selected set of units and fuels is one of the inputs to the Economic Dispatch Problem. The solutions of the Unit Commitment Problem and the Fuel Commitment Problem use sophisticated optimization algorithms. The Unit Commitment Problem and the Fuel Commitment Problem are usually solved over a horizon of several days to properly account for constraints and costs associated with starting and stopping units.

Q31. WHAT IS THE ECONOMIC DISPATCH PROBLEM?

A. The solution to the Economic Dispatch Problem is the determination of which units will be used to serve customer load at each instant in time while meeting constraints and minimizing cost of serving the customer load. Available resources include generating units that are running (or "on-line") and purchased power opportunities that can be scheduled from third parties within the upcoming hour.

The solution to the Economic Dispatch Problem is a specific implementation of a classical optimization technique known as the Lagrangian Method. The Lagrangian Method solves a set of equations describing the elements that compose the overall cost function along with a set of constraints. The Lagrangian Method guarantees a minimum cost solution based upon the given assumptions. The Lagrangian Method requires that each resource be described based on its incremental cost of producing energy.

Q32. HOW IS A GENERATING UNIT'S INCREMENTAL PRODUCTION COST DETERMINED?

A. In general terms, the incremental production cost of a generating unit is the product of the incremental cost of fuel, the incremental heat rate, and the incremental transmission loss factor plus any incremental operations and maintenance costs.

The incremental cost of fuel is the cost of the fuel that has not yet been procured for a generating unit. Sometimes this fuel is referred to as "avoidable" fuel. Essentially, in order to be considered an incremental fuel, the fuel supply must really be optional. In other words, if the fuel is selected for use, it can be purchased; if the fuel is not selected for use, it need not be purchased or used. In addition to direct fuel costs, it is also appropriate to include other incremental costs associated with the fuel, such as taxes, transportation, and the cost of emissions allowances.

The incremental heat rate of a unit is characterized by the quotient of the incremental amount of heat input to the unit measured in British thermal units ("Btu") and the incremental output of the unit measured in kilowatt-hours ("kWh") and is expressed in Btu/kWh. The incremental heat rate is represented by a polynomial equation over the load range of the unit.

The incremental transmission loss factor represents the incremental or avoidable transmission losses that would occur as a result of increasing generation at a particular generating unit or energy source compared to increasing generation at all the other generating units or energy sources on the transmission system. For example, suppose a system were composed of two generators and one load. One of the generators is located adjacent to the load and suffers no loss in delivering its output to the load. The other generator is located at a great distance from the load and must transmit its output over a transmission line that consumes 5 percent of the output of the unit in losses. In effect, the remote unit is only delivering 95 percent of its output to the load. One way to place the two units on an equal footing with respect to their effectiveness at delivering their output to the load would be to increase the cost of the remote unit in proportion to its transmission losses. In this case, the incremental transmission loss factor would be 1 divided by 0.95 or 1.053. This is the essential principle of the incremental transmission loss factor.

Incremental operations and maintenance costs are those non-fuel operations and maintenance costs that can be tied directly to the production level of the unit.

Q33. BUT DOES ECONOMIC DISPATCH IMPLY THAT EACH GENERATOR WILL OPERATE AT ITS MOST EFFICIENT LEVEL?

A. No. The objective of Economic Dispatch is to produce the lowest overall System cost, not to make each generator operate at its most efficient level. Cost depends not only on the efficiency of a unit, but its fuel costs and how far on the transmission grid the power must flow before reaching customers. It is the combination of these factors that determines cost, not just the efficiency of a unit. Thus, in achieving the lowest reasonable overall cost, it is reasonable to accept losses in efficiency if those losses are more than offset by gains in other areas.

Q34. IN GENERAL, WHAT TYPES OF DATA ARE NEEDED TO SOLVE THE UNIT COMMITMENT, FUEL COMMITMENT, AND ECONOMIC DISPATCH PROBLEMS?

A. A number of different types of data are needed, including:

(1) the load requirements that must be met with some combination of units and purchased resources;

(2) the key parameters that describe the operating characteristics and efficiencies of each generating unit, including:

- heat rate;
- startup and shutdown cost;
- startup and shutdown time limits;
- minimum and maximum output;
- rate of output change or "ramp rate";
- emissions rates and costs;
- variable operations and maintenance costs;
- fuel cost, type, and availability; and

- equipment availability and maintenance schedules;

(3) the transmission constraints;

(4) any purchased power or sale opportunities; and

(5) operating reserve requirements.

Q35. WHY ARE THERE SEVERAL SEPARATE SHORT-RUN PLANNING AND OPERATIONS PROCESSES INSTEAD OF JUST ONE ALL-ENCOMPASSING PROCESS?

A. There are several important reasons for having separate short-run planning and operations processes, the first being the lack of a single comprehensive mathematical model. Another important reason is that the markets for fuel and purchased power during the Reconciliation Period were segmented in time along the same time horizons as the short-run planning and operations processes. This is a major reason for the selection of the specific time horizons for the short-run planning and operations processes. A third important reason is the need for a team to have a focus that is manageable. By separating the overall decision-making into coordinated processes, it is possible to design each team so that there is work for each team member and a span of information that is manageable. An additional reason for the multiple processes is the lack of computer hardware with enough computational power and versatility to satisfy the demands of all the mathematical models used in the separate short-run planning and operations processes.

Finally, the uncertainty associated with many of the key variables in the decision-making process has a tendency to get resolved as time passes. In other words, the closer the execution of the process is to the study horizon, many of the planning assumptions become more certain or predictable. I believe that successive application of the basic analytical principles embedded in the short-run planning and operations processes over the different time horizons produces a better overall solution to the problem of providing reliable and economic service to the customers.

B. Monthly Energy Planning Process

Q36. PLEASE DESCRIBE THE MONTHLY ENERGY PLANNING PROCESS DURING THE RECONCILIATION PERIOD.

A. A Monthly Energy Plan is established approximately two or three business days before the start of each month. Its primary purpose is to provide reasonable estimates of fuel and power needs over the upcoming month so that the System can make the reasonable and necessary monthly procurements of fuel and power to meet customer demands.

Q37. WHO IS INVOLVED IN PREPARING THE MONTHLY ENERGY PLAN?

A. A team composed of representatives from Solid Fuels, Gas and Oil Supply, Power Marketing, and Operations Planning departments prepares the Monthly Energy Plan.

Q38. PLEASE DESCRIBE THE MAJOR PROCESS STEPS IN THE MONTHLY ENERGY PLANNING PROCESS.

A. The Monthly Energy Planning Process for the upcoming month starts at the beginning of the current month.

The Monthly Energy Planning Process includes a Monthly Request for Proposals as the first step. The Monthly Request for Proposals step requires that the latest forecast information concerning the next month's weather, load, power sales, fuel and purchased power price and availability, transmission constraints, and unit status be gathered by the 1st of the month. These data are then incorporated into the production cost and load and capability models. Concurrently, market participants are solicited for monthly proposals to sell power to the System. Offers are due within the first three business days of the month. Analysis of the offers is completed approximately three days later, and contracts are negotiated with those suppliers who provided proposals that result in expected savings in production cost over the month. Any proposals that result in a contract are then included in the succeeding steps of the Monthly Energy Planning Process.

Between the 10th and the 13th of the month, the production cost model is used to make an initial estimate of the optimal unit commitment and associated avoided costs for the upcoming month.

Between the 13th and 19th of the month, the Monthly Energy Planning Team meets formally in what is referred to as the Preliminary

Monthly Energy Plan Meeting to review assumptions and results. At this meeting, the Monthly Energy Planning Team decides upon any additional changes in data or assumptions. After this meeting, the fuel and power buyers continue to monitor the fuel and power markets for any changes.

Between the 19^{th} and the 22^{nd} of the month, another data update is performed.

Between the 22^{nd} and the 25^{th} of the month, the Monthly Energy Planning Team meets again formally in what is referred to as the Final Monthly Energy Plan Meeting to review assumptions and results. At this meeting, the Monthly Energy Planning Team decides upon the final plan for the upcoming month.

While I have specified certain days of the month corresponding to the various steps in the Monthly Energy Planning Process, this represents typical timing of the steps. Depending upon circumstances, the actual timing of the steps of a particular Monthly Energy Plan may differ from the typical timing.

Q39. WHAT MODELS ARE USED IN THE MONTHLY ENERGY PLANNING PROCESS?

A. The principal models used in the Monthly Energy Planning Process are a load and capability model and a production cost model. The load and capability model is a spreadsheet summary of the expected weekly peak loads and expected resource availability over the time horizon. The

PROSYM production cost model is used in the Monthly Energy Planning Process.

Q40. WHAT IS THE RESULT OF THE MONTHLY ENERGY PLANNING PROCESS, AND HOW IS IT USED?

A. An example of a Final Monthly Energy Plan prepared during the Reconciliation Period is included as Exhibit DSJ-2. One of the primary results of the Monthly Energy Planning Process is a reasonable estimate of the projected fuel consumption by each of the power plants and the expected mix of purchased power. This forecast allows the Gas & Oil Supply and Solid Fuels departments to formulate fuel procurement and transportation strategies for the month for an appropriate portion of the projected fuel consumption, consistent with the power purchasing and sales strategy, and consistent with the anticipated usage of the nuclear units. Likewise, the Monthly Energy Plan allows the Power Marketing department to formulate its strategy while maintaining consistency with what is being purchased in the fuels markets.

C. Weekly Procurement Process

Q41. PLEASE DESCRIBE THE WEEKLY PROCUREMENT PROCESS DURING THE RECONCILIATION PERIOD.

A. The Weekly Procurement Process focuses on evaluating purchased power opportunities for the next week. Extensions of the seven-day horizon of the Next-Day Planning Process are developed for key inputs such as load, long-term power purchases and sales, planned outages, transmission constraints, and fuel costs to provide a baseline of hourly production costs for the next week. In the baseline case, the load is met by hypothetically committing additional System units. Then potential purchase opportunities are evaluated to see if costs to the System are less than the hypothetical units committed in the baseline case.

Q42. WHO IS INVOLVED IN PREPARING THE WEEKLY PROCUREMENT PROCESS?

A. The Entergy Transmission Weekly Operations staff and the Independent Coordinator of Transmission's ("ICT") Weekly Procurement Process staff perform the Weekly Procurement Process, based in part on inputs provided by the EMO.

Q43. PLEASE DESCRIBE THE MAJOR PROCESS STEPS IN THE WEEKLY PROCUREMENT PROCESS.

A. The Weekly Procurement Process follows steps as specified in Attachment V of the Entergy Open Access Transmission Tariff. EMO staff prepares and submits data to Weekly Operations which includes the most up to date ten-day load forecast, cost and operating characteristics of the System's network resources. In addition, EMO staff solicits offers from suppliers and forwards those offers to Weekly Operations. Weekly

Operations staff, with oversight of the ICT, performs a combined optimization of production cost and transmission service to establish a baseline case relying only on the System's network resources. Following this step, Weekly Operations staff performs a combined optimization of production cost and transmission service using both the System's network resources and the offers from suppliers. If there are offers from suppliers in the second optimization that displace some of the System's network resources and result in a lower overall cost, the ICT Weekly Procurement Process staff will certify the results of the optimization and communicate the results to EMO staff. Finally, the power buyers will finalize commercial arrangements for the offers selected by the Weekly Procurement Process.

Q44. WHAT MODELS ARE USED IN THE WEEKLY PROCUREMENT PROCESS?

A. The Weekly Procurement Process relies on the same load forecasting model that is used in the Next-Day Planning Process and described in more detail in the next section. The production cost model used is a Security Constrained Unit Commitment ("SCUC") model and was developed specifically for the Weekly Procurement Process. The new production cost model performs a joint optimization of production cost and transmission service.

