NorthWestern Energy
Delivering a Bright Future

August 28, 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
PSC Set 7 Data Requests (050-075)

Dear Ms. Whitney:

Enclosed for filing is a copy of NorthWestern Energy's responses to PSC Set 7 Data Requests in Docket Nos. D2013.5.33/D2014.5.46. It has been hand delivered to the Montana Public Service Commission and the Montana Consumer Counsel this date. It has been mailed to the service list in this docket, e-filed on the PSC website, and emailed to counsel of record.

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 responses to PSC Set 7 Data Requests (050-075) 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: August 28, 2015

Tracy Lowney Killoy

Tracy Lowney Killoy
Administrative Assistant
Regulatory Affairs

Docket Nos.
D2013.5.33/D2014.5.46
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PSC-050

Regarding: Colstrip Outages
Witness: Barnes

a. Please explain whether either of Colstrip Units 3 or 4 have experienced a forced outage since NWE filed direct testimony in this matter.

b. If there has been a forced outage as identified in (a), please explain the circumstances, cause, and the length of the outage.

RESPONSE:

a. Yes.

b. See Attachment.

Unit	Hours	Event Desc	Date Offline	Date Online	Event Type
3	72.93	Boiler Reheat Tube leak in vicinity of 2L retract	2/13/2014 22:17	2/16/2014 23:13	U1
3	62.58	Boiler tube leak (waterwall) at the top of the south coutant slope.	3/22/2014 18:10	3/25/2014 8:45	U1
3	1.63	Unit trip - low steam drum level - feedwater controls	3/25/2014 8:54	3/25/2014 10:32	U1
3	1.73	Unit trip - high steam drum level - improper direction	3/25/2014 10:38	3/25/2014 12:22	U1
3	1.97	Unit trip - Operator error - OSP/ESP controls	3/25/2014 13:01	3/25/2014 14:59	U1
3	9.4	auxiliary transformer (13.8 kv x tap changer)- fails to move - oil leak/refill.	4/11/2014 13:21	4/11/2014 22:45	U2
3	9.08	ATR trip - unknown fault on NWE's 500 KV transmission line	4/15/2014 6:45	4/15/2014 15:50	U1
3	2.45	Unit trip during startup due to a voltage relay problem - Gross MW/Net MW indication	4/15/2014 15:52	4/15/2014 18:19	U1
3	1.15	Voltage Regulator - (PSS and AVR will not in auto) exceeded voltage range limits	4/15/2014 20:53	4/15/2014 22:02	U1
3	0.37	Generator testing - zero power facotr load rejection test	7/5/2014 14:58	7/5/2014 15:20	U2
3	1.37	3A BFPT overspeed trip - low steam drum level caused unit trip during runback	7/7/2014 11:26	7/7/2014 12:48	U1
3	4.67	Unit trip - low pressure on 3B aux turbine lube oil supply (manual trip initiated	7/7/2014 15:06	7/7/2014 19:46	U1
3	4.22	500-4 and 500-5 opened in the switch yard causing Unit trip followed by relay coordination issues	7/7/2014 20:05	7/8/2014 0:18	U1
3	22.42	3B Circulating Water Pump trip - unit trip during the controls run back on the Unit	8/23/2014 0:47	8/23/2014 23:12	U1
3	2.33	Trip on Boiler Circ. Pump Delta P - 3B Auxiliary Turbine Tripped off due to faulty vacuum switch - control issue on run back	9/18/2014 3:38	9/18/2014 5:58	U1
3	4.98	Trip on low drum level - 3B Auxiliary Turbine EHC Fluid Leak	9/18/2014 17:37	9/18/2014 22:36	U1
3	2.18	Unit trip during weekly preventative mainteance tests	9/19/2014 22:46	9/20/2014 0:57	U1
3	3.78	3B Aux Turbine EHC leak caused loss of system pressure resulting in Unit trip	9/24/2014 3:26	9/24/2014 7:13	U1
3	2.37	Unit trip following loss of 3B aux. turbine - trip on low steam drum level	9/25/2014 1:38	9/25/2014 4:00	U1
3	3.17	Acceleration Trend Relay trip due to disturbance on the transmission system	10/18/2014 4:23	10/18/2014 7:33	U1
3	1.73	Turbine trip (BMS) due to speed sensor issues	10/26/2014 22:41	10/27/2014 0:25	U1
3	1.58	Turbine trip (BMS) due to speed sensor issues	10/27/2014 0:27	10/27/2014 2:02	U1

3	11.98	Turbine trip (BMS) due to speed sensor issues	10/27/2014 2:16	10/27/2014 14:15	U1
3	70.97	Boiler Tube Leaks - Water wall and near 11L Retract	11/6/2014 23:59	11/9/2014 22:57	U3
3	31.07	3B Boiler Water Circulating Pump - Purge line leak	12/26/2014 23:23	12/28/2014 6:27	U2
3	3.03	Unit trip due to fault on turbine DCS I/O cards - poor connection - repositioned and secured cards	3/3/2015 15:24	3/3/2015 18:26	U1
3	30.72	Unit outage due to leak on 3B boiler circ pump purge line	3/17/2015 12:19	3/18/2015 19:02	U2
3	29.43	Unit trip due to Auxiliary transformer sudden pressure relay	3/25/2015 22:16	3/27/2015 3:42	U1
3	61.3	Electrical fault for 3C coal pulverizer tripped 3A3 electrical bus	5/5/2015 20:01	5/8/2015 9:19	U1
3	75.8	Boiler tube leak - finishing superheat	5/9/2015 1:02	5/12/2015 4:50	U1
3	48.07	Unit tripped due to boiler tube leak on the nose arch	7/15/2015 5:20	7/17/2015 5:24	U1
4	21.35	NWE rolled phase wires on current input on the ATR - Caused Gross MWs to report incorrectly	1/22/2014 8:11	1/23/2014 5:32	U1
4	4.87	Primary Generator Protection CT Circuit fault causing trip - inadvertant fault while testing primary generator relay	4/8/2014 16:34	4/8/2014 21:26	U1
4	6.25	ATR trip - Unknown fault on NWE's 500 kv transmission line	4/15/2014 6:45	4/15/2014 13:00	U1
4	1.83	Unit trip during startup while realigning FW flow - high steam drum level	4/15/2014 13:26	4/15/2014 15:16	U1
4	110.2	Boiler tube Leak - corner #1 at 3&1/2 elevation	4/23/2014 0:33	4/27/2014 14:45	U3
4	1.98	Boiler circ pump delta p - trip on boiler circ pp delta psi	7/3/2014 14:38	7/3/2014 16:37	U1
4	2.52	4B Auxiliary turbine trip - thrust bearing	7/23/2014 15:40	7/23/2014 18:11	U1
4	63.12	Boiler reheat tube leak - offline for repair	7/31/2014 9:10	8/3/2014 0:17	U1
4	16.52	Unit 4 tripped due to loss of startup transformer associated with Unit 3 trip	8/23/2014 0:49	8/23/2014 17:20	U1
4	72.42	Boiler tube leak on the division wall	1/31/2015 13:35	2/3/2015 14:00	U1
4	4.3	4-5A Venturi pump motor tripped on high amps/4-5-B on clearance - no permissive to start sisterID fan - low air flow trip	2/7/2015 9:23	2/7/2015 13:41	U1
4	1.67	Unit trip - low stream drum level - human performance error	4/26/2015 3:57	4/26/2015 5:37	U1
4	70.98	Unit 4 turbine lube oil cooler leak	5/1/2015 3:50	5/4/2015 2:49	U3
4	2.37	Unit trip - flame failure - human performance event	5/4/2015 8:21	5/4/2015 10:43	U1

U1 - Unplanned outage that requires the immediate removal from service

U2 - Unplanned outage that is postponed but necessary to be removed from service within 6 hours

U3 - Unplanned outage that is postponed but necessary to be removed from service by end of weekend

NorthWestern Energy
Docket D2013.5.33/D2014.5.46
Electric Tracker

Montana Public Service Commission
Set 7 (050-075)

Data Requests received August 14, 2015

PSC-051

Regarding: CU4 Acquisition
Witness: Corcoran and Barnes

Please identify any place in NWE's application or representations that it made in D2008.6.69 where the company identified that the inter-lamination insulation on the 1985 generator was no longer considered state-of-the-art.

RESPONSE:

No such representations were made, as the filing in PSC Docket No. D2008.6.69 pre-dated, by almost five years, the 2013 forced outage at Colstrip Unit 4 and the subsequent root cause analysis conducted by Mr. Halpern and Mr. Ward.

PSC-052

Regarding: Cost recovery of outage costs
Witness: NorthWestern Legal Department

For each of the other Colstrip Unit 4 regulated-utility co-owners, please explain whether or not their customers have had to bear the entirety of the replacement power costs resulting from the plant outage.

RESPONSE:

NorthWestern is not aware if every co-owner of CU4 that is a regulated utility was able to recover its respective replacement power costs from its customers. Through research, NorthWestern was able to determine that Avista Corporation was permitted to recover all of its Idaho jurisdictional replacement power costs from its customers in Idaho, but was only able to recover some of its replacement power costs in Washington due to a previously approved settlement agreement.

Portland General did not ask for specific recovery of the replacement power costs it incurred due to the 2013 outage. Its total power costs for the year fell within a previously established deadband so there would have been no collection permitted.

In Utah, it appears that PacifiCorp was able to recover the replacement power costs it incurred due to the outage, but was denied recovery in Washington because PacifiCorp had failed to establish a Purchase Cost Adjustment Mechanism as previously ordered to do by the Washington Utilities and Transportation Commission.

NorthWestern has no information on whether Puget Sound asked for and was permitted to recover its costs in Washington. Nor does NorthWestern have any information regarding PacifiCorp's actions regarding this matter in its Oregon, California, Wyoming or Idaho jurisdictions.

PSC-053

Regarding: Judgment Proceeds
Witness: Corcoran

You argue that including the replacement power costs in rates in these proceedings would not provide NWE with an opportunity for a double recovery in the event of the recovery of proceeds from successful litigation (6:21-7:7).

a. In light of your contention, please identify where, in MCA 69-8-103(8), judgment proceeds could be considered an "electricity supply cost."

b. If NWE stands to pass through in their entirety the proceeds of successful, but time-consuming and costly litigation, please explain what financial incentive NWE itself has to embark on such litigation, regardless of its merits.

RESPONSE:

a. Mr. Corcoran did not testify that judgment proceeds were an electricity supply cost. He testified that the ratemaking process was fully capable of capturing any such judgment and crediting it to the ratepayers. He indicated the Commission could and should address crediting in its final order in this docket, should it deem it necessary.

b. NorthWestern will not pursue non-meritorious litigation, for any reason. The decision to pursue any legal claim must necessarily be based upon consideration of the expense of litigation, and the likelihood of an actual monetary recovery. NorthWestern would use the same decision criterion regarding litigation to secure financial benefits on behalf of customers.

PSC-054

Regarding: LRAM Policy's Influence on DSM Acquisition
Witness: Corcoran

You say that "NorthWestern has been **acting in reliance** upon Order No. 6674e [which established the LRAM program] ever since it was issued." [emphasis added] (11:2-3). Are you suggesting that the absence of an LRAM would change NWE's acquisition activities relative to DSM and, if so, how would they change?

RESPONSE:

I would be speculating to opine on what, if anything, would change if there were no LRAM. NorthWestern has not been faced with that situation since the LRAM was established shortly after the Legislature imposed the DSM obligation. As I stated in response to questions during the LRAM hearing, NorthWestern has an obligation to acquire DSM. I indicated that NorthWestern will continue to comply with the law, continue to conduct evaluations of DSM, and continue to watch the DSM programs very closely. However, I would note that the existence of the LRAM affects many decisions, not just acquisition activities. Complying with DSM mandates without LRAM would be painful. Without the LRAM, NorthWestern may have advocated different positions in the 2007 and 2009 rate cases; it may have taken different positions before the Legislature; and it may have changed its approach to DSM, to the extent that it could while still complying with the statutory requirements. The important point is that the LRAM is in effect and NorthWestern acted accordingly, relying on its potential to be made whole for DSM through the LRAM.

PSC-055

Regarding: Documentation
Witness: Goetz

a. Provide the "document indicating a declination by the insurer to pursue litigation on potential subrogation interests" (6:10-11)

b. Provide all the documentation you relied on to make your statement that you "have reviewed information on general industry practice regarding limitation of consequential damages in contracts such as the PPL/Siemens contract involved here." (6:11-14).

RESPONSE:

a. Please see the response to Data Request MEIC-071a.

b. The information upon which Mr. Goetz relied was provided in a telephone discussion with Mr. Fred Lyon. The discussion is referenced at page 6, lines 16-19 of Mr. Goetz's testimony.

NorthWestern Energy
Docket D2013.5.33/D2014.5.46
Electric Tracker

Montana Public Service Commission
Set 7 (050-075)

Data Requests received August 14, 2015

PSC-056

Regarding: Lack of Privity between NWE and Siemens
Witness: Goetz

a. Is it common for a multi-owner electric generating unit to contract through a single plant operator for maintenance, with no privity among other owners?

b. Do you believe it would be wise for NWE, in future relationships, to seek to establish privity by making itself a party to maintenance contracts?

c. Would it be appropriate for the Commission to disallow costs from recovery for NWE if PPL, acting as the representative or agent of the co-owner NWE, had acted negligently or imprudently?

RESPONSE:

a. Mr. Goetz was not engaged to make such a determination and has no opinion, nor basis for an opinion, on the subject.

b. Mr. Goetz was not engaged to make such a determination and has no opinion, nor basis for an opinion, on the subject.

c. Mr. Goetz was not engaged to make such a determination and has no opinion, nor basis for an opinion, on the subject.

PSC-057

Regarding: Documentation
Witness: Lyon

a. Provide the full citation to the textbook referred to on 6:17-19.

b. When was the article provided as Exhibit__FL-2 published, and how has the risk tolerance of counterparties in the relationships you describe changed since then?

c. Are all the exhibits FL-3 to FL-8 agreements for new construction projects, or are they agreements for maintenance similar to the Siemens-PPL arrangement?

RESPONSE:

a. After peer review, Penwell elected not to publish the proposed book. Consequently, there is no citation.

b. The article was published in 2001. With respect to the issue of consequential damages, the risk tolerance of the parties has not changed since that time. Overall risk tolerance will vary depending on how robust the market is and whether utilities or vendors are more able to leverage terms. But with respect to consequential damages, it makes no difference; the vendors are unwilling to accept such risk.

c. The referenced agreements are for new construction projects. However, the risk considerations and profiles are the same for a maintenance or repair contract with vendors unwilling to assume the risk of consequential damages in the event that an outage results.

PSC-058

Regarding: Outage Insurance
Witness: Lyon

a. Describe how you are aware of the fact that IPPs "are more likely to purchase [outage] insurance" (14:20-21).

b. Please provide the examples you are familiar with of IPPs who have purchased such insurance.

c. Please explain why a thinly capitalized firm would be more likely to purchase outage insurance.

d. Please explain why regulated utilities could not pass along the cost of outage insurance in their rates (14:23-24).

RESPONSE:

a. See the response to Data Request MEIC-087a.

b. See the response to Data Request MEIC-087a.

c. A thinly capitalized company would not have the balance sheet strength to offset the cost of replacement power which could lead to a breach of its power purchase agreement and loan covenants. Consequently, this risk could be minimized by an insurance product.

d. I did not testify that regulated utilities could not pass along the cost of outage insurance in their rates. I testified that IPPs could more easily capture these costs in their rates (in the pro forma of the PPA). The IPPs are not subject to the regulatory considerations of an IOU and can calculate its rate independent of important prudency considerations that govern the rate recovery of a regulated utility.

PSC-059

Regarding: Interlaminar Insulation
Witness: Halpern

You note in several places that in 1985 the interlaminar insulation, Alkophos, was "state-of-the-art" (8:22-23; 10:17), caveating this description with "at the time this machine was built" (9:18).

a. Please describe what was state-of-the-art practice in interlaminar insulation, circa 2008 and 2009.

b. Please describe what state-of-the-art practice is today.

c. Provide any technical articles or publications you are aware of that describe the state-of-the-art practice in (a) and (b).

RESPONSE:

a. In the context of my reply I use "State of the art insulation" as the commonly used electrical insulation which was used on all Westinghouse generators at the time, and which provided the ability to electrically insulate one lamination from another. These laminations are 0.018 inches thick and are insulated with a coating of Alkophos™ (used since the late 1960s), an inorganic, aluminum phosphate compound which was used on all Westinghouse generators manufactured at that time, and which operated successfully for many years on hundreds of generators.

   It is my understanding that Siemens uses a different coating, or insulation, in its generators. I have not worked on generators where I had to know the composition of the new coating, so I cannot provide its specifications, and I do not know what date Siemens transitioned to the new insulation.

b. See the response to subpart a above.

c. See the response to subpart a above. I am not aware of any documents responsive to this request.

PSC-060

Regarding: Interlaminar Insulation Tests
Witness: Halpern

a. Explain why prior tests would have found the insulation to be "acceptable" (10:20) but by the time of the outage there was "inadequate interlaminar insulation" (11:10).

b. When was the last time the interlaminar insulation could have been tested?

c. Please provide the years when the "core was tested several times during prior outages to determine if the insulation was acceptable and it ultimately passed those tests" (10:19-21), indicating whether it failed a test initially or at any time before it ultimately passed.

d. Please provide the written results of the tests described in (c).

e. Did the tests described in (c) test for the conditions described at 9:3-6? Explain.

RESPONSE:

a. The interlaminar insulation was more than likely inadequate since the generator was manufactured. Generally, prior El Cid test results found that the laminations were at acceptable levels because there were no signs of shorting. However, there were some instances where the levels were not acceptable. When the test results showed unacceptable levels within the laminations, those areas were repaired and retested.

b. The laminations could have been El Cid tested after rotor insertion and prior to the installation of the air gap baffle. However, in my experience as a generator expert, it is not industry practice to do testing at that point in time.

c. The statement in my testimony was based on verbal conversations. I was advised that this type of testing has occurred several times in the past and has ultimately passed. In some instances some work needed to be done but when retested the unit passed testing with acceptable levels.

d. See the response to subpart c above.

e. See the response to subpart c above.

PSC-061

Regarding: Definition of Terms
Witness: Halpern

a. Please describe what an "air gap baffle" is, and how it is "insert[ed]" (11:11) into the generator.

b. Please describe what a "skid pan" is and how it could be "damage[d]" (11:12).

RESPONSE:

a. The air gap baffle, or air gap barrier, consists of circumferential rings on the stator core's inner diameter, which are in close proximity to the zone rings on the rotating field. They serve to segregate different pressure zones in the stator for ventilation purposes.

Air gap baffles are installed after the rotor is installed, by sliding them into position axially on a string of wedges (different from the slot wedges), which are linked together with a rod, and then tensioned in position.

b. A skid pan is a metallic pan which is installed on the stator core inner diameter to allow the rotor to be slid into the stator on a sliding shoe. The skid pan was not damaged. It can damage the core when installed if it has contact with the laminations.

PSC-062

Regarding: Documentation
Witness: Halpern

a. Please provide Item No. 28 in Exhibit__(RAH-3), "Lessons Learned from Generator Failures". If it is a PowerPoint or other electronic file other than a Word document, please provide both a hard copy and an active digital form.

b. Please provide Items No. 26 and 27 in Exhibit__(RAH-3). If either file is a PowerPoint or other electronic file other than a Word document, please provide both a hard copy and an active digital form.

RESPONSE:

a. See Attachment and see the electronic version in the "PSC-062" folder on the attached CD.

b. See Attachments 1 and 2 see the electronic versions in the "PSC-062" folder on the attached CD.

