Audit of the Available Flowgate Capacity Process

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PERFORMED BY

Southwest Power Pool

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I. Executive Summary

A. Overview

Pursuant to Federal Energy Regulatory Commission ("FERC" or "Commission") Order No. 888, the Commission requires that transmission providers calculate and publicly post Available Transfer Capability ("ATC"). Although FERC established minimum requirements for ATC calculations and postings on a contract-path basis, it did not mandate a uniform methodology. Instead, each individual transmission owner has been allowed to file its own ATC methodology as Attachment C to its Open Access Transmission Tariff ("OATT" or "Tariff").

In 2002, some time after its initial institution of formal ATC calculations, Entergy began computing Generator Operator Limits ("GOL") to supplement its ATC calculations. Seeking an improvement over the ATC/GOL methodology, in 2003 Entergy introduced a flow-based process for ATC calculation, which was implemented on April 27, 2004.

After conditional approval and a series of FERC orders, Entergy compliance and informational filings, and various intervenor comments, FERC launched a Section 206 investigation into Entergy's implementation of its Available Flowgate Capacity ("AFC") program to determine whether Entergy has complied with prior AFC-related orders; whether Entergy's provision of transmission system accessibility is just, reasonable and not unduly discriminatory; and whether quality control issues may exist with Entergy's AFC methodology.

Since March 22, 2005, FERC has held the AFC hearing in abeyance pending the outcome of the Independent Coordinator of Transmission ("ICT") proposal developed by Entergy.

Entergy requested that Southwest Power Pool (SPP), as the proposed Entergy ICT, conduct an audit of the implementation of Entergy's AFC process. This report is presented as a response to that request.

B. OBJECTIVE

SPP's objective was to evaluate Entergy's implementation of its AFC process and to make findings and recommendations as needed. The AFC process is used to calculate available transfer capability and evaluate transmission service requests under the Entergy OATT.

C. METHODOLOGY

SPP used the following methodology to perform a process audit on Entergy's implementation of its AFC process:

- Research prior FERC orders and regulations for comparison with Entergy's current AFC processes.
- Perform tests of data inputs and model parameters on benchmark models.
- Compare data inputs to benchmark models or other appropriate models.

D. Findings and Recommendations

Findings and recommendations have been reported at the end of each section in Part IV., Audit Findings. SPP has made ten recommendations. Appendix 1 contains a summary of recommendations and also lists the specific section of the report where each recommendation was provided.

II. Procedural Background

On April 24, 1996, FERC issued Order 888, which required, *inter alia*, that all transmission providers calculate and publicly post ATC values.[1] This order opened the electric transmission system to wholesale competition and allowed customers to reserve transmission service based on the ATC calculations. Accordingly, transmission providers must evaluate new requests for short-term transmission service using these ATC calculations. If sufficient ATC is available, the transmission service request ("TSR") must be approved. However, if sufficient ATC is unavailable, the TSR must be denied. Any denial is subject to the transmission customer's right to request a system impact study, which includes an evaluation of any transmission system upgrades necessary to increase system capacity in accommodation of the request.

[1] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order 888-B, 81 FERC ¶ 61,248 (1997).

Although Order No. 888 established minimum requirements for calculating and posting ATC, FERC did not require a uniform process for performing ATC calculations. Rather, FERC allowed all transmission providers to file individual methodologies for calculating ATC. This allowed transmission providers to account for regional differences in calculating the amount of capacity that was available.

Shortly after Order 888 was issued, Entergy began calculating ATC to measure the transfer capability. Then, in 2002, Entergy implemented a system of calculating GOL to make transmission capacity decisions. Finally, on August 29, 2003, Entergy filed revisions to its OATT to implement a flow-based methodology for the determination of transmission capacity.[2]

On February 11, 2004, FERC granted conditional approval of Entergy's proposal, and the AFC methodology was made effective on April 27, 2004.[3] FERC conditioned its approval on numerous modifications to Entergy's proposal, including greater specificity of the criteria, methods and process used in the AFC process;[4] a requirement to make certain information publicly available; and other requirements to clearly define language in the Entergy OATT. Entergy made a compliance filing on March 12, 2004 and then made an additional informational filing on March 19, 2004 to conform to the

[2] *Entergy Services Inc*., 109 FERC ¶ 61,281 (2004).

[3] *Entergy Services, Inc*., 106 FERC ¶ 61,115 (2004) (February 11 Order).

[4] The Commission listed five items in particular: (1) the specific criteria used to identify the flowgates that Entergy will monitor, (2) the criteria and procedures for adding or de-listing flowgates, (3) the method for evaluating the percentage of counterflows to use in the powerflow model, (4) the response factor threshold and the criteria for modifications to the threshold, and (5) the bases for transmission line ratings. *Id*.

requirements issued by FERC. A major aspect of these compliance filings was the preparation and publication of an AFC process manual. The AFC manual provided a detailed description of the AFC process, the operating and reliability assumptions underlying the AFC calculations, and any remaining business practices that were not required in the tariff sheet revisions

On July 12, 2004, FERC issued an order on Entergy's March 12th Compliance filing.[5] The order required that Entergy provide additional information regarding the AFC process and further revisions to Attachment C of its OATT. Specifically, the July 12th Order required several substantive changes to the OATT Attachment C and the AFC Process Manual. The order also required Entergy to clarify some of the language used in Attachment C and requested further information on various computational issues. On August 13, 2004, Entergy made its second compliance filing.

On December 17, 2004, the Commission instituted hearing procedures under Section 206 of the Federal Power Act ("FPA")[6] to investigate "Entergy's implementation of the AFC program, whether Entergy has complied with the Commission's prior orders on AFC matters, and whether Entergy's provision of access to its transmission system is just, reasonable and not unduly discriminatory."[7] The second compliance filing was accepted by the Commission on December 17, 2004 and was made subject to the outcome of the AFC hearing.

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[5] *Entergy Services, Inc*., 108 FERC ¶ 61,046 (2004) (July 12 Order).

[6] 16 U.S.C. § 824e (2000).

[7] *Entergy Services Inc.*, 109 FERC ¶ 61,281 (2004).

Finally, on March 22, 2005, FERC ordered that the AFC hearing be held in abeyance pending Entergy's response to the Entergy ICT proposal in Docket No. EL05-52.[8] During the interim, Entergy has held numerous stakeholder meetings and has proposed to have SPP, as the Entergy ICT, conduct an audit of its AFC process.

III. Methodology

On August 17, 2005, SPP committed, in its function as the Entergy ICT, to perform a process audit on Entergy's implementation of its AFC process. Through several meetings with Entergy and its stakeholders, SPP developed the scope of the process audit. SPP publicly posted the audit scope on Entergy's OASIS website (http://oasis.e-terrasolutions.com/OASIS/EES/) and the SPP-hosted Documentum eRoom.[9] An email distribution list of AFC Audit Stakeholders is maintained by SPP, and the official audit scope was also distributed through this means. SPP then began gathering all filings, documents and any data from Entergy related to the development and implementation of the current AFC process. This information was assimilated and scrutinized by SPP for use in the audit and then compared to the requirements mandated by FERC. SPP also completed a limited technical review of the data used in Entergy's planning models and AFC processes to confirm that Entergy is following the processes outlined in its filings.

[8] 110 FERC ¶ 61,295 (2005).

[9] *See* Exhibit 1.

All tests of data inputs and model parameters have been performed on two benchmark models for peak hourly and monthly load for Summer 2005, the peak hourly model from July 25, 2005 (1:17 a.m. resynchronization) and the August 2005 monthly model (posted July 29, 2005). It is important to note that the hourly model is an Energy Management System (EMS) model, while the monthly model is a power flow model. As timestamp issues were provided to SPP, they were evaluated based upon the stakeholder weighted prioritization of issues. The respective data inputs to the AFC process were first compared to the two benchmark models and then to respective data inputs for the appropriate model in which the issue existed.

IV. Audit Findings

A. Software Comparison

a. Background and Analysis

As an initial task of the audit, SPP identified and documented all instances where Response Factor Calculation software ("RFCalc") or OASIS Automation software ("OA") differ from 'off-the-shelf' versions, including macros, modules, or other software created or modified for Entergy's use in the AFC process. Entergy provided the requisite data, as well as detailed descriptions of any modifications of the software.

b. Findings

Entergy uses customized versions of two AREVA software packages, RFCalc and OA. The changes to Entergy's RFCalc are listed below.

- Entergy's version generates response factors on a source-specific basis rather than a control-area-to-control-area basis.
- Proxy flowgates limit transmission service sales at generators to PMax. Proxy flowgates limit transmission service sales across interfaces to interface limit.
- All positive and negative impacts are considered in power flow calculations (i.e. no transmission distribution factor cutoff is applied at this point in the calculation process), and all negative impacts (or counterflows) are summed to determine the total counterflow.
- Generator-specific participation factors entered through the unit commitment input file allow for the accounting of zonal import limits.
- A special feature allows a zeroing out of disconnected sources.
- Entergy's RFCalc also contains enhanced model and data posting options, which provide for daily posting of four random hourly models and one peak hour model.

Entergy's OA also differs from the 'off-the-shelf' version. These differences are listed below.

