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Issue: Fuel and Purchased Power
Expenses: Risks Associated with Expenses;
Fuel Adjustment Clause; In-Service Criteria;
O&M Expense
Witness: Brad P. Beecher
Type of Exhibit: Direct Testimony
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**Before the Public Service Commission
of the State of Missouri**

Direct Testimony

of

Brad P. Beecher

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OF
BRAD P. BEECHER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY
OF
BRAD P. BEECHER
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION
CASE NO.

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Brad P. Beecher. My business address is 602 Joplin Street, Joplin, Missouri.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. The Empire District Electric Company ("Empire" or "Company"). I am Vice President – Energy Supply.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND FOR THE COMMISSION.

A. I graduated from Kansas State University in 1988 with a Bachelor of Science Degree in Chemical Engineering.

Q. PLEASE GIVE AN OVERVIEW OF YOUR PROFESSIONAL EXPERIENCE.

A. I was employed by Empire immediately following my graduation from Kansas State University in May of 1988. From May of 1988 through August of 1999, I held roles as a staff engineer at Empire's Riverton Power Plant, in budgeting and fuel procurement in our Energy Supply Department, and finally as Director of Strategic Planning. I went to work in August 1999 for Black & Veatch. Between August of 1999 and February of 2001, I held roles as Service Area Leader for the Strategic Planning Group of Black & Veatch's Power Sector Advisory Services and as Associate Director of Marketing and Strategic Planning in their Energy E&C Group. I rejoined Empire as General Manager – Energy Supply in February 2001. I was elected Vice President – Energy Supply in April 2001. Currently, my responsibilities include all of Empire's energy supply functions including power plant construction, operation & maintenance, energy trading, and fuel procurement.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS CASE BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION ("COMMISSION")?

A. My direct testimony provides information on several topics. In Section II, I describe Empire's need for either a Fuel and Purchased Power Adjustment Clause ("FAC") and/or an Interim Energy Charge ("IEC") to appropriately address the volatility of natural gas and non contract purchase energy. In Section III, I present information surrounding Empire's successful proactive management of on-system fuel and purchased power costs. In Section IV, I present the proposed level of expenses for fuel and purchased power for the test year in this case and describe some of the challenges in determining the appropriate level of expense. In Section V, I address proposed in-service criteria for Energy Center Units 3 and 4 that were declared commercial in April of 2003.

II. EMPIRE'S NEED FOR FUEL ADJUSMENT CLAUSE OR INTERIM ENERGY CHARGE

Q. WHAT IS YOUR UNDERSTANDING OF THE ROLE AND RESPONSIBILITY OF THE COMMISSION WITH REGARD TO SETTING RATES FOR ELECTRIC UTILITIES?

A. The Commission is responsible for determining and prescribing just and reasonable rates for the services furnished by electric utilities under its jurisdiction. In accordance with the Commission's own mission statement, such just and reasonable rates should ensure that Missourians receive safe and reliable utility services and that a regulatory process is used that is efficient and responsive to all parties. To me, this means that rates need to be set at a fair level for all parties involved and that risk tradeoffs need to be evaluated in setting those rates. As the cost of capital experts' testimony shows, the returns this Commission has previously allowed have been inadequate and are lower than the rates of return other state Commissions' have allowed for utilities, the vast majority of which also enjoy the benefit of the risk-mitigating fuel adjustment clauses.

Q. WHAT METHOD IS EMPIRE PROPOSING IN THIS CASE TO DETERMINE FUEL AND PURCHASED POWER COST?

A. Empire has filed tariffs indicative of three separate methods. Our preferred method would be a Fuel and Purchased Power Adjustment Clause (FAC). Another alternative filed is an Interim Energy Charge. A third, but less desirable alternative would be a traditional forecast which most certainly will be highly contentious among the parties. We believe this third alternative is the most unsatisfactory of the three methods and will produce the least reasonable outcome. In the past, the revenue requirements determined using this method led to significant debates among the parties that we are trying to avoid in this rate proceeding and that, based on current market conditions, would virtually certainly lead to under-recovery of fuel costs.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE IEC.

A. In Empire's Missouri rate case (Case No. ER-2001-299), the parties acknowledged the volatility of natural gas and unpredictability of spot purchased power and the Commission ultimately implemented a rider termed the IEC. In addition to a fixed amount of fuel and purchased power expense that Empire was allowed to recover through its rates, the IEC allowed a new charge that was subject to true-up and refund to account for the volatility and unpredictability of natural gas and spot purchase power prices. I believe that it was a good method to remove a portion of the volatility that can negatively affect Empire, its customers, and its shareholders. Recently, the Commission approved a similar rider also termed the IEC in Case No. ER-2004-0034 involving Aquila, Inc. The testimony in that case involving the IEC follows much of the same reasoning as was utilized in the 2001 Empire case.

Q. DOES EMPIRE BELIEVE THE IEC IS AN EFFECTIVE MEANS OF ADDRESSING THE VOLATILITY IN THE NATURAL GAS AND WHOLESALE ELECTRICITY MARKETS?

A. Yes. Implementation of an IEC will result in rates that allow Empire to recover at least the level of fuel and purchased power expenses which it has experienced on an historical basis, and at most, costs which were recently prevalent in the market. The IEC would allow Empire to ultimately recover its actual prudently incurred fuel and purchased power costs (as determined through a Staff audit) within a band set during a rate proceeding. Since there is a cap on the IEC, Empire may still be subject to losses due to large swings in the natural gas and wholesale electricity markets. An IEC however, does help to minimize the effects of some of the peaks and valleys that are certain to occur in the natural gas and purchased power markets. Since the IEC contains a floor, an IEC does not prevent Empire's customers from paying more than actual fuel and purchased power costs in the event those costs are below the floor.

Q. DO YOU HAVE AN ALTERNATIVE TO THE IEC?

A. Yes. The IEC, as its name suggests, is only an "interim" solution. The IEC does not stop natural gas from being volatile or wholesale purchase power prices from changing. By virtue of its past design, it will expire which will nearly automatically necessitate another full blown rate proceeding. Such full blown rate proceedings take time and result in significant expenses for which our customers or shareholders must ultimately pay. Empire is supporting efforts by a broad range of utilities within the State of Missouri to implement fuel adjustment clause legislation. To the extent that legislation is enacted to enable a fuel adjustment clause, we can avoid lags in passing through changes in fuel costs (up and down) which should provide for a more financially sound utility. In total it should further the Commission's mission of providing a process to allow for just and reasonable assurance that Missourians receive safe and reliable utility services and that a regulatory process is used that is efficient and responsive to all parties.

Q. WHY IS EMPIRE PROPOSING A FAC OR IEC IN THIS RATE CASE RATHER THAN APPROACHES THE COMPANY HAS SUPPORTED IN THE PAST?

A. First and foremost, addressing high natural gas and volatile spot purchase power contracts is essential to Empire's continued financial health. Empire burned 6.5 million MMBtu of natural gas in 2003 and we expect to burn nearly 10 million MMBtu in a normalized year. Understating natural gas prices in a rate proceeding by only $1/MMBtu could cause our shareholders to absorb $6.4 M in reduction to retained earnings in just 1 year. The $6.4 M represents nearly 20% of the retained earnings accumulated in our Company since its formation in 1944. The traditional regulatory process simply takes too long for us to absorb a mistake that could easily be twice as large.

Empire believes that a contested rate case can protect the interests of both the Company and its customers. However, a rate case result that does not recognize nor provide for the volatility associated with natural gas prices and purchased power prices through either an IEC or FAC does not provide that protection for either its customers or its shareholders.

Without an IEC or a FAC, the parties to the case are forced to stake out positions. The Commission Staff runs its computer models and uses a combination of historical data and judgment to determine a number for fuel and purchased power that the Company nearly always considers is too low; Staff then stakes its position on the low number throughout the contested rate case. Empire conversely uses a combination of historical data and judgment to determine a number as the value for fuel and purchased power, that the Staff nearly always considers too high. This tends to force the Commission to decide between what might be extremes, or to pick some random number in the middle when there may be no concrete evidence to support it. All of this seems to be unproductive when history shows that is impossible to accurately predict what the actual prices will be.

If the rate case revenues are set by the Commission at a value that is too low, the customers do not cover the operational costs incurred by Empire. Under this scenario, over the long run, both shareholders and customers suffer the consequences. The stock does not hold its value and the cost of capital increases as Empire's ratings fall. If the rate case revenues are set too high, the customers pay more than the operational costs incurred with no mechanism for true-ups or refunds.

As stated earlier, in Empire's Case No. ER-2001-299 an IEC was implemented to deal with most of the same issues. At the time of the stipulation gas prices were high from a historical perspective (over $5.50/MMBtu). However, it wasn't too far back in history when gas prices were low (around $3.50/MMBtu). The IEC helped to appropriately balance gas prices and non-contract purchase power risks. In the months that followed the implementation of the IEC, natural gas and wholesale power prices fell and our customers subsequently received a refund that they would not have received if gas prices had been set at then-current levels without an IEC in place. We are once again at a time when the price for natural gas is quite high and no one can be certain where it will go from here. I think the fact the Commission and other parties to Case No. ER-2004-0034 (Aquila) recently recognized this and implemented an IEC is evidence that the Commission is attempting to bring a reasonable and practical solution to this problem by balancing the competing interests.

III. EMPIRE'S MANAGEMENT OF FUEL AND PURCHASED POWER EXPENSES

Q. WHAT TRENDS HAVE BEEN DRIVING CHANGES IN EMPIRE'S FUEL COSTS?

A. Empire has been adding gas-fired generation since the mid-1990s. The units added included approximately 90 MW in 1995, 150 MW in 1997, 150 MW in 2001 (the 1997 and 2001 units became part of State Line Combined Cycle) and 100 MW in 2003. While these units have provided for low capital cost capacity, the variable energy costs are more expensive than the coal-fired energy that made up a majority of our energy mix in the early 1990s. Natural gas is currently the primary fuel source for 704 MW of our 1264 MW of generating capacity (56%). A total of 30% of our energy in 2003 was generated from our natural gas fired units or purchased on the spot market.

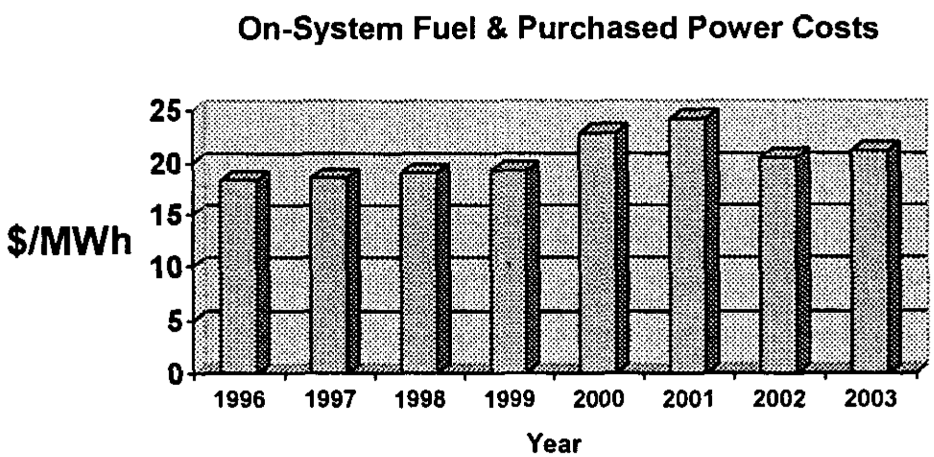
Empire's gas-fired capacity additions were in-line with a national trend given that gas-fired capacity additions were viewed as more friendly to the environment than coal and requiring less capital investment in a time of great uncertainty as to the regulatory treatment generation would be afforded. The gas-fired generation trend also affected the wholesale power market. Because so many simple cycle gas turbines and combined cycle units were added throughout the U.S. during the 1990s and early 2000s, the prices for spot market wholesale power now reflect gas-fired generation pricing many hours of the year.

Compounding the effects of the addition of gas-fired generation, natural gas prices have increased from between $2-3/MMBtu in the mid-1990s to over $4.50/MMBtu for the majority of 2003.

Q. HOW HAS THE ADDITION OF THE GAS-FIRED GENERATION AND THE INCREASE IN GAS PRICES AFFECTED EMPIRE'S OVERALL ENERGY COSTS?

A. Empire's costs on a $/MWh basis increased from $18.33/MWh in 1996 to $21.15/MWh in 2003. The average annual increase from 1996 through 2003 was just 2.06%. Given the shift in fuel mix from coal to gas and given the dramatic increase in wholesale natural gas prices, I believe this modest increase in costs is a direct result of Empire's active management of prices and risks. Information pertaining to on-system fuel and purchased power costs for 1996 through 2003 is presented in Figure 1 below.

Figure 1



Q. THE COSTS APPEAR TO PEAK IN 2000 AND 2001. WHAT CAUSED THE INCREASE?

A. Our annual costs peaked at $24.17/MWh in 2001. We actually hit a twelve-month rolling peak of $24.79 at the end of November 2001. The increase in expenses was driven by many factors. One of the main factors was an increase in natural gas prices. Natural gas prices increased dramatically in 2000 and 2001. We were buying gas on an as needed basis and as the natural gas prices ran up so did our expenses. The increase in expenses affected net income directly. An extended outage on our low-cost Asbury generating station also contributed to this peak in costs. During the outage, we upgraded controls and replaced cyclone burners. We also found we had a damaged main generator step-up transformer and had to operate in a derated condition for a period of time.

Q. WHAT HAS EMPIRE DONE TO ALLEVIATE SOME OF THE RISK DUE TO VOLATILE NATURAL GAS PRICES?

A. While the 2001 IEC was in effect, Empire implemented an Energy Risk Management Policy and added personnel that specifically focus their efforts on the purchasing and hedging of power and natural gas. The Energy Risk Management Policy sets targets as to how much natural gas Empire must have hedged at any point in time. In general the Risk Management Policy brings more sophistication and consistency to our fuel procurement. Our risk management policy is attached as Schedule BPB-1.

Q. YOU MENTION THE TERM "HEDGED". PLEASE EXPLAIN WHAT THE TERM "HEDGED" MEANS.

A. Hedging is a strategy used to offset investment or price risk, specifically to protect against price movements. Hedging can be used by individual investors, as well as companies and financial institutions. Empire's Risk Management Policy allows the utilization of traditional physical purchases and the utilization of financial tools such as call options, collars, swaps, and futures contracts to protect against adverse price movements.

Q. WHAT DETERMINES HOW MUCH NATURAL GAS IS HEDGED BY EMPIRE AND WHEN SUCH NATURAL GAS IS HEDGED?

A. Empire originally enacted a Risk Management Policy ("RMP") in 2001 that establishes the approach and internal rules that Empire will use to manage specifically its power and natural gas commodity risk. The policy is revised approximately annually to reflect lessons learned and changes in markets and financial instruments. The RMP targets for hedging of natural gas are:

A minimum of 10% of year four expected gas burn
A minimum of 20% of year three expected gas burn
A minimum of 40% of year two expected gas burn

A minimum of 60% of year one expected gas burn

Up to 80% of any year's expected requirement can be hedged if appropriate, given the associated volume risk.

Thus, by the end of 2003, our policy required that we have 60-80 percent of 2004 gas needs hedged, 40-80 percent of 2005 needs, 20-80 percent of 2006 needs, and 10-80 percent of 2007 needs. Empire is in effect dollar cost averaging the price of natural gas to remove volatility for both Empire and our customers. Schedule BPB-2, attached to this direct testimony, shows Empire's natural gas positions as of April 16, 2004.

Q. HOW WOULD YOU CHARACTERIZE EMPIRE'S HEDGING STRATEGY?

A. Empire's hedging strategy has been valuable as it has provided significant stability to our customers rates and shareholder returns. For example, in 2003 since we did not have a rate proceeding, Empire's shareholders would have paid approximately $13.5 million more for natural gas had Empire not hedged its natural gas purchases. Alternatively, if we had been able to effect a quick rate proceeding, our customers would have paid more. As shown on Schedule BPB-3, Empire paid an average hedged price in 2003 of $3.02/MMBtu for natural gas. If the natural gas had not been hedged, the weighted average price based on NYMEX close would have been a higher value of $5.12/MMBtu.

Q. WHAT IS NYMEX?

A. NYMEX stands for New York Mercantile Exchange. NYMEX provides a standard contract by which to hedge natural gas commodity risk. The standard contract point is at the Henry Hub in Louisiana. It is commonly considered the most liquid price transparent pricing point for natural gas in the U.S.

Q. PLEASE COMPARE YOUR 2003 ACTUAL COSTS OF NATURAL GAS TO 2003 CLOSING NYMEX PRICES.

Table 1

NYMEX Market Contract Closes

Month of 2003	**Price $/MMBtu**
January	4.97
February	5.66
March	9.00
April	5.12
May	5.11
June	5.96
July	5.33
August	4.65
September	4.88
October	4.44
November	4.46
December	4.88

As a comparison, Empire's average cost of natural gas commodity in 2003 was $3.02/MMBtu, which is lower in every month than the value of NYMEX contracts.

Q. WHAT WAS THE MOST SIGNIFICANT FACTOR IN ALLOWING EMPIRE TO EXPERIENCE GAS COSTS AT THE $3.02/MMBTU LEVEL?

A. Our hedging program is designed to provide more predictable gas prices that are fair to the customer and shareholder. We began our hedging program in late 2001. At that time, natural gas commodity costs were between $3/MMBtu and $4/MMBtu. Pursuant to our RMP, we hedged a portion of our needs. In essence we took low cost positions in 2001 and 2002 relative to the 2004 market. This policy served Empire and its customers very well in 2003.

Q. WHAT WOULD EMPIRE'S AVERAGE PRICE IN 2003 BEEN FOR NATURAL GAS IF THE ACTUAL PRICE OF NATURAL GAS HAD FALLEN TO $2/MMBTU?

A. Many variables would have changed, including the economy, our customers demand, and spot purchased power prices to name a few. But, ignoring those, our expense for natural gas would have been in the $3.02/MMBtu range. In other words, we took positions that hedged against price fluctuations and that we believed protected both customer and shareholder from excessive risks of fuel price volatility.

Q. DO YOU EXPECT YOUR HEDGING PROGRAM TO PRODUCE RESULTS IN THE $3/MMBtu PRICE RANGE IN 2005?

A. No. We have only about 60% of our anticipated 2004 needs and 40% of our 2005 needs hedged at an average price of $4.15/MMBtu. As of the market close on April 21, 2004, the futures market for natural gas contracts were priced as shown in Table 2. In order for Empire to achieve average gas prices of $3/MMBtu in 2004 or 2005, the price for natural gas would have to fall well below $3/MMBtu to offset the $4.15/MMBtu contractual obligations that we already have in place. With current prices for 2004 and 2005 consistently above $5/MMBtu, Empire cannot possibly expect its hedging program to result in gas prices in 2004 or 2005 as low as $3/MMBtu. Rather, average prices will have to be expected to increase above the $4.15 level. In fact, based on current forecasts, Empire expects natural gas costs to increase to $4.50 MMBtu for 2004.

