, however, dispute can still be controlled. And in that effort, the industry has learned some valuable lessons which can and will be incorporated into the next round of construction. EPC contracting has not eliminated dispute. Because of overly aggressive risk allocation, so some projects continue to have delays, claims, and litigation.

Proactive project management remains the best way to keep dispute from raging out of control and destroying a project. To achieve this result, owners and contractors increasingly have relied on partnering or team building relationships developed during the pre-performance stages to create a framework for effective project communications. These partnering efforts are frequently a contract requirement, although language must be used to clarify that they do not in any way alter contractual obligations. Open-book contracting or the development of long term relationships supplement this approach and creative an atmosphere of mutual trust intended to control dispute.

The EPC construction industry has built into contracts a layer of dispute resolution techniques which are intended to build a firewall around disputes which may otherwise burn over into the holocaust of construction litigation. These contractually mandated techniques include dispute review boards (DRBs) which are usually appointed boards of experienced energy construction professionals who meet during performance to help the parties resolve differences which may arise. If DRBs are not successful or preferred, other contracts mandate structured negotiations and then mediation (consensual non-binding negotiations using a third party) as prerequisites to litigation. All of these techniques are intended to keep the parties out of court and have worked well in recent years, predicated upon the mutual good faith of owner and contractor and the recognition that construction litigation usually serves no one's interests other than the lawyers.

As new plants are brought under contract during the next several years, in many ways they will reflect recent experience. Performance issues will be addressed by virtue of guarantees intended to backstop evolving technology. Schedule issues will be critical given the labor shortages. Pricing will reflect these new marketplace realities. These issues will be worked out in the context of potentially innovative project delivery systems. EPC approaches will remain popular, especially on project-financed jobs. These contracts are not necessarily a panacea. Under any circumstances, however, it will be prudent for the industry to remember that a harsh EPC contract serves the interest of no one. Too frequently they create more problems than they solve - shifting risk which leads to unpredictable results. The best contract remains a fair contract - each party controlling the risk it can control. The result is much more likely to be a project built on time, on budget - which,

after all, is the goal of all construction, then and now. EPC contracts should be carefully considered - they are most appropriate with IPPs, risk averse projects. Competitive IOUs and national energy companies should aggressively consider the alternatives.

ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT

Introduction

This ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT (the "Agreement") is entered into as of the 8th day of April, 2008 (the "Effective Date"), by and between GEORGIA POWER COMPANY, a Georgia corporation ("GPC"), acting for itself and as agent for OGLETHORPE POWER CORPORATION (AN ELECTRIC MEMBERSHIP CORPORATION), an electric membership corporation formed under the laws of the State of Georgia, MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA, a public body corporate and politic and an instrumentality of the State of Georgia, and THE CITY OF DALTON, GEORGIA, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners, and a consortium consisting of WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Monroeville, Pennsylvania ("Westinghouse"), and STONE & WEBSTER, INC. a Louisiana corporation having a place of business in Charlotte, North Carolina ("Stone & Webster"). Except where the context otherwise requires, Westinghouse and Stone & Webster hereinafter are individually referred to as a "Consortium Member" and collectively as "Contractor". Owners and Contractor may be referred to individually as a "Party" and collectively as the "Parties".

Recitals

WHEREAS, Owners desire to develop, license, procure and have constructed a two-unit, nuclear-fueled electricity generation facility to be located at the existing site of the Vogtle Electric Generating Plant in Waynesboro, Georgia;

WHEREAS, it is the expectation of GPC that construction of the new facility will begin upon issuance of a certificate for public convenience and necessity by the Georgia Public Service Commission, that all costs incurred in the construction of the facility will be incurred in compliance with such certificate, as it may be amended, and that all costs incurred by GPC during the construction period and verified by the Georgia Public Service Commission will be included in the rate base and fully recovered;

WHEREAS, Westinghouse is engaged in the business of designing, developing, supplying and testing commercial nuclear facilities and has developed a pressurized water Nuclear Power Plant known as the AP1000 for which the U.S. Nuclear Regulatory Commission has issued a Standard Design Certification in the form of a rule set forth in Appendix D to 10 C.F.R. Part 52;

WHEREAS, Stone & Webster is engaged in the business of designing and constructing industrial and power generation facilities;

WHEREAS, Westinghouse and Stone & Webster desire to assist Owners in the licensing of and to design, engineer, procure, construct and test two AP1000 Nuclear Power Plants and related facilities, structures and improvements at the Vogtle plant site in Georgia to be designated VEGP Units 3 and 4; and

WHEREAS, Owners and Contractor now desire to enter into this Agreement to provide for, among other things, the design, engineering, procurement, installation, construction and technical support of start-up and testing of equipment, materials and structures comprising the Facility.

NOW, THEREFORE, in consideration of the recitals, the mutual promises herein and other good and valuable consideration, the receipt and sufficiency of which the Parties acknowledge, the Parties, intending to be legally bound, stipulate and agree as follows:

ARTICLE 17 LIMITATION OF LIABILITY

17.1 NO CONSEQUENTIAL DAMAGES .
IN NO EVENT SHALL CONTRACTOR OR CONTRACTOR INTERESTS OR OWNERS OR OWNERS' INTERESTS BE LIABLE, WHETHER BASED ON CONTRACT (INCLUDING BREACH, WARRANTY, ETC.) OR TORT (INCLUDING FAULT, NEGLIGENCE AND STRICT LIABILITY), OR OTHERWISE, UNDER ANY WARRANTY OR OTHERWISE, RELATING TO OR ARISING OUT OF THE WORK OR THIS AGREEMENT, FOR ANY CONSEQUENTIAL, INDIRECT, SPECIAL, PENAL, OR INCIDENTAL LOSS, DAMAGE OR INJURY, INCLUDING ANY SUCH DAMAGES WHICH RESULT FROM LOSS OF USE OF PROPERTY, EQUIPMENT OR SYSTEMS, LOSS BY REASON OF FACILITY SHUTDOWN OR SERVICE INTERRUPTION, COSTS OF CAPITAL OR EXPENSES THEREOF, LOSS OF PROFITS OR REVENUES OR THE LOSS OF USE THEREOF, LOST BUSINESS OPPORTUNITY, OR COST OF PURCHASED OR REPLACEMENT POWER (INCLUDING ADDITIONAL EXPENSES INCURRED IN USING EXISTING POWER FACILITIES) OR FROM CLAIMS OF CUSTOMERS.

ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT

Introduction

This ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT (the "Agreement") is entered into as of the 31st day of December, 2008 (the "Effective Date"), by and between FLORIDA POWER CORPORATION, d/b/a PROGRESS ENERGY FLORIDA, INC. ("Owner"), and a consortium consisting of WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Monroeville, Pennsylvania ("Westinghouse"), and STONE & WEBSTER, INC., a Louisiana corporation having a place of business in Baton Rouge, Louisiana ("Stone & Webster"). Except where the context otherwise requires, Westinghouse and Stone & Webster hereinafter are individually referred to as a "Consortium Member" and collectively as "Contractor". Owner and Contractor may be referred to individually as a "Party" and collectively as the "Parties".

Recitals

WHEREAS, Owner desires to develop, license, procure and have constructed a nuclear-fueled electricity generation facility;

WHEREAS, Westinghouse is engaged in the business of designing, developing and supplying commercial nuclear facilities and has developed a pressurized water Nuclear Power Plant known as the AP1000 (the "AP1000 Nuclear Power Plant") for which the U.S. Nuclear Regulatory Commission has issued a Standard Design Certification in the form of a rule set forth in Appendix D to 10 C.F.R. Part 52;

WHEREAS, Stone & Webster is engaged in the business of designing and constructing industrial and power generation facilities;

WHEREAS, Westinghouse and Stone & Webster desire to assist Owner in the licensing of, and to design, engineer, procure, construct, and test two AP1000 Nuclear Power Plants and related facilities, structures and improvements at an unimproved, "greenfield" site in Levy County, Florida (the "Facility");

WHEREAS, Owner and Contractor now desire to enter into this Agreement to provide for, among other things, the licensing support, design, engineering, procurement and installation of Equipment (as defined below), and construction and testing of the Facility; and

WHEREAS, Westinghouse, under a separate agreement between Westinghouse and Owner dated the Effective Date, will be supplying Nuclear Fuel and Related Services (as defined below) for the Facility.

ARTICLE 17 LIMITATION OF LIABILITY

17.1 No Consequential Damages.
EXCEPT TO THE EXTENT THE PAYMENT OF LIQUIDATED DAMAGES OR PERFORMANCE OF AN EXPRESS REMEDY COULD OTHERWISE BE DEEMED TO BE SUCH DAMAGES, IN NO EVENT SHALL OWNER OR ITS AFFILIATES OR THEIR CONTRACTORS, OR CONTRACTOR OR CONTRACTOR INTERESTS, BE LIABLE TO EACH OTHER, WHETHER BASED ON CONTRACT (INCLUDING BREACH, INDEMNITY OR WARRANTY) OR TORT (INCLUDING FAULT, NEGLIGENCE AND STRICT LIABILITY), UNDER ANY WARRANTY OR OTHERWISE, RELATING TO OR ARISING OUT OF THE WORK OR THIS AGREEMENT, FOR ANY PUNITIVE DAMAGES OR ANY CONSEQUENTIAL, INDIRECT, SPECIAL OR INCIDENTAL LOSS, DAMAGE OR INJURY, INCLUDING ANY SUCH DAMAGES WHICH RESULT FROM LOSS OF USE OF PROPERTY, EQUIPMENT OR SYSTEMS, LOSS BY REASON OF FACILITY SHUTDOWN OR SERVICE INTERRUPTION, COSTS OF CAPITAL OR EXPENSES THEREOF, LOSS OF PROFITS OR REVENUES OR THE LOSS OF USE THEREOF, OR COST OF PURCHASED OR REPLACEMENT POWER (INCLUDING ADDITIONAL EXPENSES INCURRED IN USING EXISTING POWER FACILITIES) OR FROM CLAIMS OF CUSTOMERS.
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ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT

Introduction

This ENGINEERING, PROCUREMENT AND CONSTRUCTION AGREEMENT (the "Agreement") is entered into as of the 23rd day of May, 2008 (the "Effective Date"), by and between SOUTH CAROLINA ELECTRIC & GAS COMPANY ("SCE&G"), for itself and as agent for the South Carolina Public Service Authority, a body corporate and politic created by the laws of South Carolina ("Santee Cooper") pursuant to the Limited Agency Agreement between SCE&G and Santee Cooper dated May 23, 2008 attached hereto as Exhibit V (the "Limited Agency Agreement"); and a consortium consisting of WESTINGHOUSE ELECTRIC COMPANY LLC, a Delaware limited liability company having a place of business in Monroeville, Pennsylvania ("Westinghouse"), and STONE & WEBSTER, INC., a Louisiana corporation having a place of business in Charlotte, North Carolina ("Stone & Webster"). Except where the context otherwise requires, Westinghouse and Stone & Webster hereinafter are individually referred to as a "Consortium Member" and collectively as "Contractor". Without limiting the authority of SCE&G to act as agent on behalf of Santee Cooper as provided in Section 3.6(a) hereof, references herein to "Owner" shall mean each of SCE&G and Santee Cooper. Owner and Contractor may be referred to individually as a "Party" and collectively as the "Parties".

Recitals

WHEREAS, Owner desires to develop, license, procure and have constructed a nuclear-fueled electricity generation facility;

WHEREAS, Westinghouse is engaged in the business of designing, developing and supplying commercial nuclear facilities and has developed a pressurized water Nuclear Power Plant known as the AP1000 (the "AP1000 Nuclear Power Plant") for which the U.S. Nuclear Regulatory Commission has issued a Standard Design Certification in the form of a rule set forth in Appendix D to 10 C.F.R. Part 52;

WHEREAS, Stone & Webster is engaged in the business of designing and constructing industrial and power generation facilities;

WHEREAS, Westinghouse and Stone & Webster desire to assist Owner in the licensing of and to design, engineer, procure, construct, and test one or two AP1000 Nuclear Power Plants and related facilities, structures and improvements at the V.C. Summer station;

WHEREAS, Owner and Contractor now desire to enter into this Agreement to provide for, among other things, the design, engineering, procurement and installation of equipment and materials, and construction and testing of the Facility;

ARTICLE 17 LIMITATION OF LIABILITY

17.1 No Consequential Damages.
EXCEPT TO THE EXTENT THE PAYMENT OF LIQUIDATED DAMAGES COULD OTHERWISE BE DEEMED TO BE SUCH DAMAGES, IN NO EVENT SHALL CONTRACTOR OR CONTRACTOR INTERESTS BE LIABLE, WHETHER BASED ON CONTRACT (INCLUDING BREACH, WARRANTY, INDEMNITY, ETC.) OR TORT (INCLUDING FAULT, NEGLIGENCE AND STRICT LIABILITY), UNDER ANY WARRANTY OR OTHERWISE, RELATING TO OR ARISING OUT OF THE WORK OR THIS AGREEMENT, FOR ANY CONSEQUENTIAL, INDIRECT, SPECIAL, PENAL, OR INCIDENTAL LOSS, DAMAGE OR INJURY, INCLUDING ANY SUCH DAMAGES WHICH RESULT FROM LOSS OF USE OF PROPERTY, EQUIPMENT OR SYSTEMS, LOSS BY REASON OF FACILITY SHUTDOWN OR SERVICE INTERRUPTION, COSTS OF CAPITAL OR EXPENSES THEREOF, LOSS OF PROFITS OR REVENUES OR THE LOSS OF USE THEREOF, OR COST OF PURCHASED OR REPLACEMENT POWER (INCLUDING ADDITIONAL EXPENSES INCURRED IN USING EXISTING POWER FACILITIES) OR FROM CLAIMS OF CUSTOMERS.

Exhibit 10.3 DEVELOPMENT AND CONSTRUCTION SERVICES AGREEMENT

Introduction

This Development and Construction Services Agreement ("Contract") is entered into this 6th day of November, 2009 by and between Grant County Wind, LLC, a Minnesota limited liability company ("GCW") and the ten additional signature parties hereto who are each individual wind generator companies and the members of GCW (each a "Generator LLC"; the Generator LLCs and GCW, collectively "Owner") and Juhl Energy Development, Inc., a Minnesota corporation ("Contractor" and collectively with the Owner, the "Parties"). This Contract is intended to supersede any prior written or oral agreements or understandings between the Parties and their respective predecessors and/or affiliates with respect to the subject matter hereof.

Recitals

A. Owner wishes to obtain the services of Contractor for the development, design, engineering, construction, procurement, installation, erection, and financing of a commercial wind energy generation project (the "Project") on property in which Owner will have control or ownership interest (the "Project Site"), which Project shall include, but is not limited to, the ten (10) [brand omitted] Wind Turbine Generators and related equipment supplied pursuant to the Turbine Supply Agreement (collectively, the "Turbine Equipment"), meteorological stations, foundations (including those for transformers, met masts and Wind Turbines), a collection system, a substation, all facilities necessary to interconnect the Turbine Equipment to the Project's substation, all access roads, interconnection facilities, switchgear, transformers, pad transformers, grid interconnects, electrical works (whether above ground or below ground), control works, cable and pipe ducting, a communications system, communications system cables and interface hardware, maintenance buildings, fiber-optic cabling, staging areas, crane pads, fencing, barriers, and FAA warning lights.

B. Contractor is willing to provide such services on the terms and for the consideration described herein.

C. The Parties wish to set forth the basic terms on which they will proceed with development of the Project.

11. Limitation of Liability.

(a) Overall Limitation of Liability. The aggregate liability of Contractor, its Subcontractors, agents and employees, to Owner (or any successor thereto or assignee thereof) for any and all claims and/or liabilities arising out of or relating in any manner to the BOP Work as is set forth on Exhibit A or to Contractor's performance or non-performance of its obligations with respect to the BOP Work, whether based in contract, tort (including negligence), strict liability, or otherwise, shall not exceed, in the aggregate, fifteen percent (15%) of the Contract Price; provided, however, that upon Substantial Completion, such aggregate liability shall be limited to ten percent (10%) of the Contract Price. Notwithstanding the foregoing, the preceding limits of liability shall (i) exclude any liability satisfied by the proceeds of insurance maintained by Contractor in accordance with this Contract, or which would have been satisfied by insurance had Contractor maintained proper insurance in accordance with this Contract; (ii) not apply to any claims for fraud, gross negligence or willful misconduct, or failure to pay Subcontractors; (iii) not apply with respect to the indemnification obligations pursuant to Section 10; and (iv) exclude the Contractor's warranty obligations under Section 8.

(b) Consequential Damages. Owner and Contractor hereby waive all claims against each other (and against each other's parent company and affiliates and [name intentionally omitted]) for any consequential, incidental, indirect, special, exemplary or punitive damages (including, but not limited to, loss of actual or anticipated profits, revenues or product; loss by reason of shutdown or non-operation; increased expense of operation, borrowing or financing; loss of use or productivity; or increased cost of capital), and regardless of whether any such claim arises out of breach of contract or warranty, tort (including negligence), product liability, contribution, strict liability or any other legal theory.

CONTRACT FOR ENGINEERING, PROCUREMENT AND CONSTRUCTION SERVICES NEW PLYMOUTH POWER PLANT

Introduction

THIS CONTRACT ("Contract") is made and entered into this _____ day of April, 2009, by and between Idaho Power Company, an Idaho corporation with offices located at 1221 West Idaho Street, Boise, Idaho ("Owner") and Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co., a Delaware corporation with offices located at 7311 W 132nd St., Suite 300, Overland Park, KS 66213, and TIC-The Industrial Company, a Delaware corporation with offices located at 2211 Elk River Road, Steamboat Springs, CO 80487 ("Contractor"), for the design, engineering, procurement and construction services, as more fully described herein.

Recitals

WHEREAS, Owner wishes to have Contractor furnish certain engineering, procurement, construction management and construction services related to the Project, as more fully described in this Contract; and

WHEREAS, Owner desires to furnish certain plant equipment, interconnects, the Facility Site, and other items related to the Project, as more fully described in this Contract; and

WHEREAS, Contractor desires to engineer, procure materials, manage construction, construct and start up the Project, as more fully described in this Contract.

ARTICLE 26 LIMITATIONS OF LIABILITY

26.1 Limitation of Liability.
(a) The liability of Contractor, its members and their affiliates or related companies, for all claims, losses, damages and expenses arising from or related to in any way the performance of this Contract shall not exceed the lesser of (i) ***, excluding any assignments of OFE, or (ii) ***. Owner hereby releases Contractor from any liability in excess thereof. In addition, the total liability cap will be reduced by the proceeds of contractually specified/required insurance. Limitations on liability shall apply even in the event of breach of contract or warranty, tort (including negligence), strict liability or other basis of legal liability and shall extend to the partners, licensors, Subcontractors, and related entities of Contractor, Contractor's directors, officers, employees, and agents and the directors, officers, employees, and agents of Contractor's licensors, Subcontractors, and related entities of Contractor.

(b) Notwithstanding any other provision herein to the contrary, Contractor's risk is specifically limited for all Owner assigned or specified subcontractor items, if any, to that scope and extent of risk that each Owner assigned or specified subcontractor has accepted in its scope. This back-to-back limitation applies specifically to, but is not limited to, termination by any such Owner assigned or specified subcontractor, indemnification, patent indemnification, changes, delays, performance guarantees, emissions, noise, availability/reliability guarantees, and other guarantees of any kind, liquidated damages, liability caps, and warranty. Owner shall retain the collection risk as relates to obligations of such Owner assigned or specified subcontractor including, but not limited to, any liquidated damages. CONTRACTOR SHALL ACCEPT NO RISK FOR OFE WHETHER RISK IS FOR PERFORMANCE, DELAY, OR OTHERWISE.

(c) Upon completion of the Work or termination of the Contract, provisions relating to indemnity, waivers, releases, and limitation of liability, including, but not limited to Article 26, shall remain in full force and effect.

26.2 Consequential Damages.
In no event shall either Party hereto or any Subcontractor of any tier or any related company of either Party, including their agents, assignees, and affiliates, be liable for the loss of profits or revenue, loss of use of the equipment or any associated equipment, cost of capital, cost of substitute equipment, facilities or services, down time costs, costs in excess of estimates, loss of opportunity, loss of data, loss of goodwill, governmental penalties or sanctions imposed on Owner and/or claims of customers of the other Party for such damages or for any special, indirect, exemplary, incidental, punitive, or consequential loss or damages and Owner hereby releases Contractor and all Subcontractors and Contractor hereby releases Owner therefrom. This limitation does not apply to the liquidated damages specified in Article 27 herein.

ENGINEERING AND CONSTRUCTION AGREEMENT

Introduction

This ENGINEERING AND CONSTRUCTION AGREEMENT (the "Agreement") is entered into as of the 5th day of May, 2008 (the "Effective Date"), between DUKE ENERGY CAROLINAS, LLC, a North Carolina limited liability company having its principal place of business in Charlotte, North Carolina ("Owner"), and SHAW NORTH CAROLINA, INC., a North Carolina corporation having its principal place of business in Charlotte, North Carolina ("Contractor" and, together with Owner, collectively the "Parties" and individually a "Party").

Recitals

WHEREAS, Owner has announced its intent to procure, construct, install and commission a new nominally rated 620 MW combustion turbine combined cycle electric power plant at the Buck Generating Facility (the "Facility") in Rowan County, North Carolina, which will consist of (i) two combustion turbine generators, (ii) two natural circulation, duct fired, heat recovery steam generators and (iii) one reheat condensing steam turbine generator (the "Project");

WHEREAS, Contractor is engaged in the business of designing, engineering, constructing and commissioning power generating facilities; and

WHEREAS, Owner has entered into the Owner Equipment Contracts for the supply of the Owner Equipment, which is intended to be installed and commissioned by Contractor;

NOW, THEREFORE, in consideration of the recitals, the mutual promises herein and other good and valuable consideration, the receipt and sufficiency of which the Parties acknowledge, the Parties, intending to be legally bound, stipulate and agree as follows:

17. LIMITATION OF LIABILITY

17.1 No Consequential Damages. [*]THEREOF, LOSS OF PROFITS OR REVENUES OR THE LOSS OF USE THEREOF, OR COST OF PURCHASED OR REPLACEMENT POWER.
GY CAROLINAS LLC

18 Am. Jur. Legal Forms 2d § 253:171.55

American Jurisprudence Legal Forms 2d
Database updated November 2012
Chapter 253. Uniform Commercial Code
Article 2. Sales
III. Form, Formation, and Readjustment of Agreement
D. Formation of Agreement [UCC § 2-204]
1. Form of Agreement

Summary Correlation Table

§ 253:171.55. Agreement for sale of goods—Equipment—Turbine generator

EQUIPMENT PURCHASE AGREEMENT

This Equipment Purchase Agreement (this "Agreement") is made this *[date of agreement]* (the "Effective Date"), between *[name of seller]*, a *[name of state]* limited liability company, having its principal office at *[address of seller]* ("Seller"), and *[name of buyer]*, a *[name of state]* limited liability company, having its principal office at *[address of buyer]* ("Buyer").

RECITALS

A. Buyer desires to purchase one *[name of manufacturer]* industrial gas turbine generator package and associated equipment, parts, structures and records located at or pertaining to Seller's facility in or near *[name of city]*, *[name of state]*, as such items are more particularly described in Exhibit *[designation of exhibit]*, attached to and by this reference made a part of this Agreement (collectively, the "Equipment"). The Equipment shall include only those items described in Exhibit *[designation of exhibit]*.

B. Seller owns the Equipment and is ready, willing and able to sell the Equipment to Buyer pursuant to the terms and subject to the conditions set forth in this Agreement.

In consideration of the matters described above, and of the mutual benefits and obligations set forth in this Agreement, the parties agree as follows:

SECTION ONE. PURCHASE AND SALE OF EQUIPMENT

A. Upon the terms and subject to the conditions contained in this Agreement, on the Closing Date (defined below), Seller shall sell, assign, transfer, convey and deliver to Buyer, and Buyer shall purchase from Seller, any and all of Seller's interest in and rights to the Equipment. As the term is used in this Agreement and the exhibits to this Agreement, "Equipment" shall also mean and include copies of all of Seller's records and files which relate to any of the Equipment, including but not limited to the following: (i) operations, maintenance, environmental and engineering records; (ii) facility records; (iii) accounting files and operating statements and files; (iv) any and

all contracts, purchase orders or other agreements with third parties including those with vendors, suppliers or OEM's; and (v) any other records or files in the possession of Seller relating to the Equipment, save and except for records the disclosure of which would jeopardize any privilege available to Seller relating to such records, would cause Seller to breach a confidentiality obligation to which it is bound, or would cause Seller to violate any applicable law; provided, however, that Seller's corporate minute books, charter documents, corporate stock record books and such other books and records as pertain to the organization, existence or share capitalization of Seller and such other books and records that do not relate to the Equipment shall not be included.

B. By this Agreement, Seller does now assign to Buyer any and all existing assignable warranties, service life policies and patent indemnities of manufacturers of components of the Equipment, if any; and upon the request of Buyer, Seller shall give Buyer reasonable assistance in enforcing the rights of Buyer arising as a result of this Agreement but Buyer shall promptly reimburse Seller for the actual and reasonable costs and expenses incurred by Seller in rendering such assistance; and, from time to time, upon the request of Buyer, Seller shall give notice (with copies to Buyer) to any such manufacturers of the assignment of such warranties, service life policies and patent indemnities to Buyer.

SECTION TWO. PURCHASE PRICE AND PAYMENT TERMS

A. Purchase Price.

In accordance with the following paragraph B, Buyer shall pay Seller for the Equipment the sum of $*[dollar amount of purchase price]* (the “Purchase Price”), as allocated by the parties to the Equipment.

B. Payment Terms.

1. Not later than one business day after the Effective Date, Buyer shall deposit with Seller the sum of $*[dollar amount of deposit]* as a deposit towards the Purchase Price (the “Deposit”), which Deposit shall be applied towards the payment of the Purchase Price at Closing. The Deposit shall be (i) held by Seller in an account designated by Seller in its sole discretion, without interest accrual for the benefit of Buyer, and (ii) nonrefundable to Buyer except as expressly set forth in this Agreement.

2. At the Closing (as defined below), Buyer shall transfer and pay to Seller the balance of the Purchase Price (i.e., the Purchase Price less the Deposit and any amounts that Seller owes to Buyer pursuant to Section Eight, subparagraph A(2) below) by wire transfer of immediately available funds into an account designated in writing by Seller.

SECTION THREE. ASSUMPTION OF LIABILITIES; POSSESSION AND REMOVAL OF EQUIPMENT; TITLE AND RISK OF LOSS

A. Assumption of Liabilities.

At the Closing, Buyer shall assume and agree to pay, perform and discharge when due all liabilities arising out of, in connection with or related to the ownership, removal, operation, use or maintenance of the Equipment relating to periods on or after the Closing Date (as defined below).