- Through feedback received from Entergy's AFC stakeholder process, the desire for a second Scenario Analyzer was recognized and implemented in their version of OA. This Scenario Analyzer displays all limiting flowgates and polls only confirmed transmission service. Redirected transmission service for network resources can be processed by this customized version of OA.

- In instances where an outage of OA or OASIS prevents a request entered prior to the noon deadline from being acted on until after noon, the ATC calculator has been modified to calculate firm AFC numbers in the Operating Horizon.
- Effective ATC values are calculated on a five-minute interval and uploaded to the http://www.entergy.com/transmission website, allowing for a multiple path view in lieu of a single path view given in the scenario analyzer.
- The transmission request processor user interface (TRPUI) filter lock has been modified to allow the customization of more parameters shown on the user interface rather than simply the time parameter. Service type validation checks against Point of Receipt (POR), Point of Delivery (POD), source, sink, and customer have also been added.
- The data export capability that produces .csv files was modified to allow embedded commas in the reservation comment field.
- A notification popup alerts the user when the communication link between the client and the host, known as the repeater, fails.
- Other variations from the 'off-the-shelf' version of OA include access to resynchronization times on the TRPUI and cancellation of updating and posting AFC values for the current hour.

c. Conclusions and Recommendations

As a function of this audit, SPP finds that all of the Entergy changes to the 'off-the-shelf' version of RFCalc and OA were warranted and serve to increase transparency,

aid customer service and add improved functionality to these software packages. A separate recommendation concerning RFCalc is presented in Section IV.I.(5)(a).

B. DATA SELECTION AND USE

1. Network Customer Data and the Effect of Network Customer Decisions

a. Background and Analysis

In the February 11, 2005 Order, the Commission requested that Entergy describe any operating reliability assumptions that influence its modeling, including any transmission margins assumed in AFC power flow cases and any other relevant information. FERC also required that Entergy clearly state how it selected numerous types of data, including: the specific criteria used to identify the flowgates that Entergy will monitor, the method for evaluating the percentage of counterflows to use in the power flow model, the response factor threshold and the criteria for modifications to the threshold, and the bases for transmission line ratings. Entergy responded in its March 12th compliance filing by stating that the AFC Process Manual includes a description of the AFC process, the operating and reliability assumptions underlying the AFC calculations, and any remaining business practices that Entergy uses in its AFC analysis. Entergy also revised its OATT to include many of the requested specifications in Attachment C of the Tariff.

In the July 12, 2005 Order, FERC directed Entergy to further revise its tariff to clearly indicate the criteria and associated numerical values used to identify relevant flowgates and to select or de-list flowgates. Entergy responded in its August 13th compliance filing by issuing revised tariff sheets that included the numerical values and

by updating the AFC process manual. The criteria for flowgates and transmissions facilities are presented in Section 2 of the AFC Process Manual, Revised October 31, 2005. Section 3 of Attachment C also describes the criteria and numerical values used.

SPP used the July 22 FERC Order and Entergy's subsequent compliance filing to gauge Entergy's compliance with FERC's mandates regarding flowgate identification and removal. Furthermore, in order to validate that Entergy conformed to stated FERC positions on the issue of data selection and use, SPP researched FERC policy and precedent to gain a clear understanding of the requirements for implementation of an AFC process. SPP then thoroughly examined Entergy's Attachment C, the AFC Process Manual and various compliance filings to gauge Entergy's compliance with FERC standards.

To further verify Entergy's compliance, data inputs to the model development process (EMS and power flow) were checked against the benchmark models for each specific type. The inputs included: transmission facility outages, generation outages, unit commitment, generation dispatch, projected load levels, and transaction data. Special inputs to the EMS models for the Operating Horizon (12-36 hours, depending on proximity to noon) include all firm schedules and all accepted, confirmed and counteroffer non-firm reservations. The data is received from various sources feeding into the Entergy AFC process such as Transmission Automated Outage Request System ("TAORS") for transmission outages, Entergy Energy Management Organization ("EMO") inputs for unit commitment and dispatch, network resources from other network customers, purchase and sales transactions from OASIS, and net interchange schedules from the scheduling system.

With regard to data provided to Entergy by network customers, the provision of unit commitment data (or Designated Network Resource [DNR] levels) is submitted through OASIS transmission service requests. New requests are entered with a designation that the unit is a new DNR or an increase in the designation of an existing DNR. Existing requests are recalled in order to reduce a designation or to de-list a DNR. As stated in Section 5.8.1.2 of Entergy's Response to Staff Question 2-1 in Docket No. EL05-22, other factors affecting the generation dispatch can include unplanned unit outages and unplanned de-rating of transmission facilities, Qualified Facility puts, load forecasting, and short-term purchases by network customers.

The primary assumptions made by Entergy when modeling in the Operating and Planning Horizon involve generation outages, load, net area interchange, transactions, and unit dispatch.

Three basic assumptions made for generation outages are that all network resource oil and gas generators are modeled in service if they are not on planned maintenance, emergency or long term outage; network resource generators other than oil and gas are modeled in service if the dispatch for the generator in unit commitment file is non-zero; and all merchant facilities, Independent Power Producers and Qualifying Facilities (IPP and QF), are always modeled in service.

For the purpose of modeling load, Entergy considers system load for hourly models to be the hourly integrated value for each hour supplied by EMO. Entergy system load for daily models is the peak load for the day derived from EMO monthly energy plans. Load forecasts for Tennessee Valley Authority (TVA) are received from TVA via

a data exchange format called SDX. Load forecasts for other companies surrounding Entergy including AECI, CSWS, AMRN, EDE, LAFA, SPA, OKGE, LAGN and LEPA[10] are obtained from SPP via FTP site. These load forecasts are scaled to match the equivalent model while maintaining the shape of load curve. Load forecasts for CLECO are received from CLECO and are used without scaling. Load forecasts for external areas other than those listed above are derived by using a scaling factor.

When calculating Net Area Interchange, Entergy makes assumptions for internal and external control areas. For the Entergy control area, where all transactions of the control area known, net area interchange is calculated by summing up all transactions crossing control area boundaries. For external control areas where the transactions of control with Entergy are available, net area interchange is computed using real time net interchange and transactions with Entergy

Entergy uses transactions assumptions in its Operating and Planning Horizons. In the Operating Horizon models, all firm schedules and all accepted, confirmed and counteroffer non-firm reservations are modeled. In the Planning Horizon models all firm and non-firm reservations with status of accepted, confirmed or counteroffer are modeled. Schedules are not included in the Planning Horizon because during these hours and days schedules are not available for use in power flow models. In this case reservations are used in place of the schedules. Certain reservations are excluded from the models through use of an exclude file. Reservations that are in the queue for a System Impact Study or Facility Study are excluded to keep them from withholding

[10] A NERC Control Area acronym list can be obtained at http://www.nerc.com/~filez/ctrlarealist.htm.

capacity in the short term market. Once a reservation's status changes to a final state (confirmed, refused, withdrawn, etc), it is removed from the exclude file. Network reservations that represent the native load-owned resources are excluded because they are handled in the unit commitment file. Subsystem files for hourly models only include units that are online and have an assigned participation factor. Therefore, these units are the only participants in the transfer because RFCalc specifically uses units that are online in the calculation of response factors.

A major assumption for transmission outages is that all planned and unplanned transmission outages with voltage level 115 kV or more are included in AFC operating and planning models. All outages of bus breakers and power transformers are manually inserted into the models.

Hourly dispatch for day 1 to day 7 for all network resource units is provided by EMO. The dispatch is updated at least once daily. Dispatch for day 7 to 31 (daily peak cases) is generated from monthly energy plans supplied by EMO. Daily and hourly dispatch for network resources is capped to Network Resource Designation (NRD) for the plant. Dispatch and PMin of units in Amite South and WOTAB[11] is adjusted to meet the import limit requirements. In the power flow models, OASIS reservations and schedules are modeled on top of base dispatch. This becomes the start point (base point) of power flow solution. Dispatch of oil and gas network resources can be adjusted by RFCalc to meet the load and net interchange requirement. The adjustment is

[11] Both Amite South and WOTAB (West of the Atchafalaya Basin) are sub-areas with the Entergy Control Area.

accomplished using reserve-based participation factors. IPPs and QFs are dispatched to the level of the reservations and schedules that are active from that facility.

Entergy's monthly modeling assumptions are discussed and summarized below, as necessary to fully understand Entergy's Study Horizon modeling process. This summary includes assumptions made by Entergy for dispatch, line outages, load, imports, transactions, and unit commitment.

When constructing its monthly models, Entergy makes the following dispatch assumptions: IPP units in the Study Horizon models are dispatched to the level of the reservations that are active for that facility; QF/cogeneration units are dispatched to the level of the load at the facility in order for the QF to serve the host load entirely; and if there are any reservations from the units, they are added to the units dispatch level. In the absence of any OASIS reservations, the net injection from the QF into the Entergy system is zero MWs. Network resource units are dispatched economically using the ECDI function of PSS/E to create a least-cost dispatch for each case. Occasionally, the case is dispatched by zones, rather than by area, to enforce zonal import limits. For this instance, an IDEV file that recreates the dispatch is saved.

