shareholders and its ratepayers differently from the traditional prudence standard, in that those shareholders would share more in the risk of additional or unexpected costs While the traditional application of the prudence standard is appropriate in this case, circumstances may dictate otherwise in the future, as long as the utility is given proper notice of what standard the Commission will employ. Accordingly, the Commission does not adopt the ALJ's discussion in the final paragraph on page 87 of the PFD, finding it overbroad and potentially misleading

C. The Doctrine of Res Judicata

In finding that the doctrine of *res judicata* does not preclude an examination of one of EGS's long-term natural gas contracts, the PFD concludes that "[b]ecause the reasonableness of the Pontchartrain swing contract was not fully and fairly litigated in Docket No 13170, the findings of reasonableness in that proceeding do not act to collaterally estop the Commission's review of the prudence of that contract in a litigated proceeding."[5] The PFD bases its conclusion that the contract was not "fully and fairly" litigated upon the fact that Docket No 13170 was a stipulated case. Also, as a secondary ground for finding that the doctrine of *res judicata* does not apply, the PFD notes that the specific terms of the stipulation in Docket No 13170 reserved the issue of the prudence of the Pontchartrain swing contract for a future date Although the Commission agrees with the PFD's conclusion that the contract is subject to review in the instant proceeding, it does not concur in every aspect of the PFD's rationale in reaching that conclusion

The Commission finds that the existence of a stipulation in a docket does not, in itself, make issues of decisional prudence reviewable in subsequent proceedings. For example, if a stipulation includes a specific statement that a contract is prudent and the final order either memorializes or references such a finding, then *res judicata* precludes the relitigation of the prudence of such contract in subsequent proceedings. Thus, the existence of a stipulation may or may not preclude litigation of certain issues in subsequent proceedings, depending upon the language in the stipulation itself and/or the final order issued in the settled proceeding For these

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[5] PFD at 45.

reasons, the Commission does not adopt the discussion of *res judicata* on pages 44 and 45 of the PFD.

The stipulation executed in Docket No. 13170, did not specify that the Pontchartrain contract was prudent. In fact, it specifically stated that none of the agreements reached by the parties had any precedential effect.[6] The conclusion of law in Docket No 13170 addressing the prudent incurrence of fuel and purchased power expenses, including those expenses incurred under the Pontchartrain swing contract, qualifies its findings with the phrase "[c]onsistent with the terms of the revised stipulation and agreement".[7] Therefore, the decision by EGS to enter into that contract, as well as underlying terms and prices in that contract, are subject to review in this proceeding. For the reasons discussed in Section IX.A.4.b ii of the PFD, however, no disallowance relating to the Pontchartrain swing contract is warranted

II. Allocation of Fuel Cost Disallowances to Texas Retail Non-Fixed Fuel Factor Customers

Under both EGS's and the General Counsel's respective fuel cost allocation methodologies, only Texas retail customers that are billed under the fixed fuel factor benefit from a systemwide fuel cost disallowance approved by the Commission Because the fuel expenses allocated to EGS's non-fixed fuel factor customers in the Texas retail jurisdiction are not included in reconcilable fuel balance, such customers do not receive their proportionate share of any credit related to systemwide disallowed fuel costs, under either EGS's or the General Counsel's methodology.

There is no question that the Commission has jurisdiction over all rates and charges in the Texas retail jurisdiction. In this case, to assure that all Texas retail customers, including non-fixed fuel factor customers, receive their proportionate share of any systemwide fuel cost

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[6] The stipulation in Docket No. 13170 states "[t]his Revised Stipulation and Agreement is entered into solely for settlement purposes; it does not constitute an admission by any signatory as to any material issue and may not be used as precedent by any person or entity or as evidence of agreement by a Party or the Commission to the resolution of any issues." Revised Stipulation and Agreement at 6 (Feb. 15, 1995)

[7] *Application of Gulf States Utilities Company to Reconcile Fuel Costs*, Docket No 13170, Conclusion of Law No. 6, 20 P.U.C. BULL. 1026 (April 18, 1995).

disallowance, the allocation of the total fuel cost disallowance must be addressed separately for those non-fixed fuel factor customers.

The Commission agrees in the PFD's conclusion that the General Counsel's fuel cost allocation methodology should be adopted as the appropriate method for allocating fuel costs to Texas retail fixed fuel factor customers. The General Counsel's methodology for allocating systemwide fuel costs to Texas retail fixed fuel factor customers is as follows:

$$\textbf{Texas Retail Allocator (TRA)} = \frac{\textbf{Texas fixed-fuel-factor kWh sales @ plant}}{\textbf{EGS adjusted system kWh sales @ plant}}$$

To ensure that EGS's Texas retail non-fixed fuel factor customers also receive their proportionate share of the Commission-approved systemwide fuel cost disallowance, the General Counsel's methodology should also be applied to such customers as well.

The numerator in the General Counsel's methodology, or "Texas fixed-fuel-factor kWh sales @ plant," is calculated by the following method: (1) taking total Texas retail sales *at the meter*; (2) subtracting Texas non-fixed-fuel-factor kWh sales; and (3) adjusting the result for line losses to determine Texas retail kWh sales to fixed-fuel-factor customers *at the plant*. The denominator, or " EGS adjusted system kWh sales @ plant," is calculated according to the General Counsel's methodology by the following: (1) taking the EGS system kWh sales *at the meter*, (2) subtracting off-system sales, and (3) adjusting the result for line losses to obtain adjusted system sales in kWh *at the plant*.

To similarly calculate the systemwide fuel costs allocable to EGS's Texas retail non-fixed fuel factor customers, the Commission finds that General Counsel's methodology should be applied to such customers as follows:

$$\textbf{Texas Retail Allocator Non-FF (TRA non-FF)} = \frac{\textbf{Texas non-fixed fuel factor kWh sales @ plant}}{\textbf{EGS adjusted system kWh sales @ plant}}$$

The numerator in this methodology, or "Texas non-fixed fuel factor kWh sales @ plant," is calculated by the following method: (1) taking total Texas retail sales *at the meter*; (2) subtracting Texas fixed-fuel-factor kWh sales; and (3) adjusting the result for line losses to determine Texas retail kWh sales to non-fixed-fuel-factor customers *at the plant*. The denominator, or " EGS adjusted system kWh sales @ plant," is calculated according to the General Counsel methodology by the following: (1) taking the EGS system kWh sales *at the meter*; (2) subtracting off-system sales; and (3) adjusting the result for line losses to obtain adjusted system sales in kWh *at the plant*.

Because EGS's Texas retail non-fixed fuel factor customers are charged on a monthly basis, these customers do not accumulate an over/(under) recovered fuel balance in the same manner as EGS's Texas retail fixed fuel factor customers. Consequently, a surcharge of EGS's under-recovered fuel balance (less any allocated systemwide disallowance) is not required for its Texas retail non-fixed fuel factor customers. Therefore, the only adjustment necessary for EGS's Texas retail non-fixed fuel factor customers is a credit for their proportionate share of any systemwide Commission-approved disallowance or adjustment, with interest, for each month of the reconciliation period.

III. Cities Disallowance Relating to EGS's Short-Term Gas Contracts

P.U.C. SUBST. R. 23.23(b)(3)(A)(iii) states that, in addition to other information specifically listed in the subsection, a utility's petition to reconcile fuel expenses must provide "the quantities purchased and the unit prices and total prices paid under *any contract during the reconciliation period*." (emphasis added) Regarding its short-term natural gas contracts, EGS did not include specific information by contract in its petition consistent with the requirements of P.U.C. SUBST. R. 23.23(b)(3)(A)(iii).

In an attempt to ascertain the reasonableness of EGS's short-term natural gas purchases, the Cities filed Request for Information (RFI) Cities-24-1, which requested EGS to provide "the MMBtu purchased by individual contract on a monthly basis . . . . Please reflect the actual amounts, with prior period adjustments allocated to the appropriate month."[8] EGS responded to this RFI as follows:

[8] Cities Exh. 94.