B. Possession and Removal of Equipment.

At and after Closing, Seller agrees to permit Buyer and its representatives free and unencumbered access to the site where the Equipment is located so that Buyer can remove the Equipment (the "Removal"). Buyer will at all times while on the site abide by Seller's safety rules and regulations, a copy of which will be provided by Seller to Buyer prior to the Removal. Buyer will work closely with Seller's site personnel to ensure that the Removal shall not interfere with the Seller's operations at the site and Buyer shall comply with the provisions of Section *[designation of section]*, as set forth in Exhibit *[designation of exhibit]*, the terms of which are by this reference incorporated and made a part of this Agreement. Buyer shall complete the Removal no later than *[number of days]* days after the Closing Date unless prohibited from doing so due to Excusable Delay. After such *[number of days]*-day period, Buyer agrees to pay Seller storage fees of $*[dollar amount of daily storage fee]* per day for any Equipment not so removed within such *[number of days]*-day period unless prior arrangements are made or the parties agree otherwise. Seller agrees, at no cost to Seller, to cooperate with the Removal. Following the Removal, Buyer shall restore Seller's remaining facility to a condition which is as near as possible to its original condition as existed prior to the Removal.

C. Title and Risk of Loss.

Title to and risk of loss, damage and destruction of the Equipment shall transfer from Seller to Buyer upon the Closing Date.

SECTION FOUR. REPRESENTATIONS AND WARRANTIES

A. Seller Representations and Warranties.

Seller represents and warrants to Buyer that:

1. At the Closing Date, Seller shall have full legal and beneficial title to the Equipment, free and clear of any and all security interests, liens, claims, charges or encumbrances of any nature whatsoever, together with full power and lawful authority to deliver the Equipment to Buyer; and upon delivery of the Assignment and Bill of Sale to Buyer in accordance with Section Eight, subparagraph D(2), Seller shall have transferred marketable title to the Equipment to Buyer.

2. Seller is an entity duly organized, validly existing and in good standing under the laws of the jurisdiction in which it is formed and has the requisite power and authority to own, lease and operate its properties and to carry on its business as now conducted. Seller is duly qualified to transact business and is in good standing in each jurisdiction in which its ownership of the Equipment and commitments made under this Agreement makes such qualification necessary.

3. Seller has the requisite power and authority to execute this Agreement and to consummate the transactions contemplated by this Agreement. The execution and delivery of this Agreement by Seller and the consummation by Seller of the transactions contemplated by this Agreement have been duly authorized by all necessary action on the part of Seller.

4. The execution and delivery by Seller of this Agreement and the consummation of the transactions contemplated by this Agreement do not and will not (i) violate any provision of the constituent documents of Seller, (ii) violate any order of any governmental authority to which Seller is bound or subject, (iii) violate any applicable law, or (iv) result in the imposition or creation of any lien upon the Equipment. This Agreement has been duly executed and delivered by Seller and, assuming due execution and delivery by Buyer, constitutes a valid and binding obligation of Seller, enforceable against Seller in accordance with its terms. Notwithstanding the foregoing, (i) Seller is required to deliver *[number of days]* days' prior written notice of the sale of the Equipment to the *[name of state]* Independent System Operator ("ISO") and the Federal Energy Regulatory Commission ("FERC"), and (ii) Seller has requested a waiver of such notice requirements from ISO and FERC. In addition, Seller has executed certain contracts with respect to the availability of the Equipment.

5. To Seller's knowledge, except for notice to ISO and FERC, no order or permit issued by, or declaration or filing with, or notification to, or waiver from any governmental authority is required on the part of Seller in connection with the execution and delivery of this Agreement, or the compliance or performance by Seller with any provision contained in this Agreement.

6. All taxes due and payable by Seller with respect to the ownership of the Equipment have been paid or are being contested in good faith through the appropriate proceedings.

7. There is no legal action or order pending or, to Seller's knowledge, overtly threatened against Seller that seeks to restrain or prohibit or otherwise challenge the consummation, legality or validity of the transactions contemplated by this Agreement.

8. Except for such notices as have been disclosed to Buyer in writing, Seller, to Seller's knowledge, has not received any written notice that the Equipment is in violation of any applicable laws.

9. No rights of first offer or other preferential rights to purchase any of the Equipment are held by third parties.

B. Knowledge Defined.

In this Agreement, references to the "knowledge" of Seller shall refer only to the actual knowledge of the Designated Employee (as defined below) of Seller, and shall not be construed, by imputation or otherwise, to refer to the knowledge of Seller, or any affiliate of Seller, or to any other officer, agent, manager, representative or employee of Seller or any affiliate of the same or to impose upon such Designated Employee any duty to investigate the matter to which such actual knowledge, or the absence of actual knowledge, pertains. As used in this Agreement, the term "Designated Employee" shall refer to the following person: *[name of designated employee of seller]*.

C. Survival of Seller's Representations and Warranties.

The representations and warranties of Seller set forth in paragraph A of this Section Four shall survive Closing for a period of *[number of days]* days; provided, however, notwithstanding the foregoing to the contrary, subparagraph A(1) of this Section Four shall survive for a period of *[[number of months]/[number of years]] [months/years]*. No claim for a breach of any representation or warranty of Seller shall be actionable or payable if the breach in question results from or is based on a condition, state of facts or other matter which was specifically disclosed by Seller to and accepted by Buyer in writing prior to Closing.

D. As-Is.

EXCEPT AS AND TO THE EXTENT EXPRESSLY SET FORTH IN THIS AGREEMENT, (i) SELLER MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESS, STATUTORY OR IMPLIED, AND (ii) SELLER DISCLAIMS ALL LIABILITY AND RESPONSIBILITY FOR ANY REPRESENTATION, WARRANTY, STATEMENT OR INFORMATION MADE OR COMMUNICATED (ORALLY OR IN WRITING) TO BUYER OR ANY OF ITS AFFILIATES, EMPLOYEES, AGENTS, CONSULTANTS OR REPRESENTATIVES (INCLUDING, BUT NOT LIMITED TO, ANY OPINION, INFORMATION, PROJECTION OR ADVICE THAT MAY HAVE BEEN PROVIDED TO BUYER BY ANY OFFICER, DIRECTOR, EMPLOYEE, AGENT, CONSULTANT, REPRESENTATIVE OR ADVISOR OF SELLER OR ANY OF ITS AFFILIATES). IN PARTICULAR AND WITHOUT LIMITING THE GENERALITY OF THE FOREGOING, SELLER DISCLAIMS ANY REPRESENTATION OR WARRANTY, EXPRESS, STATUTORY OR IMPLIED, AS TO (i) THE MAINTENANCE, REPAIR, CONDITION, QUALITY, SUITABILITY, DESIGN OR MARKETABILITY OF THE EQUIPMENT, (ii) THE CONTENT, CHARACTER OR NATURE OF ANY INFORMATION MEMORANDUM, REPORTS, BROCHURES, CHARTS OR STATEMENTS PREPARED BY SELLER OR THIRD PARTIES WITH RESPECT TO THE EQUIPMENT, (iii) ANY OTHER MATERIALS OR INFORMATION THAT MAY HAVE BEEN MADE AVAILABLE TO BUYER OR ITS AFFILIATES, OR ITS OR THEIR EMPLOYEES, AGENTS, CONSULTANTS, REPRESENTATIVES OR ADVISORS IN CONNECTION WITH THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT AND THE ASSIGNMENT AND BILL OF SALE OR ANY DISCUSSION OR PRESENTATION RELATING TO THE SAME, AND (iv) ANY IMPLIED OR EXPRESS WARRANTY OF FREEDOM FROM PATENT OR TRADEMARK INFRINGEMENT. EXCEPT AS EXPRESSLY SET FORTH IN THIS AGREEMENT, SELLER FURTHER DISCLAIMS ANY REPRESENTATION OR WARRANTY, EXPRESS, STATUTORY OR IMPLIED, OF MERCHANTABILITY, FREEDOM FROM LATENT VICES OR DEFECTS, FITNESS FOR A PARTICULAR PURPOSE OR CONFORMITY TO MODELS OR SAMPLES OF MATERIALS OF ANY ASSETS, RIGHTS OF A PURCHASER UNDER APPROPRIATE STATUTES TO CLAIM DIMINUTION OF CONSIDERATION OR RETURN OF THE PURCHASE PRICE, IT BEING EXPRESSLY UNDERSTOOD AND AGREED BY THE PARTIES TO THIS AGREEMENT THAT BUYER SHALL BE DEEMED TO BE OBTAINING THE EQUIPMENT IN ITS PRESENT STATUS, CONDITION AND STATE OF REPAIR, “AS IS” AND “WHERE IS” WITH ALL FAULTS OR DEFECTS (KNOWN OR UNKNOWN, LATENT, DISCOVERABLE OR UNDISCOVERABLE), AND THAT BUYER HAS MADE OR CAUSED TO BE MADE SUCH INSPECTIONS AS BUYER DEEMS APPROPRIATE. AS PART OF THE PROVISIONS OF THIS PARAGRAPH D, BUT NOT AS A LIMITATION, BUYER AGREES, REPRESENTS AND WARRANTS THAT THE MATTERS RELEASED IN THIS PARAGRAPH ARE NOT LIMITED TO MATTERS WHICH ARE KNOWN OR DISCLOSED, AND BUYER WAIVES ANY AND ALL RIGHTS AND BENEFITS WHICH IT NOW HAS, OR IN THE FUTURE MAY HAVE CONFERRED UPON IT, BY VIRTUE OF THE PROVISIONS OF FEDERAL, STATE OR LOCAL LAW, RULES OR REGULATIONS,

INCLUDING, BUT NOT LIMITED TO, *[CITATION OF STATUTE]* WHICH PROVIDES AS FOLLOWS: "*[TEXT OF STATUTE REGARDING SCOPE OF GENERAL RELEASES]*." Seller and Buyer acknowledge that the compensation to be paid to Seller for the Equipment has been decreased to take into account that the Equipment is being sold subject to the provisions of this paragraph D. Seller and Buyer agree that the provisions of this paragraph D shall survive the Closing Date.

E. Buyer's Representations and Warranties.

Buyer represents and warrants to Seller that:

1. Buyer is an entity duly organized, validly existing and in good standing under the laws of the jurisdiction in which it is formed and has the requisite power and authority to own, lease and operate its properties and to carry on its business as now conducted. Buyer is duly qualified to transact business and is in good standing in each jurisdiction in which its commitments under this Agreement makes such qualification necessary.

2. Buyer has the requisite power and authority to execute this Agreement and to consummate the transactions contemplated by this Agreement. The execution and delivery of this Agreement by Buyer and the consummation by Buyer of the transactions contemplated by this Agreement have been duly authorized by all necessary action on the part of Buyer. This Agreement has been duly executed and delivered by Buyer and, assuming due execution and delivery by Seller, constitutes a valid and binding obligation of Buyer, enforceable against Buyer in accordance with its terms.

3. The execution and delivery by Buyer of this Agreement and the consummation of the transactions contemplated by this Agreement do not and will not (i) violate any provision of the constituent documents of Buyer, (ii) violate any order of any governmental authority to which Buyer is bound or subject, or (iii) violate any applicable law.

4. To Buyer's knowledge, no order or permit issued by, or declaration or filing with, or notification to, or waiver from any governmental authority is required on the part of Buyer in connection with the execution and delivery of this Agreement, or the compliance or performance by Buyer with any provision contained in this Agreement.

5. There is no legal action or order pending or, to Buyer's knowledge, overtly threatened against Buyer that seeks to restrain or prohibit or otherwise challenge the consummation, legality or validity of the transactions contemplated by this Agreement.

6. No person has acted, directly or indirectly, as a broker, finder or financial advisor for Buyer in connection with the transactions contemplated by this Agreement, and Seller is not or will not become obligated to pay any fee or commission or like payment to any broker, finder or financial advisor, as a result of the consummation of the transactions contemplated by this Agreement based upon any arrangement made by or on behalf of Buyer.

F. Knowledge Defined.

In this Agreement, references to the "knowledge" of Buyer shall refer only to the actual knowledge of the Designated Employee (as defined below) of Buyer, and shall not be construed, by imputation or otherwise, to refer to the knowledge of Buyer, or any affiliate of Buyer, or to any other officer, agent, manager, representative or employee of Buyer or any affiliate of the same or to impose upon such Designated Employee any duty to investigate the matter to which such actual knowledge, or the absence of actual knowledge, pertains. As used in this Agreement, the term "Designated Employee" shall refer to the following person: *[name of designated employee of buyer]*.

G. Survival of Buyer's Representations and Warranties.

The representations and warranties of Buyer set forth in paragraph E of this Section Four shall survive Closing for a period of *[number of days]* days. No claim for a breach of any representation or warranty of Buyer shall be actionable or payable if the breach in question results from or is based on a condition, state of facts or other matter which was specifically disclosed by Buyer to and accepted by Seller in writing prior to Closing.

SECTION FIVE. INSPECTION, PRESERVING AND OPERATING THE EQUIPMENT

A. Inspection and Access.

Immediately following the Effective Date, Buyer and its representatives shall, upon prior written notice to Seller, have access to the site where the Equipment is located so that Buyer and its representatives can inspect the Equipment and review the books, records and information relating to the Equipment, and speak to the personnel of Seller that may have information relating to the history, operation and maintenance of the Equipment; provided, however, that Seller shall have the right to have a representative present at any such access to the site. Such activities shall include the Buyer's right to check and borescope the turbines and meggering the generators and such other tests and inspections deemed appropriate by Buyer in order to assess the integrity and condition of the Equipment, provided that any and all such testing and inspections shall be made only upon prior written notice to Seller, Seller shall have the right to have a representative present for any such testing, all of such testing shall be performed in compliance with all applicable laws, and Buyer shall deliver to Seller a copy of any data, results or reports prepared in connection with such testing. Buyer will at all times while on the site abide by Seller's safety rules and regulations, a copy of which will be provided by Seller to Buyer prior to execution of the work. Seller agrees to cooperate with Buyer and provide all reasonable assistance in relation to Buyer performing its inspection activities. Prior to the Closing, Buyer, at Buyer's sole cost and expense, shall have the right to remove the gas turbine engine and related hardware from the site for purposes of further testing and repair. Notwithstanding the foregoing to the contrary, if Buyer's inspections of or tests upon the Equipment would cause the operation of the Seller's facilities to be interrupted, or should Buyer remove the gas turbine equipment from the site, Buyer shall provide Seller, at Buyer's sole cost and expense, with such temporary replacement equipment as is necessary for Seller to maintain such operation until the earlier of the Closing or Buyer's reinstallation of the Equipment in operating condition. If Buyer elects to remove the Equipment, Buyer shall maintain insurance on the Equipment in the amount of the Purchase Price for any damage or destruction of the Equipment while in Buyer's possession. Upon prior written notice to Seller, Buyer shall also be permitted to speak directly with vendors and suppliers associated with the Equipment, including the OEMs, and if required Seller shall promptly provide all necessary authorization and assistance in order that Buyer can freely engage said vendors and suppliers in obtaining information from them as part of Buyer's inspection activities, provided that Seller shall have the right to have a representative participate in any such engagement. Following any inspection, testing or removal of

the Equipment, Buyer shall restore the Equipment to its original condition as existed prior to any such inspections or tests. Upon request by Seller, Buyer shall provide Seller with evidence that Buyer has a policy of general liability insurance, from an insurer and in an amount reasonably acceptable to Seller, which insurance shall (i) name Seller as an additional insured party, and (ii) provide coverage against any claim for personal liability or property damage caused by Buyer or its agents, employees or contractors in connection with such inspections, tests and removal activities.

B. Preserving the Equipment.

During the period from the Effective Date to and through the Closing Date, Seller shall use commercially reasonable efforts to conduct its business (as it pertains to the Equipment) in all material respects in the ordinary course of business and to maintain and preserve the Equipment consistent with Seller's past practices.

SECTION SIX. INDEMNIFICATION

A. Buyer Indemnity.

Buyer assumes liability for, and agrees to indemnify, protect, save and keep harmless Seller and its directors, officers, and employees from and against any and all liabilities, obligations, losses, damages, penalties, claims (including but not limited to claims involving strict or absolute liability in tort), actions, suits, costs, expenses and disbursements, including but not limited to reasonable attorney's fees and expenses, of any kind or nature, which may be imposed on, incurred by or asserted against Seller arising out of and in connection with (i) a breach by Buyer of its obligations under this Agreement; (ii) acceptance, ownership, delivery, possession, use, operations, maintenance, repair, function, registration, sales, return, storage, or other disposition of the Equipment or any accident in connection with the Equipment (including but not limited to latent and other defects, whether or not discoverable) after the transfer of the title of the Equipment to Buyer on the Closing Date; or (iii) the negligence of Buyer, or any of its employees, representative, contractors or agents; provided, however, that Buyer shall not be required to indemnify Seller or its assigns for any claim resulting from acts which would constitute Seller's misconduct or negligence or a breach by the Seller of the terms of this Agreement.

B. Seller Indemnity.

Seller assumes liability for, and agrees to indemnify, protect, save and keep harmless Buyer and its directors, officers, and employees from and against any and all liabilities, obligations, losses, damages, penalties, claims (including but not limited to claims involving strict or absolute liability in tort), actions, suits, costs, expenses and disbursements, including but not limited to reasonable attorney's fees and expenses, of any kind or nature, which may be imposed on, incurred by or asserted against Buyer arising out of and in connection with (i) a breach by Seller of its obligations under this Agreement; (ii) acceptance, ownership, delivery, possession, use, operations, maintenance, repair, function, registration, sales, return, storage, or other disposition of the Equipment or any accident in connection with the Equipment (including but not limited to latent and other defects, whether or not discoverable) before the transfer of the title of the Equipment to Buyer on the Closing Date, including any claims arising out of existing contracts affecting or based upon the Equipment; or (iii) the negligence of Seller, or any of its employees, representative, contractors or agents; provided, however, that Seller shall not be required to indemnify

Buyer or its assigns for any claim resulting from acts which would constitute Buyer's misconduct or negligence or a breach by the Buyer of the terms of this Agreement or any other agreement between Seller and Buyer.

SECTION SEVEN. TAXES

All ad valorem taxes, real property taxes and personal property taxes relating to the Equipment for the year in which the Closing Date occurs shall be apportioned as of the Closing Date between Seller and Buyer. Seller shall be liable for the portion of such taxes based upon the number of days in the year occurring prior to the Closing Date, and Buyer shall be liable for the portion of such taxes based upon the number of days in the year occurring on and after the Closing Date. For any year in which an apportionment is required, Buyer shall file all required reports and returns incident to these taxes assessed for the year in which the Closing Date occurs that are not filed by Seller as of the Closing Date. Seller shall pay to Buyer, at the time of Buyer's remittance, Seller's share of such taxes. If Seller has paid any portion of such taxes apportioned to Buyer under this Section Seven, Buyer shall pay to Seller, promptly upon notice from Seller of the portion of such taxes apportioned to Buyer, Buyer's share of such taxes. Buyer shall pay all sales taxes, if any, arising in connection with the sale of the Equipment.

SECTION EIGHT. CLOSING

A. Conditions Precedent to Obligations of Each Party.

The respective obligations of Seller and Buyer to consummate the transactions contemplated by this Agreement are subject to the fulfillment, on or prior to the Closing Date, of the following conditions:

1. No order issued by any court of competent jurisdiction preventing the consummation of the transactions contemplated by this Agreement shall be in effect, nor shall any material proceeding initiated by any governmental authority of competent jurisdiction having valid enforcement authority seeking such an order be pending, nor shall there be any action taken, or any law or order enacted, entered or enforced that has not been subsequently overturned or otherwise made inapplicable to this Agreement, that makes the consummation of the transactions contemplated by this Agreement illegal.

2. Any waiting period (including any extension of a waiting period) applicable to the purchase and sale of the Equipment to Buyer under the regulations of any other applicable governmental antitrust or competition authority shall have been terminated or expired and any waivers or approvals required by any bodies applicable to transactions contemplated by this Agreement shall have been obtained; provided, however, that Buyer may, upon written notice to Seller not later than *[number of days]* days prior to the Closing Date, elect to extend the Closing Date to a date which is not later than *[number of days]* days from the Effective Date, to permit for the termination or expiration of any such waiting period or the obtaining of any such waivers or approvals, as applicable. If the Closing is not extended pursuant to this subparagraph 2, this Agreement shall terminate and the Deposit shall be returned to Buyer. If the Closing is extended pursuant to this subparagraph 2, and if Buyer has removed the gas turbine engine from the site and has provided a temporary replacement of the turbine engine, then Seller agrees during the extended period to pay Buyer an amount equal to $*[dollar amount of stand-by fee]* for each *[number of days]*-day period, or portion of a *[number of days]*-day period, as a stand-by fee, plus $*[dollar amount of daily fee for operation of temporary equipment]* for each day that the temporary equipment is operated.

B. Conditions Precedent to Obligations of Buyer.

The obligation of Buyer to consummate the transactions contemplated by this Agreement is subject to the fulfillment, on or prior to the Closing Date, of each of the following conditions (any or all of which may be waived by Buyer, in whole or in part, subject to applicable law):

1. All of the representations and warranties of Seller contained in this Agreement shall be true and correct in all material respects on and as of the Closing Date, except those representations and warranties of Seller that speak of a certain date, which representations and warranties shall have been true and correct in all material respects as of such date;

2. Seller shall have performed and complied with in all material respects its obligations and covenants required by this Agreement to be performed or complied with by Seller on or prior to the Closing Date; and

3. Buyer shall have been furnished with the documents referred to in paragraph D of this Section Eight.

C. Conditions Precedent to Obligations of Seller.

The obligations of Seller to consummate the transactions contemplated by this Agreement are subject to the fulfillment, prior to or on the Closing Date, of each of the following conditions (any or all of which may be waived by Seller, in whole or in part, subject to applicable law):

1. All of the representations and warranties of Buyer contained in this Agreement shall be true and correct in all material respects on and as of the Closing Date, except those representations and warranties of Buyer that speak of a certain date, which representations and warranties shall have been true and correct in all material respects as of such date;

2. Buyer shall have performed and complied with in all material respects all obligations and covenants required by this Agreement to be performed or complied with by them on or prior to the Closing Date; and

3. Seller shall have been furnished with the documents referred to in paragraph E of this Section Eight.

D. Documents to Be Delivered by Seller.

At the Closing, Seller shall deliver to Buyer the following:

1. a certificate of an officer of Seller certifying that the closing conditions set forth in subparagraph B(1) of this Section Eight have been satisfied;

2. the Assignment and Bill of Sale substantially in the form of Exhibit *[designation of exhibit]* attached to this Agreement, and such other instruments of conveyance necessary for the transfer of the Equipment, duly executed by Seller; and

3. a Non-Foreign Affidavit in compliance with the provisions of Treasury Regulation § 1.1445-2(b)(2) certifying that Seller is not a foreign person within the meaning of the Code.

E. Documents to Be Delivered by Buyer.

At the Closing, Buyer shall deliver to Seller the following:

1. evidence of the wire transfer referred to in Section Two, subparagraph B(2) of this Agreement;

2. a certificate of an officer of Buyer certifying that the closing conditions set forth in subparagraph C(1) of this Section Eight have been satisfied; and

3. the Assignment and Bill of Sale substantially in the form of Exhibit *[designation of exhibit]* attached to this Agreement, and such other instruments of conveyance necessary for the transfer of the Equipment, duly executed by Buyer.

F. Time and Place of Closing.

The closing of the purchase and sale of the Equipment (the "Closing") shall take place at the facility site where the Equipment is located at *[time of day]*, local time, on *[date of closing]*, and after the conditions to Closing set forth in paragraphs A, B and C of this Section Eight (excluding conditions that, by their terms, cannot be satisfied until the Closing) have been satisfied (or waived by the party entitled to waive such condition) (as the same may be extended pursuant to the provisions of subparagraph A(2) of this Section Eight, the "Closing Date"), or at such other location or time as may be agreed by the parties.

G. Failure of Condition.

In the event of the failure of any condition to Closing set forth in paragraph A or B of this Section Eight, then this Agreement shall terminate and the Deposit shall be returned to Buyer and Seller shall pay Buyer any amounts owed pursuant to subparagraph A(2). In the event of the failure of any condition to Closing set forth in paragraph C of this Section Eight, then this Agreement shall terminate and the Deposit shall be retained by Seller less any amounts Seller owes to Buyer pursuant to subparagraph A(2).

SECTION NINE. DEFAULT AND REMEDIES

A. Events of Default.

It shall be an event of default if all or any of the following shall have occurred (an “Event of Default”):

1. If either party shall default in the performance of any of the material provisions contained in the Agreement, which default shall continue for *[number of days]* business days after written notice of default to the defaulting party; or

2. If any representation or warranty by either party made in this Agreement or in any statement or certificate furnished or required under this Agreement, or in connection with the execution and delivery of this Agreement, proves untrue in any material respect as of the date of issuance or making of the statement or certificate.

B. Remedies.

1. Upon the occurrence of an Event of Default by Seller, Buyer shall be entitled, as its sole remedy, either (a) to receive any amounts Seller owes to Buyer under Section Eight, subparagraph B(2), and the return of the Deposit and any other moneys paid by Buyer to Seller as of the date of the Event of Default, which return shall operate to terminate this Agreement and release Seller from any and all liability under this Agreement; or (b) to enforce specific performance of Seller's obligation to execute the documents required to convey the Equipment to Buyer, it being agreed that the remedy of specific performance shall not be available to enforce any other obligation of Seller under this Agreement. Buyer waives its rights to seek damages upon the occurrence of an Event of Default by Seller under this Agreement. Buyer shall be deemed to have elected to terminate this Agreement and receive any amounts Seller owes to Buyer under Section Eight, subparagraph A(2), the Deposit, and any other moneys paid by Buyer to Seller as of the date of the Event of Default, if Buyer fails to file suit for specific performance against Seller in a court having jurisdiction in *[name of county]*, *[name of state]*, on or before *[number of days]* days following the date upon which Closing was to have occurred.

2. Upon the occurrence of an Event of Default by Buyer, Seller shall be entitled to retain the Deposit (less any amounts Seller owes to Buyer under Section Eight, subparagraph A(2)) as liquidated damages (the “Liquidated Damages”), which shall be the sole and exclusive remedy and measure of damages as a result of the occurrence of an Event of Default by Buyer. Seller waives its rights to seek damages upon the occurrence of an Event of Default by Buyer under this Agreement. THE PARTIES HAVE AGREED THAT SELLER'S ACTUAL DAMAGES, IN THE EVENT OF A FAILURE TO CONSUMMATE THIS SALE DUE TO BUYER'S DEFAULT UNDER THIS AGREEMENT, WOULD BE EXTREMELY DIFFICULT OR IMPRACTICABLE TO DETERMINE. AFTER NEGOTIATION, THE PARTIES HAVE AGREED THAT, CONSIDERING ALL THE CIRCUMSTANCES EXISTING ON THE DATE OF THIS AGREEMENT, THE AMOUNT OF THE LIQUIDATED DAMAGES IS A REASONABLE ESTIMATE OF THE DAMAGES THAT SELLER WOULD INCUR IN SUCH EVENT. BY PLACING THEIR INITIALS BELOW, EACH PARTY SPECIFICALLY CONFIRMS THE ACCURACY OF THE STATEMENTS MADE ABOVE AND THE FACT THAT EACH PARTY WAS REPRESENTED BY COUNSEL WHO EXPLAINED, AT THE TIME THIS AGREEMENT WAS MADE, THE CONSEQUENCES OF THIS LIQUIDATED DAMAGES PROVISION. THE FOREGOING IS NOT INTENDED TO LIMIT BUYER'S INDEMNITY OBLIGATIONS UNDER OTHER SECTIONS OF THIS AGREEMENT.