The following assumptions pertaining to line outages are made by Entergy when developing its monthly models. All 500kV lines that are scheduled out of service for one day are modeled out of service for the entire month and all 115kV – 230kV lines that are scheduled out of service for at least five days are modeled out of service for the entire month. Multiple lines will be scheduled out of service when the outages overlap or when non-overlapping outages have no impact on one another. Critical lines that may not be

out of service for the required time frame, but should be modeled out of service to better reflect the system conditions for the month may also be modeled out of service. Line outages in models are updated at least once a month and posted on OASIS. Typically OASIS Study horizon model posting are updated once a week with new creation times, but newly retrieved line outages information is not typically included in this update.

Load assumptions are made and used by Entergy when developing monthly models. Entergy's load for each month is the peak value forecasted by EMO for the month. Cogeneration, industrial, and auxiliary load is assumed to be constant for every month. LAGN, SMEPA, ETEC, MDEA, SRMPA, and TVA[12] embedded loads are added to the case based on either a load forecast, or monthly factors of the peak value. DENL's load is scaled for each month based on load forecast. CLECO, LAGN, and DERS loads in the non-peak models for each season are scaled by a factor. The LAFA load is modeled based on the load forecast data for each month.

The only assumption made by Entergy on an import in monthly models is for the Amite South. The Amite South import is held to a value of approximately 2000 MW.

Transaction assumption made by Entergy for monthly models specifies that all monthly transactions are modeled in the appropriate month. Transactions which serve embedded loads, such as LAGN, SMEPA, ETEC, SRMPA, TVA, MDEA, will match the value of the embedded load for the month. Transactions between CLECO and LAFA are adjusted so that the Bonin generator only generates 1 MW. Transactions which serve DENL match the load in DENL minus 20 MW of their own generation. Transactions

[12] *See infra* n. 10 for a list of acronyms.

which serve DERS match the load in the control area. Long term firm contracts are assumed to expire if not renewed 60 days prior to the end date of the contract. If the date of the monthly model creation is greater than 60 days before the end of the contract, rollover rights are assumed. If the date of the monthly model creation is within 60 days of the transaction end date, and a renewal has not been confirmed, the transaction is removed from the models representing the months after the end date of the contract. Transaction data and all other topology in models are updated and posted on OASIS at least once a month. Transaction data is typically updated weekly in models and this is the reason posting dates on OASIS typically change weekly for Study Horizon models.

The assumptions made for unit commitment are related to the line outage assumptions. All units that are offline for at least two weeks are assumed to be out of service for the entire month. An exception to the previous statement is that if two units in the same region are out of service in non-overlapping times during the month, only one unit is modeled offline. IPP units that have reservations are placed on-line, but if the facility has multiple units at one station, only the units that are required to meet the level of reservations are set on-line. On a more individual base, CLECO unit outages follow the same principle as the Entergy unit outages. Sterlington 7, Paterson 3 & 4, Moses, Lynch, Monroe, Mablevale, Ritchie, and Lake Catherine 1, 2, & 3 units are modeled out of service at all times if there is already a sufficient amount of generation, because these units do not normally run. The Natchez unit is also modeled offline because it usually does not run and because the unit has been de-staffed.

b. Findings

Transaction data and generation dispatch in both benchmark models have been evaluated. SPP was only able to verify the hourly generation dispatch data for the base load units. SPP was unable to verify the hourly generation dispatch for oil and gas units because the data received from Entergy is an unsolved starting point for the power flow model. These values will change once they are input into the model and RFCalc reaches a solution.

The formula for determining the amount of generation in the base case is only used for IPPs/QF and base loaded units of Entergy. The value is calculated by adding the MW of base case to the MW of transmission reserved to the MW of transmission scheduled. Unlike oil and gas units in Entergy, IPP/QF and base load units are not on Automatic Generation Control (AGC). Therefore, IPP/QF output remains fixed, while all oil and gas units in Entergy can move during power flow solution to balance the system (Load + Net Interchange + Losses = Generation). All other data inputs matched the respective models. An evaluation of a sample of transmission service requests (TSRs) processed by the benchmark models has occurred and is reported in Section IV.B.(2) of this report.

The following describes the software logic currently in place for committing and dispatching units in the AFC process as well as the logic in place for handling changes in unit commitment or dispatch. The software logic is described in two parts; one for the Operating and Planning Horizon models and the other for the Study Horizon models.

i. Operating and Planning Horizon Models

The generation dispatch in the EMS models is, for the most part, a manual process with limited software logic. The hourly dispatch for day 1 to day 7 for all network resource units is provided by EMO and is updated at least once daily. The dispatch for day 7 to 31 (daily peak cases) is generated from monthly energy plans supplied by EMO. OASIS reservations and schedules are modeled on top of base dispatch and this becomes the start point of the power flow solution. The software logic involved in the power flow solution is such that the dispatch of oil and gas network resources can be adjusted by RFCalc to meet the load and net interchange requirements. The adjustment is performed using reserve based participation factors.

ii. Study Horizon Models

There are three separate types of units modeled in the monthly loadflow models (Study Horizon) and the unit commitment and dispatch process varies with each type of unit. The three unit types are IPP units, cogeneration units, and network resource units (all other units). The IPP units are dispatched to the level of the reservations that are active for that facility. Cogeneration units are dispatched to the level of the load at the facility so that the host load is served entirely by the cogeneration unit. If there are any reservations from the units, those are added to the dispatch level of the units. In the absence of any OASIS reservations, the net injection from the cogeneration unit into the Entergy system is zero MW. The third type of unit is the network resource unit, which utilizes some PSS/E software logic in determining dispatch levels. The network resource units are dispatched economically using the ECDI function of PSS/E. An ECDI file

containing heat rate and fuel cost information is passed to PSS/E and PSS/E sets the level of generation according to the economic information, so that the case achieves a least-cost dispatch.

c. Conclusions and Recommendations

From the in-depth review and comparison of Entergy's models, SPP concludes that network customer data is processed in accordance with the specific procedures identified in Entergy's Attachment C, the AFC Process Manual, various compliance filings, and a collection of assumptions detailed in this report. SPP recommends that all assumptions that provide an additional level of detail beyond those assumptions currently posted with the AFC models, be formally documented. Adding the assumptions to appropriate sections of the AFC Process Manual could be a preferred option. The AFC stakeholder process is considering Entergy's practice of modeling QFs; therefore, SPP is neither evaluating nor making recommendations concerning QFs, but rather allowing the AFC stakeholder process to handle this issue.

2. AFC Impact and TSR Logs

a. Background and Analysis

The AFC impact log indicates whether AFC is available for a transmission service request (TSR). A transmission service request is either manually granted (accepted or counteroffered) or denied based on the results recorded in the AFC impact log. SPP performed an evaluation of the accuracy of the AFC impact log and the resulting action taken for a transmission service request as recorded in the TSR log.

SPP randomly selected 150 TSRs and compared them to the corresponding AFC impact log from July 25, 2005; January 8, 2006; January 9, 2006; and January 10, 2006.

b. Findings

SPP's investigation produced one discrepancy concerning a TSR that was approved but did not have available AFC.

c. Conclusions and Recommendations

While the accuracy concerning Entergy's AFC impact logs and transmission service requests during the selected periods that were examined is very high, enhancements to the procedure are still recommended. It is also SPP's recommendation that the process be further automated to ensure the correct processing of every transmission service request.

C. DATA ADJUSTMENT PROCESS

a. Background and Analysis

In the February 11 Order, FERC mandated that Entergy indicate, with greater specificity, the criteria, methods and procedures it will use in its AFC process. In response, Entergy submitted a March 12th compliance filing, followed by a March 19th informational filing.

Consequently, documentation of the types of adjustments to data inputs or model parameters made by Entergy Transmission engineering is warranted. Therefore, SPP evaluated the process by which changes or adjustments to AFC data, models, outputs, and software are made by Entergy Transmission engineering.

AFC data is received from a variety of sources, including OASIS, customers, and internal and external control areas. Transmission facility outages, generation outages, unit commitment, generation dispatch, projected load levels, transaction data, and flowgate listings are included in the list of data inputs. Changes or adjustments to AFC data, models, outputs, and software may, at times, be required.

Regardless of why it may be requested, every change in the software, hardware, or data must be clearly defined and evaluated for cost, schedule, and system impact. In addition, all changes must be scheduled and approved by management before implementation in production. Entergy voluntarily follows Sarbanes-Oxley ("SOX") guidelines for EMS software changes.

For purposes of this discussion, a change is defined as any activity that impacts the production environment beyond the desktop. Changes are generally requested for one of three reasons: (1) a problem exists with regard to software, hardware, or data; (2) a system component needs to be changed as part of the routine operation of Information

Technology (IT) infrastructure;[13] or (3) improvements are to be made as part of an IT project. [14]

Maintenance of database models within the EMS software purchased by Entergy from AREVA has been delegated to the EMS Database (EMS DB) Team. The following databases are of primary importance: Supervisory Control and Data Acquisition (SCADA), Network, Generation, Alarm, Open Access Gateway (OAG), Mapboard, and Contingency. Entergy's weekly EMS change process is summarized sequentially below.

First, change requests are submitted to an EMS Database Team member. This may be accomplished by a variety of means, including: submission of a Help Request Management software (HRM) system change request ticket, Systems Operations Center (SOC) verbal or email request prior to the entry of an HRM ticket, Transmission Operation Center (TOC) direct communication of a change request, SOC discovery of a TOC change via a model comparison program, EMS DB analyst detection of new and/or changed devices per revised company one-line diagrams, and field personnel submission of substation changes.