Q45. WHAT IS THE RESULT OF THE WEEKLY PROCUREMENT PROCESS, AND HOW IS IT USED?

A. After the ICT certifies the results of the Weekly Procurement Process, the winning Third Party offers are communicated to EMO staff in the form of an email. The power buyers use this information to make commercial arrangements for the offers selected by the Weekly Procurement Process.

D. Next-Day Planning Process

Q46. PLEASE DESCRIBE THE NEXT-DAY PLANNING PROCESS DURING THE RECONCILIATION PERIOD.

A. The Next-Day Planning Process generally prepares a rolling seven-day plan each business day for the current day, the next day, and five additional days. The main purpose of the Next-Day Planning Process is to make reasonable unit commitment, fuel commitment, and purchased power decisions for the days in the immediate future.

Q47. WHO IS INVOLVED IN PREPARING THE NEXT-DAY PLAN?

A. A team composed of representatives from Gas and Oil Supply, Power Marketing, and Operations Planning departments prepares the Next-Day Plan.

Q48. PLEASE DESCRIBE THE MAJOR PROCESS STEPS IN THE NEXT-DAY PLANNING PROCESS.

A. The Next-Day Planning Process develops and uses the most up-to-date information possible concerning unit status, fuel and power prices and availability, transmission constraints, and forecasted load. The Next-Day Planning Process begins with the load forecast. Inputs to the load forecast include historical loads, historical temperatures, and forecasted temperatures. Next, the load and capability model is used to determine if projected reserves are adequate, given the load forecast and expected resource availability. Because unit commitments often involve long lead times and extended minimum run times, unit startups tend to be a major focus of the Next-Day Planning Process. If scheduled resources are inadequate to meet load plus reserves, an analysis is performed to determine whether starting an available unit or purchasing from the wholesale market is more economic. If resources available to commit are inadequate, a reliability purchase from the wholesale market will be made. Once scheduled resources are adequate, System economics and projected fuel and purchased power needs are evaluated using the production cost model. The fuel and power buyers will buy the fuel and power determined by the results of the Next-Day Planning Process. When the production cost simulations are complete, the Next-Day Planning Process Team meets to review the input assumptions and results.

Q49. WHAT MODELS ARE USED IN THE NEXT-DAY PLANNING PROCESS?

A. The principal models used in the Next-Day Planning Process are a load forecasting model, a load and capability model, an in-house spreadsheet model, and a production cost model. EMO uses a short-term load forecasting model called the Advanced Artificial Neural Network Short-Term Load Forecaster ("AANNSTLF") to forecast loads for a seven-day period. The load and capability model used in the Next-Day Planning Process is called Load Capability Plan and is similar to the load and capability model used in the Monthly Energy Planning Process, but is more detailed. The spreadsheet model is called RO Grid and is used to evaluate available units to commit versus purchase opportunities from the wholesale market. The production cost model used in the Next-Day Planning Process is Generation Operations.

Q50. PLEASE DESCRIBE AANNSTLF.

A. AANNSTLF was developed several years ago under the direction of the Electric Power Research Institute. Pattern Recognition Technologies was the main contractor. AANNSTLF uses a neural network technique that has found wide acceptance within the electric utility industry for short-term load forecasting. The neural network technique uses historical load and temperature data to forecast load, but gives more weight to the information from the previous two or three days.

Q51. FROM WHAT SOURCE DOES THE EMO OBTAIN THE TEMPERATURE FORECASTS USED IN AANNSTLF?

A. The EMO has long running contracts with commercial vendors of weather data. In addition to these sources, the EMO also accesses information from public sources, such as the Weather Channel and CNN. The temperature forecast used on any particular day is the result of combining judgment and experience with the information from all available sources.

Q52. WHAT IS THE RESULT OF THE NEXT-DAY PLANNING PROCESS, AND HOW IS IT USED?

A. An example of the types of information prepared as part of the Next-Day Planning Process for one day during the Reconciliation Period is included as Exhibit DSJ-3. The information includes the load forecast, the temperature forecast, unit status information, a load and capability report and some key outputs from the production cost simulations. The information is used to plan unit startups and shutdowns, to purchase and sell power in the next-day wholesale market, and to purchase gas in the next-day market.

E. Current Day Process

Q53. PLEASE DESCRIBE THE CURRENT DAY PROCESS DURING THE RECONCILIATION PERIOD.

A. The Current Day Process includes planning for a twenty-four hour period and the actual operation of the System generation including the purchase and sale of wholesale power. The planning aspect of the Current Day Process is a batch process that is designed to be executed multiple times throughout each business day as circumstances change. The operation aspect of the Current Day Process is a continuous twenty-four hours a day, 365 days a year process. It includes responsibility for balancing the load and generation and maintaining Entergy's Area Control Error ("ACE") within standards set by the North American Electric Reliability Corporation ("NERC"). Maintaining reliability and minimizing cost are the objectives of both the planning and operation aspects of the Current Day Process.

Q54. WHO IS INVOLVED IN THE CURRENT DAY PROCESS?

A. A team composed of representatives from Gas and Oil Supply, Power Marketing, Energy Management Operations, and Operations Planning departments is involved in the Current Day Process. The members of the Current Day Team are referred to as the Fuels Analyst, the Hourly Marketer, the Generation Dispatcher, and the Planning Analyst, respectively.

Q55. PLEASE DESCRIBE THE MAJOR PROCESS STEPS IN THE CURRENT DAY PROCESS.

A. The planning aspect of the Current Day Process begins with the Next-Day Plan prepared on the prior day by the Next-Day Planning Process Team. The Planning Analyst then updates the load and capability application with the latest load forecast and the latest resource availability from the Generation Dispatcher and the Hourly Marketer. At about the same time, the Planning Analyst updates the production cost model with the same load and resource data and, in addition, obtains the latest fuel price and availability information from the Fuels Analyst. Based on the results of the load and capability analysis and the production cost simulations, the Planning Analyst makes recommendations to the Current Day Team regarding the current and projected reliability of the System and the current and projected economics of the System. The entire Current Day Team then decides on the best course of action and the Generation Dispatcher, the Hourly Marketer, and the Fuels Analyst implement the chosen course of action in real-time.

If any material changes occur on the System since the development of the last load and capability forecast or production cost simulation, the Current Day Team will update the appropriate data and the Planning Analyst will rerun the models. Material changes include events such as changes in the load forecast, changes in the availability or capacity of the generating units caused by outages or limitations to generator output, changes in transmission capability, changes in fuel delivery, and changes in wholesale purchases or sales.

Resources that can be brought on-line within the Current Day Process time horizon, both owned generation and purchased power agreements, have expanded the alternatives available to the Current Day Team to reliably and economically serve the customers of the EOCs, including ETI customers.

Q56. WHAT MODELS ARE USED IN THE CURRENT DAY PROCESS?

A. The principal models used in the Current Day Process for planning are two load forecasting models, a load and capability model, and a production cost model. The load forecasting models include AANNSTLF and an in-house model that is designed to update the AANNSTLF forecast for the Current Day time horizon as actual hourly loads are received. The load and capability model is the same model used in the Next-Day Process, but it focuses on the twenty-four hour planning horizon used by the Current Day Process. The production cost model used in the Current Day Process is Generation Operations.

The principal models used in the Current Day Process for operation reside on the Generation Management System ("GMS"), a computer hardware and software system. In addition to its other uses, the GMS is used to gather real-time data, including load data and unit generation data. The principal models used in the Current Day Process that reside on GMS include an Automatic Generation Control ("AGC") program and an Economic Dispatch ("ED") program. AGC is used to control a group of specially equipped generating units to meet the ACE standards, and ED is used to minimize the cost of power from the on-line units by performing a classical equal incremental cost (equal lambda) dispatch.

In addition to these models on the GMS, several other models and computerized systems are used to aid the Current Day Team in operating the System. First, an in-house system known as the Operations Transaction System ("OTS") is used by the Current Day Team to electronically receive information (declarations) from the major fossil power plants and to electronically deliver information (instructions) to the major fossil power plants. In addition, the Current Day Team uses a Gas Telemetry System to gather real-time data on gas consumption at the major gas-fired power plants. The Current Day Team also uses OASIS to schedule transmission service. Finally, the Current Day Team uses weather data, such as current Doppler radar images and temperature forecasts, to anticipate changes in load.

Q57. WHAT IS THE RESULT OF THE CURRENT DAY PROCESS, AND HOW IS IT USED?

A. An example of the types of information prepared as a part of the Current Day Process is contained in Exhibit DSJ-4. This information includes the results of the hourly load forecast program, the load and capability model, and the production cost simulations. The production cost simulations provide information on the expected avoided cost that is used in making decisions regarding purchased power and information on expected gas consumption that is used in making decisions regarding purchases of gas.

F. Overall Goals of the Short-Run Planning and Operations Processes

Q58. WHAT ARE THE OVERALL GOALS OF THE SHORT-RUN PLANNING AND OPERATIONS PROCESSES?

A. The ultimate overall goal of the short-run planning and operations processes is to provide reliable and economic power to the EOCs' customers. While all aspects of the future can never be known with complete certainty, each of the short-run planning and operations processes described above function very effectively to enable the EMO to reliably forecast the needs of all of the customers of the EOCs, and to acquire a reasonable mix of fuel and purchased power at a reasonable cost, which benefits ETI's customers. During the Reconciliation Period, the short-run planning and operations processes were the mechanisms used for ensuring that the power provided was obtained at the lowest reasonable cost consistent with reliability standards.

Q59. DID THE FOUR SHORT-RUN PLANNING AND OPERATIONS PROCESSES ADDRESS THE CAPACITY REQUIREMENTS OF THE ENTERGY SYSTEM DUE TO LOAD GROWTH?

A. No. The capacity requirements of the Entergy System due to load growth are addressed in the longer-term processes depicted in Company witness Thiry's Figure MHT-2 and discussed by Company witness Cooper in his Direct Testimony. The four short-run planning and operations processes that I discuss treat any resource or capacity additions that came from the longer-term processes as part of the set of options that are available to help meet the short-term energy requirements of the EOCs.

VI. CONSTRAINTS AFFECTING SYSTEM OPERATIONS DURING THE RECONCILIATION PERIOD

Q60. IN THE NORMAL COURSE OF PLANNING AND OPERATING THE ENTERGY SYSTEM DURING THE RECONCILIATION PERIOD, WHAT TYPICAL CONSTRAINTS HAD TO BE CONSIDERED?

A. The following typical constraints were encountered in the normal course of planning and operating the Entergy System during the Reconciliation Period:

(1) load constraints;

(2) unit constraints;

(3) fuel constraints;

(4) transmission constraints;

(5) operating reserve constraints; and

(6) purchased power constraints.

Q61. PLEASE DESCRIBE TYPICAL LOAD CONSTRAINTS IN MORE DETAIL.

A. Load constraints impact the planning and operation of the System in three different ways. First, the main focus of planning and operating the System centers on ensuring that sufficient resources will be available at the anticipated peak load hour. Insufficient resources could lead to the shedding of firm load. Second, typical load constraints involve planning and operating the System through the minimum load of the day. Here, while still remembering that there will be a peak hour later in the day, units have to be backed down or taken off-line to ensure that no excess generation occurs. If too many units are on-line, there may be a problem with aggregate minimum generation levels. One consequence is that economic purchased power opportunities may have to be foregone. At the extreme, excess power must be sold at a loss. While the phenomenon must be watched carefully on any day, it becomes more difficult in the winter when the minimum load might occur in the early morning hours and the peak load may occur only a few hours later. The third typical way in which load constraints impact the short-run planning and operations processes involves the normal increases and decreases of load as load moves from minimum to maximum and back. Here, adequate resources must be available to meet these ever-changing variations in load.