SELLER: *[seller's initials]*

BUYER: *[buyer's initials]*

SECTION TEN. MISCELLANEOUS

A. Notices.

Any and all notices given or required to be given under this Agreement shall be in writing and shall be deemed to have been adequately given when received by the party to whom such notice is being given. Notices shall be addressed as follows:

If to Buyer: *[name of buyer], [address of buyer]*, Attn: *[name or title of contact person for buyer]*;

If to Seller: *[name of seller], [address of seller]*, Attn: *[name or title of contact person for seller]*;

or such other address as the respective parties to this Agreement shall from time to time designate in writing to the other party.

B. Exhibits.

All Exhibits described in this Agreement shall be deemed to be incorporated and made a part of this Agreement, except that if there is any inconsistency between this Agreement and the provisions of any Exhibit, the provisions of the Exhibit shall control. The parties shall, from time to time prior to or at the Closing by written agreement, supplement or amend the description of the Equipment in this Agreement and the Exhibits to accurately and more fully reflect the list of Equipment that is being conveyed under this Agreement.

C. Headings.

Section and paragraph headings set forth in this Agreement are for convenience of reference only and shall not in any manner be deemed to limit or restrict the context of the section or paragraph to which they relate.

D. Applicable Law.

This Agreement is entered into and shall be governed by and interpreted in accordance with the laws of *[name of state]*, notwithstanding its conflict of law provisions.

E. Entire Agreement.

This Agreement supersedes all prior understandings, representations, negotiations, and correspondence between the parties and constitutes the entire agreement between the parties with respect to the transaction contemplated and shall not in any manner be supplemented, amended or modified by any course of dealing, course of performance or usage of trade or by any other means except by a written instrument executed on behalf of the parties by their duly authorized officers.

F. Confidentiality.

Seller and Buyer agree to treat this Agreement and the terms of this Agreement as confidential and, without the prior written consent of the other party to this Agreement, not to disclose the terms of this Agreement to any other person except (i) to its counsel and accountants or other agents or professional advisors in connection with or relating to the transactions contemplated by this Agreement; (ii) to any court, governmental agency or instrumentality or other supervising body requesting such disclosure; (iii) to any person as may be required by any government regulation or order (including any regulation, request or order of a bank regulatory agency or authority or under any disclosure requirements affecting public companies, including, but not limited to, regulations of the Securities and Exchange Commission), law, statute, regulations, decrees, subpoenas or court orders; (iv) its directors, officers, employees, affiliates, successors and assigns; (v) to any banks or other financial institutions in any debt financing by or for the benefit of Buyer; or (vi) in connection with any enforcement of the terms of this Agreement. Seller and Buyer shall cause its officers, directors, agents, and employees to comply with this paragraph F. Notwithstanding the foregoing to the contrary, Seller shall, upon reasonable prior written notice to Buyer, have the right to issue press releases regarding this transaction.

G. Further Assurances.

Seller and Buyer agree that from and after the Closing Date, each of them will, and will cause their respective representatives and affiliates to, execute and deliver such further instruments of conveyance and transfer and take such other action as may reasonably be requested by any party to this Agreement to carry out the purposes and intents of this Agreement.

H. Casualty Loss.

If, subsequent to the date of this Agreement and prior to the Closing, a portion of the Equipment in excess of $*[dollar amount of value of equipment]* is damaged or destroyed by fire or other casualty, is taken in condemnation or under the right of eminent domain, or proceedings for such purposes are pending or threatened (collectively, "Casualty Loss"), Buyer shall have the option to either (a) purchase the Equipment notwithstanding any such Casualty Loss, without reduction of the Purchase Price; or (b) terminate this Agreement without further obligation of either party except that Buyer shall be entitled to receive any amounts Seller owes to Buyer under Section Eight, subparagraph A(2), and the return of the Deposit and all other monies paid to Seller towards the Purchase Price. In the event of clause (a) above, Seller shall: (x) at the Closing, pay to Buyer all sums paid to Seller by insurance companies and other third parties by reason of the Casualty Loss of such Equipment; (y) assign, transfer and set over to Buyer all of the right, title and interest of Seller in and to any unpaid awards or other payments from third parties arising from the Casualty Loss; and (z) not voluntarily compromise, settle or adjust any material

amounts payable by reason of any Casualty Loss of any portion of the Equipment without first obtaining the written consent of Buyer.

I. Expenses.

Except as otherwise set forth in this Agreement, Seller and Buyer shall each bear its own expenses (including but not limited to attorney's fees) incurred in connection with the negotiation and execution of this Agreement and each other agreement, document and instrument contemplated by this Agreement and the consummation of the transactions contemplated by this Agreement.

J. Submission to Jurisdiction.

The parties agree to unconditionally and irrevocably submit to the exclusive jurisdiction of the federal or state courts sitting in *[name of state]*, and any appellate court from any of such federal or state courts, for the resolution of any claim or dispute relating to or arising under this Agreement.

K. Excusable Delay.

Neither Seller nor Buyer shall be responsible to the other for any delay ("Excusable Delay") in the performance of its duties under this Agreement due to any cause beyond its reasonable control and not occasioned by its intentional act, fault or negligence including but not limited to acts of nature, strikes, lockout or other industrial disturbances, acts of public enemies, orders of any kind of the government of the United States or any state or local government or any of their departments, agencies or officials, or any civil or military authority, insurrections, riots, earthquake, fire, storm, adverse weather conditions, restraint of government and people, civil disturbances, or explosions. Either Seller or Buyer shall promptly notify the other when an Excusable Delay has occurred or is likely to be incurred and in each case specify to the extent practicable the estimated extent of such delay. Either party may terminate this Agreement if the Excusable Delay lasts more than *[number of days]* days.

L. Severability.

If any provision of this Agreement is invalid or unenforceable, the balance of this Agreement shall remain in effect.

M. Limitation of Liability.

NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THIS AGREEMENT OR OTHERWISE, NO PARTY TO THIS AGREEMENT (OR ANY OF ITS SUBSIDIARIES, AFFILIATES OR ASSIGNS) SHALL, UNDER ANY CIRCUMSTANCE, BE LIABLE TO ANY OTHER PARTY (OR ANY OF ITS SUBSIDIARIES, AFFILIATES OR ASSIGNS) FOR ANY CONSEQUENTIAL, EXEMPLARY, SPECIAL, INCIDENTAL OR PUNITIVE DAMAGES CLAIMED BY SUCH OTHER PARTY UNDER THE TERMS OF OR DUE TO ANY BREACH OF THIS AGREEMENT, INCLUDING, BUT NOT LIMITED TO, LOSS OF REVENUE OR INCOME, COST OF CAPITAL, OR LOSS OF BUSINESS REPUTATION OR OPPORTUNITY.

N. Binding Effect; Assignment.

This Agreement shall be binding upon and inure to the benefit of the parties and their respective successors and permitted assigns. No assignment of this Agreement or of any rights or obligations under this Agreement may be made by Seller or Buyer (by operation of law or otherwise) without the prior written consent of the other party to this Agreement and any attempted assignment without the required consent shall be void. Notwithstanding the foregoing, Buyer may be entitled to assign its rights in and to this Agreement to an affiliate or subsidiary entity without the consent of Seller, provided that (a) the assignee shall expressly assume all of Buyer's obligations under this Agreement pursuant to a written agreement in form and substance reasonably acceptable to Seller, (b) Seller receives a copy of such assignment and assumption agreement on or before *[number of days]* business days prior to the Closing, and (c) the assignee shall be deemed to have reaffirmed all of the representations and warranties of Buyer in this Agreement.

O. Counterparts.

This Agreement may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

P. Broker, Finder, and Financial Advisor Fees.

If the transaction contemplated by this Agreement is consummated, but not otherwise, Seller agrees to pay to *[name of broker]* (the “Broker”) at Closing a brokerage commission pursuant to a separate written agreement between Seller and Broker. Each party agrees that should any claim be made for brokerage commissions or finder's fees by any broker, finder or financial advisor other than the Broker by, through or on account of any acts of such party or its representatives, that party will indemnify and hold the other party free and harmless from and against any and all loss, liability, cost, damage and expense in connection with the same. The provisions of this paragraph P shall survive Closing or earlier termination of this Agreement.

SECTION ELEVEN. AFFIRMATION BY THE PARTIES

A. In performance of its duties under this Agreement, each Party is prohibited from engaging directly or indirectly in any illegal, immoral or unethical conduct. Illegal conduct shall be that defined under the laws of the United States.

B. Each Party shall comply, and require that its affiliates, agents, and employees comply, in all respects with the United States Foreign Corrupt Practices Act, any comparable law or regulation in any applicable jurisdiction and any multilateral international conventions dealing with bribery and corrupt practices, as they may be amended from time to time, regardless of whether they are by their terms otherwise applicable to them. Without limiting the generality of the foregoing, no Party under this Agreement will use, and will require that its respective agents, adviser, and affiliates will not use, any payment or other benefit derived in connection with this Agreement to offer, promise or pay any money, gift or any other thing of value to any person for the purpose of influencing official actions or decisions affecting this Agreement or any of the transactions contemplated under this Agreement in connection with the services, while knowing or having reason to know that any portion of this money, gift or thing

will, directly or indirectly, be given, offered or promised to: (i) an employee, officer or other person acting in an official capacity for any government or its instrumentality; or (ii) any political party, party official or candidate for political office.

C. The Parties will not, and will require that their respective employees, agents, and adviser will not, conduct business with or assist an entity or person owned or controlled by, a "suspected terrorist" as defined by U.S. Executive Order 13224.

The parties have executed this Agreement at *[place of execution]* the day and year first set forth above.

[Name of seller]
By:
_____ *[Name of officer of seller]*
[Title of officer of seller]
[Name of buyer]
By:
_____ *[Name of officer of buyer]*
[Title of officer of buyer]
[Acknowledgments]
[Attach exhibits]

Notes

Drafter's Notes

For forms of acknowledgments, see §§ 7:1 et seq.

West's Key Number Digest

West's Key Number Digest, Sales 1 to 484

Legal Encyclopedias

Agreement for sale of goods. Am. Jur. 2d, Sales §§ 98 et seq.

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End of Document

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Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF RONALD A. HALPERN

ON BEHALF OF NORTHWESTERN ENERGY

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Halpern Experience List	Exhibit__(RAH-2)
Halpern Papers and Presentations	Exhibit__(RAH-3)
Root Cause Analysis CU4 Core Failure Event *(public and protected versions)*	Exhibit__(RAH-4)

Witness Information

Q. Please state your name and business address.

A. My name is Ronald A. Halpern and my business address is 2098 Lynnwood Drive, Schenectady, New York 12309.

Q. By whom are you employed and in what capacity?

A. I am the President of Generator Consulting Services, Inc. ("GCS").

Q. Please summarize your educational background.

A. I have a Bachelor of Engineering degree in Mechanical Engineering from the City College of New York. I also have taken MBA courses at the University of Minnesota.

Purpose of Testimony

Q. What is the purpose of your testimony in this consolidated docket?

A. NorthWestern Energy ("NorthWestern") has retained me as an expert witness to testify regarding the root cause of the forced outage at Colstrip Unit 4 ("CU4") on July 1, 2013, and to rebut portions of the Pre-filed Direct Testimony of David A. Schlissel, filed on behalf of the Sierra Club and the Montana Environmental Information Center ("MEIC"), with respect to the outage.

I was retained by the CU4 operator, Talen Energy ("Talen") (formerly PPL Montana, LLC), immediately after the forced outage occurred, investigated the incident, and determined the likely cause. I joint authored the Root Cause Analysis ("RCA") for the incident with Robert Ward, another subject matter expert. Mr. Schlissel relied on the RCA when he prepared his testimony for the Sierra Club and the MEIC in this case. I explain in my testimony how some of the conclusions drawn by Mr. Schlissel from the RCA are simply wrong.

Q. What are your qualifications to testify as an expert on these issues?

A. As mentioned above, I am the President of GCS in Schenectady, New York. GCS specializes in both commercial and technical consulting on large power generator operation, maintenance, service, testing and inspection, and failure/root cause analysis. In my current position at GCS, I advise utility and industrial power generators, generator Original Equipment Manufacturers ("OEMs"), insurance companies, industry organizations, and failure investigation companies on all aspects of generators. Frequently, I am asked to investigate highly complicated and unusual failures or operational issues to determine the root cause. I also counsel and advise power generators on proper maintenance and solutions to generic industry problems on generators. I have done this work for the past 17 years.

I was with General Electric ("GE") for over 25 years in generator engineering in the generator service business. In my last position with GE, I was the Generator Product Line Manager in GE Services. A copy of my resume is provided as Exhibit__(RAH-1). A copy of my experience list is provided as Exhibit__(RAH-2).

Q. Please describe your experiences with generator outages.

A. In my prior career with GE, I managed outages as a field engineer and generator specialist. Subsequently, I provided a higher level of technical support to field personnel who were executing outages when I was in the engineering department. In my consulting practice, one of my primary objectives is to advise utilities on the proper specification preparation, proposal evaluation, outage planning and execution as well as review of post outage issues such as failures similar to the issue at CU4 in July 2013.

I am also knowledgeable about the type of Siemens generator used in CU4, which is the subject of this case. During the past 17 years as a consultant I have done work on 16 Siemens/Westinghouse generators (see Exhibit__(RAH-2) for those projects that are marked with an S or W).

Q. Please identify representative industry-related writings authored by you.

A. They are listed in my Exhibit__(RAH-3).

Q. Please identify representative industry-related speaking engagements which you have had.

A. They are listed in my Exhibit__(RAH-3).

Q. Have you ever testified before the Montana Public Service Commission?

A. No. However, I have testified before the utility regulatory commissions in Wyoming and Oregon regarding PacifiCorp's Hunter core failure in 2000 and before the Indiana commission regarding Duke Energy Indiana's Gibson 4 generator failure in 2008. I also have been an expert witness in several court cases. See Exhibit__(RAH-2).

Root Cause Analysis

Q. Please describe your investigation of the July 1, 2013 forced outage at CU4 and your preparation of the RCA.

A. I made two trips to the site. One was soon after the failure to (1) inspect the stator before any extensive repair or disassembly work was done on the unit and (2) advise Talen on the repair. The second trip was after some disassembly was done in order to inspect various components of the unit. These trips were very important in determining the root cause. As I already have testified, I then joint authored the RCA with Robert

Ward. Both public and protected versions of the RCA, which contains proprietary information belonging to Siemens, are being provided as Exhibit__(RAH-4).

Q. Does the RCA conclusively establish the cause of the July 1, 2013 forced outage at CU4?

A. No, it does not. In cases of core damage, such as occurred at CU4, the physical evidence that points to exactly what caused the damage is destroyed due to the melting of the core. Therefore, there is no "smoking gun" that can conclusively point to a cause. Typically, in core damage situations you are left with melted masses of metal. That was the case with the 2013 forced outage at CU4.

Q. If one is unable to determine the exact cause of an outage when there is core damage, how is the most likely cause of an outage determined, and what was the most likely cause of the outage at CU4 in 2013?

A. The most likely cause of damage is determined by the prior circumstances that can be factually ascertained and from the timing of events leading up to the outage. Through informed deduction one can determine the most likely cause of the failure. One can also eliminate possibilities that could cause similar core failures by inspecting certain components to see if characteristics are present that would be typical of such failures. In this

case, with the use of an all-inclusive fault tree and eliminating those scenarios that could not be the root cause, we were left with the most probable root cause.

As stated in the RCA, the most likely scenario that caused the failure at CU4 was inadequate interlaminar insulation combined with damage from one of the events noted below. This was discussed in detail in Scenario No. 3 of the RCA.

In short, since the areas of the core failure were destroyed, it was impossible to ascertain with certainty if there was any damage caused by rotor insertion activities, which are normally routine and inconsequential. However, general inadequate, or lack of, interlaminar insulation is the most probable root cause of the failure, but the catalyst to drive the laminations together could have been either: (1) rotor insertion, (2) damage from the skid pan, or (3) installation of the air gap baffles.

Q. Can you please describe the purpose and construction of the laminations and core and its importance to the generator?

A. The principle of electricity generation is that a conductor moves in a magnetic field, which then generates a current in the conductor. In the case of a generator, the magnetic field is the rotor, which is an electromagnet that rotates and is turned by the turbine. The conductor is

the stator windings composed of heavy copper wire. These wires are where the electrical current is generated and subsequently flows out of the unit to the electrical grid.

To hold the stator windings in place and to channel the magnetic field created by the rotor, a laminated core is needed. The laminations consist of sheet steel coated with an electrical insulation known as Alkophos, which is a very thin coating of insulation. There are thousands of these laminations stacked together to make the laminated core.

The insulation is very important because it prevents contact between the laminations. If the insulation is inadequate, the laminations could have contact and then that portion of the core can act as a conductor and create heat. If one or two laminations have contact, it is not an issue. It is generally estimated that it would take four to five laminations shorted together to create enough heat to start melting the core and causing damage. However, the exact number depends on many variables.

Q. The RCA noted that the insulation on the laminations in the generator at CU4 was inadequate. Can you please explain this statement?

A. When this generator was constructed in 1985, the insulation was state-of-the-art technology. As noted in my previous answer, Alkophos was used

to insulate the laminations. At the time, all Westinghouse generators used this form of insulation. This coating is a very thin layer of insulation, only a fraction of an inch in thickness – similar to paint on a wall. It was later determined that, depending on the application of the insulation, this form of insulation could vary in thickness and in spots be non-existent, and where bare, could result in possible shorting and damage to the core. The adjacent coating thickness normally keeps the bare spots from contact. The test of laminations is not done individually but across a stack of laminations, similar to the same conditions of construction and service.

That statement needs to be put in perspective, however. Many generators with this form of insulation have been running successfully for many years. To my knowledge, no generators have failed because of this factor.

Q. If the application of the insulation was uneven or too thin in places, did this fall outside an acceptable level according to industry standards at the time?

A. No. At the time that this machine was built, the application of the coating of the insulation had a certain tolerance band acceptable within the industry. The generator at CU4 fell within the acceptable tolerance band.

Q. If that is the case, why was the application of the insulation raised as an issue in the RCA?

A. It was later determined that if the coating on several laminations was on the lower side of the tolerance band, and these laminations were randomly placed together or were from the same batch that had thin insulation, then the proximity of these laminations near each other could present a weak spot. These weak spots, however, may never be an issue.

The weak spots would become an issue if something caused these contiguous laminations to be forced together. For example, when a rotor is installed, should the rotor accidentally hit the core, or if there is wear from vibration and movement in service, then these laminations would be forced together and create heat which will melt the core and result in a failure.

Q. In your opinion, are units constructed with this form of insulation unreliable and should problems be anticipated or expected?

A. No. Hundreds of generators have been running for many years with this design and, at the time, it was the state-of-the-art insulation. In this case, CU4 ran for almost 30 years with this insulation without any problems. Additionally, the core was tested several times during prior outages to determine if the insulation was acceptable and it ultimately passed those tests. These machines have run without any problems associated with the insulation for many years and have proven to be reliable.

Q. At page 12 (lines 4-11), Mr. Schlissel suggests that because NorthWestern is not aware of other instances where interlaminar insulation was found to be inadequate that this supports the finding that work performed during the planned outage in May and June of 2013 led to the forced outage. Do you agree with this conclusion?

A. No. The work performed during the planned outage in May and June alone could not have caused the catastrophic failure. The final El Cid test proved that the core was not damaged during the maintenance work. It had to be preceded by the condition of inadequate interlaminar insulation. Both factors, inadequate interlaminar insulation combined with something during reassembly, like rotor insertion damage, air gap baffle insertion, or skid pan damage, were needed.

Q. At pages 13-14 of his testimony, Mr. Schlissel faults NorthWestern for not being aware of the procedures related to inspection of a generator's interlaminar insulation. Are public utilities like NorthWestern typically aware of these types of procedures?

A. No. Most utilities rely on the OEM, in this case Siemens, to provide technical expertise for the inspection and repair of their generators. OEMs have the most knowledge and experience because they deal with a large number of generators and are exposed to hundreds of different issues. No one utility would have the same broad range of expertise on generator technical issues, much less core specific issues. If there was an issue

with these cores, Siemens would probably provide either an Advisory Letter or an Availability Improvement Bulletin. None was issued. Plant personnel do not normally include generator experts who are familiar with the specifics of detailed generator problems such as what caused this failure.

Q. On page 10 (lines 19-20), Mr. Schlissel states that "[the El Cid] testing would have been able to detect any damage to the laminations existing at the time the testing was performed." Do you agree with this statement?

A. Yes, but El Cid (Electromagnetic Core Imperfection Detector) testing is not always possible. El Cid testing is the state-of-the-art system designed to identify damage to the core. It is used throughout the industry to test the core during outages and at the completion of core repair work. El Cid testing is considered standard industry practice. However, El Cid testing cannot be completed after the air gap baffles are installed because there is no room to insert the equipment needed for the testing.

Conclusion

Q. Please summarize your testimony.

A. Mr. Schlissel does not disagree with the conclusion in the RCA regarding the most likely cause. Although Mr. Schlissel relied upon the RCA as the primary basis for his opinions, he misinterpreted the key conclusion of the

RCA and offered opinions which are not supported in the RCA. The important facts that do support the RCA are:

1. Alkophos interlaminar insulation was state-of-the-art-technology when the machine was built.
2. This machine ran for almost 30 years without any problems with the laminations.
3. Many generators built with the same laminations have been in service for many years without any failures.
4. Rotor insertion damage can occur, but is rare. Such damage can be characterized as unforeseeable. The same can be said for tooth distortion by the air gap baffle trains and the skid pan insertion.
5. The core did not have any prior similar problems.
6. This failure was rare and based on a combination of two conditions occurring at close to the same time. NorthWestern could not have foreseen or prevented it.

Q. Does this conclude your testimony?

A. Yes.

Ronald A. Halpern

Generator Consulting Services, Inc.
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Experience

1998-present Generator Consulting Services, Inc. Schenectady, N.Y.

President

- Provide impartial third party commercial and technical consulting on all manufacturers large power generator operation, maintenance, service, testing & inspection, failure/root cause analysis, project planning &management, specification preparation & proposal evaluation

1974-1998 General Electric-Various assignments:

1992–1998 GE Energy Services Schenectady, N.Y.

Generator Product Line Manager

- Set strategic direction for generator business for over 10,000 GE units globally served by 60 engineers, & 300 service engineers and technicians.
- Responsible for leadership in GE's global generator parts & services business.
- Identified, generated product specifications, appropriated funding and managed annual new product development budgets and associated sales.
- Formulated GE's business wide strategy on liquid cooled generator leaks, bar abrasion and rewinds
- Mentored the GE process teams for Stators, fields, retaining rings, and uprates
- Represented GE in all customer, industry and external functions such as technical paper generation, trade shows, state of the art seminars, major technical conferences, customer meetings, trade press, press releases, insurance industry relations.
- Attended and published several papers at EPRI, CIGRE, GE SOA's, annual utility conferences, Power Gen Int'l., Latin America & Europe.
- Served as primary focus for competitive intelligence and strategy
- Evaluated and provided strategic direction for major proposals and commercial decisions
- Evaluated, reviewed and approved all major strategic and transactional headquarters pricing decisions; advised field of appropriate transactional pricing levels
- Directed commercialization efforts of new and existing products and services
- Identified and evaluated candidate organizations for acquisitions
- Project managed the BECO Pilgrim forced outage, failure investigation and record setting rewind
- Led GE's Generator efforts on Conditioned Based Maintenance strategy

- Grew liquid cooled stator rewind business while reducing installation cycles 40% to perfect the short cycle rewind capability resulting in several world record outage cycles for fossil and nuclear rewinds.
- Led the implementation, promotion and commercialization of the highly successful Epoxy injection leak repair process.
- Led the repair and rewind new business ventures on Westinghouse, Alstom, Toshiba, Hitachi, Ansaldo and other Non-GE OEM's.

1990-1992 GE Global Service and Parts Schenectady, N.Y.

Manager Gas Turbine Generator Parts/Outage Support

- Responsible for $280M gas turbine generator parts delivery group during period of record growth
- Interfaced with high level manufacturing and sourcing contacts to insure accurate and timely design and manufacturing.
- Identified, hired and organized a new group of 20+ people to manage conversions, modifications and uprates.
- Served as primary high level customer interface for escalation issues

1988-1990 GE Product Service Schenectady, N.Y.

Manager Contract Administration/Outage Support

- Established a new group of 6 engineers with contractual responsibility for selected, high priority, non-routine major global turbine generator projects having special requirements.
- Designed and implemented new systems to reduce costs and improve profitability.
- Maintained high visibility position with senior level management for commercial and technical reporting.

1985-1988 Generator Engineering Schenectady, N.Y.

Technical Leader Generator Rebuild and Supply Engineering

- Provided senior level HQ engineering technical support to field personnel.
- Responsible for supervision & training generator engineering personnel, field engineers, service shop, overseas business associates.
- Personally managed the advanced generator maintenance program which trained over 80 generator specialists, startup engineers, and shop personnel in a 6 year period.
- Transitioned experience from two departing senior engineers to preserve technical expertise.
- Presented training and information seminars to IEEE, utilities and at GE technical conferences
- Instituted a new warranty complaint tracking and processing system to expedite estimating, processing and tracking.
- Completed a project covering 25 years of stator rewinds to predict future

market potential, and competitive positioning

- Worked to effectively reduce costs for stator rewinds
- Project managed the first major generator synchronous condenser conversion
- Managed one of the first radial-axial-radial to diagonal flow field conversions to eliminate grounds, coil distortion and thermal sensitivity; provided direction for the first time temporary repair of a RAR field to generate new business.
- Authored and Published several Technical information letters
- Provided total technical management for a unique cracked shaft repair.
- Coordinated the technology transfer of the medium generator fleet from Lynn, Ma. To Schdy.
- Anchored a major failure investigation of an overseas nuclear unit
- Designed and Automated a new computer driven rewind quote and ordering system
- Led several overseas high profile failure, repair and maintenance efforts

1982-1985 Generator Engineering Schenectady, N.Y.

Technical Leader Generator Availability Engineering

- Provided senior level engineering technical support to field personnel.
- Mentored, trained and supervised less experienced office and field engineers on factory and field projects, designed several technical training courses.
- Supervised factory/manufacturing technical support for redesigns, replacement fields, retaining ring diagnostic inspections and replacements,
- Supported field ground investigations, negative sequence heating evaluations, field and stator contamination problems, rewinds and auxiliary equipment operation.
- Led the generator portion of several major GE technical conferences
- Led the technical evaluation and resolutions of unusual field thermal sensitivity vibration issues to restore several units to service
- Directed the repair of fields with unusual damage
- Provided support for manufacturing pursuit of a new field rewind business.