> The Company's accounting records are not maintained on a contract by contract basis. All purchases during each accounting period are aggregated and booked by supplier. The Gas Supply Department maintains an internal operational database which reports data by invoice . . . This database is not designed to track or to be able to aggregate by individual contract . . . There is no practical way for the Company to aggregate the requested information by contract.[9]

As noted by the General Counsel in its exceptions to the PFD, EGS never supplemented this response.[10] To examine the prudence of EGS's short-term natural gas transactions, the Cities had to resort to a review of a limited set of invoices made available at EGS's offices in Beaumont, Texas. Consequently, many of the transactions through which EGS purchased natural gas during the reconciliation period were not reviewed by the Cities or any other party[11] The Cities, based upon its review of the limited number of invoices made available, recommend a disallowance of $3,473,207 in short-term natural gas expenses on a systemwide basis This recommended disallowance reflect an amount in excess of an applied benchmark of an index price plus $0.03 per MMBtu.[12]

In its prefiled rebuttal testimony, EGS lists several reasons why the short-term natural gas contracts were not available for review, including but not limited to evolving, industry-wide contract administration practices that de-emphasize written agreements, the relocation of files during the merger consolidation process; turnover related to the merger consolidation, and the possibility that an employee may have inadvertently misfiled or destroyed some of the agreements and/or amendments.[13] EGS's rebuttal testimony also attempts to demonstrate that the Cities' proposed disallowance for EGS's short-term natural gas purchases, which was necessarily based on its review of a limited number of invoices, is inappropriate EGS notes, however, that its rebuttal analysis is incomplete in that sufficient details are no longer available

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[9] *Id.*

[10] General Counsel's Exceptions to the Proposal for Decision and Motion for Sanctions at 32 (Jan. 8, 1997).

[11] Cities Exh. 83 at 22 (Griffin direct).

[12] *Id.* at 23.

[13] EGS Exh. 61 at 24 (Harrington rebuttal).

to perform any analysis for the first three months of 1994 at the Willow Glen generating station.[14]

The Commission finds that EGS did not provide sufficient evidence to meet its burden of proof in justifying its level of short-term natural gas expenditures during the reconciliation period. By its own admission, EGS does not maintain data detailing individual short-term natural gas transactions and/or contracts. The Commission finds, however, that such data is necessary to determine whether a utility's short-term natural gas expenses are prudently incurred. Therefore, EGS's failure to comply with the requirement to provide contract-specific information in P.U.C. SUBST. R. 23.23(b)(3)(A)(iii) ultimately undermines its ability to meet its burden of proof with respect to the prudence of its expenditures associated short-term natural gas transactions. The limited evidence presented by EGS in this proceeding is insufficient to meet this evidentiary burden, particularly since EGS's rebuttal testimony addressing the Cities' proposed disallowance is incomplete.

Rather than disallow all of EGS's expenses for short-term natural gas transactions, however, the Commission finds that the preponderance of the evidence favors the adoption of the Cities' proposed disallowance of $3,473,207 on a systemwide basis EGS, as well as any other electric utility seeking a review of its short-term fuel expenditures in any future fuel reconciliation proceeding, should observe the need for providing sufficient documentation for each short-term transaction, in compliance with the Commission's rules, if it is to meet its burden of proof with regard to the prudence of such expenditures

IV. River Bend Forced Outage 94-01 (FO-94-01); Outage No. 94-03: Vessel Transmitter-Spurious Trip

The Cities propose a disallowance of $1,519,787 for imprudent management on the part of EGS relating to the FO-94-01 forced outage The PFD rejects the Cities' proposed disallowance, concluding that the forced outage was not caused, in whole or in part, by imprudent conduct on the part of EGS. The PFD concurs in the position of EGS and the

[14] *Id.*, Exh. WEH-5.

General Counsel that, regardless of whether EGS had installed maximum damping on the Rosemount Model 1153 transmitters, a noise signal of the amplitude experienced at the River Bend Nuclear Station (River Bend) on September 8, 1994 would have resulted in a reactor shutdown. The PFD further rejects the Cities' disallowance on the grounds that it did not give proper weight to the cause of the outage.[15]

The Commission, however, finds that the preponderance of the evidence supports the disallowance proposed by the Cities relating to this forced outage, based on its conclusion that had EGS exercised prudent management prior to this incident, the outage and associated replacement power costs would have been avoided. As noted by the Cities, there are several documents generated by EGS which support this conclusion of imprudent conduct.

First, EGS unqualifiedly admits to violating NRC procedures with respect to the installation of the transmitters in its response to the NRC addressing the forced outage:

> On April 6, 1993, Modification Request 93-0016, an instruction used to install Rosemount Model 1153 transmitters with damping circuitry, did not provide adequate acceptance criteria to specify the amount of adjustment that was allowed for the damping adjustment screw. Consequently, Reactor Level Transmitter 1B21*LTN080D was overly sensitive to process noise and caused the spurious reactor trip on September 8, 1994.
>
> Entergy Operations concurs with this violation and has determined that the reason for this even was an oversight on the part of engineering in that a minimum acceptance criteria was not specified in MR 93-0016.[16]
>
> On May 20, 1994, Maintenance Work Order R203595, which was intended to install a transmitter with damping circuitry, did not specifically require nor reference the installation of the damping circuitry for Transmitter 1B21*LTN080C. Consequently, the transmitter was overly sensitive to process noise and caused the spurious reactor trip on September 8, 1994.
>
> Entergy Operations concurs with this violation and has determined that the reason for this event was that the maintenance planner did not properly plan the maintenance work order (MWO).[17]

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[15] PFD at 86-87.

[16] Cities Exh. 61 at 9643.

[17] *Id.* at 9646.

This contemporaneous response to the NRC, which acknowledges a lack of e
oversight and improper planning, is unquestionably an admission of EGS's failure to address the transmitter issue prior to the forced outage.

Second, EGS was forewarned of the potential problems associated with the include damping in the transmitters or in setting the damping incorrectly. Specificall Information Letter (SIL) 463, issued by General Electric in April 1988, states in pertin

> Recently, at BWRs using fast response transmitters with no adjustable electro filtering capability, noise components in process variable signals have resulted operational problems such as inadvertent isolations, ECCS initiations and h scrams. The purpose of this SIL is to discuss methods for determining the r cause of the process instrument noise and recommend methods for no elimination or reduction through filtration of the electrical signal.
>
> * * *
>
> Process variable noise has been observed in all types of GE BWRs from BWR through BWR/6s.[18]

In its own Condition Report on the forced outage, EGS acknowledged the ap of SIL 463 and its forewarning with respect to the cause of the scram:

> Rosemount transmitters with no damping are known to be susceptible to fa indications due to process noise disturbances. This was discussed in SIL 463 a in the Rosemount literature. Based on a review of SIL 463 and the Rosemou newsletter, Engineering has determined that, with no damping installed or w damping at minimum position, the transmitters are susceptible to spurio tripping due to process noise. This scenario has been determined to be significant contributor to the root cause of the scram.[19]

Despite the existence of this documentation, EGS relies upon a mathemati based upon an after-the-fact, hypothetical calculation, to contend that the scram w occurred in the absence of any imprudence. Based on this calculation, EGS argue

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[18] Cities Exh. 100 at 38531. EGS witness Mr. Sellman acknowledged that River Bend is a B at 4619-4621.

[19] Cities Exh. 98 at 10492-10493.

disallowance is warranted. Its use of the term "mathematical proof" in its *post hoc* rationalization, however, is a misnomer when considering the following [20]

- EGS does not know the cause of the noise "spike",
- EGS did not and could not rule out that the noise "spike" may have been caused by a voltage surge or electrical interference;
- EGS "backed-into" a calculated input signal used in its hypothetical calculation,
- EGS assumed an output to the transmitter,
- EGS does not know the source, size, shape or duration of the noise "spike", and
- No one, in fact, knows the inputs; so a hypothetical calculation thereof is not relevant.[21]

In conclusion, the following points are clear from the evidentiary record in this case

- EGS personnel, through deficient maintenance work orders issued by management, installed two Rosemount Model 1153 transmitters either with or without improper damping settings when a setting of maximum damping was required. In its response to the NRC, EGS concluded that the reasons for the violations were due to an "oversight on the part of engineering" and because "the maintenance planner did not properly plan the maintenance work order";
- The susceptibility of the Rosemount transmitters to false indications due to process noise, when there is little to no damping, was identified as early as April 1988 when SIL 463 was issued, and
- EGS admitted in contemporaneous correspondence with the NRC that the spurious reactor trip on September 8, 1994 occurred because the improperly installed transmitters were overly sensitive to process noise

This preponderance of the evidence indicates that EGS installed the Rosemount transmitters with improper damping settings, that the improper installation was due to imprudent management on the part of EGS, and that such imprudent management resulted in the FO-94-01 forced outage For these reasons, the Commission adopts the Cities' proposed disallowance of $1,519,787 on a systemwide basis.

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[20] Cities Exceptions at 58 (Jan. 8, 1997).

[21] Cities Exh. 103 at 413-415; Tr. 4609-4612.