Q62. PLEASE DESCRIBE TYPICAL GENERATING UNIT CONSTRAINTS IN MORE DETAIL.

A. Some generating unit constraints are the result of the physical design characteristics of the power generating equipment. These constraints include: startup time, shutdown time, ramp rate (the rate at which units can change output expressed in megawatts ("MW") per minute), and high and low operating limits. High and low operating limits can vary depending upon circumstances. For example, certain equipment on some units can be bypassed (such as feedwater heaters) and some boilers can be operated at above normal pressure to produce additional capability during extreme peak load conditions. On the other hand, if the load is extremely low, special operating modes can temporarily be invoked (such as removing a steam-driven boiler feed pump from service) to achieve lower minimum capability. By operating in this fashion, a unit shutdown can be avoided on a unit that might be needed to meet peak load requirements the next day.

Generating units also require scheduled maintenance and equipment testing. Tests include unit efficiency testing, capability testing and emissions testing. All of these tests are performed periodically on the generating units. While being tested, a unit's availability and output level can be affected. EMO endeavors to the maximum extent possible to schedule these tests to minimize any adverse impact of the testing on the reliability and economics of the Entergy System.

Q63. PLEASE DESCRIBE TYPICAL FUEL CONSTRAINTS IN MORE DETAIL.

A. Fuel supply and transportation contract terms generally include limits on the delivery rates of fuel. These limits can consist of hourly, daily, weekly, monthly, and annual minimum and maximum delivery constraints. Units consuming fuels with constraints must be operated to meet the constraints or a contract penalty may be incurred. In addition, inventoried fuels are subject to the physical limits of the storage and transfer facilities.

Q64. PLEASE DESCRIBE TYPICAL TRANSMISSION CONSTRAINTS IN MORE DETAIL.

A. The Entergy transmission system is designed to continue providing power without interruption and without constraint to the generation system under most expected single contingency situations (where a single transmission component or generation unit is out of service) and under typical weather conditions. In the event of multiple equipment outages or extreme weather conditions, constraints imposed by Entergy's transmission system become a factor that must be considered in unit commitment decisions to maintain both System and local area reliability. Another limitation imposed by the transmission system that might affect unit commitment is the ability to import power from or export power to neighboring systems. Some generating units are required to be on-line to prevent a single contingency event from causing a violation of a voltage limit, a transient stability limit, or transmission element rating. These units are referred to as "must run" units.

Q65. WERE THERE ANY REGIONAL TRANSMISSION CONSTRAINTS THAT AFFECTED THE ETI SERVICE AREA DURING THE RECONCILIATION PERIOD?

A. Yes. Within the Entergy System there are several regional transmission constraints that can have an effect on operations and two of these regional constraints affect the ETI service area. These two ETI regional constraints are West of the Atchafalaya Basin ("WOTAB") – comprising essentially the western half of Louisiana and all of the ETI service area – and Western WOTAB – a subset of WOTAB comprising approximately the region within the ETI service area west of the Trinity River. In both cases, limited transmission capability into these regions requires that generation within each region be on-line to provide reliable service to the region. During the Reconciliation Period, both regional transmission constraints were tracked and operational plans, such as unit commitment plans or purchased power plans were sometimes adjusted to ensure that the regional transmission constraints were met. All of the planning processes within the Entergy System, from long-term to short-term planning, must plan for these regional transmission constraints. Because the short-run processes must take into account both planned transmission outages and actual unplanned transmission outages, there is a large focus on these regional constraints within the Next-Day and Current Day processes.

Q66. WHAT WERE THE TYPICAL TRANSMISSION CONSTRAINTS ON THE ENTERGY SYSTEM DURING THE RECONCILIATION PERIOD?

A. Exhibit DSJ-5 provides a summary of the typical transmission constraints on the Entergy System during the Reconciliation Period.

Q67. PLEASE DESCRIBE THE TYPICAL OPERATING RESERVE CONSTRAINTS IN MORE DETAIL.

A. NERC establishes the general requirement that every system maintain adequate operating reserve. Each Regional Reliability Council that is a member of NERC may establish its own more specific requirements for its members. Operating reserve is provided by sources of power that can be called upon within a short period of time in the event of a contingency, such as a unit trip, a transmission line trip, or a sudden increase in load.

Q68. HOW DID THE SYSTEM MEET ITS OPERATING RESERVE REQUIREMENTS DURING THE RECONCILIATION PERIOD?

A. Throughout the Reconciliation Period, the System met its operating reserve requirements by participation in the SPP Reserve Sharing Group.

Through participation in the SPP Reserve Sharing Group, the Entergy System saved on fuel expenses associated with meeting its operating reserve requirements compared to the fuel expenses the Entergy System would have incurred had it met its operating reserve requirements as a stand-alone system. In particular, NERC requires operating reserves equal to the worst single contingency on the electrical system – usually defined as the loss of the electrical system's largest single generator – plus regulating margin. If the Entergy System had operated as a stand-alone system during the Reconciliation Period, its operating reserve requirements would have been up to 1,400 MW. The SPP Reserve Sharing Group represents an electrical system that is over twice the peak load of the Entergy System, but has a worst single contingency that is approximately the same as the Entergy System's stand-alone worst single contingency. Operating reserves are shared proportionately based on peak load by the members of the SPP Reserve Sharing Group, so the Entergy System, by participating in the SPP Reserve Sharing Group, reduced its operating reserve obligation to less than half of the operating reserves it would have otherwise needed on a stand-alone basis.

Q69. WAS THE SYSTEM'S OPERATING RESERVE REQUIREMENT GENERALLY A FIXED AMOUNT DURING THE RECONCILIATION PERIOD?

A. No. During the Reconciliation Period, the Entergy System's operating reserve requirement as a member of the SPP Reserve Sharing Group varied daily based on parameters described in Section 6 of the SPP Criteria. As a member of the SPP, the Company's compliance with the Criteria is mandatory. Section 6 of the Criteria establishes the method for determining the minimum requirements governing the amount of reserves to be maintained among members of the SPP Reserve Sharing Group on a daily basis.

Q70. HOW IS THE OPERATING RESERVE REQUIREMENT INCLUDED IN THE ENTERGY SYSTEM'S SHORT-RUN PLANNING AND OPERATIONS PROCESSES?

A. The operating reserve requirement is added to the load forecast to determine the total generation requirement.

Q71. PLEASE DESCRIBE TYPICAL PURCHASED POWER CONSTRAINTS IN MORE DETAIL.

A. With the separation of transmission from the power merchant function under FERC Order Nos. 888 and 889, it is not only necessary to find a seller of power at the appropriate price but also to secure transmission for power purchased. Transmission limitations on other systems can impact the ability to flow some or all of the power into one's own system.

Further, the purchased power market is composed of several distinct markets, each with its own constraints, which roughly parallel the time horizons used by the short-run planning and operations processes. Some sellers are unwilling to sell power in the size (MW) and shape (hours during the day) needed to completely optimize a buyer's overall cost. Consequently, purchased power can have hourly, daily, weekly, monthly, and annual minimum and maximum delivery constraints much like those discussed for fuels.

Finally, some of the power purchased during the Reconciliation Period was purchased as "non-firm" power. Non-firm power is supplied on an "if, as and when available" basis. These non-firm purchases include all purchases from Qualifying Facilities ("QFs") under the Public Utilities Regulatory Policy Act ("PURPA") and some purchases from merchant power plants or neighboring utilities. Purchases from merchant power plants or neighboring utilities may be non-firm due to the lack of firm transmission service or the type of product being offered. When the EMO purchased such non-firm power, the EMO ran some gas-fired units owned by the EOCs, including some owned by ETI, at least at minimum load to back-up the non-firm power to continue reliably serving customers.

Q72. WERE THESE NON-FIRM PURCHASES STILL BENEFICIAL FOR ETI AND IT'S CUSTOMERS?

A. Yes. The combination of non-firm purchased power and operation of generation owned by the EOCs at low levels resulted in lower total fuel and purchased power costs than would have otherwise occurred.

Q73. DID THE PURCHASED POWER MARKET CHANGE SIGNIFICANTLY DURING THE RECONCILIATION PERIOD?

A. No. The capacity of merchant power plants and QFs changed little during the Reconciliation Period.

VI. CONCLUSION

Q74. DO YOU HAVE AN OPINION CONCERNING THE EFFECTIVENESS OF THE PLANNING AND OPERATIONS OF THE ETI SYSTEM DURING THE RECONCILIATION PERIOD?

A. In my opinion, the ETI system, as part of the Entergy System, effectively meets the goal of providing economical, reliable power to its customers during the Reconciliation Period. I have described four short-run planning and operations processes used by the EMO to make decisions regarding the acquisition and use of resources to serve all customers of the EOCs, including those of ETI. The four short-run planning and operations processes ensured that, once reliability requirements were met, the least cost solution was sought and implemented. I therefore conclude that the

Company's mix of fuel and purchased power was reasonable and necessary during the Reconciliation Period.

Q75. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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Models Used in Short-Run Planning and Operations Processes

PROCESS	PRODUCTION COSTING	FORECASTING	OTHER MODELS
Monthly Energy Planning	PROSYM	Note 1	Load Capability Plan
Weekly Planning	Note 2	AANNSTLF	Load Capability Plan
Next-Day Planning	Generation Management/ Resource Optimizer	AANNSTLF	Load Capability Plan
Current Day	GMS (ED) Generation Management/ Resource Optimizer	AANNSTLF Hourly Load Forecaster	EMS (AGC), Load Capability Plan, OTS

Note 1: Hourly month-ahead load forecasts are taken from long-term load forecast.
Note 2: The Weekly Procurement Process uses a specially developed Security Constrained Unit Commitment model by Ventyx. The SPO uses Generation Management/Resource Optimizer to produce some of the Flexibility inputs required by the Weekly Process.

Description of Models

MODEL	DESCRIPTION	USE
Advanced Artificial Neural Network Short Term Load Forecaster (AANNSTLF) by Pattern Recognition Technologies	A load forecasting model using neural network techniques that is adaptive to recent changes in temperature and load.	In use at Entergy since 1994.
Generation Management System (GMS) including Automatic Generation Control (AGC) and Economic Dispatch (ED) by AREVA	A special purpose system of hardware and software used to control the generating system, perform real-time economic dispatch.	Over 60 control systems worldwide. In use at Entergy since 1994.
Hourly Load Forecaster Entergy in-house model	A model designed to reforecast future loads based on how close previous hour actual was to original AANNSTLF projection.	In use at Entergy since 1998.
Load and Capability Entergy in-house model	A model used to track supply and demand	In use at Entergy for over 20 years.
Operations Transactions System (OTS) by Entergy and Andersen Consulting	A system that allows power plants and the Current Day Team to communicate electronically rather than by telephone.	In use at Entergy since 1998.
PROSYM, OPSYM and Generation Management/ Resource Optimizer by Ventyx	Production cost models that facilitate Operations Planning.	PROSYM in use at Entergy since 2001; OPSYM in use since early 2003; Generation Management/Resource Optimizer in use since 2008.