1978-1982 Generator Engineering Schenectady, N.Y.

Engineer Generator Availability Engineering

- Provided technical support for maintenance and installation of GE's worldwide fleet of large steam turbine generators
- Made frequent trips to job site to resolve unusual/outstanding technical problems and advise GE field personnel and customers.
- Wrote repair procedures & resolved root cause and effect of units forced out of service, responsible for field engineering and generator specialist manuals
- Made recommendations for proper operation and protection of operating units
- Made formal technical presentations to other components, customers on state of the art maintenance activities.
- Worked with engineering design units, production and manufacturing organizations , marketing, lab

- Spearheaded the early retaining ring stress corrosion investigations and repairs to set overall policy
- Investigated early copper dust incidents and developed repair procedures.

1974-1978 Installation & Service Engineering Various locations

Installation Engineer/Field Engineer/Generator Specialist

- Responsible for field technical support for installation of 12 new 600+MW units
- Worked on the maintenance of large, medium steam, and gas turbines in the Philadelphia district
- Installed a 660 MW G3 large steam turbine in Minneapolis
- Headquarters assignment for installation of new computer system to track installations
- Graduated the Advanced Generator Maintenance Program.
- Major rebuild of several overseas generators while on loan to the international department, including turbine work.
- Tested, inspected and maintained utility and industrial Generators throughout the central U.S.

Education

- City College of New York. B.E. Mechanical Engineering
- University of Minnesota, MBA courses
- General Electric, Numerous Internal courses and programs

Publications

- Over two dozen generator technical papers

7/20/2015

Generator Consulting Services Ronald Halpern Experience List

Year	Customer	Station	MFG	Issue
2015	MidAmerican Energy	Louisa	W/S/Als	Stator Rewind Design Review,outage planning
2015	PacifiCorp	HTR3	GE	Stator Rewind Advice
2015	EPRI			Field Rewind Problems Project
2014	Oildale Energy		Als	Review RFM , PD reports
2014	Occidental Chemical	Taft	GE	Flux Probe Evaluation, Rotor Shorted turns
2014	Entergy	JAF	GE	El Cid test issues/evaluation
2014	TVA	Browns Ferry1	GE	Rotor Distance Block, ODMI
2014	MidAmerican Energy	Louisa	W/S/Als	Stator Rewind Proposal Evaluation
2014	MidAmerican Energy	Walter Scott 4	Hit	Water Leak,Cracked Phase Conn, Bar greasing
2014	Tri State G&T	Craig	GE	Operation / Maintenance Training Course
2014	Siemens AG			Consulting Opinion
2013	NextEra Energy	Seabrook	GE	Water chemistry
2013	Balancing Pool	TAKP1	Hit	Stator failure
2013	Rock Tenn	Florence	EM	Field Rewind oversight @ MDA
2013	PPL Montana	Colstrip	Sie	RCA of catastrophic core failure, repair recc's.
2013	Entergy	Pilgrim	GE	Full Stator Rewind Oversight
2013	Wisconsin Elec	Elm Road	Hit	Stator Noise Issue
2013	Dayton P&L	Killen	GE	Field Rewind Spec, Rewind Oversight @ MDA
	Oildale	CC1 GT	ALS	Review ALS inspection & testing
2012	Bechtel	Araucaria	ALS	Phase Connection Failure-ICC arbitration w/UEGA Brazil
2012	Dynegy	Independence	GE	Field Winding Failure
2012	Balancing Pool	TASD6	ALS	Transformer Failure effect on Generator
2012	Exelon	Peachbottom	GE	New Field manufacturing oversight
2012	NextEra Energy	Seabrook	GE	3rd party review of Stator Rewind,Water Chemistry Issues
2012	Xcel Energy	Hayden	NEC	Stator bar Mfg. and Rewind Oversight. Analysis Failed Bar
2012	ATCO Power	BR5	Hit	Provide New Field Spec.,review proposals
2012	Bechtel	RCEC	SIE	Contamination/Foreign Object Decision for Dis-Asm.
2011	Balancing Pool	TA SD3	ALS	Phase Connection Failure
2011	GE Canada	Peterborough	GE	Consult on LM&G stator core repari
2011	Entergy	Pilgrim	GE	RFP stator rewind Prep. Proposal evaluation, Site planning for RFO 19 stator rewind
2011	Exelon	TMI	GE	Stator Bar manufacturing oversight in GE Factory
2011	GenOn	Connemaugh	GE	Inside and Outside space block migration evaluation related to future stator rewind
2011	MidAmerican Energy	Louisa	W/ALS	Water cooled stator rewind specification for rewind
2011	NextEra Energy	Duane Arnold	GE	3rd party root cause review of RCE Failed DC leakage test and rewind due to wet bar
2011	PacifiCorp	Jim Bridger	GE	SWCS Plugging restrictions/ partial rewind
2011	Dynegy	Independence	GE	Field shorted turns evaluation

Generator Consulting Services Ronald Halpern Experience List

2011	MidAmerican Energy	Louisa	W/ALS	RCA of rewound generator end winding vibration failure, Oversight of subsequent rewind on site.
2010	Entergy	Pilgrim	GE	RFO 18: Water leaks outage prep.,testing,EMI, bar manufufacturing, site inspection oversight
2010	Exelon	Peachbottom	GE	Stator Bar manufacturing oversight in GE Factory
2010			GE	Support core inspection, testing and repairs at GE Canada LM&G Peterborough site
2010	PacifiCorp	Lakeside	W/SIE	RCA catastrophic stator failure,work with Siemens in factory to forensically disassemble & investigate
2010	Entergy	Vermont Yankee	GE	Low ALTX bearing megger, CT/transducer effects.
2010	Wadham Energy LP		Brush/SIE	stator rewedge, retaining ring indications, shorted turns
2009	Duke Energy	Gibson	GE	Investigated water cooled generator failure,acted as expert witness in prudence hearings before Indiana PUC involving near catastrophic failure
2009	Entergy	Pilgrim	GE	RFO 17: GE TIL 1292 advice and review, site inspection oversight, water leaks
2009	Exelon	Dresden	GE	Stator Bar manufacturing oversight in GE Factory
2009	Penn Pwr & Light	Brunner Island	GE	3rd party technical opinion on GE's root cause analysis of field vibration problem and proposed solutions
2009	OilDale Energy LLC		GEC/ALS	Review/condition assessment AMODIS PD,Slot leakage flux
2009	PPL Montana	Colstrip	GE	HIPOT failure, field testing, repair, partial rewind
2009	Epcor	Kapuskasing	ABB	Rotor damage salient pole
2008	Smith Enron/San Felipe/AEI	Puert Plata	GE	Investigaton of generator field thermal sensitivity and rewind due to unusual circumstances
2008			GE	C coil field rewind evaluation feasibility
2008	Exelon	Quad Cities 2	GE	Provide inspection oversight for Stator rewind
2008	Exelon	Quad Cities 2	GE	Inspection oversight for Field Rewind
2008	PSEG of NY	Bethlehem Energy Center	GE	Inspection/oversight for Core and Belly Band Tightening.Evaluation and repair of end winding vibration
2008	PP&L LLC of Montana	Colstrip	GE	Investigation & repair of Generator Field HIPOT failure
2007	Platte river Power Authority	Rawhide	W	Quality Assurance/Techncial consulting on Static exciter failure and rebuild
2007	Exelon	Dresden	GE	Engineering and Inspection support for new 4 pole nuclear field
2007	Platte river Power Authority	Rawhide	GE	Witness final testing of two new generator fields including final balance and electrical testing at GE's factory.
2007	Exelon	Clinton	GE	Manufacture of new GE exciter in Peterborough Canada-independent engineering and inspection services
2007	Exelon	Quad Cities 2	GE	Engineering/ inspection services for the manufacturing of new Stator Bars at the GE factory

Generator Consulting Services Ronald Halpern Experience List

2007	Detroit Edison	Harbor Beach	ALS	Witness Generator Disassembly and review repair procedures to find source of field winding resistance variation
2007	Public Service E&G NJ	Mercer	GE	Opinion and independent engineering verification of GE's analysis on maching error for generator field
2007	Pacific Gas & Electric	Diablo Canyon	W	Evaluation of unusual system disturbance incidents & effect on shorted field turns
2007	PacifiCorp	All	GE, W	Design a first time operations and maintenance training course for generators. Instruct at all of PacifiCorp's power plants to Operations personnel(control room operators to Operations manager), engineering and all other disciplines.
2006	Detroit Ed	Belle River	Allis Chalmers/SW	Root cause failure investigation of brushless exciter
2006	PacifiCorp	Bridger	GE	Evaluation of GE's new liquid cooled stator bar brazing process, advise re mfg. issues & decision to rewind with new bars
2006	PacifiCorp	Bridger	GE	Customer witness for field balance and testing of new and rewound fields
2006	Port Klang Malasia		GE	Mis operation incident, stator ground & water cooled rewind-damage & process evaluation & opinion
2005	Detroit Ed	River Rouge	Allis Chalmers/SW	Root cause analysis, diagnosis and repair of stator failure, subsequent hydrogen fire and explosion
2005	Detroit Ed	Belle River	Allis Chalmers/SW	Root cause investigation of field ground caused by foreign object
2005	Holland PS		GE	Field operating problems after rewind. Evaluation of condition, recommendations for repair and future operation, advice regarding warranty repair
2005	Oildale		GEC/Alstom	Damage to field, temporary/permanent repair-field rewind in factory. Quality audit/customer witness of rewind.
2005	Orion Power	Elrama	W	Court appointed expert witness as advisor to the judge in trial of utility versus repair vendor as a result of catastrophic damage to stator core.
2004	ATCO Power	Battle River	Hitachi/GE	Evaluation of GE's new liquid cooled stator bar brazing/epoxy injected barrier coating, factory Quality Audit oversight
2004	Entergy Nuclear	Vermont Yankee	GE	Comprehensive evaluation of all generator components over 5 year period leading to stator rewind due to water leaks,field rewind to correct thermal sensitivity,and power uprate. Support included pre-outage planning, specification prep for rewinds and proposal review as well as on-site outage quality assurance.
2004	Entergy Nuclear	Vermont Yankee	GE	Mis-operation incident and stator ground fault investigation
2004	Oxychem		GE	Advise on damage to Stator and repairs.
2004	PacifiCorp	Currant Creek	GE	New unit mis-operation 3 phase to ground fault , Evaluation of damage, stator rewind
2004	PG&E NEG	Brayton Point	GE	Assessment of damage to stator bars from tooling, in situ repair feasibility evaluation, strip and re-insulate repair in field and factory.

Generator Consulting Services Ronald Halpern Experience List

2003	Oildale		GEC/Alstom	Evaluation of damage to core and subsequent repair.
2003	Oxychem		ABB	Evaluate damage to Stator and recc. repairs
2003	PacifiCorp	Bridger	GE	Stator conditin evaluation
2003	PacifiCorp	Bridger	GE	Evaluation of negative sequence damage to field,slot dovetail evaluation of load service and arcing, recc. for repair and operation, first time GE TIL 1292 profiling
2002	Dynegy	Baldwin	GE	Review and opinion on core testing and repair regarding unusual core damage and high El Cid readings.
2002	First Energy	West Lorain	GE	Multiple field problems after rewind leading to replacement.Forensic dis-assembly of suspect fields to determine cause. Subsequent arbitration hearing and expert witness testimony
2002	Foster PG		Brown Boveri	Evaluation of reports of Stator and Field inspection and testing done by a service company
2002	MVM Hungary	Liter	Alstom	Evaluation of condition of two rotors after one was subjected to a double field ground. Recommendations for repair and evaluation of root cause
2002	Reliant/Maxon Young		W	Review of OEM recommended repairs for motored field and overheated forging. Inspection of stator and field.
2002	Smith Enron	Puerto Plata	GE	Evaluation of generator condition subjected to extreme moisture and contamination, and subsequent repair
2001	Duke Power	Oconee	GE	Maintenance recommendations and review for water leaks & general operational problems. Advice on seal oil misoperation incident
2001	Enron		W/Hyundai	Inspection and evaluation of stator and field damaged due to exposure in hold of cargo ship, arbitration with insurance company and manufacturer
2001	PacifiCorp	Hunter 1	W	Inspection, evaluation, RCA and recommendation for repair. Investigation of catastrophic generator failure and subsequent expert witness testimony at PUC prudence hearings in Oregon and Wyoming regarding the failure to recover losses and for rate increase.
2001	PG&E NEG	Indiantown	GE	Investigation into water leak on relatively new Liquid cooled stator
2001	Primary Energy	Portside	GE	Stator bar ground failure, core restack and evaluation of unusual lamination degradation damage
2001	SEMPRA	Elk Hills Power	GE	Evaluation of stator and field dropped while unloading. Recommendations for retrieval and workscope for inspection. Act as customers representative to follow dis-assembly, evaluation and repair
2001	Sythe Energy/Maxon Young		GE	Stator core failure, stator ground, repair estimate and workscope
2001	Hazelwood Power	Victoria, AU	AEI	Evaluation of rewound field and subsequent failure. Expert witness testimony regarding cause of failure and latent design problems by manufacturer

Generator Consulting Services Ronald Halpern Experience List

2000	Connectiv	Indian River	Allis Chalmers/SW	Inspection of stator after two prior 180 degree switching out of phase incidents.
2000	Edison Mission Energy	Loy Yang B	Hitachi	Evaluation and RCA-severe overfluxing incident. Inspection, evaluation and recommendation for repair for stator (full core restack in field, evaluation of key bars and replacement, stator rewind, field rewind.
2000	ENRON		GE/Brush	Armature winding failure investigation & repair
2000	Entergy Nuclear	Pilgrim	GE	Evaluation of stator and field after prior stator failure and rewind.
2000	PG&E NEG		W	Inspection, evaluation and recommendation for repair of field and stator for suitability for peaking operation.
2000	PG&E NEG		GE/ALST	Inspection, evaluation and recommendation for repair for 6 stators and fields for suitability for service
1999	Connectiv	Indian River	GE/ABB	Field failure due to multiple trips from motoring, static excitation failure, melted winding, inadequate ventilation
1999	ENRON		GE	Field Inspection, evaluation and recommended repair on 3 units
1999	ENRON		GE	Stator inspection, evaluation and recommended repair
1999	Intl Paper	Androscoggin	Brush	Core damage Investigation and repair
1999	Mass Power		GE	Field inspection for intermittent resistance problem, turn insulation movement, pitting on shaft.
	Special Projects:			
1999	EPRI		ALL	Proposed program for GFLEX to extend time between generator inspections
2000	EPRI		ALL	LAI Study of Inspections done with robotic equipment and their effectiveness as compared with conventional inspections where the generator rotor is removed No. 1000100. Subsequent presentation to NEIL B&M subcommittee and adoption of standards.
2004	EPRI			Structural Integrity-advice regarding inspection of field dovetails for project
1999	EPRI/EME			Provide technical advice to primary EPRI investigator for generating guidelines for conversion of aerated to Low O2 to prevent crevice corrosion and leaks
2002	GE Installation & Maintenance Publications		GE	Review and updating of GE generator Installation, Maintenance & Operations technical publications & revise to current standards.
1998	GE Mktg NPI		GE	Marketing evaluation of new products and effect on biz.
2002	GE Procedure review		GE	Evaluation of new special repair procedures and revision.
1999	GE business Development strategy review		GE	Consultant to GE Energy for strategic business development of generator service business
2000	W		W	Review of Westinghouse core issues and repairs

Generator Consulting Services Ronald Halpern Experience List

2000	GE Insulation paper		GE	Update insulation paper-Advances in Generator Stator Insulation for the Service Business. Review GE generator stator insulation systems on new and rewound generators, review characteristics and demonstrate industry leadership
2005	PWROG W GMD		W	Commissioned project by the Pressurized Water Reactor Owners Group to construct comprehensive maintenance guidelines on Westinghouse four pole nuclear generators covering all components including auxiliaries. Features include timely and current topics such as core testing and tightening, top tooth cracking, end winding vibration, retaining rings,and all major service issues
2000	Structural Integrity			Provide technical advice for Retaining Ring evaluation for EPRI project.
2005	Electric Insurance			Evaluation of generator, exciter and auxiliaries for asbestos containing material in support of legal actions
2004	BWROG GE GMD		GE	Commissioned project by the Boiling Water Reactor Owners Group to construct comprehensive maintenance guidelines on GE four pole nuclear generators covering all components including auxiliaries. Features include timely and current topics such as water leaks and rewinds, dovetail inspection and cracking, retaining rings and all major service issues.
2000			Confidentail	Business development advice re generator service business, marketing, new market penetration

Ronald A. Halpern: Technical Papers & Presentations

1. Johnston, B., Halpern, R., Tornroos, K., "Uprates and Upgrades for Air, Hydrogen and Liquid Cooled Turbine Generators," Power Gen Europe-Cologne Germany, May 1994.

2. Halpern, R., Stanton, D., "Long Term Reduction of Liquid Cooled Generator Operation & Maintenance Costs through the Utilization of Condition Based Maintenance, In-Situ Inspections and Risk Dependent Repair Options," EPRI Utility Motor and Generator Predictive Maintenance and Refurbishment Conference, November 1995.

3. Halpern, R., Travally, Andy. "Water Cooled Generator Leak Repair Options", EPRI Maintaining the Integrity of Water-Cooled Generator Stator Windings, Tampa, FL, November 1996

4. Halpern, R., Nold, R., "Generator Upgrades and Rewinds," Power Gen International, Orlando, FL, December 1996.

5. Halpern, R., "Advance Upgrade Technologies Reduce Outage Frequency & Duration in Generators of Various OEM's-Application in Latin America," Latin America Power 97, Caracas, Venezuela, April 1997.

6. Halpern, R., Nold, R., "Experience with Outage Interval Extension and Duration Reduction Utilizing Advanced Inspection, Maintenance and Upgrade Concepts for Liquid & Non-Liquid Cooled Generators," Power Gen Europe 97, Madrid, Spain, June 1997.

7. Halpern, R., "Water Cooled Generator Stator Maintenance and Repair Options," EPRI Steam Turbine Generator Workshop, Lake Buena Vista, FL, July 1997.

8. Halpern, R., "Generator Upgrades Produce Operational Dividends," Power Engineering Magazine, May 1997.

9. Cholewa, A., Halpern, R., Larson, T., Maki, D., "Global Epoxy Injection Repair of Water Cooled Stator Windings," Power Generator International, Orlando FL, December 1997.

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20. Halpern, R., “Complying With OEM Technical Advisories,” EPRI Main Generator Maintenance Issues & Solutions Conference, Orlando, FL, January 2007.

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22. Halpern, R. “Generator Operation (and Mis Operation) ”, Doble Revolutionary Machines Seminar, San Francisco, CA November 2009

23. Halpern, R. “Generator Operation”, Doble Revolutionary Machines Seminar, Hollywood, FL, November 2010

24. Halpern, R. “Operation of Large AC Generators and Consequences of Mis Operation”, Doble Revolutionary Machines Seminar, Hollywood, FL, November 2011

25. Halpern, R. “Operation of Large AC Generators and Consequences of Mis Operation”, Doble Revolutionary Machines Seminar, San Francisco, CA, September 2012

26. Halpern, R. “Generator Mis Operation”, EPRI Generation European Workshop & Turbine Generator Users Group, Rome, Italy, April 2013

27. Halpern, R. “How to Avoid Generator Mis Operation”, EPRI P65 Webcast, June 2013

28. Halpern, R. “Lessons Learned from Generator Failures” EPRI European Generator Workshop, Madrid, Spain, April 2015

29. Various Papers and Presentations Internally to GE Customers at State of the Art Seminars, Regional & Product Specific Users Conferences; Utility Fossil and Nuclear Conferences, 1982-1998.

Root Cause Analysis Report on PPL Montana Colstrip 4 Core Failure Event

Ronald A. Halpern
Generator Consulting Services, Inc.
2098 Lynnwood Drive
Schenectady, New York, USA 12309

Robert Ward
Ward Electric Service Corporation
5840 Red Bug Lake Road
Suite 500
Winter Springs, FL 32708

November 18, 2013

Pages i, ii, and iii are protected in their entirety.

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The cause of the failure was most likely inadequate interlaminar insulation permitting shorting between laminations caused during the prior outage by rotor insertion, skid pan damage or air gap baffle installation.

Pages 2 through 41 are protected in their entirety.

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In our opinion, PPL did everything according to standard industry practice such as hiring the OEM (Siemens) to perform the maintenance, performing El Cid testing on the core, operating their unit according to industry practice, (since there was no indication of mis-operation), and protecting the unit with adequate relay protection. Nothing they did or could have done, could have prevented this failure.

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Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF ROBERT T. WARD

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Robert T. Ward Resume	Exhibit__(RTW-1)

Witness Information

Q. Please state your name and business address.

A. My name is Robert T. Ward. My business address is at 5840 Red Bug Lake Road, Suite 500, Winter Springs, Florida 32708.

Q. By whom are you employed and in what capacity?

A. I am the President of Ward Electric Service Corporation ("WESC"), which is a consulting firm founded in March 1995.

Q. Please summarize your educational and professional background.

A. I am a graduate of the University of Pittsburgh where I obtained a Bachelor of Science degree in Mathematics followed by 58 credits of Electrical Engineering. I have worked for 63 years in the electric generation industry, focusing on the manufacture, maintenance, and repair of generators. I spent 45 of those years at Westinghouse Electric ("Westinghouse") in generator design, manufacturing, and maintenance. I started at Westinghouse in 1949 as an Insulation and Coil Design Engineer and in 1965 became a Field Service Engineer. I was promoted to Senior Service Engineer in 1972. Attached as Exhibit__(RTW-1) is a copy of my resume.

Purpose of Testimony

Q. What is the purpose of your testimony in this consolidated docket?

A. NorthWestern Energy ("NorthWestern") retained me as an expert witness to address the July 1, 2013, core failure at the Colstrip Unit 4 ("CU4") generator and whether there was any reason to believe the generator was at risk before that core failure.

Q. Please describe your experiences with generator outages.

A. I began dealing with generator outages in the maintenance sector of the industry in 1965, which work has continued to this day with my consulting work at WESC. My work in this area has included inspections, specification writings, and engineering functions on all phases of generator repairs and failures. I was a member of the root cause analysis teams for the core failures at Martin County #1 at Florida Power and Light, Sammis #6 at First Energy, and Hunter #1 at Utah Power. I was the repair Engineer for the partial core replacements following core failures at Willow Glenn #1 at Louisiana Power and Hudson #2 at New Jersey Gas and Electric.

Q. Please identify representative industry-related writings authored by you.

A. When I was at Westinghouse, I wrote many procedures for generator maintenance. After starting WESC in 1995, I wrote several papers that

were presented at Electric Power Research Institute-sponsored conferences, including “All About Cores” and “Core Sense”. I also presented “How To Write A Rewind Specification” at the Institute of Electrical and Electronics Engineers’ meeting in Cambridge, Massachusetts.

Q. Please identify representative industry-related speaking engagements which you have had.

A. Besides the presentations noted above, I have presented training courses on generators at Florida Power and Light, Nevada Energy, and Siemens’ Orlando headquarters.

Q. Have you ever testified before a state public service commission or a court, state or federal?

A. Yes, I have testified as an expert witness in a court case in Pittsburgh, Pennsylvania regarding a vendor’s improper maintenance repair, which caused a core failure of a 100-megawatt generator. I have also testified before court-appointed mediators regarding the value of an insurance settlement and whether a vendor was responsible for a coil failure.

<u>Prior Outages at CU4</u>

Q. Did you work on the Root Cause Analysis (“RCA”) of the forced outage at CU4 in 2013 involving the generator?

A. Yes. Because of my extensive experience with Westinghouse generators, and previous investigations of core failures, I was retained to assist Mr. Ron Halpern in developing the RCA for the 2013 forced outage involving CU4's generator.

Q. Please describe the work you did for the RCA.

A. I inspected the CU4 generator rotor at the Siemens facility in Charlotte, North Carolina. Mr. Halpern and I used a fault tree I had developed in previous investigations to determine how the damage to the generator core likely occurred. I contributed to and reviewed the final RCA before it was submitted to PPL Montana.

Q. Did you have any professional involvement with CU4 before you worked on the RCA for the 2013 forced outage?

A. Yes, I was assigned by Westinghouse to be the lead engineer for the 1987 forced outage that occurred at CU4.

Q. Please describe what caused the 1987 forced outage.

A. A windage smoothing plate[1] on the frame became loose and positioned itself across several of the circuit rings creating a fault, which tripped the generator. As a result, there was extensive burning and damage to the circuit rings and there was residue in a large area of the exciter end

[1] A windage smoothing plate is welded cover placed over components that makes the gas move less erratically; it soothes out the gas. It is like a plate over a pot hole on the road.

winding and core. This outage required extensive cleaning and replacement of some of the circuit rings and the flux shield.

Q. Did the 1987 outage have anything to do with the generator core, or cause damage to the CU4 generator core?

A. No, the damage was contained in the exciter end of the generator.

Q. Did that outage have anything to do with the laminations in the core?

A. No, this failure had no effect on the main core body laminations.

Q. Were you professionally involved with the other outages in 1993, 2000, and 2001 that were mentioned by David A. Schlissel in his testimony filed on behalf of the Sierra Club/Montana Environmental Information Center?

A. No. However, the information upon which Mr. Schlissel relied, NorthWestern's response to Data Request MCC-015, Attachment 4, page 38, provides sufficient information for someone with experience in the industry to determine: (1) what piece of equipment had an issue, (2) whether it was part of or related to the generator core, and (3) whether the action that was initiated to repair the equipment was appropriate.

Q. Was the action initiated for each of those outages noted on page 38 of Attachment 4 appropriate?

A. Taking each outage separately:

- 1986-87 - Parallel Ring Failure - Limited to Exciter End and appropriately repaired.
- 1993 - Cooler water leak caused a coil ground - Appropriate repair was made when the coil was replaced.
- 2000 - Fractured generator rotor was replaced by spare rotor. This was an appropriate action because any further growth in the fracture could destroy the whole unit if it were to disintegrate in service.
- 2001 - Water ingestion - Retaining rings of a generator rotor are susceptible to cracking and require testing and requalification. This was done.

Generator routine inspections were performed in 2003, 2006, 2009 and 2013 per recommended periods. The typical inspection period for this type of equipment is three to five years.

In my opinion, all of the prior incidents and the corresponding repairs at CU4 were appropriate.

Q. Based on reviewing page 38 of Attachment 4 provided in response to Data Request MCC-015, can you conclude whether these outages would indicate a risk of a generator core failure?

A. None of these prior outages would indicate a risk of a generator core failure like the one experienced in 2013. None of these incidents have any bearing on the core lamination insulation. Additionally, regarding the 2009 outage, when cracks are found in a turbine rotor, it results in the unit being removed from service, which was done in this instance. However, turbine rotor problems had nothing to do with the stator core or any other component of the generator.