Next, an EMS DB analyst completes a Database Change Request (DBCR) and emails it to two analysts responsible for request management. Assignment of the request is made to each model's analyst for completion of the necessary changes. An installation

[13] This includes scheduled outages for backups and OS patches.

[14] An IT project is a scoped and planned initiative that may deliver enhancements to existing systems or the creation of entirely new IT solutions.

summary report lists each DBCR and its assigned "tasks." Analysts must initial and date all task completion and quality assurance (QA) activities.

The SOC endeavors to implement only one update per week, with a noon deadline two days prior to implementation. Typically, DBCRs are issued beginning on Wednesday afternoon for installations the following Wednesday morning, and by mid-day Tuesday the models have already been installed on the development server, TSDS.

At this point, analysts perform a QA check and make the necessary pre-installation corrections. An Excel report summarizing DBCRs that are to be implemented on a given date is prepared and distributed to SOC Operations, where the report is reviewed and approved before installation of the database changes.

Entergy's EMS system operates on a pair of UNIX servers, TSEMSA and TSEMSB. The revised models are loaded onto the off-line server and then "failed over" to bring the revised models on-line. After the completion of QA checks to ensure that bugs are not introduced into the "new" models, the "new" database is accepted and the revised models are loaded onto the off-line server.

b. Findings

AFC data modifications, such as flowgate rating increases due to topology changes or the development of a temporary flowgate due to the planned outage of the monitored element of an existing flowgate, are tracked using Help Request Management software (HRM), and change tickets for adjustments are archived.

On July 17, 2005, Entergy began using Remedy software as its change management system for EMS models. Transition from HRM to Remedy is currently underway, with transition essentially complete for Change Requests. However, some changes, such as Service Requests, will continue to be entered via HRM during this interim period. Although no definite schedules have been completed, Entergy expects full transition to Remedy in 2006.

Several HRM tickets for Service Requests were reviewed at random to confirm that this process is correctly used for AFC data modification. One ticket was not correctly modeled in the corresponding models. This HRM ticket requested the outage of several generation units in the AFC model for various times. However, some of the generators remained in the models for both the Operating and Planning Horizons and the Study Horizon during part of their scheduled outage times.

Concerning output integrity, SPP found no instances in which model outputs are adjusted. As described above, inputs to processes that generate AFC outputs may be changed according to the specific procedures that have been developed by Entergy.

c. Conclusions and Recommendations

In a specific instance, the existing use of HRM failed to generate outages in the model. Therefore, SPP recommends enhancement of this quality control process. One possible enhancement may tie the HRM ticket more closely to the model update process through a higher level of automation.

D. MODEL PARAMETERS

1. Parameter Selection

a. Background and Analysis

In keeping with FERC's directives, SPP determined that an evaluation of the accuracy of model parameters used in AFC models, including flowgates, participation factors, response factors, and counterflows, was warranted.

The accuracy of results depends upon the accuracy of the process and process inputs and parameters. Inputs were previously discussed. Model parameters, such as flowgates, participation factors, response factors on those flowgates, and transaction counterflows, are selected based upon criteria defined above in Section IV.C. of this report.

Entergy's commitment to modify the response factor cutoff is set forth in Section 5.5 of its AFC Process Manual. In the event that operating conditions call for a reevaluation of the current response factor threshold, Entergy will reevaluate and revise the threshold as needed. All changes will be filed with FERC.

b. Findings

Section 2.2 of the AFC Process Manual documents three processes for addition of a flowgate and four steps for flowgate removal. The flowgate change process is discussed in IV.D.(3) of this report. This process is not verifiable because, although Entergy maintains a revision log that shows changes to the flowgate list, Entergy does not use

HRM or Remedy to show how the change process occurred. Separately, a comparison of the appropriate revision of the flowgate list to the monthly benchmark model demonstrated a discrepancy between the flowgate list and the monitor file used in determining their AFC values. The August 2005 monthly benchmark model and its corresponding flowgate monitor file were reviewed to ensure that all flowgates specified to be monitored were in fact being monitored within the model when performing AFC calculations. It was determined that thirteen flowgates were not being monitored as a result of a monitor file that did not properly match the loadflow model data. The monitor file designates a "from" bus number and a "to" bus number to designate a line to monitor. When the "from" and "to" bus numbers specify a line that is not in the loadflow model, the end result is that the flowgate that was intended to get monitored does not. This is most likely a result of the model bus numbers changing and the monitor file not being updated to incorporate these changes.

Participation factors were a topic of discussion at early AFC stakeholder meetings. A criterion was settled at the August 17, 2005 stakeholder meeting to bring conclusion to this particular issue. There was no need to review this participation factor list in comparison to the benchmark models because the models were developed before the new criterion.

Section 4.4 of the AFC Process Manual states that counterflows are to be included in all three horizons. Additionally, 100% of counterflows due to firm schedules are included in the Operating Horizon. The review of the transaction counterflows in comparison to those included in the benchmark models is complete, and all counterflows were included in the benchmark models.

According to Section 5.4 of the AFC Process Manual, Entergy only considers Response factors at or above a 3% threshold when determining whether to approve a transmission service request. Thus, if the response factor for a particular flow gate is less than 3%, the AFC process will not consider that flow gate in its determination of whether transmission service should be granted. The benchmark models, as well as other sample models, were evaluated to ensure that all response factors were at or above the 3% threshold.

c. Conclusions and Recommendations

SPP concludes that participation factors, response factors, and counterflows are processed by Entergy according to documented practices. Concerning the flowgate change process, SPP recommends enhancing current quality control processes to include flowgate revisions. Three possible options are as follows: implementing a process that automatically updates the flowgate monitor file each time the loadflow bus numbers change; developing the monitor file using bus names, as opposed to bus numbers, if the bus names remain static and, thereby, eliminating the need to continue updating the monitor file each time the loadflow model changes; or coinciding with the Section IV.C. recommendation, submitting these changes for approval and tracking through HRM and Remedy.

2. Uniform Application of the Process and Audit Trail

a. Background and Analysis

SPP also evaluated and documented Entergy's processes for ensuring uniform application of criteria to the entire system and for creating auditable trails for any variances from the criteria.

b. Findings

"Inputs" and "outputs" are synonymous in many instances because software algorithms calculate outputs that are used as inputs to future process steps. According to the AFC Process Flowchart in Section 1.3 of the AFC Process Manual, the majority of inputs to the Operating and Planning Horizon calculation engines are the same. Accordingly, the software engines themselves (RFCalc and RFLOADER) have responsibility for both horizons. Inputs to the Study Horizon come from many of the same sources also, although the PowerGEM AFC/ATC (PAAC) Offline Calculator does not share responsibility with any other horizon.

In verifying whether these inputs are uniformly applied to the entire system, SPP found an instance of variation between the inputs of the Operating and Planning Horizon models and the Study Horizon models. The issue involved the mislabeling of a flowgate. Evaluation of a recent model shows that the change has yet to occur in the Operating and Planning Horizon models, though the AFC flowgate list used for all horizons has been updated. This issue is discussed further in Section I.(1).

c. Conclusions and Recommendations

SPP concludes that existing quality control procedures of entering HRM tickets did not prevent the occurrence of model input variation and recommends enhancements to this QC process. As previously stated, SPP recommends that Entergy include an automated link between HRM and manual entry of changes in the model.

E. OASIS POSTING PRACTICES

a. Background and Analysis

In the February 11 Order, FERC requested that Entergy post certain other data and models on Entergy's OASIS so that transmission customers and other interested parties could verify the AFC results computed by Entergy. More specifically, FERC asked Entergy to post engineering data and model assumptions, such as the list of identified flowgates and power flow cases and unit-specific supporting input files that can be downloaded for both the real-time AFC database and the longer–term planning monthly databases in a common text exchange power flow format. Entergy responded in its March 12th compliance filing by committing to post the models used in the AFC process so that transmission customers can reproduce the AFC results. These models include a daily peak model for each day from day 1 through day 31. Entergy also committed to post a monthly model for each month for 18 months. All models would be available for customers to download from OASIS in PSS/E RAWD format.

In the July 22 Order, the Commission requested that Entergy evaluate alternative ways to provide customers with information to assess the reasons for service denials,

including evaluation of an automated procedure. Entergy responded to this order in its August 13th compliance filing, stating that the development of an automated procedure for evaluating the complex interaction of the factors that result in approval or denial of transmission service was not possible prior to the AFC implementation date. However, Entergy committed to contact a third party vendor to inquire about the feasibility of developing software to convert EMS-based models into a format that can be used by transmission customers.

b. Findings

SPP verified that Entergy fulfilled their commitments regarding with posting practices. A few specific instances of postings with incorrect data are discussed in Section I.

c. Conclusions and Recommendations

As recommended in Section IV.B.(1), posting additional levels of detail to assumptions should prove useful and add greater transparency to the AFC process.

F. ARCHIVAL POLICIES

a. Background and Analysis

The procedures for preservation of monthly AFC data, hourly AFC data, and AFC impact logs are set forth below, as are the steps necessary for reproduction of Study Horizon AFC calculations.