February 2013 Energy Plan
Final

01/24/12

February 2013

Sun	Mon	Tue	Wed	Thu	Fri	Sat
					1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21	22	23
24	25	26	27	28		

Prepared by ENTERGY CORPORATION

Fuel

February 2013 Final MEP

Natural Gas Price Forecast

Company	Plant	Fuel	Transport	Basis To Henry Hub	Tax	Delivered Price ($3.52)
EAI	Ouachita	0.00%	$0.00	$0.06	0.0%	$3.58
	Hot Spring	1.60%	$0.036	($0.04)	4.25%	$3.72
	Couch	-0.09%	$0.25	$0.00	6.0%	$4.00
	Lynch	-0.09%	$0.25	$0.00	6.0%	$4.00
	Moses	0.46%	$0 25	$0.00	5.2%	$3.99
	Mabelvale	-0.09%	$0.25	$0.00	6.0%	$4.00
	Lake Catherine	-0.09%	$0.25	$0.00	6.0%	$4.00
ETI	Nelson	0.00%	$0.03	$0.00	0.0%	$3.55
	Willow Glen	0.00%	$0.18	$0.11	0.0%	$3.81
	SanJac	0.00%	$0.14	$0.21	0.0%	$3.87
	Sabine	0.00%	$0.04	$0.01	0.0%	$3.57
	Lewis Creek	0.00%	$0.01	$0.04	0.0%	$3.57
ELI	Acadia	0.00%	$0.10	$0.02	0.0%	$3.64
	Little Gypsy	0.00%	$0.00	$0.10	0.0%	$3.62
	Ninemile	0.00%	$0.00	$0.10	0.0%	$3.62
	Waterford	0.00%	$0.00	$0.10	0.0%	$3.62
	Buras	0.00%	$0.00	$0.50	0.0%	$4.02
	Sterlington	0.00%	$0.00	$0.05	0.0%	$3.57
	Perryville	1.46%	$0.027	($0.050)	0.0%	$3.55
EMI	Baxter Wilson	0 00%	$0.00	$0.06	0.0%	$3.58
	Hinds	1.77%	$0.01	($0.06)	0.0%	$3.53
	Attala	1.77%	$0.01	($0 06)	0.0%	$3.53
	Rex Brown	0.00%	$0.00	$0.11	0.0%	$3.63
	Gerald Andrus	0.00%	$0.13	$0.07	0.0%	$3.72
	Delta	0.01%	$0.12	$0.07	0.0%	$3.71
ENOI	Michoud	1.60%	$0.00	$0.10	0.0%	$3.68
AECC	Bailey	2.52%	$0.00	$0.10	6.0%	$3.93
	McClellan	2.52%	$0.00	$0.10	5.2%	$3.90

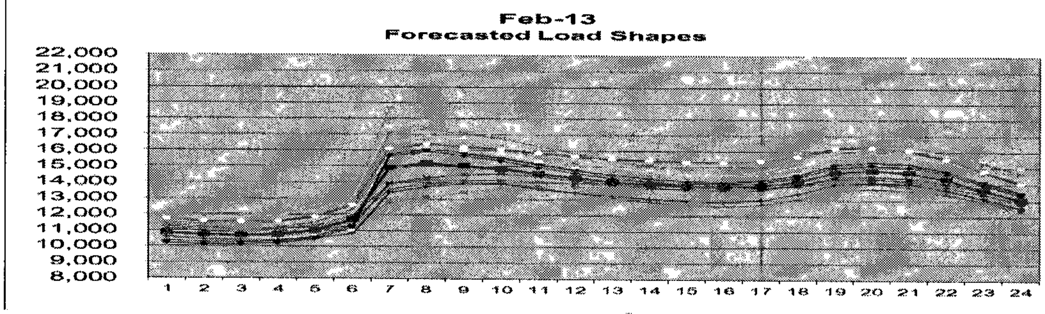
Sabine → Ninemile: $0.05
Perryville → Attala: ($0.02)

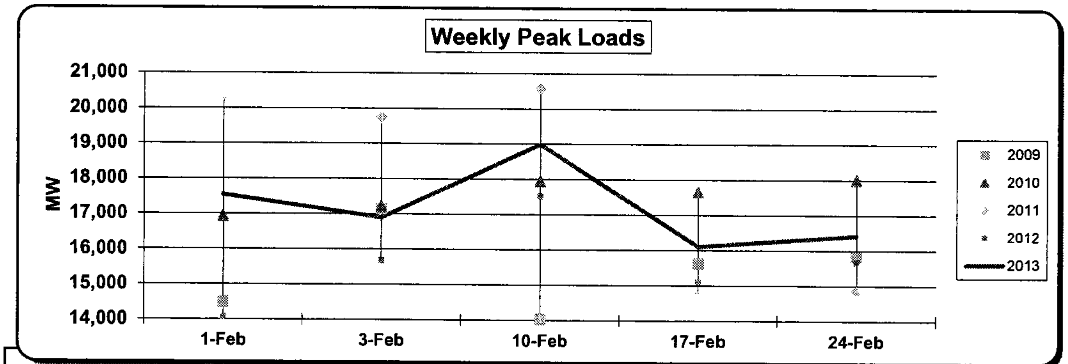
Oil Status/Price

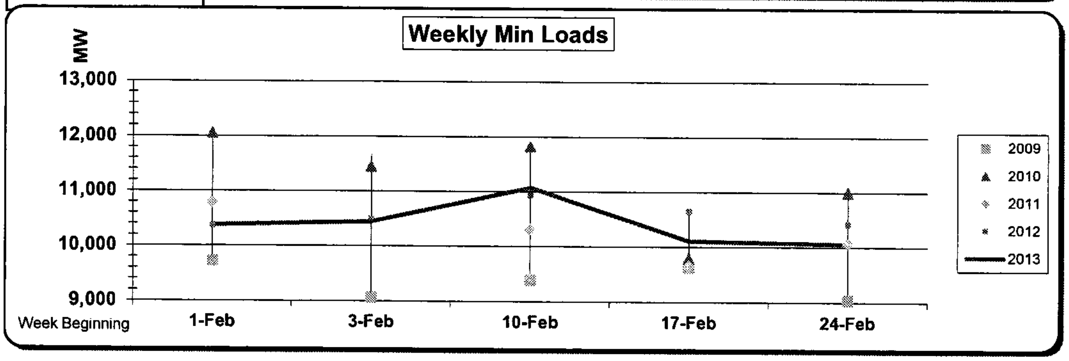
	$/BBL	$/MMBtu	Raw Spread
1% Estimated Price @ Lower River:	$102.89	$15.83	$12.31

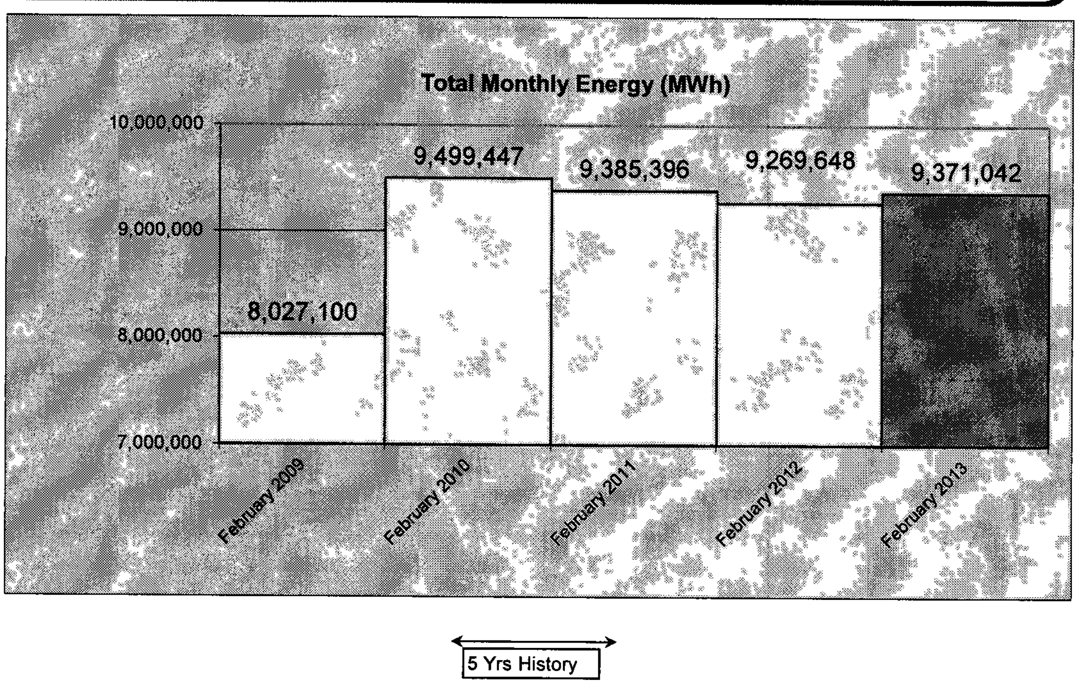
Unit	Oil Type	% or MW On Oil	Oil Price	Blend Price	Gas Price	Spread
BW1	# 6	0%	16.14	-	3.58	
BW2	# 6	0%	16.14	-	3.58	
Andrus	# 6	0%	16.28	-	3.72	
WF1	# 6	0%	16.23	-	3.62	
WF2	# 6	0%	16.23	-	3.62	
WF4	# 2	0%	14.02	-	3.62	
NM4	# 2	0%	22.57	-	3.62	
NM5	# 2	0%	22.57	-	3.62	
MI3	# 6	0%	16.23	-	3.68	
LG2	# 2	0%	14.02	-	3.64	
WG2	# 2	0%	22.20	-	3.81	
WG4	# 6	0%	16.29	-	3.81	
WG5	# 6	0%	16.29	-	3.81	
DE1	# 6	0%	17.39	-	3.71	
DE2	# 6	0%	17.39	-	3.71	
ST7	# 2	0%	14.60	-	3.57	
BA1	# 6	0%	5.70	-	3.93	
MC1	# 6	0%	5.70	-	3.93	