V. River Bend Forced Outage 94-02 (FO-94-02); Outage No. 94-04: Recirculation Pump Seals

On October 8, 1994, a recirculation pump seal failed River Bend, resulting in forced outage FO-94-02, which lasted 5.8 days. Earlier in the year, during River Bend refueling outage No. 5,[22] EGS replaced the nuclear facility's failed recirculation pump seals with new tungsten carbide seals, on the advice of a consultant. The Cities recommend a disallowance of $545,548 associated with the forced outage that subsequently resulted, claiming that EGS's decision to use tungsten carbide seal material, rather than silicon carbide seal material during the refueling outage was an imprudent one. In finding that this forced outage was prudent and recommending no disallowance, the PFD concludes that the Cities' analysis appears to focus on recurring problems at River Bend, rather than the prudence of actions taken by EGS to correct the pump circulation seal problem.[23]

The Commission finds, however, that the preponderance of the evidence supports the Cities' proposed disallowance relating to this forced outage. EGS's decision to use tungsten carbide sealant was imprudent because it was not reasonable in light of the circumstances, information, and options available to EGS at the time the decision was made. Both the evidence upon which EGS relies in making its case for prudence, as well as the evidence presented by the Cities, supports the Commission's conclusion here.

In arguing that it acted prudently in using new tungsten carbide seals, EGS relies heavily on advice elicited from its consultant, MPR Associates (MPR), whom EGS hired to evaluate the options of silicon carbide versus tungsten carbide for the recirculation pump seals.[24] As noted by the Cities, the flaw in MPR's analysis is that EGS's engineering failed to give MPR the necessary information (*i.e.*, design parameters) regarding particulates in the facility. As a result

[22] River Bend Refueling Outage No. 5 (RF-5) began on April 15, 1994 and ended on July 6, 1994. PFD at 77.

[23] PFD at 90.

[24] EGS Exh. 13 at 28-29, MBS-7.

of this failure, MPR predicated its conclusions to use the silicon-carbide option on inadequate data, as reflected in MPR's report, which states in pertinent part:

> . . . we conclude that it is reasonable to expect that an N 7500 seal at River Bend with the tungsten-carbide option would experience accelerated wear if it operated without seal injection or otherwise subjected to high concentrations of abrasive particulates.[25]
>
> Conclusions
>
> 1. The principal benefit of using the silicon-carbide option is improved abrasion resistance.
> 2. The improved abrasion resistance provided by the silicon-carbide would be of use in the event of contamination by a high concentration of abrasive particles or a need for extended operation, more than a week or so, without seal injection. These are considered to be low probability events.
> 3. Given the low probability of the events described in item 2, the benefit of using the silicon-carbide option is judged to be small.
> 4. The principal risk of using the silicon-carbide option is that silicon-carbide material has a low fracture toughness and limited operating experience in comparison to the alternative, tungsten-carbide material.
> 5. The additional risk of using silicon-carbide instead of tungsten-carbide is judged to be small.
> 6. The risk of using silicon-carbide, although judged to be small, is not considered to be warranted by the expected benefits.[26]

Because MPR assigned a low probability event to the occurrence of a high concentration of abrasive particles, it appears that EGS did not adequately inform MPR of the purge water quality or the possibility of a crud burst occurring at River Bend. Had EGS properly provided the consultant with purge water quality data and an assessment of the probability of a crud burst, there is strong evidence to suggest that MPR's report would have recommended using silicon carbide, rather than the tungsten carbide that eventually failed and resulted in the forced outage.

EGS previously admits to its failure to consider these matters in deciding which of the two seal options to choose. In its contemporaneous assessment of the cause of the forced outage,

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[25] EGS Exh. 13, MBS-7 at 3.

[26] *Id.* at 5-6.

EGS acknowledges that "[t]he tungsten carbide seals installed during Refuel Outage (RF)-05 under MR 93-0079 were not the correct design for this application, considering purge water quality and the possibility of a crud burst occurring." Further, in establishing the contributing cause to the seal failure and resulting forced outage, EGS states that "[t]he risk assessment used for the tungsten-carbide seal design was not complete in that consideration of crud burst and the possible effects of crud burst was not included" and that "criteria for seal purge water purity was not established during the risk assessment." EGS then goes on to note:

> Risk assessment for use of tungsten-carbide versus silicon carbide seals was not adequate because no criteria for particulate levels was defined by the vendor or asked for by design engineering. Additionally, effects from crud burst or system perturbations on seal life were not addressed during the risk assessment. Operating experience on water quality problems with seal purge was not checked.[27]

This contemporaneous documentation in response to the forced outage demonstrates that EGS believed its risk assessment regarding the use of the tungsten-carbide seal was incomplete and inadequate. The Commission finds that the failure to perform an adequate risk analysis of the use of the tungsten-carbide seals was imprudent on the part of EGS, given that a reasonable utility manager would have employed all relevant information available at the time in its assessment of the risk of using of tungsten-carbide versus silicon-carbide seals. By its own admission, EGS did not perform such an analysis. Therefore, the Commission concludes that forced outage FO-94-02 was the result of EGS's imprudence. The preponderance of the evidence supports the Cities' recommended disallowance of $545,548 on a systemwide basis.

VI. River Bend Forced Outage 94-03 (FO-94-03); Outage No. 94-05: Human Error

Forced outage FO-94-03 at River Bend occurred on December 4, 1994, and lasted approximately 7.4 days. This outage was caused by a technician's mistake, which in turn caused a reactor trip or scram during the monthly testing of the Main Steam Isolation Valves (MSIVs)

[27] Cities Exh. 48-B, Tab 23 at 4649-4654 [Condition Report 94-1409].

at River Bend.[28] The Cities claim that this forced outage was the result of imprudent management on the part of EGS and, consequently, a disallowance of $657,386 is appropriate.[29] The PFD concludes, however, that "human error" causing a reactor shutdown are expected to occur at nuclear power plants like River Bend from time to time, and that EGS's management could not have prevented this particular outage. Therefore, the PFD finds no imprudence and recommends no disallowance associated with the forced outage.[30]

The Commission disagrees with the PFD's conclusions. The preponderance of the evidence demonstrates that the forced outage was caused by EGS's imprudent management, which was a contributing factor in the human error resulting in the scram. Again, by its own admission, EGS acknowledges this imprudence. In its official response to the NRC with regard to this forced outage, EGS states in pertinent part:

> Entergy Operations concurs with this violation and believes that the reason for the event was that the technicians who performed the surveillance test procedure (STP) failed to properly self-check their work. A contributing cause of this event was that work practices were less than adequate in that the independent verification method did not identify the mispositioning of the local power range monitor (LPRM) switches. Another contributing cause of the violation was that inadequate corrective actions were taken in response to a previous event.
>
> * * *
>
> Entergy Operations concurs with this violation and has determined that the reason for this event was human error on the part of the maintenance technician in that he failed to follow the procedure as written due to a miscommunication. A contributing cause was that verification steps to verify channel status had been removed during a previous revision.[31]

Given these statements by EGS in contemporaneous correspondence with the NRC, the improper modification of verification step procedures was a contributing cause to the human error that occurred prior to the forced outage. In modifying the verification procedures, EGS established

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[28] PFD at 91.

[29] Cities Exh. 48 at 92.

[30] PFD at 93-94.

[31] Cities Exh. 61 at 9636-9638.

an independent verification method that, as EGS states, established a work practice that was "less than adequate."

Furthermore, subsequent to this forced outage, EGS summarized the corrective steps taken and results achieved in a report to the NRC, which states in pertinent part:

> To address the associated human performance issues, individual counseling/discipline was administered as determined necessary by department management. In addition, management expectations were reinforced to site personnel regarding the personal accountability and procedure compliance through management meetings which discussed the specific issues and the overall philosophy of human performance improvement.
>
> * * *
>
> In addition, procedure STP-058-4501 revision 11, was revised to include verification of circuit status lights (located in the back panel) and ammeters for each channel prior to proceeding to the next channel.[32]

Again, this documentation shows that EGS viewed the actions and decisions of its technicians as controlled and/or affected by management actions and decisions, given that management implemented corrective measures to ensure that such a mistake was not repeated.

EGS argues that "[t]he actions and decisions of technicians and contractors should be found imprudent only if there is imprudence of management leading to those actions or decisions."[33] As a matter of policy, the Commission finds that utility management is responsible for the work-related actions and decisions of its employees. Such management is responsible for establishing, monitoring, and enforcing appropriate operations and procedures and for ensuring that its employees perform up to those standards. Inadequate, substandard, or otherwise inappropriate work methods or products reflect the cumulative actions and decisions of utility management. In other words, an employee's conduct generally does not occur in a vacuum. Therefore, a utility's assertion of "human error" will rarely, if ever, shield it from being responsible for events it alleges were the sole result of such an "error".

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[32] *Id.*

[33] EGS Exh. 13 at 4.

For the reasons stated, the Commission concludes that preponderance of the evidence supports the Cities proposed disallowance of $657,386 on a systemwide basis.