Table 2

Future Market Prices as of Market Close March 2, 2004

Month	**2004**	**2005**
January		6.26
February		6.21
March		6.02
April		5.41
May	5.59	5.28
June	5.66	5.28
July	5.74	5.33
August	5.78	5.34
September	5.75	5.29
October	5.77	5.31
November	5.94	5.47
December	6.12	5.62

IV. PROPOSED LEVEL FOR FUEL AND PURCHASED POWER EXPENSES

Q. WHAT LEVEL OF EXPENSE FOR ON-SYSTEM FUEL AND PURCHASED POWER IS EMPIRE RECOMMENDING IN THIS CASE?

A. As stated earlier, Empire's first preference is a FAC. Empire recommends a FAC that has charges based on an expense of $121,665,153 total Company for on-system fuel and purchased power for the projected energy requirements of 5,042,800 MWh. On a unitized basis, this value of revenue requirements reflects expenses at a level of $24.13/MWh. Adjustments would be made on a periodic basis conforming to law or the terms of a stipulation.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I utilized actual twelve-month ending cost and tried to make just and reasonable adjustments for a minimal number of variables. I made five adjustments from actual cost; they are 1) normalized energy, 2) natural gas costs, 3) new natural gas transportation, 4) escalation of delivered coal prices, and 5) the replacement of the American Electric Power ("AEP") short-term contract energy. Table 3 summarizes the adjustments.

Table 3

Adjustments to Twelve Month Ending December 31, 2003

	MWh	$	$/MWh
Actual TME 12/31/03	4,950,161	104,714,009	21.15
Weather/Growth Adjustment	92,639	2,130,697	29.24
New Gas Transport		2,250,000	
Delivered Coal Price Escalation (2%)		523,893	
Natural Gas Prices (3.02 to 4.60 for 6.45M MMBtu)		10,190,379	
Replace AEP Short-term Contract Energy		1,278,108	
Total	5,042,800	121,665,153	24.13

Q. WILL YOU PLEASE PROVIDE THE RATIONALE BEHIND EACH ADJUSTMENT?

A. Yes.

Actual TME 12/31/03

This row in the table represents actual MWh, $, and $/MWh for calendar year 2003. As presented in Figure 1 above, 2003 results are in line with 2002 results. There were no major or abnormal outages on our generating plants. I would not expect the wholesale spot market to dramatically change year over year.

Weather/Growth Adjustment

This adjustment was made to match requested expenses with the normalized revenues and kWh in this case. The MWh were priced at Empire's average incremental power cost for 2003 of $29.24/MWh.

New Gas Transport

Empire entered into a gas transportation agreement with Southern Star to help serve the new combustion turbines at Empire's Energy Center. The pipeline upgrade was expected to be in service during the fall of 2003. However, due to construction difficulties, the pipeline was not placed in service at that time. We now expect the pipeline to be in service by June 2004 and for Empire to begin making its contractually obligated payment at that time. This amounts to an annualized expenditure of $2,250,000.

Delivered Coal Price Escalation

This adjustment was made to account for the escalation of coal commodity and freight prices that Empire experiences on an annual basis under current contract terms. Empire has contracts with various coal and freight providers that have differing terms of escalation. When all of these terms are taken into consideration, Empire's commodity plus freight price of coal stands to increase approximately 2% (on a $/MMBtu basis) in 2004 when compared to 2003 prices.

Natural Gas Prices

Our hedging program resulted in average natural gas commodity prices of $3.02/MMBtu in 2003 for the 6,450,000 MMBtu of natural gas that we burned. In 2005, when rates will be in effect from this case, we have about 4,200,000 MMBtu of gas hedged at $4.15/MMBtu and the remainder is unhedged. As you can see in Table 2, 2005 gas prices currently average $5.44/MMBtu. Applying $5.44/MMBtu to 2,250,000 MMBtu and $4.15/MMBtu to 4,200,000 MMBtu gives a weighted average price of $4.60/MMBtu. Applying the difference between \$4.60/MMBtu and \$3.02/MMBtu to the actual burn of 6,450,000 MMBtu gives an adjustment of \$10,190,379.

<u>Replace AEP Short-term Contract Energy</u>

In 2002 and for the first half of 2003, Empire was able to procure a favorable short-term purchase power contract with AEP. In 2003 this contract contributed 201,428 MWh to Empire's on-system energy needs at an average price of \$29.55 (average price includes capacity demand charges). This power is no longer available from AEP. An adjustment has been made to replace this energy with energy from Empire's State Line Combined Cycle ("SLCC") unit at a price of \$35.90/MWh, the average price found in Run 1 for SLCC generation presented in Ms. Tietjen's testimony.

Q. HOW DOES THIS METHOD OF CALCULATING FUEL AND PURCHASED POWER COSTS COMPARE TO THE METHOD USED IN PREVIOUS RATE CASES?

A. In previous rate cases in which I have been involved in Missouri, fuel and purchased power expenses have generally been estimated by both Company and Staff utilizing their respective hourly computer models. In almost every circumstance, we ended up with a very sophisticated "battle of the models." I believe that the models themselves will generally provide the same answer given the same input data. The arguments that Empire and the Staff typically have had revolved around just a couple of input variables. The variables of contention have been natural gas prices and the price as well as the availability of non-contract purchase energy. I reviewed the Fuel and Purchased Power testimony in the recent Aquila electric rate Case No. (ER-2004-0034) and the large fuel and purchased power issues in that case were also natural gas pricing and non-contract purchased power costs and availability.

Q. WHY HAVE NATURAL GAS COSTS BEEN AN ISSUE?

A. In my opinion, they have been an issue because natural gas prices are so volatile. The Staff wants to make sure the consumers get the benefit of low gas prices and selects a method or data that will yield a low gas price forecast. The Company wanted to make sure the shareholders do not shoulder the weight for high gas prices and selects a method or data that results in a higher gas price forecast. Neither the Staff, nor the Company can accurately forecast the natural gas prices however. This is why the Company is now strongly advocating the use of an FAC or an IEC. I, as well as future witnesses for Staff, The Office of Public Counsel, and other intervenors, could write pages of testimony showing forecast of prices, why the futures market is not a good indicator of future prices, and why the past prices are not a perfect predictor of future prices. However, at this time I am hopeful that all parties to the case will see the necessity of either the FAC or IEC and we can focus our efforts on appropriate measures and conditions around the FAC or IEC.

Q. WHAT ABOUT NON CONTRACT PURCHASE ENERGY?

A. Non-contract purchase energy is even more difficult to forecast. The price and availability of non-contract energy is based upon conditions in the market resulting from utilities other than Empire both inside and outside of the State of Missouri. Factors that will affect the price and availability of that energy include transmission cost, transmission availability, coal prices, natural gas prices, planned and forced outage rates, weather, heat rates, water availability, and market perception to name just a few – all from organizations other than Empire. In addition, non-contract energy generally directly competes with the natural gas-fired generation and hence the quantity of gas the model projects will be utilized in test year. If too much non-contract energy at a cheap price is made available in the model, then the natural gas-fired resources in the model will not be utilized. Therefore, it is possible to agree on a gas price and still significantly disagree on fuel and purchased power expense. Again, a review of the issues in the recent Aquila case read like a review of the Empire cases in 2001 and 2002. Without the implementation of a FAC or IEC, this issue is sure to result in "battling of the models" in this case.

Q. WHAT IS EMPIRE RECOMMENDING FOR AN IEC?

A. Empire witness Jill Tietjen concurrently files testimony in the more traditional "model" fashion. The model provides the basis for the base charge of $105,000,000 ($20.82/MWh) and the IEC of $20,000,000 for a total of $125,000,000 ($24.79/MWh). The base and the IEC were derived by reflecting forecast natural gas pricing and spot purchase power price assumptions in our hourly dispatch model. The assumptions surrounding the model are also provided by Ms. Tietjen.

Q. IF EMPIRE IS NOT ABLE TO UTILIZE ONE OF ITS PREFERRED METHODS TO DETERMINE FUEL AND PURCHASED POWER COSTS (AN IEC OR FAC), WHAT WOULD EMPIRE RECOMMEND FOR BASE ON-SYSTEM FUEL AND PURCHASED POWER COSTS?

A. Under this circumstance, Empire would revert to the more traditional production forecast modeling of on-system fuel and purchased power costs. Empire's base run (Run 1) forecasts on-system fuel and purchased power costs of $123,017,327 ($24.39/MWh) for 5,042,800 MWh of energy, which Empire's rate filing is based on. Again, the assumptions surrounding the model are presented in Ms. Tietjen's testimony. It should be noted that this modeled value for on-system fuel and purchased power costs compares very favorably to the simple, straight-forward method I presented above. By making only five adjustments to twelve-month-ending 2003 on-system fuel and purchased power costs, I arrived at a cost of $121,665,153 ($24.13/MWh), a difference of only $1.35 million or 1.1 percent.

V. IN-SERVICE CRITERIA FOR ENERGY CENTER UNITS 3 AND 4

Q. DO YOU HAVE PROPOSED IN-SERVICE CRITERIA FOR ENERGY CENTER UNITS 3 AND 4?

A. Yes I do. Energy Center Units 3 and 4 were declared commercial by the Company in late April 2003. Through February 2004, these units have provided 52,724 MWh to the system and have run for a total of 2,587 hours. Under any criteria, these units have performed very well for the Company and its customers. During the fall of 2002, Empire worked with Staff to attempt to ascertain the in-service criteria that would be utilized on Energy Center 3 and 4. Empire proposes the following criteria:

1. All major construction is completed.
2. All pre-operational tests have been successfully completed.
3. Unit will successfully demonstrate its ability to initiate the proper start sequence resulting in the unit operating from zero rpm (or turning gear) to full load when prompted at a location (or locations) from which it will be normally operated.
4. If unit has fast start capability, unit will demonstrate its ability to meet fast start criteria.
5. Unit will successfully demonstrate its ability to initiate the proper shutdown sequence from full load resulting in zero rpm (or turning gear) when prompted at a location (or locations) from which it will be normally operated.
6. Unit will successfully demonstrate its ability to operate at minimum load for one hour.
7. Unit will successfully demonstrate its ability to operate at or above 98% of full load for four continuous hours.
8. Unit will successfully meet all operational guarantees.

9. Transmission facilities shall be capable of exporting the entire plant net capacity.

10. Units shall demonstrate the ability to start on distillate fuel.

11. Units shall demonstrate the ability to transfer from natural gas to distillate fuel.

Q. HAVE THE ENERGY CENTER UNITS 3 AND 4 MET EACH OF THE PROPOSED IN-SERVICE CRITERION?

A. Yes they have. Schedule BPB-4 contains a report completed by plant management detailing and documenting the performance for each of the criteria.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

THE EMPIRE DISTRICT ELECTRIC COMPANY

ENERGY RISK MANAGEMENT POLICY

August 21, 2003

Services You Count On

THE EMPIRE DISTRICT ELECTRIC COMPANY
ENERGY RISK MANAGEMENT POLICY

TABLE OF CONTENTS

1 STANDARDS OF OVERALL COMPANY PROGRAM

INTRODUCTION

The purpose of the Energy Risk Management Policy (RMP) document is to define the approach and internal rules that The Empire District Electric Company (EDE) will utilize to manage its power and natural gas commodity risk. The content of this document establishes and describes the EDE policy in assuming, assessing, and controlling the level of natural gas commodity risk exposure involved in the normal course of serving EDE's native load energy requirements.

OBJECTIVES

It is the policy of EDE NOT to engage in financial or commodity transactions unless they are related to underlying exposures related to supplying EDE's native load or to hedge back-to-back off-system transactions. It is the express intention of EDE to prohibit financial or physical commodity transactions that would reasonably be considered outside of EDE's core business activities.

The following are specific RMP objectives for EDE that represent a balanced financial and operational focus:

OBJECTIVE #1

Provide an organizational structure to support management goals and budget performance by mitigating energy price volatility and; hence, limiting fluctuations in the cost of supplying power to retail customers.

The RMP provides an organizational structure for effectively assessing and managing risk associated with EDE's natural gas supply and wholesale power activities. It provides a framework for effective control, audit, and reporting. The procedures set forth allow for the management of operational risks without placing undue restrictions on the operations of EDE.

OBJECTIVE #2

Allow utilization of physical and financial tools to provide a predictably priced reasonable cost gas-supply.

EDE's cost to generate, purchase, and supply power is greatly impacted by fluctuations in the market price of energy sources such as coal, natural gas, oil, and wholesale electricity. This RMP outlines procedures on how hedge positions will be employed to limit these market fluctuations in the price of natural gas and; hence, provide EDE with tools to manage expenses to generate, purchase, and supply power for its customer base.

2. RESPONSIBILITY FOR ENERGY RISK MANAGEMENT POLICY

The Officer Group as listed below is responsible for maintaining and overseeing the RMP:

The Officer Group is comprised as follows:

President and CEO
Vice President – Finance and CFO
Vice President – Energy Supply
Vice President – Regulatory and General Services
Vice President – Strategic Development
Vice President – Commercial Operations

From time to time, the Officer Group will report to the Board of Directors on the risk management activities surrounding natural gas risk. Officer Group activities shall include:

- Providing the Risk Management Oversight Committee (RMOC) authorization to engage in those activities consistent with prudent risk management and related trading practices which correlate with the native load requirements of EDE;
- Recognizing financial instruments such as futures, swaps, options, as well as physical market position management, can be effective transaction tools; and
- Providing sufficient management involvement, financial controls, and systems to monitor, report, and ensure the integrity of the RMP at all levels.

RISK MANAGEMENT OVERSIGHT COMMITTEE

The RMOC is charged to monitor aggregate risks and ensure they are managed in accordance with the RMP. The RMOC will meet periodically to assess aggregate risks and review EDE's market positions and exposures and strategy.

The RMOC is comprised as follows:

Chairman
Vice President – Finance and CFO

Members:
Vice President – Energy Supply
Vice President – Regulatory and General Services
Controller and Assistant Treasurer and Secretary
Director of Wholesale Energy Group

Internal Control Members:
President and CEO
Director of Internal Audit
Sr. Risk Management Accountant
Wholesale Energy Trader(s)

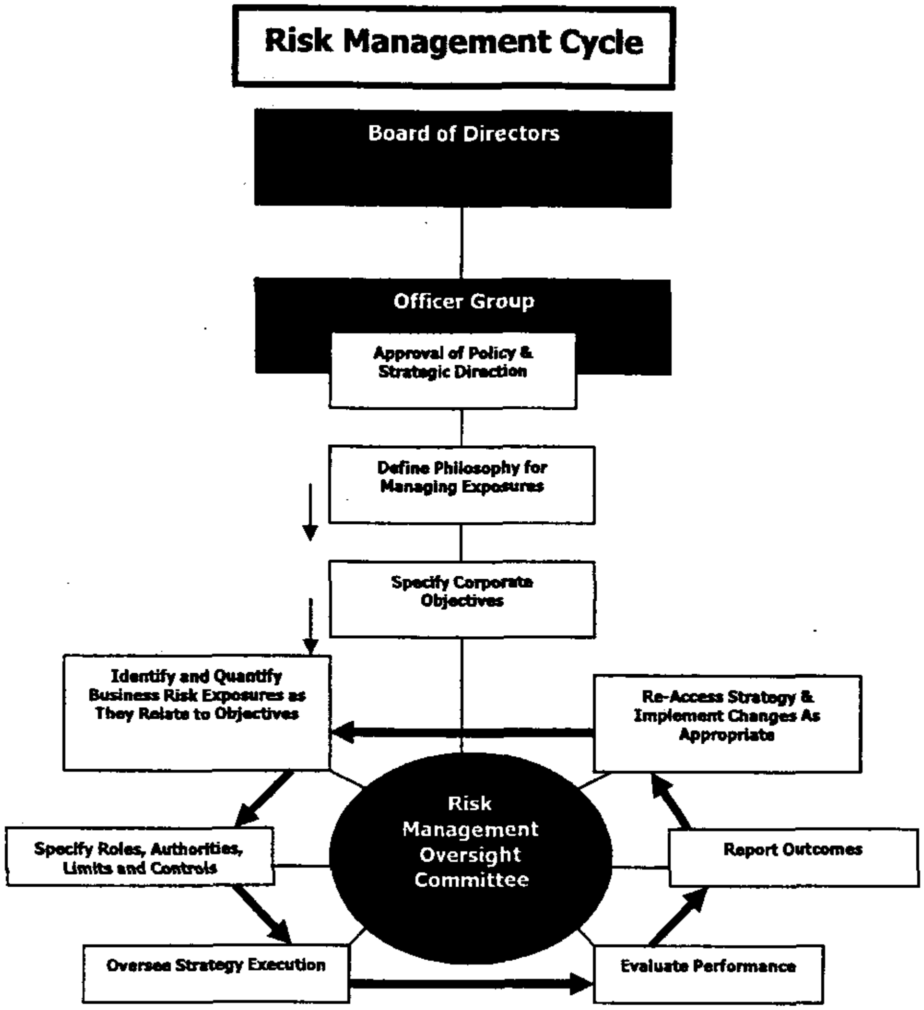
RMOC RESPONSIBILITIES

- **Approve Hedging Strategies** – Develop and approve strategies that achieve risk management objectives.
- **Individual Trading Authorization** – Approve a list of individuals authorized to establish trading relationships and execute trades. The hierarchy of oversight will include opening futures accounts, executing International Swap Dealer Association (ISDA) master agreements, placing futures orders, and entering into transactions per a master swap agreement.
- **Set Transaction Exposure Limits** – Approve limits on volumes and length of coverage of all outstanding physical, futures, options, and Over-the-Counter (OTC) positions.
- **Ensure Credit Approval and Documentation** – The credit approval / monitoring process is described in Appendix 13, Credit Risk / Procedures Policy.
- **Establish Procedures and Develop Reporting Systems** – Ascertain appropriate checks and balances are in place and financial reporting is correct.
- **Establish Approved Counterparty List** – Establish an approved counterparty trading checklist to be used by the Wholesale Energy Group.

Any member of the RMOC has authority to call committee meetings and the responsibility to ensure that all activities are in accordance with this program. The committee may meet in person, through telephone conference calls, and/or electronic mail. The RMOC secretary (who is not a member of the RMOC) will keep regular minutes and records of meetings and actions.

At any time a RMOC member believes the committee has failed to adequately address a situation in which the member believes price or credit speculation is taking place, that member shall submit a written statement describing the concern to the President and CEO or the Director of Internal Audit.

RMOC CYCLE



3 RISK

COMPANY EXPOSURE

EDE's exposure spans activity in both the physical fuels market and the financial derivative markets that have developed to accommodate natural gas and power. Without risk management, EDE will be subject to cost and pricing uncertainty, as well as uncertainty in meeting budgeted earnings and cash flow.

The primary components of EDE's risk exposure are operations risk, market risk, and credit risk. The RMP is designed to address the management of these risks in the aggregate.

OPERATIONS RISK

Involves the potential increased cost for items such as providing replacement power to serve customers due to the unscheduled outage of generation plants, interruptions of power purchases from other parties, or interruption of gas supply.

MARKET RISK

Involves the potential change in value of a commodity contract, liability, or cash flow caused by adverse fluctuations in market factors over a pre-defined holding period. Types of market risk include:

- **Price Risk** – Uncertainty associated with changes in the price level of commodity fuel costs.
- **Liquidity Risk** – Risk associated with the diminished market activity of a fuel commodity.
- **Volume Risk** – Supply or demand deviation from forecast (for example, the risk of not having enough or having too much natural gas to meet forecasted obligations). Volume risk is highly correlated with price risk because availability of wholesale electricity is high and price low when the weather is mild causing reduced volume need. Conversely, when weather is extreme causing an increase in our underlying needs, the price of wholesale electricity may increase exponentially.
- **Calendar Risk** – Exposure due to time differential in commodity value between actual physical delivery and financial position expiration.
- **Basis Risk** – Exposure due to a difference in commodity value between different delivery points or between cash market prices and the pricing points used in the financial markets.