February 2013 Final MEP -- Load & Energy

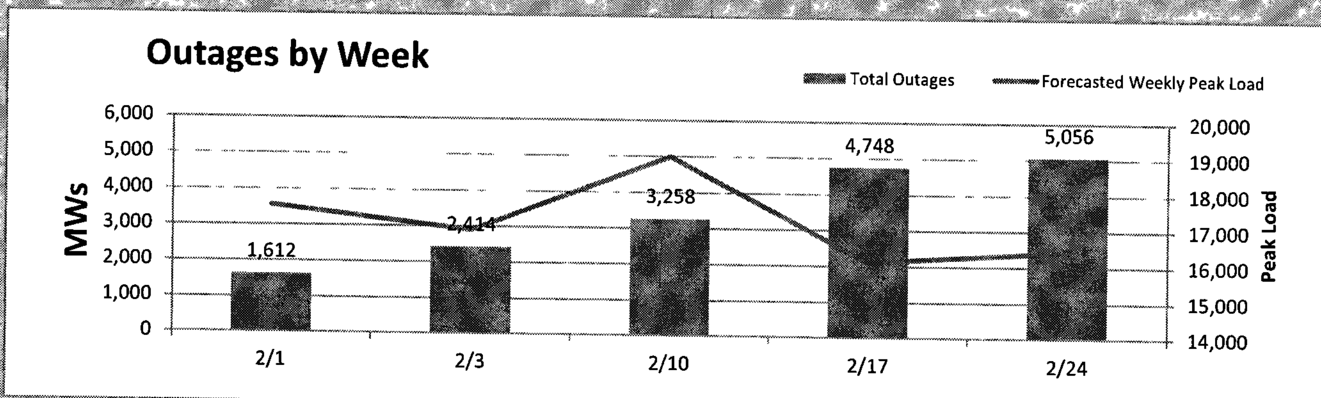








February 2013 Final MEP -- Outages



Unit	Rating	Duration	Outage Start	End	2/1	2/3	2/10	2/17	2/24
Total MW in Outage:					**1,612**	**2,414**	**3,258**	**4,748**	**5,056**
L CATH 4	528	23	27-Oct-12	6-Apr-13	528	528	528	528	528
B WLSN 1	515	14	19-Jan-13	27-Apr-13	515	515	515	515	515
L CATH 3	96	4	19-Jan-13	16-Feb-13	96	96	96		
MICHOD 3	470	11	19-Jan-13	6-Apr-13	470	470	470	470	470
RE 3	3	19	19-Jan-13	1-Jun-13	3	3	3	3	3
DG 1	46	2	2-Feb-13	16-Feb-13		46	46		
DG 2	32	2	2-Feb-13	16-Feb-13		32	32		
L GPSY 1	244	9	2-Feb-13	6-Apr-13		244	244	244	244
PV 2 CC 1	480	10	2-Feb-13	13-Apr-13		480	480	480	480
WH BLF 2	844	6	9-Feb-13	23-Mar-13			844	844	844
NEL6 6	550	6	16-Feb-13	30-Mar-13				550	550
Oxy B	135	1	16-Feb-13	17-Feb-13				135	
RVB 1	979	4	16-Feb-13	16-Mar-13				979	979
LC 1	230	3	23-Feb-13	16-Mar-13					230
REXBRN 4	213	2	23-Feb-13	9-Mar-13					213
ANDRUS 1	741	5	2-Mar-13	6-Apr-13					
L CATH 1	47	4	2-Mar-13	30-Mar-13					
L CATH 2	47	4	2-Mar-13	30-Mar-13					
SAB 4	531	8	2-Mar-13	27-Apr-13					
WATERF 1	411	4	2-Mar-13	30-Mar-13					
Oxy B	135	3	4-Mar-13	22-Mar-13					
SAM 3_4	26	3	9-Mar-13	30-Mar-13					
MCCLEL 1	134	2	16-Mar-13	30-Mar-13					
SAB 3	400	2	16-Mar-13	30-Mar-13					
FRONTIER ND CD	150	2	21-Mar-13	29-Mar-13					
FRONTIER ND CD2	150	2	21-Mar-13	29-Mar-13					
Carville B	240	2	22-Mar-13	30-Mar-13					
ARK NU 1	851	6	23-Mar-13	4-May-13					
L GPSY 2	415	2	23-Mar-13	6-Apr-13					
Acadia 2 2x1	509	6	30-Mar-13	11-May-13					
INDEPN 1	836	8	30-Mar-13	25-May-13					
L GPSY 3	528	3	30-Mar-13	20-Apr-13					
LC 2	230	3	30-Mar-13	20-Apr-13					
SAM 1_2	25	3	30-Mar-13	20-Apr-13					
SANJAC 1	75	2	31-Mar-13	9-Apr-13					
ATA 21	492	6	6-Apr-13	18-May-13					
CAJUN2 3	247	3	6-Apr-13	27-Apr-13					
LYNCH 3	110	3	6-Apr-13	27-Apr-13					

Modeling Assumptions

February 2013 Final MEP

Power Portfolio

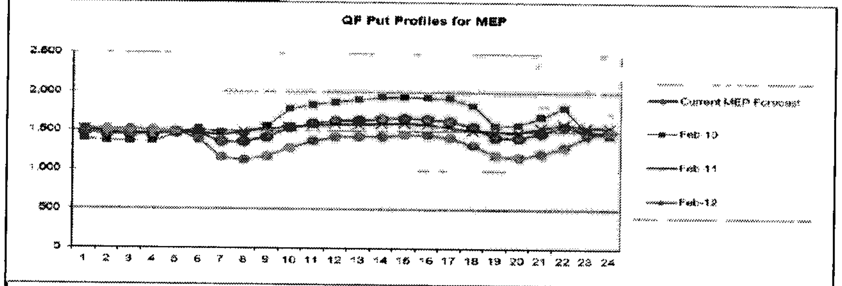
		%	2/1/13	2/3/13	2/10/13	2/17/13	2/24/13
Purchases	SPA Peaking	3%	100	100	100	100	100
	Long Term (> 1yr)	20%	610	610	550	475	685
	MediumTerm (1M - 1yr)	20%	590	590	590	590	590
	Short Term (< 1M)	56%	1,600	1,800	1,800	1,400	1,600
	Total:		2,900	3,100	3,040	2,565	2,975
Sales	CoOwnership		(703)	(703)	(641)	(641)	(708)
	Total:		(703)	(703)	(641)	(641)	(708)

(Peak Hour MW)

Across Peak, Energy Limited
LT - 1095 MW>> Frontier-300, SRW3-100, Oxy325+135+60, CSP-75, Dow-100
Yearly - 485 MW >> Carville ABC-485
Monthly - 0 MW>>

0

QF Put Profile



Regional Breakout	On-Peak	Off-Peak
North	6%	6%
South	42%	39%
WOTAB	41%	44%
Amite South	11%	12%
	100%	100%

Derates / Forced Outages

	Derate Max	Orig Max	Cause	Plan for Return
Ninemile 4	500	734	*Main Transformer*	TBD - 2013
L Cath 4		528	*Cracked steam pipe*	May-13
Nelson 6		550	*Turbine blade damage*	Feb-13
TOTAL:	500	1,812		

Lost MW: 1,312

Transmission Import Limits

	Nominal	Week of 2/1/2013	2/3/2013	2/10/2013	2/17/2013	2/24/2013
Sheridan-South	2,050	2050	2050	2050	2050	2050
Western	1,200	1200	1200	1200	1200	1200
WOTAB	1,440	1,440	1,440	1,440	1,440	1,440
DSG	2,100	2100	2100	2100	2100	2100
Amite-South	2,950	2,950	2,950	2,950	2,950	2,950

Ouachita Transmission Check

	Max	Week of 2/1/2013	2/3/2013	2/10/2013	2/17/2013	2/24/2013
Ouachita Transmision Output Capacity	800	800	800	800	800	800
Expected Ouachita Output		478	268	800	538	800
Excess Capacity		322	532	0	262	0

Reliability -- Page #1

February 2013 Final MEP

Line	*Regional Reliability*	2/1/13	2/3/13	2/10/13	2/17/13	2/24/13	
				Western			
1	Weekly Peak Load	1,271	1,225	1,372	1,170	1,192	Assume 7.0% of System Load
2	Transmission Import Capability	1,200	1,200	1,200	1,200	1,200	
3	Required Area Generation (G-0)	71	25	172	-30	-8	
4	Committed Generation	760	760	760	760	530	0
	Frontier Next Day #1	150	150	150	150	150	
	Frontier Next Day #2	150	150	150	150	150	
	LC 1	230	230	230	230	PO	
	LC 2	230	230	230	230	230	
	SANJAC 1	0	0	0	0	0	
	SANJAC 2	0	0	0	0	0	
5	*LEVEL 1 (G minus 0)*	760	760	760	760	530	
6	*LEVEL 2 (G minus 1)*	459	505	358	560	308	

Line		2/1/13	2/3/13	2/10/13	2/17/13	2/24/13	
				WOTAB			
7	Weekly Peak Load	4,575	4,410	4,938	4,211	4,292	Assume: 25.2% of System Load
8	Transmission Import Capability	1,440	1,440	1,440	1,440	1,440	
9	Required Area Generation (G-0)	3,135	2,970	3,498	2,771	2,852	
10	Committed Generation	3,342	3,342	3,417	3,342	3,354	
	Frontier Must Run	150	150	150	150	150	
	Frontier Next Day	150	150	150	150	150	
	LC 1	230	230	230	230	PO	
	LC 2	230	230	230	230	230	
	SANJAC 1	0	0	0	0	0	
	SANJAC 2	0	0	0	0	0	
	TBD 1	40	40	40	40	40	
	TBD 2	40	40	40	40	40	
	SAM 1_2	25	25	25	25	25	
	SAM 3_4	26	26	26	26	26	
	Carroll Street Call Option	0	0	75	0	75	
	SRW Call Option	0	0	0	0	0	
	SAB 1	0	0	0	0	0	
	SAB 2	0	0	0	0	0	
	SAB 3	400	400	400	400	400	
	SAB 4	0	0	0	0	0	
	SAB 5	480	480	480	480	480	
	NEL 1	110	110	110	110	110	
	NEL 2	110	110	110	110	110	
	NEL 3	0	0	0	0	0	
	NEL 4	410	410	410	410	410	
	NEL6 6	PO	PO	PO	PO	PO	
	Calcasieu 1	0	0	0	0	0	
	Calcasieu 2	0	0	0	0	167	
	Acadia 2 2x1	509	509	509	509	509	
	Acadia 2 2x1 Dual	52	52	52	52	52	
	Acadia 2 2x1 PA	0	0	0	0	0	
	1x16 (Expected Purchases)	600	600	600	600	600	
	1x12 (Expected Purchases)	0	0	0	0	0	
Line	1x8,1x6 (Expected Purchases)	0	0	0	0	0	
11	*LEVEL 1 (G minus 0)*	727	892	439	1,091	1,022	
12	*LEVEL 2 (G minus 1)*	317	482	29	681	612	Should be >= 0 Planning Requirement

Unit Specific RMR Rules					
System Load	17,555	16,900	18,996	16,111	16,432
WOTAB 230 KV (Nel4, Nel6, SB4, SB5) commit: SysLoad<19000 = min2; >19,000 =min3					
	OK	OK	OK	OK	OK
Sabine 138 KV unit commitment: 1 Unit Year Round					
	OK	OK	OK	OK	OK
Lewis Creek unit commitment: System Load<19285 =min 0; Load>19285 but < 22785 =min1, Load > 22785 =min 2. (Assumes 300 Frontier, 150 MW Sanjac).					
Western % of System 7.0%	OK	OK	OK	OK	OK

Reliability -- Page #2

February 2013 Final MEP

Regional Reliability	2/1/13	2/3/13	2/10/13	2/17/13	2/24/13	
Line	DSG (Downstream of Gypsy)					
1 Weekly Peak Load	3,050	2,940	3,292	2,807	2,861	Assume 14.7% of System Load
2 Transmission Import Capability	2,100	2,100	2,100	2,100	2,100	
3 Required Area Generation (G-0)	950	840	1,192	707	761	
4 Committed Generation	1,613	1,613	1,613	1,613	1,613	
NINEMI 3	128	128	128	128	128	0
NINEMI 4	500	500	500	500	500	
NINEMI 5	750	750	750	750	750	
MICHOD 2	235	235	235	235	235	
MICHOD 3	PO	PO	PO	PO	PO	
BURAS 8	0	0	0	0	0	
5 *LEVEL 1 (G minus 0)*	663	773	421	906	852	
6 *LEVEL 2 (G minus 1)*	(87)	23	(329)	156	102	

	2/1/13	2/3/13	2/10/13	2/17/13	2/24/13	
Line	Amite South					
1 Weekly Peak Load	5,083	4,900	5,487	4,679	4,769	Assume 28.0% of System Load (incl Cajun/Cleco)
2 Transmission Import Capability	2,950	2,950	2,950	2,950	2,950	
3 Required Area Generation (G-0)	2,133	1,950	2,537	1,729	1,819	
4 Committed Generation	3,668	3,668	3,944	3,944	3,668	
WATERF 1	0	0	0	0	0	
WATERF 2	0	0	411	411	0	
WATERF 3	1,180	1,180	1,180	1,180	1,180	
Oxy A	325	325	325	325	325	
Oxy B	135	135	PO	PO	135	
Oxy C	0	0	0	0	0	
L GPSY 1	0	PO	PO	PO	PO	
L GPSY 2	415	415	415	415	415	
L GPSY 3	0	0	0	0	0	
NINEMI 3	128	128	128	128	128	
NINEMI 4	500	500	500	500	500	
NINEMI 5	750	750	750	750	750	
BURAS 8	0	0	0	0	0	
MICHOD 2	235	235	235	235	235	
MICHOD 3	PO	PO	PO	PO	PO	
5 *LEVEL 1 (G minus 0)*	1,535	1,718	1,407	2,215	1,849	
6 *LEVEL 2 (G minus 1)*	355	538	227	1,035	669	Should be >= 0 Planning Requirement.