Entergy produces hourly, daily and monthly power flow models of its transmission system by means of various data inputs discussed at length in Section IV.B. The AFC software generates a numeric value representing the amount of additional transfer capability available for specific flowgates under certain projected system conditions. The hourly AFC data[15], monthly AFC data[16], AFC impact logs[17] and any other relevant data are archived as zip files and stored on EMS servers, backup tapes and DVDs. According to Entergy's archival policies, the DVDs are marked for indefinite retention.

Although Entergy's Transmission Operational Planning group administers the AFC process, the Technology Delivery group (TDG)[18] archives the AFC data, and has done so since April 27, 2004. Initially, the TDG saved hourly AFC data by coding the AFC software and related applications to automatically "write" all hourly AFC data to a file system located on the locally-connected storage area network attached to Entergy's EMS servers at the System Operations Center in Pine Bluff, Arkansas. Additional copies of the hourly AFC data were then made by use of a commercial, robotic tape library and backup system. In early April 2005, Entergy's archival processes were disrupted when the backup process for saving all EMS operational data failed due to the accumulation of approximately 19,000 hourly AFC data-related files on the EMS servers. The TDG

[15] Hourly powerflow models, AFC values and data inputs

[16]Monthly power flow models, AFC values and data inputs

[17] The logs which track the evaluation of individual TSRs and the respective AFC values applied

[18] An organization with the Entergy Transmission Business Unit of Entergy which provides software and IT services for the Transmission Operational Planning group.

responded by restoring the normal backup process and designing a new archiving operation which would create two copies of the historic data on computer tapes; one copy being stored off-site and the other copy being stored within the robotic tape library. After duplication of the hourly AFC data, the data on the EMS servers is then deleted to free up storage space.

On April 18, 2005, the TDG attempted to archive the hourly AFC historical data for the period of April 27, 2004 through January 31, 2005. Unfortunately, however, the archiving attempt resulted in the "loss" of that period's hourly AFC historical data. Entergy is "conducting a top-to-bottom review of the archive and backup processes currently employed to maintain all transmission system operational data that will include review by an outside expert."[19] SPP, as auditor of the Entergy AFC Process, is not the 'outside expert' who will extensively review these processes. On October 31, 2005, Entergy filed a notice with FERC in Docket No. ER05-1065-000 regarding the incident

Section 9 of Entergy's Offline Study Horizon AFC Calculations and PowerGEM AFC/ATC (PAAC) Calculator Manual, Version 1.7, describes the archival procedure for monthly model data. Each time PAAC runs, an Access database entry is made. The Access database stores the following study information: performance date, start month, end month, name of the person conducting the study, comments and the AFCs' upload date. Study Horizon AFC study results are stored on the machine that ran the study, backed up to another file server and archived to DVD.

[19] *Entergy Services, Inc.*, Certified Statement of Douglas J. Mader at P 14.

b. Findings

Entergy states that it is compliant with these archival policies. The specific loss of the archived data is being handled in a separate FERC filing.

c. Conclusions and Recommendations

With the exception of the April 27, 2005 archival issue, SPP has determined that Entergy has sufficient archival procedures in place.

G. COORDINATION WITH OTHER REGIONS

a. Background and Analysis

Another important factor with respect to AFC calculation is the coordination of AFCs with entities outside Entergy's control area. Entergy has a history of coordination with SPP, TVA, SOCO and other large organizations connected to the Entergy system. However, with the development of the AFC process, the magnitude of effectual communication with these systems has increased. Section 10 of the AFC Process Manual and Section 7 of Attachment C to Entergy's OATT outline the general process for regional coordination concerning transfer capability.

The AFC Process Manual and Attachment C establish that Entergy endeavors to: coordinate transfer capability values with neighboring utilities in accordance with NERC & Regional Reliability Council criteria, continue to develop seasonal reliability models on a Regional Reliability Council basis, make source assumptions in order to coordinate

transfer capability values with neighboring transmission providers, coordinate reservation and schedule information with neighboring control areas where necessary, honor flowgate limits on neighboring transmission systems when constraints are experienced, consider the effects of system conditions and transmission service that has been sold by other transmission providers in order to produce credible constrained facility AFCs, and honor the constrained facility limits of other transmission providers to the extent that these transmission providers honor their own constrained facilities.

Entergy also states in Section 7 of Attachment C that it may exchange near-term planning information, reservations and schedules with other transmission providers so that the power flow models contain details for both their system and the other transmission providers' transmission systems and periodically exchange constrained facility AFC with other transmission providers.

d. Findings

Entergy currently exchanges AFC-related data with TVA, CLECO and SPP, and is working to include SOCO data and automate the data exchange process.

c. Conclusions and Recommendations

Though Entergy is receiving load forecast data from some neighboring entities and incorporating it into its models, neighboring entity data is often not updated as frequently as is received or developed for data for customers internal to the Entergy control area.

SPP recommends that this exchange of data with neighboring entities be enhanced through tighter and more frequent coordination with surrounding regions.

H. QUALITY CONTROL

a. Background and Analysis

Pursuant to comments filed by intervenors in the December 17 Order, FERC also agreed to investigate quality control issues that may exist with respect to Entergy's AFC methodology. SPP has reviewed Entergy's quality control policies for RFCalc, PAAC, as well as its EMS Test and Rollback Plans. A discussion of each follows. In Section IV.C., the use of HRM tickets is fully discussed.

Entergy transmission engineering maintains a written policy for its RFCalc quality control process. The policy dictates that RFCalc quality control checks be performed at specific times every weekday and after every EMS failover for the following items: unit commitment data, load forecast data, outage data, RFCalc power flow options, RFCalc options, and OA postings. Entergy also preserves daily logs of its RFCalc quality control checks.

Entergy transmission engineering also maintains a written policy for its PAAC quality control process. This quality control process for AFC calculations in the Study Horizon employs the output of various text files to ensure correct operation of the processes in place.

As for Entergy's EMS Test and Rollback Plans, the SOC EMS DB Team maintains the quality control procedures set forth below.

Entergy has an EMS Test Plan in place which directs that database loading is to occur one day in advance of a production install, when the PDS Server is available, so that modelers may check their work. Upon completion, modelers are required to initial a sign-off form.

Entergy's Rollback Plan dictates that EMS systems are to operate on dual servers, one in production and the other on standby. First, the standby server is loaded with the proposed database install. Then, a forced failover of the production server transfers the new database install to the standby server. The modelers verify a post-failover checklist within twenty minutes of installation and monitor the new database for approximately thirty minutes to an hour. If successful, the new standby server is updated with the new production database and verified. Otherwise, the system is failed back over to the previous production server to restore the last good production database.

As stated in Section IV.C., AFC data modifications, such as flowgate rating increases due to topology changes or the development of a temporary flowgate due to the planned outage of the monitored element of an existing flowgate, are tracked using HRM.

b. Findings

SPP verified that Entergy does preserve daily logs of its RFCalc quality control check. Due to the nature of the EMS test rollback plans, SPP did not perform checks for these quality control procedures. SPP finds that the PAAC quality control procedures, as

outlined in Section 6.0 of Entergy's Offline Study Horizon AFC Calculations PowerGEM AFC/ATC (PAAC) Calculator Manual Version 1.7 (dated December 1, 2005), were followed in the samples evaluated.

As stated in Section IV.C., several HRM tickets were reviewed at random to confirm that this process is correctly used for AFC data modification. One ticket was not correctly modeled in the corresponding models. This HRM ticket requested the outage of several generation units in the AFC model for various times, however some of the generators remained in the models for both the Operating and Planning Horizons and the Study Horizon during part of their scheduled outage times.

c. Conclusions and Recommendations

SPP recommends that Entergy's quality control processes be enhanced. Possible enhancements may include a single document controlling change management of the quality control processes, increased automation such as in the use of HRM tickets to provide necessary feedback assuring that requested modifications have been performed, and use of HRM tickets (or successor software) in the Study Horizon modeling process.

I. SPECIFIC ISSUES

1. Flowgate Issues

a. Flowgate Ratings

i. Background and Analysis

In order to further examine Entergy's AFC process, SPP has reviewed two flowgate ratings issues. In the first instance, SPP reviewed a specific discrepancy in the rating of the Danville-Magazine 161 kV tie line jointly owned by Entergy and AEP West. AEP West rated the line as a 148 MVA, while Entergy initially assigned a 127 MVA rating. The discrepancy was discovered in the daily model for August 8, 2005, posted on August 5, 2005 before 11:00 am. As a result of an internal examination of the rating difference, Entergy's flowgate revision log stated the higher rating was applied by Entergy on August 16, 2005. An HRM ticket was created to facilitate the addition of this change to the AFC models.

SPP also investigated an issue concerning the ratings of multiple flowgates pertaining to the Mt. Olive to Hartburg 500 kV line. The AFC Flowgate List as of January 12, 2006 showed the flowgate rating for MTOHTB_WEBWL as 1000 MVA, and those of MOLIVEHARTBG and MOHTB_WBWL_D as 1732 MVA each.

ii. Findings

SPP reviewed the August 8th daily model and verified the rating of 127 MVA for the Danville-Magazine 161 kV tie line. SPP then reviewed models posted after the revision date of the flowgate rating. The monthly model for July 2006 created on December 23, 2005 reflected the revised rating of 148 MVA, as recorded in version 3.0 of the AFC Revision Log posted on OASIS. An hourly model for January 3, 2006, posted on December 28, 2005, did not reflect the revised rating of 148 MVA. However, the AFC Flowgate List contains the 148 MVA rating, and this list overwrites the modeled rating during the AFC calculation process.