LESSONS LEARNED FROM GENERATOR FAILURES

Ron Halpern
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EPRI European Generator Workshop
April 21, 2013
Madrid, Spain

Generator Failures Lessons Learned

GCS

1. NOISE
2. CONNECTING THE DOTS
3. CORE FAILURE

Noise Investigation

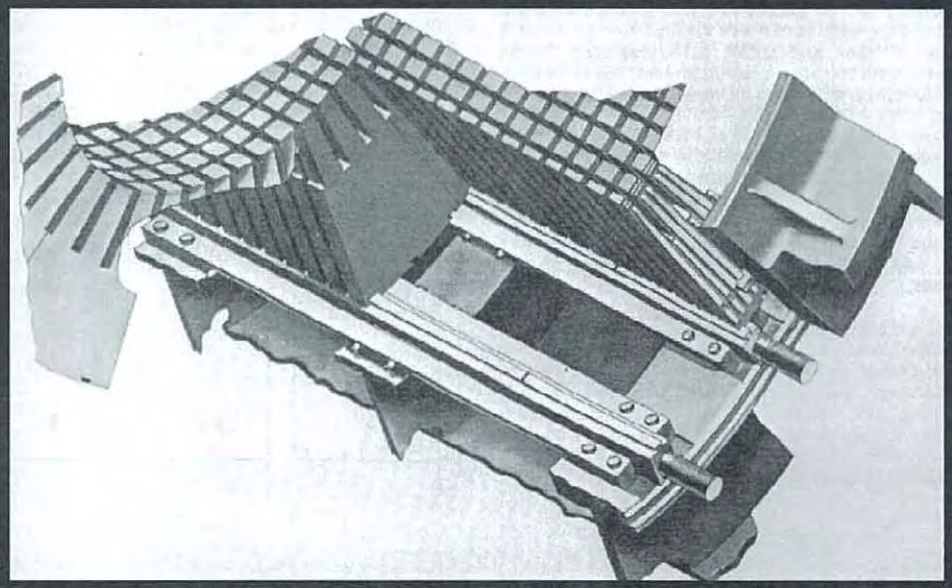
- Visual Inspection
  - ⇨ Measure Clearances
- Operation/Load dependent
- Ventilation/Gas Flow
- Recording
- Noise survey/ position
- Harmonic Noise Index

Generator Failures Lessons Learned

GCS

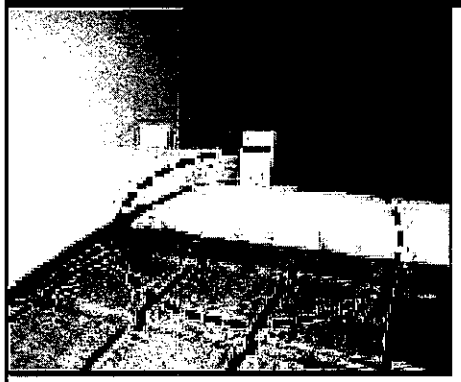
Noise Causes

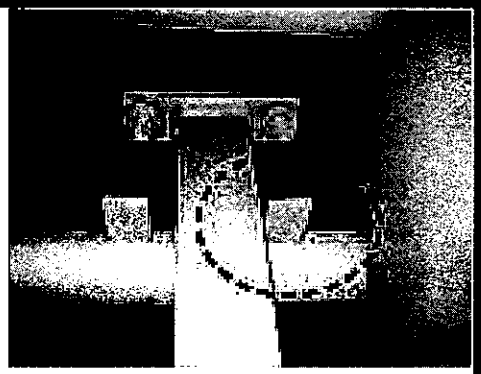
- "Transformer hum" aka 60 cycle hum
- Loose hardware: Core (key bars), cooler baffles, end winding hardware, pipe supports
- Foreign objects

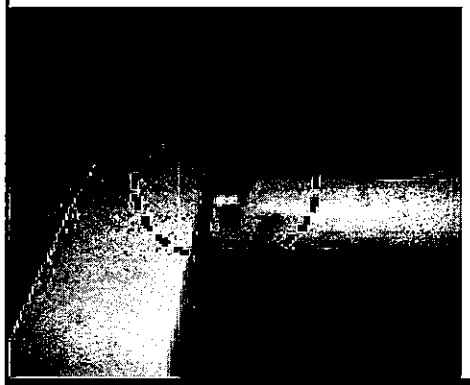


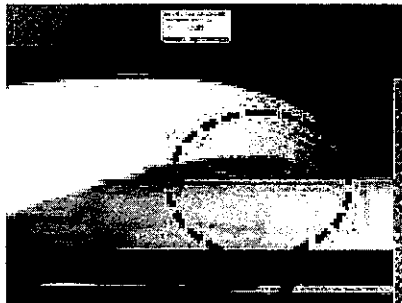
Generator Failures Lessons Learned

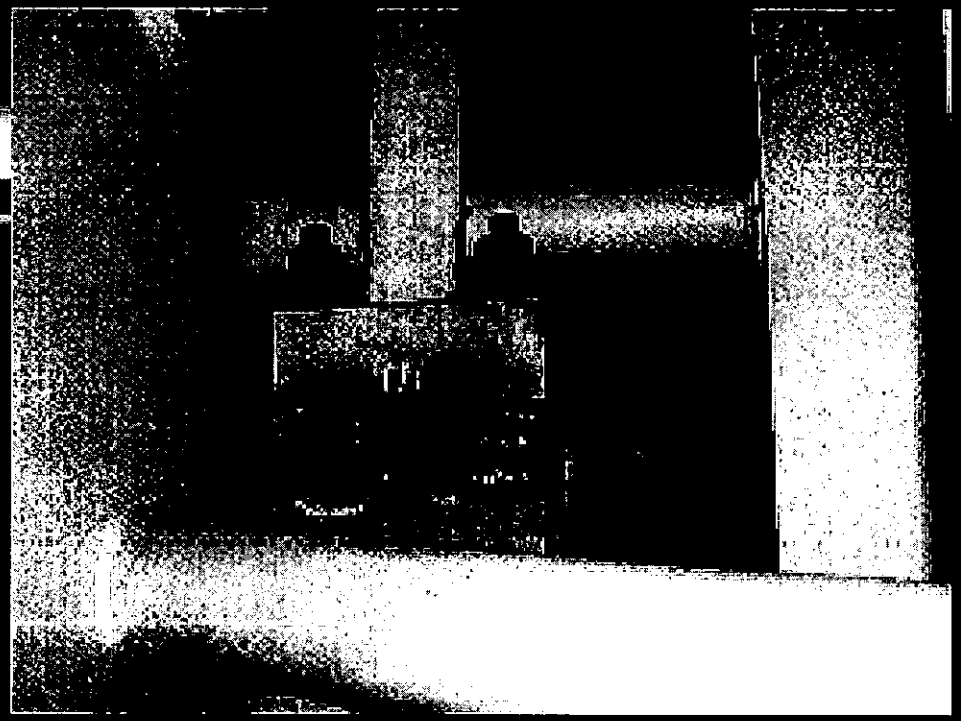
GCS





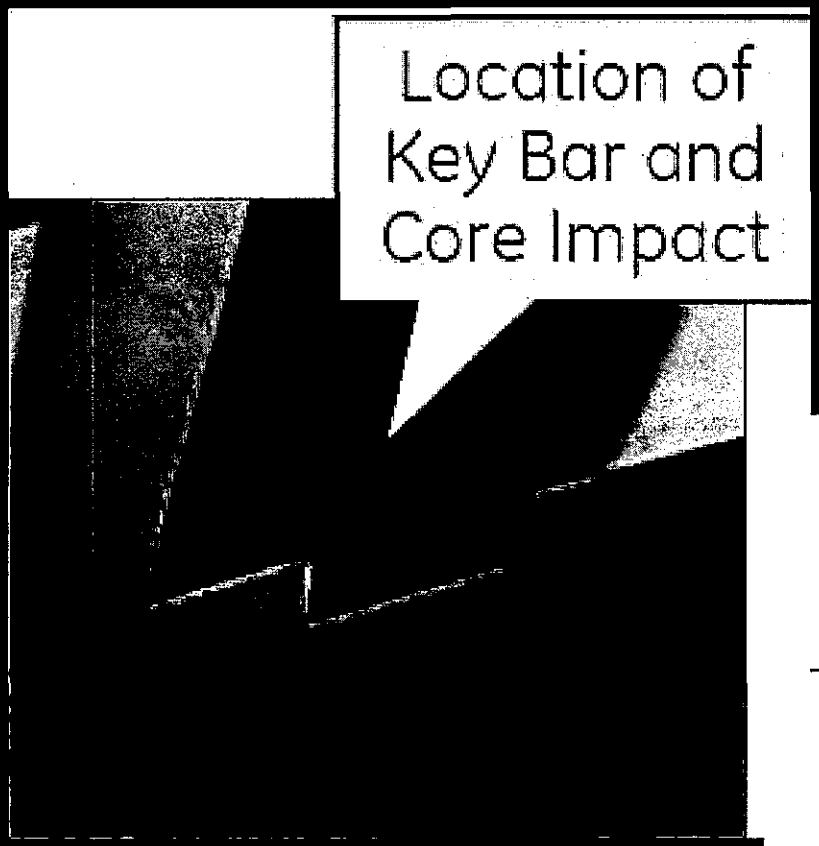


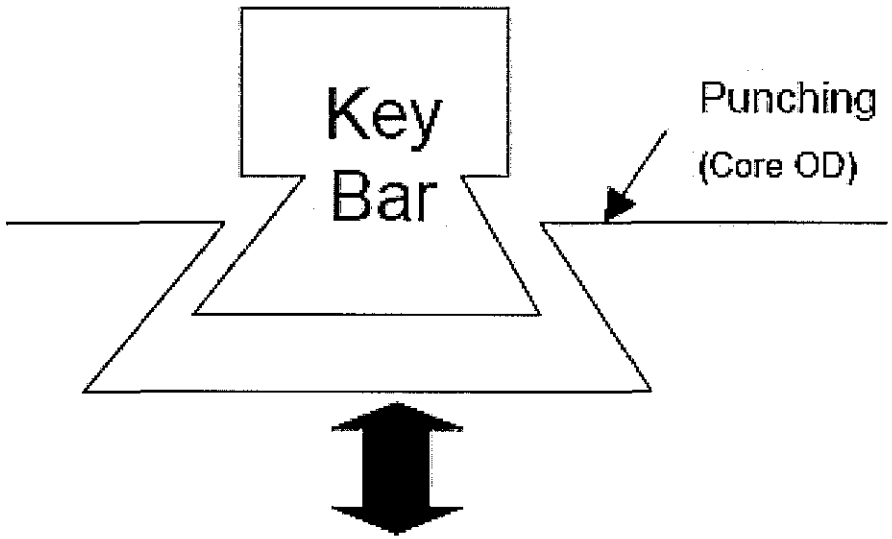




Generator Failures Lessons Learned

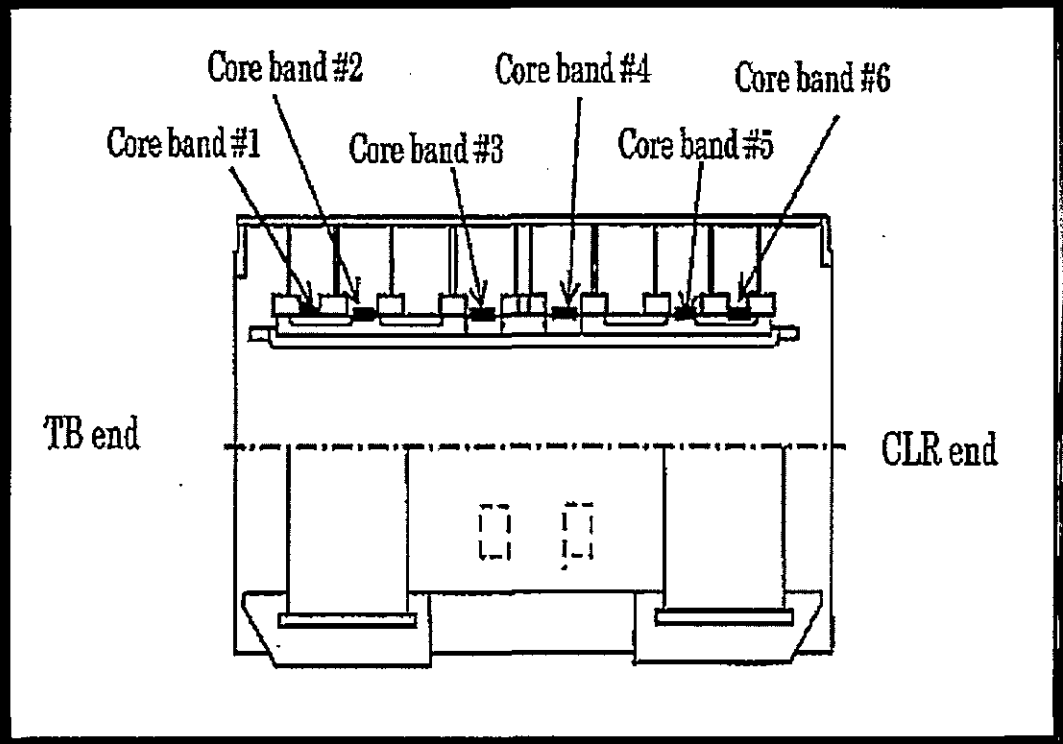
GCS

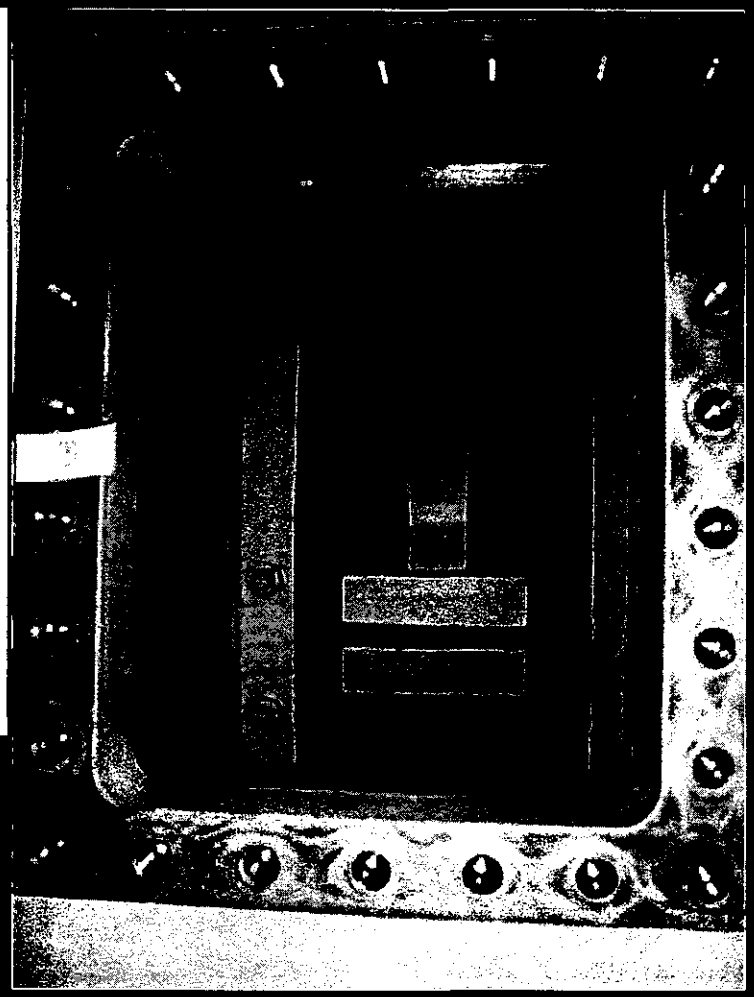




Core motion 2 per rev under electromagnetic force

Generator Failures Lessons Learned GCS





During the investigation the OEM did a very detailed meticulous job measuring all clearances to find cause

Lessons Learned

Do not ignore possibility of two conditions occurring at the same time

If you hear something say something

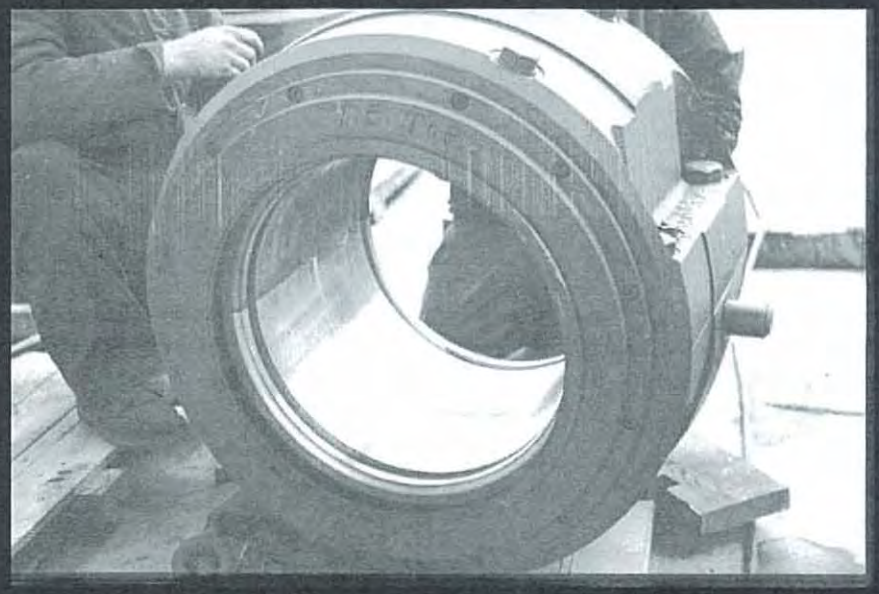
Generator Failures Lessons Learned

GCS

Connecting the Dots

Shaft Voltage Monitoring

- Damage to bearings, hydrogen seal rings
- Shaft grounding: brush maintenance (carbon, copper braid, sohre)
- Shaft voltage to ground at brush < 5 – 6 volts zero to peak



Generator Failures Lessons Learned GCS
Gas Monitoring System

What is the operator instructed to do after the alarm is confirmed ?

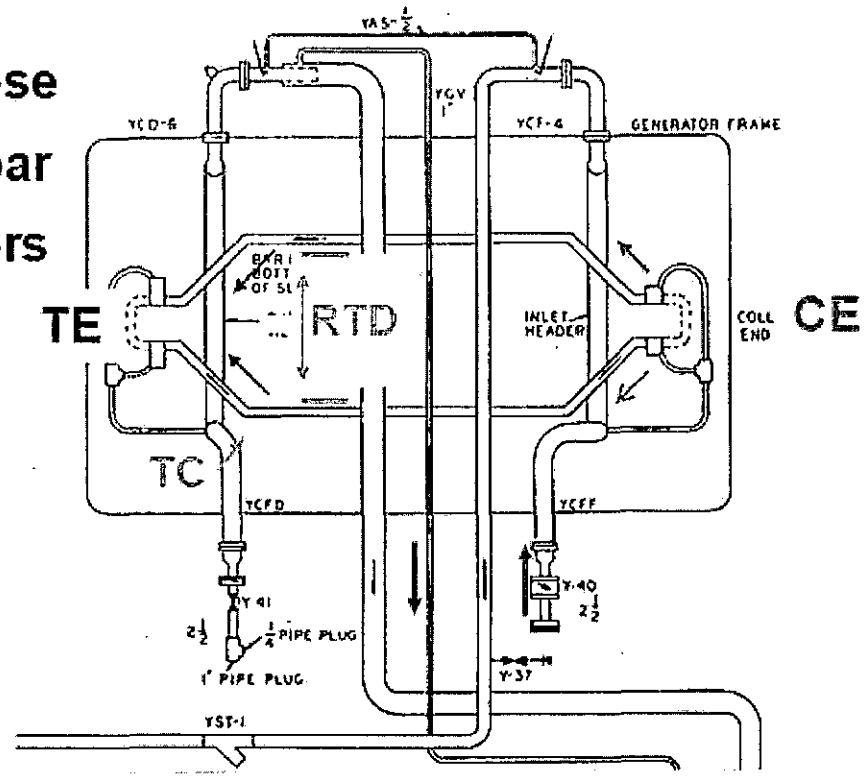
1. Contact system engineer
2. Reduce load until alarm clears, or it is determined that it is false. If the alarm remains after reducing load to minimum, the machine is removed from service
3. Activate filter, if the current indicated on the chart recorder returns to normal-trip generator, or if the core monitor is still in the alarm mode, activate the P collector. Reduce load; if alarm clears while the load is being removed, collect a second sample for comparison to the alarm sample.
4. Trip
5. Take sample and send it to OEM
6. Check flow, check filter, initiate sample, verify stator temperatures. Decide to reduce power or shutdown
7. Take P sample, then reduce load while recording operating data. NOTIFY the Shift Manager. If ordered by the Shift Manager,

Generator Failures Lessons Learned

GCS

Single-Pass System (Temperature Monitoring)

- Thermocouples (TC)
  - One for each TE discharge hose
  - Water from 1 top & 1 bottom bar
- Resistance Temperature Detectors
  - Located in each slot at TE between top & bottom bar

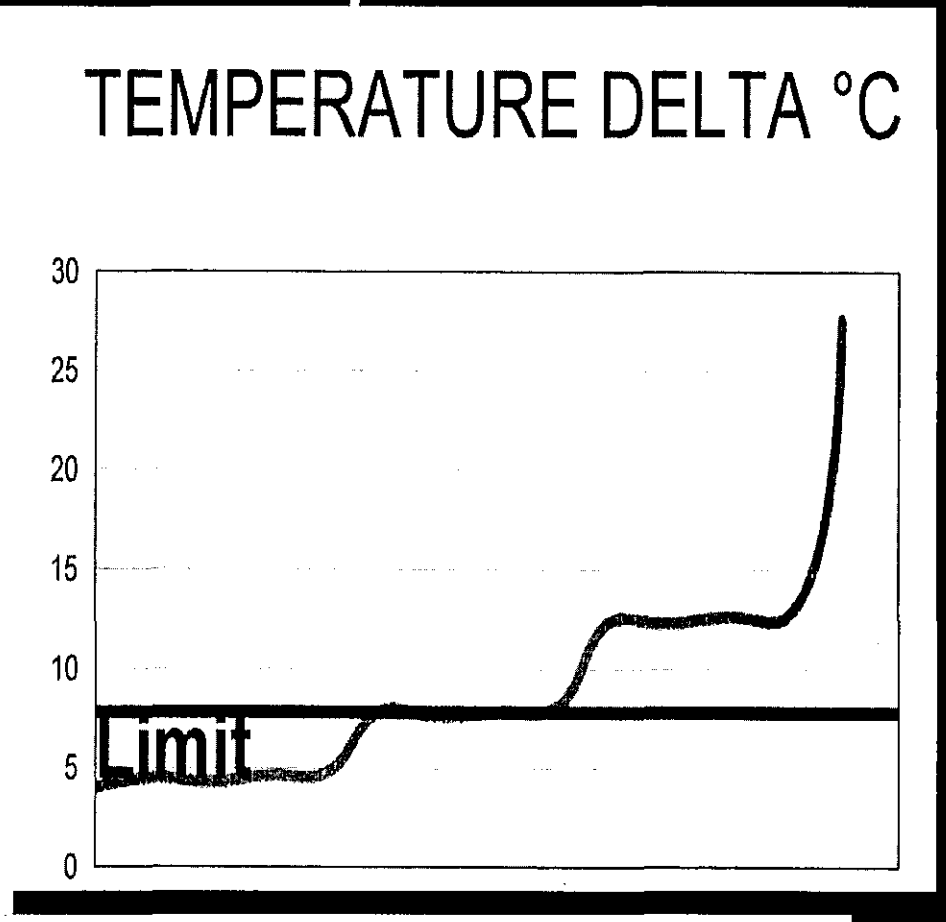


Generator Water Circuit Schematic

Generator Failures Lessons Learned GCS

Gradually Increasing Outlet Temperatures

- Reduce load
- Check RTD's
- Water Chemistry-restrictions
  - Makeup water
  - Conductivity
  - Oxygen content (plugging of vent)
  - Filters/Resin Bed

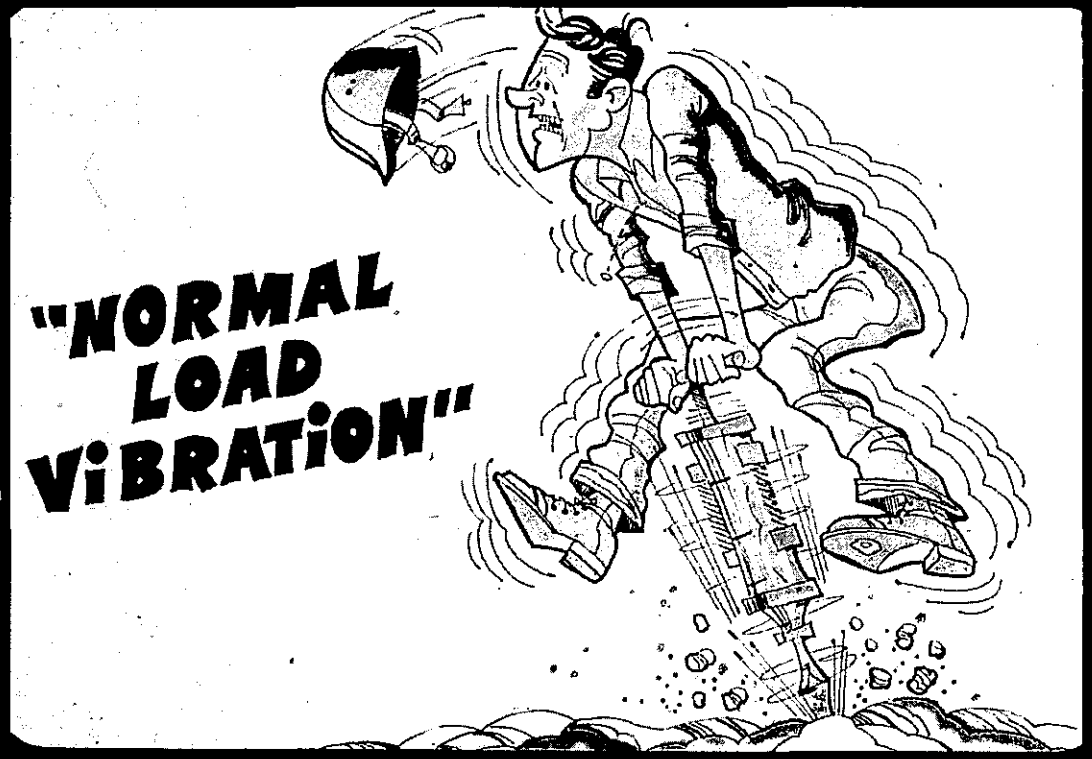


Always find cause of alarm before increasing load

Generator Failures Lessons Learned

GCS

- Small Increase in generator bearing vibration
- Small decrease in oil pressure



Generator Failures Lessons Learned

GCS

Connecting the Dots

- Shaft Voltage Change
- Core Monitor Spike
- Increased Rise in TC temp
- Slight Increase in bearing vibration
- Slight decrease oil pressure