VII. Revenues from Off-System Sales

In its preliminary order in this docket, the Commission concluded that EGS's adders and margins from off-system sales should be credited, in their entirety, to EGS's ratepayers subsequent to April 28, 1994, which is the issuance date of the final order in Docket No. 12712.[34] Also, in its preliminary order, the Commission inquired as to whether there is good cause to justify an exception to the allocation of 100 percent of the revenues from off-system sales to ratepayers during the reconciliation period subsequent to the issuance of the final order in Docket No. 12712.[35] During the hearing on the merits, no party presented evidence to support a good cause exception to the 100 percent allocation required by P.U.C. SUBST. R. 23.23(b)(2)(B)(vi)(III).

In an RFI, General Counsel requested EGS to provide the impact upon its financial condition of retaining none of the margins from off-system sales subsequent to the date of the final order in Docket No. 12712. EGS responded that "[t]he financial impact of not retaining 25% of the margins from off-system sales for the period March 1994 through June 1995 is $741,442 before taxes (this amount is 25% of the Off-System Sales Revenues in excess of Fuel Costs allocated to the Texas retail jurisdiction for this time period)."[36] The Commission observes that the period of time referenced in EGS's response, March 1994 through June 1995, does not on its face correspond to the period specified in the General Counsel's RFI.

Furthermore, the financial impact calculated by EGS appears to conflict with an adjustment of $335,097 later calculated by General Counsel.[37] Based upon the information in

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[34] Preliminary Order at 4-8 (Feb. 26, 1996).

[35] *Id.* at 3, Issue No. 9.

[36] GC Exh. 9, Attachment JBG-2 at 3.

[37] GC Exh. 13A, Staff Schedule C at 2, Column (m).

the evidentiary record, the Commission finds that an adjustment of $741,442, as calculated by EGS, is appropriate on a Texas retail basis for fixed fuel factor customers. In addition, the Commission finds that EGS's non-fixed fuel factor Texas retail customers are also entitled to their proportionate share of off-system sales revenues. The off-system sales revenue credit allocated to these customers should be considered in the calculation of the level of fuel costs allocated to Texas retail non-fixed fuel factor customers (and the resulting credit for such customers), as outlined in Section I of this Order.

VIII. Surcharge Methodology

P.U.C. SUBST. R. 23.23(b)(3)(C)(v) requires that, unless otherwise ordered by the Commission, all refunds and surcharges shall be made through a one-time bill credit or charge. The Commission finds that it is not in the public interest in this case to require a one-time surcharge, as recommended by the PFD.

Rather, the Commission finds that EGS should implement a surcharge of its under-recovered eligible fuel balance for its Texas retail fixed fuel factor customers (and a refund to its Texas retail non-fixed fuel factor customers) beginning in the first practicable billing cycle subsequent to the date of this Order and ending with the billing cycle for June 1997 consumption. The surcharge (and refund for Texas retail non-fixed fuel factor customers) shall be based upon the determination of the Commission in this Order. Any modification on rehearing shall be accounted for at such time as the Commission's Order in this proceeding becomes administratively final.

IX. Modifications To The PFD's Proposed Findings And Conclusions

1. The Commission adopts the findings of fact (FF) and conclusions of law (CL) recommended in the PFD, with the exceptions described below. The reasons for these changes are also described below, as required by Section 2003.047 of the Government Code.

2. Proposed Finding of Fact No. 50 is revised to read as follows to clarify the function of the fuel cost allocation methodology proposed by the Commission Staff.

FF50. The fuel cost allocation methodology proposed by Commission Staff allocates to the Texas retail fixed fuel factor customers their proportionate share of fuel costs, based on the fuel costs EGS actually incurs to serve each type of customer.

3. Proposed Finding of Facts Nos. 59A and 59B are added and Conclusion of Law No. 2 is modified to clarify that, as discussed in Section II of this Order, the Commission has jurisdiction over Texas retail sales, regardless of whether the customer is charged via the fixed fuel factor or otherwise. As such, EGS's Texas retail non-fixed fuel factor customers should benefit from any Commission-authorized fuel cost disallowance in the same manner as EGS's Texas fixed fuel factor customers.

FF59A. EGS serves Texas retail customers that are not charged the fixed fuel factor, and these customers do not automatically receive the benefit of a fuel cost disallowance that is flowed through to customers via the fixed fuel factor. Therefore, EGS's Texas retail non-fixed fuel factor customers must be credited their proportionate share of any Commission-authorized fuel cost disallowance directly through the same mechanism by which such customers are billed for fuel each month.

FF59B. The fuel cost allocation methodology proposed by the Commission Staff for allocating fuel costs to the Texas retail fixed fuel factor customers is an appropriate methodology to apply in determining the level of Commission-authorized fuel cost disallowance that is properly allocated to EGS's Texas retail non-fixed fuel factor customers.

CL2. The Public Utility Commission of Texas (Commission) has jurisdiction over this proceeding under PURA95 §§1.101(a), 2.001, 2.208, and 2.212(g). The jurisdiction of the Commission extends to all Texas retail customers of EGS, including those customers that pay the fixed fuel factor and those that are classified as non-fixed fuel factor customers.

4. As discussed in Section III of this Order, the Commission finds that the ALJ's recommendation regarding the Cities proposed disallowance relating to EGS's short-term gas contracts is not supported by the preponderance of the evidence. Accordingly, proposed Findings of Fact Nos. 83 and 84 are deleted, Findings of Fact 83A and 84A are added, and Conclusion of Law No. 16 is modified.

FF83A. EGS did not provide sufficient evidence to meet its burden of proof in justifying its level of short-term natural gas expenditures during the reconciliation period. Furthermore, EGS's rebuttal testimony relating to the Cities' proposed disallowance of short-term natural gas expenditures is incomplete.

FF84A. The limited evidence presented by EGS relating to its short-term natural gas contracts is insufficient to allow the Commission to determine whether individual short-term natural gas purchasing decisions were prudent. Therefore, EGS has not met its burden of proof with respect to its short-term natural gas expenditures and the preponderance of the evidence favors the adoption of the Cities' proposed disallowance of $3,473,207 on a systemwide basis.

CL16. EGS's long- and short-term natural gas contracts and expenses were reasonable and necessary to provide reliable electric service to its customers during the reconciliation period, with the exception of: (a) $62,958 in spot-gas purchases at Willow Glen in March 1994, which EGS failed to show was reasonable and necessary as required by P.U.C. SUBST. R. 23.23(b)(3)(B)(i)(I), and (b) $3,473,207 in short-term natural gas expenditures for which EGS failed to meet its burden of proof in demonstrating that such expenses were reasonable and necessary.

5. Findings of Fact Nos. 183, 184 and 185 are deleted because, as discussed in Section IV of this Order, these findings are not supported by the preponderance of evidence. Findings of Fact Nos. 183A, 183B, 183C, 183D, 183E and 183F and Conclusion of Law No. 17A are added to reflect the Commission's findings regarding forced outage FO-94-01.

FF183A. The evidence presented by the Cities demonstrates that the validity of EGS's after-the-fact calculation of the effect of the process noise on the improperly installed Rosemount Model 1153 transmitters is, at best, questionable, thus, EGS has not established that the transmitters were not the cause of FO-94-01

FF183B. In its response to the NRC regarding FO-94-01, EGS concluded that the reasons for the violations were due to an "oversight on the part of engineering" and because "the maintenance planner did not properly plan the maintenance work order "

FF183C. EGS admitted in contemporaneous correspondence with the NRC that the reason for the spurious reactor trip on September 8, 1994 was because the improperly installed transmitters were overly sensitive to process noise

FF183D. The problem with the Rosemount 1153 transmitters with little or no damping being susceptible to false indications due to process noise was identified as early as April 1988 when SIL 463 was issued.

FF183E. Given that EGS personnel installed the transmitters improperly, that there were known problems with the improperly installed transmitters, and that EGS did not establish that the improperly installed transmitters were not the cause of FO-94-01, it follows that the improperly installed transmitters were the cause of FO-94-01

FF183F. The improper installation of the Rosemount 1153 transmitters was due to imprudent management on the part of EGS. Therefore, the associated replacement power costs were not reasonable and necessary expenses, and a disallowance of $1,519,787 on a systemwide basis is appropriate.

CL17A. EGS failed to show that $1,519,787 of replacement power costs associated with forced outage FO-94-01 were reasonable and necessary as required by P.U.C. SUBST. R. 23.23(b)(3)(B)(i)(I).

6. Findings of Fact Nos. 188 and 191 are modified as shown below and Findings of Fact Nos 189, 190, and 192 are deleted because, as discussed in Section V of this Order, these

findings are not supported by the preponderance of evidence. Findings of Fact Nos. 188A, 188B, 188C and 188D and Conclusion of Law No. 17B are added to reflect the Commission's findings regarding forced outage FO-94-02.

FF188. The new recirculation pump seal design failed due to accelerated wear caused by particles in the reactor cooling water at RBNS.

FF191. A "crud burst" is a phenomenon that occurs in water systems due to particulate accumulation on the inside surfaces of water pipes during normal operation.