Unit Specific RMR Rules					
System Load	18,155	17,500	19,596	16,711	17,032
DSG 230 KV (NM4, NM5, MI3) commitment: System Load <22253 =min 2; Load>22253 =min 3					
DSG % of System 15.0%	OK	OK	OK	OK	OK
DSG 115 KV (MI2, NM3, NM1, NM2) commitment: System Load <24846 =min 0; Load>24846 but <26333 =min 1; Load>26333 =min 2					
DSG % of System 15.0%	OK	OK	OK	OK	OK
Run Rex Brown 3, 4 or Hinds Commitment: System Load > 21,333 =min 1					
MS % of System 15.0%	OK	OK	OK	OK	OK
McClelland RMR commit: System Load<16,000 = min 0; Load >16,000 =min 1					
	OK	OK	OK	OK	OK

February 2013 Final MEP -- Unit Commitment

EAI	2/1/13	2/3/13	2/10/13	2/17/13	2/24/13
ARK NU 1	851	851	851	851	851
ARK NU 2	1,005	1,005	1,005	1,005	1,005
COUCH 2	0	0	0	0	0
INDEPN 1	836	836	836	836	836
INDEPN 2	842	842	842	842	842
L CATH 4	PO	PO	PO	PO	PO
LYNCH 3	0	0	0	0	0
MABLEVALE 1 - 4	0	0	0	0	0
HOTSPRING	0	0	630	0	630
OUACHITA #1	238	268	268	268	268
OUACHITA #2	240	0	270	270	270
OUACHITA #3	0	0	262	0	262
WH BLF 1	815	815	815	815	815
WH BLF 2	844	844	PO	PO	PO

ETI					
LC 1	230	230	230	230	PO
LC 2	230	230	230	230	230
FRONTIER ND CD	150	150	150	150	150
FRONTIER ND CD2	150	150	150	150	150
SANJAC 1	0	0	0	0	0
SANJAC 2	0	0	0	0	0
SAB 1	0	0	0	0	0
SAB 2	0	0	0	0	0
SAB 3	400	400	400	400	400
SAB 4	0	0	0	0	0
SAB 5	480	480	480	480	480
Carroll Str Park Call Option	0	0	75	0	75
SRW #3 Call Option	0	0	0	0	0

EGSL					
NEL 1	110	110	110	110	110
NEL 2	110	110	110	110	110
NEL 3	0	0	0	0	0
NEL 4	410	410	410	410	410
NEL6 6	PO	PO	PO	PO	PO
Calcasieu #1	0	0	0	0	0
Calcasieu #2	0	0	0	0	167
Acadia	561	561	561	561	561
CAJUN2 3	247	247	247	247	247
RVB 1	979	979	979	PO	PO
Dow Call Option	0	0	100	0	100
WG 1	0	0	0	0	0
WG 2	0	0	0	0	0
WG 4	0	0	0	0	0
Carville A	185	185	185	185	185
Carville B	240	240	240	240	240
Carville C	0	0	0	0	0

HYDRO:					
HYDROS (ALL)	494	416	416	494	494
AECC:					
BAILEY 1	0	0	0	0	0
MCCLEL 1	134	134	134	134	134

Committed AGC Units | UNITS IN PORTFOLIO | 70

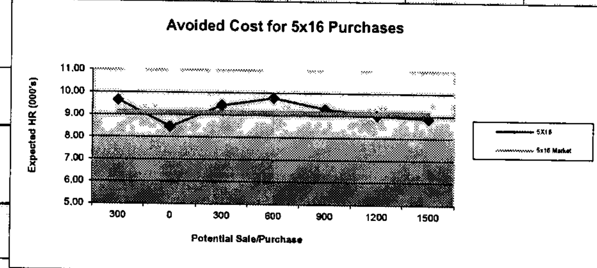
ELI	2/1/13	2/3/13	2/10/13	2/17/13	2/24/13
BURAS 8	0	0	0	0	0
L GPSY 1	0	PO	PO	PO	PO
L GPSY 2	415	415	415	415	415
L GPSY 3	0	0	0	0	0
NINEMI 3	128	128	128	128	128
NINEMI 4	500	500	500	500	500
NINEMI 5	750	750	750	750	750
PERRYVILLE #1	543	PO	PO	PO	PO
STERLN 7	0	0	0	0	0
WATERF 1	0	0	0	0	0
WATERF 2	0	0	0	411	0
WATERF 4	0	0	0	0	0
WATERF 3	1,180	1,180	1,180	1,180	1,180
Oxy A	325	325	325	325	325
Oxy B	135	135	PO	PO	135
Oxy C	0	0	0	0	0

EMI					
ANDRUS 1	0	0	660	660	0
B WLSN 1	PO	PO	PO	PO	PO
B WLSN 2	0	0	545	545	0
G GULF 1	1,463	1,463	1,463	1,463	1,463
ATTALA	492	492	492	492	492
HINDS	485	485	485	485	485
REXBRN 3	0	0	0	0	0
REXBRN 4	0	0	0	0	PO
REXBRN 5	0	0	0	0	0
ENOI					
MICHOD 2	235	235	235	235	235
MICHOD 3	PO	PO	PO	PO	PO

L&C Balance

Energy Gen (MW):	17,432	16,601	18,164	16,607	16,130
AECC + SPA Schedules	67	67	67	67	67
RELIABILITY Placeholder	0	0	0	0	0
Monthly Purchases	105	105	105	105	105
Weekly/ND Purchases	1,600	1,800	1,800	1,400	1,600
Hourly Purchases	150	150	150	150	150
Total Resources	19,354	18,723	20,286	18,329	18,052
Load:	(17,55[illegible])	(16,900)	[illegible]	[illegible]	[illegible]
SPP Reserves (Nominal):	(600)	(600)	(600)	(600)	(600)
Total Sales (less SPA):	(708)	(708)	(641)	(641)	(208)
Total Demand	(18,863)	(18,208)	(20,237)	(17,352)	(17,740)
Excess / Deficient	491	515	49	977	312
Uncommitted MW:	6,364	6,360	4,608	4,504	5,440

	Based on HH @ $3.52	Sales		Purchases				
	MW Blocks	300	0	300	600	900	1200	1500
ON-PEAK	North LD Market HR = 9.12							
5X16	*Avg Avd Cost ($/MWh)*	34.00	29.81	33.21	34.42	32.72	31.72	31.30
	HR =	9.66	8.47	9.43	9.78	9.29	9.01	8.89
		7 X 16	7 X 12					
NORTH / SOUTH	*Avd Cost (500 MW)*	32.82	30.90					
		9.32	8.78					
WOTAB	*Avd Cost (300 MW)*	32.44	30.59					
		9.22	8.69					
OFF-PEAK		5X8	7X8					
	Avd Cost (500 MW)	17.97	20.02					
		5.10	5.69					
COMBO		500						
Wrap	*Avg Marg Cost*	23.72	•					
		6.74						

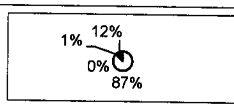


Average HRs and Costs for Units Running Part of the Month

Average Cost $33.45 *Avg HR* 9,268

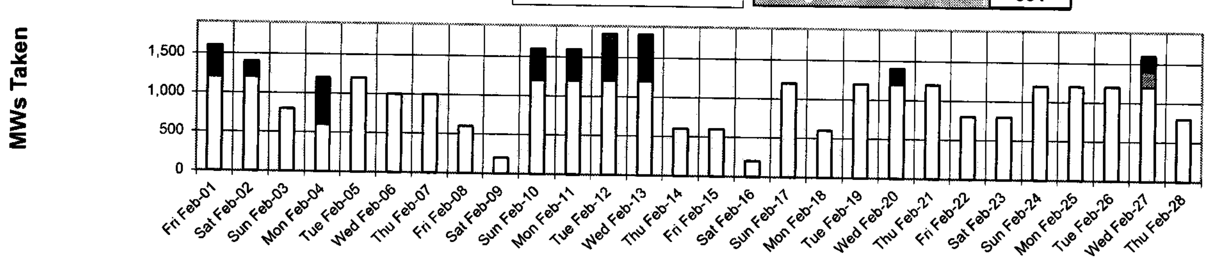
Unit	Avg Cost	Avg HR	On-line Hrs	Unit	Avg Cost	Avg HR	On-line Hrs
PV 2 CC Duct 1	$ 29.09	8,200	41	Ouachita #2 Duct	$ 30.98	8,655	251
PV 2 CC 1	$ 24.59	6,931	41	Ouachita #2	$ 25.54	7,134	314
Ouachita #3 Duct	$ 30.98	8,655	115	Ouachita #1 Duct	$ 30.98	8,655	333
Ouachita #3	$ 25.57	7,143	115	Ouachita #1	$ 25.58	7,144	432
HotSpring Duct	$ 32.48	8,721	126	LC 1	$ 38.21	10,703	552
HotSpring 21	$ 26.41	7,091	126	HINDS 21	$ 24.75	7,007	566
WATERF 2	$ 44.00	12,154	168	ACADIA 2 2x1 Duc	$ 30.70	8,434	605
ANDRUS 1	$ 36.97	9,938	168	NINEMI 3	$ 56.10	15,498	672
B WLSN 2	$ 35.84	10,012	168	L GPSY 2	$ 53.37	14,742	672

Weekly / Daily On-Peak Blocks

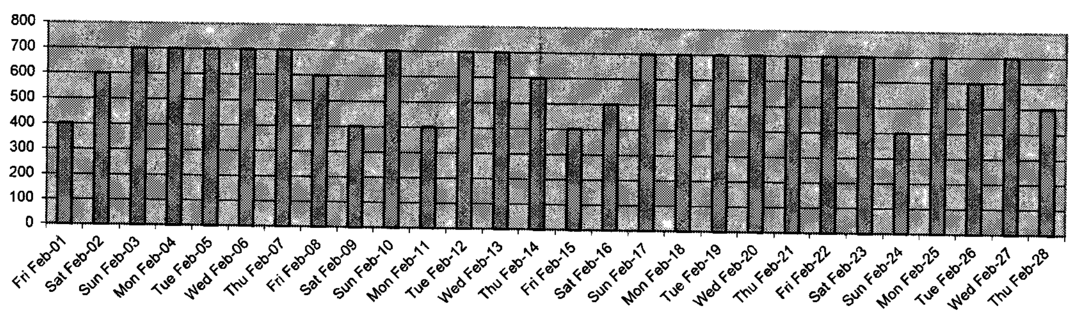


On-Peak Price ($/MWh):
M-F: $32.10 Sa-Sun: $30.08

Average 981



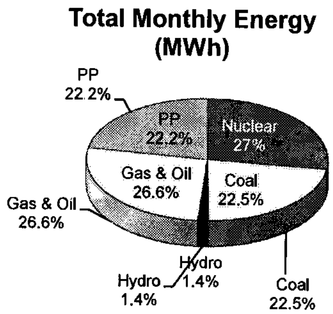
Daily / Hourly Off-Peak Purchases

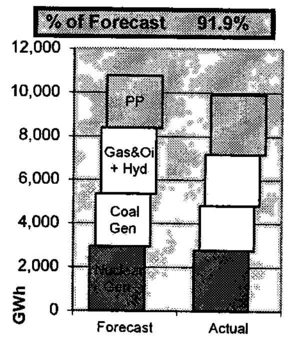


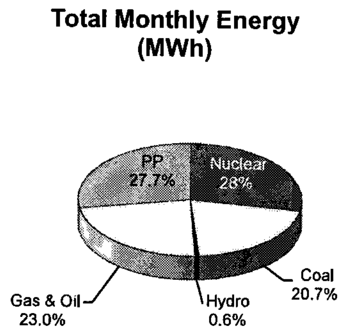
Resource Portfolio Analysis

February 2013 Final MEP

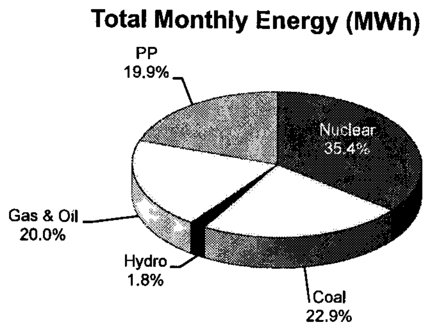
FORECAST Month of December 2012 | **ACTUAL Month of December 2012**