Generator Failures Lessons Learned

GCS

Phase Connection Failure

Lessons Learned

- **Make sure to Connect the Dots**
- **Consider all anomalies**
- **Escalate**

Look at the Forest as well as the Trees

Generator Failures Lessons Learned

GCS

Core Failure Causes

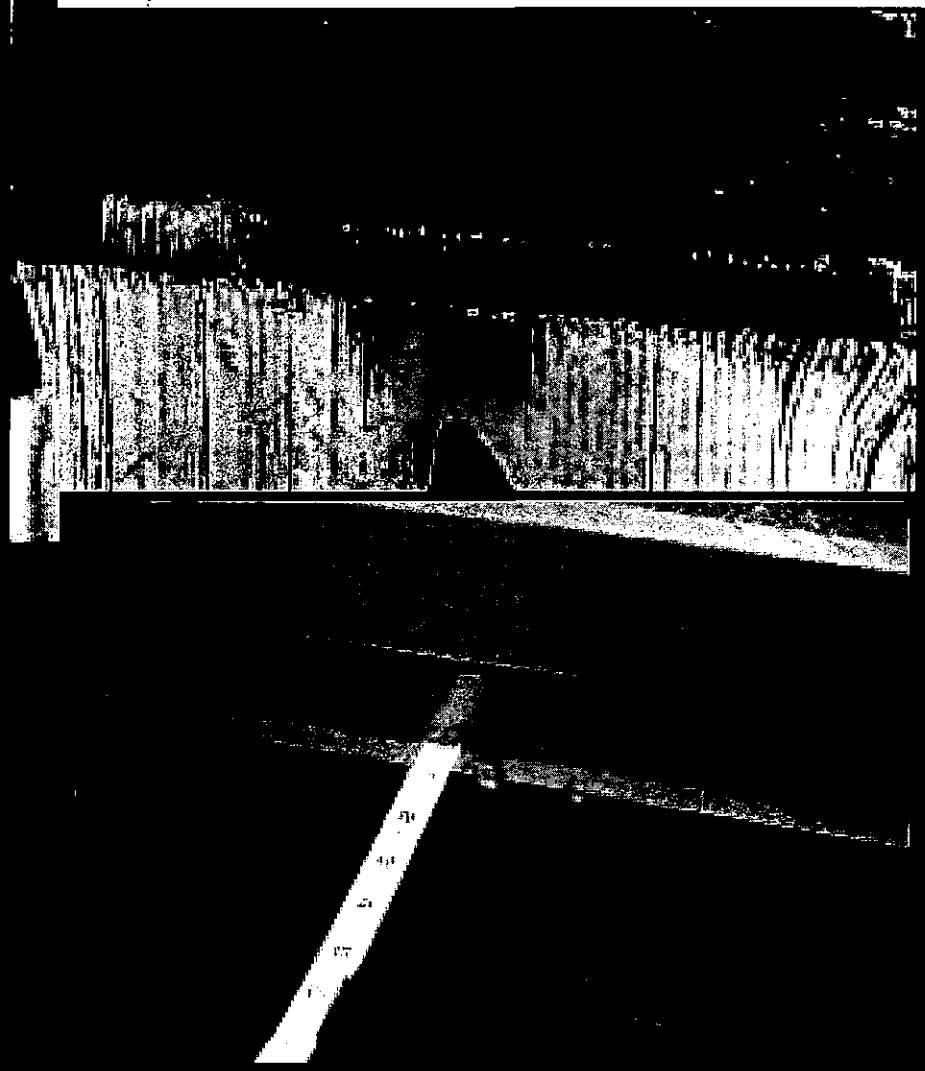
- Winding Failure root cause
- Core failure root cause
- Through studs
- Foreign Object
- Lamination Insulation
- Damage from Repair Work
- Original Design/Assembly

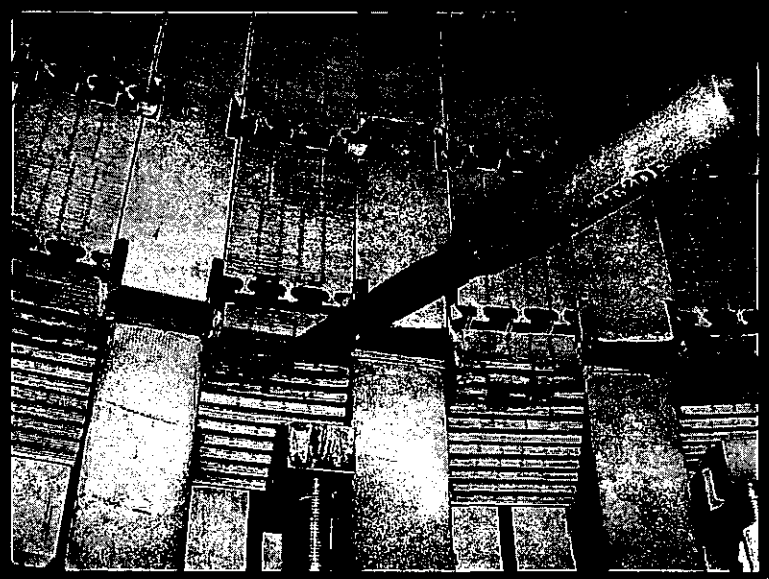
Root Cause Sometimes Difficult to Determine Since Evidence is Melted

Generator Failures Lessons Learned

GCS

Examples of Core Problems
from Maughan Engineering Consultants





Generator Failures Lessons Learned

GCS

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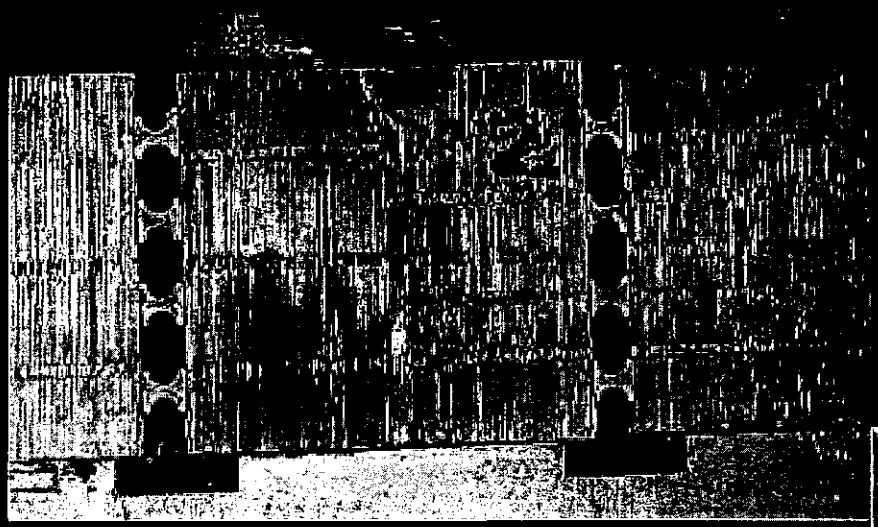


Generator Failures Lessons Learned

GCS

Core Failure Investigation

- Fleet History
- Review similar units
- Operational History
- Repair History
- Original Design/Assembly

Generator Failures Lessons Learned

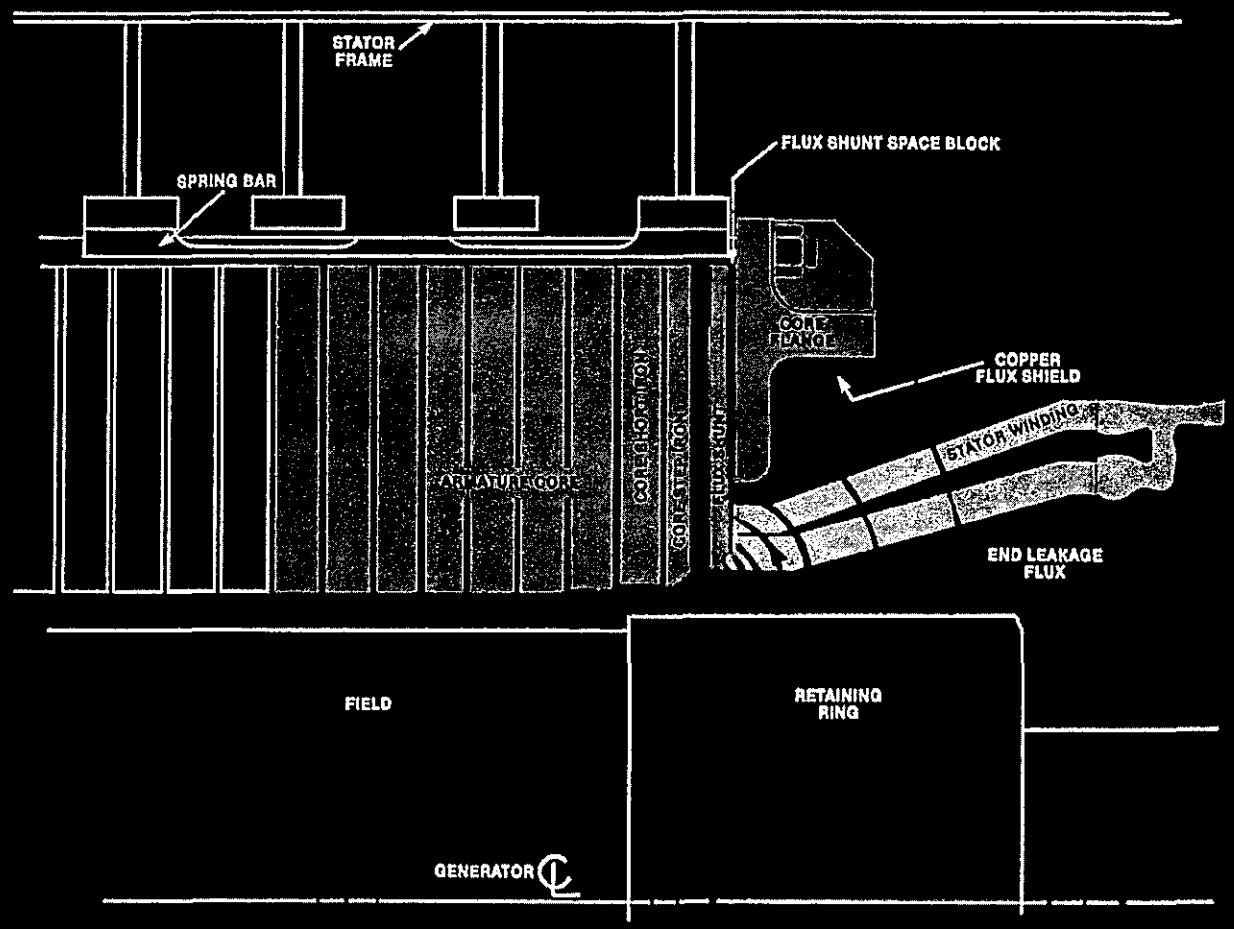
GCS

Operational Cause

- Overvoltage (>5%)
- Volts/Hertz (>118% for 2 seconds or. > 105% continuous)
- Asynchronous Operation (pole slippage)
- Synch out of phase
- Loss of excitation
- Excessive excitation while off line
- Regulator anomalies or failure
- Load rejection while under manual (DC) regulator control
- Decreasing speed while the AC regulator or the operator attempts to maintain rated voltage

Generator Failures Lessons Learned

GCS



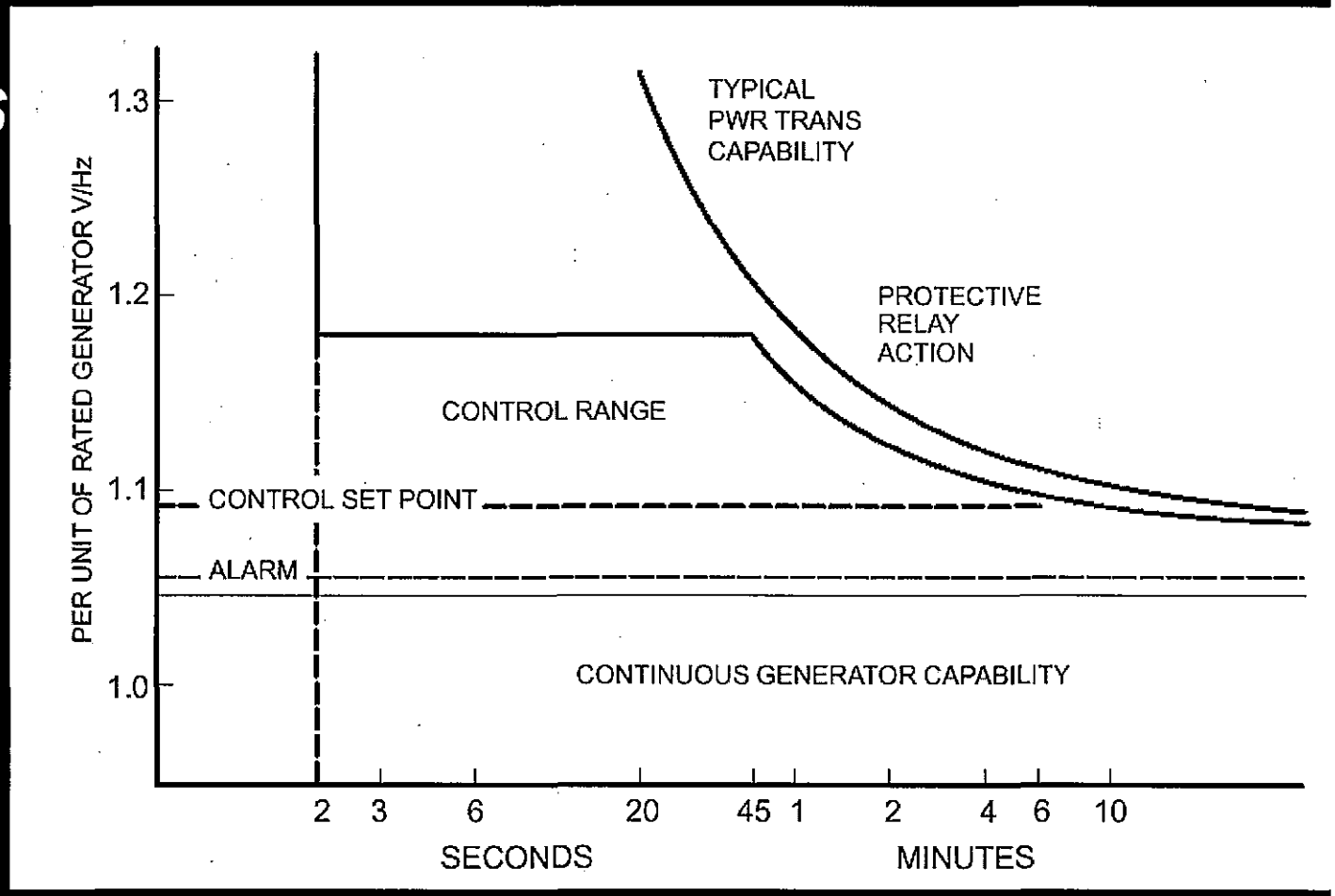
Over fluxing can breakdown core insulation and result in rapid core melting

Generator Failures Lessons Learned

GCS

Generator Failures Lessons Learned GCS

Stator Volts Per Hertz Relay



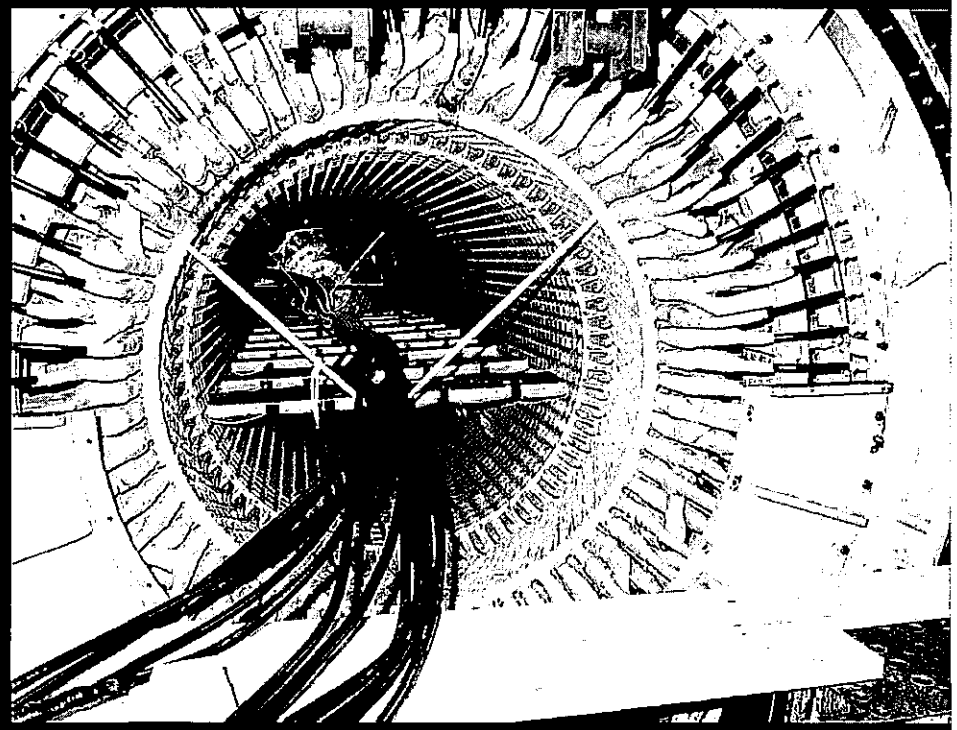
Detection: Volts/Hertz relay -
Trip: 118% - 2 sec. delay; 110-118%- 45 sec

Generator Failures Lessons Learned

GCS

Core Testing

- EL CID
- Ring (Loop) Test



GENERATOR MIS OPERATION

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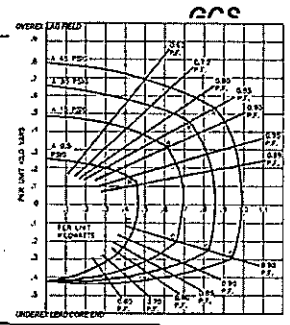
EPRI Generation European Workshop
April 16, 2013
Rome, Italy

Objective: To give you additional understanding about Generator Operation to avoid damage

- Does not teach how to operate the generator
- Share with you experiences
- Help prevent future potential damage

Operation

Unbalanced Stator Current	Negative Sequence Limits
Loss of Stator Coolant	Runback
Off Frequency	+/- 5% 60 Hz
V/Hz protection	1.05 normal; 1.10 short time (1 min.)
Stator Overcurrent	+/- 5% Voltage
Stator Ground	Trip
Stator Phase-Phase	Trip
Field Ground	Trip
Over Excitation	Time vs. Voltage
Synch out of phase	+/- 10°
Motoring (Induction)	Negative Seq. Limits
Loss of Excitation	Trip
Loss of Synch	Trip



Stator Overtemp (RTD, TC, Gas)	Instruction Book
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Always Operate Within the Capability Curves

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- Instantaneous Neutral Overcurrent – 50N
- Inverse Time Neutral Overcurrent - 51N
- Inverse Time Overcurrent with Voltage Restraint or Voltage Control – 51V
- Phase Overvoltage – 59
- Neutral Overvoltage – 59N
- Multi-Purpose Overvoltage – 59X
- VT Fuse-Loss Detection and Blocking – 60FL
- Field Ground – 64F
- Residual Directional Overcurrent – 67N
- Out-of-Step – 78
- Over/Under Frequency – 81
- Under Frequency Accumulation – 81A
- Rate of Change of Frequency -81R
- Phase Differential Current – 87
- Ground Differential Current – 87GD

Generator MisOperation *GCS*

Type of Trips

1. Simultaneous trip-Valves closed, Gen.Brkr.Open, remove X
2. Generator trip-Gen.Brkr.Open, remove X
3. Generator Breaker trip- Gen.Brkr.Open
4. Sequential trip-Turb.trip, Valves closed, reverse Power (3 sec), Gen. Brkr. Open, which trips X
5. Manual trip- manual Turb. Trip, when reverse power then Gen Brkr and X
6. Manual runback and trip- reduce load, sequential trip
7. Automatic runback-reduce load automatically
8. Manual runback- manually reduce load

Generator MisOperation *GCS*

Stator Volts Per Hertz

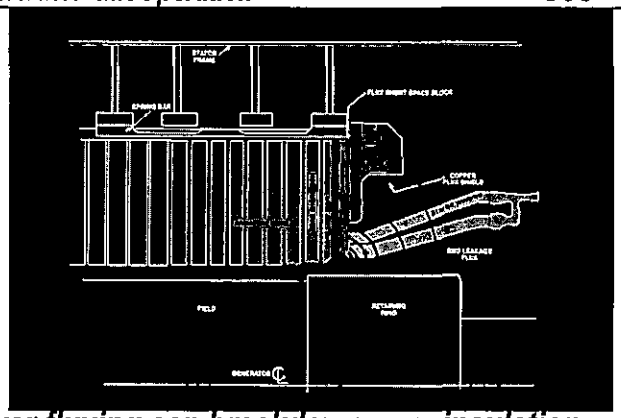
- Voltage/frequency (volts/Hertz) proportional to flux in the generator and step-up transformer cores
- Over fluxing (105%-110%) increases core loss, elevating core temperatures.
- Over fluxing (above 110%) saturates portions of the core to the point that flux flows out into adjacent structures.