FF188A. EGS did not properly inform MPR with purge water quality data or of the possibility of a crud burst occurring. Had the consultant been properly informed, MPR's report indicates that it would have recommended silicon carbide rather than the tungsten-carbide that eventually failed and caused forced outage FO-94-02.

FF188B. The risk assessment performed by EGS management for use of tungsten-carbide versus silicon carbide seals was not adequate because no criteria for particulate levels was defined by the vendor or asked for by design engineering.

FF188C. A reasonable utility manager would have employed all relevant information available at the time in its assessment of the risk of using of tungsten-carbide versus silicon-carbide seals. EGS failure to perform an adequate risk analysis constitutes imprudence.

FF188D. Because forced outage FO-94-02 was the result of imprudent management on the part of EGS, the associated replacement power costs were not reasonable and necessary expenses. Therefore, a disallowance of $545,548 on a systemwide basis is appropriate.

CL17B. EGS failed to show that $545,548 of replacement power costs associated with forced outage FO-94-02 were reasonable and necessary as required by P.U.C. SUBST. R. 23.23(b)(3)(B)(i)(I).

7. Findings of Fact Nos. 198 and 199 are deleted because, as discussed in Section VI of this Order, these findings are not supported by the preponderance of evidence. Findings of Fact Nos. 199A, 199B, 199C, 199D, and 199E and Conclusions of Law Nos. 9A and 17C are added to reflect the Commission's findings regarding forced outage FO-94-03.

FF199A. A contributing cause to the human error causing forced outage FO-94-03 was the improper modification of verification step procedures by EGS management. By removing the verification procedures, EGS management set up an independent verification method that established a work practice that was, as stated by EGS, "less than adequate."

FF199B. The decision by EGS management to remove the verification procedure was not reasonable in light of the circumstances, information and options available at the time, and was therefore imprudent.

FF199C. The actions and decisions of EGS's technicians that led to forced outage FO-94-03 were controllable and/or affected by EGS management.

FF199D. The ultimate performance of a utility's technicians is a function of the adequacy and reasonableness of the utility's management. With respect to FO-94-03, EGS's management was neither adequate nor reasonable because EGS management did not have in place the basic procedures or the necessary safeguards to prevent such a catastrophic event from occurring as the result of such a simple mistake.

FF199E. Because forced outage FO-94-03 was the result of imprudent management on the part of EGS, the associated replacement power costs were not reasonable and necessary expenses. Therefore, a disallowance of $657,386 on a systemwide basis is appropriate.

CL9A. Utility management is responsible for the work-related actions and decisions of its employees. Utility management is responsible for establishing, monitoring and enforcing appropriate operations and procedures and for ensuring that its employees perform up to those standards. Inadequate, substandard, or otherwise inappropriate work methods or products reflect the cumulative actions and decisions of utility management.

CL17C. EGS failed to show that $657,386 of replacement power costs associated with forced outage FO-94-03 were reasonable and necessary as required by P.U.C. SUBST. R. 23.23(b)(3)(B)(i)(I).

8. Finding of Fact No. 214A is added to more thoroughly reflect the ALJ's recommendation as discussed in Section XI.C.2. of the PFD.

FF214A. EGS did not present sufficient evidence to show that it needed the capacity as required by P.U.C. SUBST. R. 23.66(d)(1)(D) when it renegotiated the Agrilectric contract in 1994.

9. Finding of Fact No. 220A is added to clarify the amount of off-system margins and/or adders that should be allocated to ratepayers for the period covering April 28, 1994 through the end of the reconciliation period, consistent with Findings of Fact Nos. 216 through 220.

FF220A. An adjustment of $741,442, as calculated by EGS, represents the amount of off-system sales margins and/or adders that should be allocated to Texas retail fixed fuel factor ratepayers for the period covering April 28, 1994 through the end of the reconciliation period.

10. Proposed Findings of Fact Nos. 245 and 247 are deleted as they are inconsistent with the Commission's decision to surcharge over a period of time exceeding one billing period.

11. Proposed Finding of Fact No. 9 is modified as follows to clarify the language in P.U.C. SUBST. R. 23.23(b)(3)(D) regarding the procedural schedule for a fuel reconciliation.

FF9. EGS voluntarily extended the procedural schedule in this case in an effort to accommodate the Commission's issuance of a final order in the case by January 31, 1997; however, P.U.C. SUBST. R. 23.23(b)(3)(D) does not impose a jurisdictional

deadline that requires the Commission to issue a final o
subsequent to filing of a materially complete petition by

12. Proposed Findings of Fact Nos. 235, 236, 237, 238, anc
21, 22 and 23 are deleted because the total fuel expend
by the Commission in this Order differ from the total f
proposed by the ALJ in his PFD.

13. Conclusions of Law Nos. 12 and 17 are modified f
discussed in Section I of this Order.

CL12. Because the stipulation and final orde
reserved, in a non-contested proceeding, the review of
issues, *res judicata* does not preclude the consideration (

CL17. EGS failed to show that 12.94 days
River Bend Nuclear Station (RBNS) were prudently
EGS's replacement purchased power costs for that po
and necessary as required by P.U.C. SUBST. R. 23.23
cost-of-service rate regulation applicable to EGS, EGS
costs associated with an extended forced outage that is
imprudent management. However, implementation in t
service-based regulation, such as performance-based re
from the traditional application of the prudence standard

X. Ordering Paragraphs

1. The petition filed by EGS on December 7, 1995, for r
January 1, 1994 through June 30, 1995, is approved to

2. EGS shall surcharge its Texas retail fixed fuel facto
recovery allocable to such customers, with interest, b

billing cycle following the date of this Order and continuing through June 1997 The amount of the surcharge shall be based upon the Commission's findings in this Order, with adjustments on rehearing, if any, being accounted for at such time as the Commission's Order in this proceeding becomes administratively final

3. EGS shall refund its Texas retail non-fixed fuel factor customers the total systemwide fuel cost disallowances and adjustments allocable to such customers, with interest, beginning with the first practicable billing cycle following the date of this Order and continuing through the billing cycle for June 1997 consumption The amount of the refund shall be based upon the Commission's findings in this Order, with adjustments on rehearing, if any, being accounted for at such time as the Commission's Order in this proceeding becomes administratively final

4. EGS shall, in cooperation with Commission Staff, develop surcharge or refund factors, as appropriate, for EGS's Texas retail fixed fuel factor and non-fixed fuel factor customers in accordance with P.U.C. SUBST. R 23 23(b)(3)(C) and consistent with this Order Prior to implementing any surcharge or refund, EGS shall file with the Commission a status report, accompanied by supporting data, documenting the computation of the surcharge and refund factors developed pursuant to this Order

5. EGS shall file, on or before August 31, 1997, a compliance report detailing by rate class the projected and actual amounts surcharged and/or refunded to its Texas retail customers pursuant to this Order.

6. All motions, applications, or other requests for relief not expressly granted in this Order are denied for want of merit.

XI. Findings of Fact and Conclusions of Law

A. Findings of Fact

1. On December 7, 1995, Entergy-Gulf States, Inc , (EGS) filed an application with the Public Utility Commission of Texas (Commission) requesting approval of total fuel and purchased-power costs of approximately $318 million All of EGS's customers in all areas served by it in Texas will be affected by this application

2. With its application, EGS also requests authorization to defer the collection of its under-recovered fuel expense of $22,375,752, to be collected through a surcharge in a future proceeding. Alternatively, EGS proposes collection of its under-recovered fuel expenses through a surcharge of $22,275,752, less any Commission-authorized fuel cost disallowances, over a 12-month period.

3. EGS provided both published and direct mail notice of its application, as well as direct written notice to all of the parties in its last fuel reconciliation proceeding, *Application of Gulf States Utilities Company to Reconcile Fuel Costs,* Docket No 13170, 20 P U C BULL 1026 (April 18, 1995) (mem.).

   a. On January 31, 1996, EGS began providing published notice once a week for two consecutive weeks in newspapers of general circulation in each of the counties in its service area affected by the application EGS completed published notice on September 4, 1996.

   b. On February 6, 1996, EGS provided direct mail notice of its application to all of its retail customers in the form of an insert in monthly bills

   c. On June 4, 1996, EGS provided direct mail notice of its application to its large industrial customers affected by the application

   d. On August 14, 1996, EGS filed initial affidavits attesting that it provided published notice and direct mail notice to its retail customers, as well as direct written notice to the parties in Docket No 13170

e. On September 23, 1996, EGS filed revised affidavits attesting that published notice of its application had been completed

4. The following parties intervened: Certain Cities[38] served by EGS (Cities), North Star Steel Texas, Inc., (North Star); Texas Industrial Energy Consumers (TIEC), the State of Texas, the Office of Public Utility Counsel (OPC); and the Commission's General Counsel The State of Texas withdrew on July 17, 1996. TIEC did not actively participate in the hearing, but did monitor certain issues.