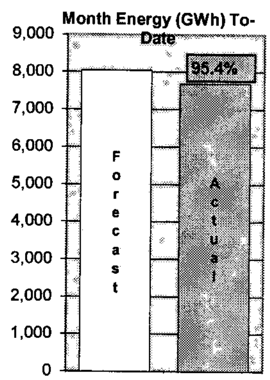


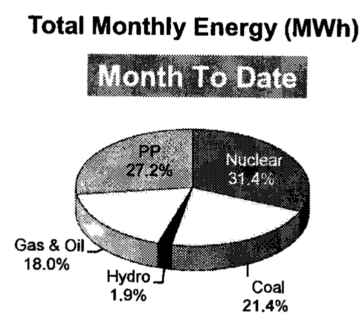




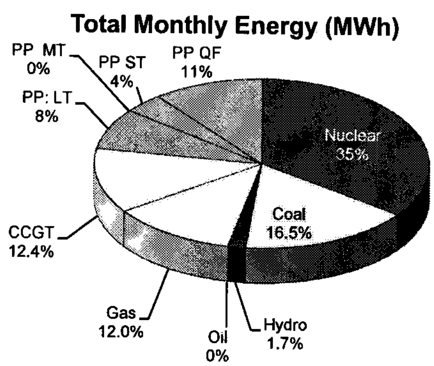
FORECAST Month of January 2013 | **ACTUAL Month of January 2013**

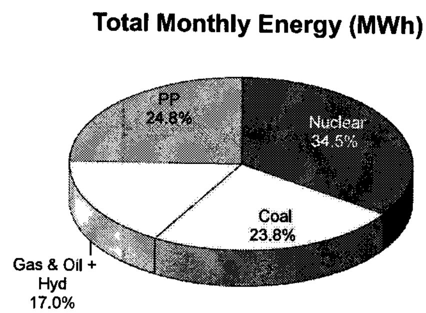






FORECAST Month of February 2013 | **ACTUAL Average of February 2010 - 2012**

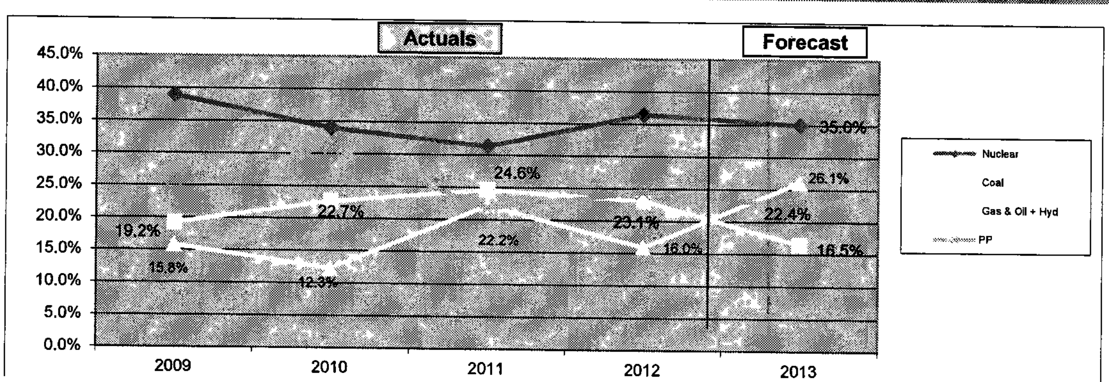




Total PP = 22.4%

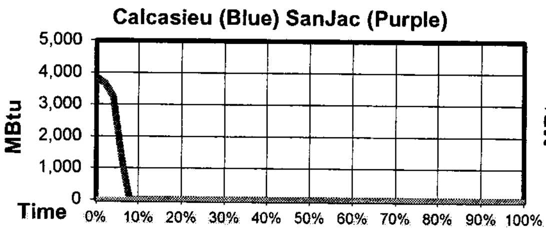
Total G,O&H = 26.1%

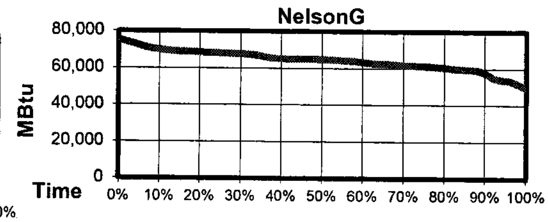
Resource Mix Trends for February

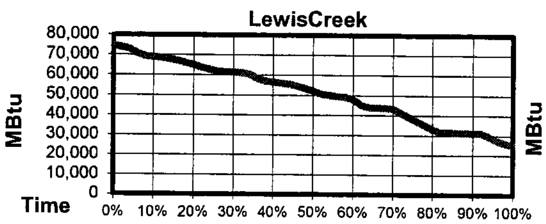


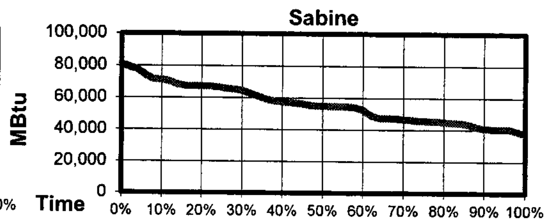
Daily Fuel Duration Curves

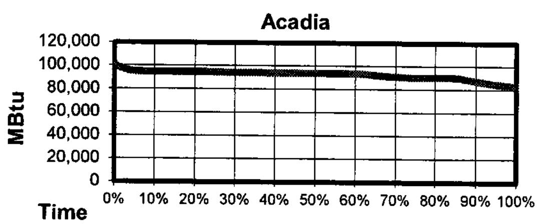
February 2013 Final MEP

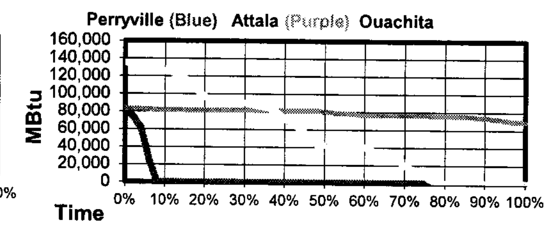


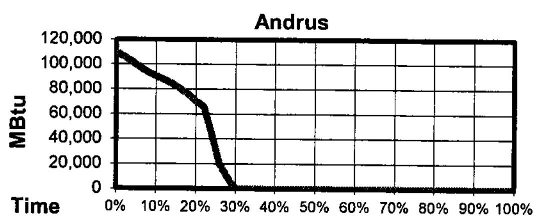


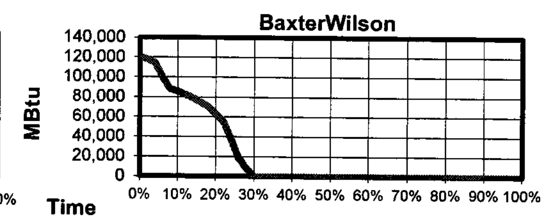


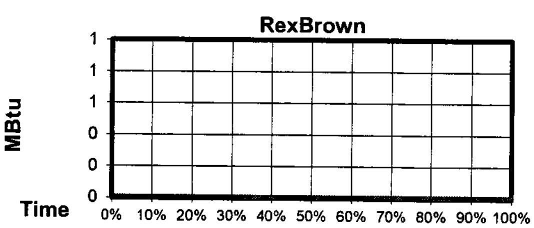


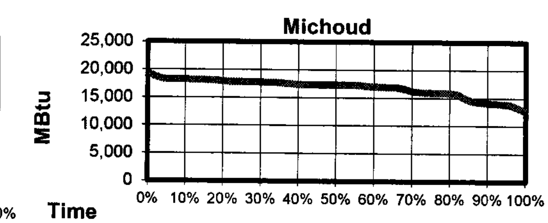


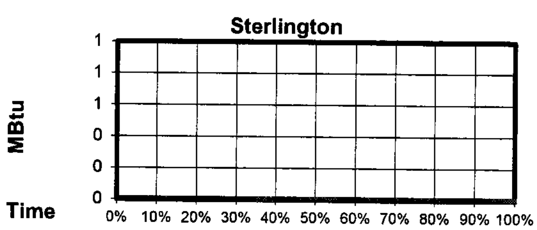


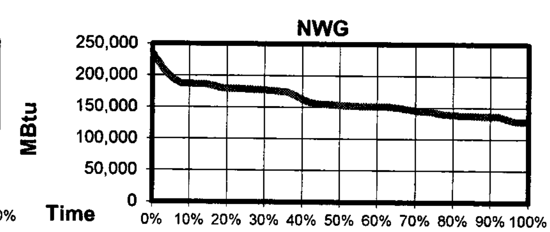


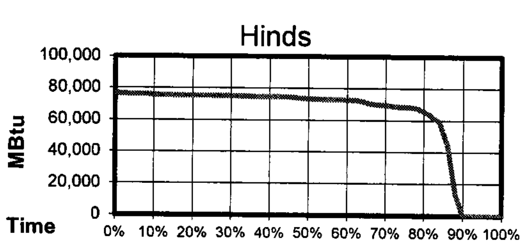


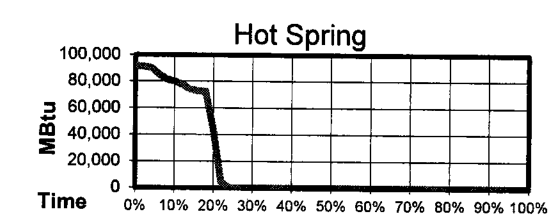












Results: Fuel Volumes

February 2013 Final MEP
FUEL SUMMARY

	Plant Name		02/01/13	02/03/13	02/10/13	02/17/13	02/24/13	Daily Average	Max Day	Min Day	Hourly Max (Day Rate)	Total Burn
Coal	Average (Tons of Coal/day) for days burned							(Tons of Coal/day)				
	Independence	Fuel	20,350	19,724	19,715	19,723	20,007	19,817				554,874
		L&C MW	836; 842	836; 842	836; 842	836; 842	836; 842					
	White Bluff	Fuel	19,906	12,885	9,069	9,074	9,842	10,936				306,217
		L&C MW	815, 844	815; 844	815; PO	815, PO	815, PO					
	Nelson 6	Fuel										
		L&C MW	PO	PO	PO	PO	PO					
	Cajun2 Unit3	Fuel										
		L&C MW	247	247	247	247	247					
Gas	Fuel: Avg (MMBtu/day) for days burned; Total (MMBtu)							GAS - (MMBtu/day)				(MMBtu)
	Acadia	Avg	87,623	89,565	92,959	95,723	94,181	92,639	100,450			2,593,883
		Total	175,248	626,964	650,727	670,077	470,914					*Gas Only*
Dave		L&C MW	561	561	561	561	561					
	Willow Glen	Avg	0	0	0	0	0					
		Total	0	0	0	0	0					*Gas Only*
Pete		L&C MW	0; 0; 0; 0; 0	0; 0; 0; 0; 0	0; 0; 100, 0, 0	0, 0; 0; 0, 0	0, 0, 100, 0, 0					
	SanJac	Fuel	0	0	0	0	0					
		Total	0	0	0	0	0					
Gary		L&C MW	0; 0	0; 0	0; 0	0, 0	0, 0					
	Nelson 3 & 4	Avg	56,902	64,646	61,314	69,123	63,509	64,176	75,298	49,580	0	1,796,926
		Total	113,804	452,520	429,199	483,859	317,545					
Gary		L&C MW	0; 410	0; 410	0, 410	0, 410	0; 410					
	Lewis Creek	Avg	39,494	57,363	49,106	64,972	29,359	50,924	74,781	25,360	51,840	1,425,866
		Total	78,988	401,549	343,746	454,816	146,794					
Gary		L&C MW	230, 230	230; 230	230; 230	230, 230	PO; 230					
	Sabine	Avg	43,493	60,746	49,245	65,025	51,755	56,103	80,827	38,009	246,977	1,570,876
		Total	86,986	425,223	344,717	455,175	258,775					
Gary		L&C MW	0; 0; 400; 0; 480	0; 0, 400, 0; 480	0; 0; 400, 0; 480	0; 0, 400; 0; 480	0, 0, 400; 0; 480					
	LewisC & Sabine	Avg	82,987	118,109	98,351	129,997	81,114	107,027	155,608	63,368	298,817	2,996,742
		Total	165,974	826,772	688,463	909,992	405,569					
	Hot Spring	Avg	0	0	83,686	0	77,567	81,646	91,568			489,877
		Total	0	0	334,744	0	155,134					
Brad		L&C MW	0	0	0	0	0					
	Lake Cath 4	Avg	0	0	0	0	0				419,575	
		Total	0	0	0	0	0					
Helen		L&C MW	PO	PO	PO	PO	PO					
	Hinds	Avg	68,518	73,858	70,452	72,988	74,936	72,641	76,507		51,840	1,743,381