Generator MisOperation *GCS*

Stator Volts Per Hertz Causes:

- Regulator failure
- Load rejection while under control of the dc regulator
- Excessive excitation with the generator offline
- Decreasing speed while the ac regulator or the operator attempts to maintain rated stator voltage
- (Likely to occur offline but can occur online)

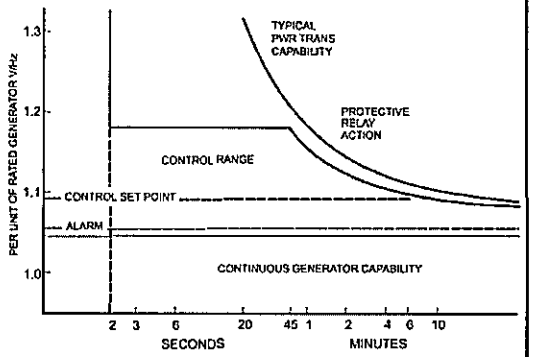
Generator MisOperation *GCS*



Over fluxing can breakdown core insulation and result in rapid core melting

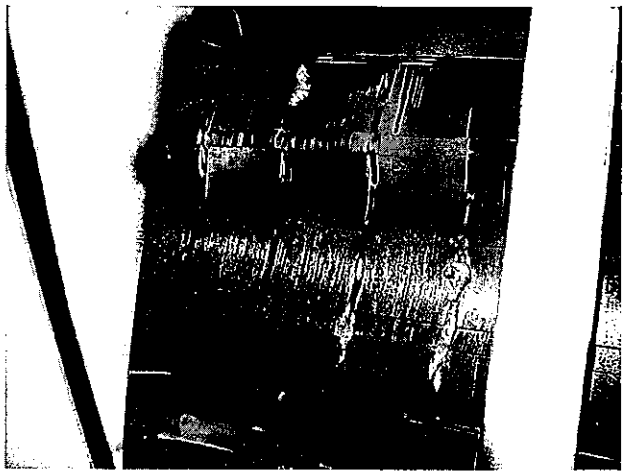
Generator MisOperation — GCS

Stator Volts Per Hertz Relay



Detection: Volts/Hertz relay -
Trip: 118% - 2 sec. delay; 110-118%- 45 sec

Generator MisOperation — GCS



Generator MisOperation — GCS

Circulating Currents in the Surface of the Rotor

- Rotating magnetic field resulting from the three phase armature currents

Generator MisOperation — GCS

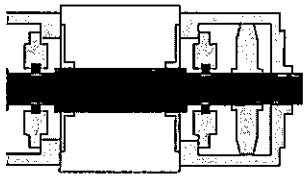
Circulating Currents in the Surface of the Rotor

- Unbalanced Armature Current
- Induction Motoring
- Loss of Excitation

Generator MisOperation — GCS

Continuous Operation with Unbalanced Armature Current

NA2 Generator



Gas Temp
30.58
31.02
30.81
30.46
30.71
as Temp 4 NW

H2 Gas Pressure
Pressure 47.04
Press 35.93

H2 Gas Temperature
Temp 94.89
Temp Cnt 35.93
Temp Cnt 94.96

NA Plant I
NA2 General
NA2 He

Amp Phase
A 6.43
B 6.37
C 6.31

Calc Load Lim
Min 100.00
Max 255.00

Gross KVolts 19.73

Max Calc Net Gen
Day A 201.79
Hr/Da 201.79

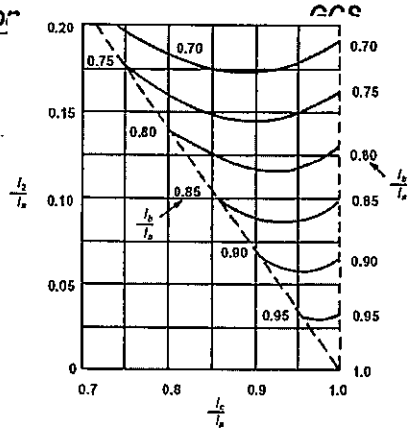
Megawatts
MW 218.86
MW 218.86
Gross 215.99
Net 207.36
Unit 2 Net 200.28

Megawatt II
Gross Shutdown
Net Shutdown

- Theoretically: All three-phase currents are equal
- Reality: They are never equal
- What unbalance is permissible?

Generator MisOperation — GCS

Negative Phase Sequence Current from the Magnitudes of the three phase currents



I_2 = negative phase sequence current
I_a = largest of three phase currents
I_b = smallest of three phase currents
I_c = phase current of intermediate value
(all currents in per unit or in amperes)

Generator MisOperation — GCS

Continuous Operation with Unbalanced Armature Current

Permissible Continuous I_2

up to 960 MVA) 8%

Transient Operation with Unbalanced Armature Currents

Directly Cooled Generators	Permissible $(I_2)^2t$
up to 800 MVA	10%

Generator MisOperation — GCS

Continuous Operation with Unbalanced Armature Current

(46 Neg. Seq. Relay)

Action:

- 1. Reduce the current unbalance
- 2. Reduce the generator kVA output.
- 3. Reduce the terminal voltage
  - (down to a minimum of 95% of rated voltage, taking precautions that the underexcited reactive capability is not exceeded.)
- 4. Type 1 trip
  - (to prevent potential for overspeed on load rejection)

Generator MisOperation *GCS*

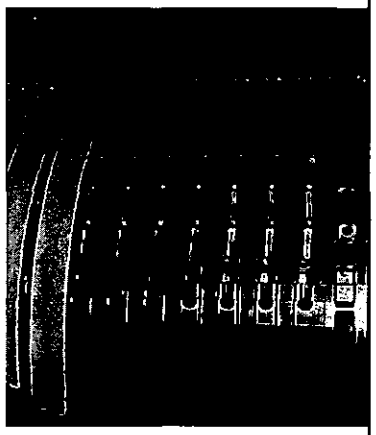
Loss of Excitation

- Loss of synch and operation as induction motor
- Induced currents in surface of rotor
- Detection- LOX relay
  - Type 1 simultaneous trip
  - Type 2 generator trip

Generator MisOperation *GCS*

Loss of Excitation

- Loss of Excitation while in operation may result in severe rotor surface heating
- LOX relays will trip unit immediately, or, immediate manual trip as soon as discovered



Generator MisOperation *GCS*

Loss of Synchronism (78)

- Out-of-step operation or pole slipping Detection: loss-of-synchronization, LOX relays
- Pulsating torques, winding stresses, core end heating and (I2)
- Type 3 breaker trip to permit immediate resynchronization.
- Type 1 trip alternate.

Generator MisOperation *GCS*

Abnormal Frequency Operation

- Severe system disturbance.
- Under or over frequency operation as long as load and voltage are within acceptable limits.
- Turbine is more sensitive to off frequency

Generator MisOperation *GCS*

Subsynchronous Resonance (SSR)

- Under freq. current oscillations in the Stator from (HVDC) or series capacitor compensation
- TVMS
- Pole-face amortisseur windings

Generator MisOperation *GCS*

Inadvertent Energization

- Operation as an Induction motor (without X) with I2 damage
- Worst case- Breaker close while on gear
- Very short time and severe damage
- Overcurrent relays armed by speed relay
  - (Always in service)

Generator MisOperation *GCS*

Motoring

- Synchronous (with X) OK for Gen. , Turb. may have pblm.
- Induction motoring (w/o X) causes severe I2
- Reverse power relay w/time-delay pick-up of 10 to 30 seconds
  - Type 1 simultaneous trip.
  - Type 2 generator trip or Type 3 breaker trip

Generator MisOperation *GCS*

Synchronizing Errors

- Synchronize (or switch) not greater than 10° out of phase
- Common Causes: Improper connection of PT's, synchroscopes
- 120° is worst
- Accumulated events
- Inspect internals if severe incident

Generator MisOperation *GCS*

Synchronizing Errors

25

Generator MisOperation *GCS*

Loss of Stator Water Coolant

26

Generator MisOperation *GCS*

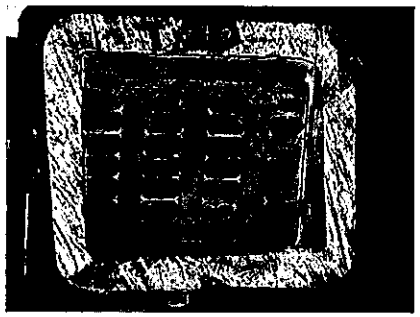
Stator Winding Cooling System-Issues

- Leaks
- Plugging
- Monitoring (high temperatures)
- Makeup water
- Conductivity 1st Alarm: 0.5 µmhos/cm- replace resin
  - 2nd alarm 9.9 µmhos/cm- manual runback/trip
- Oxygen content-design to be High O_2
  - Any condition which changes the original design i.e. plugging of YTV vent
- Y Strainer rivets/ plugging
- Cupric/Cuprous oxide buildup/plugging
- Resin Bed

27

Generator MisOperation *GCS*

Water Chemistry



28

Generator MisOperation *GCS*

Shaft Voltage Monitoring

Damage can be severe to bearings, hydrogen seal rings, front standard, PMG, shaft driven pumps

- Damage Shaft grounding brush maintenance (carbon, copper braid, sohre)
- CE bearing, seal casing is insulated
- Shaft voltage to ground at brush < 5 – 6 volts zero to peak

Generator MisOperation *GCS*

Operation

Unbalanced Stator Current	Negative Sequence Limits
Loss of Stator Coolant	Runback
Off Frequency	+/- 5% 60 Hz
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Stator Ground	Trip
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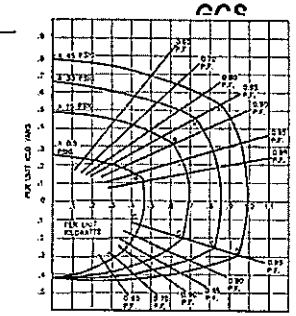
Over Excitation	Time vs. Voltage
Synch out of phase	+/- 10°
Motoring (Induction)	Negative Seq. Limits
Loss of Excitation	Trip
Loss of Synch	Trip



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Always Operate Within the Capability Curves

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

How to Avoid Generator Misoperation

P65 Webcast Series
June 20-21, 2013

Jan Stein
Senior Project Manager, EPRI

Webcast Attendee Instruction

- This webcast will be recorded. If you do not desire to be a participant please disconnect now.
- Questions and Answers…
  - Type your questions during webcast
  - On your phone, use * 8 to "raise your hand" for a question and use # 8 to "lower your hand".

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Schedule: EPRI 2013 P65 Webcast Series

Topic	EPRI Lead	Date
Generator End-Winding Vibration On-line Monitoring	Jan Stein	Mar. 14 Sept 12
Summary of 2012 Program 65 Deliverables	Steve Hesler	May 28-29
Generator Fan/Blower Design, Inspection, and Maintenance	Jan Stein	June 12-13
How to Avoid Generator Misoperation	Jan Stein	June 20-21
Turbine Lube Oil Preventive Maintenance	Grant Lanthorn	July 15-16
Turbine Casing and Valve Inspection	Jay Richardson	TBD 3Q
Shaft Voltage: Sources and Grounding	Jan Stein	TBD 3Q
Turbine Supervisory Instrumentation	Grant Lanthorn	TBD 3Q
Maintenance of EHC Fluid	Grant Lanthorn	TBD 4Q

Today

All webcasts are recorded and archived on EPRI web at P65 Cockpit

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Technical Webcast Series – 2012 Topics

Steam Turbine Generators

- Over 25 Webcast recordings archived for industry access on EPRIweb; Program 65 Cockpit (http://membercenter.epri.com/programs/056608/pages/events.aspx)
- Eight new topics were added to webcast library in 2012:
  1. Generator core testing
  2. Generator electrical testing
  3. Generator Retaining Ring Inspection
  4. Steam Turbine Blade Flutter
  5. Main Generator 100% Stator Winding Ground Protection
  6. Preventive Maintenance Basis Database for Major Components
  7. On-line Monitoring of Generator End-Winding Vibration
  8. Turbine Overspeed Trip Systems

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P65 Webcast Download Location

- Go to www.epri.com; use EPRI login
- Click "Program Cockpits" →

- Click Program 65, "Steam Turbines-Generators and Auxiliary Systems
- Click "Meetings and Webcasts" on left-hand column
- Click "Webcasts" tab along top of page
- Click on titles to download slides and webcast recording files

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Professional Development Hours

- Please send an e-mail to Judson Ashby (rashby@epri.com). You will be sent the appropriate certificate.

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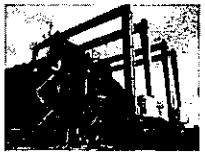
Safety Message – Portable Cranes

- Temporary cranes increasingly used to support outages
- Large engineered lifts (example, stators)
- Safety issue:
  - Proximity of "onlookers" to lift
  - Failure to appreciate that unsafe zone is based on more than the simple case of a dropped load
  - Potential for collapse/tipping of crane itself must be taken into account
  - As always.... Better to err on the safe side



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Ron Halpern

Ron is a Mechanical Engineer who worked for GE for 25 years as a field Engineer, Generator Specialist, Generator Engineer, Technical Leader and Generator Product Manager. As a consultant, for the past fifteen years, his company specializes in all aspects of generator maintenance and operation. He gets involved with non routine and highly complex issues concerning generator technical problems.

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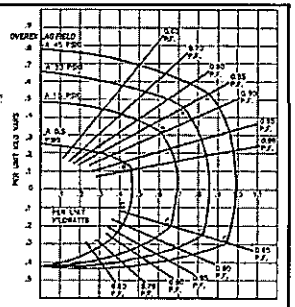

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- Rate of Change of Frequency -81R
- Phase Differential Current – 87
- Ground Differential Current – 87GD

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Type of Trips

1. Simultaneous trip-Valves closed, Gen.Brkr.Open, remove X
2. Generator trip-Gen.Brkr.Open, remove X
3. Generator Breaker trip- Gen.Brkr.Open
4. Sequential trip-Turb.trip, Valves closed, reverse Power (3 sec), Gen. Brkr. Open, which trips X
5. Manual trip- manual Turb. Trip, when reverse power then Gen Brkr and X
6. Manual runback and trip- reduce load, sequential trip
7. Automatic runback-reduce load automatically
8. Manual runback- manually reduce load

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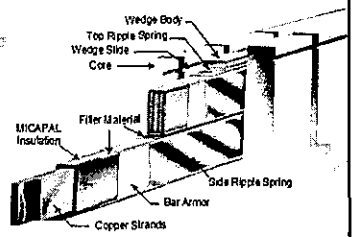
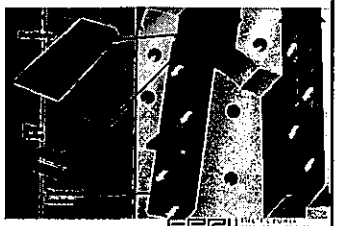
Stator Bar Slot Support

- **Bars must not move in slots**
  - **Side filler/springs**
  - **Top wedges, springs**
  - **Conforming material**





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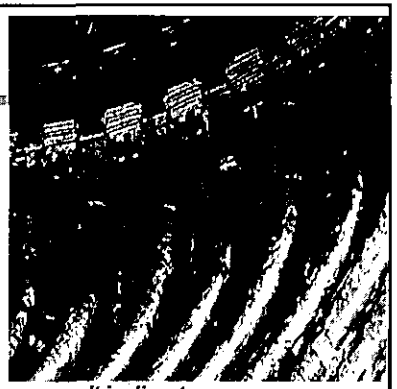
Stator Ground Fault



- Fault between stator winding and ground
  - Single ground
  - Usually followed by second ground
  - Causes: Foreign objects, water leaks, insulation degradation, failed connectors…
- ***Second ground (same phase) can result in disastrous consequences-may not be picked up by differential relay protection***
- ***Detection-Ground Fault relay (59GN,THD,Low-Freq.Injection,3rd Harmonic, <100%>)***
  - ***Type 1 simultaneous trip within several seconds***

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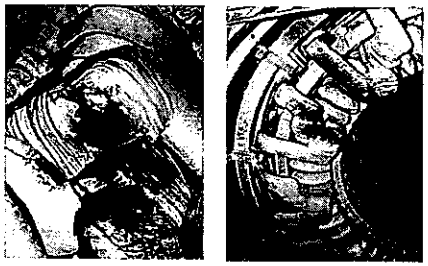
Stator Phase-to-Phase Fault



- Fault between two phases of the armature winding
  - Very large current flow/serious damage
  - Ground likely-Detection-Differential relay Ground Fault

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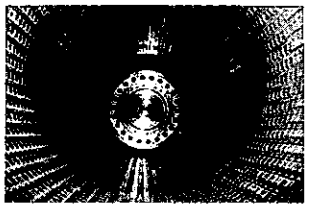
Contamination from failure



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Stator Volts Per Hertz

- Voltage/frequency (volts/Hertz) proportional to flux in the generator and step-up transformer cores
- Over fluxing (105%-110%) increases core loss, elevating core temperatures.
- Over fluxing (above 110%) saturates portions of the core to the point that flux flows out into adjacent structures.

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Stator Volts Per Hertz Causes:

- Regulator failure
- Load rejection while under control of the dc regulator
- Excessive excitation with the generator offline
- Decreasing speed while the ac regulator or the operator attempts to maintain rated stator voltage
- (Likely to occur offline but can occur online)

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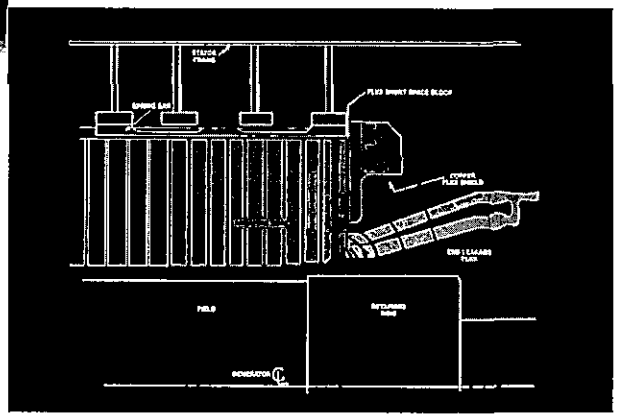

Over fluxing can breakdown core insulation and result in rapid core melting

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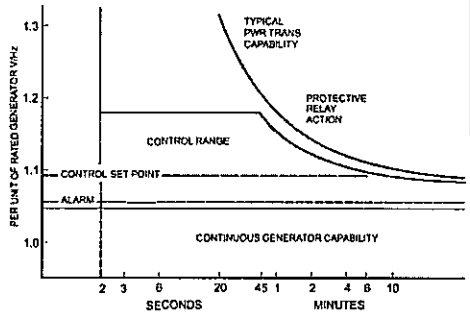
Stator Volts Per Hertz Relay



Detection: Volts/Hertz relay -
Trip: 118% - 2 sec. delay; 110-118%- 45 sec

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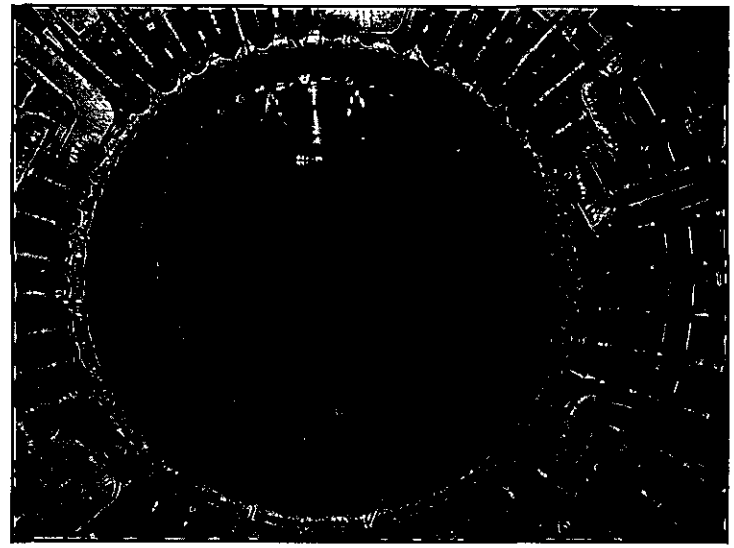

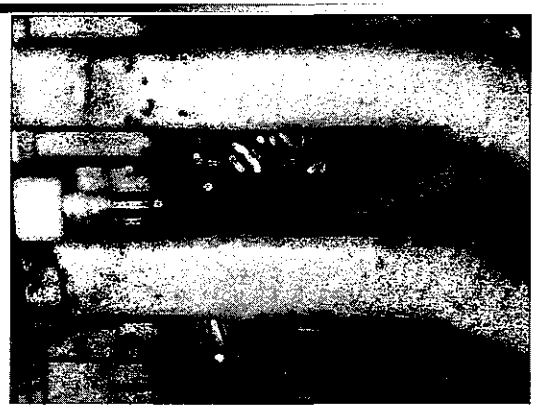

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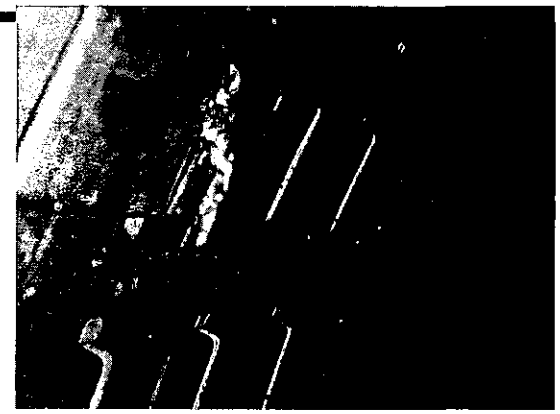

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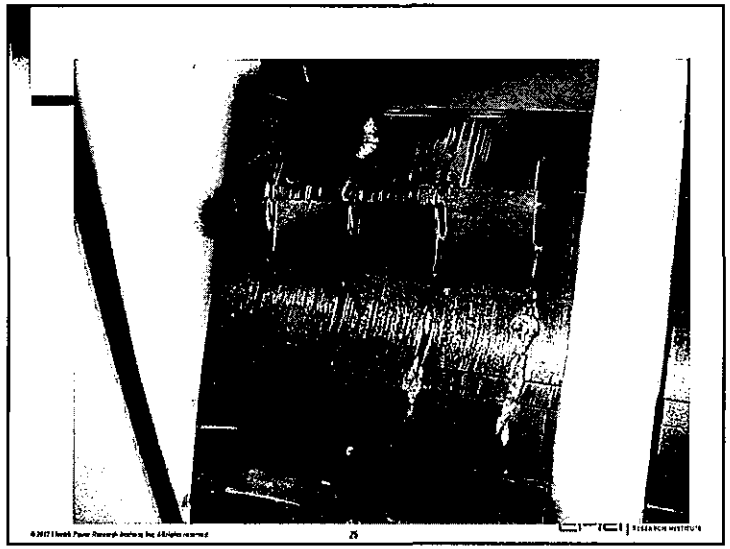
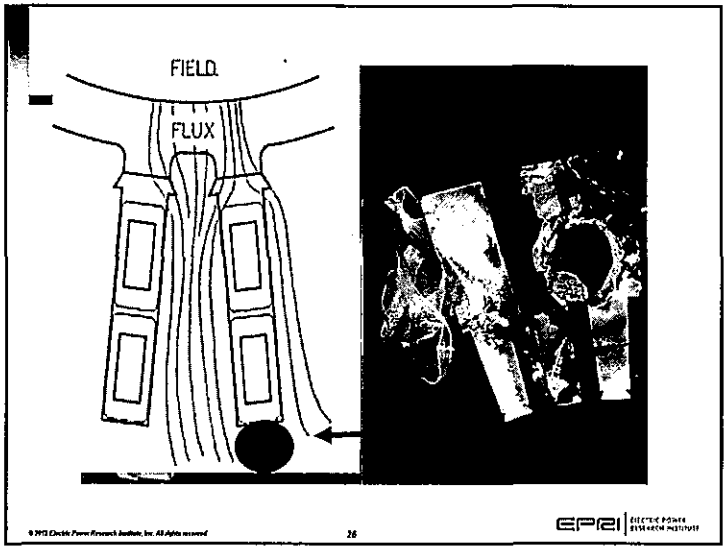
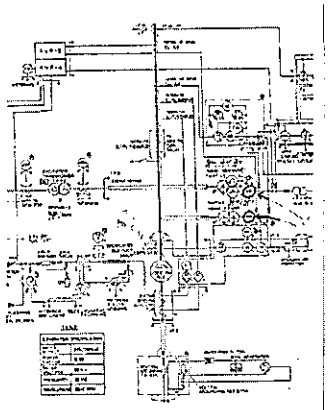