COUNTERPARTIES/CREDIT RISK

A component of the overall RMP is the management of credit exposure. EDE's exposure is different when transacting on the New York Mercantile Exchange (NYMEX) versus when transacting OTC.

The creditworthiness of trading partners or clearinghouses is a function of both qualitative and quantitative factors. Such factors are centered on the credit rating assigned to a company by major credit rating services and an evaluation of the company's ability to financially meet its obligations to EDE. Typical sources of credit-related information are credit rating reports (published by one or more of the commonly recognized rating agencies, such as Dunn & Bradstreet, Standard & Poor's, or Moody's), general market intelligence, electronic news releases, and other public information sources. Based on these resources, the RMOC will provide oversight as to each approved counterparty's ongoing creditworthiness.

Credit risk associated with maintaining an account with a futures clearinghouse is considerably less than that with OTC counterparts. This distinction exists because the collective clearinghouse members of NYMEX, which includes virtually every major energy company and financial institution in the country, guarantee the performance on all positions placed on the exchange. Requiring margin deposits and daily mark-to-market by clearinghouse members allows for incremental monitoring and control of transactions and eliminates the potential for sudden defaults on contracts.

ESTABLISHING CREDIT RESPONSIBILITIES

As defined in Appendix 13 – Credit Risk / Procedures Policy, establishing limits and creditworthiness monitoring will be done independent of the trading function and will be performed by the Risk Management Accountant in Finance (with oversight by the RMOC), in order to guarantee appropriate segregation of duties within EDE. All trading activity with a particular counterpart who no longer meets EDE's credit standards will be halted. A Counterparty Credit Exposure Report will be included as part of the weekly Position Report described later. The report will summarize the total amount of exposure by counterparty by hedging instrument based on current mark-to-market amounts.

4. HEDGE STRATEGY

EDE's Missouri and Kansas retail rates are not subject to a fuel cost adjustment clause. As such, the only time EDE's rates are adjusted for changes in fuel costs is during a rate proceeding. The regulatory schedule for a rate proceeding in Missouri requires 11 months from the date of filing before new rates come into effect. Adding preparation time for a rate case, this period could stretch to 12 or 13 months. This regulatory schedule combined with the volatility of natural gas necessitates that EDE focus on procuring fuel over periods longer than 18 months to help prevent EDE's revenues from lagging its costs.
EDE's strategic focus addresses both the regulatory structure and volatility by attempting to protect against volatile natural gas costs for EDE plants. To best utilize the economic trade-offs between generating with on-system resources versus buying non-firm wholesale power, EDE will apply risk management strategies. EDE will attempt to lessen the risks associated with variances in the volume of fuel consumed relative to budgeted fuel consumption volume.

EDE's specific hedge strategy goals are to provide for predictable fuel and purchased power costs over a multi-year period and to provide a framework to allow EDE to manage its risk positions.

EDE's RMP is designed to provide the Wholesale Energy Group with a more comprehensive set of tools to mitigate the adverse impacts associated with changing natural gas or wholesale electricity prices.

EDE's risk management strategies involve an active and continual "mark-to-market" assessment of market conditions to match its supply portfolio to its portfolio of retail and wholesale obligations.

In effect, these strategies set out to determine how much market risk is reasonable to best minimize costs and volatility, while still providing EDE's customers with reasonable fuel costs.

An overview of the hedging targets for natural gas is outlined below.

NATURAL GAS

At least yearly, EDE will model its electric system with a production cost model to establish an expected gas burn for retail load for each of the next four years. This budgeted gas burn will be the same as that utilized in EDE's financial projections.

From time to time as conditions change (i.e. unit outages, gas commitments, purchase power commitments), the Wholesale Energy Group shall re-model EDE's system to establish a new "expected" gas burn for native load.

EDE will utilize the following procurement guidelines:

- Hedge a minimum of 10% of year four expected gas burn
- Hedge a minimum of 20% of year three expected gas burn
- Hedge a minimum of 40% of year two expected gas burn
- Hedge a minimum of 60% of year one expected gas burn

The Wholesale Energy Group will have the flexibility to hedge up to 80% of any year's expected requirements while being cognizant of volume risk.

(By December 31 of current year we should have a minimum of 60% of the next years projected gas burn hedged.)

This progressive dollar cost averaging approach is intended to protect our customers and shareholders from volatility in the marketplace. In addition, the progressive approach allows for increasing uncertainty of gas needs inherent in forecasting events occurring further in the future.

If changes in expected gas burns occur that make us more than 100% hedged in any give month, immediate steps will be taken to reduce our hedged position to 100% or less.

5. INTERNAL CONTROLS

Internal controls are essential in ensuring adherence to the RMP and include the authorization of acceptable instruments, limits, and credit standards. Additional checks and balances including segregation of departmental duties, market position monitoring, and a management reporting structure should be in place to verify and reconcile the integrity of EDE's risk management activity results.

SEGREGATION OF DEPARTMENTAL RESPONSIBILITIES

An appropriate segregation of duties is fundamental in controlling EDE's risk management operations and includes activities such as approvals, verifications, and reconciliations. A clear separation between transacting, credit review and approval, margining and cash settlements, and accounting has been established with respect to the RMP.

Wholesale Energy Group, Finance, and Internal Audit are the departments most directly impacted by energy supply risk management activities.

AUTHORIZATION PARAMETERS

INSTRUMENTS

A primary responsibility of the RMOC is the review and approval of tools acceptable for implementation of the risk management strategy.

The various hedging instruments that EDE is authorized to use by this RMP is described as follows:

- **Physical Forward Contract** – Contract for future physical delivery of a designated quantity of a fuel source or power supply at a designated price, time, and location. Physical forward contracts obligate both the buyer and seller to accept the agreed-upon price, regardless of the market price when the delivery takes place.
- **Futures Contract** – Standardized binding agreement to buy or sell a specified quantity or grade of a commodity at a later date. Futures contracts are freely transferable, can be traded exclusively on regulated exchanges, and are settled daily based on their current value in the marketplace.
- **Put Option / Call Option** – Contract giving the holder the right, but not the obligation, to purchase or sell the underlying futures contract at a specified price within a specified period of time in exchange for a one-time premium payment. The contract also requires the writer, who receives the premium, to meet these obligations. (Use of these instruments in a manner that precludes them from falling under hedge accounting treatment is prohibited.)
- **OTC Instrument** – Any financial or physical instrument that is customized and created by a counterpart to replicate the risk profile associated with a commodity. The OTC swap is a contractual agreement between two parties to exchange a series of cash flows, for a stipulated period of time, based on agreed-upon parameters and price fluctuations in some underlying commodity or market index. There is a monthly settlement price, which is the difference between the fixed price of the contract and the index price in the publication

for that month's date. If the index price for the delivery period is higher than the fixed price of the OTC contract, then the seller pays the buyer the difference. If the index price is lower, the buyer pays the seller the difference. This policy approves the use of OTC forwards and options for natural gas and power. Power examples include: 5x16, 7x24, 5x8, 2x24, 7x8, 1x16, etc. (Use of these instruments in a manner that precludes them from falling under hedge accounting treatment is prohibited.)

LIMITS

AUTHORIZED TRADERS AND TRADING LIMITS

- **"Round Trip" Trades Prohibited** – "Round trip" transactions shall be strictly prohibited. Round trip transactions, as used herein, refer to simultaneous (or nearly simultaneous) energy purchases and sales of equal duration, price and volume. Employees engaging in such transaction shall be subject to progressive discipline up to and including termination of employment.

- **Off-Premise Trading** – Off-premise trading is not allowed.

Authorized traders, along with approval and transaction limits, are listed in Appendix 12.

6. REPORTING POSITION REPORT

The Position Report contains a list of all open and recently closed transactions for EDE trade-based activity and serves as a crucial element of RMP control and management. The Position Report has multiple applications for risk management review that includes account transaction tracking and evaluation as well as overall performance evaluation.

The Position Report is updated and distributed weekly by the Wholesale Energy Group (WEG). Its primary objectives are:

- Allow for marking individual transactions to market;
- Provide data for transactions as well as portfolio analysis; and
- Simplify accounting and program results evaluation through analysis of the closed positions list.

MARK-TO-MARKET

All positions will be mark-to-market (using the appropriate NYMEX prices or other suitable market indicator as defined by the underlying contract) weekly or as determined by the RMOC on the Position Report by Wholesale Energy Group. This analysis is performed to appropriately reflect the current value and cash flows associated with open positions and to provide timely information regarding EDE's market risk and exposure.

The Wholesale Energy Group is responsible for verifying the validity of the market data used in mark-to-market calculations through the Position Report, with Finance performing a subsequent review as a check on this report's accuracy. On certain OTC positions, it may be difficult to obtain an accurate mark-to-market value. In these instances, Wholesale Energy Group will provide the most precise estimate of values and will identify the source and reliability of the data.

ADDITIONAL MANAGEMENT REPORTING

Management reports are to be based on the principles of adequate compliance limit monitoring, accuracy of data sources, and frequency and quality of information. All reports should communicate the price risks assumed by EDE. Information pertaining to performance measurement and program evaluation will be included in required reports and will be used as a basis for RMOC discussions and future strategy setting.

MINIMUM REPORTING REQUIREMENTS

The following table identifies the various reports to be generated by different departments or management levels, the normal regularity, and circulation of the document.

Report	Distribution	Normal Frequency	Originator
Position Report	WEG Risk Mgt. Acct. RMOC	Weekly and Quarter-End	WEG
Man Financial Account Statements via email	WEG Risk Mgt. Acct.	Daily – Others	RMI
Minutes of RMOC Meetings	RMOC	Monthly	RMOC Secretary
Counterparty Credit Exposure Report	RMOC WEG Risk Mgt. Acct.	Weekly	WEG (as reviewed by Risk Mgt. Acct.)

DISCIPLINE

Any violation by an employee of the RMP will be subject to the Progressive Discipline Policy as outlined in the Personnel Policy Manual of EDE.

7. POLICY REVIEW

On an annual basis, the RMOC will review and mutually make a recommendation to the Officer Group on the adequacy of the RMP and any necessary changes.

8. CONFLICTS OF INTEREST

Personnel responsible for executing and managing EDE's trading activity will not be authorized to enter into energy-related commodity transactions on behalf of others or themselves unless specifically approved by the RMOC.

9. DUTIES AND WORK FLOW

Appendices are listed as follows:

- **Credit Risk and Procedures Policy – Appendix 1**
- **Duties for Wholesale Energy Group – Appendix 2**
- **Duties for Finance – Appendix 3**
- **Duties for Auditing – Appendix 4**
- **Work Flow to Execute Trade – Appendix 5**
- **Procedure for Hedge Transactions and Reconciliation – Appendix 6**
- **Trade Ticket – Appendix 7**
- **Confirmation Procedure – Appendix 8**
- **Position Report – Appendix 9**
- **Mark to Market Report – Appendix 10**
- **Broker Account Statement – Appendix 11**
- **Authorized Traders – Appendix 12**

APPENDIX 1

THE EMPIRE DISTRICT ELECTRIC COMPANY

CREDIT RISK/PROCEDURES POLICY

July 18, 2003

EMPIRE

Services You Count On

I: INTRODUCTION

The purpose of this policy is to establish a consistent process whereby the credit risk of future financial loss due to counterparty physical or financial non-performance is significantly diminished for energy purchases and / or sales. This Credit Risk/Procedures Policy will govern any energy transactions relating to natural gas and / or purchased power conducted by Empire District Electric Company.

II: POLICY OVERVIEW

In general, all energy suppliers and / or purchasers will be subject to a financial review in accordance with Empire District Electric standards for determination of creditworthiness. Evaluation of a company's financial strength and its ability to deliver its product or to pay is crucial.

A credit review cannot be viewed as the mechanism to prevent any and all losses, but it can help identify those companies where performance has been a problem in the past or may present a problem in the future. Established limits combined with proper monitoring oversight will help Empire District Electric to effectively mitigate possible losses due to counterparty insolvency.

III: RESPONSIBILTIES

Risk Management Oversight Committee

The Risk Management Oversight Committee (RMOC) shall give final approval for all credit policies and procedures. In today's business environment, a formularized credit rating approach for rating counterparties may not be practical. The RMOC will provide oversight by reviewing weekly Position Reports produced by the Wholesale Energy Group (WEG) and by formal discussions of counterparty credit limits, credit risk, credit exposure, etc. at the RMOC meetings. The Risk Management Accountant will provide monthly credit rating status reports of counterparties. WEG will report on credit exposure by counterparties in the weekly Position Report.

RMOC Committee Members

This group is defined in the Energy Risk Management Policy.

Risk Management Accountant

The Risk Management Accountant shall monitor the credit exposures created through the trading of energy and derivative products, and ensure that the RMOC is aware of any inappropriate credit exposure.

Primary Responsibilities include the following:

- On-going monitoring of existing counterparty credit/financial strength, see On-Going Financial/Credit Strength Monitoring Procedures section below
- Monitor credit exposures created by the trading of energy and / or derivative products, see On-Going Financial/Credit Strength Monitoring Procedures section below
- Oversee the development and administration of systems necessary to support the above activities
- Monitoring trade activity with each counterparty

Wholesale Energy Group

The Wholesale Energy Group optimizes the use of generation, purchased power and natural gas as outlined in the Risk Management Policy.

Primary Responsibilities include the following:

- Keeping abreast of market trade talk and communicate knowledge to the Risk Management Accountant
- Coordination of legal documentation appropriate for each counterparty such as Master Agreements, International Swaps Derivative Agreements (ISDA), etc.
- Monitoring trade activity with each counterparty

Legal Services

An outsourced legal services group shall be used by the Wholesale Energy Group in counterparty agreement negotiations. While it is not always possible to achieve, the Wholesale Energy Group will work with legal services to seek netting and/or set-off agreements with counterparties on all contracts.

Netting provisions allow counterparties to settle with each other the net of all transactions for a given period rather than gross amounts involved in a series of transactions. If a company buys power from a counterparty and also sells them power, the final transaction will take both aspects into consideration and pay the difference between the two. The non-defaulting party may also perform a closeout of any existing positions and include this balance in the netting calculation. This provision can eliminate a large amount of downside potential associated with counterparties that default.

Set-Off can be viewed in simple terms as netting among different governing agreements. For instance, Empire District Electric may be transacting both electricity and natural gas with the same counterparty under two different governing agreements. Set-Offs allow for amounts owed or received under both agreements to be netted against each other.

On-Going Financial/Credit Strength Monitoring Procedures

The Risk Management Accountant shall be responsible for reviewing on an on-going basis the credit rating status of counterparties. In addition, the Risk Management Accountant will follow business news reports on counterparties for any potential information that may indicate a change in creditworthiness. The Risk Management Accountant will also work in close contact with WEG to stay abreast of any current negative supplemental information gained from direct contact within the energy industry.

If any declining creditworthiness information develops on a counterparty, such as their credit rating is downgraded by Moody's or Standard and Poor's, the Risk Management Accountant will notify the RMOC of such development by email.

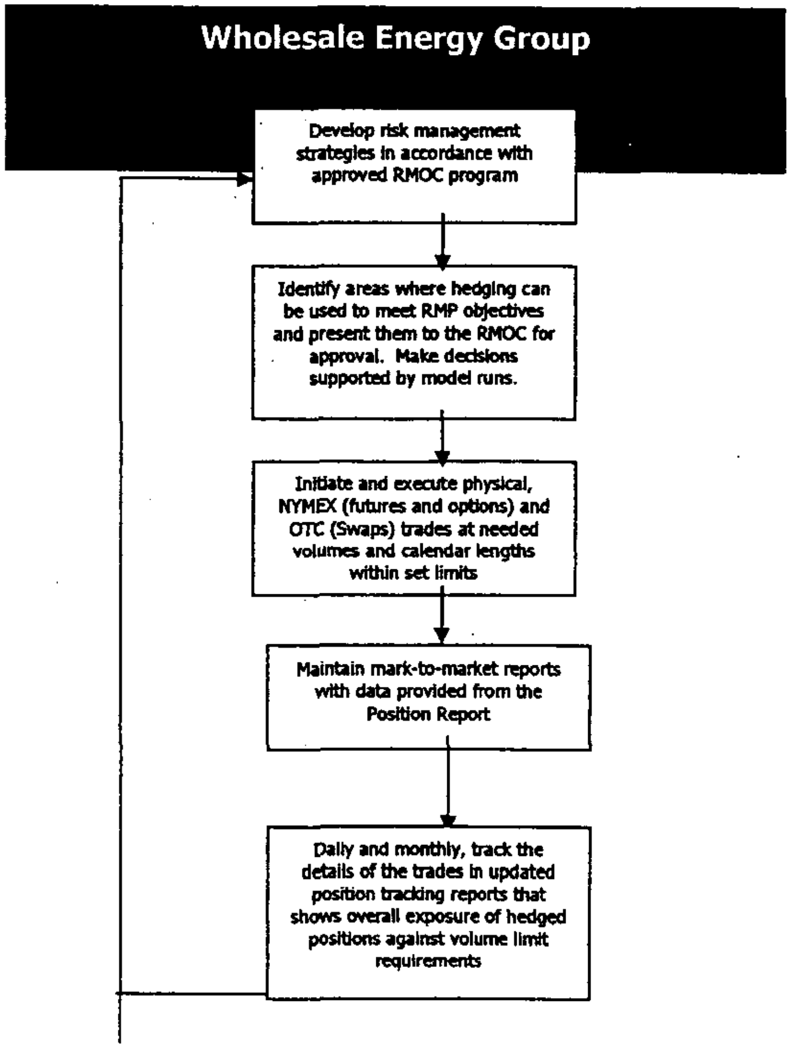
Furthermore, if a counterparty's credit rating is downgraded to investment grade (Baa by Moody's, BBB by Standard and Poor's) or below, the Risk Management Accountant will additionally notify the Chief Financial Officer, Controller and Vice-President of Energy Supply by phone of the downgrade. The Risk Management Accountant would also notify the Wholesale Energy Group to halt any further trades with this counterparty until further notice. Any member of the RMOC could then call a special meeting of the RMOC for discussion or add this information to the agenda of the next regularly scheduled RMOC meeting.

APPENDIX 2

WHOLESALE ENERGY GROUP

Responsible for analyzing the market and developing appropriate strategies and tactics in line with the RMP.

Responsibilities include the following:



APPENDIX 3

FINANCE

Responsible for the provision of financing Wholesale Energy Group hedge transactions. In addition, Finance will crosscheck hedge positions placed by Wholesale Energy Group in physicals, swaps, futures, and options for accuracy and accordance with EDE's RMP. Accountable for review of account balances for any associated margin requirements with day-to-day activity and also responsible for the following:

Finance

Perform credit analysis, approval, and limit monitoring *(On-going)*

↓

Reconcile daily activity reports from Wholesale Energy Group and daily statements from brokers and banks independent of the Position report

↓

Approve, send, and verify wire transfers in or out of trading accounts

↓

Decide whether or not to put trading funds into interest bearing treasury bills or cash

↓

Review accuracy of monthly account statements from broker pertaining to margin account balances

↓

Alert RMOC when transactions taken exceed the limits and standards of the RMP on any discrepancies from this policy as well as any other irregularity, which could expose EDE to financial or legal liability

↓

Develop and apply accounting policies to financial transactions (compliant with FASB 80 or FASB 133 (as amended by FASB 149) to the extent applicable)

APPENDIX 4

INTERNAL AUDIT

Review documentation as needed to verify the RMP defined limits of EDE hedge transactions and operations and will periodically confirm the internal controls in place are effective in protecting the objectives of EDE's risk management program.