In regard to the March 1993 event, a replacement of a coil is not a large event and can be done in the same period as a planned outage. In fact, water leaks on generators are quite common. Again, however, this incident had no bearing on the core lamination insulation.

Q. Mr. Schlissel, at pages 18-19 of his testimony, suggests that CU4 has experienced significant problems in the past. Do you agree that the problems identified by Mr. Schlissel in his testimony were significant problems or that these prior outages represent a pattern of problems with the unit?

A. I completely disagree with Mr. Schlissel's assessment. A generator of 28 to 30 years that only had one significant failure in 2013 does not represent a problem for the owners nor does it suggest that there was pattern of problems that signified to the owners that the generator would fail in 2013.

Q. Were the 1987 and 2009 outages significant failures?

A. They were not. The 1987 incident was repaired quickly and the 2009 outage was a planned rotor inspection and test program. The 1987 generator was an unusual failure of some significance as a failure, but the effect of the outage was not significant because it was addressed and resolved quickly. The 2009 outage was a longer outage because of a turbine problem; the generator was undergoing standard maintenance and did not experience a problem. It was not involved nor did it contribute to the outage length.

Q. Given your experience with Westinghouse generators and generators in general, are core failures common?

A. Core failures of Westinghouse generators have been very rare. There have only been a handful of catastrophic-type failures with large generators manufactured between 1976 and 1997, and none of these core failures were similar to the 2013 incident of the CU4.

Q. Does this conclude your testimony?

A. Yes.

ROBERT T. WARD

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CAREER OBJECTIVE

Since retiring from Westinghouse in 1994, Mr. Ward has formed his own Corporation and has worked part time in providing the technologies in many areas of his expertise. The assignments have been foreign and national and have ranged from manufacturing evaluations and advice, root cause analysis, technical projects, to simple inspections and tests.

EDUCATION

BS Mathematics, University of Pittsburgh 1954
Completion of 58 Engineering Credits- University Of Pittsburgh 1954-1958

EMPLOYMENT

President, Ward Electric Service Corporation, 1995 to present.
Provided engineering solutions for OEM generator problems of many kinds. Performed various consulting and inspection duties for Partial Discharge problems, coil manufacturing, stator and rotor winding and core damage. Managed several EPRI projects. Performed root cause studies. Have written purchasing and manufacturing specifications and conducted generator-training sessions on both stators and rotors. Has supplied and presented papers to EPRI and IEEE conferences on core and winding issues.

Senior Service Engineer, Westinghouse Electric Corp., 1972 to 1995
Provided the necessary support to marketing, field engineers, and drafting to keep the Westinghouse fleet of generators available for service. Duties included redesign of generators for uprating and improved performance, maintenance recommendations and specifications to address problems related to operating conditions analysis of root causes of various service related incidents, and the preparation of procedures and processes to carry out the maintenance programs. These included field header and cap replacements on liquid cooled generators. These procedures included the use of high frequency equipment and TIG methods of repair.

Field Service Engineer, Westinghouse Electric Corp., 1965 to 1972
Performed complete maintenance inspections, repairs, rewinding and testing of all types of electrical rotating equipment. Developed and wrote procedures for repairing, testing, rewinding and inspecting electrical apparatus. Executed field rewinds and core rebuilding/repair on all types of generators.

Insulation and Coil Design Engineer, Westinghouse Electric Corp., 1949-1965
Designed all types of rotating machine coils and insulation systems. Thorough detail design was experienced on insulation systems for both generator rotors and stators. Assignments included shop manufacturing follow and providing the necessary process specs for doing the work. Product serviced included magnet design and manufacture. Total knowledge of coil manufacturing operations and requirements.

Patents and Disclosures

Holder of nine patents and 17 disclosures on generator windings and associated equipment.

Membership in Professional Societies

Institute of Electrical Engineers----Life Member
Committee member for IEEE Maintenance Guide P62 and Rewind Specification P1665
EPRI Advisor and Project Leader

Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF MICHAEL J. BARNES

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Outage Insurance Quotes	Exhibit__(MJB-1)
Outage Insurance Analysis	Exhibit__(MJB-2)

Witness Information

Q. Please state your name and business address.

A. My name is Michael J. Barnes and my business address is 1944 Monad Road, Billings, Montana 59102.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy ("NorthWestern") as the Superintendent of Joint Owned Thermal Operations.

Q. Please summarize your educational and employment experiences.

A. I hold two engineering degrees from Montana College of Mineral Science and Technology, a BS in Engineering Science and a BS in Environmental Engineering. I have worked for NorthWestern since it acquired The Montana Power Company's ("MPC") transmission and distribution assets in 2002, including its interest in Colstrip Unit 4 ("CU4"). Prior to working for NorthWestern, I worked for MPC from 1994 to 2002.

In my current role as Superintendent of Joint Owned Thermal Operations, I am responsible for NorthWestern's interest in four joint owned thermal facilities in four states representing approximately 440 MW of generating capacity. I have been responsible for managing either MPC's or NorthWestern's interest at Colstrip since 2000. I am responsible for managing NorthWestern's interests in the CU4 operation including fuel

supply. Prior to CU4 becoming a utility resource, I was also responsible for origination and contract administration of electric sales contracts and the development and execution of hedging strategies to protect profitability on sales from the facility.

Q. Have you ever testified before the Montana Public Service Commission ("Commission")?

A. Yes, I testified before this Commission in Docket No. D2008.6.69, the docket in which NorthWestern's interest in CU4 was approved as a utility resource, and in Docket No. D2008.8.95, NorthWestern's compliance filing regarding the Dave Gates Generating Station.

Purpose of Testimony

Q. What is the purpose of your testimony in this consolidated docket?

A. The purpose of my testimony is to rebut portions of the testimony of David A. Schlissel, filed on behalf of the Sierra Club and the Montana Environmental Information Center ("Sierra Club/MEIC"), and the testimony of John W. Wilson, filed on behalf of the Montana Consumer Counsel ("MCC"). Specifically, my testimony addresses: (1) NorthWestern's decision regarding a possible lawsuit against Siemens or Talen Energy Montana, LLC ("Talen") (f/k/a PPL Montana, LLC) for the cost of replacement power; (2) the overall performance of CU4; and (3) whether

NorthWestern should have had outage insurance covering the cost of replacement power for CU4.

<u>Outage at CU4 in 2013 – Lawsuit against Siemens or Talen</u>

Q. Has NorthWestern decided whether to file suit against Siemens or Talen regarding the 2013 forced outage?

A. Yes. NorthWestern has determined that it will not file a lawsuit against Siemens or Talen regarding the 2013 forced outage.

Q. Has any other owner of CU4 filed suit against Siemens?

A. To my knowledge, no other owner has filed, or intends to file, suit against Siemens. Additionally, I have been advised via an email from FM Global, the property insurer for CU4, that it does not intend to file suit against Siemens to try to recover the $26.5 million paid for property damage to the owners for the 2013 forced outage.

Q. Dr. Wilson testifies that it was imprudent for NorthWestern to not ascertain whether Talen, as the operator of CU4, believed the work performed by Siemens was improper, negligent, or not in accordance with industry standards before seeking to recover replacement power costs in rates. Do you agree with that statement?

A. No. What Talen may or may not have concluded about the work done by Siemens was obviously informed by the Root Cause Analysis ("RCA").

The RCA was inconclusive as to the exact cause of the outage. The maintenance contract for CU4 between Talen and Siemens expressly excluded any claims for consequential damages, including replacement power. What rights Talen may or may not have against Siemens does not change the fact that there was a forced outage at CU4, and NorthWestern had to acquire replacement power to meet the needs of its customers.

Colstrip Unit 4 – Overall Performance

Q. Please describe the overall performance of CU4 since NorthWestern first included it in rates.

A. The overall performance of CU4, which because of the Reciprocal Sharing Agreement includes the performance of Colstrip Unit 3, has been good since it was first included in rates in 2009. Within our industry, the Equivalent Availability Factor ("EAF") is used as a measure of generator performance. The EAF is the fractional amount of the net maximum generation that can be provided after all types of outages are taken into account. The EAF at Colstrip Units 3 and 4 since CU4 was first included in rates has been 81.41% through 2014. This EAF was achieved despite the outages in 2009 and 2013.

Even with the 2009 and 2013 outages, Colstrip Units 3 and 4 performed better in the last 10 years (2005 to 2014) at an EAF of 85.02% compared to the 10 years previous (1995 to 2004) at an EAF of 84.38%. In fact, the

average EAF over the last 24 years is 84.34%. Thus, even though the outages in 2009 and 2013 impacted the EAF in those two years, the EAF from 2009 to 2014 is less than 3% lower than the 24-year average EAF. Additionally, Colstrip Units 3 and 4 operated well above average from 2010 to 2012. During that time, the EAF was near 91%.

Q. Mr. Schlissel, on behalf of the Sierra Club/MEIC, suggests that NorthWestern should have evaluated outage insurance prior to June 2013 because CU4 had experienced an extended forced outage in 2009. In your opinion, was the 2009 outage an indicator that CU4 and its generator were unreliable and would continue to experience issues in the future?

A. No. The 2009 outage was a completely different issue than the 2013 outage. The two outages involved different equipment. The 2009 issue was a low pressure ("LP") turbine problem. In fact, the unit did not even fail, but had a crack in a steeple/blade attachment interface that was discovered during a routine inspection. The turbine and the generator rotor (the generator rotor is the magnet which spins within the generator stator) are connected via in-line shafts, but are separate pieces of equipment. As such, a problem with a turbine blade attachment in 2009 is certainly not an indicator of a possible core failure in 2013. There is no logical or causal connection between the two.

To further clarify the difference between the 2009 and 2013 outages, there are four turbines per unit and a series of interconnected shafts to which blades are attached; the blades cause the interconnected shaft to spin when steam energy is released onto the blades. During the 2009 CU4 overhaul, a very small crack was identified on one of the LP turbines where a blade is attached to the turbine shaft; subsequently both LP turbines were sent off-site for inspection and repair. In contrast, with the 2013 outage, the generator stator (the core iron holding the coils of wire) and associated equipment, including the generator rotor, were damaged.

The 2009 and 2013 outages were unrelated events on separate and distinct pieces of equipment; as such, it is not reasonable to believe that the 2009 LP turbine blade steeple crack outage would be an indicator or predictor that the generator would experience the issues it did in 2013.

Q. Despite the two recent forced outages, do you believe that CU4 has been a reliable asset to NorthWestern?

A. Yes. This is especially true because of the Reciprocal Sharing Agreement with Talen. This agreement effectively spreads the risk of forced outages across both Colstrip Units 3 and 4. This agreement was very beneficial to NorthWestern and its customers during the forced outage events at CU4 in 2009 and 2013 since NorthWestern continued to receive output from Colstrip Unit 3, which means it did not have to purchase as much energy

in the market and it only had to pay 15% of the cost to repair CU4 versus 30%. As noted in my 2008 CU4 testimony in Docket No. D2008.6.69, there is always a risk that either plant could be down due to damages and that the time the plant is down could be considerable when there are long lead times required for some parts.

Notwithstanding that possibility, as noted above, Colstrip Units 3 and 4 have still been available over 81% of the time since the Commission approved NorthWestern's request to include CU4 in rates. The North American Electric Reliability Corporation (NERC) Generating Availability Data System ("GADS") reports that coal-fired generating units similar in size to Colstrip Units 3 and 4 operated with an average EAF of 82.81% over the period 2009 to 2013. Nationwide, GADS reports data on 102 coal-fired generating plants of this size. Colstrip Units 3 and 4 remain very near this average despite the 2009 and 2013 outages, which negatively affected their EAF.

Outage Insurance

Q. Do you agree with the advocacy of MCC witness Wilson and Sierra Club/MEIC witness Schlissel that NorthWestern should have had outage insurance for CU4?

A. I do not. Outage insurance for a coal-fired generating station does not make a great deal of economic sense over the long term. It is expensive

and it provides limited benefits which are similar to a financial product. In effect, a purchaser of outage insurance is pre-paying replacement power costs to potentially lessen the increased cost resulting from procurement of replacement power during a future outage event. To my knowledge, none of the joint owners of CU4 had any outage insurance which covered any of the cost of replacement power when the forced outage occurred at CU4 on July 1, 2013.

Q. Please explain how outage insurance works.

A. Outage insurance isn't "insurance" in the traditional sense where the risk to the insurer is spread across many policyholders, as is typical of property insurance, medical insurance, etc. It is 'one-off' insurance where the risk of one party, in this case the generator's requirement to replace power that is lost as a result of an outage, is partially transferred to a counter-party, the insurer, for the cost of annual premiums. For outage insurance, the potential insured determines the desired price protection and obtains a price quote for that level of protection from an insurer such as Lloyds. The operating characteristics of the generating unit, the expected market price of power over the term of coverage, and the counter-party's margin determine the price quote, which changes from year to year as market price expectations change, or the operating characteristics of the generating unit change. Outage insurance is not designed to be a cost effective alternative to purchasing replacement

power when it is needed. It is really a financial product, very similar to a call option.

Q. What involvement, if any, have you had with obtaining a price quote for outage insurance for CU4?

A. I assisted NorthWestern's Risk Manager in obtaining a price quote for outage insurance for Colstrip Units 3 and 4. After the Commission issued its Order No. 7219h in Docket No. D2012.5.49, NorthWestern sought a price quote for outage insurance for its generating assets, including Colstrip Units 3 and 4. I worked with NorthWestern's Risk Manager and its insurance broker to develop the information needed to obtain a price quote for outage insurance.

Q. Please describe the process utilized to develop the information needed to obtain the price quote.

A. NorthWestern contacted its insurance broker about outage insurance that would cover Colstrip Units 3 and 4 and engaged in several discussions relative to terms and conditions of the structure for this type of insurance, such as amount of coverage desired, strike price desired, location of pricing hub, hours of coverage required, duration limits, deductible (time element / dollar amount), etc. NorthWestern also provided the insurance broker with historical performance information on Colstrip Units 3 and 4 for the insurer's use in developing the quote.

Q. Did NorthWestern obtain a price quote for outage insurance for CU4?

A. Yes. Attached as Exhibit__(MJB-1) are copies of the quotes NorthWestern received for outage insurance at CU4. Pages 1 and 2 are the quote dated September 30, 2014. Pages 3 and 4 are the quote dated March 6, 2015.

Q. Why did the premium cost change between quotes?

A. I believe it is because the market price of power dictates the magnitude of a payment in a covered event, and the market changed significantly between quotes. Outage insurance premium cost is heavily influenced by the predicted market price of electricity compared to the strike price. The higher the market price compared to the strike price, the more exposure to the insurance company in the event of a covered outage. Simply stated, the premium price would be a reflection of the increased or decreased magnitude of risk of potential payment made to the covered party by the insurer in a covered event. The predicted cost of power at the Mid-Columbia trading hub ("Mid-C") changed between quotes from an average price of approximately $33/MWh for the coverage period to approximately $25/MWh for the coverage period.

Q. Please explain the coverage that would have been provided if NorthWestern had procured this outage insurance.

A. If NorthWestern had procured this outage insurance, the insurance company would only make a payment during a covered event to the extent that the market price of electricity was higher than the strike price. The payment received would equal this difference times the volume loss as a result of the outage subject to the limits of the policy.

The quotes received by NorthWestern, although indicative of expected premium costs, were offered for discussion and review. Execution of any actual purchase of outage insurance would be subject to, among other things, customary legal and credit approvals and the execution of mutually acceptable documentation. Additionally, any changes in the market price would affect the ultimate cost of insurance. Some of the general terms and conditions relative to the quotes received by NorthWestern are listed below.

- Coverage period – 1 year
- Policy Limit – $10,000,000
- Settlement type – Financial settlement
- Pricing Hub – Mid-C – Daily (7 X 24)
- Covered Event Duration – 150 consecutive calendar days (145 days excess of the Event Duration)
- Event Duration – 5 days – Coverage would not start on any outage until the 6th day of the outage.
- Strike prices of $20/MWh and $35/MWh.

Q. Why were the quotes only for one year of coverage?

A. The coverage was only offered for one year by the insurer to manage the premium cost over a relatively short timeframe. The cost of the premium is relative to predicted cost of electricity over the term of the coverage and, as such, the premium cost reflects the potential for upward movement in the electric market over the term of the coverage. Since the electric markets are volatile and unpredictable in the long term, the shorter the term of the coverage, the more aggressive the quote can be.

Q. Why is there a policy limit?

A. A policy limit caps the exposure to the insurer allowing the premium cost to be kept lower.

Q. Mr. Barnes, assume that NorthWestern had obtained outage insurance during each year of its ownership of CU4 on terms similar to those reflected in the price quotes shown in Exhibit__(MJB-1). Under that assumption, do you have an opinion as to whether the purchase of outage insurance would have been cost effective, and if so, what is that opinion?

A. I do have an opinion, and my opinion is that it would not have been cost effective.

Q. What is the factual basis for your opinion?

A. The factual basis for my opinion is set forth in Exhibit__(MJB-2). The exhibit was developed to estimate the cost of premiums and the magnitude of any insurance payments given the outage history at Colstrip Units 3 and 4 as though outage insurance been in place since NorthWestern acquired the asset in 2002.

To estimate the premiums, consideration must be given to the market price of electricity relative to the premium cost, as the cost to the insurer is dependent on the market price relative to the strike price in the event of a covered outage. Using the two quotes, with premiums associated with strike prices of $20/MWh and $35/MWh, respectively, the premium associated with each strike price was plotted against the net difference between the strike price and anticipated market at the time of the quote. This data was graphed and was best fit using 2nd order polynomial equation (the graph, the trendline, and the equation are shown in the exhibit) where “x” is equal to the net difference between the market and the strike price and “y” is the resulting premium. The R-squared value, an indication of how well raw data correlates to an equation, is equal to 0.999 which makes the equation a reasonable predictor of premiums in a given electricity market.

Since it is not known when a premium quote would have been requested in previous years and it is not known exactly what the predicted market

would have been at the time of the quote request, the actual annual Mid-C average was used as a proxy for the predicted market.

To estimate the payments that would have been received relative to payments that would have been incurred, I simply multiplied the difference between the actual historical Mid-C price during the year of a given outage and the strike price of $20/MWh times the estimated maximum generation lost during outages actually incurred by Colstrip Unit 3 or 4 subject to the terms and conditions of the quotes.

As is evidenced in the exhibit, a simple comparison between the cost of outage insurance premiums and the expected payments received during covered events shows that the long term cost of premiums would far outweigh any benefits received in the event of outages. NorthWestern's customers would incur not only the cost of replacement power procured during an outage not covered by an insurance payment, but also the overall cost of annual premiums. In the alternative, purchasing replacement power when it is needed and foregoing the cost of premiums associated with insurance is much more cost effective.

Q. What happens if NorthWestern is covered by outage insurance and the market price is below the strike price at the time of the outage?

A. Because NorthWestern is only entitled to payment on the positive difference between the then-current market price of electricity and the strike price times the lost generation volume, no payment is made to NorthWestern on any day that the price of power is less than the strike price.

Q. Mr. Barnes, please describe the assumptions you made in preparing Exhibit__(MJB-2).

A. They are listed below.

- The analysis is dependent on the assumption that the equation developed for predicting the cost of a premium in a given market is an accurate reflection of costs.
- The analysis presumes that the actual market price for electricity was the same as the predicted market price at the time the annual insurance was procured. This is an unknown; however, it can be assumed that if the predicted price of power was higher or lower than the actual prices listed, the premium cost would have been different.
- The analysis assumes that even once a claim has been paid, the premium cost predicted by the equation would continue to be reflective of the cost of the premium that was being offered by the insurer in subsequent years in spite of experiencing a covered event. After a covered outage, insurers are likely to increase the premium cost to recoup previous paid losses.

- The analysis assumes that payments for the outages in 2002, 2009, and 2013 would occur within the one-year coverage period for that year and would not be part of any bridge from one coverage year to the next. It is not realistic to believe NorthWestern would be able to negotiate insurance for the next year while down due to a forced outage, especially if timing of the outage was close to the start of a new insurance year.
- The analysis assumes, in the event there was a coverage event, that the actual historical annual average price is a good proxy for calculating payment on lost generation during a covered outage. The reality is that the payment calculation would fluctuate on daily basis during the outage with the daily price of power (some days could be higher, some days could be lower).

Q. Does this conclude your testimony?

A. Yes.

Archer
Contingent Energy Risk

Northwestern Energy - 2015 Colstrip Units 3, 4

Indicative Price Quote

PROPRIETARY & CONFIDENTIAL

Company Contact:	John Ramonas	Phone: 612-313-1606	Cellular:	E-Mail: jramonas@hayscompanies.com
Archer Contact:	Paul Wohl	Phone: 913-981-9942	Cellular: 913-485-0688	E-Mail: pwohl@archer-risk.com

Date: September 30, 2014
Insured (Legal Entity & Domicile): Northwestern Energy, Sioux Falls, SD
Perils Insured Against: Losses incurred due to Unplanned Outages (U1, U2, U3, SF) and Unplanned Derates (D1, D2, D3)

Inception Date: January 1, 2015
Expiration Date: December 31, 2015
Delivery Days/Hours: Monday - Sunday, Including NERC Holidays (7x24, HE 0100-2400, All Hours)

Covered Unit(s) (Include Technology): Colstrip Generating Stati Conventional Coal Fired Furnace

	Unit #3	Unit #4
Capacity (MW):	740	740
Capacity Limit (MW):	111	111
	0.15	0.15

Power Price Index (PPI) ($/MWh): Mid-C On-Peak
Event Duration Limit (EDL): 150 consecutive calendar days (145 days excess of the Event Retention)
Event Retention (d): 5 days
Term $ Deductible: See Premium below
Policy Limit ($): $10,000,000

Settlement Type: Financial Settlement
Settlement Calculation: Day Ahead Market Settlement (DAM) - Daily (7x24)
- Average of the applicable hours of the DAM PPI less the IP

Non-Standard Coverage: N/A

Colstrip Insured Price ($/MWh):	$35.00/MWh	$20.00/MWh	$20.00/MWh
Term $ Deductible:	$0	$0.00	$1,000,000.00
Net Premium:	$540,000.00	$1,260,000.00	$890,000.00
Brokerage Comm/Fees:	$60,000.00	$140,000.00	$98,888.89
Surplus Lines Tax (2.50%):	$15,000.00	$35,000.00	$24,722.22
Premium Total Costs:	$615,000.00	$1,435,000.00	$1,013,611.11

TRIA Coverage: This coverage contains an exclusion for events caused by terrorism

The terms set forth above are non-binding and are for discussion purposes only. Execution of any transaction is subject to, among other things, customary legal and credit approvals and the execution of mutually acceptable documentation. Neither Archer Contingent Energy Risk, Ariel Syndicate 1910, nor their affiliates is providing tax, accounting or legal advice; you should rely on your own tax, accounting and legal advisors.

Archer
Contingent Energy Risk

Northwestern Energy - 2015 Colstrip 3, 4

PROPRIETARY & CONFIDENTIAL

SWBC and Archer (We) receive compensation from Ariel Reinsurance, a surplus lines insurer (the "Insurer") that is our sole provider of the type of insurance that you are considering purchasing. Our compensation includes a percentage of the premium that you pay for your insurance policy. We may receive additional payments from the Insurer to defray the cost of services provided on its behalf, including the cost of advertising, training, employee compensation and other expenses. We may also earn interest on premiums received from you and forwarded to the Insurer from our bank accounts. In addition, the Insurer may pay us additional compensation in the form of contingent commissions, supplemental commissions and/or profit sharing arrangements, which may be based on the total volume of business we produce for it, the growth rate in business generation, retention of business, loss ratios, net profits in excess of threshold amounts or other factors.

Archer
Contingent Energy Risk

Northwestern Energy - 2015 Colstrip Units 3, 4

Indicative Price Quote

PROPRIETARY & CONFIDENTIAL

Company Contact:	John Ramonas	**Phone:**	612-313-1606	**Cellular:**		**E-Mail:**	jramonas@hayscompanies.com
Archer Contact:	Paul Wohl	**Phone:**	913-981-9942	**Cellular:**	913-485-0688	**E-Mail:**	pwohl@archer-risk.com

Date: March 6, 2015

Insured (Legal Entity & Domicile): Northwestern Energy, Sioux Falls, SD

Perils Insured Against: Losses incurred due to Unplanned Outages (U1, U2, U3, SF) and Unplanned Derates (D1, D2, D3)

Inception Date:	May 1, 2015
Expiration Date:	April 30, 2016

Delivery Days/Hours: Monday - Sunday, Including NERC Holidays (7x24, HE 0100-2400, All Hours)

Covered Unit(s) (Include Technology): Colstrip Generating Station — Conventional Coal Fired Furnace

	Unit #3	Unit #4
Capacity (MW):	740	740
Capacity Limit (MW):	111	111
	0.15	0.15

Power Price Index (PPI) ($/MWh): The Mid Columbia ICE Index:
For each day which is a Sunday or NERC Defined Holiday; the ICE Off-Peak Day-Ahead index as published in the Mid-Columbia section of "ICE Day Ahead Power Price Report"; For all other days; the time weighted average of the On-Peak and Off-Peak ICE indices for such day, which is equal to the sum of (i) and (ii) with such sum divided by 24, where: (i) equals 16 times The ICE On-Peak Day-Ahead index as published in the Mid-Columbia section of "ICE Day Ahead Power Price Report", and (ii) equals 8 times The ICE Off-Peak Day-Ahead index as published in the Mid-Columbia section of "ICE Day Ahead Power Price Report".