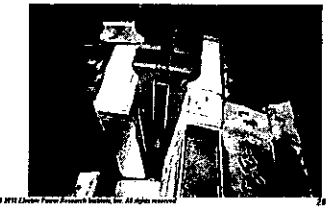


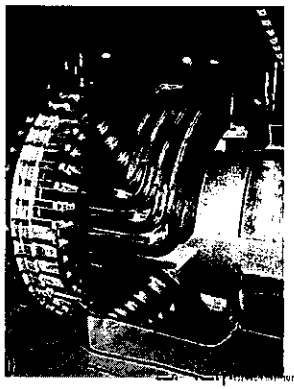
Cause of Failure:
Damage can occur very quickly and to catastrophic level
Do not increase field current without an indication of voltage



Rotor (Field)

- Winding:
  - Single circuit
  - Multiple coils
  - Multiple Layers (turns)
- 250-500 volts
- Insulated from grounded forging





Field Over-excitation

- Short Time (Transient) Operation for field

– Time (seconds)	10	30	60	120
Field voltage (percent)	208	146	125	112

- Detection-Maximum Excitation Limit.
  - Prevents prolonged field overcurrent by recalibrating the current regulator, transferring to another regulator, and finally, producing a trip signal, as required
- Loss of P.T. signal to the voltage regulator is one cause of field overcurrent
- Type 4 Sequential trip
- Type 1 simultaneous trip
  - (Hi resp. Exc. To prevent staying at ceiling)

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Field Ground Fault

- Excitation source is ungrounded :
  - Therefore, a single ground will not cause damage.
  - However, a second ground can be disastrous
- Detection-Field Ground relay alarm (not on rotating rectifier)
  - Type 4 Sequential trip

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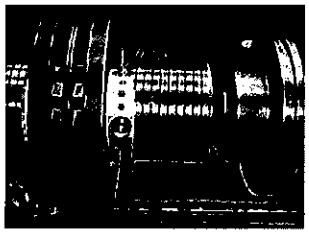
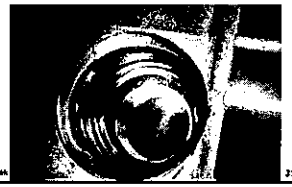
Examples of Field Grounds





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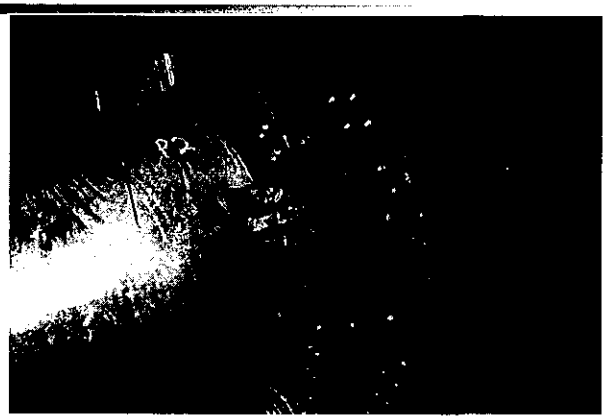
Double Field Ground Fault



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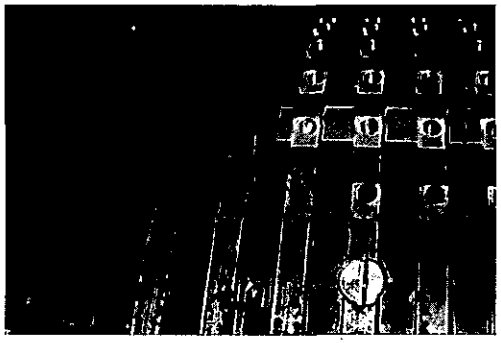
Poorly protected field



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Field Failures & Repairs- Shorted Turns

- Breakdown in the insulation between turns
- Most common cause of thermal sensitivity
- Flux~ AmpereTurns
- Problem: Multiple Shorts requiring increased current
- Not a Problem unless vibration is high (thermally sensitive), or you run out of current

- Shorted turn Detection
  - Copper resistance
  - Impedance test
  - Flux Probe
  - RSO

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Shorted Field Turns- Coil Distortion

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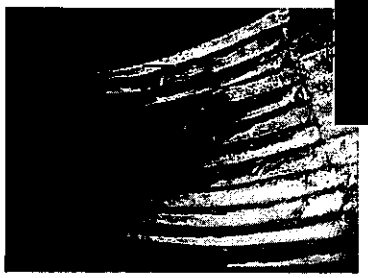
Shorted Field Turns- Contamination



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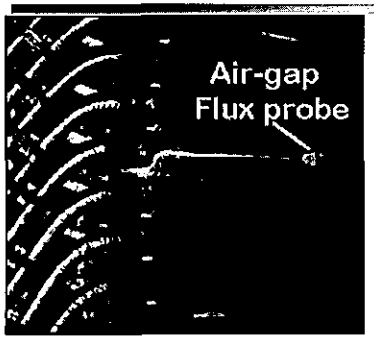
Shorted Turn Detection with Flux Probes



Permanent flux probe mounted in core

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Generator Rotor Thermal Sensitivity

- Causes the rotor vibration to change as the field current is increased
- Causes rotor bowing:
  - uneven temperature distribution circumferentially around the rotor
  - axial forces which are not distributed uniformly in the circumferential direction
- *May* limit operation at high field currents or VAR loads due to excessive rotor vibration.
- Characterized by a once-per-revolution frequency response

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Rotor Thermal Sensitivity

- Repeatable/Reversible
  - Shorted turns
  - Blocked ventilation
  - May be compromised balanced
- Irreversible (slipstick)
  - Non Symmetric tightness of components i.e. wedges, cu in slot, filler
  - Bring down to gear to eliminate

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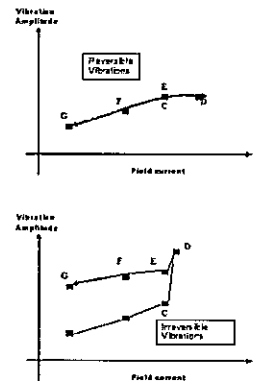
Generator Rotor Thermal Sensitivity-Reversible and Irreversible



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Circulating Currents in the Surface of the Rotor

- Rotating magnetic field resulting from the three phase armature currents

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Circulating Currents in the Surface of the Rotor

- Unbalanced Armature Current
- Induction Motoring
- Loss of Excitation

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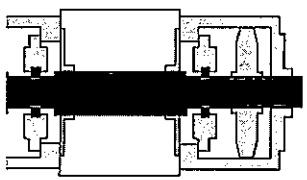
Continuous Operation with Unbalanced Armature Current

NA2 Generator



Gas Temp
30.58
31.02
30.81
30.46
30.71

as Temp 4 NW

H2 Gas Pressure
Pressure 47.04
Press 35.93

H2 Gas Temperature
Temp 94.89
Temp Cnt 35.93
Temp Cnt 94.96

NA Plant
NA2 Generat
NA2 He

Amp Phase
A 6.43
B 6.37
C 6.31

Calc Load Lim
Min 100.00
Max 255.00

Gross KVolts 19.73

Max Calc Net Gen
Day A 201.79
Hr/Da 201.79

Megawatts
MW 218.66
MW 218.86
Gross 215.99
Net 207.36
Unit 2 Net 200.28

Megawatt H
Gross Shutdown
Net Shutdown

- Theoretically: All three-phase currents are equal
- Reality: They are never equal
- What unbalance is permissible?

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Continuous Operation with Unbalanced Armature Current

Permissible Continuous I_2
up to 960 MVA) 8%

Transient Operation with Unbalanced Armature Currents

Directly Cooled Generators up to 800 MVA	**Permissible $(I_2)^2t$ 10%**

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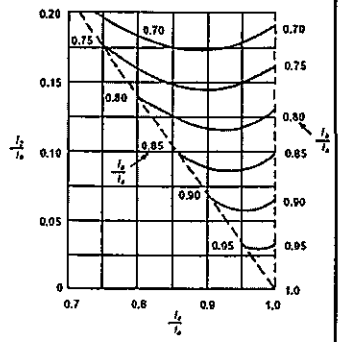
Negative Phase Sequence Current from the Magnitudes of the three phase currents



I_2 = negative phase sequence current
I_a = largest of three phase currents
I_b = smallest of three phase currents
I_c = phase current of intermediate value
(all currents in per unit or in amperes)

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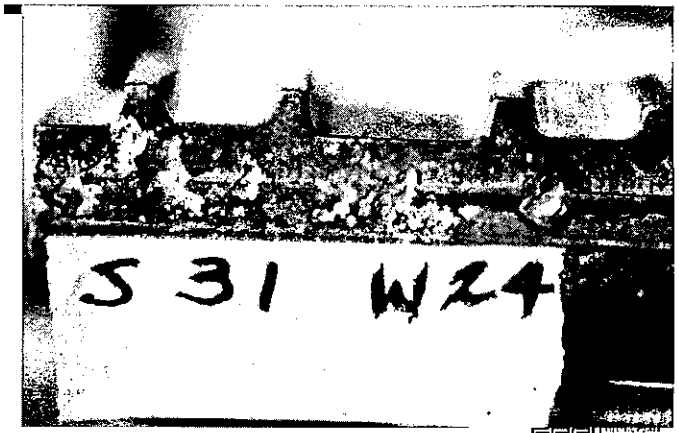
Circulating Currents on Surface of Rotor



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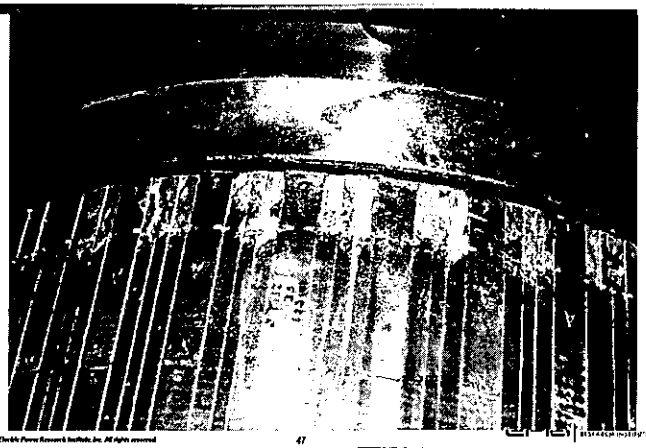
Circulating Currents on Surface of Rotor



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Continuous Operation with Unbalanced Armature Current
(46 Neg. Seq. Relay)

Action:

- 1. Reduce the current unbalance
- 2. Reduce the generator kVA output.
- 3. Reduce the terminal voltage
  - (down to a minimum of 95% of rated voltage, taking precautions that the underexcited reactive capability is not exceeded.)
- 4. Type 1 trip
  - (to prevent potential for overspeed on load rejection)

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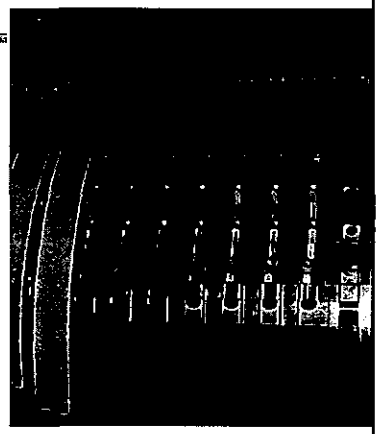
Loss of Excitation

- Loss of Excitation while in operation may result in severe rotor surface heating
- LOX relays will trip unit immediately, or, immediate manual trip as soon as discovered



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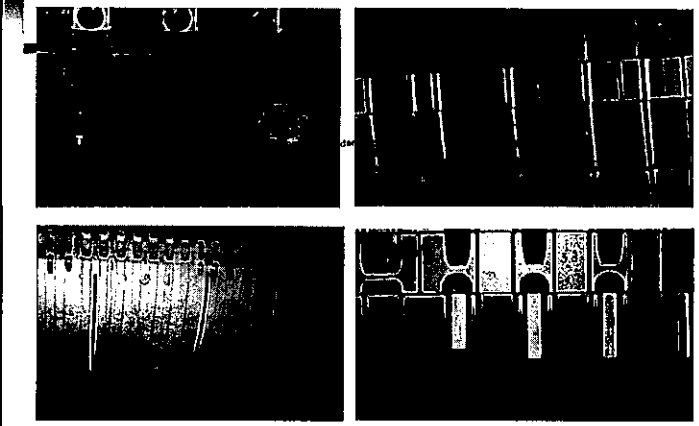
Loss of Excitation



- LOX relays will trip unit immediately, or, immediate manual trip as soon as discovered

Loss of Synchronism (78)

- Out-of-step operation or pole slipping Detection: loss-of-synchronization, LOX relays
- Pulsating torques, winding stresses, core end heating and (I2)
- Type 3 breaker trip to permit immediate resynchronization.
- Type 1 trip alternate.

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Inadvertent Energization

- Operation as an Induction motor (without X) with I2 damage
- Worst case- Breaker close while on gear
- Very short time and severe damage

- Overcurrent relays armed by speed relay
  - (Always in service)

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Inadvertent Energization –Catastrophic Failure

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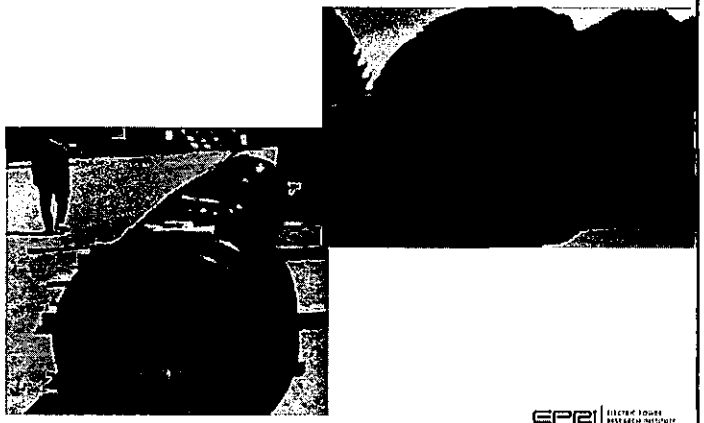
Inadvertent Energization



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Motoring

- Synchronous (with X) OK for Gen. , Turb. may have pblm.
- Induction motoring (w/o X) causes severe I2
- Reverse power relay w/time-delay pick-up of 10 to 30 seconds
  - Type 1 simultaneous trip.
  - Type 2 generator trip or Type 3 breaker trip

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Synchronizing Errors

- Synchronize (or switch) not greater than 10° out of phase
- Common Causes: Improper connection of PT's, synchroscopes
- 120° is worst
- Accumulated events
- Inspect internals if severe incident

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Synchronizing Errors

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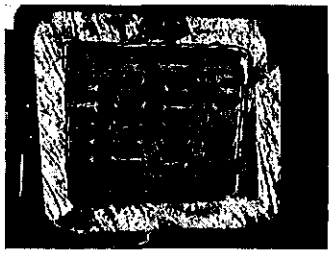
Stator Winding Cooling System-Op Issues

- Leaks (clip-strand,O rings)
- Plugging (High O_2 and Low O_2)
  - Cupric/Cuprous oxide buildup/plugging
- Monitoring (high temperatures)
- Makeup water
- Conductivity



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Shaft Voltage Monitoring

Damage can be severe to bearings, hydrogen seal rings, front standard, PMG, shaft driven pumps

- Damage Shaft grounding brush maintenance (carbon, copper braid, sohre)
- CE bearing, seal casing is insulated
- Shaft voltage to ground at brush < 5 – 6 volts zero to peak

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Questions and Discussion

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More Information

Ron@gencs.com

jstein@epri.com

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Schedule: EPRI 2013 P65 Webcast Series

Topic	EPRI Lead	Date
Generator End-Winding Vibration On-line Monitoring	Jan Stein	Mar. 14 Sept 12
Summary of 2012 Program 65 Deliverables	Steve Hesler	May 28-29
Generator Fan/Blower Design, Inspection, and Maintenance	Jan Stein	June 12-13
How to Avoid Generator Misoperation	Jan Stein	June 20-21
Turbine Lube Oil Preventive Maintenance	Grant Lanthorn	July 15-16
Turbine Casing and Valve Inspection	Jay Richardson	TBD 3Q
Shaft Voltage: Sources and Grounding	Jan Stein	TBD 3Q
Turbine Supervisory Instrumentation	Grant Lanthorn	TBD 3Q
Maintenance of EHC Fluid	Grant Lanthorn	TBD 4Q

All webcasts are recorded and archived on EPRI web at P65 Cockpit

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Communication on P65 Webcasts

Contact Judson Ashby at rashby@epri.com or (704) 595-2712 if you:

- have not received this webcast invitation from EPRI, and wish to be on EPRI's P65 webcast contact list
  - Include name, title, company, contact information
- Need instructions on accessing previous webcast recordings/presentations on EPRI web.

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PSC-063

Regarding: Operator Staff with Expertise in Generators
Witness: Barnes

Mr. Halpern writes that, regarding aspects of generator operation such as procedures related to inspection of a generator's interlaminar insulation, that "most utilities rely on the OEM, in this case Siemens, to provide technical expertise for the inspection and repair of their generators."

a. Please describe whether PPL and, now, Talen, has anyone on its staff with sufficient familiarity with this kind of generator to understand the "procedures related to inspection of a generator's interlaminar insulation."

b. Please identify by name, address and contact information, any person you have identified in (a).

RESPONSE:

a. I believe that Talen does have personnel who understand the procedures for and results from El Cid testing of a generator's interlaminar insulation. I do not know, however, if Talen has any personnel who are qualified to perform such procedures nor the equipment necessary.

b. At a minimum, Talen's Plant Manager, Neil Dennehy, and Project Engineer, Eric Petritz, may have the knowledge noted in response to subpart a above.

PSC-064

Regarding: Knowledge of Generators
Witness: Barnes

a. Please describe generally your expertise on the topic of generators such as that at CU4, and particularly with the potential for or causes of generator failure.

b. Did you ever express concerns to the plant operator or to Siemens about the plant's interlaminar insulation?

c. Please describe what you knew about interlaminar insulation before the events of July 2013.

RESPONSE:

a. I have general knowledge on this topic.

b. No.

c. I knew that interlaminar insulation was insulation between the metal laminations that made up the core iron.

PSC-065

Regarding: Equivalent Availability Factor (EAF)
Witness: Barnes

What was the EAF of CU4 from its first day of operation to 1995?

RESPONSE:

NorthWestern is not in possession, custody, or control of this information prior to 1990. Please see the response to Data Request MEIC-072c.

PSC-066

Regarding: Hypothetical Insurance Costs
Witness: Barnes

a. In Exhibit__(MJB-2) you present a table showing the supposed costs and benefits of outage insurance for 2002 to 2014. When you calculated the "Payments on received as a result of BI insurance" [*sic*], please explain more precisely the data input for the "Annual actual Mid C price." Was it an annualized price of Mid-C you used, or hourly or monthly?

b. Please describe why there is not "Payments on received as a result of BI insurance" for 2014 in your hypothetical exhibit.

c. Please provide all work papers and information you used to compile this exhibit.

RESPONSE:

a. It was an annualized average price.

b. The assumption was that it would not be possible, nor prudent, to acquire insurance for coverage in 2014 for an outage that began in 2013 and continued into 2014 due to the likely high premium to be charged by the insurance company.

c. Please see the response to Data Requests MEIC-072c and MEIC-094.

PSC-067

Regarding: Hedging Outcomes and Hedging Strategy
Witness: Markovich

At (4:22-5:6) you testify:

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?

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.

a. Please explain in detail why a counterparty would have to be able to influence the market in order to expect profit from its fixed-for-float transactions with a fully regulated public utility.

b. Please explain why more resources and/or aptitude to predict the market would not be sufficient to enable a counterparty to expect a profit from its fixed-for-float transactions with a fully regulated public utility.

c. Please explain whether NorthWestern is willing to pay a premium for stable supply costs, and if not, why not. In other words, is NorthWestern willing to enter into off-system, fixed price transactions, the expected value of which exceed the expected value of forecast index prices plus transaction cost?

d. Would such a premium contribute toward the positive expected return for the float counterparty?

e. If you have empirical evidence to support the equivalence of fixed and float positions with respect to expected financial gain, please provide.

RESPONSE:

a. The issue revolves around the incentive to try to beat the market. A sophisticated speculator may be very good at predicting future market fundamentals, i.e. weather, catastrophic events, and other items that influence market prices. In the end, however, the forecasted items must come to fruition in order for a speculator to profit. Nothing is guaranteed. Weather may be different than predicted, catastrophic events may or may not occur, new laws and regulations may emerge. In order for speculators to guarantee

PSC-067 cont'd

profitability they must be able to influence or manipulate markets in their favor; anything less than that is still left to chance. Entities may be financially incented to try to beat the market but unless they can control the outcome it is not certain they will do so.

b. See the response to part a, above. More resources and/or aptitude to predict the market is helpful to speculators, but those attributes cannot guarantee success. At the time a forward transaction is consummated a speculator may expect to make a profit, but in order to do so the forecasted events and assumptions inherent in his/her valuation must be realized.

c. In forward markets, "market" is determined based on transactions between willing buyers and willing sellers; discounts and premiums are not associated with market transactions. NorthWestern's long term hedges were procured via competitive solicitations with numerous counterparties responding, and in most instances respondents' offers were priced very close to each other. NorthWestern always chose the lowest priced offers.

One of NorthWestern's hedging strategy's goals is to gain stability in customers' rates. When NorthWestern enters into fixed priced transactions for delivery of future energy, it pays what the forecasted market price of electricity is at the time the transaction is commenced. The fixed priced transaction itself results in some stability in customers' rates. Increasing the amount paid for such energy to some amount above market price does not create stability, it means that customers pay more.

d. If such a premium as suggested in subpart c were to be paid, it would most likely provide a positive expected result for the counterparty in the transaction, but it would not guarantee a positive result as market prices can change daily resulting in expected profits being different from what is actually realized.

e. We do not have such evidence.