APPENDIX 5

FOR ANY HEDGE TRANSACTION

(Physical, Exchange-Traded or OTC)

**Please reference Appendix 7 for a graphical representation of this process*

DAILY

1. **Monitor Market Prices/Identify Need for a Hedge in line with Hedging Strategy Objectives**

✓ Wholesale Energy Group will monitor prices for opportunities to meet RMP hedge goals and objectives.

2. **Determine Best Strategy within Limits to Achieve Hedging Objective**

✓ Within the RMOC approved limits, Wholesale Energy Group will determine the best hedge strategies to implement in line with objectives.

✓ For any chosen strategies that exceed a specified time period or dollar limit, the Vice President – Energy Supply must verify that the chosen hedge transaction meets objectives.

3. **Confirm Counterparty Meets Credit Requirements**

✓ For an OTC transaction, the prospective counterparty must be crosschecked with the Approved Counterparty Credit List for credit verification.

4. **Implement Transaction**

✓ Wholesale Energy Group prepares internal documentation for current order.

5. **Communicate Order**

✓ Wholesale Energy Group executes a hedge with broker and/or counterpart by picking up the phone and calling in information that is simultaneously recorded via a trading ticket (*reference example in Appendix 7 in next section*) which is date/time stamped and entered into a position tracking report and FUTRAK software.

6. **Broker Documents and Executes Transaction**

✓ In addition, the broker and the NYMEX floor representatives keep their own trading tickets to document the transaction.

7. **Verify Transaction (Verbal and Written)**

✓ Broker and/or counterpart verifies hedge fill via phone initially to Wholesale Energy Group.

✓ Written confirmations will be sent to Wholesale Energy Group and Finance the following business day via e-mail or fax. The confirmation/contract is examined by the WEG Energy Trader for accuracy by crosschecking to the input on the trading ticket. If everything is in agreement, the appropriate WEG representative (as defined in Appendix 12, Trading Authorities) will sign the confirmation/contract and fax back to the counterparty. If there are disagreements, these will be resolved and then the confirmation/contract will be signed and faxed to the counterparty. A copy of the trading ticket is sent to the Risk Management Accountant to be matched up with the confirmation/contract.

8. Confirm Accuracy of Transaction

✓ Wholesale Energy Group crosschecks daily broker Account Statement confirmations against internal Position Report for accuracy

✓ Wholesale Energy Group provides mark-to-market reports that tracks the value of the hedge based on current market price.

9. Track Positions

✓ This Wholesale Energy Group Position Report is forwarded to Finance as a check for accuracy on market value and is compared to the broker daily Account Statement report.

10. Reconcile Positions Daily with Broker via Finance

✓ On a daily basis, Finance will determine and verify cash flow receipts and obligations. If EDE is on margin call, funds will be wired to the broker to keep the hedge account equity in line with the current market value.

MONTHLY AND ON-GOING

1. Reconcile Monthly Account Statements

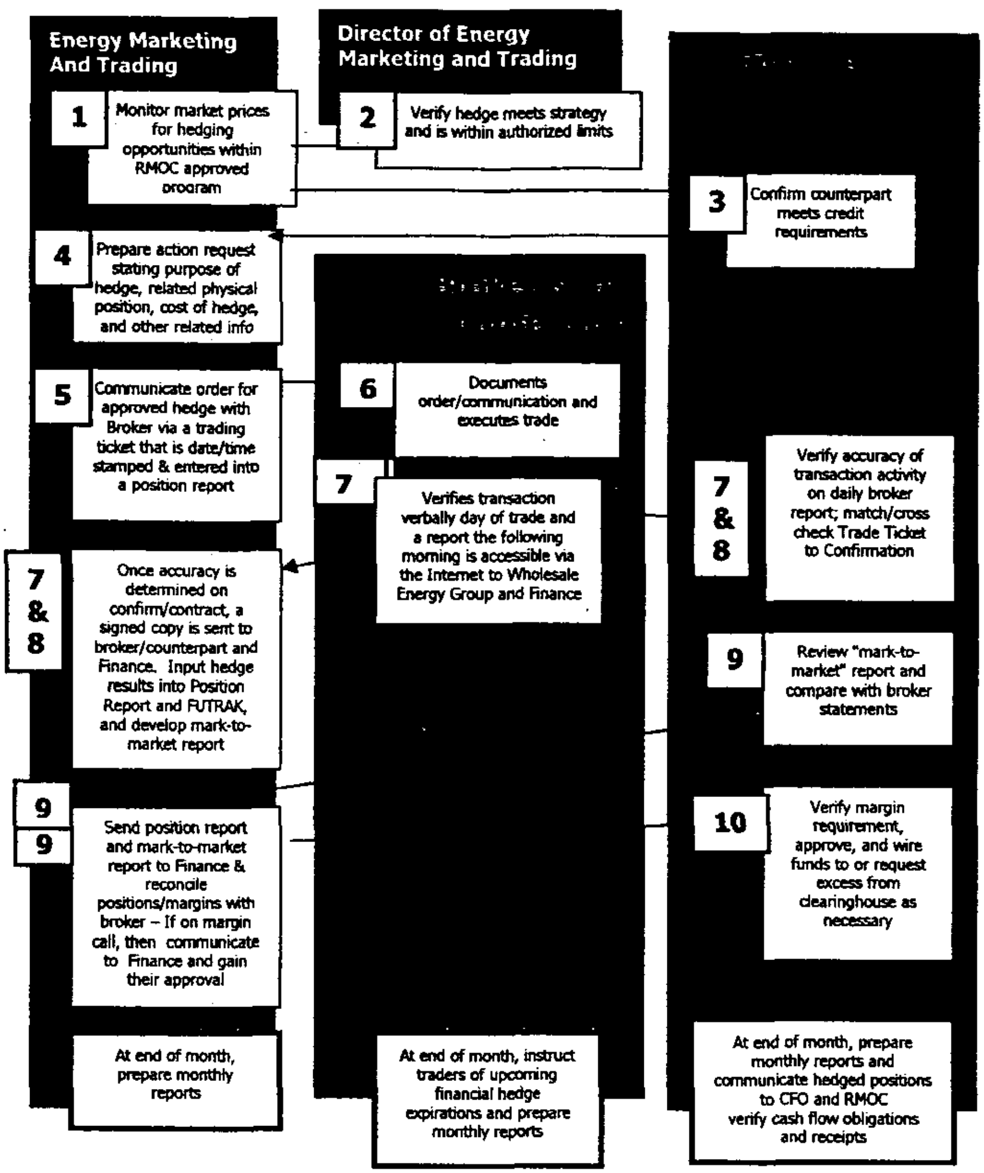
✓ Finance reconciles broker and/or counterpart statements with internal Position Report and FUTRAK software.

2. Review of Transaction/Reporting

✓ On a monthly basis, Wholesale Energy Group will review with the RMOC the strategy and positions taken. On at least a semi-annual basis, the results of the RMP hedge strategy will be reported to the Board of Directors by the RMOC.

APPENDIX 6

PROCEDURAL FLOW
FOR
HEDGE TRANSACTIONS & RECONCILIATION



***Internal Audit will periodically review process to verify accuracy and compliance**

APPENDIX 7

TRADE TICKET

The ability to internally track hedge transactions is crucial to providing an audit trail whereby all parties involved in the decision-making process are notified of a hedge position. This notification of a transaction is also the primary document in tracking a hedge and providing information for the Position Report. Included in the document will be the volumes hedged, the price or instrument used, the length of time for the hedge, and the counterpart to the transaction. Internal Trade Transaction Ticket(s) are included on the following pages.

Energy Trade Confirmation Sheet A

Trader: Greg PSE: EDE

Trade Ticket Number G082203SA Path: EDE/WRI

Date 8/22/2003 Sale

HE	MW	$/MWH	$	Cost $/MWH	Cost $
0100			0		0.00
0200			0		0.00
0300			0		0.00
0400			0		0.00
0500			0		0.00
0600			0		0.00
0700			0		0.00
0800			0		0.00
0900			0		0.00
1000			0		0.00
1100			0		0.00
1200			0		0.00
1300			0		0.00
1400			0		0.00
1500			0		0.00
1600			0		0.00
1700	30	75.00	2250	64.73	1,941.90
1800	50	70.00	3500	64.73	3,236.50
1900			0		0.00
2000			0		0.00
2100			0		0.00
2200			0		0.00
2300			0		0.00
2400			0		0.00
02AA					
Totals	80		5,750.00		5,178.40

Comments: Net Margin: 571.60

Sold to Westar.

Avg cost 64.73

Avg revenue 71.88

Deal type: WSPP Economy Sale

Fax or Voice Confirmation voice

Eligible for Incentive (Y/N):

Margin: 7.15

Source Unit: EC unit 2

Source Unit Cost: $/MWH 64.73

Incentive amount: ____

Supervisor's initials: ________

Empire District Electric Company			Trade	G22
Internal Trade Transaction Ticket			Trade Date	9-Sep-
			Trade Time	11:50

Buy/Sell	Instrument	Type	Strike Price	Market
Buy	Futures	Normal		NYMEX
			Premium	

Location	Quality	Delivery Start Date	Exercise
Henry Hub	Firm	01-Jul-05	
		Delivery End Date	Settlement Date
		31-Aug-05	01-Jul-05
			01-Aug-05

Price Type	Price Differential /		Volumetric Quantity			
Fixed	4.58	Jul-05	Rate			
	4.58	Aug-05	Total Qty	200,000	Jul-05	
				200,000	Aug-05	

Transmission/Transport Charges

Scheduling

Counter Party	Mark-to-Market	Broker Commission
NYMEX	Henry Hub	

General

Energy Trader: Greg

Energy Trader's ________

Transaction Objective Based on Empire's Risk Management Policy

Purchased gas futures to financially lock in a portion of Calendar 2005 gas

Middle Office - Risk Management ______ Doug Gallemore

Back Office - Accounting ______ Doug Gallemore

Back Office - Tax Accounting ______ Jay

This Transaction complies with:
Ordinary Property Obligations
(IRC Section 1221

Identification
(Treas. Regs. Section 1.1221-2(e))

Distribution:
Energy Trading
Risk Management
Tax Accounting
Treasury

APPENDIX 8

CONFIRMATION PROCEDURE

Exchange Traded Confirmations

Wholesale Energy Group will verbally confirm every transaction with broker and/or counterpart on the trade date. Trade confirmations on the daily open position statements will be sent by the broker (on the following business day) to Wholesale Energy Group and Finance. Wholesale Energy Group must check for accuracy on the following business day, input updates into the position report and Futrak, maintain a mark-to-market report, and forward said report to Finance. Finance is responsible for verifying the confirmation against the transacting records.

Physical and OTC Financial Confirmations

Wholesale Energy Group must verbally confirm every transaction with the broker/counterpart on the trade date. For physical and financially settled OTC transactions, written or email confirmations of the applicable business terms and conditions will be completed by Wholesale Energy Group and forwarded to Finance by the end of the second business day following the trade day. Finance is responsible for verifying the confirmation against the transacting records.

The following procedures will be adhered to at all times:

- The trader will review a copy of the confirmation for completeness and initial the confirmation.
- The trader will enter the trade into the Position Report and Futrak.
- Confirmations will be completed, signed, and sent to the counterpart by WEG within two business days.
- Original trade tickets and confirmations will be kept by Finance until after the transaction has settled. Once the transactions have settled, the confirmations and tickets will be maintained.

APPENDIX 9

POSITION REPORT

The Empire District Electric Company

Gas Position Summary as of October 6, 2003

	November 2003	December 2003	Nov-Dec 2003	Year 2004 60% to	Year 2005 40% to	Year 2006 20% to	Year 2007 0% to 20%	Net All Years
Budget DTh	394,656	882,590	1,277,246	10,492,844	11,261,182	12,232,134	12,884,705	48,148,111
Expected DTh	510,900	877,800	1,388,700	10,492,844	11,261,182	12,232,134	12,884,705	48,259,565
Policy minimum hedged DTh (2)	408,720	702,240	1,110,960	6,295,706	4,504,473	2,446,427	0	14,357,566
Policy maximum hedged DTh	510,900	877,800	1,388,700	8,394,275	6,756,709	4,892,854	2,576,941	24,009,479
Amount Hedged from Upside Volatility	395,000	675,000	1,070,000	6,620,000	3,800,000	1,300,000	600,000	13,390,000
percentage	**77%**	**77%**	**77%**	**63%**	**34%**	**11%**	**5%**	**28%**
Amount Hedged from Downside Volatility	395,000	675,000	1,070,000	6,620,000	3,800,000	1,300,000	600,000	13,390,000
percentage	**77%**	**77%**	**77%**	**63%**	**34%**	**11%**	**5%**	**28%**
Bookout per physical Dth, all positions	-3.659	-4.716	-4.188	-10.091	3.949	3.988	4.203	1.870
Average Cost per Dth hedged	**2.288**	**3.386**	**2.981**	**3.312**	**4.119**	**4.188**	**4.203**	**3.613**
Net All Positions Marked to Market $ (1)	818,435	950,095	1,768,530	8,844,225	1,478,350	211,600	45,600	12,348,305
PHYSICAL HEDGES								
Purchased Dth	100,000	100,000	200,000	600,000	2,400,000	1,000,000	600,000	4,800,000
Purchased $	325,500	325,500	651,000	2,256,000	9,636,000	4,050,000	2,521,500	19,114,500
Purchased $/DTh	**3.255**	**3.255**	**3.255**	**3.760**	**4.015**	**4.050**	**4.203**	**3.982**
Market $	452,500	478,500	931,000	2,789,475	10,955,400	4,199,500	2,567,100	21,442,475
Market $/Dth (on Williams Pipeline)	**4.525**	**4.785**	**4.655**	**4.649**	**4.565**	**4.200**	**4.279**	**4.467**
Gain/(Loss) versus current market	127,000	153,000	280,000	533,475	1,319,400	149,500	45,600	2,327,975
FINANCIAL HEDGES								
Swap/Futures Dth Purchased	375,000	375,000	750,000	6,300,000	1,400,000	300,000	0	8,750,000
Net Cost, $/Dth	**3.093**	**3.093**	**3.093**	**3.307**	**4.298**	**4.648**	**0.000**	
Market $/Dth (at Henry Hub or Swap	**4.396**	**4.652**	**4.524**	**4.652**	**4.411**	**4.855**	**0.000**	
Swap Settlement - Receipt / (Payment)	488,475	584,575		8,474,550	158,950	62,100	-	9,768,650
Swap/Futures Dth Sold or Settle	280,000	0	280,000	280,000	0	0	0	560,000
Net Cost, $/Dth	**4.935**	**0.000**	**4.935**	**4.150**	**0.000**	**0.000**	**0.000**	
Market $/Dth (at Henry Hub or Swap	**4.767**	**0.000**	**4.767**	**4.735**	**0.000**	**0.000**	**0.000**	
Swap Settlement - Receipt / (Payment)	47,040	-	47,040	(163,800)	-	-	-	(116,760)
Call Dth (Buy a Call)	0	0	0	0	0	0	0	0
Call Strike $/Dth	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Market $/Dth (at Henry Hub or Swap	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Cost of Call $/Dth	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Value $ of Call Position	-	-	-	-	-	-	-	0
(Cost) $ of Call Position	-	-	-	-	-	-	-	0
Collar Dth	200,000	200,000	400,000	-	-	-	-	400,000
Floor $/Dth	**3.350**	**3.350**	**3.350**	**0.000**	**0.000**	**0.000**	**0.000**	
Ceiling $/Dth	**4.000**	**4.000**	**4.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Market $/Dth (at Henry Hub or Swap	**4.767**	**5.034**	**4.901**	**0.000**	**0.000**	**0.000**	**0.000**	
Cost of Floor $/Dth	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Value of Ceiling $/Dth	**0.780**	**1.063**	**0.921**	**0.000**	**0.000**	**0.000**	**0.000**	
(Cost) / Value $ of Collar Position	155,920	212,520	368,440	-	-	-	-	368,440
Put Dth (Sell a Put)	0	0	0	0	0	0	0	0
Put Strike $/Dth	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Market $/Dth (at Henry Hub or Swap	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Revenue from Put $/Dth	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	**0.000**	
Value $ of Put Position	-	-	-	-	-	-	-	0
(Cost) $ of Put Position	-	-	-	-	-	-	-	0

Note 1: Market data using NYMEX Close Prices as of October 3, 2003.

Note 2: Policy minimums and maximums are 12/31/2003 targets

APPENDIX 10

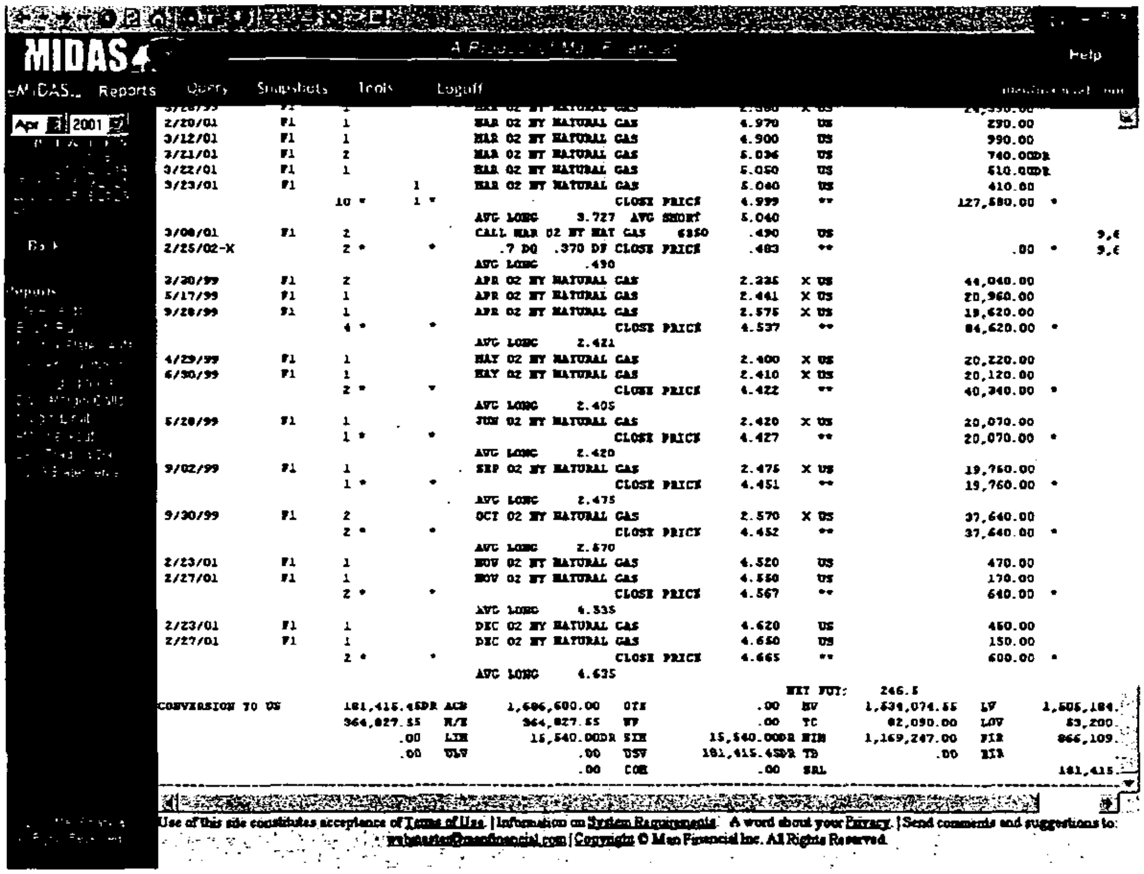
MARK-TO-MARKET REPORTING

As mentioned previously, all positions will be "mark-to-market" (using the appropriate NYMEX prices as defined by the underlying contract) weekly. This analysis is performed by Wholesale Energy Group to appropriately reflect the current value and cash flows associated with open positions and to provide timely information regarding EDE market risk and exposure. Wholesale Energy Group is responsible for verifying the validity and accuracy of the market data used in mark-to-market calculations through the position report on a weekly basis. All positions will be "marked-to-market" (using the appropriate NYMEX prices as defined by the underlying contract) at the end of each month using FUTRAK accounting software by the Risk Management Accountant. The resulting entries will then be recorded in EDE's general ledger.