5. On January 9, 1996, the Commission transferred this case to the State Office Of Administrative Hearings (SOAH) to conduct a hearing and prepare a Proposal for Decision (PFD) with findings of fact and conclusions of law

6. On January 22, 1996, the Administrative Law Judge (ALJ) held the initial prehearing conference and adopted a protective order. On February 5, 1996, the Protective Order was modified and adopted.

7. On February 26, 1996, the Commission issued the Preliminary Order, including issues to be addressed and areas not to be addressed at the hearing

8. The hearing on the merits was convened on September 9, 1996, and concluded on October 8, 1996.

9. EGS voluntarily extended the procedural schedule in this case in an effort to accommodate the Commission's issuance of a final order in the case by January 31, 1997, however, P.U.C. SUBST. R. 23.23(b)(3)(D) does not impose a jurisdictional deadline that requires the Commission to issue a final order within the one-year time frame subsequent to filing of a materially complete petition by the utility

[38] The Cities include Port Neches, Groves, Nome, Vidor, Beaumont, China, Conroe, Port Arthur, and Nederland.

10. EGS, as one of five wholly-owned operating subsidiaries of the Entergy Corporation, serves a 28,000 square-mile area stretching across 350 miles of Gulf Coast region from Baton Rouge, Louisiana, to within 50 miles of Austin, Texas.

11. EGS's electric utility operations are approximately evenly divided between Texas and Louisiana, with the Company divided into two general customer-service regions as follows: the Southwest Region, headquartered in Beaumont, Texas, and ranging from Somerville, Texas, to Jennings, Louisiana, and the Southern Region, headquartered in Baton Rouge, Louisiana, and ranging from Jennings to the Bogalusa District of the Louisiana Power & Light Company.

12. Throughout its two customer-service regions, EGS provides electric utility service to over 595,000 customers.

13. EGS owns four fossil-fuel powered generating plants, including two in Texas and two in Louisiana. Approximately 44 percent, or 2,410 megawatts (MW) of EGS's total generating capacity is provided by its Texas power plants, which are located near Bridge City, Orange County, Texas (Sabine Station), and near Willis, Montgomery County, Texas (Lewis Creek Station).

14. EGS's Louisiana power plants provide the remaining 56 percent, or 3,076 MW of fossil fuel-powered generating capacity, and are located near St. Gabriel, Iberville Parish, Louisiana (Willow Glen Station), and Westlake, Calcasieu Parish, Louisiana (Nelson Station).

15. All of EGS's Texas and Louisiana power plants, with the exception of Nelson Station, Unit 6, normally use natural gas as a base-load fuel. Nelson Station, Unit 6, is a 550 MW coal-fired generating unit that has no natural gas fuel burning capability. EGS owns approximately 70 percent, or 385 MW of Nelson Station, Unit 6. The remaining 30 percent, or 165 MW, of Nelson Station, Unit 6, is owned in part by the Sam Rayburn Municipal Power Agency

(SRMPA) (accounting for 20 percent or 110 MW) and by Sam Rayburn G&T, Inc., (SRG&T) (accounting for 10 percent or 55 MW).

16. EGS also owns 42 percent, or 227 MW, of a coal-fired generating unit known as Big Cajun II, Unit 3, operated by the Cajun Electric Power Cooperative, Inc., (CEPCO), and located near New Roads, in Pointe Coupee Parish, Louisiana.

17. In addition to all of the foregoing generating capacity, EGS also owns a 70 percent share in the River Bend Nuclear Station, a Boiling Water Reactor (BWR) Nuclear Power Plant located near St. Francisville, Louisiana.

18. The Entergy Corporation (Entergy) is an investor-owned public utility holding company headquartered in New Orleans, Louisiana.

19. Entergy's five wholly-owned operating companies include Entergy-Arkansas, Inc., Entergy-Gulf States, Inc., (EGS), Entergy-Louisiana, Inc., Entergy-Mississippi, Inc., and Entergy-New Orleans, Inc. Collectively, the five Entergy Operating Companies (EOC) provide electric utility service to approximately 2.4 million retail customers.

20. The Federal Energy Regulatory Commission (FERC) approved the merger of EGS and Entergy, along with the corresponding Entergy System Agreement (ESA) amendment, effective January 1, 1994, in Opinion No. 385, *Entergy Service, Inc., and Gulf States Utilities Company,* 65 F.E.R.C. (CCH) Par. 61,332 (1993).

21. The Entergy System Agreement (ESA) is the contract that provides the basis for the joint planning and operation of the Entergy System, including the EOCs. The ESA governs the wholesale power transactions among the EOCs by providing for joint operation and establishing the basis for equalizing, among the EOCs, the costs associated with the construction, ownership, and operation of system facilities.

22. Entergy's System Operations Center (SOC) and Resource Planning Department are responsible for implementing the ESA. The SOC is responsible for billing the different EOCs in accordance with the six service schedules that make up the ESA, and the payments and receipts under those schedules are set forth for each EOC in the monthly Intra-System Bill (ISB)

23. The ESA was originally approved by the FERC in Opinion No 234, *Middle South Energy, Inc.*, 31 F.E.R.C. (CCH) Par. 61,305 (1985), along with six service schedules as follows: MSS-1, Reserve Equalization; MSS-2, Transmission Equalization, MSS-3, Exchange of Electric Energy Among the Companies; MSS-4, Unit Power Purchases, MSS-5, Distribution of Revenue from Sales Made for the Joint Account of All the Companies, and MSS-6, Distribution of Operating Expenses of Systems Operations Center Proposed Schedule MSS-7, Merger Fuel Protection Procedures, the so-called "fuel tracker," is pending but has not been finally approved by the FERC.

24. Schedule MSS-2 provides for transmission equalization payments to equalize the costs among the EOCs associated with Entergy's transmission grid The payments under MSS-2 are calculated according to an FERC-approved formula

25. Schedule MSS-3 determines the pricing and exchange of energy among the EOCs By approving Schedule MSS-3, the FERC has determined how the EOCs will be reimbursed for energy sold to the exchange energy pool and how that energy is to be purchased

26. Under Schedule MSS-3, if an EOC such as EGS supplies EGS-generated energy to the pool, the supplying Company receives an Operations & Maintenance (O&M) adder, the purpose of which is to reimburse the EOC for the incremental costs associated with making the sale to the exchange energy pool. This FERC-approved O&M adder is not reflected in fuel costs and is separate and distinct from the off-system sales adder referenced in Commission Preliminary Order Issue No. 9.

27. In contrast, when an EOC makes energy that was purchased outside the Entergy operating system available to the pool, it is reimbursed only for the costs of the energy under Schedule MSS-3.

28. Schedule MSS-5 addresses the net balance from energy sales made to companies other than EOCs for the joint accounts of all EOCs ("Joint Account Sales"). The net balance is calculated by deducting any costs associated with Joint Account Sales from the gross revenues received for the sales, and is then distributed among the EOCs in proportion to each EOC's "Responsibility Ratio."

29. According to the ESA, an EOC's "Responsibility Ratio" is its own load responsibility divided by the system load responsibility, which is the average of the previous 12-months hourly loads coincident with the system's monthly peak hourly load.

30. During January through August 1994, EGS experienced significantly higher natural gas prices than the $1.85 per MMBtu forecasted price upon which EGS's fixed fuel factors in effect during the reconciliation period were based.

31. During the first eight months of the reconciliation period, EGS's actual system-weighted average natural gas prices ranged from $1.95 to $2.86 per MMBtu. During that time, EGS's under-recovered fuel balance, including interest, increased to $27,564,084, but then decreased to $22,375,752 through June 30, 1995, with the decline in natural gas prices.

32. Because of the size of the under-recovery and its projection that it would continue to operate in a state of material under collection, in September 1994, EGS filed with the Commission an application styled: *Application of Gulf States Utility Company to Surcharge a Cumulative Under-Collection of Fuel and Purchased Power Costs,* Docket No. 13409, 20 P.U.C. BULL. 686 (Jan. 18, 1995) (mem.). Docket No. 13409 was resolved by stipulation.

33. The Commission's Order in Docket No 13409 directed EGS to reconcile, in calendar year 1995, its fuel and purchased power costs from January 1, 1994, and for the next twelve months thereafter. EGS filed the instant application on December 7, 1995, in compliance with the Commission's Order.

34. During the merger proceedings in Docket No 11292, EGS and Entergy predicted merger-related fuel savings of approximately $40 5 million on a systemwide basis, of which approximately $35 million, or 86.4 percent, represents EGS's Texas jurisdictional share of the projected merger-related fuel savings.