PSC-068

Regarding: Outage Cost Estimate
Witness: Markovich

a. Please describe the significant differences in "the historical operation performance of CU3 and CU4" that you refer to in 11:19-20 that would lead them to operate significantly differently.

b. Please explain the difference between the data used to populate the row labeled "Actual monthly spot purchase prices" in Exhibit__(KJM-1) and the data used to populate Mr. Barnes' data for the column entitled "Annual actual Mid C Price" for 2013 and 2014.

RESPONSE:

a. The statement is intended to reflect the notion that forecasted volumes of output from NorthWestern's ownership in Colstrip are based on the projected output from CU3 and CU4, due to the reciprocal sharing agreement between those units. The output from the combined units, regardless of the individual performance of each unit, forms the basis of the forecast. For an example of how the two units operate differently, see the Attachment provided in response to Data Request PSC-050b.

b. The data used to populate "Actual monthly spot purchase prices" in Exhibit__(KJM-1) was based on actual hourly transactions NorthWestern made during the CU4 outage. Mr. Barnes' prices in the column entitled "Annual actual Mid C Price" for 2013 and 2014 are annualized average day-ahead prices posted by Intercontinental Exchange (ICE).

PSC-069

Regarding: Excel Updates
Witness: Schwartzenberger

Please provide updated electronic versions of Exhibit_(WMT-1) and Exhibit_(WMT-3).

RESPONSE:

See the "PSC-069" folder on the CD attached to Data Request PSC-062. Exhibit__(JS-1) is the updated version of Exhibit__(WMT-1), and Exhibit__(JS-2) is the updated version of Exhibit__(WMT-3).

PSC-070

Regarding: Transmission Costs
Witness: Markovich, parts a, c, d, e / Bennett, part b

a. Please explain why there was a 52 "MW" off-system sale of excess "energy" to WAPA at Crossover during April 2014. *See* PSC-041.

b. Please identify the line(s) in Mr. Bennett's revised exhibits where this sale appears.

c. Please explain whether this sale consisted of one-time or recurring transaction(s), and describe the nature of the transaction(s), including counterparty, price, and term.

d. Please explain whether NorthWestern predicted having 52 MW of having excess energy in April 2014, and if so, provide documentation of having so predicted.

e. Please identify and quantify the extent to which individual electricity supply resources caused NorthWestern to have 52 MW of excess energy in April 2014.

RESPONSE:

a. The volumes from the on-system portfolio of resources were forecasted to be greater than the volumes needed to serve load during off-peak hours in April 2014. NorthWestern contacted its counterparties to see if any of them were interested in purchasing some of the excess. WAPA had a need for this energy, and on February 26, 2014 Northwestern and WAPA agreed to a 52 MW sales/purchase delivered to Crossover, a transmission interconnection point between Northwestern and WAPA.

b. Exhibit__(FVB-1 Rev)13-14, page 1, line 33.

c. This was a one-time 52 MW term, off-peak sale to WAPA for April 2014 at $26.00 per MWh delivered to Crossover. The deal was consummated on February 26, 2014.

d. In Docket No. D2013.5.33, Exhibit__(FVB-2)13-14, page 3 of 5, row 45 first shows expected volumes for spot sales during April 2014. Subsequent monthly and daily updates confirmed excess volumes, and the decision to sell 52 MW of off-peak energy during April 2014 was made on February 26, 2014.

e. Since NorthWestern does not "paint" megawatts from individual resources, I am unable to identify specific resources that caused the need for this sale. The supply portfolio in its entirety was long so the excess was sold.

PSC-071

Regarding: Spion Kop Variable Revenues
Witness: Bennett

a. Should line 44 of Exhibit_(FVB-8)13-14 represent the product of lines 39 and 40?

b. Why were "NWE Spion Kop Revenues" (line 44 of Exhibit_(FVB-8)13-14) negative from January through June 2014? *See* PSC-042.

RESPONSE:

a. No. On an actual basis the metered reads vary from estimated loads and result in under- or over-collection of the revenues. However, on an estimated basis, the product of estimated loads on line 39 multiplied by the calculated rate on line 40 would equal revenues.

b. In January, rates implementing NorthWestern's December 2013 Property Tax Tracker went into effect. For Spion Kop, a property tax refund was implemented. This refund was larger than the DSM lost revenue values, resulting in a net revenue refund. The incremental property tax adjustment values reflecting the refund are shown on line 50 and the lost revenue values are included on lines 52 and 53 of Exhibit__(FVB-8)13-14.

PSC-072

Regarding: DGGS Variable Costs
Witness: Bennett

a. Please identify the specific language in Order 7219h that caused "the correcting entry to adjust fuel costs to actual market prices" in May 2014. *See* PSC-043.

b. Please identify where in Order 7219h the Commission approved actual market prices.

c. Please provide supporting workpapers for the May 2014 "MPSC-Related Fuel Adjustment" that appears on line 56, page 2 of Exhibit_(FVB-6)13-14 in Docket D2014.5.46.

RESPONSE:

a. Docket No. D2012.5.49 Final Order No. 7219h ¶ 122 of the ordering section states: "Excluding $1,419,427 for incremental regulation costs during the DGGS outage and lost revenues that were not actually incurred, NorthWestern's request to recover electricity supply costs incurred during the 2011-2012 tracking period is APPROVED". The electricity supply costs incurred for DGGS included a change in the computation of the Energy Supply Cost (7 MW) component of the DGGS Fuel Cost from a constant value approved in the DGGS Filing in Docket No. D2008.8.95 to a value based on Mid-C monthly prices minus $7/MWh. This change was explained in the Prefiled Direct Testimony of Michael R. Cashell on pages MRC-4 and MRC-11 through MRC-14. This change was included in Exhibit__(FVB-6)11_12 lines 56 and 57 in Docket No. D2012.5.49 for July 2011 through June 2012.

b. See the response to part a, above.

c. See the response to Data Request MCC-106 for supporting workpapers for the adjustment which reflects the value of the Energy Supply Cost (7 MW) component of the DGGS Fuel Cost at Mid-C minus $7 from July 2012 through June 2014.

PSC-073

Regarding: Revised Exhibits
Witness: Bennett

Please provide revised exhibits (including in electronic format) in which any errors or typos identified by NorthWestern to-date have been corrected. To these extent errors or typos have been identified in a data request, please use footnotes or an index to cross-reference specific corrections.

RESPONSE:

Please refer to the attached revised exhibits: Attachment 1, Exhibit__(FVB-1 Rev)12-13 and Attachment 2, Exhibit__(FVB-1 Rev)13-14. Electronic versions are provided in the "PSC-073" folder on the CD attached to Data Request PSC-062.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		**Electric Supply Cost Tracker**													
2		**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3															
4			Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
5			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
6		Total Sales and Unit Costs													
7		MWh	508,737	551,049	516,614	445,633	451,251	507,415	565,008	522,733	487,459	461,420	443,486	448,231	5,909,036
8		Supply Cost	$ 39.1902	$ 38.1487	$ 38.7757	$ 38.7570	$ 39.1902	$ 38.9468	$ 38.9932	$ 38.4429	$ 39.1080	$ 39.0577	$ 38.9658	$ 38.9658	$ 39.1902
9		YNP MWh	3,924	1,502	2,621	2,162	1,481	671	555	532	568	553	756	3,281	18,605
10		YNP Supply Rate	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000	$ 60.0000
11		Prior Year(s) Deferred Expense	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	$ 1.9331	
12															
13															
14		Electric Cost Revenues													
15		NWE Electric Supply	$ 19,077,519	$ 21,086,958	$ 19,785,214	$ 17,255,477	$ 17,557,654	$ 19,866,465	$ 22,095,107	$ 20,294,221	$ 18,880,319	$ 18,047,326	$ 17,304,839	$ 17,431,924	$ 228,683,023
16		YNP Electric Supply	$ 235,417	$ 90,103	$ 157,269	$ 129,707	$ 89,185	$ 40,534	$ 33,304	$ 31,922	$ 33,888	$ 33,017	$ 47,667	$ 207,531	$ 1,129,545
17		Subtotal	$ 19,312,937	$ 21,177,061	$ 19,942,483	$ 17,385,184	$ 17,646,839	$ 19,906,999	$ 22,128,411	$ 20,326,143	$ 18,914,207	$ 18,080,343	$ 17,352,507	$ 17,639,455	$ 229,812,568
18		Prior Year(s) Deferred Expense	$ 1,911,087	$ 383,254	$ 1,092,388	$ 946,625	$ 961,494	$ 1,078,367	$ 1,200,713	$ 1,110,621	$ 1,035,866	$ 980,617	$ 942,002	$ 952,052	$ 12,595,087
19		Total Revenue	$ 21,224,024	$ 21,560,314	$ 21,034,872	$ 18,331,809	$ 18,608,333	$ 20,985,366	$ 23,329,124	$ 21,436,764	$ 19,950,073	$ 19,060,960	$ 18,294,509	$ 18,591,507	$ 242,407,655
20															
21		Electric Supply Expenses													
22		Net Base Purchases	$ 12,803,996	$ 13,853,532	$ 13,308,976	$ 14,348,111	$ 13,869,570	$ 14,308,324	$ 18,135,782	$ 16,750,733	$ 17,272,347	$ 17,672,167	$ 16,959,353	$ 16,308,250	$ 185,591,140
23		Net Base Sales	$ (278,580)	$ (390,724)	$ (300,788)	$ (411,288)	$ (343,035)	$ (317,880)	$ (356,968)	$ (327,158)	$ (394,345)	$ (377,092)	$ (409,432)	$ (391,012)	$ (4,298,302)
24		Net Term Purchases	$ 4,175,907	$ 4,279,656	$ 1,536,552	$ 1,250,316	$ 1,317,860	$ 2,717,212	$ 980,805	$ 911,035	$ 813,080	$ 402,492	$ 413,683	$ 429,736	$ 19,228,335
25		Net Term Sales	$ (2,314,541)	$ (2,552,505)	$ (652,977)	$ (862,687)	$ (577,920)	$ (1,047,820)	$ (2,046,704)	$ (1,915,008)	$ (2,349,150)	$ (1,879,808)	$ (1,995,241)	$ (2,032,710)	$ (20,227,071)
26		Net Spot Purchases	$ 1,501,518	$ 1,427,581	$ 547,903	$ 881,806	$ 1,164,280	$ 1,390,939	$ 1,160,097	$ 802,450	$ 1,076,168	$ 565,087	$ 1,582,064	$ 3,390,583	$ 15,490,476
27		Net Spot Sales	$ (30,952)	$ (151,070)	$ (127,366)	$ (256,873)	$ (282,063)	$ (145,446)	$ (297,088)	$ (450,505)	$ (563,668)	$ (284,498)	$ (127,462)	$ (65,674)	$ (2,782,665)
28		Other Tracker Costs	$ 2,787,893	$ 4,092,350	$ 2,042,396	$ 2,303,391	$ 3,544,794	$ 2,526,286	$ 2,396,420	$ 1,562,877	$ 1,859,531	$ 2,968,743	$ 2,527,260	$ 3,023,968	$ 31,635,908
29		Total Electric Supply Expenses	$ 18,645,240	$ 20,558,820	$ 16,354,695	$ 17,252,776	$ 18,693,487	$ 19,431,615	$ 19,972,344	$ 17,334,425	$ 17,713,964	$ 19,067,091	$ 18,950,225	$ 20,663,138	$ 224,637,820
30															
31		NWE Transmission Costs													
32															
33		Other Services (Wheeling)	$ 47,679	$ 53,042	$ 50,455	$ 81,375	$ 80,868	$ 88,725	$ 90,264	$ 134,174	$ 116,442	$ 78,422	$ 76,680	$ 57,149	$ 955,275
34		Ancillary Cost (Disallowed)	$ (13,781)	$ (47,093)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (15,863)	$ (219,499)
35		Total NWE Transmission	$ 33,898	$ 5,949	$ 34,592	$ 65,513	$ 65,006	$ 72,862	$ 74,401	$ 118,312	$ 100,580	$ 62,560	$ 60,818	$ 41,286	$ 735,776
36															
37		Administrative Expenses													
38		MPSC Tax Collection	$ 41,570	$ 42,712	$ 41,533	$ 41,636	$ 42,512	$ 47,532	$ 53,057	$ 49,147	$ 44,926	$ 43,096	$ 41,835	$ 41,998	$ 531,553
39		MCC Tax Collection	$ 24,942	$ 25,627	$ 24,920	$ 12,672	$ 12,938	$ 14,466	$ 16,148	$ 14,958	$ 13,673	$ 13,116	$ 12,732	$ 12,782	$ 198,974
40		Modeling	$ 76,190	$ 54,671	$ 52,379	$ 88,046	$ 25,830	$ 12,175	$ 38,480	$ 40,292	$ 39,355	$ 6,750	$ 95,001	$ 1,813	$ 530,979
41		Trading & Marketing	$ 9,927	$ 7,774	$ 6,325	$ 8,782	$ 8,121	$ 7,424	$ 7,184	$ 7,184	$ 7,981	$ 5,822	$ 10,000	$ 5,847	$ 92,371
42		Administration	$ 38,027	$ 8,900	$ 4,400	$ 4,400	$ 4,400	$ 67,618	$ 4,428	$ 5,259	$ 99,871	$ 4,485	$ 5,171	$ 22,104	$ 269,063
43		Total Administrative Expenses	$ 190,657	$ 139,684	$ 129,556	$ 155,535	$ 93,801	$ 149,215	$ 119,296	$ 116,840	$ 205,806	$ 73,269	$ 164,739	$ 84,543	$ 1,622,940
44															
45		Carrying Cost Expense													
46		Carrying Costs	$ 86,042	$ 80,930	$ 51,482	$ 46,127	$ 48,053	$ 39,530	$ 18,791	$ (6,762)	$ (19,620)	$ (18,808)	$ (13,081)	$ 1,423	$ 314,107
47		Total Carrying Costs	$ 86,042	$ 80,930	$ 51,482	$ 46,127	$ 48,053	$ 39,530	$ 18,791	$ (6,762)	$ (19,620)	$ (18,808)	$ (13,081)	$ 1,423	$ 314,107
48															
49															
50		Total Expenses	$ 18,955,837	$ 20,785,383	$ 16,570,326	$ 17,519,951	$ 18,900,346	$ 19,693,223	$ 20,184,832	$ 17,562,815	$ 18,000,730	$ 19,184,112	$ 19,162,701	$ 20,790,390	$ 227,310,644
51															
52		Deferred Cost Amortization	$ 1,911,087	$ 383,254	$ 1,092,388	$ 946,625	$ 961,494	$ 1,078,367	$ 1,200,713	$ 1,110,621	$ 1,035,866	$ 980,617	$ 942,002	$ 952,052	$ 12,595,087
53		(under collection)/over collection													
54		Monthly Deferred Cost	$ 357,100	$ 391,678	$ 3,372,158	$ (134,767)	$ (1,253,507)	$ 213,777	$ 1,943,579	$ 2,763,328	$ 913,477	$ (1,103,769)	$ (1,810,194)	$ (3,150,935)	$ 2,501,925
55		Cumulative Deferred Cost	$ 357,100	$ 748,778	$ 4,120,936	$ 3,986,169	$ 2,732,661	$ 2,946,438	$ 4,890,017	$ 7,653,345	$ 8,566,822	$ 7,463,054	$ 5,652,859	$ 2,501,925	
56															
57		Note 1 PSC_001 updated with actual information replacing estimated information for April, May, and June 2013.													
58		2 MCC-042 revised 7 aMW output of DGGS in cell J27 page 3.													
59		3 MCC-052 updated response corrected MWh output of Basin on page 3 line 52.													
60		4 PSC-045 with staff communication corrected the off system spot and term volume and cost categories.													
61		5 PSC-073 with this exhibit provides the current docket version of this exhibit.													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4														
5			**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**
6			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
7														
8		Note: for supply cost expense positive value reflects an under collection, negative an (over collection).												
9	Deferred Supply Cost Expense													
10		Beginning Balance	$ 15,312,718	$ 13,044,530	$ 12,269,599	$ 7,805,053	$ 6,993,195	$ 7,285,208	$ 5,993,064	$ 2,848,772	$ (1,025,177)	$ (2,974,520)	$ (2,851,368)	$ (1,983,176)
11		Monthly Deferred Cost	$ (2,268,187)	$ (774,932)	$ (4,464,546)	$ (811,858)	$ 292,013	$ (1,292,143)	$ (3,144,292)	$ (3,873,949)	$ (1,949,343)	$ 123,152	$ 868,192	$ 2,198,882
12		Ending Balance	$ 13,044,530	$ 12,269,599	$ 7,805,053	$ 6,993,195	$ 7,285,208	$ 5,993,064	$ 2,848,772	$ (1,025,177)	$ (2,974,520)	$ (2,851,368)	$ (1,983,176)	$ 215,706
13														
14														
15	Total Capital		$ 13,044,530	$ 12,269,599	$ 7,805,053	$ 6,993,195	$ 7,285,208	$ 5,993,064	$ 2,848,772	$ (1,025,177)	$ (2,974,520)	$ (2,851,368)	$ (1,983,176)	$ 215,706
16														
17														
18														
19	Cost of Capital		Rate	% Capitalization	Rate of Return									
20		Long-Term Debt	5.76%	52.00%	3.00%									
21		Common Equity	10.25%	48.00%	4.92%									
22														
23		Average Cost of Capital			7.92%									
24														
25	Deferred Supply Expense													
26		Carrying Charge	7.92%											
27														