SPP also verified that, as of January 12, 2006, the AFC Flowgate List contained the ratings for the Mt. Olive to Hartburg flowgates as stated above. On January 20, 2006 the rating of MOHTB_WBWL_D was changed from 1732 MVA to 1000 MVA.

The flowgates MTOHTB_WEBWL and MOHTB_WBWL_D are rated at a 1000 MVA due to a voltage stability limit that is applicable for the contingency of the Webre – Wells 500 kV line. These flowgates represent flow across the Mt. Olive to Hartburg 500 kV line north/south (Mt. Olive to Hartburg) and south/north, respectively.

iii. Conclusions and Recommendations

The conclusion drawn from the Danville-Magazine instance is that the HRM ticket created for this model update was closed before the modification was made to the Operating/Planning Horizon models thus creating a disconnect between the AFC Revision Log and the Flowgate List. The use of HRM generated the modification to the

AFC Flowgate List, which overwrites the modeled rating during the AFC calculation process rating, but did not generate the change in the posted Operating/Planning Horizon models. SPP recommends enhancement of this quality control process. One option may be to create an automated link between the model databases and HRM (or future change management software) that prevents the closing of an HRM ticket prior to verification that the documented modification has occurred in the posted models.

Concerning the Mt. Olive to Hartburg flowgates, SPP concludes that the use of three flowgates for the same monitored element appears unnecessary and can reduce the top fifteen flowgates reported to thirteen for some paths.. Because two of the flowgates are rated at 1000 MVA based upon voltage stability and direction of flow, it appears unnecessary to monitor the third flowgate for thermal purposes at the higher rating of 1732 MVA. It is SPP's recommendation that Entergy examine this instance and consider enhancements to the flowgate addition rules. A possible modification may include a one-step process for public notification to stakeholders concerning flowgate changes in addition to the current notification process, which involves monitoring and comparing the flowgate number stated in the revision log with the AFC Flowgate List which states number and flowgate name. Another option to accomplish this greater transparency may be to include the flowgate name in the revision log.

b. Base Case Overloads

i. Background and Analysis

Base cases include AFC power flow cases with no additional transfers, i.e. post-contingency overloads, and power flow cases used for ATC calculations. Base case overloads are overloads under no contingency and no additional transfer, i.e. pre-contingency overloads.

FERC specifically addressed Entergy's use of base case overloads in its ATC calculations when Entergy used the GOL process. In that proceeding, the intervenors argued that Entergy's use of overloads in the base case was prejudicial to non-network resources. Entergy responded that its process and base case models were fully compliant with NERC standards, and that Entergy should not be required to redispatch in order to provide additional capacity on its transmission system. FERC agreed with Entergy that "[Entergy was] not required to investigate redispatch alternatives for new transmission requests unless an SIS has been requested by a transmission customer."[20] However, FERC noted that Entergy was required to calculate transmission capacity according to good utility practices, and analysis of short-term requests should simulate likely near-term conditions. FERC also suggested that Entergy's use of static load and its lack of seasonal ratings should be investigated in a technical conference. Because Entergy revised its ATC calculation proposal to abandon the GOL process in pursuit of an AFC process, a technical conference was never convened.

[20] *Entergy Services, Inc.*, 103 FERC ¶ 61,271, at P 16 (2003).

Several base case line overloads were reported including occurrences in the July 2005 monthly models posted on April 12, 2005; January monthly model posted on November 16, 2005; January 2006 monthly models posted on November 18, 2006; and February 2006 monthly models posted on November 18, 2005.

ii. Findings

The respective monthly models were reviewed and base case flows for the lines in question were checked against their ratings. SPP verified that multiple base case overloads existed in the AFC models.

iii. Conclusions and Recommendations

Long-term Planning models are subject to NERC and SERC criteria concerning base case overloads. But because the Operating, Planning, and Study Horizon models are not considered Long-term Planning models, SPP finds no evidence of a criteria requirement to mitigate base case overloads. SPP recommends that Entergy provide a means for stakeholders to upgrade facilities that limit AFC. An option for implementing this concept may be to develop a policy similar to SPP's OATT Attachment AA which allows transmission customers to make transmission service prepayments for the transmission provider's use in expanding the system.

c. Resynchronization and Last Good Solution

i. Background and Analysis

SPP reviewed a specific issue concerning AFC on the Cottonwood PMax flowgate. AFC was decreased by 185 MW from 195 MW to 10 MW for July 1, 2005 for the 4:30 a.m. planning horizon resynchronization on June 29, 2005. This was caused by RFCalc's inability to reach a valid power flow solution. Knowing that the RFCalc application would not be able to reach a valid power flow solution for every resynchronization, AREVA addressed such situations by designing RFCalc to copy relevant data from the previous solved time points during each resynchronization event where a valid power flow solution was not reached.

ii. Findings

Entergy determined that the 4:30 a.m. planning horizon resynchronization on June 29, 2005 had several timepoints that failed to reach solution. The last good solution of planning horizon timepoints occurred on June 28, 2005 at 11:30 p.m.; the AFC on the COTTONW_PMAX flowgate was reported as 195 MW at this time. For this resynchronization, the timepoints that did not have a good power flow solution were assigned values from the previous good solution, which happened to be the operating horizon resynchronization at 4:00 a.m. on June 29, 2005. This resulted in the AFC value for the COTTONW_PMAX flowgate being set to 10 MW. RFCalc is designed to update power flow models only when the power flow solution is successful; therefore the models

were not updated during the 4:30 a.m. resynchronization. The issue was resolved by 6:00 p.m. on June 29, 2005

iii. Conclusions and Recommendations

SPP concludes that the use of the last good solution method has been proven through time by AREVA. However, due to the time period that lapsed between the notification and resolution of this issue, SPP does recommend that Entergy explore ways to enhance its process.

d. Flowgate Response Factors

i. Background and Analysis

Due to the AFC value on the UnionPP-Entemo path at hours 8 to 16 on January 17, 2006, the effects of the flowgate GRIMTZ_WDN were researched. More specifically, the response factor for this flowgate, which may have been affecting this path, was in question.

ii. Findings

In an attempt to verify the response factor for the flowgate GRIMTZ_WDN, SPP found that, when trying to reproduce a response factor from RFCalc by using MUST[21], a subsystem file was needed to produce the correct response factor. In order to create an

[21] Managing and Utilizing System Transmission (MUST) is a Siemens/PTI software used to calculate transmission transfer capabilities taking into account the impact of transactions and generation dispatch.

utilizable subsystem file, SPP found that not all units that have an assigned participation factor participate in the transfer. RFCalc only uses online units in the calculation of response factors. No subsystem files were posted for the operating/planning horizon.

iii. Conclusions and Recommendations

While SPP concludes that the response factor was calculated correctly by the AFC process, SPP recommends that an enhancement to Entergy's posting practices include posting a subsystem file on OASIS coincident with Operating/Planning Horizon models. Also, enhanced documentation concerning the assumptions necessary for RFCalc to make response factor calculations should prove useful and add greater transparency to the AFC process.

2. Transmission Outage Issues

a. TAORS vs. OASIS Outage Posting

i. Background and Analysis

SPP investigated an issue regarding the modeling of a scheduled outage time period for an outage caused by Hurricane Rita. As a result of the unplanned outage of the Sabine – Big Three line, Entergy entered outage data into TAORS to track the progress. That data was then imported into OASIS to calculate updated AFC values. The outage resolution was first modeled as February 2006, then updated to reflect the December 31, 2005 date.

ii. Findings

SPP investigated the issue by examining the two systems used by Entergy to enter outage data, TAORS and OASIS, and by exploring the mechanisms used to report outages in the AFC process. While similar data on outages is maintained in both systems, the data is used for different purposes. TAORS posts outage data intended to make users aware of planned outages throughout transmission systems. This information is not utilized in creating models and is not related to the AFC process. In maintaining accurate and updated outage information, OASIS outage postings are used to calculate hourly AFC power flow models. RFCalc imports these outages from TAORS, but only uses those outages that are relevant for the particular time period being modeled Therefore, the outage information used to create models is only completely accurate during the modeled time frame.

In examining this particular situation, SPP found that a model using the OASIS system was created on October 20, 2005, the deadline for the November 1 monthly model posting. This information predicted February 2006 as the resolution date and was reflected in the January 2006 model. Entergy subsequently used updated outage data collected October 26th, after the November reporting deadline, to shorten the resolution date to December 31, 2005, and reflected this data on TAORS.

iii. Conclusions and Recommendations

SPP concludes that the nature of the outage, the inherent usage differences between the TAORS and OASIS, and model posting deadlines explain this modeling

issue. It is SPP's recommendation that the outage posting process be enhanced. An option could include a synchronization of these two systems on some periodic and frequent basis and additional documentation of this enhancement for increased transparency.

b. OASIS Outage Postings and Monthly Models

i. Background and Analysis

SPP investigated an issue regarding the modeling of a scheduled outage. The OASIS outage posting reported the outage of the Derbigny-Michoud Switchyard, but the switchyard was not modeled out of service in the January 2006 monthly model posted on November 16, 2005.

ii. Findings

SPP verified that the line was in service in the January 2006 monthly model. SPP also discovered that Derbigny-Michoud was a line damaged by Hurricane Katrina. After the damage was incurred, an outage was entered into TAORS on October 5, 2005. The revision log for TAORS showed that on November 2, 2005 the outage end date was changed from November 8, 2005 to February 1, 2006, causing the outage to appear in the OASIS outage postings for January 2006. According to Entergy's OASIS, the January 2006 monthly model posted November 16, 2005 was created after the change in end date, and, therefore, should have reflected the outage.