APPENDIX 11

DAILY BROKER ACCOUNT STATEMENT

The RMI Account Statement shown below is an illustration of the daily report that Wholesale Energy Group and Finance can access on the Internet daily to confirm the previous day's trading activities:



2/20/01	F1	1		MAR 02 NY NATURAL GAS	4.970	US	290.00	
3/12/01	F1	1		MAR 02 NY NATURAL GAS	4.900	US	990.00	
3/21/01	F1	2		MAR 02 NY NATURAL GAS	5.036	US	740.00DR	
3/22/01	F1	1		MAR 02 NY NATURAL GAS	5.050	US	510.00DR	
3/23/01	F1		1	MAR 02 NY NATURAL GAS	5.040	US	410.00	
		10 *	1 *	CLOSE PRICE	4.999	**	127,580.00 *	
				AVG LONG 3.727 AVG SHORT	5.040			
3/08/01	F1	2		CALL MAR 02 NY NAT GAS 6350	.490	US		9,6
2/25/02-X		2 *	*	.7 DQ .370 DF CLOSE PRICE	.483	**	.00 *	9,6
				AVG LONG .490				
3/30/99	F1	2		APR 02 NY NATURAL GAS	2.225	X US	44,040.00	
5/17/99	F1	1		APR 02 NY NATURAL GAS	2.441	X US	20,960.00	
9/20/99	F1	1		APR 02 NY NATURAL GAS	2.575	X US	19,620.00	
		4 *	*	CLOSE PRICE	4.537	**	84,620.00 *	
				AVG LONG 2.421				
4/29/99	F1	1		MAY 02 NY NATURAL GAS	2.400	X US	20,220.00	
6/30/99	F1	1		MAY 02 NY NATURAL GAS	2.410	X US	20,120.00	
		2 *	*	CLOSE PRICE	4.422	**	40,340.00 *	
				AVG LONG 2.405				
5/20/99	F1	1		JUN 02 NY NATURAL GAS	2.420	X US	20,070.00	
		1 *	*	CLOSE PRICE	4.427	**	20,070.00 *	
				AVG LONG 2.420				
9/02/99	F1	1		SEP 02 NY NATURAL GAS	2.475	X US	19,760.00	
		1 *	*	CLOSE PRICE	4.451	**	19,760.00 *	
				AVG LONG 2.475				
9/30/99	F1	2		OCT 02 NY NATURAL GAS	2.570	X US	37,640.00	
		2 *	*	CLOSE PRICE	4.452	**	37,640.00 *	
				AVG LONG 2.570				
2/23/01	F1	1		NOV 02 NY NATURAL GAS	4.520	US	470.00	
2/27/01	F1	1		NOV 02 NY NATURAL GAS	4.550	US	170.00	
		2 *	*	CLOSE PRICE	4.567	**	640.00 *	
				AVG LONG 4.535				
2/23/01	F1	1		DEC 02 NY NATURAL GAS	4.620	US	460.00	
2/27/01	F1	1		DEC 02 NY NATURAL GAS	4.650	US	150.00	
		2 *	*	CLOSE PRICE	4.665	**	600.00 *	
				AVG LONG 4.635				

NET FUT: 246.5

CONVERSION TO US	181,415.45DR	ACB	1,606,600.00	OTE	.00	MV	1,534,074.55	LV	1,505,184.
	364,027.55	R/E	364,027.55	UP	.00	TC	82,090.00	LOV	53,200.
	.00	LIN	15,540.00DR	SIN	15,540.00DR	MIN	1,169,247.00	FIR	866,109.
	.00	ULV	.00	USV	181,415.45DR	TB	.00	EIR	
			.00	COM	.00	SRL			181,415.

APPENDIX 12

TRADING AUTHORIZATION

	Physical Power Purchases and Sales	Other Physical and Financial Transactions
Rick McCord	Up to $5 million	Up $5 million
Katie Barton	Next 7 days and up to $5 million	Next 7 days and up to $5 million
Tim Wilson	Next 7 days and up to $5 million	Next 7 days and up to $5 million
Greg Sweet	Next 7 days and $5 million	Next 7 days and up to $5 million
Karl Doner	Next 3 days	None
John Deffenbaugh	Next 3 days	None
Jim Graham	Next 3 days	None
Bob Hallam	Next 3 days	None
Kenny Myers	Next 3 days	None
Jim Johnston	Next 3 days	None
Mike Stuart	Next 3 days	None

- The persons listed above are authorized only to engage in the types of transactions specifically approved by the RMOC and the Energy Risk Management Policy.
- Although system dispatchers should do whatever is necessary to ensure system reliability, they should immediately notify the Wholesale Energy Group in the event they enter into a single transaction exceeding $250,000 in a calendar day.

Transactions greater than $5 million must be approved by the RMOC or, in the event the RMOC cannot meet, by at least two-thirds (2/3) of Senior Officers appointed to the RMOC.

SCHEDULE BPB-2

The Empire District Electric Company
Gas Position Summary as of April 16, 2004

	May 2004	June 2004	July 2004	Aug-Dec 2004	Year 2005 60% min	Year 2006 40% min	Year 2007 20% min	Year 2008 10% min	Net All Years
Budget DTh	680,858	1,013,900	1,412,471	4,079,553	10,513,865	11,115,944	11,739,629	12,749,586	53,305,805
Expected DTh (3)	652,349	948,934	1,429,858	3,977,507	10,513,865	11,115,944	11,739,629	12,749,586	53,127,671
Policy minimum hedged DTh (2)	521,879	759,147	1,143,887	3,182,005	6,308,319	4,446,378	2,347,926	1,274,959	19,984,499
Amount Hedged from Upside Volatility Dth	530,000	570,000	700,000	2,620,000	4,200,000	2,200,000	2,400,000	1,200,000	14,420,000
percentage	81%	60%	49%	66%	40%	20%	20%	9%	27%
Amount Hedged from Downside Volatility Dth	50,000	50,000	700,000	2,620,000	4,200,000	2,200,000	2,400,000	1,200,000	13,420,000
percentage	8%	5%	49%	66%	40%	20%	20%	9%	25%
Bookout per physical Dth, all positions	-12.024	-15.912	-22.003	-19.075	3.382	3.234	3.783	N/A	1.277
Average Cost per Dth hedged	3.894	4.147	3.569	3.272	4.147	4.271	4.515	4.635	4.020
Net All Positions Marked to Market $ (1)	866,700	1,066,250	1,374,700	6,179,500	5,006,400	1,476,150	451,500	64,800	16,486,200
PHYSICAL HEDGES									
Purchased Dth	50,000	50,000	50,000	250,000	2,400,000	1,000,000	600,000	0	4,400,000
Purchased $	188,000	188,000	188,000	940,000	9,636,000	4,050,000	2,521,500	-	17,711,500
Purchased $/DTh	3.760	3.760	3.760	3.760	4.015	4.050	4.203	0.000	4.025
Market $	265,500	270,650	274,550	1,410,750	13,122,900	4,710,000	2,721,000	-	22,775,350
Market $/Dth (on Williams Pipeline)	5.310	5.413	5.491	5.643	5.468	4.710	4.535	0.000	5.176
Gain/(Loss) versus current market	77,500	82,650	86,550	470,750	3,486,900	660,000	199,500	-	5,063,850
FINANCIAL HEDGES									
Swap/Futures Dth Purchased	500,000	500,000	650,000	2,650,000	1,800,000	1,200,000	1,800,000	1,200,000	10,300,000
Net Cost, $/Dth	3.242	3.242	3.554	3.319	4.323	4.456	4.619	4.635	
Market $/Dth (at Henry Hub or Swap location)	5.310	5.413	5.536	5.648	5.167	5.136	4.759	4.689	
Swap Settlement - Receipt / (Payment)	1,034,000	1,085,500	1,288,150	6,172,150	1,519,500	816,150	252,000	64,800	12,232,250
Swap/Futures Dth Sold or Settle	500,000	500,000	0	280,000	0	0	0	0	1,280,000
Net Cost, $/Dth	5.250	5.650	0.000	4.150	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap location)	5.610	5.703	0.000	5.805	0.000	0.000	0.000	0.000	
Swap Settlement - Receipt / (Payment)	(180,000)	(26,500)	-	(463,400)	-	-	-	-	(669,900)
Call Dth (Buy a Call)	480,000	520,000	0	0	0	0	0	0	1,000,000
Call Strike $/Dth	6.000	6.500	0.000	0.000	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap location)	5.610	5.703	0.000	0.000	0.000	0.000	0.000	0.000	
Cost of Call $/Dth	0.135	0.145	0.000	0.000	0.000	0.000	0.000	0.000	
Value $ of Call Position	-	-	-	-	-	-	-	-	0
(Cost) $ of Call Position	(64,800)	(75,400)	-	-	-	-	-	-	(140,000)
Collar Dth	-	-	-	-	-	-	-	-	0
Floor $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Ceiling $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap location)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Cost of Floor $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Value of Ceiling $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
(Cost) / Value $ of Collar Position	-	-	-	-	-	-	-	-	0
Put Dth (Sell a Put)	0	0	0	0	0	0	0	0	0
Put Strike $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Market $/Dth (at Henry Hub or Swap location)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Revenue from Put $/Dth	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Value $ of Put Position	-	-	-	-	-	-	-	-	0
(Cost) $ of Put Position	-	-	-	-	-	-	-	-	0

Note 1: Market data using NYMEX Close Prices as of April 16, 2004.
Note 2: Policy minimums are 12/31/2004 targets
Note 3: Expected Dth for 2004 revised due to revised outage schedules. 1/19/04.

2003 Natural Gas Costs

	MMBTtu	Cost before Derivative (Gain)/Loss $	Derivative (Gain)/Loss $	Total $	Total $/MMBtu
January	680,005	2,256,459	(1,010,879)	1,245,580	1.83
February	279,972	1,728,991	(925,445)	803,546	2.87
March	308,378	1,605,329	(2,803,389)	(1,198,060)	(3.89)
April	1,018,936	4,981,480	(588,829)	4,392,651	4.31
May	512,097	2,581,526	(908,620)	1,672,906	3.27
June	377,956	2,018,553	(1,304,321)	714,232	1.89
July	1,185,653	5,359,026	(1,047,499)	4,311,526	3.64
August	1,444,713	6,751,960	(669,382)	6,082,578	4.21
September	28,291	140,276	(793,237)	(652,961)	(23.08)
October	22,990	(105,206)	(62,610)	(167,816)	(7.30)
November	170,607	568,615	(131,247)	437,368	2.56
December	420,009	2,247,109	(427,980)	1,819,129	4.33
Total	**6,449,607**	**30,134,117**	**(10,673,437)**	**19,460,680**	**3.02**

***Figures presented are for commodity charges and do not include firm transportation (pipeline delivery) charges.*

Proposed In-Service Criteria for two Pratt and Whitney FT8 Twin Pac's at the Empire Energy Center

1. All major construction is completed.

   All major construction has been completed. A site tour is available at any time to demonstrate this point.

2. All pre-operational tests have been successfully completed.

   Per-operational tests were conducted and recorded in accordance with Pratt & Whitney Commissioning Manuals and Brush Generator commissioning manual. These manuals are available for review at the site.

3. Unit will successfully demonstrate its ability to initiate the proper start sequence resulting in the unit operating from zero rpm (or turning gear) to full load when prompted at a location (or locations) from which it is normally operated.

   These engines have between 174 and 202 starts as of March 26, 2004. In Attachment A are trend graphs for each engine showing a start sequence in the recent past. The units are normally started to the local control skids. This is where most of the starts have been initiated, the units can and have been started from the central control room on site. The electronic records do not record where the start is initiated from.

4. If the unit has fast start capability, unit will demonstrate its ability to meet fast start criteria.

   These units do not have a separate fast start capability.

5. Units will successfully demonstrate its ability to initiate the proper shutdown sequence from full load resulting in zero rpm (or turning gear) when prompted at a location (or locations) from which it is normally operated.

   In Attachment B are trend graphs for each engine showing a normal shutdown sequence in the recent past.

6. Unit will successfully demonstrate its ability to operate at minimum load for 1 hour.

   Since new, each of the engines has operated over 700 hours and each unit has produced over 27,000 MWH. The units have operated successfully at all load points including minimum load.

7. Unit will successfully demonstrate its ability to operate at or above 98% of full load for 4 continuous hours.

   In Attachment C are trend graphs for each unit demonstrating their ability to operate at or above 98% of full load for 4 hours.

8. Unit will successfully meet all operational guarantees.

   Performance testing was conducted by Power Generation Technologies. Operational guarantees were met. The test report is available for review at the plant site.

9. Transmission facilities will successfully demonstrate its capability to export the entire plant net capacity.

   In Attachment D is a copy of "Generation Interconnection Study" performed for the Southwest Power Pool. This study demonstrates little or no impact on the transmission system as a result of these new units under contingency conditions. We have completed the work identified at the end of the report.

   Similar studies show that under normal conditions (no contingencies) the new units have no impact on the transmission system.

   In addition to the study, we have operated all four units at the Energy Center at the same time on three different times last July and August with no limitation on our transmission system.

10. Unit will successfully demonstrate its ability to start on Liquid fuel.

    In Attachment E is a copy the log book entries for unit 4 on April 15, 2003 showing that unit 4 was started on liquid fuel twice and transferred from liquid fuel to natural gas.

    Similar tests were run on unit 3 during startup.

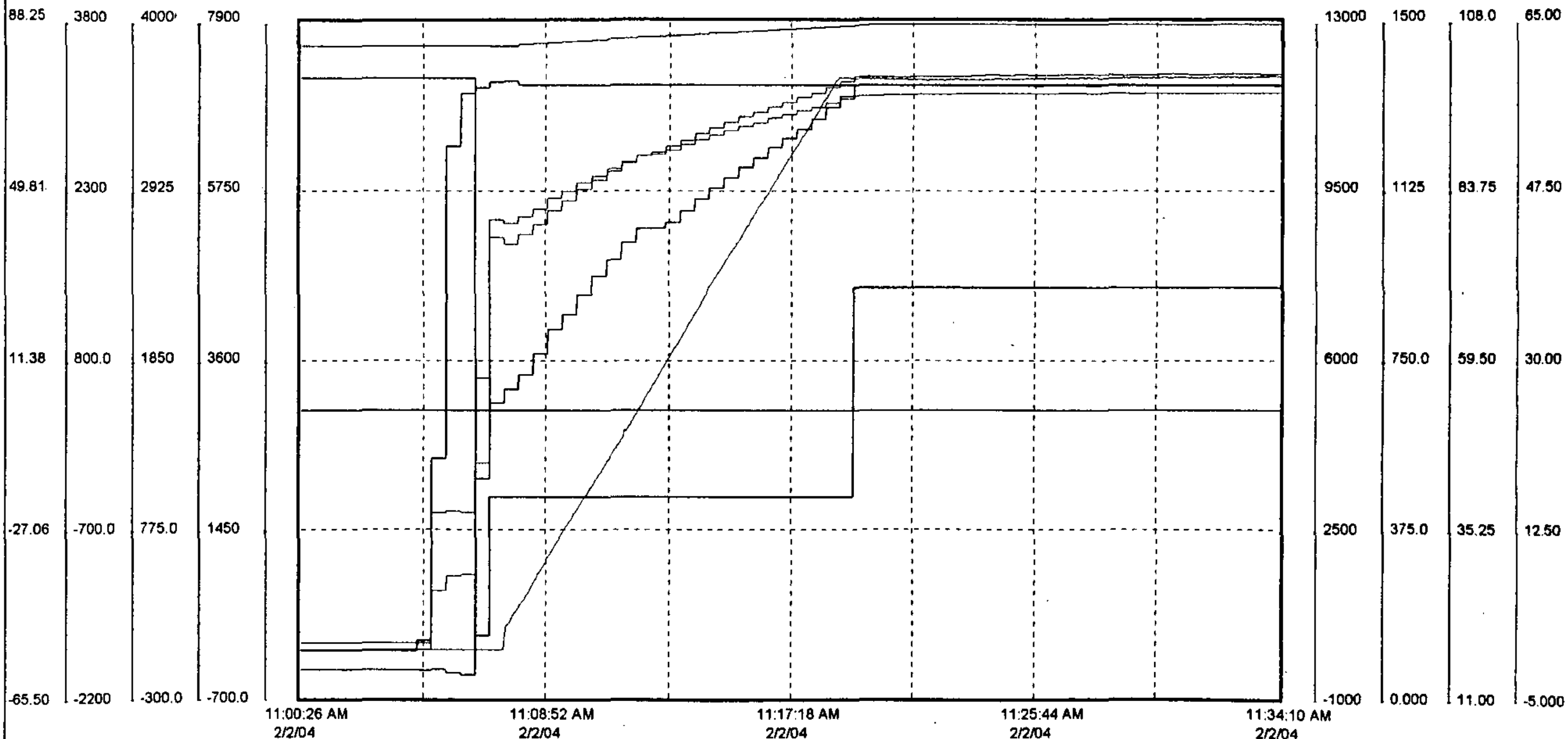
11. Units will successfully demonstrate its ability to transfer for natural gas fuel to liquid fuel.

    In Attachment F is a copy of the log book entries for unit 4 for January 29, 2004 showing that we transferred from Natural gas to liquid fuel.
    Also in Attachment F for unit 3 is a copy of the log book entries for December 12, 2003 showing that we transferred from natural gas to liquid fuel.