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		Electric Supply Cost Tracker													
2		Electric Tracker Projection													
3															
4		Volumes in MWh	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
5			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
6		Off System Transactions													
7		Fixed Price													
8		Base Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Competitive Solicitations	28,600	29,400	27,600	29,400	28,025	28,600	103,400	93,598	103,275	100,400	103,256	99,992	775,546
10		Base Fixed Price Sales	-	-	-										-
11		Competitive Solicitations	-	-	-	-	-	-			-	-			-
12		Term Fixed Price Purchases	90,000	75,564	19,200	21,600	20,000	40,000	-	-	-	-			266,364
13		Term Fixed Price Sales	-	-	-	-	-	-			-	-			-
14		Index Price													
15		Base Index Price Purchases	-	-	-	-	-	-			-	-			-
16		Base Index Price Sales		-	-	-	-	-			-	-			-
17		Competitive Solicitations	(28,600)	(29,400)	(27,600)	(29,515)	(28,025)	(28,600)	(29,000)	(26,402)	(28,975)	(28,400)	(29,000)	(28,000)	(341,517)
18		Term Index Price Purchases	-	-	-	-	-	-			-	-			-
19		Term Index Price Sales	(90,000)	(75,600)	(19,200)	(21,600)	(20,000)	(40,000)	(74,400)	(67,200)	(74,300)	(72,000)	(74,400)	(71,992)	(700,692)
20		Spot Purchases	-		-	-	-	-			-	-	-	-	-
21		Spot Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
22															
23		On System Transactions													
24		Fixed Price													
25		Rate-Based Assets													
26		Colstrip Unit 4	89,669	149,166	148,514	150,045	152,348	138,213	159,562	143,944	151,263	125,201	84,803	73,679	1,566,407
27		Dave Gates Generating Station	5,208	5,208	5,040	5,208	5,047	5,208	5,208	4,704	5,201	5,040	5,208	5,040	61,320
28		Spion Kop	-	-	-	-	15,216	15,967	18,619	17,979	12,171	12,100	9,874	8,846	110,772
29		Base Fixed Price Purchases													
30		PPL 7 Year Contract	124,200	125,400	118,800	125,400	120,125	123,000	124,200	112,800	124,075	121,200	124,200	120,000	1,453,400
31		Judith Gap	21,604	26,452	28,382	40,055	43,758	48,594	67,086	57,104	42,072	48,752	34,928	30,398	489,185
32		Other Non-QF	14,334	11,321	8,600	5,524	3,933	11,769	3,921	11,832	3,863	3,600	8,313	11,793	98,803
33		Competitive Solicitations	20,000	21,600	19,200	21,600	20,000	20,000	20,800	19,200	20,800	20,800	20,800	20,000	244,800
34		QF Tier II	51,659	65,484	71,306	77,783	72,898	75,106	74,544	65,138	75,784	72,895	69,638	52,246	824,481
35		QF Tier II Adjustments	(6,001)												(6,001)
36		QF-1 Tariff Contracts	3,518	3,402	2,938	4,379	5,401	5,540	6,315	5,280	4,966	20,816	11,645	8,145	82,345
37		Term Fixed Price Purchases	2,158	-	-	-	1,971					12,750	6,288	7,239	30,406
38		Term Fixed Price Sales	(6,458)	(6,558)	(5,312)	(5,472)	-					-	(1,950)	-	(25,750)
39		Index Price													
40		Base Index Price Purchases													
41		Competitive Solicitations	28,600	29,400	27,600	29,400	28,025	28,600	45,400	40,800	45,325	43,600	45,400	44,000	436,150
42		Term Index Price Purchases	79,733	73,709	36,000	18,473	19,566	50,572	34,149	31,277	23,792	11,925	13,184	10,000	402,380
43		Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
44		Spot Purchases	161,548	71,006	26,049	31,509	42,873	66,174	40,619	30,231	31,593	29,356	69,353	109,173	709,484
45		Spot Sales	(2,861)	(7,524)	(6,447)	(10,886)	(13,661)	(6,488)	(12,419)	(20,176)	(24,466)	(15,484)	(10,805)	(9,029)	(140,246)
46		Imbalance, Current Month Estimate	41,876	11,831	7,153	7,145	12,115	-	17,703	3,591	-	-	-	-	101,414
47		Imbalance, Prior Months True-up	(4,324)	(30,248)	41,876	-	11,901	-	27,548	27,548	(17,703)	(3,591)	-	-	53,007
48		Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
49															
50		Ancillary and Other													
51		Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
52		Basin Creek Variable Costs	2,209	4,109	1,175	2,873	606	4,584	3,863	1,261	4,215	1,517	2,744	4,632	33,789
53		Basin Creek Fuel													
54		Basin Creek Storage													
55		Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
56		Wind Other Cost													
57		DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
58		DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
59		DSM Lost Revenue Adjustment													
60															
61		Total Delivered Supply	626,872	553,722	530,873	502,921	542,122	586,840	637,119	552,509	502,951	510,478	493,479	496,162	6,535,847
62															
63		Electric Tracker Projection Excluding Generation Assets Cost of Service													
64		Total Supply Expense													
65															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
66		Energy Supply Revenue (Expense)	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Total
67			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
68		Off System Transactions													
69		Fixed Price													
70		Base Fixed Price Purchases													
71		Competitive Solicitations	$ 1,652,140	$ 1,691,460	$ 1,595,040	$ 1,691,460	$ 1,616,260	$ 1,652,140	$ 4,362,240	$ 3,958,958	$ 4,357,660	$ 4,252,320	$ 4,357,147	$ 4,215,360	$ 35,402,185
72		Base Fixed Price Sales													
73		Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74		Term Fixed Price Purchases	$ 2,488,500	$ 2,203,344	$ 689,760	$ 775,980	$ 718,500	$ 1,439,000		$ -		$ -	$ -	$ -	$ 8,315,084
75		Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
76		Index Price													
77		Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -
78		Base Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -					$ -
79		Competitive Solicitations	$ (278,580)	$ (390,724)	$ (300,788)	$ (411,288)	$ (343,035)	$ (317,880)	$ (356,968)	$ (327,158)	$ (394,345)	$ (377,092)	$ (409,432)	$ (391,012)	$ (4,298,302)
80		Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Term Index Price Sales	$ (1,996,020)	$ (2,339,392)	$ (492,616)	$ (701,256)	$ (577,920)	$ (1,047,820)	$ (2,046,704)	$ (1,915,008)	$ (2,349,150)	$ (1,879,808)	$ (1,849,592)	$ (2,032,710)	$ (19,227,996)
82		Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83		Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84															
85		On System Transactions													
86		Fixed Price													
87		Rate-Based Assets													
88		Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89		Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90		Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91		Base Fixed Price Purchases													
92		PPL 7 Year Contract	$ 6,532,920	$ 6,596,040	$ 6,248,880	$ 6,602,310	$ 6,324,581	$ 6,475,950	$ 6,545,340	$ 5,944,560	$ 6,538,753	$ 6,393,300	$ 6,551,550	$ 6,330,000	$ 77,084,184
93		Judith Gap	$ 645,025	$ 900,168	$ 968,872	$ 1,205,418	$ 1,399,531	$ 1,597,468	$ 2,186,368	$ 1,861,475	$ 1,272,812	$ 1,126,079	$ 791,726	$ 699,921	$ 14,654,864
94		Other Non-QF	$ 796,609	$ 601,173	$ 433,511	$ 219,619	$ 160,166	$ 160,166	$ 160,166	$ 632,668	$ 160,166	$ 160,166	$ 484,402	$ 599,910	$ 4,568,721
95		Competitive Solicitations	$ 1,080,500	$ 1,166,940	$ 1,037,280	$ 1,166,940	$ 1,080,500	$ 1,080,500	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,123,805	$ 1,080,500	$ 13,225,405
96		QF Tier II	$ 1,820,403	$ 2,401,298	$ 2,614,791	$ 2,852,303	$ 2,673,170	$ 2,754,137	$ 2,733,528	$ 2,388,610	$ 2,778,999	$ 2,673,060	$ 2,553,625	$ 2,263,546	$ 30,507,471
97		QF Tier II Adjustments	$ (102,929)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ (102,929)
98		QF-1 Tariff Contracts	$ 176,549	$ 183,130	$ 183,013	$ 280,493	$ 346,402	$ 345,883	$ 400,936	$ 333,981	$ 302,745	$ 1,419,709	$ 624,634	$ 535,593	$ 5,133,068
99		Term Fixed Price Purchases	$ 49,613	$ -	$ -	$ -	$ 12,210	$ -	$ -	$ -	$ -	$ 108,000	$ 88,651	$ 120,224	$ 378,698
100		Term Fixed Price Sales	$ (318,521)	$ (213,113)	$ (160,361)	$ (161,431)	$ -	$ -	$ -	$ -	$ -	$ -	$ (145,649)	$ -	$ (999,075)
101		Index Price													
102		Base Index Price Purchases													
103		Competitive Solicitations	$ 202,780	$ 313,324	$ 227,588	$ 329,568	$ 268,960	$ 242,080	$ 623,484	$ 593,200	$ 737,492	$ 523,812	$ 472,464	$ 583,420	$ 5,118,172
104		Term Index Price Purchases	$ 1,637,793	$ 2,076,312	$ 846,792	$ 474,336	$ 587,150	$ 1,278,212	$ 980,805	$ 911,035	$ 813,080	$ 294,492	$ 325,032	$ 309,512	$ 10,534,552
105		Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106		Spot Purchases	$ 1,501,518	$ 1,427,581	$ 547,903	$ 881,806	$ 1,164,280	$ 1,390,939	$ 1,160,097	$ 802,450	$ 1,076,168	$ 565,087	$ 1,582,064	$ 3,390,583	$ 15,490,476
107		Spot Sales	$ (30,952)	$ (151,070)	$ (127,366)	$ (256,873)	$ (282,063)	$ (145,446)	$ (297,088)	$ (450,505)	$ (563,668)	$ (284,498)	$ (127,462)	$ (65,674)	$ (2,782,665)
108		Imbalance, Current Month Estimate	$ 399,560	$ 193,149	$ 105,034	$ 154,795	$ 242,355	$ 736,503	$ 399,525	$ 75,251	$ 39,937	$ (43,349)	$ 100,285	$ 368,329	$ 2,771,374
109		Imbalance, Prior Months True-up	$ (7,046)	$ (9,973)	$ (43,697)	$ 135,151	$ 93,255	$ (154,795)	$ 186,406	$ 10,391	$ (136,485)	$ 484,099	$ 376,922	$ 499,407	$ 1,433,635
110		Imbalance, Accounting & BA Expense	$ 875,495	$ 458,459	$ 43,697	$ 89,215	$ (168,855)	$ 154,795	$ -	$ (151,788)	$ 253,777	$ -	$ -	$ -	$ 1,554,794
111															
112		Ancillary and Other													
113		Basin Creek Fixed Costs	$ 452,985	$ 452,985	$ 452,985	$ 452,985	$ 878,354	$ 452,985	$ 412,077	$ 460,191	$ 460,191	$ 467,562	$ 898,486	$ 481,990	$ 6,323,776
114		Basin Creek Variable Costs	$ 10,883	$ 19,638	$ 5,668	$ 13,455	$ 2,955	$ 21,343	$ 18,083	$ 6,010	$ 19,533	$ -	$ -	$ -	$ 117,568
115		Basin Creek Fuel	$ 73,669	$ 93,036	$ 47,924	$ 87,122	$ 40,935	$ 166,984	$ 152,305	$ 69,993	$ 160,109	$ 87,335	$ 116,541	$ 114,794	$ 1,210,748
116		Basin Creek Storage	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 3,000	$ 36,000
117		Operating Reserves	$ 104,160	$ 104,160	$ 100,800	$ 104,160	$ 100,940	$ 111,600	$ 111,600	$ 100,800	$ 111,450	$ -	$ -	$ -	$ 949,670
118		Wind Other Cost	$ 24,523	$ 2,873	$ 5,476	$ 18,177	$ 767,871	$ 2,871	$ 6,955	$ 26,728	$ 4,445	$ 33,285	$ 10,821	$ 767,705	$ 1,671,728
119		DSM Program & Labor Costs	$ 455,133	$ 2,379,492	$ 925,980	$ 849,801	$ 1,188,455	$ 635,469	$ 710,938	$ 566,772	$ 548,044	$ 1,541,279	$ 625,676	$ 409,552	$ 10,836,590
120		DSM Lost T& D Revenues	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 395,530	$ 4,746,366
121		DSM Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,341)	$ (16,341)
122															
123		Total Delivered Supply	$ 18,645,240	$ 20,558,820	$ 16,354,695	$ 17,252,776	$ 18,693,487	$ 19,431,615	$ 19,972,344	$ 17,334,425	$ 17,713,964	$ 19,067,091	$ 18,950,225	$ 20,663,138	$ 224,637,820
124			Wind Other Cost includes: Judith Gap impact fees and property tax charges, Global Energy fees, 3 Tier fees, electric service at met towers, and met tower site leases.												
125		Electric Tracker Projection Excluding Generation Assets Cost of Service													
126		Unit Costs													
127															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
128		**Energy Supply Unit Costs**	**Jul-12**	**Aug-12**	**Sep-12**	**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Total**
129			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
130		**Off System Transactions**													
131		**Fixed Price**													
132		Base Fixed Price Purchases													
133		Competitive Solicitations	$ 57.77	$ 57.53	$ 57.79	$ 57.53	$ 57.67	$ 57.77	$ 42.19	$ 42.30	$ 42.19	$ 42.35	$ 42.20	$ 42.16	$ 45.65
134		Base Fixed Price Sales													
135		Competitive Solicitations	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
136		Term Fixed Price Purchases	$ 27.65	$ 29.16	$ 35.93	$ 35.93	$ 35.93	$ 35.98	n/a	n/a	n/a	n/a	n/a	n/a	$ 31.22
137		Term Fixed Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
138		**Index Price**													
139		Base Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
140		Base Index Price Sales													
141		Competitive Solicitations	$ 9.74	$ 13.29	$ 10.90	$ 13.93	$ 12.24	$ 11.11	$ 12.31	$ 12.39	$ 13.61	$ 13.28	$ 14.12	$ 13.96	$ 12.59
142		Term Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
143		Term Index Price Sales	$ 22.18	$ 30.94	$ 25.66	$ 32.47	$ 28.90	$ 26.20	$ 27.51	$ 28.50	$ 31.62	$ 26.11	$ 24.86	$ 28.24	$ 27.44
144		Spot Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
145		Spot Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
146															
147		**On System Transactions**													
148		**Fixed Price**													
149		Rate-Based Assets													
150		Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
151		Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152		Spion Kop	n/a	n/a	n/a	n/a	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153		Base Fixed Price Purchases													
154		PPL 7 Year Contract	$ 52.60	$ 52.60	$ 52.60	$ 52.65	$ 52.65	$ 52.65	$ 52.70	$ 52.70	$ 52.70	$ 52.75	$ 52.75	$ 52.75	$ 52.67
155		Judith Gap	$ 29.86	$ 34.03	$ 34.14	$ 30.09	$ 31.98	$ 32.87	$ 32.59	$ 32.60	$ 30.25	$ 23.10	$ 22.67	$ 23.03	$ 29.96
156		Other Non-QF	$ 55.57	$ 53.10	$ 50.41	$ 39.76	$ 40.72	$ 13.61	$ 40.85	$ 53.47	$ 41.46	$ 44.49	$ 58.27	$ 50.87	$ 46.24
157		Competitive Solicitations	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03
158		QF Tier II	$ 35.24	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 36.67	$ 43.32	$ 37.00
159		QF Tier II Adjustments													
160		QF-1 Tariff Contracts	$ 50.18	$ 53.83	$ 62.30	$ 64.05	$ 64.13	$ 62.43	$ 63.49	$ 63.25	$ 60.96	$ 68.20	$ 53.64	$ 65.76	$ 62.34
161		Term Fixed Price Purchases	$ 22.99	n/a	n/a	n/a	$ 6.19	n/a	n/a	n/a	n/a	$ 8.47	$ 14.10	$ 16.61	$ 12.45
162		Term Fixed Price Sales	$ 49.32	$ 32.50	$ 30.19	$ 29.50	n/a	n/a	n/a	n/a	n/a	n/a	$ 74.69	n/a	$ 38.80
163		**Index Price**													
164		Base Index Price Purchases													
165		Competitive Solicitations	$ 7.09	$ 10.66	$ 8.25	$ 11.21	$ 9.60	$ 8.46	$ 13.73	$ 14.54	$ 16.27	$ 12.01	$ 10.41	$ 13.26	$ 11.73
166		Term Index Price Purchases	$ 20.54	$ 28.17	$ 23.52	$ 25.68	$ 30.01	$ 25.28	$ 28.72	$ 29.13	$ 34.17	$ 24.70	$ 24.65	$ 30.95	$ 26.18
167		Term Index Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
168		Spot Purchases	$ 9.29	$ 20.11	$ 21.03	$ 27.99	$ 27.16	$ 21.02	$ 28.56	$ 26.54	$ 34.06	$ 19.25	$ 22.81	$ 31.06	$ 21.83
169		Spot Sales	$ 10.82	$ 20.08	$ 19.76	$ 23.60	$ 20.65	$ 22.42	$ 23.92	$ 22.33	$ 23.04	$ 18.37	$ 11.80	$ 7.27	$ 19.84
170		Imbalance, Current Month Estimate	$ 9.54	$ 16.33	$ 14.68	$ 21.66	$ 20.00	n/a	$ 22.57	$ 20.96	n/a	n/a	n/a	n/a	$ 27.33
171		Imbalance, Prior Months True-up	$ 1.63	$ 0.33	$ (1.04)	n/a	$ 7.84	n/a	$ 6.77	$ 0.38	$ 7.71	$ (134.82)	n/a	n/a	$ 27.05
172		Imbalance, Accounting & BA Expense													
173															
174		**Ancillary and Other**													
175		Basin Creek Fixed Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
176		Basin Creek Variable Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
177		Basin Creek Fuel	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
178		Basin Creek Storage	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
179		Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
180		Wind Other Cost	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
181		DSM Program & Labor Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
182		DSM Lost T& D Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
183		DSM Lost Revenue Adjustment	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
184															
185															
186		**Total Delivered Supply**	$ 29.75	$ 37.13	$ 30.81	$ 34.31	$ 34.48	$ 33.11	$ 31.35	$ 31.37	$ 35.22	$ 37.35	$ 38.40	$ 41.65	$ 34.37
187															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		**Electric Supply Cost Tracker**													
2		**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3															
4			Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
5			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
6		Total Sales and Unit Costs													
7		MWh	491,640	533,182	550,670	474,011	456,075	524,347	590,410	528,895	537,758	475,663	449,909	444,983	6,057,542
8		Supply Cost	$ 39.8325	$ 39.4847	$ 40.7410	$ 40.5827	$ 39.5796	$ 39.3337	$ 39.1947	$ 38.7076	$ 38.9291	$ 38.6198	$ 38.0174	$ 36.9313	$ 39.5796
9		YNP MWh	2,528	2,579	2,453	2,559	1,778	597	583	633	662	520	906	3,821	19,619
10		YNP Supply Rate	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000	$ 63.3000
11		Prior Year(s) Deferred Expense	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	$ 0.5808	
12															
13															
14		Electric Cost Revenues													
15		NWE Electric Supply	$ 18,937,887	$ 21,120,134	$ 22,182,096	$ 19,264,384	$ 18,371,613	$ 20,748,735	$ 23,392,560	$ 20,550,287	$ 20,904,263	$ 18,489,345	$ 17,297,443	$ 16,741,957	$ 238,000,704
16		YNP Electric Supply	$ 159,858	$ 163,134	$ 155,131	$ 161,814	$ 112,477	$ 37,515	$ 36,441	$ 39,892	$ 40,998	$ 32,776	$ 57,651	$ 245,505	$ 1,243,192
17		Subtotal	$ 19,097,745	$ 21,283,268	$ 22,337,227	$ 19,426,198	$ 18,484,090	$ 20,786,250	$ 23,429,001	$ 20,590,179	$ 20,945,261	$ 18,522,121	$ 17,355,094	$ 16,987,462	$ 239,243,896
18		Prior Year(s) Deferred Expense	$ 250,196	$ (292,395)	$ (320,673)	$ (273,651)	$ (265,160)	$ (304,887)	$ (343,401)	$ (306,796)	$ (312,757)	$ (276,487)	$ (261,515)	$ (258,625)	$ (2,966,153)
19		Total Revenue	$ 19,347,940	$ 20,990,873	$ 22,016,555	$ 19,152,547	$ 18,218,930	$ 20,481,363	$ 23,085,601	$ 20,283,383	$ 20,632,503	$ 18,245,634	$ 17,093,578	$ 16,728,837	$ 236,277,743
20															
21		Electric Supply Expenses													
22		Net Base Purchases	$ 18,030,042	$ 17,130,630	$ 16,707,311	$ 18,436,727	$ 18,004,113	$ 19,884,914	$ 19,726,406	$ 17,715,083	$ 17,622,882	$ 17,458,202	$ 16,553,287	$ 16,013,598	$ 213,283,195
23		Net Base Sales	$ (527,824)	$ (55,800)	$ (418,868)	$ (453,448)	$ (427,803)	$ (616,672)	$ (481,980)	$ (757,212)	$ (386,049)	$ (376,320)	$ (407,736)	$ (398,043)	$ (5,307,755)
24		Net Term Purchases	$ 3,678,881	$ 3,540,687	$ 1,415,822	$ 1,528,492	$ 1,611,939	$ 4,320,724	$ 2,500,160	$ 1,365,085	$ 313,274	$ 293,720	$ 323,336	$ 2,665,087	$ 23,557,208
25		Net Term Sales	$ (3,047,088)	$ (3,346,968)	$ (2,839,070)	$ (2,958,244)	$ (2,852,948)	$ (5,469,152)	$ (3,847,376)	$ (5,308,317)	$ (2,264,860)	$ (2,547,112)	$ (1,957,581)	$ (2,118,099)	$ (38,558,815)
26		Net Spot Purchases	$ 3,947,944	$ 3,859,283	$ 3,472,448	$ 2,489,486	$ 2,955,787	$ 4,365,147	$ 2,647,380	$ 8,483,122	$ 3,321,160	$ 1,355,289	$ 2,991,999	$ 2,737,902	$ 42,636,947
27		Net Spot Sales	$ (149,520)	$ (169,048)	$ (148,545)	$ (184,224)	$ (50,186)	$ (109,659)	$ (269,746)	$ (421,526)	$ (123,391)	$ (144,617)	$ (29,314)	$ (103,148)	$ (1,902,925)
28		Other Tracker Costs	$ 3,864,403	$ 2,667,114	$ 2,383,214	$ 2,956,992	$ 3,219,256	$ 4,236,614	$ 2,487,528	$ 2,643,536	$ 1,728,160	$ 2,926,502	$ 3,341,588	$ 2,479,020	$ 34,933,926
29		Total Electric Supply Expenses	$ 25,796,837	$ 23,635,898	$ 20,572,311	$ 21,815,781	$ 22,460,158	$ 26,611,916	$ 22,762,372	$ 23,719,771	$ 20,211,177	$ 18,965,663	$ 20,815,578	$ 21,276,317	$ 268,643,781
30															
31		NWE Transmission Costs													
32															
33		Other Services (Wheeling)	$ 71,076	$ 90,141	$ 51,915	$ 60,715	$ 40,830	$ 47,286	$ 58,786	$ 76,297	$ 45,042	$ 220,535	$ 38,991	$ 32,784	$ 834,399
34		Ancillary Cost (Disallowed)	$ (15,863)	$ 28,688	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ (1,013)	$ 2,700
35		Total NWE Transmission	$ 55,213	$ 118,828	$ 50,903	$ 59,703	$ 39,818	$ 46,273	$ 57,774	$ 75,284	$ 44,030	$ 219,522	$ 37,979	$ 31,772	$ 837,099
36															
37		Administrative Expenses													
38		MPSC Tax Collection (.0023)	$ 43,886	$ 47,818	$ 50,023	$ 79,447	$ 75,284	$ 85,081	$ 92,874	$ 83,322	$ 83,713	$ 74,036	$ 69,358	$ 67,267	$ 852,109
39		MCC Tax Collection (.0007)	$ 13,357	$ 14,553	$ 15,224	$ 20,800	$ 19,717	$ 22,283	$ 24,324	$ 21,823	$ 21,925	$ 19,390	$ 18,165	$ 17,617	$ 229,179
40		Modeling	$ 84,921	$ 11,177	$ 75,084	$ 38,042	$ 31,667	$ 54,177	$ 14,000	$ 66,355	$ -	$ 1,250	$ 30,770	$ 57,439	$ 464,883
41		Trading & Marketing	$ 9,994	$ 7,591	$ 6,514	$ 9,326	$ 7,804	$ 8,282	$ 5,507	$ 9,392	$ 5,516	$ 6,950	$ 9,797	$ 7,454	$ 94,127
42		Administration	$ 9,637	$ 12,013	$ 37,589	$ 51,714	$ 5,239	$ 275,400	$ 2,981	$ 8,875	$ 74,840	$ 6,307	$ 2,604	$ 3,524	$ 490,923
43		Total Administrative Expenses	$ 161,795	$ 93,151	$ 184,434	$ 199,329	$ 139,712	$ 445,224	$ 139,685	$ 189,767	$ 185,994	$ 107,933	$ 130,894	$ 153,302	$ 2,131,220
44															
45		Carrying Cost Expense													
46		Carrying Costs	$ 45,692	$ 64,966	$ 57,370	$ 77,154	$ 107,020	$ 151,699	$ 151,872	$ 177,457	$ 177,365	$ 193,738	$ 212,672	$ 245,508	$ 1,662,513
47		Carry Adjustment										$ 8,132			$ 8,132
48		Total Carrying Costs	$ 45,692	$ 64,966	$ 57,370	$ 77,154	$ 107,020	$ 151,699	$ 151,872	$ 177,457	$ 177,365	$ 201,870	$ 212,672	$ 245,508	$ 1,670,645
49															
50															
51		Total Expenses	$ 26,059,538	$ 23,912,843	$ 20,865,019	$ 22,151,967	$ 22,746,707	$ 27,255,113	$ 23,111,703	$ 24,162,279	$ 20,618,566	$ 19,494,988	$ 21,197,124	$ 21,706,898	$ 273,282,745
52															
53		Deferred Cost Amortization	$ 250,196	$ (292,395)	$ (320,673)	$ (273,651)	$ (265,160)	$ (304,887)	$ (343,401)	$ (306,796)	$ (312,757)	$ (276,487)	$ (261,515)	$ (258,625)	$ (2,966,153)
54		(under collection)/over collection													
55		Monthly Deferred Cost	$ (6,961,793)	$ (2,629,575)	$ 1,472,209	$ (2,725,768)	$ (4,262,617)	$ (6,468,863)	$ 317,298	$ (3,572,099)	$ 326,695	$ (972,867)	$ (3,842,030)	$ (4,719,436)	$ (34,038,849)
56		Cumulative Deferred Cost	$ (6,961,793)	$ (9,591,369)	$ (8,119,160)	$ (10,844,928)	$ (15,107,546)	$ (21,576,409)	$ (21,259,111)	$ (24,831,210)	$ (24,504,515)	$ (25,477,383)	$ (29,319,413)	$ (34,038,849)	
57															
58		Note 1 MCC_076 folder on CD attached to MCC-019 contained attachments updated with actual information replacing estimated information for April, May, and June 2014.													
59		2 PSC-022 corrected the entry in cell N78 moved to cell N102 on page 3.													
60		3 PSC-045 corrected the off system spot to term categories on page 3.													
61		4 PSC-073 with this exhibit provides the updated footnote version of this exhibit.													