February 2013 Final MEP
FUEL SUMMARY

Plant Name		02/01/13	02/03/13	02/10/13	02/17/13	02/24/13	Daily Average	Max Day	Min Day	Hourly Max (Day Rate)	Total Burn
Brad	Total	137,036	517,003	422,712	291,952	374,679					
	L&C MW	*240*	*0*	*240*	*240*	*240*					

Results: Fuel Volumes (continued)

February 2013 Final MEP
FUEL SUMMARY

	Plant Name		02/01/13	02/03/13	02/10/13	02/17/13	02/24/13	Daily Average	Max Day	Min Day	Hourly Max (Day Rate)	Total Burn
	Ouachita	Avg	42,096	38,376	89,281	85,456	94,195	81,730	135,671	29,669	0	1,582,461
		Total	42,095	191,875	535,667	341,815	470,961					
Garrett & Helen		L&C MW	238, 240, 0	238, 0; 0	238, 240, 232	238; 240; 0	238, 240; 232					
	Michoud	Avg	14,001	16,866	15,912	18,306	17,006	16,808	19,462	12,664	0	470,627
		Total	28,002	118,065	111,387	128,141	85,032					
Dave		L&C MW	0; 235; PO	0; 235; PO	0; 235; PO	0; 235; PO	0; 235, PO					
	Attala	Fuel	71,680	76,778	78,056	82,165	80,698	78,780	83,590			2,205,845
		Total	143,361	537,447	546,389	575,157	403,492					
Garrett		L&C MW	492	492	492	492	492					
	Gerald Andrus	Avg Gas	0	0	79,424	80,645	0	88,559	109,861		354,710	640,277
		Total	0	0	317,695	322,582	0					
Helen		L&C MW	0	0	660	660	0					
	B. Wilson	Avg	0	0	72,872	85,089	0	87,475	120,304			631,846
		Total	0	0	291,489	340,356	0					
Helen		L&C MW	PO; 0	PO; 0	PO; 545	PO; 545	PO; 0					
	Rex Brown	Avg	0	0	0	0	0				204,694	
		Total	0	0	0	0	0					
Helen		L&C MW	0, 0; 0	0; 0; 0	0; 0; 0	0; 0; 0	0; 0, PO					
	Sterlington	Avg	0	0	0	0	0					
		Total	0	0	0	0	0					
Pete		L&C MW	0; 0	0; 0	0; 0	0; 0	0, 0					
	Perryville	Avg	74,845	0	0	0	0	74,845	82,798			149,690
		Total	149,690	0	0	0	0					
Brad		L&C MW	480	PO	PO	PO	PO					
	Ninemile	Avg	120,680	145,937	126,430	152,458	132,940	138,566	175,731	113,554	31,526	3,879,841
		Total	241,359	1,021,573	885,027	1,067,221	664,708					
Pete		L&C MW	0, 0, 128; 500; 750	0, 0, 128, 500, 750	0, 0, 128, 500, 750	0, 0, 128; 500, 750	0, 0, 128; 500, 750					
	Waterford 1 & 2	Avg Gas	0	0	21,561	19,322	0	0	31,854	0	133,538	0
		Total	0	0	107,804	57,966	0					
Pete		L&C MW	0; 0	0; 0	0; 411	0, 411	0; 0					

Results: Fuel Volumes (continued)

February 2013 Final MEP
FUEL SUMMARY

Pete

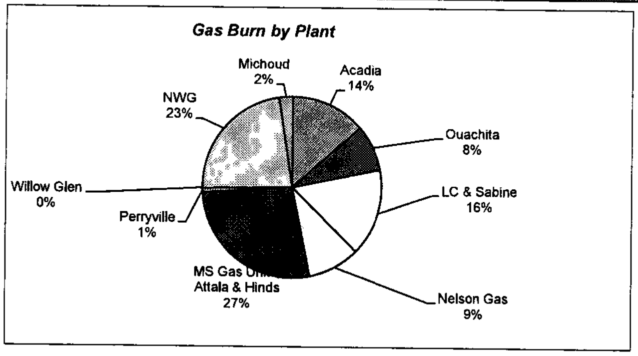
Plant Name		02/01/13	02/03/13	02/10/13	02/17/13	02/24/13	Daily Average	Max Day	Min Day	Hourly Max (Day Rate)	Total Burn
Little Gypsy	Avg	12,669	20,329	14,461	20,579	14,203	17,283	27,807	11,878	111,125	483,923
	Total	25,337	142,300	101,224	144,050	71,013					
	L&C MW	0; 415, 0	PO; 415, 0	PO, 415; 0	PO; 415; 0	PO, 415; 0					
NM/WF/LG	Avg Gas	133,348	166,266	162,452	192,359	147,143	155,849	235,392	125,431	276,190	4,363,764
	Total	266,696	1,163,873	1,094,055	1,269,237	735,721					Gas Only

Oil

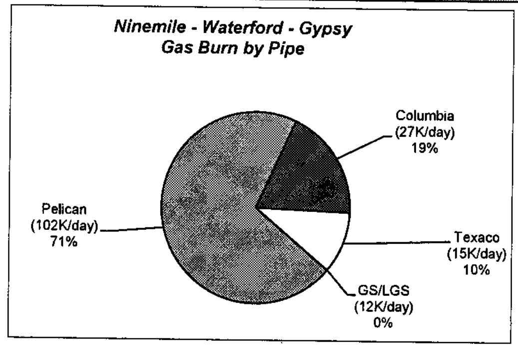
Dave

Average (MMBtu/day) for days burned		02/01/13	02/03/13	02/10/13	02/17/13	02/24/13	Tot MMBtu	Tot Barrels of Oil
Gerald Andrus	Fuel	0	0	0	0	0	0	0
0%	L&C MW	0	0	660	660	0		
B. Wilson	Fuel	0	0	0	0	0	0	0
0%;0%	L&C MW	PO; 0	PO; 0	PO, 545	PO; 545	PO, 0		
Michoud 3	Fuel	0	0	0	0	0	0	0
0%	L&C MW	PO	PO	PO	PO	PO		
Ninemile 2, 4, & 5	Fuel	0	0	0	0	0	0	0
#REF!	L&C MW	0; 500, 750	0; 500, 750	0, 500; 750	0; 500, 750	0; 500; 750		
Little Gypsy 2	Fuel	0	0	0	0	0	0	0
0%	L&C MW	415	415	415	415	415		
Delta 1 & 2	Fuel	0	0	0	0	0	0	0
0%; 0%	L&C MW	0; 0	0; 0	0; 0	0, 0	0; 0		
Sterlington 7	Fuel	0	0	0	0	0	0	0
0%	L&C MW	0	0	0	0	0		
Willow Glen 2,4,5	Fuel	0	0	0	0	0	0	0
0%;00%;00%	L&C MW	0; 0; 0; 0	0, 0; 0; 0	0; 100; 0; 0	0, 0, 0, 0	0; 100; 0; 0		
Waterford 1 & 2	Fuel	0	0	0	0	0	0	0
0%; 0%	L&C MW	0; 0	0; 0	0; 411	0; 411	0, 0		
						TOTALS:	0	0

February 2013 Final MEP
Key Fuel Burn Breakdowns



Plant	Gas Total MBtu	%
Acadia	2,593,883	14%
Ouachita	1,582,461	8%
LC & Sabine	2,996,742	16%
Nelson Gas	1,796,926	9%
MS Gas Units, Attala & Hinds	5,221,349	27%
Perryville	149,690	1%
Willow Glen	-	
NWG	4,363,764	23%
Michoud	470,627	2%
Total Gas Burn MEP	**19,175,442**	100%

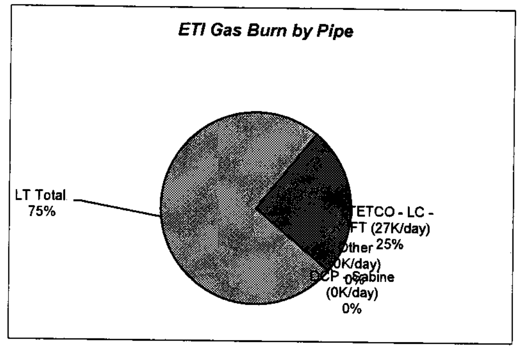


	NWG Gas	*February*	Total MBtu	
LT:	Pelican (102K/day)		2,856,000	70.8%
LT:	Columbia (27K/day)		756,000	18.7%
		Subtotal:	**3,612,000**	89.6%
Spot:	Texaco (15K/day)		420,000	10.4%
Other:	GS/LGS (12K/day)		12	0.0%
		Total:	**4,032,012**	100.0%

Long Term Gas (flow vs yearly min)

ELI	Evangeline			
Yearly Min	36,750,000			
			% of Min	
2013	Total MMBtu	MMBtu/day	100.00%	
1st Qtr	8,580,078	95,334	23.35%	estimate
2nd Qtr	10,000,000	111,111	27.21%	estimate
3rd Qtr	12,265,000	136,278	33.37%	estimate
4th Qtr	5,904,922	64,184	16.07%	**plug**
Total	36,750,000		100.00%	

ETI	Embridge			
Yearly Min	27,375,000			
			% of Min	
2013	Total MMBtu	MMBtu/day	100.00%	
Dec 2011 - Feb 2012	6,344,431	70,494	23.18%	estimate
Mar 2012 - May 2012	6,505,583	71,490	23.76%	estimate
Jun 2012 - Aug 2012	6,440,000	70,000	23.53%	estimate
Sep 2012 - Nov 2012	8,084,986	87,880	29.53%	**plug**
Total	27,375,000		100.00%	



	Entergy Texas Gas	*February*	Total MBtu	
LT:	Enbridge-Sabine (70K/day)		1,960,000	65%
LT:	Enbridge-LC (10K/day)		280,000	9%
		LT Total:	**2,240,000**	75%
Spot:	TETCO - LC - FT (27K/day)		756,000	25%
	DCP - Sabine (0K/day)		-	0%
	Other (0K/day)		-	0%
		Total:	**756,000**	25%
		Total Burn	**2,996,000**	100%