Event Duration Limit (EDL): 150 consecutive calendar days (145 days excess of the Event Retention)

Event Retention (d): 5 days

Term $ Deductible: $0

Policy Limit ($): $10,000,000

Settlement Type: Financial Settlement

Settlement Calculation: Day Ahead Market Settlement (DAM) - Daily (7x24)
- Average of the applicable hours of the DAM PPI less the IP

Non-Standard Coverage: N/A

Colstrip Insured Price ($/MWh):	$35.00	$20.00
Net Premium:	$310,000.00	$800,000.00
Brokerage Comm/Fees:	$34,444.44	$88,888.89
Surplus Lines Tax (2.50%):	$8,611.11	$22,222.22
Premium Total Costs:	$353,055.56	$911,111.11

Note - Full year 2014 Event level GADS data is required for final pricing (Dec 2014 only was provided)

TRIA Coverage: This coverage contains an exclusion for events caused by terrorism

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Archer
Contingent Energy Risk

Northwestern Energy - 2015 Colstrip 3, 4

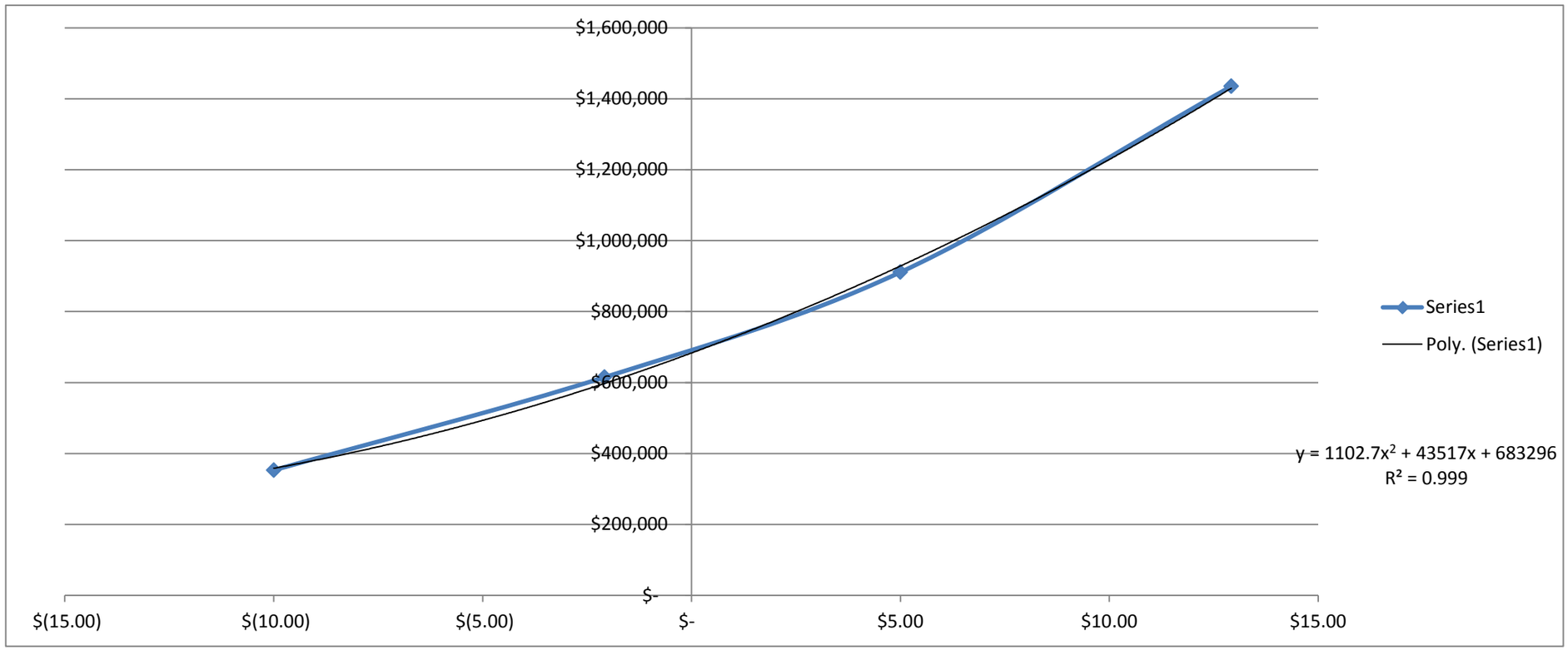
PROPRIETARY & CONFIDENTIAL

SWBC and Archer (We) receive compensation from Ariel Reinsurance, a surplus lines insurer (the "Insurer") that is our sole provider of the type of insurance that you are considering purchasing. Our compensation includes a percentage of the premium that you pay for your insurance policy. We may receive additional payments from the Insurer to defray the cost of services provided on its behalf, including the cost of advertising, training, employee compensation and other expenses. We may also earn interest on premiums received from you and forwarded to the Insurer from our bank accounts. In addition, the Insurer may pay us additional compensation in the form of contingent commissions, supplemental commissions and/or profit sharing arrangements, which may be based on the total volume of business we produce for it, the growth rate in business generation, retention of business, loss ratios, net profits in excess of threshold amounts or other factors.

Colstrip BI analysis

	Annual actual MID C Price	Strike	Difference Between Strike and Actual		Estimated premium Cost based on 2nd order polynomial fitment of quote and market data	Payments on received as a result of BI Insurance
2002	$ 22.43	$ 20.00	$ 2.43		$ 795,603.19	$ 608,764.73
2003	$ 38.04	$ 20.00	$ 18.04		$ 1,826,957.62	
2004	$ 42.39	$ 20.00	$ 22.39		$ 2,210,751.53	
2005	$ 58.59	$ 20.00	$ 38.59		$ 4,005,321.52	
2006	$ 45.37	$ 20.00	$ 25.37		$ 2,497,057.07	
2007	$ 51.42	$ 20.00	$ 31.42		$ 3,139,730.14	
2008	$ 58.97	$ 20.00	$ 38.97		$ 4,054,095.68	
2009	$ 32.57	$ 20.00	$ 12.57		$ 1,404,616.07	$ 5,023,417.22
2010	$ 32.81	$ 20.00	$ 12.81		$ 1,421,748.66	
2011	$ 23.81	$ 20.00	$ 3.81		$ 864,866.57	
2012	$ 19.28	$ 20.00	$ (0.72)		$ 652,535.40	
2013	$ 32.48	$ 20.00	$ 12.48		$ 1,398,397.54	$ 4,988,489.62
2014	$ 33.58	$ 20.00	$ 13.58		$ 1,477,612.82	
				2002-2014	$ 25,749,293.81	$ 10,620,671.56
						$ 15,128,622.24 Net loss

Date of Quote	3/6/2015	9/30/2014	3/6/2015	9/30/2014
Predicted 1yr 7x24 price of power at time of quote (Mid-C)	$ 25.00	$ 32.92	$ 25.00	$ 32.92
Strike	$ 35.00	$ 35.00	$ 20.00	$ 20.00
difference between strike and predicted electric market	$ (10.00)	$ (2.08)	$ 5.00	$ 12.92
premium quote	$ 353,000	$ 615,000	$ 911,000	$ 1,435,000



Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33/D2014.5.46
Annual Electric Supply Filing
NorthWestern Energy

PREFILED REBUTTAL TESTIMONY

OF KEVIN J. MARKOVICH

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibit

Replacement Power Cost Calculation	Exhibit__(KJM-1)

Witness Information

Q. Please state your name and business address.

A. My name is Kevin J. Markovich and my business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am NorthWestern Energy's ("NorthWestern") Director of Energy Supply Market Operations.

Q. Are you the same Kevin J. Markovich who submitted prefiled direct testimony in these consolidated dockets?

A. Yes, I am.

Purpose of Testimony

Q. What is the purpose of your rebuttal testimony?

A. My testimony will primarily address issues and concerns raised by the Montana Consumer Counsel ("MCC") in the Pre-filed Direct Testimony of George L. Donkin ("Donkin Direct Testimony") dated May 8, 2015 regarding NorthWestern's hedging practices. My testimony also addresses the replacement power costs incurred as a result of the outage in 2013 at Colstrip Unit 4 ("CU4") and why $8,243,475 is the most accurate calculation of replacement power costs.

NorthWestern's Hedging Practices

Q. MCC's witness, Mr. Donkin, again takes issue with NorthWestern's hedging practices and characterizes NorthWestern's off-system fixed priced hedges as "hedging losses" in his testimony. Please address the terminology used in the Donkin Direct Testimony and explain why these transactions are not "losses."

A. Mr. Donkin makes the same arguments regarding NorthWestern's hedging practices as he made to the Montana Public Service Commission ("Commission") in NorthWestern's 2012 Annual Electric Supply filing in Docket No. D2012.5.49. In those arguments, he uses the term "hedging losses," indicating there is some profit or loss component to the hedging in question. That terminology in and of itself is confusing, potentially creating a misunderstanding of what hedging is and what it is intended to accomplish in the case of NorthWestern.

In Barron's *Dictionary of Finance and Investment Terms,* Hedge/Hedging is defined as a "strategy used to offset investment risk. A perfect hedge is one eliminating the possibility of future gain or loss." Further, in that same dictionary, Speculator is defined as a "market participant who tries to profit from buying futures and options contracts by anticipating future price movements." NorthWestern does not speculate on future price movements, in either natural gas or electric portfolio supply management. NorthWestern uses hedging as a tool for managing price risk and the

resulting rates charged to its customers. All fixed price energy supply market transactions that NorthWestern enters into are a form of hedging which serves to reduce price risk to its customers. Speculative trading is strictly prohibited in NorthWestern's internal risk management policies (up to and including termination for any offense) and it is something NorthWestern does not do. NorthWestern only uses hedge transactions to stabilize price volatility.

Q. Can you please explain the type of hedges NorthWestern utilizes and why these hedges are important to NorthWestern's customers and the supply portfolio?

A. NorthWestern has developed a hedging strategy that is reviewed every two years as part of NorthWestern's biennial electricity supply resource planning. NorthWestern has several different hedges, both on-system and at the Mid-Columbia ("Mid-C") market. On-system hedges include physical resources and contracts that contain pricing provisions that are fixed and not tied to any market or index. Mid-C hedge transactions are fixed price purchases at Mid-C that are sold back at market prices at Mid-C. The Mid-C hedge transactions lock in or fix the price of on-system market purchases used to serve customers.

Q. On page 7, lines 2-12, Mr. Donkin asserts that the counterparties to these hedging transactions have more incentive to "beat the market"

and so "NorthWestern appear[s] to be more likely [ ] the loser over time." Do you agree with this assertion?

A. No. Such statements are factually unfounded and cannot be supported. For those comments to be true, the NorthWestern counterparties would have to be able to influence future market prices to ensure they win their "bets" with NorthWestern. In a liquid and robust market, such as exists at the Mid-C, with many participants and an electronic trading platform providing transparent pricing, manipulating the market would be very difficult. In addition, with the regulatory oversight provided by the Federal Energy Regulatory Commission and now the Commodities Futures Trading Commission, such behavior would very likely be detected.

Furthermore, at the time NorthWestern enters into a fixed price purchase to hedge costs, it has the opportunity to instead enter into a fixed price sale at approximately the same price. However, at the time of the tracker periods involved in this docket, because the supply portfolio was short energy, NorthWestern rarely entered into a fixed price sale because selling energy would make it even shorter, thereby increasing risk to customers. The electricity market has moved from a period of high prices to a period of low prices. Had the opposite occurred, meaning a market price shift from being low to very high, the fixed price hedges would have provided lower costs to customers, and claims about market manipulation incentives to win "bets" would be nonexistent.

NorthWestern's Energy Supply activities are limited to the Montana market, which includes Mid-C. We know and understand the loads and market where we transact, and we are proficient at scheduling, balancing, transacting, and managing risk for our customers. Given NorthWestern's knowledge of the market and the regulatory oversight noted earlier, Mr. Donkin's assertions are unsupported.

Q. On page 18, lines 5-10, Mr. Donkin again recommends "that the Commission direct NorthWestern to terminate its off-system electricity supply cost hedging strategies and activities." Do you agree with this recommendation?

A. No. Again, an off-system fixed price hedge transaction is a valuable tool that lowers price risk for our customers. When NorthWestern entered into these off-system transactions, it was based on information known at the time of the transactions, and it is recognized that as time goes on new and additional information will become known that will and can affect what actual market prices are at the time of delivery. Actual market prices that turn out to be different from prices agreed to in previous periods are reflective of changes in market conditions and fundamentals and do not result from one party being more sophisticated than the other.

Q. On page 16, Mr. Donkin notes that in your direct testimony you said that if the hydroelectric acquisition were approved, the hedging

strategy would be reevaluated in light of the acquisition. Has this occurred?

A. That evaluation is in progress and is being done as part of preparation for NorthWestern's 2015 Electricity Supply Resource Procurement Plan which is due in December of 2015.

Q. With the acquisition of the hydroelectric facilities ("the Hydros"), Mr. Donkin at page 17, lines 12-13, claims that the NorthWestern "will need to acquire very little new, on-system electricity supplies for several years into the future." Is this true?

A. It is true only in a limited context. Looking at it on a total annual energy basis it is true. However, it is not true throughout the course of the year. NorthWestern will be short of on-peak energy in high load months (December-February and July-August) and long on energy in all off-peak periods. Given its current supply portfolio, NorthWestern will still have to make on-peak market purchases in the winter and summer, and it will have to sell excess off-peak energy throughout the entire year. NorthWestern will still be faced with a challenging situation: It must purchase higher priced on-peak energy and sell lower priced off-peak energy. On-peak energy prices are higher and more volatile than off-peak energy prices, and without the ability to hedge those purchases with off-system fixed priced transactions, NorthWestern's customers will be at the

mercy of spot market prices during times when market supply is needed to serve load, namely the dead of winter and summer.

Given the way electricity is scheduled and consumed, and that it cannot be stored, NorthWestern will be in the "market" one way or another every day and every hour, regardless of its resource portfolio. A resource portfolio cannot be constructed to address every supply and load possibility: Loads change every second; resources go offline and then come back, and transmission outages occur without notice. The market is the most appropriate mechanism for dealing with these daily and hourly uncertainties.

Q. At page 19, lines 6-9, Mr. Donkin testifies that "supply quantities at future index prices are expected to be so low that if they are not hedged and an unexpected upward spike in market prices were to occur, there would be very little impact on total electricity supply costs." Do you agree?

A. No. As mentioned earlier, NorthWestern will be short on-peak energy and long off-peak energy which means it must buy higher-priced energy and sell lower-priced energy. During the recent heat wave in the West in June and July 2015, on-peak and off-peak market prices diverged dramatically, and on July 1, 2015 on-peak prices were over $60 per MWh higher than off-peak. Once again, if NorthWestern is not allowed to hedge on-peak

energy prices, customers could be exposed to substantial market volatility and prices during extreme weather conditions.

Q. Mr. Donkin also recommends that the Commission disallow any costs that may have been incurred for new hedging transactions entered into after the acquisition of the Hydros on November 18, 2014. In this consolidated docket, is NorthWestern requesting to recover any costs incurred for the period of time from November 18, 2014 or after?

A. No. This docket only requests costs incurred during two tracker periods: July 2012 through June 2013 and July 2013 through June 2014. The Commission will consider costs incurred on or after November 18, 2014 in the electric supply tracker docket filed on May 29, 2015 in Docket No. D2014.7.58.

Q. Even though costs incurred on or after November 18, 2014 are not and should not be at issue in this docket, since the acquisition of the Hydros, has NorthWestern entered into any new off-system fixed price term purchases at Mid-C?

A. No.

Q. Do you believe that NorthWestern's hedging practices, including the use of off-system fixed priced transactions, is a valuable tool that helps customers?

A. Yes. NorthWestern's Hedging Plan ("Plan") has been in existence for many years, and it works. Even though NorthWestern's hedging strategy will change in the plan to be filed in December of 2015, given the acquisition of the Hydros, the Plan accomplished what was intended. During recent periods of declining market prices, customer rates have decreased. Under the Plan, portfolio costs move in the same direction as the market, but less dramatically. While rates have decreased, customers have still enjoyed protection against rising prices. NorthWestern's Plan is disciplined; it provides flexibility in decision-making without allowing for speculation or gambling; it works in periods of high <u>and</u> low prices; and, very importantly, it provides results that are directly aligned with the Commission-approved Procurement Guidelines. The Plan that NorthWestern prepares and follows has worked exactly as planned. It has provided rates that are reasonable, stable, and reflect market conditions over time.

<u>Replacement Power Costs for Colstrip Unit 4</u>

Q. What does NorthWestern believe is the most accurate amount of replacement power costs incurred because of the outage in 2013 at CU4?

A. NorthWestern believes that the most accurate amount is approximately $8.2 million. My Exhibit__(KJM-1) shows the calculation.

Q. Please explain why this is the most accurate amount of replacement power costs.

A. NorthWestern believes that this is the most accurate value for replacement costs incurred during the CU4 outage because: 1) it is based on the historical capacity factor of CU4, which is consistent with the CU4 forecasted supply in the original 2013/2014 tracker filing in May 2013; and 2) it incorporates actual market prices paid for energy by NorthWestern during the outage.

Other estimates that have been made have used the capacity factor of Colstrip Unit 3 ("CU3") during the outage. This is flawed because CU3 and CU4 are separate units with separate operating and maintenance histories, and it is not reasonable to assume CU4 would have performed exactly the same as CU3 during the outage. It is more appropriate to use what NorthWestern expected to receive from its share of Colstrip in its 2013/2014 annual tracker filing, a forecast based on the historical operating performance of CU3 and CU4 taking into consideration the Reciprocal Sharing Agreement that is in place.

For its evaluation, NorthWestern calculated the average hourly on-system market price it paid for energy during the CU4 outage. The calculation is based on actual transactions entered into. NorthWestern believes this is the most appropriate price to use because it is based on on-system transactions in markets where NorthWestern likely replaced energy from CU4.

Q. This calculation and explanation were not part of your direct testimony. Please explain why not.

A. My prefiled direct testimony described the factors that had to be considered in replacing energy from CU4 during the outage as well as the challenges inherent in trying to calculate an after-the-fact value of the replacement power. NorthWestern identified the key drivers in performing the calculation, assumed capacity factor and market prices, and performed a calculation to estimate the replacement power costs during the CU4 outage.

Q. Does this complete your testimony?

A. Yes, it does.

Estimated cost of Colstrip Unit 4 outage Hourly Price NWDS Actual Average Hourly Price & Historical Capacity Factor

	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Total
Actual MWh with outage[1]	73,215	81,713	79,371	71,355	70,692	81,925	104,897	458,271
Capacity factor[2]	91.0%	91.0%	91.0%	91.0%	91.0%	91.0%	91.0%	
Estimated MWh without outage[3]	150,303	150,303	145,454	150,303	145,454	150,303	150,303	892,120
Actual variable cost with outage[4]	1,527,767	1,610,318	1,561,015	1,488,015	1,413,922	1,460,984	1,724,690	10,786,711
Actual fuel cost with outage[4]	1,258,603	1,344,565	1,297,141	1,233,848	1,126,537	1,359,517	1,516,331	9,136,542
Fuel cost per MWh[5]	$17.19	$16.45	$16.34	$17.29	$15.94	$16.59	$14.46	
Estimated fuel cost without outage[6]	2,583,783	2,473,193	2,377,126	2,598,990	2,317,939	2,494,224	2,172,692	17,017,947
Estimated variable cost without outage[7]	**2,852,947**	**2,738,946**	**2,641,000**	**2,853,157**	**2,605,324**	**2,595,691**	**2,381,051**	**18,668,116**
Estimated MWh lost from outage[8]	77,088	68,590	66,083	78,948	74,762	68,378	45,406	479,255
Actual monthly spot purchase prices[9]	27.92	34.34	33.55	32.88	34.24	48.99	41.23	
Cost to replace MWh lost from outage[10]	2,152,558	2,355,651	2,217,130	2,595,978	2,559,962	3,349,693	1,872,046	17,103,018
Cost of providing expected CU4 MWh with outage[11]	**3,680,325**	**3,965,969**	**3,778,145**	**4,083,993**	**3,973,884**	**4,810,677**	**2,618,598**	**26,911,591**
Change in supply cost from CU4 outage [12]	*827,378*	*1,227,023*	*1,137,145*	*1,230,837*	*1,368,560*	*2,214,986*	*237,547*	*8,243,475*

Notes:

1. Reported in May 29, 2014 Electricity Supply Tracker, D2014.5.46, Exhibit_(FVB-1)13-14, p. 3
2. **Historical Capacity Factor**
3. (222 * capacity factor * hrs per month) Assumes CU4 would have operated at CU3 capacity factor absent the outage
4. Reported in May 29, 2014 Electricity Supply Tracker, D2014.5.46, Exhibit_(FVB-4)13-14, p. 2
5. (Actual fuel cost / actual MWh with outage)
6. (Estimated MWh without outage * Fuel cost per MWh)
7. (Estimated fuel cost without outage + non-fuel variable costs) Non-fuel variable costs are the difference between actual variable & fuel costs with outage. This assumes other components of CU4 "variable" costs, such as the property tax adjustment and DSM lost revenue, would have been the same had the outage not occurred.
8. One-half of estimated MWh without outage, based on reciprocal sharing agreement
9. **Hourly Price NWDS Actual Average Hourly Price**
10. (Estimated MWh lost from outage * spot purchase price) Assumes NWE replaced all lost production with spot purchases.
11. (Actutal variable cost + Cost to replace MWh lost from outage)
12. (Cost of providing expected CU4 MWh with outage - variable cost without outage)

Department of Public Service Regulation
Montana Public Service Commission
Consolidated Docket Nos. D2013.5.33 and D2014.5.46
Annual Electric Supply Tracker Filings
NorthWestern Energy

PREFILED TESTIMONY

OF JOE SCHWARTZENBERGER

ON BEHALF OF NORTHWESTERN ENERGY

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Exhibits

Corrected 2013-2014 Program Savings	Exhibit__(JS-1)
Corrected 2013-2014 Lost Revenues	Exhibit__(JS-2)

Witness Information

Q. Please state your name and business address.

A. My name is Joe Schwartzenberger. My business address is 40 East Broadway, Butte, Montana 59701.

Q. By whom are you employed and in what capacity?

A. I am NorthWestern Energy's ("NorthWestern") Director of Regulatory Affairs.

Q. Please summarize your education and employment experience.

A. I attended Montana State University ("MSU"), receiving a Bachelor of Science degree in Mechanical Engineering Technology in 1982. I also earned a Master of Business Administration degree from the University of Montana in 2000. During my career, I have attended various seminars and sessions regarding a variety of electric and natural gas utility engineering, business, finance and regulatory subjects, including the University of Idaho Utility Executive Course. I am a registered Professional Engineer in Montana.

After graduating MSU, I was employed by Bechtel Power Corporation as a field construction engineer in Colstrip, Montana and then at San Onofre Nuclear Generating Station in southern California. I began my career with the Montana Power Company ("MPC") in 1986 as a Plant Engineer in Colstrip. I relocated to Butte, Montana with MPC and progressed through a number of engineering positions becoming Manager of Technical Services in

1993 with responsibility for providing technical support for MPC's Demand-Side Management ("DSM") programs. In 1997, I was promoted to Director of Operations with responsibility for managing an unregulated energy services subsidiary of MPC. In 2002, I transferred to the Government and Regulatory Affairs Department as Manager of Regulatory Support Services with primary responsibility for NorthWestern's Universal System Benefits ("USB") and DSM programs. I was promoted to my current position in 2004. As pertains to this testimony, I have more than 20 years of experience in planning, designing, implementing and/or managing utility conservation programs in Montana with both NorthWestern and MPC.

Q. What are your responsibilities as Director of Regulatory Affairs?

A. I am the director responsible for state and federal regulatory activities, DSM and USB programs, electric load research, short-term electric load forecasting, and collecting and managing electric load data to meet various internal and external needs in Montana.

I regularly participate in the preparation and/or consideration of the testimony, exhibits, and workpapers in NorthWestern's proceedings before the Montana Public Service Commission ("Commission") and the Federal Energy Regulatory Commission.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony presents corrected lost revenues for the 2013-2014 tracker year.

William Thomas submitted Prefiled Direct Testimony on behalf of NorthWestern in both of these consolidated dockets. Mr. Thomas retired from NorthWestern in November 2014. As a result, in addition to submitting this testimony, I adopt the testimony previously filed and sponsored by Mr. Thomas.

Corrected 2013-2014 Tracker Year Lost Revenues

Q. Why do lost revenues for the 2013-2014 tracker year need to be corrected?

A. NorthWestern provided in electronic format updated lost revenues for the 2013-2014 tracker year based on 12 months of actual program data in response to Data Request MCC-061. In this response, the lost revenues computations included on Exhibit__(WMT-3) are supported by program savings inputs from Exhibit__(WMT-1). As explained in the response to Data Request PSC-006, NorthWestern inadvertently omitted an adjustment to the 2013-2014 lost revenues computations to account for an 8.6% Compact Fluorescent Lighting ("CFL") storage rate as required by Commission Order

No. 7219h, ¶¶ 68 and 76 in Docket No. D2012.5.49. The corrected lost revenues include this adjustment.

Q. What is the impact of this correction?

A. Lost revenues for the 2013-2014 tracker year as presented on Exhibit__(WMT-3) provided in response to Data Request MCC-061 are $10,058,433. 2013-2014 tracker year lost revenues with the 2013-2014 tracker year program savings corrected for the 8.6% storage rate are $9,997,974 as shown on page 1 of Exhibit__(JS-2). The program savings in Exhibit __(JS-1), which are inputs to the lost revenues computations on Exhibit__(JS-2), reflect the 8.6% CFL storage rate adjustment.

Q. Have any other changes been made to the 2013-2014 lost revenues computations presented in Exhibits__(WMT-1) and (WMT-3) that were provided in response to Data Request MCC-061?

A. No. The computations on Exhibits__(JS-1) and (JS-2) are otherwise identical to Exhibits__(WMT-1) and (WMT-3), respectively.

Q. Does this correction to the 2013-2014 lost revenues impact the 2012-2013 lost revenues presented on Exhibit__(WMT-3) provided in response to Data Request MCC-061?

A. No, the 2012-2013 lost revenues already reflected the 8.6% CFL storage rate. NorthWestern proposes recovery of $7,126,381 in lost revenues for the 2012-

2013 tracker year as shown on Exhibit_(WMT-3) provided in response to the data request and on page 1 of Exhibit__(JS-2).

A. Does this conclude your testimony?

Q. Yes, it does.

Table A: Reported Electricity Savings from 2013-14 USB and DSM Program Activity

Programs	Annualized Energy Savings[1]			
	USB		DSM	
	kWh	aMW	kWh	aMW
E+ Energy Audit for the Home or Business (Elec)	1,344,176	0.15	-	-
E+ Business Partners Program	-	-	3,743,349	0.43
E+ Irrigation	758,105	0.09	-	-
E+ Commercial Lighting Rebate Program	-	-	13,628,208	1.56
E+ Residential Lighting Programs	-	-	24,547,835	2.80
Builder Operator Certification	2,004,298	0.23	-	-
Northwest Energy Efficiency Alliance (NEEA)	-	-	10,199,954	1.16
Energy Star 80 Plus Program	-	-	1,292,350	0.15
E+ Free Weatherization Program & Fuel Switch	384,301	0.04	-	-
E+ Renewable Energy Program	610,797	0.07	-	-
Energy Star New Homes Program	28,798	0.00	-	-
E+ Residential NC Electric Rebate Program	-	-	9,059	0.00
E+ Residential EX Electric Rebate Program	-	-	36,855	0.00
E+ Commercial NC Electric Rebate Program	-	-	388,687	0.04
E+ Commercial EX Electric Rebate Program	-	-	1,393,055	0.16
Total	**5,130,475**	**0.59**	**55,239,352**	**6.31**

Note 1: Annualized energy savings are based on 12 months of actual savings (July - June).