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	**Electric Supply Cost Tracker**													
2	**Electric Tracker Projection Excluding Generation Assets Cost of Service**													
3														
4														
5			**Jul-13**	**Aug-13**	**Sep-13**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**
6			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
7														
8		Note: for supply cost expense positive value reflects an under collection, negative an (over collection).												
9	Deferred Supply Cost Expense													
10		Beginning Balance	$ 215,706	$ 6,927,304	$ 9,849,274	$ 8,697,739	$ 11,697,158	$ 16,224,936	$ 22,998,686	$ 23,024,789	$ 26,903,684	$ 26,889,747	$ 28,139,101	$ 32,242,647
11		Monthly Deferred Cost	$ 6,711,598	$ 2,921,970	$ (1,151,536)	$ 2,999,420	$ 4,527,778	$ 6,773,750	$ 26,102	$ 3,878,895	$ (13,938)	$ 1,249,355	$ 4,103,545	$ 4,978,061
12		Ending Balance	$ 6,927,304	$ 9,849,274	$ 8,697,739	$ 11,697,158	$ 16,224,936	$ 22,998,686	$ 23,024,789	$ 26,903,684	$ 26,889,747	$ 28,139,101	$ 32,242,647	$ 37,220,708
13														
14														
15	Total Capital		$ 6,927,304	$ 9,849,274	$ 8,697,739	$ 11,697,158	$ 16,224,936	$ 22,998,686	$ 23,024,789	$ 26,903,684	$ 26,889,747	$ 28,139,101	$ 32,242,647	$ 37,220,708
16														
17														
18														
19	Cost of Capital		Rate	% Capitalization	Rate of Return									
20		Long-Term Debt	5.76%	52.00%	3.00%									
21		Common Equity	10.25%	48.00%	4.92%									
22														
23		Average Cost of Capital			7.92%									
24														
25	Deferred Supply Expense													
26		Carrying Charge	7.92%											
27														

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		Electric Supply Cost Tracker													
2		Electric Tracker Projection													
3															
4		Volumes in MWh	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
5			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
6		Off System Transactions													
7		Fixed Price													
8		Base Fixed Price Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Competitive Solicitations	113,800	114,600	109,187	114,575	110,122	113,000	113,800	103,150	113,674	110,782	112,949	110,000	1,339,639
10		Base Fixed Price Sales													-
11		Competitive Solicitations	-		-	-	-	-		-	-				-
12		Term Fixed Price Purchases	-		-	-	-	20,000	10,400	-	-	-	-	-	30,400
13		Term Fixed Price Sales	-		-	-	-	-		-	-				-
14		Index Price													
15		Base Index Price Purchases	-		-	-	-	-		-	-				-
16		Base Index Price Sales													-
17		Competitive Solicitations	(29,000)	(18,600)	(27,600)	(29,410)	(28,025)	(28,600)	(29,000)	(26,400)	(28,975)	(28,400)	(29,000)	(28,000)	(331,010)
18		Term Index Price Purchases													-
19		Term Index Price Sales	(84,800)	(96,000)	(81,587)	(85,200)	(82,100)	(104,400)	(95,200)	(76,523)	(84,700)	(82,400)	(84,296)	(82,000)	(1,039,206)
20		Spot Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
21		Spot Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
22															
23		On System Transactions													
24		Fixed Price													
25		Rate-Based Assets													
26		Colstrip Unit 4	73,215	81,713	79,371	71,355	70,692	81,925	104,897	139,201	139,201	93,548	57,568	55,395	1,048,081
27		Dave Gates Generating Station	5,208	5,208	5,040	5,208	5,047	5,208	5,208	4,704	5,201	5,040	5,208	5,208	61,488
28		Spion Kop	6,049	5,584	8,714	11,128	15,057	20,147	18,319	11,614	13,798	13,769	5,335	9,602	139,116
29		Base Fixed Price Purchases													
30		PPL 7 Year Contract	124,200	125,400	118,800	125,400	120,125	123,000	124,200	112,800	124,075	121,200	124,200	120,000	1,463,400
31		Judith Gap	21,737	21,414	28,462	42,122	44,484	69,225	73,897	49,623	48,195	47,860	24,519	31,406	502,944
32		Other Non-QF	9,674	8,810	-	(586)	3,605	3,720	3,720	3,360	4,446	4,494	(3,450)	11,064	48,857
33		Competitive Solicitations	20,800	21,600	19,200	51,000	20,000	20,000	20,800	19,200	20,800	20,800	20,800	20,000	275,000
34		QF Tier II	69,242	63,517	63,538	63,538	72,104	73,684	68,425	58,245	54,961	66,538	67,658	34,412	755,862
35		QF Tier II Adjustments	-	-	-					-					-
36		QF-1 Tariff Contracts	22,919	10,687	3,689	22,503	14,149	13,580	15,135	10,063	11,189	12,035	7,089	12,678	155,715
37		Term Fixed Price Purchases	11,160	21,960	16,575	13,167	12,690	13,035	1,950	-	5,775	1,950	1,950	1,875	102,087
38		Term Fixed Price Sales	(1,950)	-	(1,800)	(2,025)	(1,875)	(1,875)	(1,950)	(1,818)	-	(17,654)	(1,950)	(1,875)	(34,772)
39		Index Price													
40		Base Index Price Purchases													
41		Competitive Solicitations	45,400	34,200	44,424	15,600	34,080	45,800	45,376	40,741	45,325	43,600	45,400	43,905	483,851
42		Term Index Price Purchases	86,320	82,080	38,400	43,200	42,958	63,381	51,963	19,186	10,400	10,400	10,400	78,000	536,688
43		Term Index Price Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
44		Spot Purchases	113,022	105,031	89,915	71,663	92,220	79,625	62,075	97,561	118,995	82,565	120,901	113,617	1,147,190
45		Spot Sales	(5,213)	(7,761)	(5,480)	(6,462)	(1,894)	(2,609)	(7,021)	(9,600)	(3,610)	(5,812)	(2,116)	(4,671)	(62,249)
46		Imbalance, Current Month Estimate	-	-	-	-	-	-	-	-	-	-	-	-	-
47		Imbalance, Prior Months True-up	-	-	-	-	-	-	-	-	-	-	-	-	-
48		Imbalance, Accounting & BA Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
49															
50		Ancillary and Other													
51		Basin Creek Fixed Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
52		Basin Creek Variable Costs	10,351	18,772	5,189	8,575	10,771	15,115	9,492	4,365	1,181	451	3,138	1,113	88,513
53		Operating Reserves	-	-	-	-	-	-	-	-	-	-	-	-	-
54		Wind Other Cost													
55		DSM Program & Labor Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
56		DSM Lost T& D Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
57		DSM Lost Revenue Adjustment													
58															
59		Total Delivered Supply	612,134	598,215	514,037	535,351	554,210	622,961	596,486	559,472	599,930	500,766	486,303	531,729	6,711,594
60															

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		Electric Supply Cost Tracker													
2		Electric Tracker Projection													
3															
61		Electric Tracker Projection Excluding Generation Assets Cost of Service													
62		Total Supply Expense													
63															
64		Energy Supply Expense	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
65			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
66		Off System Transactions													
67		Fixed Price													
68		Base Fixed Price Purchases													
69		Competitive Solicitations	$ 5,004,440	$ 5,065,860	$ 4,771,290	$ 4,998,361	$ 4,781,318	$ 4,943,020	$ 5,004,440	$ 4,550,340	$ 4,999,830	$ 4,893,980	$ 4,979,089	$ 4,833,100	$ 58,825,068
70		Base Fixed Price Sales													
71		Competitive Solicitations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
72		Term Fixed Price Purchases	$ -	$ -	$ -	$ -	$ -	$ 792,500	$ 439,400	$ -	$ -	$ -	$ -	$ -	$ 1,231,900
73		Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
74		Index Price													
75		Base Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -			$ -
76		Base Index Price Sales													
77		Competitive Solicitations	$ (527,824)	$ (55,800)	$ (418,868)	$ (453,448)	$ (427,803)	$ (616,672)	$ (481,980)	$ (757,212)	$ (386,049)	$ (376,320)	$ (407,736)	$ (398,043)	$ (5,307,755)
78		Term Index Price Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79		Term Index Price Sales	$ (3,047,088)	$ (3,346,968)	$ (2,839,070)	$ (2,958,244)	$ (2,852,948)	$ (5,469,152)	$ (3,847,376)	$ (5,308,317)	$ (2,264,860)	$ (2,138,808)	$ (1,957,581)	$ (2,118,099)	$ (38,146,511)
80		Spot Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81		Spot Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82															
83		On System Transactions													
84		Fixed Price													
85		Rate-Based Assets													
86		Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87		Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88		Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89		Base Fixed Price Purchases													
90		PPL 7 Year Contract	$ 6,557,760	$ 6,621,120	$ 6,272,640	$ 6,627,390	$ 6,348,606	$ 6,500,550	$ 6,570,180	$ 5,967,120	$ 6,563,568	$ 6,417,540	$ 6,576,390	$ 6,354,000	$ 77,376,864
91		Judith Gap	$ 656,209	$ 729,879	$ 973,798	$ 1,268,736	$ 1,426,426	$ 2,274,288	$ 2,428,739	$ 1,624,791	$ 1,461,608	$ 1,106,208	$ 565,757	$ 723,742	$ 15,240,182
92		Other Non-QF	$ 620,879	$ 412,482	$ (17,774)	$ (44,485)	$ 164,376	$ 164,376	$ 164,376	$ 164,376	$ 164,376	$ 164,376	$ 79,306	$ 567,705	$ 2,604,371
93		Competitive Solicitations	$ 1,123,720	$ 1,166,940	$ 1,037,280	$ 1,609,850	$ 1,490,500	$ 1,080,500	$ 1,123,720	$ 1,037,280	$ 1,123,720	$ 1,123,720	$ 1,123,720	$ 1,080,500	$ 14,121,450
94		QF Tier II	$ 2,587,574	$ 2,373,630	$ 2,374,415	$ 2,918,821	$ 2,694,526	$ 2,753,571	$ 2,557,042	$ 2,176,616	$ 2,053,893	$ 2,486,525	$ 2,528,379	$ 1,256,326	$ 28,761,319
95		QF Tier II Adjustments									$ -				
96		QF-1 Tariff Contracts	$ 762,132	$ 446,810	$ 521,172	$ 646,882	$ 682,434	$ 938,013	$ 905,781	$ 682,290	$ 717,406	$ 772,928	$ 348,625	$ 750,692	$ 8,175,164
97		Term Fixed Price Purchases	$ -	$ 464,400	$ 11,550	$ -	$ -	$ 22,224	$ -	$ -	$ 11,550	$ -	$ -	$ -	$ 509,724
98		Term Fixed Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (408,304)	$ -	$ -	$ (408,304)
99		Index Price													
100		Base Index Price Purchases													
101		Competitive Solicitations	$ 717,328	$ 313,908	$ 774,489	$ 411,172	$ 415,926	$ 1,230,596	$ 972,128	$ 1,512,271	$ 538,481	$ 492,924	$ 352,020	$ 447,533	$ 8,178,777
102		Term Index Price Purchases	$ 3,678,881	$ 3,076,287	$ 1,404,272	$ 1,528,492	$ 1,611,939	$ 3,506,000	$ 2,060,760	$ 1,365,085	$ 301,724	$ 293,720	$ 323,336	$ 2,665,087	$ 21,815,584
103		Term Index Price Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104		Spot Purchases	$ 3,947,944	$ 3,869,283	$ 3,472,448	$ 2,489,486	$ 2,955,787	$ 4,365,147	$ 2,647,380	$ 8,483,122	$ 3,321,160	$ 1,355,289	$ 2,991,999	$ 2,737,902	$ 42,636,947
105		Spot Sales	$ (149,520)	$ (169,048)	$ (148,545)	$ (184,224)	$ (50,186)	$ (109,659)	$ (269,746)	$ (421,526)	$ (123,391)	$ (144,617)	$ (29,314)	$ (103,148)	$ (1,902,925)
106		Imbalance, Current Month Estimate	$ 848,368	$ 147,733	$ 307,897	$ 25,898	$ 213,277	$ 771,799	$ 129,566	$ 1,172,250	$ (200,305)	$ (63,568)	$ (6,996)	$ (306,244)	$ 3,039,675
107		Imbalance, Prior Months True-up	$ 563,109	$ 16,493	$ (43,640)	$ (449,843)	$ (281,238)	$ 942,027	$ 96,511	$ 61,326	$ 14,801	$ 918,816	$ 611,056	$ 164,261	$ 2,613,679
108		Imbalance, Accounting & BA Expense	$ 12,938	$ (64,184)	$ 28,982	$ 7,076	$ 6,940	$ (10,450)	$ 27,990	$ -	$ 33,047	$ -	$ -	$ -	$ 42,340
109															
110		Ancillary and Other													
111		Basin Creek Fixed Costs	$ 337,431	$ 337,431	$ 341,391	$ 744,585	$ 796,268	$ 341,321	$ 355,119	$ 357,705	$ 346,440	$ 350,235	$ 532,011	$ 253,035	$ 5,092,969
112		Basin Creek Variable Costs	$ 427,829	$ 528,975	$ 497,509	$ 190,060	$ 597,368	$ 620,269	$ 428,230	$ 246,731	$ 122,126	$ 50,903	$ 200,690	$ 47,147	$ 3,957,838
113		Operating Reserves	$ 245,520	$ 245,520	$ 237,600	$ 245,570	$ 237,933	$ 245,520	$ 245,520	$ 222,660	$ 245,190	$ 237,600	$ 216,000	$ 216,000	$ 2,840,633
114		Wind Other Cost	$ 25,617	$ 4,428	$ 14,625	$ 4,343	$ 821,644	$ 2,276	$ 32,910	$ 2,409	$ 36,651	$ 8,521	$ 821,961	$ 2,434	$ 1,777,819
115		DSM Program & Labor Costs	$ 870,626	$ 917,752	$ 465,883	$ 1,697,454	$ 397,439	$ 866,557	$ 708,460	$ 117,232	$ 666,988	$ 960,772	$ 503,643	$ 1,166,772	$ 9,339,576
116		DSM Lost T& D Revenues	$ 532,966	$ 532,966	$ 532,966	$ 491,849	$ 464,409	$ 463,223	$ 463,223	$ 463,223	$ 463,223	$ 463,223	$ 463,223	$ 845,235	$ 6,179,728
117		DSM Lost Revenue Adjustment	$ -	$ -	$ -	$ -	$ (34,785)	$ (5,928)	$ -	$ -	$ -	$ -	$ -	$ 90,360	$ 49,668
118															
119		Total Delivered Supply	$ 25,796,837	$ 23,635,898	$ 20,572,311	$ 21,815,781	$ 22,460,158	$ 26,611,916	$ 22,762,372	$ 23,719,771	$ 20,211,177	$ 18,965,663	$ 20,815,578	$ 21,276,317	$ 268,643,781
120			Wind Other Cost Includes: Judith Gap impact fees and property tax charges, consulting work on met towers, 3 TIER corecasting fees, electric service at met towers, and WREGIS charges.												

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1		Electric Supply Cost Tracker													
2		Electric Tracker Projection													
3															
121		Electric Tracker Projection Excluding Generation Assets Cost of Service													
122		Unit Costs													
123															
124		Energy Supply Unit Costs	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Total
125			Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
126		Off System Transactions													
127		Fixed Price													
128		Base Fixed Price Purchases													
129		Competitive Solicitations	$ 43.98	$ 44.20	$ 43.70	$ 43.63	$ 43.42	$ 43.74	$ 43.98	$ 44.11	$ 43.98	$ 44.18	$ 44.08	$ 43.94	$ 43.91
130		Base Fixed Price Sales													
131		Competitive Solicitations	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
132		Term Fixed Price Purchases	n/a	n/a	n/a	n/a	n/a	$ 39.63	$ 42.25	n/a	n/a	n/a	n/a	n/a	$ 40.52
133		Term Fixed Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
134		Index Price													
135		Base Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
136		Base Index Price Sales													
137		Competitive Solicitations	$ 18.20	$ 3.00	$ 15.18	$ 15.42	$ 15.27	$ 21.56	$ 16.62	$ 28.68	$ 13.32	$ 13.25	$ 14.06	$ 14.22	$ 16.04
138		Term Index Price Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
139		Term Index Price Sales	$ 35.93	$ 34.86	$ 34.80	$ 34.72	$ 34.75	$ 52.39	$ 40.41	$ 69.37	$ 26.74	$ 25.96	$ 23.22	$ 25.83	$ 36.71
140		Spot Purchases	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
141		Spot Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
142															
143		On System Transactions													
144		Fixed Price													
145		Rate-Based Assets													
146		Colstrip Unit 4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147		Dave Gates Generating Station	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148		Spion Kop	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149		Base Fixed Price Purchases													
150		PPL 7 Year Contract	$ 52.80	$ 52.80	$ 52.80	$ 52.85	$ 52.85	$ 52.85	$ 52.90	$ 52.90	$ 52.90	$ 52.95	$ 52.95	$ 52.95	$ 52.87
151		Judith Gap	$ 30.19	$ 34.08	$ 34.21	$ 30.12	$ 32.07	$ 32.85	$ 32.87	$ 32.74	$ 30.33	$ 23.11	$ 23.07	$ 23.04	$ 30.30
152		Other Non-QF	$ 64.18	$ 46.82	n/a	$ 75.91	$ 45.60	$ 44.19	$ 44.19	$ 48.92	$ 36.97	$ 36.58	$ (22.99)	$ 51.31	$ 53.31
153		Competitive Solicitations	$ 54.03	$ 54.03	$ 54.03	$ 31.57	$ 74.53	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 54.03	$ 51.35
154		QF Tier II	$ 37.37	$ 37.37	$ 37.37	$ 45.94	$ 37.37	$ 37.37	$ 37.37	$ 37.37	$ 37.37	$ 37.37	$ 37.37	$ 36.51	$ 38.05
155		QF Tier II Adjustments	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
156		QF-1 Tariff Contracts	$ 33.25	$ 41.81	$ 141.28	$ 28.75	$ 48.23	$ 69.07	$ 59.85	$ 67.80	$ 64.12	$ 64.22	$ 49.18	$ 59.21	$ 52.50
157		Term Fixed Price Purchases	$ -	$ 21.15	$ 0.70	$ -	$ -	$ 1.70	$ -	n/a	$ 2.00	$ -	$ -	$ -	$ 4.99
158		Term Fixed Price Sales	$ -	n/a	$ -	$ -	$ -	$ -	$ -	$ -	n/a	$ 23.13	$ -	$ -	$ 11.74
159		Index Price													
160		Base Index Price Purchases													
161		Competitive Solicitations	$ 15.80	$ 9.18	$ 17.43	$ 26.36	$ 12.20	$ 26.87	$ 21.42	$ 37.12	$ 11.88	$ 11.31	$ 7.75	$ 10.19	$ 16.90
162		Term Index Price Purchases	$ 42.62	$ 37.48	$ 36.57	$ 35.38	$ 37.52	$ 55.32	$ 39.66	$ 71.15	$ 29.01	$ 28.24	$ 31.09	$ 34.17	$ 40.65
163		Term Index Price Sales	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
164		Spot Purchases	$ 34.93	$ 36.84	$ 38.62	$ 34.74	$ 32.05	$ 54.82	$ 42.65	$ 86.95	$ 27.91	$ 16.41	$ 24.75	$ 24.10	$ 37.17
165		Spot Sales	$ 28.68	$ 21.78	$ 27.11	$ 28.51	$ 26.50	$ 42.03	$ 38.42	$ 43.91	$ 34.18	$ 24.88	$ 13.85	$ 22.08	$ 30.57
166		Imbalance, Current Month Estimate	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
167		Imbalance, Prior Months True-up	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
168		Imbalance, Accounting & BA Expense													
169															
170		Ancillary and Other													
171		Basin Creek Fixed Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
172		Basin Creek Variable Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
173		Operating Reserves	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
174		Wind Other Cost	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
175		DSM Program & Labor Costs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
176		DSM Lost T& D Revenues	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
177		DSM Lost Revenue Adjustment	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
178															
179															
180		Total Delivered Supply	$ 42.14	$ 39.51	$ 40.02	$ 40.75	$ 40.53	$ 42.72	$ 38.16	$ 42.40	$ 33.69	$ 37.87	$ 42.80	$ 40.01	$ 40.03
181															

PSC-074

Regarding: Spot Market Transactions
Witness: Markovich

a. Please confirm that "[o]ff system purchases and sales net out to zero each month regardless of the line item where they are shown" in Mr. Bennett's Exhibits that show such information from July 2012 through June 2014. *See* PSC-045b.

b. Please identify any months from July 2012 through June 2014 in which NorthWestern sold more energy than it purchased in the spot market, and quantify the net amount sold.

c. Is it accurate to classify index-based sales used to effectuate Mid-C hedge transactions (entered into just prior to the start of the month) as spot sales?

d. Is there a better category (i.e., line item) for index-based sales used to effectuate Mid-C hedge transactions (entered into just prior to the start of the month) that already appears in Mr. Bennett's exhibits? *See* PSC-074.

RESPONSE:

a. Off-system term (30 days and longer) transactions should net to zero each month regardless of the line item where they appear. At times a Mid-C transaction might get curtailed which will cause the volumes to not exactly net to zero.

b. See the response to Data Request PSC-073. The revised exhibits show that from July 2012 through June 2014 there are no months in which NorthWestern sold more energy than it purchased in the spot market.

c. No. It is more accurate to classify these transactions as term sales rather than spot sales. The index based sales used to effectuate Mid-C hedge transactions are term transactions whose price or sales value is calculated on day-ahead prices during the term of the transaction. Each day during the term of the transaction contains a different pricing component; the individual day-ahead prices are averaged to come up with an average monthly price.

d. Term index priced sales is an appropriate category to describe these transactions as they are term (30 days and longer) transactions whose price is determined based on an index of day-ahead prices.

PSC-075

Regarding: Estimating Imbalance and Tracker Modeling
Witness: Bennett, parts a, b, c, e / Markovich, part d

In response to PSC-047 you said that "the model used for the tracker. . . . is a balanced model. To project excess purchases or excess sales creates an arbitrary, speculative state in the model."

a. Did NorthWestern use the same model for the tracker before and after July 2012? Please identify the model and its source, and describe how it works.

b. Please explain in detail how the model used for the tracker accounts for hours in which supply from owned and contracted resources exceeds retail customer load.

c. Please identify, by month from July 2012 through June 2014, the number of times the model used for the tracker accounted for an hour in which supply from owned and contracted resources exceeded retail customer load.

d. Please confirm that the model used for the tracker matches estimated resources with forecasted retail customer load *on an hourly basis*, that "imbalance" is an intra-hour service, and the model used for the tracker is not capable of intra-hour adjustments.

e. Please describe the extent to which the limitations of the model used for the tracker are the reason that NorthWestern stopped estimating future imbalance, and describe any other reasons why it stopped estimating future imbalance expenses in July 2012.

RESPONSE:

a. No, currently NorthWestern uses the deal capture system webTrader in combination with Microsoft Excel to group the transactions into the tracker categories requested in conversations with MPSC staff. Previously, only a Microsoft Excel workbook was used for the tracker model.

b. If forecast resources exceed the forecast load, the spreadsheet forecasts that a spot sale is necessary to balance the system.

c. The forecast model does not use hourly values, but uses the cumulative monthly values.

d. No, the model uses monthly values and does not have intra-hour capability. Unlike regulation service, imbalance is calculated hourly, not intra-hour. At this time, the model used for the tracker is not capable of either hourly or intra-hour adjustment for imbalances.

PSC-075 cont'd

e. On a day ahead and hourly basis NorthWestern balances resources to load and does not project long or short positions. The updated model adopts our actual practice to mimic the net zero position utilized in the day ahead and real-time practices.