35. In actual fact, EGS experienced merger-related fuel savings of approximately $12 million in 1994 and $9.6 million in 1995, or approximately $21 6 million on an Entergy systemwide basis, of which approximately $9 6 million is EGS's Texas jurisdictional share

36. EGS's actual merger-related fuel savings were not as high as Entergy and EGS projected in the merger proceedings due to the cumulative effect of natural gas price volatility during the reconciliation period and due to the inputs into EGS's "PROMOD" computer model used to project merger-related fuel savings.

37. EGS's Texas jurisdictional share, or $9 6 million, of the merger-related fuel savings is reasonable, given the actual data inputs available to EGS to make the PROMOD runs and the volatile natural gas prices during the reconciliation period

38. EGS's fuel factors set in Docket No 10894 were not based on the merger forecast gas prices or other assumptions, but proved to be set too low based on a forecasted gas price of $1.76/MMBtu, since gas prices during the first eight months of the reconciliation period ranged from $1.95/MMBtu to $2.86/MMBtu.

39. In Docket No. 12712, EGS's fuel factors were again revised effective in March 1994 to approximate a gas price of $1.85/MMBtu, but gas prices did not decline to that level until September 1994, further contributing to an increase in EGS's fuel cost under-recovery

40. EGS's recoverable fuel expense during the reconciliation period was approximately $59.1 million higher, or $22.9 million higher on a Texas jurisdictional basis, in 1994 than was recovered through EGS's fixed fuel factors approved in Docket No 12712

41. Therefore, there is no correlation between the amount of EGS's fuel cost under-recovery during the reconciliation period and its projected merger-related fuel savings, because the under-recovery was a function of EGS's fixed fuel factors, which were set too low in relation to highly volatile commodity gas prices.

42. Because there is no correlation between the level of EGS's merger-related fuel savings and the amount of its fuel-cost under-recovery during the reconciliation period, it would not be appropriate to offset EGS's fuel-cost under-recovery by any short-fall in projected merger-related fuel savings.

43. EGS's Texas retail fixed-fuel-factor customers receive merger-related fuel savings through EGS's fixed-fuel-factor and its impact on their monthly bills, because EGS's merger-related fuel savings are embedded in EGS's reconcilable fuel and purchased power costs

44. Whether EGS's Texas retail customers paying the fixed fuel factor received a proportionate share of EGS's merger-related fuel savings depends on how EGS allocates fuel costs to its Texas retail fixed-fuel-factor ratepayers

45. To the extent that EGS's fuel costs are lower than they would have been had the merger with Entergy not occurred, this fuel cost reduction would be passed through to EGS's customers on a proportionate basis if EGS allocated fuel costs on a proportionate basis

46. EGS's Texas retail customers did no savings because EGS does not allocate fuel c to the fuel costs actually incurred to serve eac

47. Entergy's systemwide merger-relate customers since these savings are embedded i a result of the merger. A correct, proportio fixed-fuel-factor customers should result in i EGS's merger-related fuel savings.

48. EGS's fuel costs are allocated to its T ratio of Texas fixed-fuel-factor kWh sales at "Texas Retail Allocator"), with the non-fixe denominator of the Texas Retail Allocator. E sales from its calculation of its adjusted sys from the fuel cost allocation altogether.

49. Because there is an average fuel co customer imposes on the EGS system whethe of incremental or average fuel cost, EG proportionately allocate fuel costs or merger-r customers on a consistent basis because it d factor customers' usage.

50. The fuel cost allocation methodolog Texas retail fixed fuel factor customers their costs EGS actually incurs to serve each type o

51. The net effect of the Commission Staff's fuel cost allocation methodology is that a slightly lower, more proportionate share of EGS's systemwide fuel costs are allocated to EGS's Texas retail fixed-fuel-factor customers than under EGS's methodology

52. EGS allocates system fuel costs differently among its Texas retail fixed-fuel-factor customers and its special rate, non-fixed-fuel-factor customers, depending on whether the energy charge on the tariff schedule for the non-fixed-fuel-factor customers is based on system "average fuel cost," or whether it is based on "incremental fuel cost "

53. If the energy charge on the tariff schedule for a special rate, non-fixed-fuel-factor customer is based on systemwide average fuel cost, then the kWh sales and expenses incurred to serve that customer class are not subtracted by EGS in its fuel cost allocation methodology to account for these customers' fuel costs.

54. Conversely, if the energy charge on the tariff schedule for a special rate, non-fixed-fuel-factor customer is based on system incremental fuel cost, then EGS subtracts the kWh sales and expenses incurred to serve that customer class from its fuel cost allocation methodology, i e , EGS removes their usage and expenses from the fuel cost allocator utilized to impute or determine the fuel costs for EGS's customers

55. EGS currently has six special rate schedules which do not use a fixed fuel factor to recover fuel expenses. Because these six special rate schedules are non-cost-based discount rates, there is no requirement in the tariffs that they recover costs through a fuel factor Some of the special rate schedules are incentive rates and some are experimental

56. The fuel charge on a EGS special rate customer's tariff does not necessarily equate to the fuel expense incurred by EGS to serve that customer EGS's incentive and experimental rates are not necessarily based on cost causality.

57. Because EGS's fuel cost allocation methodology does not proportionately allocate fuel costs to its Texas retail fixed-fuel-factor customers and non-fixed-fuel-factor customers on a consistent basis, the fuel costs incurred by special rate, non-fixed-fuel-factor customers were subsidized by the fixed-fuel-factor customer class in any given month of the reconciliation period, depending on whether EGS's system average fuel costs were greater than or less than its system incremental fuel costs.

58. During the reconciliation period, EGS's fixed- and non-fixed-fuel-factor customers actually experienced cross-subsidies of each others' fuel costs from month-to-month. The cross-subsidies during the reconciliation period almost canceled each other out, with the difference amounting to approximately $50,000. However, the absolute magnitude of the monthly cross-subsidies or cost-shifting during the reconciliation period amounted to approximately $900,000.

59. As discussed at Section VIII of the PFD, the appropriate fuel cost allocation methodology in this case requires that EGS include fuel costs imposed on the system by non-fixed-fuel-factor customers in both the Texas Retail Allocator and in the EGS System Adjusted Expenses variables of the allocator, regardless of whether those customers' fuel costs are priced on a system incremental cost basis. This fuel cost allocation methodology thereby ensures that fuel costs are allocated proportionately to both fixed- and non-fixed-fuel-factor customers based on actual cost incurrence and that each class of customers bears its proportionate share of EGS's fuel costs. Because this fuel cost allocation methodology is based on actual fuel cost incurrence, it will also eliminate the month-to-month cost shifting or cross-subsidization that occurred between EGS's fixed- and non-fixed-fuel-factor customers during the reconciliation period.

59A. EGS serves Texas retail customers that are not charged the fixed fuel factor, and these customers do not automatically receive the benefit of a fuel cost disallowance that is flowed through to customers via the fixed fuel factor. Therefore, EGS's Texas retail non-fixed fuel factor customers must be credited their proportionate share of any Commission-authorized fuel cost disallowance directly through the same mechanism by which such customers are billed for fuel each month.

59B. The fuel cost allocation methodolog fuel costs to the Texas retail fixed fuel facto in determining the level of Commission-a allocated to EGS's Texas retail non-fixed fue

60. EGS did not present sufficient evide methodology to account for the fact that ther the fuel cost any customer imposes on EGS's fuel on the basis of system incremental fuel c

61. During the reconciliation period, EG before any disallowances, of approximately $ the reconciliation period.

62. EGS purchased approximately 44 per and acquired the remaining 56 percent thro period.

63. The factors most affecting EGS's n included the role of natural gas in EGS's ca which the Company purchased its gas. Natu EGS's energy mix during the reconciliation p

64. EGS's long-term natural gas contract requirements during the reconciliation peri reconciliation period generally followed the EGS's natural gas supplies must therefore be flexible ways to provide for the changes EGS electricity during the reconciliation period.

65. The FERC's natural gas transportation open access and unbundling initiatives promoted the development of a commodity-driven, short-term gas market during the reconciliation period. The FERC's unbundling initiative meant that full-service gas transportation services were disaggregated into gathering, transportation, imbalance control, flexibility, and storage services, with separate charges for each individual service. The impact of these developments on EGS during the reconciliation period resulted in an operational need to negotiate separate contracts for highly reliable and flexible natural gas swing services. Open access also resulted in a more competitive short-term gas market.

66. EGS's short-term gas supply purchasing strategy predicts the volume of gas to be purchased during "bid-week." Bid-week is the formalized period immediately preceding the operational month during which gas suppliers and gas purchasers conduct monthly gas supply transactions and when monthly pipeline nominations must be made.

67. Although EGS attempts to purchase the bulk of its short-term natural gas during bid-week, in reality, during the reconciliation period, EGS had to purchase as much as 30 percent of its short-term gas needs as daily or after-market gas at or near the end of the month.