Attachment A

AU04TM19_EngB_Startup

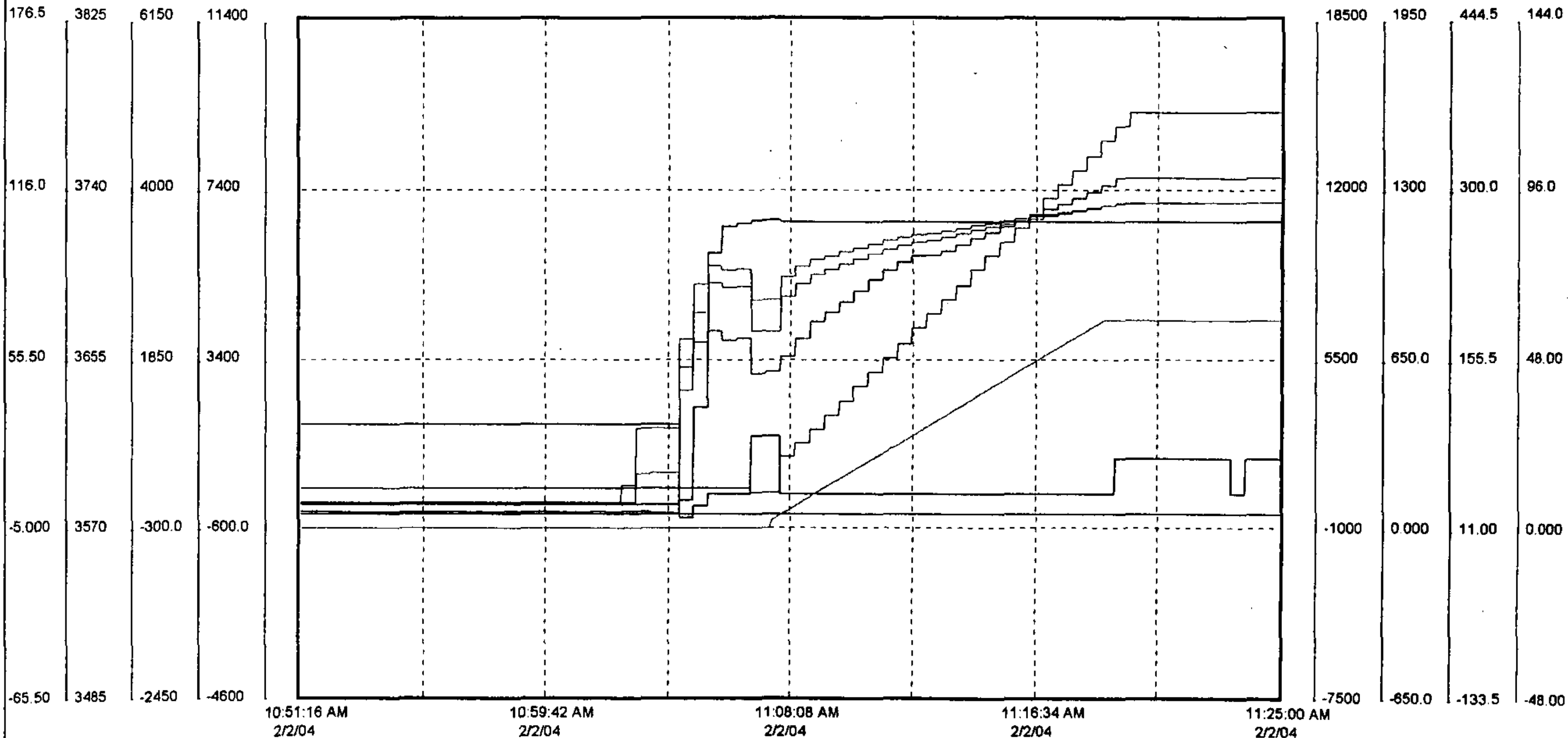
Unit 4B - Startup to Full Load



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
————	A04B00SD8PV_	NL HSS Speed	0.000	7242	5532	-700.0	7900	rpm
————	A04B00SD1PV_	NH HSS Speed	0.000	11521	9037	-1000	13000	rpm
————	A04B00SD3PV_	NP HSS Speed	0.000	3625	3078	-300.0	4000	rpm
————	A04B00AV1PV_	Average EGT	50.57	1359	996	0.000	1500	Deg F
————	A04B00SD3CO_	NP Reference	3588	3779	3705	-2200	3800	rpm
————	A04B00CN8PV_	In Control Analog	20.00	100.0	63.47	11.00	108.0	Units
————	A04BFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-65.50	88.25	%
————	A04UMWPV	MW	0.000	59.40	37.23	-5.000	65.00	MW

AU04TM18_EngA_Startup

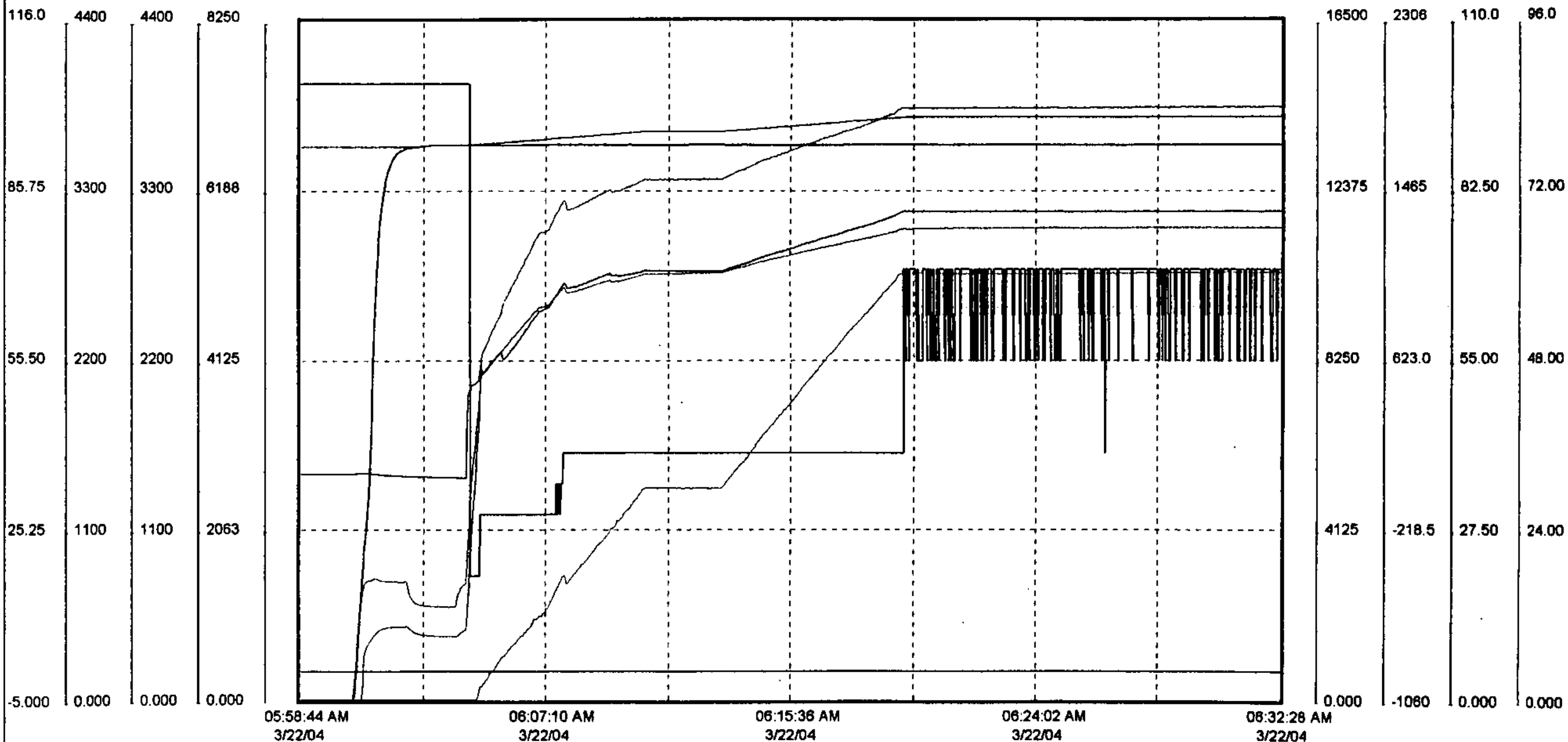
Unit 4A - Startup to Full Load



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
________	A04A00SD8PV_	NL HSS Speed	0.000	7122	3811	-4600	11400	rpm
________	A04A00SD1PV_	NH HSS Speed	0.000	11524	6466	-7500	18500	rpm
________	A04A00SD3PV_	NP HSS Speed	0.000	3626	2117	-2450	6150	rpm
________	A04A00AV1PV_	Average EGT	58.14	1348	681.1	-650.0	1950	Deg F
________	A04A00SD3CO_	NP Reference	3588	3779	3654	3485	3825	rpm
________	A04A00CN8PV_	In Control Analog	20.00	100.0	68.81	-133.5	444.5	Units
________	A04AFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-65.50	176.5	%
________	A04UMWPV	MW	0.000	59.30	21.12	-48.00	144.0	MW

AU03TM18_EngA_Startup

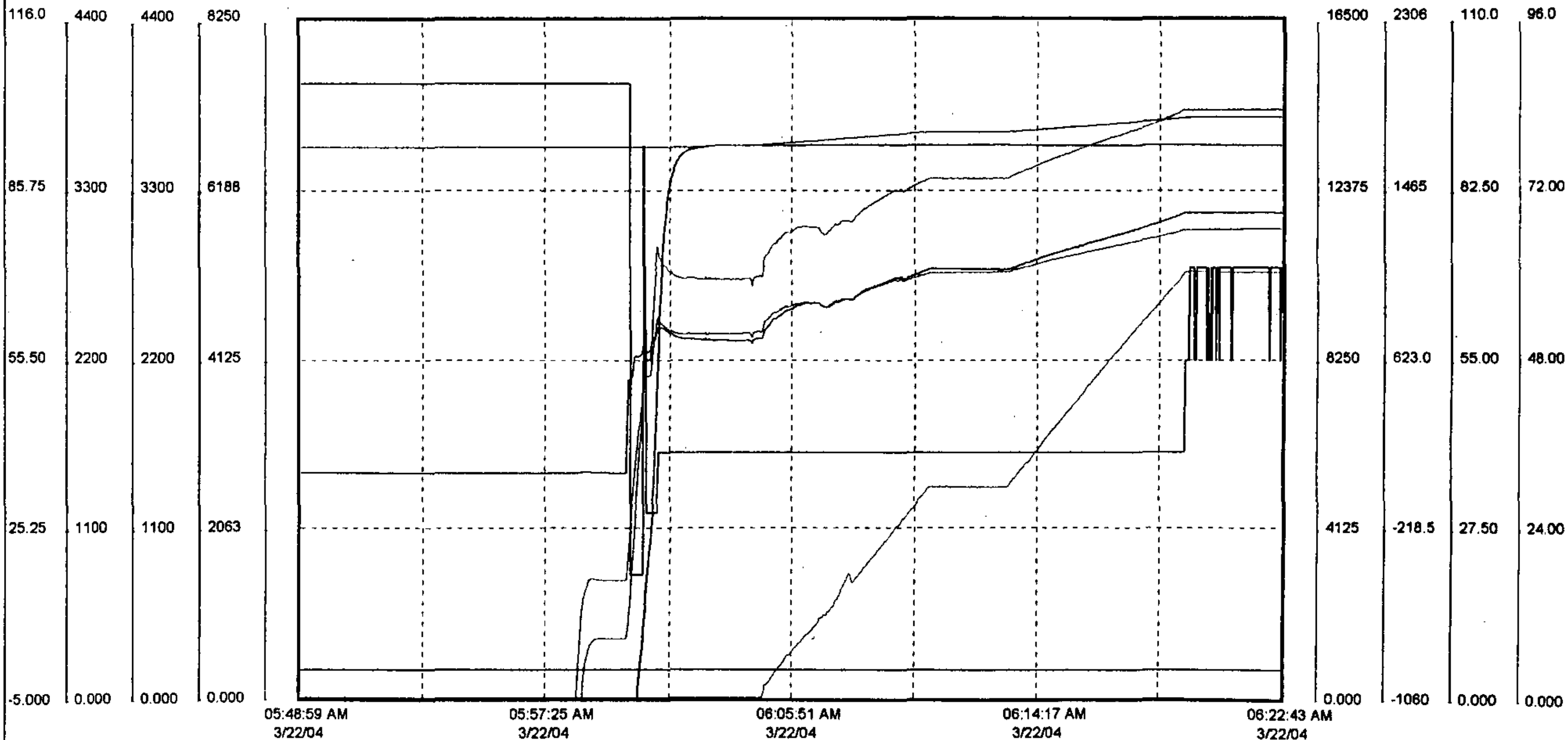
Start to Full Load



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
______	A03A00SD8PV	NL HSS Speed	0.000	7219	5592	0.000	8250	rpm
______	A03A00SD1PV	NH HSS Speed	0.000	11497	9241	0.000	16500	rpm
______	A03A00SD3PV	NP HSS Speed	0.000	3604	3343	0.000	4400	rpm
______	A03A00AV1PV	Average EGT	38.89	1367	1001	-1060	2306	Deg F
______	A03A00SD3CO	NP Reference	3590	3779	3707	0.000	4400	rpm
______	A03A00CN8PV	In Control Analog	20.00	100.0	59.60	0.000	110.0	Units
______	A03AFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-5.000	116.0	%
______	A03UMWPV	MW	0.000	60.70	36.81	0.000	96.0	MW

AU03TM19_EngB_Startup

Unit 3B - Startup to Full Load

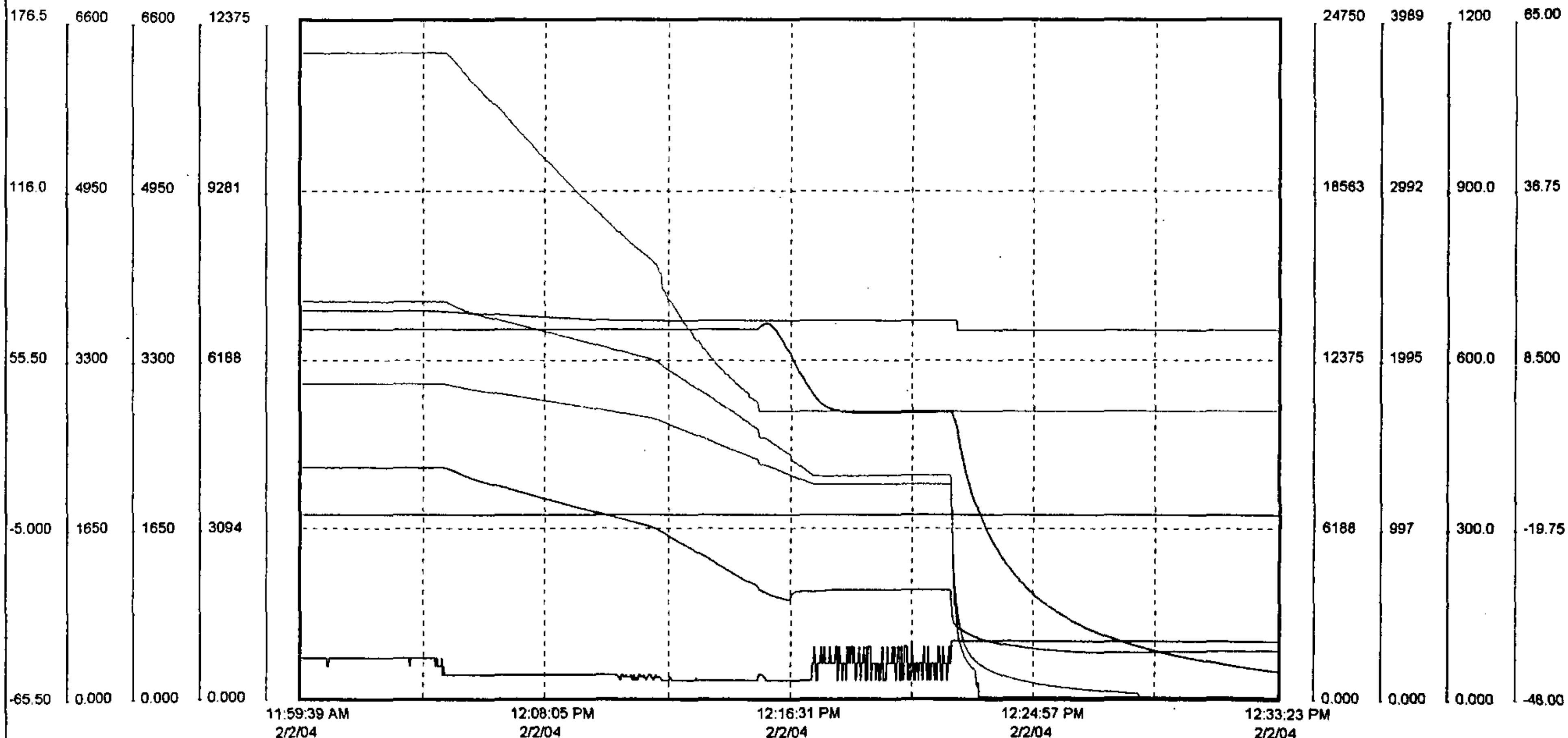


Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
______	A03B00SD8PV	NL HSS Speed	0.000	7185	4126	0.000	8250	rpm
______	A03B00SD1PV	NH HSS Speed	0.000	11433	6908	0.000	16500	rpm
______	A03B00SD3PV	NP HSS Speed	0.000	3602	2301	0.000	4400	rpm
______	A03B00AV1PV	Average EGT	58.56	1354	718.2	-1060	2306	Deg F
______	A03B00SD3CO	NP Reference	3590	3779	3652	0.000	4400	rpm
______	A03B00CN8PV	In Control Analog	20.00	100.0	62.58	0.000	110.0	Units
______	A03BFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-5.000	116.0	%
______	A03UMWPV	MW	0.000	60.60	19.30	0.000	96.0	MW

Attachment B

AU04TM19_EngB_Shutdown

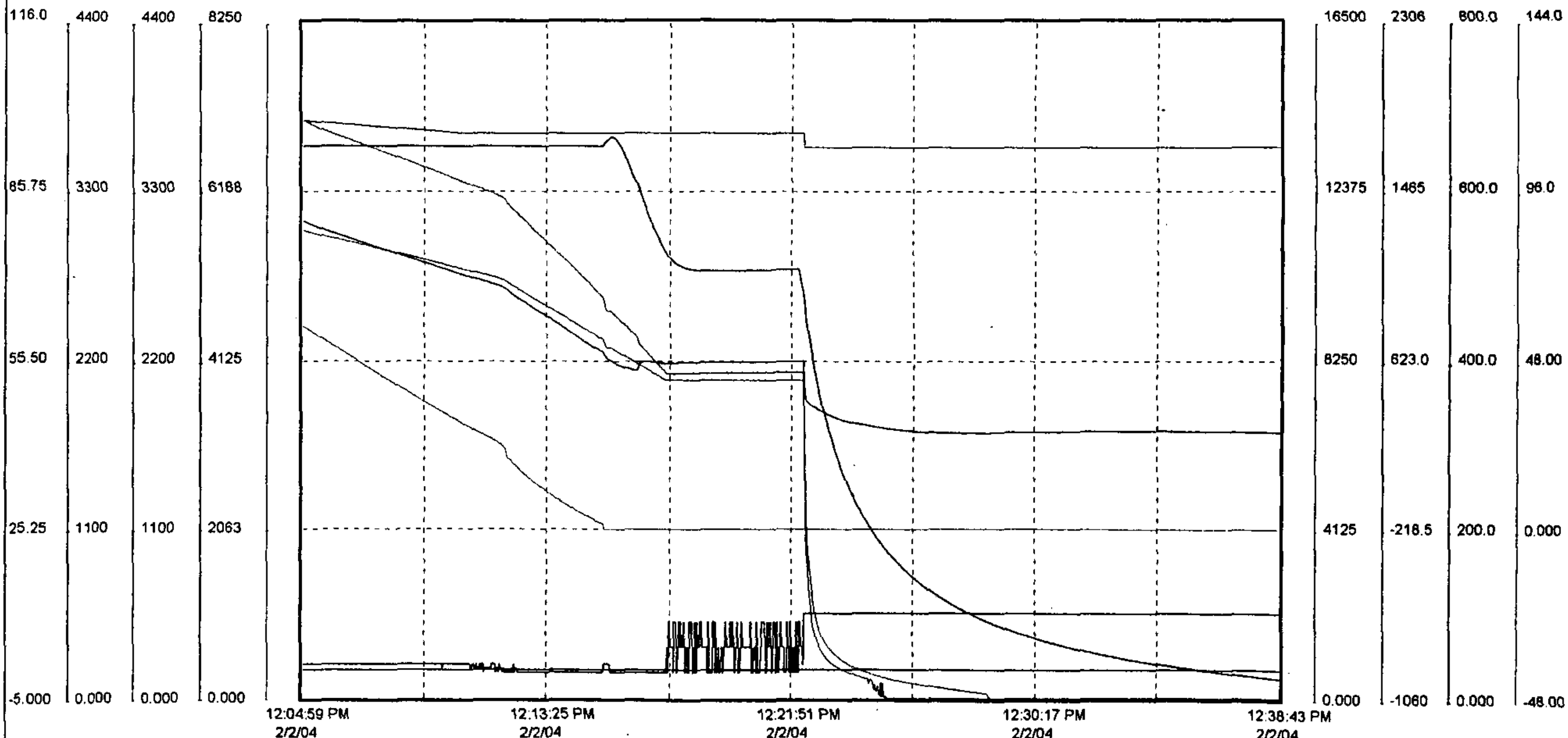
UNit 4B - Full Load to Shutdown



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
	A04B00SD8PV	NL HSS Speed	0.000	7269	3947	0.000	12375	rpm
	A04B00SD1PV	NH HSS Speed	0.000	11519	6751	0.000	24750	rpm
	A04B00SD3PV	NP HSS Speed	255.9	3658	2537	0.000	6600	rpm
	A04B00AV1PV	Average EGT	265.4	1360	759.4	0.000	3989	Deg F
	A04B00SD3CO	NP Reference	3590	3779	3675	0.000	6600	rpm
	A04B00CN8PV	In Control Analog	30.00	100.0	65.47	0.000	1200	Units
	A04BFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-65.50	176.5	%
	A04UMWPV	MW	0.000	60.00	18.88	-48.00	65.00	MW