USB + DSM savings acquired in 2013-14 Tracker Period (aMW):	6.89

Table B: Residential and Commercial Savings for Calculation of Lost T & D Revenues

Programs	USB + DSM Programs						
	% Residential	kWh	% Commercial	kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
General Default Supply DSM Expenses	0%	-	0%	-	-		
E+ Energy Audit for the Home or Business (Elec)	89%	1,200,452	11%	143,724	1,344,176		
E+ Business Partners Program	0%	-	100%	3,743,349	3,743,349		
E+ Irrigation	0%	-	100%	758,105	758,105		
E+ Commercial Lighting Rebate Program	0%	-	100%	13,628,208	13,628,208		
E+ Residential Lighting Programs	100%	24,547,835	0%	-	24,547,835		
Builder Operator Certification	0%	-	100%	2,004,298	2,004,298		
Northwest Energy Efficiency Alliance (NEEA)	82%	8,370,568	18%	1,829,387	10,199,954		
Energy Star 80 Plus Program	0%	-	100%	1,292,350	1,292,350		
E+ Free Weatherization Program & Fuel Switch	100%	384,301	0%	-	384,301		
E+ Renewable Energy Program	64%	393,790	36%	217,007	610,797		
Energy Star New Homes Program	100%	28,798	0%	-	28,798		
E+ Residential NC Electric Rebate Program	100%	9,059	0%	-	9,059		
E+ Residential EX Electric Rebate Program	100%	36,855	0%	-	36,855		
E+ Commercial NC Electric Rebate Program	0%	-	100%	388,687	388,687		
E+ Commercial EX Electric Rebate Program	0%	-	100%	1,393,055	1,393,055		
		34,971,657		**25,398,170**	**60,369,827**	**57.93%**	**42.07%**

Note 2: Overall Residential and Commercial percentages are used in calculation of Lost Revenues in Exhibit__(WMT-3).

Subtract NorthWestern Energy Facilities from Commercial Totals[3]	Residential kWh	Commercial kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
	34,971,657	**24,899,792**	**59,871,449**	**58.41%**	**41.59%**

6.83 aMW

Note 3: The savings from NorthWestern Energy facilities has been subtracted from the commercial kWh total, resulting in a reduction of Total kWh and a reduction of the Commercial Percentage of Total Savings.

Include 8.6% for CFL Storage in E+ Residental Lighting, NEEA, and Energy Star New Homes[4]	Residential kWh	Commercial kWh	Total kWh	Residential % of Total[2]	Commercial % of Total[2]
	32,615,112	**24,899,792**	**57,514,904**	**56.71%**	**43.29%**

6.57 aMW

Note 4: The savings from E+ Residental Lighting, NEEA, and Energy Star New Homes has been reduced by 8.6% for storage per Order 7219h (paragraphs 67, 68, and 124) subtracted from the residential kWh total, resulting in a reduction of Total kWh and a reduction of the Residential Percentage of Total Savings.

Electric DSM Lost Revenues

Time Period	Montana T&D	Colstrip Unit #4	Dave Gates Mill Creek Station[1]	Spion Kop[2]	Total DSM Lost Revenue
Tracker 2011-12	$ 2,307,045	$ 1,808,216	$ 215,603		$ 4,330,864
Tracker 2012-13	$ 4,079,918	$ 2,524,213	$ 504,221	$ 18,029	$ 7,126,381
Tracker 2013-14	$ 5,916,696	$ 3,233,963	$ 771,478	$ 75,837	$ 9,997,974
Tracker 2014-15	$ 7,499,123	$ 3,870,114	$ 1,011,021	$ 161,135	$ 12,541,394

Notes:

The starting point for this 'Exhibit__(JS-2)' in Docket Nos. D2013.5.33/D2014.5.46 was the spreadsheet workbook 'Exhibit__(WMT-3) Electric DSM Lost Revenues_2014-2015_D2014.5.46_12+0_FINAL' and was filed in response to MCC-061 in Docket D2014.5.46.

Tracker Period 2012-2013 based on 12 month actual reported energy savings (excluding NorthWestern Facilities DSM and 8.6% CFL storage calculation)
Tracker Period 2013-2014 based on 12 months actual reported energy savings (excluding NorthWestern Facilities DSM and 8.6% CFL storage calculation)
Tracker Period 2014-2015 based on 6.0 aMW goal.

Electric DSM Lost Revenues were reset again on Jan. 1, 2011 due to newly established T&D rates
Refer to Docket D2009.9.129, Final Order No. 7046h; and updated with Order on Remand No. 7046i effective July 8, 2011

1. DGGS began commercial service on January 1, 2011

2. Spion Kop began commercial service on December 1, 2012.

Electric DSM Lost Revenues

2011-12 Tracking Period

July 1, 2011 - December 31, 2011 Period			January 1, 2012 Forward			Averaged Rates used for 2011-12 Tracking Period[2]		
Residential:			**Residential:**			**Residential:**		
Transmission Energy	0.009078	per kwh	Transmission Energy	0.008866	per kwh	Transmission Energy	0.008972	per kwh
Distribution Energy	0.028259	per kwh	Distribution Energy	0.027599	per kwh	Distribution Energy	0.027929	per kwh
GS 1 Secondary, non-demand			**GS 1 Secondary, non-demand**			**GS 1 Secondary, non-demand**		
Transmission Energy	0.007904	per kwh	Transmission Energy	0.007719	per kwh	Transmission Energy	0.007812	per kwh
Distribution Energy	0.036600	per kwh	Distribution Energy	0.035745	per kwh	Distribution Energy	0.036173	per kwh
GS 1 Secondary, demand			**GS 1 Secondary, demand**			**GS 1 Secondary, demand**		
Transmission Demand	3.019986	per kw	Transmission Demand	2.949439	per kw	Transmission Demand	2.984713	per kw
Distribution Energy	0.004883	per kwh	Distribution Energy	0.004769	per kwh	Distribution Energy	0.004826	per kwh
Distribution Demand	6.156176	per kw	Distribution Demand	6.012368	per kw	Distribution Demand	6.084272	per kw
General Service - 1 Primary, Non Demand:			**General Service - 1 Primary, Non Demand:**			**General Service - 1 Primary, Non Demand:**		
Transmission Energy	0.008268	per kwh	Transmission Energy	0.008075	per kwh	Transmission Energy	0.008172	per kwh
Distribution Energy	0.018957	per kwh	Distribution Energy	0.018514	per kwh	Distribution Energy	0.018736	per kwh
General Service - 1 Primary, Demand:			**General Service - 1 Primary, Demand:**			**General Service - 1 Primary, Demand:**		
Transmission Demand	3.670616	per kw	Transmission Demand	3.584870	per kw	Transmission Demand	3.627743	per kw
Distribution Energy	0.007061	per kwh	Distribution Energy	0.006896	per kwh	Distribution Energy	0.006979	per kwh
Distribution Demand	4.030549	per kw	Distribution Demand	3.936395	per kw	Distribution Demand	3.983472	per kw

2012-13 Tracking Period

July 1, 2012 - December 31, 2012 Period			January 1, 2013 Forward			Averaged Rates used for 2012-13 Tracking Period[1]		
Period July 2012-June 2013			Period January 2013 forward (until next change)					
Reference: 2012 Annual Tax Tracker Filing Application December 8, 2011, Docket D2012.12.97., Final Order 7191a; Appendix A Pages 1-4			Reference: 2013 Annual Tax Tracker; December 11, 2012; Docket No. D2012.12.124; Apprendix A (by operation of law)					
Residential:			**Residential:**			**Residential:**		
Transmission Energy	0.008866	per kwh	Transmission Energy	0.009188	per kwh	Transmission Energy	0.009027	per kwh
Distribution Energy	0.027599	per kwh	Distribution Energy	0.028601	per kwh	Distribution Energy	0.028100	per kwh
GS 1 Secondary, non-demand			**GS 1 Secondary, non-demand**			**GS 1 Secondary, non-demand**		
Transmission Energy	0.007719	per kwh	Transmission Energy	0.007999	per kwh	Transmission Energy	0.007859	per kwh
Distribution Energy	0.035745	per kwh	Distribution Energy	0.037043	per kwh	Distribution Energy	0.036394	per kwh
GS 1 Secondary, demand			**GS 1 Secondary, demand**			**GS 1 Secondary, demand**		
Transmission Demand	2.949439	per kw	Transmission Demand	3.056510	per kw	Transmission Demand	3.002975	per kw
Distribution Energy	0.004769	per kwh	Distribution Energy	0.004942	per kwh	Distribution Energy	0.004856	per kwh
Distribution Demand	6.012368	per kw	Distribution Demand	6.230629	per kw	Distribution Demand	6.121499	per kw
General Service - 1 Primary, Non Demand:			**General Service - 1 Primary, Non Demand:**			**General Service - 1 Primary, Non Demand:**		
Transmission Energy	0.008075	per kwh	Transmission Energy	0.008368	per kwh	Transmission Energy	0.008222	per kwh
Distribution Energy	0.018514	per kwh	Distribution Energy	0.019186	per kwh	Distribution Energy	0.018850	per kwh
General Service - 1 Primary, Demand:			**General Service - 1 Primary, Demand:**			**General Service - 1 Primary, Demand:**		
Transmission Demand	3.584870	per kw	Transmission Demand	3.715008	per kw	Transmission Demand	3.649939	per kw
Distribution Energy	0.006896	per kwh	Distribution Energy	0.007146	per kwh	Distribution Energy	0.007021	per kwh
Distribution Demand	3.936395	per kw	Distribution Demand	4.079294	per kw	Distribution Demand	4.007845	per kw

2013-14 Tracking Period

July 1, 2013 - December 31, 2013 Period			January 1, 2014 Forward			Averaged Rates used for 2013-14 Tracking Period[2]		
Period July 2013-June 2014			Period January 2014 forward (until next change)					
Reference: 2013 Annual Tax Tracker;			Reference: 2014 Annual Tax Tracker;					
Residential:			**Residential:**			**Residential:**		
Transmission Energy	0.009188	per kwh	Transmission Energy	0.009165	per kwh	Transmission Energy	0.009177	per kwh
Distribution Energy	0.028601	per kwh	Distribution Energy	0.028529	per kwh	Distribution Energy	0.028565	per kwh
GS 1 Secondary, non-demand			**GS 1 Secondary, non-demand**			**GS 1 Secondary, non-demand**		
Transmission Energy	0.007999	per kwh	Transmission Energy	0.007979	per kwh	Transmission Energy	0.007989	per kwh
Distribution Energy	0.037043	per kwh	Distribution Energy	0.036950	per kwh	Distribution Energy	0.036997	per kwh
GS 1 Secondary, demand			**GS 1 Secondary, demand**			**GS 1 Secondary, demand**		
Transmission Demand	3.056510	per kw	Transmission Demand	3.048835	per kw	Transmission Demand	3.052673	per kw
Distribution Energy	0.004942	per kwh	Distribution Energy	0.004930	per kwh	Distribution Energy	0.004936	per kwh
Distribution Demand	6.230629	per kw	Distribution Demand	6.214984	per kw	Distribution Demand	6.222807	per kw
General Service - 1 Primary, Non Demand:			**General Service - 1 Primary, Non Demand:**			**General Service - 1 Primary, Non Demand:**		
Transmission Energy	0.008368	per kwh	Transmission Energy	0.008347	per kwh	Transmission Energy	0.008358	per kwh
Distribution Energy	0.019186	per kwh	Distribution Energy	0.019138	per kwh	Distribution Energy	0.019162	per kwh
General Service - 1 Primary, Demand:			**General Service - 1 Primary, Demand:**			**General Service - 1 Primary, Demand:**		
Transmission Demand	3.715008	per kw	Transmission Demand	3.705680	per kw	Transmission Demand	3.710344	per kw
Distribution Energy	0.007146	per kwh	Distribution Energy	0.007128	per kwh	Distribution Energy	0.007137	per kwh
Distribution Demand	4.079294	per kw	Distribution Demand	4.069051	per kw	Distribution Demand	4.074173	per kw

2014-15 Tracking Period

July 1, 2014 - December 31, 2014 Period			January 1, 2015 Forward			Averaged Rates used for 2014-15 Tracking Period[2]		
Period January 2014 forward (until next change)			Period January 2014 forward (until next change)					
Reference: 2014 Annual Tax Tracker; December 11, 2013; Docket No. D2013.12.83; Apprendix A (by operation of law)			Reference: 2014 Annual Tax Tracker; December 11, 2013; Docket No. D2013.12.83; Apprendix A (by operation of law)					
Residential:			**Residential:**			**Residential:**		
Transmission Energy	0.009165	per kwh	Transmission Energy	0.009165	per kwh	Transmission Energy	0.009165	per kwh
Distribution Energy	0.028529	per kwh	Distribution Energy	0.028529	per kwh	Distribution Energy	0.028529	per kwh
GS 1 Secondary, non-demand			**GS 1 Secondary, non-demand**			**GS 1 Secondary, non-demand**		
Transmission Energy	0.007979	per kwh	Transmission Energy	0.007979	per kwh	Transmission Energy	0.007979	per kwh
Distribution Energy	0.036950	per kwh	Distribution Energy	0.036950	per kwh	Distribution Energy	0.036950	per kwh
GS 1 Secondary, demand			**GS 1 Secondary, demand**			**GS 1 Secondary, demand**		
Transmission Demand	3.048835	per kw	Transmission Demand	3.048835	per kw	Transmission Demand	3.048835	per kw
Distribution Energy	0.004930	per kwh	Distribution Energy	0.004930	per kwh	Distribution Energy	0.004930	per kwh
Distribution Demand	6.214984	per kw	Distribution Demand	6.214984	per kw	Distribution Demand	6.214984	per kw
General Service - 1 Primary, Non Demand:			**General Service - 1 Primary, Non Demand:**			**General Service - 1 Primary, Non Demand:**		
Transmission Energy	0.008347	per kwh	Transmission Energy	0.008347	per kwh	Transmission Energy	0.008347	per kwh
Distribution Energy	0.019138	per kwh	Distribution Energy	0.019138	per kwh	Distribution Energy	0.019138	per kwh
General Service - 1 Primary, Demand:			**General Service - 1 Primary, Demand:**			**General Service - 1 Primary, Demand:**		
Transmission Demand	3.705680	per kw	Transmission Demand	3.705680	per kw	Transmission Demand	3.705680	per kw
Distribution Energy	0.007128	per kwh	Distribution Energy	0.007128	per kwh	Distribution Energy	0.007128	per kwh
Distribution Demand	4.069051	per kw	Distribution Demand	4.069051	per kw	Distribution Demand	4.069051	per kw

Notes:

1. Rates were changed as a result of the Tax Tracker. The effective date of the revised rates was January 1, 2013. This date falls at the midpoint of the 2012-2013 tracker period, so Averaged rates for the full tracker period were calculated and used in Lost Revenue calculations for 2012-2013.

2. Rates were changed as a result of the Tax Tracker. The effective date of the revised rates was January 1, 2014. This date falls at the midpoint of the 2013-2014 tracker period, so Averaged rates for the full tracker period were calculated and used in Lost Revenue calculations for 2013-2014.

Electric DSM Lost Revenues

Annual Energy Savings:

1) DSM Targets and Results:	**Tracker 2011-2012**		**Tracker 2012-2013**		**Tracker 2013-2014**		**Tracker 2014-2015**	
	Period July 2011 – June 2012		**Period July 2012 – June 2013**		**Period July 2013 – June 2014**		**Period July 2014 – June 2015**	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
Annual (Avg. MW)	6.00	6.69	6.00	7.45	6.00	6.57	6.00	6.00
Cumulative (Avg. MW)	11.51	12.20	18.20	19.65	25.65	26.22	32.22	32.22

2) Disaggregate Targets into Residential & Commercial/Industrial [2]	**Period July 2011 – June 2012**		**Period July 2012 – June 2013**		**Period July 2013 – June 2014**		**Period July 2014 – June 2015**	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
% Residential	67.4%	52.7%	69.7%	53.6%	69.7%	56.7%	55.2%	55.2%
% Commercial & Industrial	32.6%	49.9%	30.3%	46.4%	30.3%	43.3%	44.8%	44.8%
Incremental Res. (Avg. MW)	4.04	3.53	4.18	4.00	4.18	3.72	3.31	3.31
Cumulative Res. (Avg. MW)	8.09	7.65	11.84	11.65	15.83	15.37	18.68	18.68
Incremental C/I (Avg. MW)	1.96	3.34	1.82	3.46	1.82	2.84	2.69	2.69
Cumulative C/I (Avg. MW)	3.91	4.72	6.54	8.18	10.00	11.02	13.71	13.71
ck. fig.			OK	OK	OK	OK	OK	OK

2. Residential/commercial split based on DSM Program results

3) Cumulative Annual Energy Savings[3]	**Period July 2011 – June 2012**		**Period July 2012 – June 2013**		**Period July 2013 – June 2014**		**Period July 2014 – June 2015**	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
Residential (MWH)	53,843	51,591	85,368	84,544	120,364	118,350	149,151	149,151
C/I (MWH)	20,703	26,740	49,310	56,501	79,608	84,100	108,336	108,336
Total Savings (MWH)	74,546	78,332	134,677	141,045	199,972	202,450	257,487	257,487
Total Savings (Avg. MW)	8.51	8.94	15.37	16.10	22.83	23.11	29.39	29.39

3. "Half-year convention":
Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects are completed and start generating savings at different times throughout the first year. This assumption contemplates that associated projects start generating savings half way through the year on average. In the second year and beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100% for the second year and each successive year.

Electric DSM Lost Revenues

Commercial/Industrial Reduction in Peak Demand:

1) Commercial/Industrial Average Monthly Load Factor: 66%

	Tracker 2011-2012		Tracker 2012-2013		Tracker 2013-2014		Tracker 2014-2015	
2) Calculate Coincident Monthly Demand Reduction:	**Period July 2011 – June 2012**		**Period July 2012 – June 2013**		**Period July 2013 – June 2014**		**Period July 2014 – June 2015**	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
C/I Energy Savings (MWH)	20,703	26,740	49,310	56,501	79,608	84,100	108,336	108,336
C/I Energy Savings (Avg. MW)	2.4	3.1	5.6	6.4	9.1	9.6	12.4	12.4
C/I Avg. Monthly Demand Reduction (KW/Mth)*	3,581	4,625	8,529	9,773	13,769	14,546	18,738	18,738
C/I Annual Demand Reduction (KW-Mths)	42,970	55,501	102,345	117,270	165,231	174,554	224,857	224,857

3) Coincidence Factor: 100% *

* Coincidence Factor is estimated. 100% load factor assumes that, from a billing perspective, the impacts of class coincidence are offset by the potential of the impacts of specific technologies/projects to be non-coincident with the peak loads of individual customers.

	Tracker 2011-2012		Tracker 2012-2013		Tracker 2013-2014		Tracker 2014-2015	
	Period July 2011 – June 2012		**Period July 2012 – June 2013**		**Period July 2013 – June 2014**		**Period July 2014 – June 2015**	
	Target	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
4) C/I Annual Demand Reduction (KW-Mths)*	42,970	55,501	102,345	117,270	165,231	174,554	224,857	224,857

* Represents total C/I Demand reduction. Tariffs for GS-1 Primary and Secondary Non-demand customers do not include a demand charge. Demand reductions associated with such customers do not result in lost revenues.

Electric DSM Lost Revenues

Estimate Energy and Demand "Bill" Savings for Residential and C/I

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
1) Residential Savings (KWH)	53,843,360	51,591,247	85,367,567	84,544,023	120,364,119	118,349,855	149,151,437	149,151,437
2) C/I Savings								
Energy (KWH)	20,702,882	26,740,472	49,309,629	56,500,810	79,608,351	84,100,067	108,335,938	108,335,938
Demand (KW-Mths)	42,970	55,501	102,345	117,270	165,231	174,554	224,857	224,857
3) Disaggregate C&I Savings by service level (tariff)								
C&I Savings is broken out as:*								
GS-1 Secondary, non demand	1%	1%	1%	1%	1%	1%	1%	1%
GS-1 Secondary, demand	98%	98%	98%	98%	98%	98%	98%	98%
GS-1 Primary, non demand	0%	0%	0%	0%	0%	0%	0%	0%
GS-1 Primary, demand	1%	1%	1%	1%	1%	1%	1%	1%
Total C&I	100%	100%	100%	100%	100%	100%	100%	100%

4) C&I Reported Programmatic "Bill" Savings Based on Breakout in 3) Above:

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15	
	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013 – June 2014		Period July 2014 – June 2015	
Energy (KWh)	Target	Reported	Target	Reported	Target	Reported	Target	Reported
GS-1 Secondary, non demand	207,029	267,405	493,096	565,008	796,084	841,001	1,083,359	1,083,359
GS-1 Secondary, demand	20,288,825	26,205,663	48,323,437	55,370,794	78,016,184	82,418,066	106,169,219	106,169,219
GS-1 Primary, non demand	-	-	-	-	-	-	-	-
GS-1 Primary, demand	207,029	267,405	493,096	565,008	796,084	841,001	1,083,359	1,083,359
Check Total	20,702,882	26,740,472	49,309,629	56,500,810	79,608,351	84,100,067	108,335,938	108,335,938
check fig (should = 0):	-	-	-	-	-	-	-	-
Demand (KW-mth)								
GS-1 Secondary, demand	42,110	54,391	100,298	114,925	161,926	171,063	220,360	220,360
GS-1 Primary, demand	430	555	1,023	1,173	1,652	1,746	2,249	2,249
Total*	42,540	54,946	101,321	116,098	163,579	172,808	222,608	222,608

*Totals are less than totals in row 12 above because non-demand C&I customers are not billed for demand.

	A	B	C	D
1				
2	**Electric DSM Lost Revenues**			
3				
4	**Adjustment Factors (Net Savings Adjustment Ratios)**			
5				
6	**For Lost Revenue calculations for the 2011-2012 tracker period forward, these values are used. SBW, Inc. DSM Evalution Study Savings Realization rate for all Electric DSM programs**			
7				
8	**Residential**		**Net Savings Adjustment Ratio**	
9	Segment			
10	All		0.91	
11				
12	**Commercial/Industrial**		**Net Savings Adjustment Ratio**	
13	Segment			
14	All		0.91	
15				

Electric DSM Lost Revenues - Montana T&D

July 2011-June 2012

Residential

Bill Line Item	Average Rate[1] ($ per kwh)		Gross Program Savings (kwh)		SBW's NTG Adjustment Factor	Net Savings (kwh)		Estimated Lost Revenue ($)
Transmission Energy	0.008972		51,591,247		0.91	46,834,467		420,199
Distribution Energy	0.027929		51,591,247		0.91	46,834,467		1,308,040
				Sub Total Residential:		**46,834,467**		**$ 1,728,239**

Commercial & Industrial

Bill Line Item	Average Rate[1] ($ per kwh)	Average Rate[1] ($ per kw-mth)	Reported Gross Program Savings (kwh)	Reported Gross Program Savings (kw-mth)	SBW's NTG Adjustment Factor	Net Savings (kwh)	Net Savings (kw-mth)	Estimated Lost Revenue ($)
GS-1 Secondary, non demand, TX Energy	0.007812		267,405		0.91	242,750		1,896
GS-1 Secondary, non demand, Dist. Energy	0.036173		267,405		0.91	242,750		8,781
GS-1 Secondary, demand, TX Demand		2.984713		54,391	0.91		49,376	147,374
GS-1 Secondary, demand, Dist. Energy	0.004826		26,205,663		0.91	23,789,467		114,808
GS-1 Secondary, demand, Dist. Demand		6.084272		54,391	0.91		49,376	300,418
GS-1 Primary, non demand, TX Energy	0.008172		0		0.91	0		0
GS-1 Primary, non demand, Dist. Energy	0.018736		0		0.91	0		0
GS-1 Primary, demand, TX Demand		3.627743		555	0.91		504	1,828
GS-1 Primary, demand, Dist. Energy	0.006979		267,405		0.91	242,750		1,694
GS-1 Primary, demand, Dist. Demand		3.983472		555	0.91		504	2,007
			Sub Total Commercial & Industrial:			**24,274,966**		**$ 578,806**
	July 2011-June 2012		**Estimated Totals:**			**71,109,433**		**$ 2,307,045**

Note 1: Two sets of rates were used, each set was effective for 6 months of the 2011-12 tracker period

Electric DSM Lost Revenues - Montana T&D

July 2012-June 2013

Residential			**Reported**					
			Gross		**SBW's**			**Estimated**
			Program		**NTG**	**Net**		**Lost**
	Rate[1]		**Savings**		**Adjustment**	**Savings**		**Revenue**
Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
Transmission Energy	0.009027		84,544,023		0.91	76,748,955		692,813
Distribution Energy	0.028100		84,544,023		0.91	76,748,955		2,156,646
				Sub Total Residential:		**76,748,955**		**$ 2,849,458**
Commercial & Industrial			**Reported**	**Reported**				
			Gross	**Gross**	**SBW's**			**Estimated**
			Program	**Program**	**NTG**	**Net**	**Net**	**Lost**
	Rate[1]	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
GS-1 Secondary, non demand, TX Energy	0.007859		565,008		0.91	512,914		4,031
GS-1 Secondary, non demand, Dist. Energy	0.036394		565,008		0.91	512,914		18,667
GS-1 Secondary, demand, TX Demand		3.002975		114,925	0.91		104,329	313,296
GS-1 Secondary, demand, Dist. Energy	0.004856		55,370,794		0.91	50,265,535		244,064
GS-1 Secondary, demand, Dist. Demand		6.121499		114,925	0.91		104,329	638,648
GS-1 Primary, non demand, TX Energy	0.008222		0		0.91	0		0
GS-1 Primary, non demand, Dist. Energy	0.018850		0		0.91	0		0
GS-1 Primary, demand, TX Demand		3.649939		1,173	0.91		1,065	3,886
GS-1 Primary, demand, Dist. Energy	0.007021		565,008		0.91	512,914		3,601
GS-1 Primary, demand, Dist. Demand		4.007845		1,173	0.91		1,065	4,267
			Sub Total Commercial & Industrial:			**51,291,362**		**$ 1,230,460**
		July 2012-June 2013	**Estimated Totals:**			**128,040,317**		**$ 4,079,918**

Note 1: Two sets of rates were used, each set was effective for 6 months of the 2012-13 tracker period

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
76									
77	**July 2013-June 2014**								
78									
79									
80	**Residential**			**Reported**					
81				**Gross**		**SBW's**			**Estimated**
82				**Program**		**NTG**	**Net**		**Lost**
83		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
84	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
85	Transmission Energy	0.009177		118,349,855		0.91	107,437,845		985,903
86	Distribution Energy	0.028565		118,349,855		0.91	107,437,845		3,068,962
87					**Sub Total Residential:**		**107,437,845**		**$ 4,054,865**
88									
89									
90	**Commercial & Industrial**			**Reported**	**Reported**				
91				**Gross**	**Gross**	**SBW's**			**Estimated**
92				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
93		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
94	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
95	GS-1 Secondary, non demand, TX Energy	0.007989		841,001		0.91	763,459		6,099
96	GS-1 Secondary, non demand, Dist. Energy	0.036997		841,001		0.91	763,459		28,245
97									
98	GS-1 Secondary, demand, TX Demand		3.052673		171,063	0.91		155,291	474,051
99	GS-1 Secondary, demand, Dist. Energy	0.004936		82,418,066		0.91	74,819,013		369,307
100	GS-1 Secondary, demand, Dist. Demand		6.222807		171,063	0.91		155,291	966,343
101									
102	GS-1 Primary, non demand, TX Energy	0.008358		0		0.91	0		0
103	GS-1 Primary, non demand, Dist. Energy	0.019162		0		0.91	0		0
104									
105	GS-1 Primary, demand, TX Demand		3.710344		1,746	0.91		1,585	5,879
106	GS-1 Primary, demand, Dist. Energy	0.007137		841,001		0.91	763,459		5,449
107	GS-1 Primary, demand, Dist. Demand		4.074173		1,746	0.91		1,585	6,456
108				**Sub Total Commercial & Industrial:**			**76,345,932**		**$ 1,861,830**
109									
110		**July 2013-June 2014**		**Estimated Totals:**			**183,783,777**		**$ 5,916,696**
111									
112	**Note 1: Two sets of rates were used, each set was effective for 6 months of the 2013-14 tracker period**								