Upon further investigation, SPP discovered that the November 2005 series of monthly models were originally posted on November 2, 2005. An update was performed on November 16, 2005, but only included changes to transactions, not to topology. Entergy's standard procedure is to update the monthly models weekly with transaction data changes. Major topology changes are considered as appropriate.

iii. Conclusions and Recommendations

SPP concludes that the nature of the outage, the inherent usage differences between the TAORS and OASIS, and model posting deadlines coupled with the update practice of including topology changes on a monthly basis explains this modeling issue. Therefore, it is SPP's recommendation that, in addition to the outage posting process enhancement recommended in Section IV.I.(2)(i), Entergy consider further documentation of its standard procedure regarding this issue. A further enhancement could involve more frequent updates of topology data for the monthly models as well as added documentation.

3. Dispatch Issues

a. Overgeneration

i. Background and Analysis

Overgeneration can occur when EMO's expected utilization of network resources coupled with OASIS reservations and net interchange does not match EMO's load forecast. In the case of overgeneration, the software engines for all three horizons are

allowed to adjust EMO's oil and gas-fired units above the maximum power output of generation unit in order to match the load forecast.

Instances of overgeneration were investigated in the August 2005 monthly power flow model posted on March 28, 2005, January 2006 monthly model posted on November 16, 2005, and February 2006 monthly model posted on November 18, 2005.

ii. Findings

The respective models were reviewed and generation dispatch was compared to PMax values. It was verified that certain generators exceeded their PMax values.

iii. Conclusions and Recommendations

SPP concludes that the use of overgeneration is not the preferred modeling approach because it is a misrepresentation of the actual condition of the power system. It is SPP's recommendation that Entergy discontinue the practice of utilizing overgeneration and look to the stakeholder process to determine a more effective method.

A possible approach would allow the upward adjustment of IPP generation as well as EMO's oil and gas–fired generation. This could be accomplished through various means including an IPP-assisted dispatch developed based upon a merit order of IPPs in the region, or ignoring PMin limits for IPPs, allowing the prorated scaling of all IPPs in region.

b. Negative Generation

i. Background and Analysis

Negative generation can occur when EMO's expected utilization of network resources coupled with OASIS reservations and net interchange does not match EMO's load forecast. In the case of negative generation, the software engines for all three horizons are allowed to adjust EMO's oil and gas-fired units below the minimum required power output of a generation unit (PMin) and on below zero in order to match the load forecast.

ii. Findings

SPP verified multiple instances of negative generation in AFC models including the June 18, 19, 20, and June 21, 2005 daily power flow models posted on June 17, 2005 and the January 4, 2006 1:00 a.m. hourly model posted January 3, 2006.

iii. Conclusions and Recommendations

SPP concludes that the use of negative generation is not the preferred modeling approach because it is a misrepresentation of the actual condition of the power system. It is, therefore, SPP's recommendation that Entergy discontinue the practice of utilizing negative generation.

An alternate approach is to allow the downward adjustment of base load generation as well as EMO's oil and gas-fired generation. This practice should significantly reduce the instances of negative generation in the AFC models.

4. Interregional Coordinate Issues

a. Area Load Data

i. Background and Analysis

SPP investigated an issue concerning the modeling of area load data; specifically, an instance concerning the modeling of the TVA and SOCO area loads in the August 9, 2005 daily peak model posted on August 8, 2005. TVA and SOCO had loads of approximately 31,000 MW and 37,000 MW respectively; however, they were modeled as approximately 11,000 MW and 16,000 MW in the power flow model

ii. Findings

SPP examined the model and confirmed that the TVA and SOCO control area loads were modeled as approximately 11,000 MW and 16,000 MW respectively. Entergy has stated that the Operating and Planning Horizon models are unable to fully represent first tier external control areas but instead include an equivalent representation. The first tier control area models extend five to ten buses beyond Entergy's interface. The detailed load and the equivalenced load beyond the five to ten buses is then scaled to match the equivalent representation according to the shape of the load curve from the original load

forecast. CLECO, SPP, and TVA load data is received at least once weekly, and SOCO has also recently been added to the process.

iii. Conclusions and Recommendations

SPP recommends further development of coordination procedures with first tier control areas. Options could include increasing the size of Operating and Planning Horizon models to include larger representations of first tier control areas, exchanging unit commitment and dispatch assumptions with these neighboring entities, or negotiating seams agreements concerning these types of issues.

b. Area Generation

i. Background and Analysis

SPP investigated the modeling of the SPA Dardenelle plant output in the July 23 and July 24, 2005 daily power flow models posted on July 22, 2005. The model showed the plant maximum capacity of 560 MW. However, it was only being dispatched at 100 MW in the summer peak.

ii. Findings

SPP examined the issue by reviewing the power flow model for the time in question. It was confirmed that the SPA Dardenelle plant had an output of approximately 100 MW and a generating capacity of 560 MW. Entergy does not receive unit

commitment or dispatch data from neighboring control areas with the exception of CLECO.

iii. Conclusions and Recommendations

Section IV.I.(4)(a), Area Load Data, above, offers a recommendation and possible options also appropriate for the issue of Area Generation.

5. OASIS Posting Issues

a. Reservations

i. Background and Analysis

SPP investigated an issue concerning two reservations sourcing from Magnet Cove (129MW on August 19, 2005 and 800MW on October 1, 2005), and zero ATCs for all paths from Magnet Cove for the remainder of October and November 2005, as indicated by the October 11, 2005 OASIS postings.

ii. Findings

Entergy states that the August 19th issue was the result of a software bug in the RFCalc validation code provided by AREVA. Entergy manually corrected the AFC models, requested a patch to fix the RFCalc validation code from AREVA, and notified the customer once the problem was corrected.

Concerning the October 1st issue, Hurricane Rita impacted the real-time topology of the system significantly enough to suspend the standard practice of using the real-time system topology for the first three hours of solution and planned outages for the fourth hour and beyond. Entergy notified its customers of the suspension of planned outages usage in lieu of real-time topology for all hours and of this deviation from standard AFC procedures. Because the flow of the PMax flowgate was set to its maximum level to reflect the real-time topology, AFCs for all paths from Magnet Cove were set to zero.[22] The issue was resolved on October 14, 2005 when Entergy resumed use of the real-time system topology for only the first three hours.

iii. Conclusions and Recommendations

SPP concludes that the October 1st issue was an anomaly caused by Hurricane Rita. The August 19th issue raises concerns about the AREVA software logic. SPP recommends that Entergy revisit the software patch to determine that this type issue will not occur in the future.

b. OASIS Postings and Hourly Models

i. Background and Analysis

SPP reviewed an issue concerning differences between AFC values pertaining to hourly models and OASIS postings. The AFC study file, updated January 3, 2006,

[22] This is done to exclude from modeling the generating units which are disconnected from the grid or otherwise off-line. In this instance, the Magnet Cove generators' breakers were set to "open," reflecting that the generators were off-line.

showed negative AFC for the 1:00 a.m. to 2:00 a.m. hour as well as the 5:00 a.m. to 6:00 a.m. hour on the DODDAN_HARMT flowgate. The January 4, 2006 window one hourly model posted January 2, 2006, 4:31 a.m. showed that the flowgate was only 97% loaded.

ii. Findings

SPP discovered that the window one hourly model was for the 4:00 a.m. hour on January 4, 2006; therefore, it did not correspond to either hour of the AFC study file containing negative AFC. It was verified that the loading in the hourly model did match the corresponding hour in the AFC study file, meaning that the hour in question did not show negative AFC in the AFC study file.

iii. Conclusions and Recommendations

SPP concludes that Entergy's practice of posting four random hourly models from each of four six-hour windows is a transparent method of posting, and SPP has no recommendations at this time.

c. OASIS Posting and Daily model

i. Background and Analysis

SPP reviewed an issue concerning differences between AFC values pertaining to daily models and OASIS postings. The issue concerned the AFC study file updated January 3, 2006 5:24 a.m. showing -26 MW of AFC for the GRIMTZ_WDN flowgate for

all hours on January 9, 2006 and the January 9, 2006 daily model posted January 3, 2006 4:38 a.m. indicating only 87% loading.

ii. Findings

SPP verified that the loading of GRIMTZ_WDN in the daily model was 87%. It was discovered that the daily model represented the 18:00 to 19:00 hour for the day of January 9, 2006. The AFC study file was then reviewed, and the AFC for the 18:00 to 19:00 hour was determined to equal 181 MW of flow and a total transfer capability of 206 MW, resulting in an AFC of 25 MW.

iii. Conclusions and Recommendations

The AFC study file in question contained negative AFC (ranging from -12 MW to -26 MW) for every hour except hour 18:00 to 19:00, which was the hour that the daily model represented. This may have been a source of confusion pertinent to the issue.