AU04TM18_EngA_Shutdown

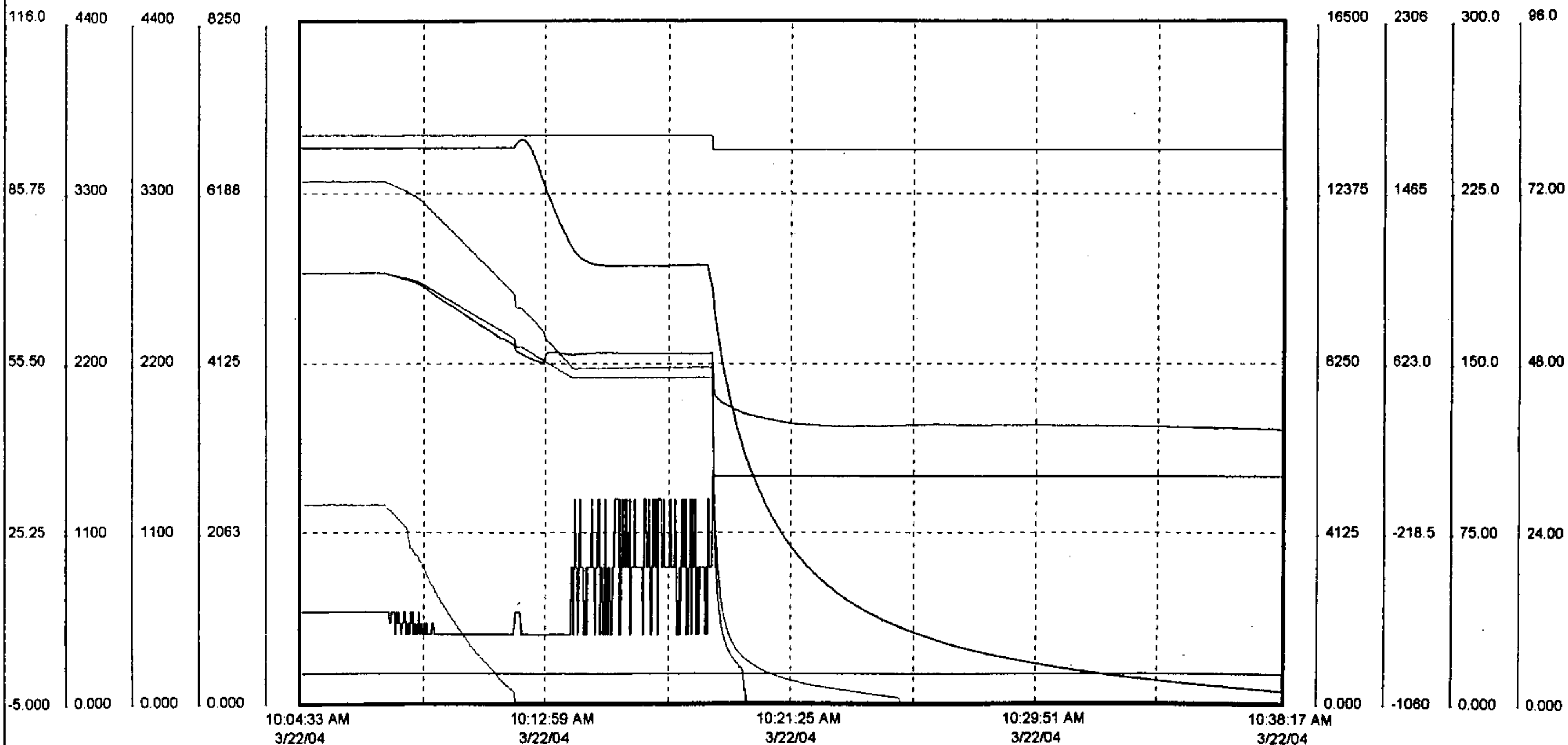
Unit 4A - Full Load to Shutdown



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
________	A04A00SD8PV	NL HSS Speed	0.000	7058	2801	0.000	8250	rpm
________	A04A00SD1PV	NH HSS Speed	0.000	11439	4967	0.000	16500	rpm
________	A04A00SD3PV	NP HSS Speed	127.9	3658	1997	0.000	4400	rpm
________	A04A00AV1PV	Average EGT	265.5	1321	586.0	-1060	2306	Deg F
________	A04A00SD3CO	NP Reference	3590	3765	3645	0.000	4400	rpm
________	A04A00CN8PV	In Control Analog	30.00	100.0	70.34	0.000	800.0	Units
________	A04AFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-5.000	116.0	%
________	A04UMWPV	MW	0.000	58.15	9.40	-48.00	144.0	MW

AU03TM18_EngA_Shutdown

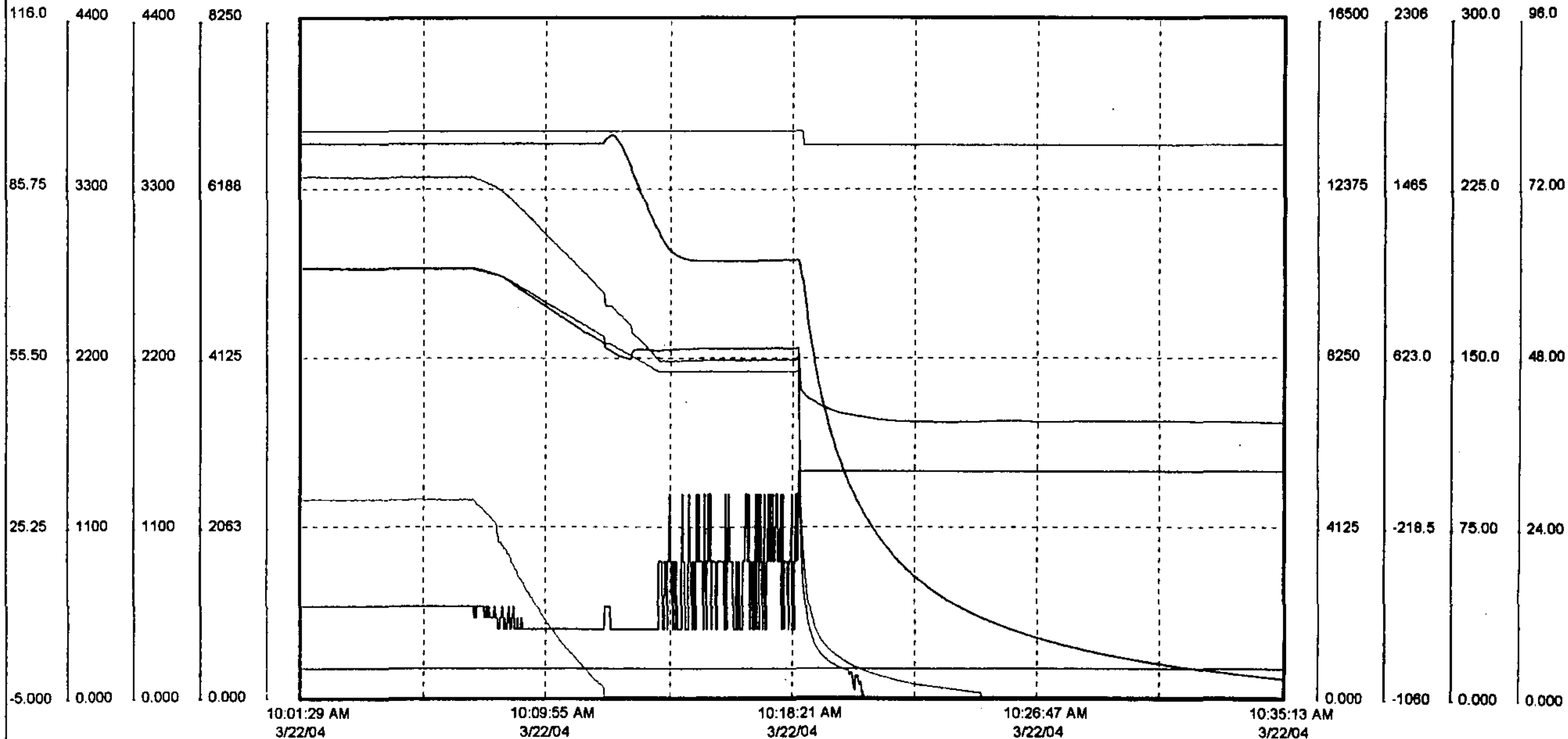
Unit 3A - Full Load to Shutdown



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
	A03A00SD8PV	NL HSS Speed	0.000	6349	2178	0.000	8250	rpm
	A03A00SD1PV	NH HSS Speed	0.000	10475	3952	0.000	16500	rpm
	A03A00SD3PV	NP HSS Speed	72.88	3656	1681	0.000	4400	rpm
	A03A00AV1PV	Average EGT	298.8	1078	535.9	-1060	2306	Deg F
	A03A00SD3CO	NP Reference	3590	3681	3628	0.000	4400	rpm
	A03A00CN8PV	In Control Analog	30.00	100.0	76.31	0.000	300.0	Units
	A03AFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-5.000	116.0	%
	A03UMWPV	MW	0.000	28.00	4.177	0.000	96.0	MW

AU03TM19_EngB_Shutdown

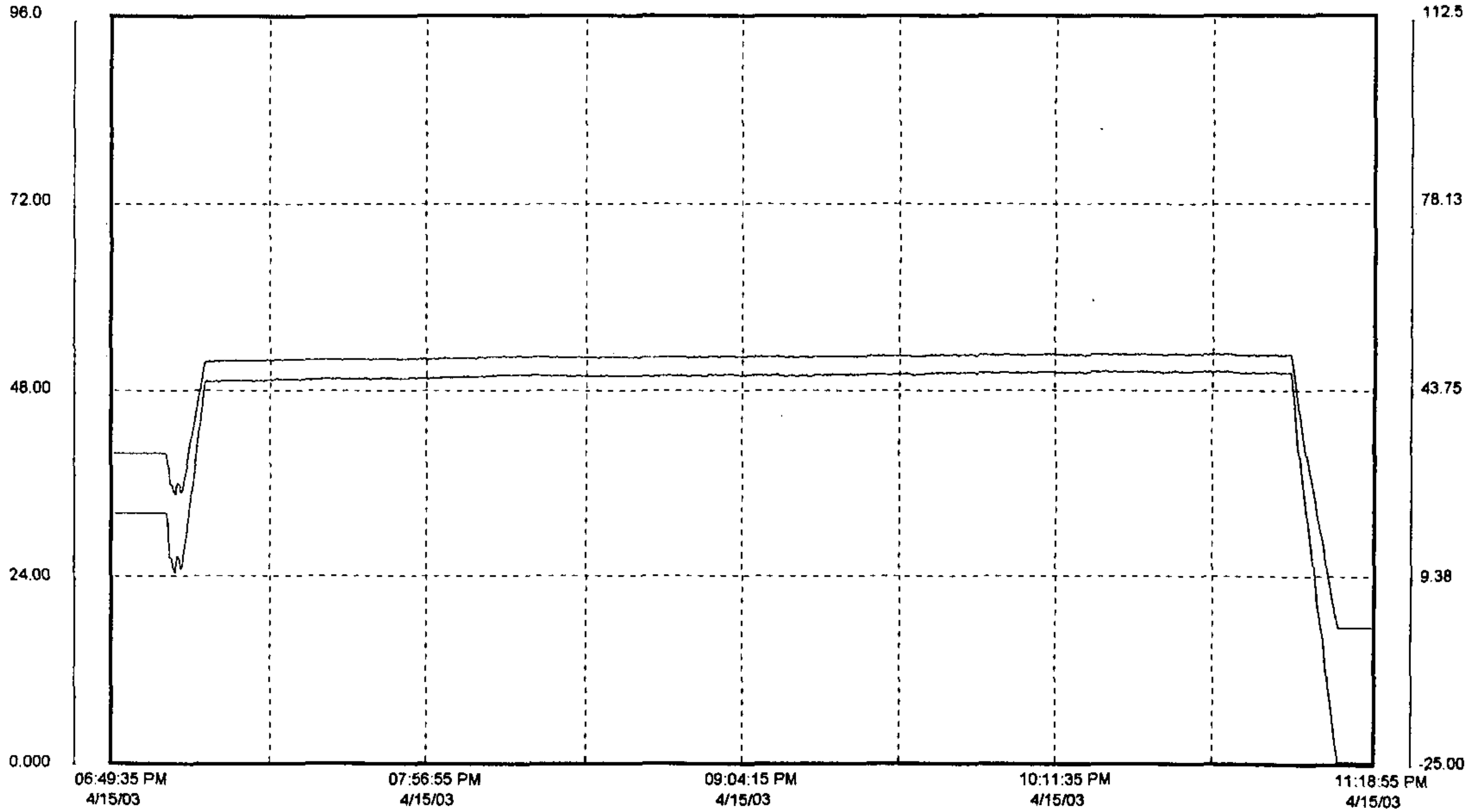
Unit 3B - Full Load to Shutdown



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
	A03B00SD8PV	NL HSS Speed	0.000	6350	2741	0.000	8250	rpm
	A03B00SD1PV	NH HSS Speed	0.000	10443	4848	0.000	16500	rpm
	A03B00SD3PV	NP HSS Speed	119.9	3656	2000	0.000	4400	rpm
	A03B00AV1PV	Average EGT	302.4	1078	598.1	-1060	2306	Deg F
	A03B00SD3CO	NP Reference	3590	3681	3636	0.000	4400	rpm
	A03B00CN8PV	In Control Analog	30.00	100.0	70.46	0.000	300.0	Units
	A03BFY1001PSSE	FY1001 Mod Valve Position Req	-0.001	-0.001	-0.001	-5.000	116.0	%
	A03UMWPV	MW	0.000	28.00	6.720	0.000	96.0	MW

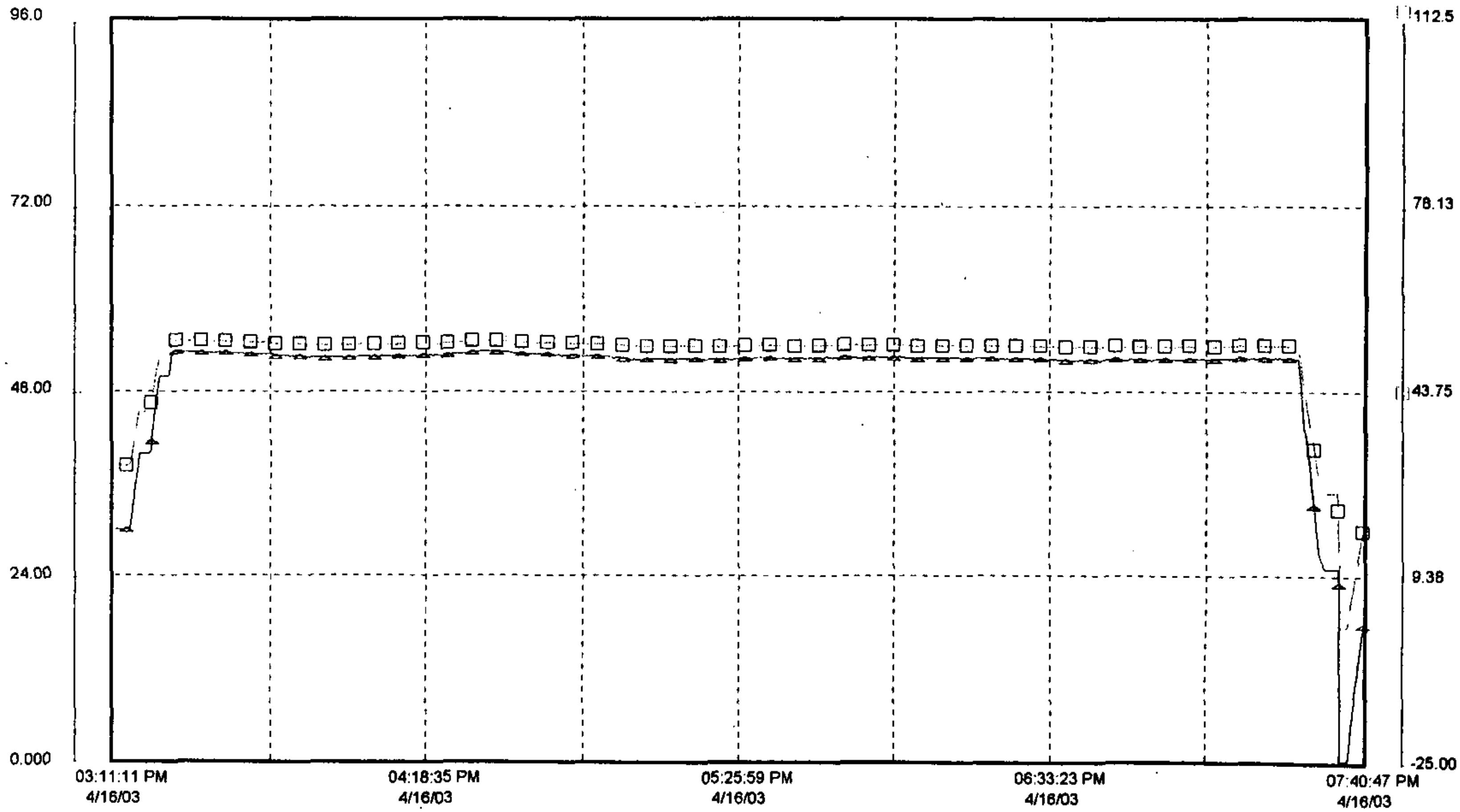
Attachment C

Trend Plot



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
———	A04UMWPV	MW	0.000	50.58	46.38	0.000	96.0	MW
———	A04UWT3801PW1	WT3801 Real Power Sensor	0.046	50.63	46.43	-25.00	112.5	MW

Trend Plot



Legend	Trend Name	Comment	Min.	Max.	Avg.	Min. Scale	Max. Scale	Eng. Units
	A03UMWPV	MW	0.000	53.32	50.34	0.000	96.0	MW
	A03UWT3801PW1	WT3801 Real Power Sensor	-0.254	53.37	50.38	-25.00	112.5	MW

Attachment D

Generation Interconnection Study
for
(2) 47 MW Generation Unit Additions
on Empire District Electric
Control Area

Performed by Empire District Electric
at request of Southwest Power Pool

(#GEN-2001-030)
(#GEN-2001-040)

January, 2002

Empire District Electric Co. (2) 47 MW Generation Unit Additions

Table of Contents

1. Introduction

Customer has made two separate requests to evaluate two 48 MW generation additions at the existing LaRussell Power station. The requests were logged as GEN-2001-030 and GEN-2001-040. A powerflow analysis, a short circuit analysis and a transient stability study was performed at the request of the Southwest Power Pool.