Electric DSM Lost Revenues - Montana T&D

	A	B	C	D	E	F	G	H	I
113									
114	**July 2014-June 2015**								
115									
116									
117	**Residential**			**TARGET**					
118				**Gross**		**SBW's**			**Estimated**
119				**Program**		**NTG**	**Net**		**Lost**
120		**Rate[1]**		**Savings**		**Adjustment**	**Savings**		**Revenue**
121	Bill Line Item	**($ per kwh)**		**(kwh)**		**Factor**	**(kwh)**		**($)**
122	Transmission Energy	0.009165		149,151,437		0.91	135,399,481		1,240,936
123	Distribution Energy	0.028529		149,151,437		0.91	135,399,481		3,862,812
124					**Sub Total Residential:**		**135,399,481**		**$ 5,103,748**
125									
126				**TARGET**					
127	**Commercial & Industrial**			**Reported**	**Reported**				
128				**Gross**	**Gross**	**SBW's**			**Estimated**
129				**Program**	**Program**	**NTG**	**Net**	**Net**	**Lost**
130		**Rate[1]**	**Rate[1]**	**Savings**	**Savings**	**Adjustment**	**Savings**	**Savings**	**Revenue**
131	Bill Line Item	**($ per kwh)**	**($ per kw-mth)**	**(kwh)**	**(kw-mth)**	**Factor**	**(kwh)**	**(kw-mth)**	**($)**
132	GS-1 Secondary, non demand, TX Energy	0.007979		1,083,359		0.91	983,472		7,847
133	GS-1 Secondary, non demand, Dist. Energy	0.036950		1,083,359		0.91	983,472		36,339
134									
135	GS-1 Secondary, demand, TX Demand		3.048835		220,360	0.91		200,042	609,895
136	GS-1 Secondary, demand, Dist. Energy	0.00493		106,169,219		0.91	96,380,279		475,155
137	GS-1 Secondary, demand, Dist. Demand		6.214984		220,360	0.91		200,042	1,243,258
138									
139	GS-1 Primary, non demand, TX Energy	0.008347		0		0.91	0		0
140	GS-1 Primary, non demand, Dist. Energy	0.019138		0		0.91	0		0
141									
142	GS-1 Primary, demand, TX Demand		3.705680		2,249	0.91		2,041	7,564
143	GS-1 Primary, demand, Dist. Energy	0.007128		1,083,359		0.91	983,472		7,010
144	GS-1 Primary, demand, Dist. Demand		4.069051		2,249	0.91		2,041	8,306
145				**Sub Total Commercial & Industrial:**			**98,347,223**		**$ 2,395,375**
146									
147		**July 2014-June 2015**		**Estimated Totals:**			**233,746,704**		**$ 7,499,123**
148									
149									

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

4	**DSM Targets and Results:**	**Tracker 2011-12**		**Tracker 2012-13**		**Tracker 2013-14**		**Tracker 2014-15**	
5		**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
6	Annual (Avg. MW)	6.00	6.69	6.00	7.45	6.00	6.57	6.00	6.00
7	Cumulative (Avg. MW)	20.51	21.20	27.20	28.66	34.66	35.22	41.22	41.22
10	Disaggregate Targets into Residential & Commercial/Industrial [1]								
11		**Tracker 2011-12**		**Tracker 2012-13**		**Tracker 2013-14**		**Tracker 2014-15**	
12		**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
13	% Residential	67.4%	52.7%	69.7%	53.6%	69.7%	56.7%	55.2%	55.2%
14	% Commercial & Industrial	32.6%	47.3%	30.3%	46.4%	30.3%	43.3%	44.8%	44.8%
15	*ck. fig.*	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
17	Incremental Res. (Avg. MW)	4.04	3.53	4.18	4.00	4.18	3.72	3.31	3.31
18	Cumulative Res. (Avg. MW)	13.07	13.38	17.56	17.37	21.56	21.10	24.41	24.41
19	Incremental C/I (Avg. MW)	1.96	3.16	1.82	3.46	1.82	2.84	2.69	2.69
20	Cumulative C/I (Avg. MW)	6.43	7.82	9.64	11.28	13.10	14.12	16.82	16.82
21	check fig:	6.00	6.69	6.00	7.45	6.00	6.57	6.00	6.00
23	1. Residential/commercial split based on DSM Program results								
25		**Tracker 2011-12**		**Tracker 2012-13**		**Tracker 2013-14**		**Tracker 2014-15**	
26	**Cumulative Annual Energy Savings[2]**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
27	Residential (MWH)	104,001	101,749	135,525	134,701	170,522	168,507	199,309	199,309
28	C/I (MWH)	49,417	54,688	76,490	83,681	106,788	111,280	135,516	135,516
29	Total Savings (MWH)	153,418	156,436	212,015	218,382	277,310	279,787	334,825	334,825
30	Total Savings (Avg. MW)	17.51	17.86	24.20	24.93	31.66	31.94	38.22	38.22
32	2. "Half-year convention":								
33	Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects								
34	are completed and start generating savings at different times throughout the first year. This assumption contemplates that								
35	associated projects start generating savings half way through the year on average. In the second year and								
36	beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100%								
37	for the second year and each successive year.								
39	3) Disaggregate C&I Savings by service level (tariff)								
41	C&I Savings is broken out as:*								
42	GS-1 Secondary, non demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
43	GS-1 Secondary, demand	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
44	GS-1 Primary, non demand	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
45	GS-1 Primary, demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
46	Total C&I	100%	100%	100%	100%	100%	100%	100%	100%
50	**Rates:**								
51	**CU4 Fixed Rates: Docket D2009.12.155, Order No. 7075b**								
52		**01/01/12**		**01/01/13**		**01/01/14**		**01/01/15**	
53	Residential	0.012734		0.012734		0.012734		0.012734	
54	GS-1 Sec Non-Demand	0.012734		0.012734		0.012734		0.012734	
55	GS-1 Sec Demand	0.012734		0.012734		0.012734		0.012734	
56	GS-1 Pri Non-Demand	0.012385		0.012385		0.012385		0.012385	
57	GS-1 Pri Demand	0.012385		0.012385		0.012385		0.012385	
58	GS-2 Substation	0.012278		0.012278		0.012278		0.012278	
59	GS-2 Transmission	0.012204		0.012204		0.012204		0.012204	

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

Tracker 2011-12						
Based on Cumulative DSM Savings Since January 2009						
Residential		**Gross**				**Estimated**
		Program			**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**		**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**		**(kwh)**	**($)**
Residential	$0.012734	101,748,654	0.91		92,367,296	1,176,205
					92,367,296	1,176,205
Commercial & Industrial		**Gross**				**Estimated**
		Program			**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**		**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**		**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.012734	546,877	0.91		496,454	6,322
GS-1 Sec Demand	$0.012734	53,593,911	0.91		48,652,483	619,541
GS-1 Pri Non-Demand	$0.012385	0	0.91		0	0
GS-1 Pri Demand	$0.012385	546,877	0.91		496,454	6,149
GS-2 Substation	$0.012278	0	0.91		0	0
GS-2 Transmission	$0.012204	0	0.91		0	0
		Sub Total General Service:			**49,645,391**	632,011
Note 1: using rates expected to be in effect at the time (see Rates tab)						
		Total CU-4-related DSM Lost Revenues				**$ 1,808,216**

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

	A	B	C	D	E	F	G	H	I	J
91		**Tracker 2012-13**								
92		**Based on Cumulative DSM Savings Since January 2009**								
93				**Reported**						
94		**Residential**		**Gross**			**Estimated**			
95				**Program**		**Net**	**Lost**			
96			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**			
97		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**			
98		Residential	$0.012734	134,701,430	0.91	122,281,783	1,557,136			
99						**122,281,783**	1,557,136			
100										
101		**Commercial & Industrial**		**Gross**			**Estimated**			
102				**Program**		**Net**	**Lost**			
103			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**			
104		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**			
105		GS-1 Sec Non-Demand	$0.012734	836,808	0.91	759,653	9,673			
106		GS-1 Sec Demand	$0.012734	82,007,170	0.91	74,446,002	947,995			
107		GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0			
108		GS-1 Pri Demand	$0.012385	836,808	0.91	759,653	9,408			
109										
110		GS-2 Substation	$0.012278	0	0.91	0	0			
111		GS-2 Transmission	$0.012204	0	0.91	0	0			
112				**Sub Total General Service:**		**75,965,309**	967,077			
113										
114		Note 1: using rates expected to be in effect at the time (see Rates tab)								
115										
116				**Total CU-4-related DSM Lost Revenues**			**$ 2,524,213**			
117										
118		**Tracker 2013-14**								
119		**Based on Cumulative DSM Savings Since January 2009**								
120				**Reported**						
121		**Residential**		**Gross**			**Estimated**			
122				**Program**		**Net**	**Lost**			
123			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**			
124		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**			
125		Residential	$0.012734	168,507,262	0.91	152,970,673	1,947,929			
126						**152,970,673**	1,947,929			
127										
128		**Commercial & Industrial**		**Gross**			**Estimated**			
129				**Program**		**Net**	**Lost**			
130			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**			
131		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**			
132		GS-1 Sec Non-Demand	$0.012734	1,112,800	0.91	1,010,199	12,864			
133		GS-1 Sec Demand	$0.012734	109,054,442	0.91	98,999,481	1,260,659			
134		GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0			
135		GS-1 Pri Demand	$0.012385	1,112,800	0.91	1,010,199	12,511			
136										
137		GS-2 Substation	$0.012278	0	0.91	0	0			
138		GS-2 Transmission	$0.012204	0	0.91	0	0			
139				**Sub Total General Service:**		**101,019,878**	1,286,035			
140										
141		Note 1: using rates expected to be in effect at the time (see Rates tab)								
142										
143				**Total CU-4-related DSM Lost Revenues**			**$ 3,233,963**			

Electric DSM Lost Revenues - Colstrip Unit 4

(fixed cost portion of CU-4 supply rate)

	A	B	C	D	E	F	G	H	I	J
144										
145		**Tracker 2014-15**								
146		**Based on Cumulative DSM Savings Since January 2009**								
147				**TARGET**						
148		**Residential**		**Gross**			**Estimated**			
149				**Program**		**Net**	**Lost**			
150			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**			
151		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**			
152		Residential	$0.012734	199,308,843	0.91	180,932,309	2,303,992			
153						**180,932,309**	2,303,992			
154										
155		**Commercial & Industrial**		**Gross**			**Estimated**			
156				**Program**		**Net**	**Lost**			
157			**Rate[1]**	**Savings**	**Adjustment**	**Savings**	**Revenue**			
158		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**			
159		GS-1 Sec Non-Demand	$0.012734	1,355,159	0.91	1,230,212	15,666			
160		GS-1 Sec Demand	$0.012734	132,805,595	0.91	120,560,747	1,535,221			
161		GS-1 Pri Non-Demand	$0.012385	0	0.91	0	0			
162		GS-1 Pri Demand	$0.012385	1,355,159	0.91	1,230,212	15,236			
163										
164		GS-2 Substation	$0.012278	0	0.91	0	0			
165		GS-2 Transmission	$0.012204	0	0.91	0	0			
166				**Sub Total General Service:**		**123,021,170**	1,566,122			
167										
168		Note 1: using rates expected to be in effect at the time (see Rates tab)								
169										
170				**Total CU-4-related DSM Lost Revenues**			**$ 3,870,114**			
171										

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15	
DSM Targets and Results:	Period July 2011 – June 2012		Period July 2012 – June 2013		Period July 2013– June 2014		Period July 2013– June 2014	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Annual (Avg. MW)	6.00	6.69	6.00	7.45	6.00	6.57	6.00	6.00
Cumulative (Avg. MW)	8.81	9.50	15.50	16.95	22.95	23.52	29.52	29.52

Disaggregate Targets into Residential & Commercial/Industrial [1]

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15	
	Target	Reported	Target	Reported	Target	Reported	Target	Reported
% Residential	67.4%	52.7%	69.7%	53.60%	69.7%	56.7%	55.2%	55.2%
% Commercial & Industrial	32.6%	47.3%	30.3%	46.40%	30.3%	43.3%	44.8%	44.8%
ck. fig.	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Incremental Res. (Avg. MW)	4.04	3.53	4.18	4.00	4.18	3.72	3.31	3.31
Cumulative Res. (Avg. MW)	6.06	5.63	9.81	9.63	13.81	13.35	16.66	16.66
Incremental C/I (Avg. MW)	1.96	3.16	1.82	3.46	1.82	2.84	2.69	2.69
Cumulative C/I (Avg. MW)	2.94	3.87	5.68	7.33	9.14	10.17	12.86	12.86
check fig:	6.00	6.69	6.00	7.45	6.00	6.57	6.00	6.00

1. Residential/commercial split based on DSM Program results

	Tracker 2011-12		Tracker 2012-13		Tracker 2013-14		Tracker 2014-15	
Cumulative Annual Energy Savings[2]	Target	Reported	Target	Reported	Target	Reported	Target	Reported
Residential (MWH)	36,128	33,876	67,652	66,829	102,649	100,635	131,436	131,436
C/I (MWH)	14,757	20,027	41,829	49,020	72,128	76,619	100,855	100,855
Total Savings (MWH)	50,885	53,903	109,482	115,849	174,777	177,254	232,292	232,292
Total Savings (Avg. MW)	5.8	6.2	12.5	13.2	20.0	20.2	26.5	26.5

2. "Half-year convention":
Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects are completed and start generating savings at different times throughout the first year. This assumption contemplates that associated projects start generating savings half way through the year on average. In the second year and beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100% for the second year and each successive year.

Disaggregate C&I Savings by service level (tariff)								
C&I Savings is broken out as:								
GS-1 Secondary, non demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
GS-1 Secondary, demand	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
GS-1 Primary, non demand	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
GS-1 Primary, demand	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Total C&I	0%	0%	100%	100%	100%	100%	100%	100%

Rates: Source: Appendix E - 05/01/11 Rate Chang	2011-12 Tracking Period					
DGGS Fixed Rate (after losses)	July-Dec 2011	Jan-June 2012	2012-13 Tracking Period	2013-14 Tracking Period	2014-15 Tracking Period
Residential	0.004018	0.004795	0.004795	0.004795	0.004795
GS-1 Sec Non-Demand	0.004018	0.004795	0.004795	0.004795	0.004795
GS-1 Sec Demand	0.004018	0.004795	0.004795	0.004795	0.004795
GS-1 Pri Non-Demand	0.003908	0.004664	0.004664	0.004664	0.004664
GS-1 Pri Demand	0.003908	0.004664	0.004664	0.004664	0.004664
GS-2 Substation	0.003874	0.004624	0.004624	0.004624	0.004624
GS-2 Transmission	0.003851	0.004596	0.004596	0.004596	0.004596

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

July 2011-June 2012

Residential					
	Average Rate[1]	**Gross Program Savings**	**Adjustment**	**Net Savings**	**Estimated Lost Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.004407	33,876,166	0.91	30,752,739	135,512
				30,752,739	135,512

Commercial & Industrial					
	Average Rate[1]	**Gross Program Savings**	**Adjustment**	**Net Savings**	**Estimated Lost Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004407	200,271	0.91	181,806	801
GS-1 Sec Demand	$0.004407	19,626,551	0.91	17,816,957	78,510
GS-1 Pri Non-Demand	$0.004286	0	0.91	0	-
GS-1 Pri Demand	$0.004286	200,271	0.91	181,806	779
GS-2 Substation	$0.004249	0	0.91	0	-
GS-2 Transmission	$0.004224	0	0.91	0	-
		Sub Total General Service:		**18,180,569**	80,091
		Total DGGS-related DSM Lost Revenues			**$ 215,603**

Note 1: Two sets of rates were used, each set was effective for 6 months of the 2011-12 tracker period

July 2012-June 2013

Residential					
	Rate[1]	**Gross Program Savings**	**Adjustment**	**Net Savings**	**Estimated Lost Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
Residential	$0.004795	66,828,942	0.91	60,667,227	290,899
				60,667,227	290,899

Commercial & Industrial					
	Rate[1]	**Gross Program Savings**	**Adjustment**	**Net Savings**	**Estimated Lost Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004795	490,202	0.91	445,005	2,134
GS-1 Sec Demand	$0.004795	48,039,810	0.91	43,610,477	209,112
GS-1 Pri Non-Demand	$0.004664	0	0.91	0	-
GS-1 Pri Demand	$0.004664	490,202	0.91	445,005	2,076
GS-2 Substation	$0.004624	0	0.91	0	-
GS-2 Transmission	$0.004596	0	0.91	0	-
		Sub Total General Service:		**44,500,487**	213,322
		Total DGGS-related DSM Lost Revenues			**$ 504,221**

Electric DSM Lost Revenues - Dave Gates Generating Station

(fixed cost portion of DGGS)

July 2013-June 2014						
		Reported				
Residential		**Gross**				**Estimated**
		Program			**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**		**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**		**(kwh)**	**($)**
Residential	$0.004795	100,634,774	0.91		91,356,117	438,053
					91,356,117	438,053
Commercial & Industrial		**Gross**				**Estimated**
		Program			**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**		**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**		**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004795	766,195	0.91		695,551	3,335
GS-1 Sec Demand	$0.004795	75,087,082	0.91		68,163,955	326,846
GS-1 Pri Non-Demand	$0.004664	0	0.91		0	-
GS-1 Pri Demand	$0.004664	766,195	0.91		695,551	3,244
GS-2 Substation	$0.004624	0	0.91		0	-
GS-2 Transmission	$0.004596	0	0.91		0	-
		Sub Total General Service:			**69,555,056**	333,425
		Total DGGS-related DSM Lost Revenues				**$ 771,478**

July 2014-June 2015						
		TARGET				
Residential		**Gross**				**Estimated**
		Program			**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**		**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**		**(kwh)**	**($)**
Residential	$0.004795	131,436,356	0.91		119,317,753	572,129
					119,317,753	572,129
Commercial & Industrial		**Gross**				**Estimated**
		Program			**Net**	**Lost**
	Rate[1]	**Savings**	**Adjustment**		**Savings**	**Revenue**
Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**		**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.004795	1,008,553	0.91		915,563	4,390
GS-1 Sec Demand	$0.004795	98,838,235	0.91		89,725,221	430,232
GS-1 Pri Non-Demand	$0.004664	0	0.91		0	-
GS-1 Pri Demand	$0.004664	1,008,553	0.91		915,563	4,270
GS-2 Substation	$0.004624	0	0.91		0	-
GS-2 Transmission	$0.004596	0	0.91		0	-
		Sub Total General Service:			**91,556,348**	438,893
		Total DGGS-related DSM Lost Revenues				**$ 1,011,021**

Electric DSM Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

4			**Tracker 2012-13**		**Tracker 2013-14**		**Tracker 2014-15**	
5	DSM Targets and Results:		**December 1, 2012 - June 30, 2013**		**Period July 2013 – June 2014**		**Period July 2013 – June 2014**	
6			**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
7		Annual (Avg. MW)	6.00	4.33	6.00	6.57	6.00	6.00
8		Cumulative (Avg. MW)	6.00	4.33	10.33	10.89	16.89	16.89
9								
10			Commercial online date for Spion Kop was December 1, 2012. Reported energy savings has been "de-rated" for the 5 months July-Nov. 2012 (153 days).					
11	Disaggregate Targets into Residential & Commercial/Industrial [1]							
12								
13			**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
14		% Residential	69.7%	53.6%	69.7%	56.7%	55.2%	55.2%
15		% Commercial & Industrial	30.3%	46.4%	30.3%	43.3%	44.8%	44.8%
16		ck. fig.	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
17								
18		Incremental Res. (Avg. MW)	4.18	2.32	4.18	3.72	3.31	3.31
19		Cumulative Res. (Avg. MW)	4.18	2.32	6.50	6.04	9.35	9.35
20		Incremental C/I (Avg. MW)	1.82	2.01	1.82	2.84	2.69	2.69
21		Cumulative C/I (Avg. MW)	1.82	2.01	3.83	4.85	7.54	7.54
22								
23		1. Residential/commercial split based on DSM Program results						
24								
25								
26	Cumulative Annual Energy Savings[2]		**Target**	**Reported**	**Target**	**Reported**	**Target**	**Reported**
27		Residential (MWH)	18,322	10,163	38,649	36,634	67,436	67,436
28		C/I (MWH)	7,958	8,799	25,556	30,048	54,284	54,284
29		Total Savings (MWH)	26,280	18,962	64,205	66,682	121,720	121,720
30		Total Savings (Avg. MW)	3.0	2.2	7.3	7.6	13.9	13.9
31								
32		2. "Half-year convention":						
33		Savings resulting from the "Increment" in any year is reduced by 50% in that year as associated projects						
34		are completed and start generating savings at different times throughout the first year. This assumption contemplates that						
35		associated projects start generating savings half way through the year on average. In the second year and						
36		beyond, projects completed in the first year generate savings for the entire year so the "Increment" is credited at 100%						
37		for the second year and each successive year.						
38								
39		Disaggregate C&I Savings by service level (tariff)						
40								
41		C&I Savings is broken out as:						
42		GS-1 Secondary, non demand	1%	1%	1%	1%	1%	1%
43		GS-1 Secondary, demand	98%	98%	98%	98%	98%	98%
44		GS-1 Primary, non demand	0%	0%	0%	0%	0%	0%
45		GS-1 Primary, demand	1%	1%	1%	1%	1%	1%
46		Total C&I	100%	100%	100%	100%	100%	100%

Electric DSM Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

Spion Kop Rates					
Docket D2012.7.75		**December 1, 2012 - June 30, 2013**		**Period July 2013 – June 2014**	**Period July 2014 – June 2015**
Residential		0.001047		$0.001253	$0.001458
GS-1 Sec Non-Demand		0.001048		$0.001254	$0.001459
GS-1 Sec Demand		0.001048		$0.001254	$0.001459
GS-1 Pri Non-Demand		0.001020		$0.001220	$0.001420
GS-1 Pri Demand		0.001020		$0.001220	$0.001420
GS-2 Substation		0.001011		$0.001209	$0.001407
GS-2 Transmission		0.001005		$0.001202	$0.001399
ck. fig. (average of rate string to observe year-to-year change)		$ 0.00102843		$ 0.00123007	$ 0.00143171

December 1, 2012 - June 30, 2013

Residential		**Reported Gross Program Savings**		**Net Savings**	**Estimated Lost Revenue**
Bill Line Item	**Rate ($ per kwh)**	**(kwh)**	**Adjustment Factor**	**(kwh)**	**($)**
Residential	$0.001047	10,163,382	0.91	9,226,305	$ 9,660
				9,226,305	$ 9,660

Commercial & Industrial		**Reported Gross Program Savings**		**Net Savings**	**Estimated Lost Revenue**
Bill Line Item	**Rate ($ per kwh)**	**(kwh)**	**Adjustment Factor**	**(kwh)**	**($)**
GS-1 Sec Non-Demand	$0.001048	87,991	0.91	79,878	$ 84
GS-1 Sec Demand	$0.001048	8,623,099	0.91	7,828,038	$ 8,204
GS-1 Pri Non-Demand	$0.001020	0	0.91	0	$ -
GS-1 Pri Demand	$0.001020	87,991	0.91	79,878	$ 81
GS-2 Substation	$0.001011	0	0.91	0	$ -
GS-2 Transmission	$0.001005	0	0.91	0	$ -
		Sub Total General Service:		**7,987,794**	$ 8,369
		Total Spion Kop-related DSM Lost Revenues			**$ 18,029**

Electric DSM Lost Revenues - Spion Kop

(fixed cost portion of Spion Kop)

	A	B	C	D	E	F	G	H	I
85		**July 2013-June 2014**							
86									
87				**Reported**					
88		**Residential**		**Gross**			**Estimated**		
89			**Average**	**Program**		**Net**	**Lost**		
90			**Rate**	**Savings**	**Adjustment**	**Savings**	**Revenue**		
91		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**		
92		Residential	$0.001253	36,634,320	0.91	33,256,589	41,654		
93						**33,256,589**	41,654		
94				**Reported**					
95		**Commercial & Industrial**		**Gross**			**Estimated**		
96			**Average**	**Program**		**Net**	**Lost**		
97			**Rate**	**Savings**	**Adjustment**	**Savings**	**Revenue**		
98		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**		
99		GS-1 Sec Non-Demand	$0.001254	300,481	0.91	272,776	342		
100		GS-1 Sec Demand	$0.001254	29,447,097	0.91	26,732,036	33,509		
101		GS-1 Pri Non-Demand	$0.001220	0	0.91	0	-		
102		GS-1 Pri Demand	$0.001220	300,481	0.91	272,776	333		
103									
104		GS-2 Substation	$0.001209	0	0.91	0	-		
105		GS-2 Transmission	$0.001202	0	0.91	0	-		
106				**Sub Total General Service:**		**27,277,588**	34,183		
107									
108				**Total Spion Kop-related DSM Lost Revenues**			**$ 75,837**		
109									
110									
111		**July 2014-June 2015**							
112									
113				**TARGET**					
114		**Residential**		**Gross**			**Estimated**		
115			**Average**	**Program**		**Net**	**Lost**		
116			**Rate**	**Savings**	**Adjustment**	**Savings**	**Revenue**		
117		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**		
118		Residential	$0.001458	67,435,902	0.91	61,218,224	89,256		
119						**61,218,224**	89,256		
120				**TARGET**					
121		**Commercial & Industrial**		**Gross**			**Estimated**		
122			**Average**	**Program**		**Net**	**Lost**		
123			**Rate**	**Savings**	**Adjustment**	**Savings**	**Revenue**		
124		Bill Line Item	**($ per kwh)**	**(kwh)**	**Factor**	**(kwh)**	**($)**		
125		GS-1 Sec Non-Demand	$0.001459	542,839	0.91	492,789	719		
126		GS-1 Sec Demand	$0.001459	53,198,250	0.91	48,293,302	70,460		
127		GS-1 Pri Non-Demand	$0.001420	-	0.91	0	-		
128		GS-1 Pri Demand	$0.001420	542,839	0.91	492,789	700		
129									
130		GS-2 Substation	$0.001407	0	0.91	0	-		
131		GS-2 Transmission	$0.001399	0	0.91	0	-		
132				**Sub Total General Service:**		**49,278,880**	71,879		
133									
134				**Total Spion Kop-related DSM Lost Revenues**			**$ 161,135**		
135									