SPP concluded that while there was negative AFC on January 9, 2006 in the AFC study file, the specific hour corresponding to the daily model showed positive AFC and matched the loading in the model.

EXHIBIT 1

Final Scope of the Process Audit

Task No.	AFC AUDIT Tasks	Subtask No.	Subtasks	scheduled commencement	scheduled completion
1	Publicly solicit comments and concerns from stakeholders			10/13/05	10/28/05
2	Research the prior FERC filings and proceedings to obtain historical perspective of AFC process	**2a**	Evaluate issues regarding the AFC process raised by stakeholders in the ICT and AFC proceedings as well as the recent AFC stakeholder meetings hosted by Entergy	10/3/05	10/13/05
3	Identify and document any and all instances where RFCalc or OA are different from the 'off-the-shelf' versions, including macros, modules, or other software created or modified for Entergy's use in the AFC process	**3a**	Contact Entergy and software developers	10/13/05	10/28/05
4	Request non-posted data	**4a**	Data needs: Databases associated with AFC model development (transaction data; full names, TRM, CBM, and a and b coefficients pertaining to TRM for flowgate list), csv-type archived TLR log from commencement of AFC process to present, NITS applications, software logic (9b), csv-type archived commitment/dispatch data and change log from commencement of AFC process to present(9c), AFC Impact Log (11b), posting practices document (11c), process document for service denial (11d), QC&A documents (12b), 6/1/05 transmission system map (AutoCad)(15b)	10/13/05	10/28/05
5	Review data used in AFC program	**5a**	Transmission facility status, generation facility status	10/3/05	10/28/05

		5b	Projected load levels	"	"
		5c	Generation commitment data	"	"
		5d	Transaction data	"	"
		5e	Any other power flow inputs, including flowgate list (monitored element, contingent element, rating, a and b coefficients pertaining to TRM), paths	"	"
6	Assess whether processes for data selection and use of data result in compliance with Commission orders, Entergy's OATT, and other applicable statutory and regulatory requirements	**6a**	Include VSTE model inputs	10/26/05	10/31/05
		6b	Include a sampling of TSRs processed by the current software to the extent necessary to evaluate current compliance---not all TSRs or models	"	"
		6c	Possibly perform more detailed analysis of individual TSRs or models	"	"
7	Document each type of adjustment to data inputs or model parameters made by Entergy Transmission engineering	**7a**	Include a complete evaluation of the process by which changes or adjustments to AFC data, models, outputs, and software are made by Entergy Transmission engineering	10/27/05	11/4/05
		7b	Possibly recommend plan for modifications specifying criteria and procedures	"	"
		7c	Possibly recommend a system for recording and preserving adjustments in an auditable log	"	"
8	Evaluate the accuracy of model parameters used in AFC models including flowgates, response factors, participation factors, and counterflows used in models	**8a**	Evaluate and document criteria for parameter selection and/or calculation	10/28/05	11/9/05

		8b	Evaluate and document process for ensuring uniform application of criteria to the entire system	"	"
		8c	Evaluate and document process for creating an auditable trail for any variances from criteria	"	"
		8d	Evaluate and document process for changing and updating list of flowgates, including process for creating an auditable trail for such changes	"	"
9	Evaluate the process used to incorporate information provided by network customers in the AFC models	**9a**	Information concerning unit commitment and generation dispatch levels of existing DNRs	11/4/05	11/14/05
		9b	Evaluate software logic for committing or dispatching units in AFC process	"	"
		9c	Evaluate any changes to commitment or dispatch data by Entergy Transmission engineering	"	"
10	Evaluate the actual unit commitment and dispatch modeled by Entergy Transmission	**10a**	Evaluate how network customers decisions on whether to purchase energy or capacity from third parties are represented by Entergy Transmission engineering for purposes of making transmission capacity available	11/7/05	11/16/05
		10b	Possibly recommend changes	"	"
11	Assess AFC Business Practices designed to ensure compliance with applicable requirements	**11a**	AFC Business Practices to include Entergy OATT, including Attachment C, and Entergy's AFC Process Manual	11/14/05	11/18/05
		11b	Assess compliance with OASIS record-keeping and posting requirements, including evaluation of the "AFC Impact Log" generated by AFC process	"	"
		11c	Assess posting practices for updates and schedules on Entergy OASIS, including resynchronization of data sets following modifications	"	"
		11d	Evaluate process and data used to provide information regarding denial of transmission service to customer	"	"
		11e	Possibly recommend changes to current BPs	"	"

12	Assess Quality Control Procedures for ensuring that the data and engineering inputs are properly incorporated into the AFC process and for ensuring quality controls are in place for software development	**12a**	Identify and evaluate any written policies used by Entergy Transmission engineering regarding rollover rights, data modifications, and other modeling assumptions or practices	11/21/05	11/29/05
		12b	Evaluate current quality control and assurance procedures applicable to the AFC process and models	"	"
		12c	Possibly recommend modifications or changes to procedures including recommendations for a process to ensure that all data and software requirements of the AFC program are conveyed to all affected Entergy Transmission personnel	"	"
13	Evaluate AFC coordination with external control areas	**13a**	Evaluate process for AFC coordination with external control areas including area interchange and updates of external model data	11/28/05	12/1/05
		13b	Possibly recommend changes	"	"
14	Identify existing policies for preserving information about the AFC process	**14a**	Identify current archival processes	11/28/05	12/1/05
		14b	Possibly recommend changes or modifications to policies in order to ensure that historical data is preserved as necessary to comply with applicable regulatory requirements	"	"
15	Evaluate any enhancements proposed by Entergy with respect to the AFC process	**15a**	Additional enhancements to the AFC process, software, or business practices	11/22/05	12/1/05
16	Evaluate issues regarding the AFC process raised in the ICT and AFC proceedings, consistent with the AFC Audit	**16a**	Evaluate specific issues that can be investigated in the scope of this audit	11/22/05	12/7/05
		16b	Specific stakeholder issues with weighted prioritization are provided in document titled "Exhibit 1 --- Summary of IPP AFC Issue Types with weighted prioritization 11282005"		"

		16c	Specific stakeholder AFC Audit scope recommendations are provided in document titled "Exhibit 2 --- Stakeholder AFC_audit_scope_recommendations_11282005"	"	"
		16d	Entergy comments to 16c are provided in document titled "Exhibit 3 --- EntergyComments-Stakeholder_AFC_audit_scope_recommendations_11282005"	"	"
17	Issue preliminary findings			12/16/05	12/16/05
18	Host a stakeholder and transmission provider meeting to present audit process and initial findings			1/4/06	1/4/06
19	Perform follow up actions from stakeholder meeting			1/5/06	1/30/06
20	Host a second stakeholder meeting to consider the additional SPP findings and proposed enhancements, if any (Optional depending on outcome of first meeting)			TBD	TBD
21	Develop final independent report based on audit review and investigation	**21a**	The report must evaluate whether the current AFC process is being implemented in a manner consistent with the Commissions AFC orders, the existing Entergy OATT provisions, and good utility practice. Report should also include modifications or improvements to the current AFC process that Entergy may consider on a going forward basis.	1/5/06	2/14/06
22	Submit report to Entergy for filing no later than February 15, 2006.			2/15/06	2/15/06
23	If necessary, submit a confidential audit report to Entergy for filing with the FERC	**23a**	SPP shall specifically identify any information, documents, or processes that stakeholders and SPP consider confidential as part of the AFC audit.	2/15/06	2/15/06
		23b	Confidential information should have a business or market sensitive nature to it.		
		23c	SPP shall keep all agreed to records confidential.		
		23d	Non-confidential information collected specifically for the AFC audit shall be subject to public release		

APPENDIX 1

Summary of Recommendations

No.	Report Section IV. Subsection(s)	SPP Recommendation
1	A.(c) I.(5)(a)(iii)	Revisit the software patch to determine that this type issue will not occur in the future
2	B.(1)(c) E.(c) I.(2)(b)(iii)	All assumptions that provide an additional level of detail beyond those assumptions currently posted with the AFC models, be formally documented
3	B.(2)(c)	AFC Impact Log and TSR Log process be further automated
4	C.(c) D.(2)(c) D.(1)(c) H.(c) I.(1)(a)(iii)	Enhancement of the HRM and other quality control processes as well as enhancement of current quality control processes to include flowgate revisions and enhancements to the flowgate addition rules
5	G.(c) I.(4)(a)(iii) I.(4)(b)(iii)	Exchange of data with neighboring entities be enhanced and further development of coordination procedures with first tier control areas
6	I.(1)(b)(iii)	Provide means for stakeholders to upgrade facilities that limit AFC
7	I.(1)(c)(iii)	Enhance notification and resolution processes concerning this resynchronization and last good solution
8	I.(1)(d)(iii)	Enhancement to posting practices to include a subsystem file coincident with

	I.(2)(a)(iii)	operating/planning horizon models and outage posting process enhancement
9	I.(3)(a)(iii)	Discontinue the practice of utilizing overgeneration and look to stakeholder process to determine more effective method
10	I.(3)(b)(iii)	Discontinue practice of utilizing negative generation and look to stakeholder process to determine more effective method