Presently, the LaRussell Power Station has two generation units each having the capabilities to produce approximately 90MW. The proposed generating units, referred to as #3 and #4, are scheduled to be in service (#3) June 2003 and (#4) December 2003. These units will be used to serve the EDE native load.

The powerflow analysis was conducted to look for equipment that overloads on the EDE, SPA, City Utilities of Springfield and two specific tie lines to Associated Electric due to the increased generation.

The short circuit analysis was conducted to evaluate the impact to short circuit capabilities at busses in close electrical proximity to the LaRussell Power Station.

The transient stability study was performed to verify machine performance following a disturbance on the system and to identify system stability issues.

2. Study Methodology

2.1 Power Flow Model

The Southwest Power Pool Load Flow Model 2004 summer peak (04sp.sav) and the 2004 winter peak (04wp.sav) models were used for the power flow analysis. However, the 04sp.sav case had a fictitious generation unit modeled at the LaRussell bus which was generating 150 MW. This generation was shifted to other actual units on the EDE system to develop a new case in which the impact of the new generators could be evaluated. The new generation was then modeled in 50 MW increments.

Evaluation of the 2006 cases, found that the generation modeled at LaRussell exceeded the existing capacity with the addition of both of the new generating units. EDE does not have the capacity of actual generation to re-dispatch from the LaRussell area; therefore, no evaluation of the new generation was done for 2006.

All generation units at the LaRussell Plant were increased to maximum capacity. Generation units at EDE Stateline Plant were reduced such that the total generation on the EDE system was equivalent to the base case generation. An 'n-1' analysis was performed in which all branches for EDE, SPA, and City Utilities of Springfield were outaged individually. Any equipment that had a loading greater than 100% of Rate B and was impacted by the additional generation at LaRussell was evaluated.

2.2 Short Circuit Model

A study was also completed to investigate how the additional generation would impact available short circuit current. The model that was used for the short circuit analysis was the 2005 summer peak (Sc05-1.raw) with the corresponding sequence data (Sc05-1.seq). No information was provided for the GSU for the new generation units so a very low impedance value of 6% for a 70 MVA transformer was modeled.

3. Discussion of Results

3.1 Power Flow Model

The results of the Power Flow study are shown in Table 1. The table contains the summer Rate B loading. The results labeled 'Base Case' were from 'n-1' study of the 04sp.sav case which had a fictitious generator modeled at the LaRussell bus producing 150 MW. The case with generation dispatched to actual units on the EDE system is labeled 'EDE Gen. Adjust'. The cases with the new generators #3 and #4 are labeled 'LaRussell 50 MW' and 'LaRussell 100 MW' respectively.

The results indicate that an AEC line from Carthage to Reads loads to 108%, the two auto-transformers at Carthage load to 109.7% and 110.5 %, the auto-transformer at Joplin 389 loads to 102%, and the 42 MVA auto-transformer at Aurora 124 loads to 102.4%. However, each of these branches are loaded beyond 100% under certain contingencies in both the Base Case study and the EDE Gen. Adjusted Study.

The winter study indicated that the new generation at LaRussell did not cause any branches to exceed the Rate B loadings.

3.2 Short Circuit Study Results

The increase in short circuit currents are shown in Table 2. The criteria for listing a bus in the Table 2 was that the bus was only one bus away from LaRussell or that there was more than a 1% increase in fault current. As can be seen in Table 2, there was little impact to the fault currents except at the LaRussell Power Station

```
.........................................................................................................................
.                  PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E   FRI, NOV 30 2001  10:12                     PAGE 1 .
.                                                                                                                        .
.                           1-2001 SOUTHWEST POWER POOL POWER FLOW MODEL                                                 .
.                           2004 SUMMER PEAK 04 SP RESULTS                                                               .
.                                                                                                                        .
.                    *** ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE 100.0 % OF RATING SET B ***               .
.........................................................................................................................

DISTRIBUTION FACTOR FILE:     E:\Generation 2004\04sp Extended.dfx
SUBSYSTEM DESCRIPTION FILE:   E:\Generation 2004\Autocont.sub
MONITORED ELEMENT FILE:       E:\Generation 2004\Autocont Extended.mon
CONTINGENCY DESCRIPTION FILE: E:\Generation 2004\04 extended.con

X-------- C O N T I N G E N C Y   E V E N T S --------X X-- O V E R L O A D E D   L I N E S --X  X--MVA(MW)FLOW--X
          X---- MULTI-SECTION LINE GROUPINGS ----X  FROM     NAME          TO      NAME     CKT  PRE-CNT  POST-CNT  RATING  PERCENT
OPEN LINE FROM BUS 59468 [AUR124 5161.00] TO BUS 59480 [MON383 5161.00] CKT 1 ------------------------------ CONTINGENCY SINGLE 54
                                    BASE CASE      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.3     37.0     36.0    100.3
                               EDE GEN ADJUST      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.6     37.2     36.0    101.1
                              LARUSSELL 50 MW      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.4     37.3     36.0    100.9
                             LARUSSELL 100 MW      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.4     37.4     36.0    101.4

OPEN LINE FROM BUS 59479 [LAR382 5161.00] TO BUS 59480 [MON383 5161.00] CKT 1 ------------------------------ CONTINGENCY SINGLE 83
                              LARUSSELL 50 MW      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.4     37.0     36.0    100.3
                             LARUSSELL 100 MW      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.4     37.6     36.0    101.9

OPEN LINE FROM BUS 59483 [JOP389 5161.00] TO BUS 59607 [JOP422 5161.00] CKT 1 ------------------------------ CONTINGENCY SINGLE 92
                                    BASE CASE      59483*JOP389 5 161 59592 JOP389 269.0 1     57.7     76.7     75.0    102.3
                               EDE GEN ADJUST      59483*JOP389 5 161 59592 JOP389 269.0 1     56.4     75.3     75.0    100.4
                              LARUSSELL 50 MW      59483*JOP389 5 161 59592 JOP389 269.0 1     57.5     76.5     75.0    102.0

OPEN LINE FROM BUS 52688 [CARTHAG5161.00] TO BUS 52690 [CARTHG 269.000] CKT 1 ---------------------------- CONTINGENCY SINGLE 277
                                    BASE CASE      52688*CARTHAG5 161 52690 CARTHG 269.0 2     52.4     91.5     84.0    108.9
                               EDE GEN ADJUST      52688*CARTHAG5 161 52690 CARTHG 269.0 2     52.4     92.5     84.0    110.1
                              LARUSSELL 50 MW      52688*CARTHAG5 161 52690 CARTHG 269.0 2     52.6     91.8     84.0    109.3
                             LARUSSELL 100 MW      52688*CARTHAG5 161 52690 CARTHG 269.0 2     52.9     92.2     84.0    109.7

OPEN LINE FROM BUS 52688 [CARTHAG5161.00] TO BUS 52690 [CARTHG 269.000] CKT 2 ---------------------------- CONTINGENCY SINGLE 278
                                    BASE CASE      52688*CARTHAG5 161 52690 CARTHG 269.0 1     53.4     92.0     84.0    109.6
                               EDE GEN ADJUST      52688*CARTHAG5 161 52690 CARTHG 269.0 1     53.4     92.1     84.0    109.6
                              LARUSSELL 50 MW      52688*CARTHAG5 161 52690 CARTHG 269.0 1     53.6     92.4     84.0    110.0
                             LARUSSELL 100 MW      52688*CARTHAG5 161 52690 CARTHG 269.0 1     53.9     92.9     84.0    110.5

OPEN LINE FROM BUS 52690 [CARTHG 269.000] TO BUS 96649 [2JASPER 69.000] CKT 1 ---------------------------- CONTINGENCY SINGLE 442
                                    BASE CASE      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.3     39.6     36.0    107.4
                               EDE GEN ADJUST      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.6     40.0     36.0    108.6
                              LARUSSELL 50 MW      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.4     39.8     36.0    108.0
                             LARUSSELL 100 MW      52690*CARTHG 269.0 96751 2REEDS  69.0 1     30.4     39.8     36.0    108.0

OPEN LINE FROM BUS 59480 [MON383 5161.00] TO BUS 59591 [MON383 269.000] CKT 1 ------------------------------ CONTINGENCY SINGLE 87
                                    BASE CASE      59468*AUR124 5 161 59537 AUR124 269.0 3     23.0     42.4     42.0    101.1
                              LARUSSELL 50 MW      59468*AUR124 5 161 59537 AUR124 269.0 3     23.0     42.5     42.0    101.3
                             LARUSSELL 100 MW      59468*AUR124 5 161 59537 AUR124 269.0 3     23.2     43.0     42.0    102.4
```

TABLE 1

Change in Fault Current with 100 MW increase in Generation at LaRussell						
Description			Fault Current		Results	
Bus #	Bus	KV	Initial	With 100 MW	Difference	% Change
52692	Springfield	161	26771	26931	160	0.6%
52688	Carthage	161	15731	16381	650	4.1%
59479	LaRussell 382	161	13672	15810	2138	15.6%
59480	Monett 383	161	10678	11102	424	4.0%
59468	Aurora 124	161	9156	9321	165	1.8%
59472	Tipton 292	161	14475	14658	183	1.3%
59591	Monett 383	69	11559	11718	159	1.4%
59476	Asbury 349	161	13463	13631	168	1.2%
59466	Atlas 109	161	14461	14757	296	2.0%
52686	Neosho SPA	161	13457	13610	153	1.1%
52690	Carthage	69	13814	13980	166	1.2%

TABLE 2

4. Transient Stability Study[1]

The transient stability analysis was performed to verify machine performance following a disturbance on the system and to identify system stability issues. The study includes an analysis of the 2002 summer peak Southwest Power Pool Transient Stability Model modified with the Empire generation units as well as certain other prospective merchant plants that are ahead of Empire in the Southwest Power Pool interconnection study queue. Machine dynamic data was included from the current stability dynamics database from SPP with additions and adjustments included for the later year generation additions. Simulation of bus fault conditions with subsequent clearing by protection systems was performed, and the machine parameters were monitored in the period during and immediately after the fault.

The study models were subjected to four fault conditions to test various levels of system disturbances. The events simulate the more probable as well as extreme cases of fault conditions as specified by NERC planning criteria.

A. Three phase fault on the LaRussell 161kV bus with subsequent clearing of the LaRussell-Monet 161kV line in 5 cycles.

B. Three phase fault on the LaRussell 161kV bus with subsequent clearing of the LaRussell-Springfield 161kV line in 5 cycles.

C. Three phase fault on the LaRussell 161kV bus with subsequent clearing of the LaRussell-Carthage 161kV line in 5 cycles.

Analysis of the machine dynamics indicates that the system remains stable following the disturbances for all contingencies tested for both LaRussell #3 and LaRussell #4 additions.

---

[1] The Transient Stability information is from the Southwest Power Pool (SPP) Report "Transient Stability Study Empire District Electric Co. (2) 47 MW Generation Unit Additions to LaRussell Power Station". The SPP performed the Transient Stability Study.

5. Facility Analysis

5.1 LaRussell Substation

The LaRussell Substation #382 will be converted from a "Ring Bus" configuration to a "Breaker and a Half" to allow for the two new generator terminations. The total cost of this modification will be $2,500,000.

5.2 Aurora Substation

The Aurora Substation 161/69 kV 42 MVA auto-transformer's loading increased due to the new generation at LaRussell. There are currently 2 other older and smaller auto-transformers in parallel with the 42 MVA auto-transformer. Currently, it is recommended that all of these auto-transformers be replaced with one 150 MVA. The cost of this modification is $2,000,000.

Attachment E

	16:00	1475.9 MW 37.6 MW Aux
	16:14	Lowered Load to 22.5 MW
	16:40	Lowered Load to 20.2 MW
	1648	Lowered Load to 18 MW
Liquid fuel	17:00	1499.4 MW 37.7 MW Aux
	17:03	Gen breaker opened
4 fuel meter reading	17:03	End of Run 1500.1 MW 37.7 MW Aux
	04-15-03	*
ading fa	07:31	*Start both engines, Fuel oil, wet, base load selected.
	07:37	Generator Breaker Closed Unit on line
x	07:46	Unit at Base load EGT IN Control
	07:48	A - F/oil 997 B F/OIL 1073
	08:00	1515.5 mwH 38.3 mwH AUX.
	09:00	1564.0 MWH 38.4 MWH AUX
		A Engine F/oiL 1221 B Engine F/oiL 1300
	10:00	1612.4 38.6 MWH AUX
6.8 mw		A engine F/oiL 1399 B engine F/oil 1479
et, base load sel	11:00	1660.2 MWH 38.7 MWH AUX
nline		A ENGNE FUEL OIL 1579 B ENGINE FUEL OIL 1663
	12:00	1707.2 MWH 38.8 mWH AUX
LOWER LOAD		A engine fuel oil 1757 B. engine fuel oil 1845
37.0 Aux	12:11	Stop both engines
id Fuel wet	12:20	Generator Breaker Open Unit off line
		1719.3 mWH 38.9 mWH AUX
	12:32	*Start both engines on Fuel oil
W Aux	12:37	Unit on line
MW Aux	12:39	Stop engine A
	12:42	BAse load EGT IN Control 22.2 MW
	12:48	Start A engine
MW Aux	12:58	BAse load w/ both engines 46.3 MW
MW	13:00	1728.6 MWH 38.9 MWH Aux
MW Aux		A Fuel Oil 1826 B Fuel Oil 1956
MW	14:00	1774.1 mw 39.1 mw Aux FOA - 2005 FOB - 2132

From Unit 4 Log Book

16

04-15-03 (cont.)		04/16/03	
15:00	1820.2 MW 39.2 MW Aux	0747	Start
	Engine A F/o 2181 Engine B F/o 2309	0752	Gen
15:48	Selected Program Mode Load set at	0802	Achiev
	95% 43.70 MW	0900	2237
16:00	1865.5 MW 39.3 MW AUX	0950	Started
	Engine A F/oil 2353 Engine B. F/oil 2486	10:00	2289.
16:32	Load Lowered to 41.40 90% load.	11:00	2341.
17:00	1908.4 MW 39.5 MW Aux.	11:54	Dropp
	Engine A F/oil 2516 Eng. B. Fuel Oil 2657	12:00	2390.
17:25	Lowered load to 36.7 MW 80% load	12:42	Dropp
18:00	1947.0 MW 39.5 MW AUX	13:00	2438
	Engine A F/oil 2666 Eng. B F/oil 2815	13:27	DROPPED
18:12	Lowered load to 32.2MW 70% load.	14:00	248
19:00	1979.8 MW 39.7 MW Aux	14:07	DROPPE
	Eng A F/oil 2796 Engine B F/oil 295	15:00	2518
* 19:02	Xfer to Gas Fuel	15:05	Stop
19:06	Unit @ Base load 49.5 MW.	15:11	Gener
19:15	End F/OIL COUNT A = 2800.8 B = 2957.0	15:11	252
20:00	2028.5 MW 39.8 MW Aux	4/24/03	
21:00	2076.6 MW 39.9 MW AUX		
21:20	Walked unit down noted leak on RTD on	07:00	Adde
	top of Generator Oil tank. Small drip	5/02/03	
	coming from filter drain plug on South.	14:11	START
	Checked lube oil levels all full. Generator	14:13	PT BREA
	lube oil ½" above full mark.	14:20	START E
22:00	2126.6 MW 40.1 MW Aux	14:25	REAC
23:00	2176.9 MW 40.2 MW Aux	14:35	TURBIN
23:01	Stop Both engines	15:41	
23:11	Generator Breaker open unit off line	15:48	
23:25	2182.0 MW 40.2 MW AUX	15:59	
04-16-03		16:50	
00:14	operate/lockout switches to lockout position	16:59	Gen

Attachment F

+ 1716 ENG A E11D THRS. Dif. ALARM
2015 Lowered Load to 51.5 MW
2056 Stopped Both Engines
2104 GEN. BREAKER Open Unit offline
1-28-04
0603 Start Both engines
0603 Trip 125 VDC Charger
0604 Restart Both engines
0610 Unit Online
0613 Base Load Selected
0617 Eng B Trip PB DOT
0618 Restart Eng B
610 + 0620 Pressure Ratio Alarm Eng B PTTB
0703 61 MW 25° Inlet 14.5 ppm Nox
0822 Lower load to 55 - to raise unit #4 for NO_x
0828 " " " 30 mw
0841 Raise load to 40 mw
0856 Lower load to 25 mw.
1032 Stop both engines
1036 Unit off line.
1500 Changed TC on 3B #4 Exhaut - it has a bad terminal on the
20:22 Checked screens, everything looks ok Lockout/Operate permissive switch locked on
1-29-04
0300 Walk Thru Completed
0652 Start Both Engines
0652 Trip 125 VDC charger
0652 Restart Both Engines
0659 Generator Breaker closed unit online.
0702 Eng A Trip caused by PBDOT
0702 Generator Breaker open
0704 Generator Breaker closed
0710 Restart Eng. A.
* 0716 Transfer to liquid Fuel
0719 Raise load to 40 MW
0902 Lower load to 25 mw
0911 Stop Eng A.
0946 Lower load to 17 mw
1007 Base load selected
1104 Program load selected
1104 Lower load to 15 MW
1142 Transfer to Gas

From Unit 3
Log Book

714	START B
720	B FTL 86EB
731	Start B
732	B Trip Cold CAN
736	Start 4B
736	B Trip Cold CAN
	TE009 Low
756	A PTTB Pressure Diff Alarm
733	B Bently K Flange Alarm
0824	Start 4B
824	B Trip Cold CAN TE009 100°
	500 on ot.
09:00	Stop engine A
09:01	PTTB PT1701 Pr Sensor Gros
	(ENG A PTTB.) (TRIP unit off Line
1820	STARted "B" ON GAS 25MW Selected
1826	Generator Breaker Closed - Unit on Lin
1956	Stopped "B" Engine
1959	Generator Breaker Open - Unit off Li
2100	✓ screens AOK, Ready Light, Unit ready to start
	Cal gas @ 1200
12:12-03	
0100	Walk thru complete
06:57	Start Both engines
07:02	unit on line
* 07:09	transferred to fuel oil @ 25MW
08:04	Stop Both engines