68. EGS's long-term natural gas supply contracts included the Pontchartrain and Spindletop Gas Distribution System (SGDS) agreements, which were both signed in 1984 and amended in 1991. The high degree of flexibility, reliability, and swing provided by the Pontchartrain and SGDS contracts gave EGS the ability to maximize its purchasing activities in the short-term gas market by purchasing base-load, interruptible short-term gas with the assurance that it could still meet its swing requirements.

69. Both agreements contain supplier's Weighted Average Cost of Gas (WACOG) pricing mechanisms, plus a seller's margin pricing mechanism of $0.31 per MMBtu. The supplier's WACOG price term is capped by a gas market index and a fuel oil alternative price ceiling, giving the seller an incentive to offer EGS competitive long-term gas prices.

70. EGS's natural gas acquisition strategy of maximizing its spot gas purchases permits it to take advantage of a swing transportation agreement with Sabine Gas Transmission Company (SGT) and the capacity in the Spindletop Storage Facility. On August 1, 1991, EGS entered into an agreement with SGT whereby SGT has the responsibility of providing EGS with natural gas transportation services, delayed transportation services, swing service, and storage capacity in the Spindletop natural gas storage facility in return for a transportation fee.

71. SGT's legal right to market unused capacity in the Spindletop storage facility is limited by the agreement, pursuant to which EGS has first priority on capacity and deliverability of natural gas. SGT must obtain prior approval from EGS before entering into any third-party transactions.

72. Although EGS may release unused capacity in Spindletop back to SGT for marketing to third parties, all net revenues, defined as revenues less electricity, operations, and maintenance expenses, from third-party transactions must be immediately credited to reduce the "pay-off amount" owed by EGS to SGT as long as the pay-off amount is greater than zero, under the terms of the agreement.

73. Because the pay-off amount under the SGT agreement was greater than zero during the reconciliation period, EGS did not directly receive any of the revenues from third-party transactions in excess capacity in the Spindletop storage facility during the reconciliation period.

74. During the reconciliation period, SGT received approximately $488,602.15 in third-party net revenues attributable to third-party transactions in the Spindletop storage facility. After the reconciliation period, SGT received an additional $47,973.32 in net revenues from third-party transactions also conducted during the reconciliation period, for total reconciliation period third-party revenues of $536,575.47.

75. The value to third parties of the excess capacity in SGT's Spindletop storage facility during the reconciliation period was greatly diminished due to (1) the limited amount of excess

capacity available after EGS's requirements were met, (2) the period when excess storage was available for released to third parties; and (3) the geographic proximity of the Spindletop storage facility to major gas marketing centers.

76. There was very little excess capacity available for third-party transactions in the Spindletop natural gas storage facility during the reconciliation period EGS needed approximately 1,000,000 MMBtu of working gas capacity in Spindletop during the reconciliation period for operational purposes and maintenance of system flexibility and reliability alone. EGS needed between 1,500,000 MMBtu and 1,700,000 MMBtu of additional capacity for seasonal price arbitrage during the fall and winter months of the reconciliation period.

77. During the reconciliation period, third-party utilization of Spindletop accounted for only about 15 percent of the injections and 19 percent of withdrawals

78. EGS did permit SGT to market excess capacity in Spindletop to Koch, Centana, and Eastex Gas Marketing Companies during the reconciliation period

79. EGS's offset, through SGT, of the pay-off amount with net third-party revenues from the marketing of excess capacity in Spindletop during the reconciliation period was reasonable, because EGS will likely require additional storage capacity in Spindletop in the future and that capacity will enable EGS to reduce its reliance on more expensive long-term and spot natural gas.

80. EGS's efforts to market excess capacity in the SGT Spindletop natural gas storage facility during the reconciliation period were reasonable, to the extent any excess capacity existed after EGS's requirements were met and in light of the greatly diminished value of such services to third parties.

81. EGS had to purchase a significant amount of its short-term gas on a daily and weekly basis after bid-week in response to changes in its system operational conditions during the reconciliation period, including changing customer demand for electricity, unanticipated changes in the availability of off-system economy energy, fuel supply and transportation constraints, and compliance with interstate pipeline tariffs and rules.

82. On average, during the reconciliation period, EGS purchased approximately thirty percent of its monthly short-term gas supplies after bid-week. The amount of short-term gas EGS purchased daily during the reconciliation period varied significantly during the reconciliation period, based on the bidders' anticipation of market changes and EGS's anticipation of market changes and variations in the short-term market.

83. Deleted.

83A. EGS did not provide sufficient evidence to meet its burden of proof in justifying its level of short-term natural gas expenditures during the reconciliation period. Furthermore, EGS's rebuttal testimony relating to the Cities' proposed disallowance of short-term natural gas expenditures is incomplete.

84. Deleted.

84A. The limited evidence presented by EGS relating to its short-term natural gas contracts is insufficient to allow the Commission to determine whether individual short-term natural gas purchasing decisions were prudent. Therefore, EGS has not met its burden of proof with respect to its short-term natural gas expenditures and the preponderance of the evidence favors the adoption of the Cities' proposed disallowance of $3,473,207 on a systemwide basis.

85. Although there was no reason for EGS to burn fuel oil instead of natural gas at EGS's Willow Glen Station in March 1994 because there was no gas curtailment at that time and the generating unit would have been derated, EGS had nevertheless burned fuel oil at the Willow

Glen Station generating units at or very near to the time of the March 1994 spot natural gas purchases from Koch and Pontchartrain.

86. Entergy and EGS therefore could have made the switch from natural gas to fuel oil at Willow Glen in March of 1994 and knew or should have known that the price differential existed, making fuel oil the more economical fuel to burn

87. $62,958 represents the difference between the price of natural gas and fuel oil at Willow Glen Station in March 1994, based on the number of MMBtu used, and therefore this natural gas fuel expense was unreasonably incurred and should be disallowed

88. The inventory price for No. 6 fuel oil at Willow Glen Station in March 1994 was $2.3145/MMBtu, and the price of spot natural gas was $2 42/MMBtu and $2 60/MMBtu, depending on the supplier.

89. EGS purchased 48,732 MMBtu of natural gas from Koch Gas Services Co at $2.42/MMBtu and 136,327 from Pontchartrain Natural Gas System at $2 60/MMBtu in March 1994.

90. The total MMBtu available from No 6 fuel oil at Willow Glen Station in March 1994 was equivalent to the total 185,059 MMBtu of natural gas purchased at the higher price

91. A motion for sanctions is required to (1) contain all of the factual allegations necessary to apprise the parties of the conduct at issue; (2) request specific relief, and (3) be verified by affidavit. P.U.C. PROC. R. 22.161(e).

92. The request for imposition of sanctions filed by General Counsel with its Initial Closing Brief does not contain the level of factual allegations necessary to apprise the parties of the conduct alleged to be at issue on the part of EGS because it is not clearly stated and it is not verified by sworn affidavit. In any event, a hearing must be held before a ruling on a motion for

sanctions can be made, provided the motion is properly before the Commission in accordance with P.U.C. PROC. R. 22.161(e).

93. EGS's long-term Pontchartrain natural gas swing contract was effective on November 1, 1991, and was subject to review by the Commission in a previous fuel reconciliation in Docket No. 13170, *Application of Gulf States Utilities Company to Reconcile Fuel Costs,* 20 P.U.C. BULL. 1026 (April 18, 1995) (Conclusion of Law No. 6).

94. Docket No. 13170 was a stipulated or settled fuel proceeding, and the doctrine of collateral estoppel or "issue preclusion" applies to facts that were fully and fairly litigated in the prior action.

95. The reasonableness of EGS's Pontchartrain long-term natural gas swing contract was not fully and fairly litigated in Docket No. 13170 because that docket was stipulated and the agreement specifically reserved agreed issues for consideration in future proceedings. EGS was a party to the agreement.

96. EGS entered into the Pontchartrain and Spindletop Gas Distribution System (SGDS) long-term natural gas contracts in 1984 after an earlier long-term agreement with Exxon USA became less economical. These identical contracts are reasonable and are based on the seller's WACOG plus a margin of $0.31/MMBtu.

97. The Pontchartrain and SGDS long-term gas supply agreements provide EGS with a high degree of flexibility and reliability because they allow significant long-term gas supplies to be shifted between EGS's Willow Glen Station, which is located in Louisiana, and it Texas power plants. The seller's margin of $0.31/MMBtu reasonably accounts for the high degree of swing and flexibility in these contracts.

98. At the time EGS entered into the Pontchartrain and SGDS long-term agreements, the seller's WACOG was an appropriate and reasonable measure of pricing for long-term natural gas

used in the industry. The SGDS contract was only recently changed to an index when it was renegotiated in 1994 at the new supplier's request for deliveries through a different pipeline

99. The use of a published index, plus a margin of $0 15/MMBtu, as a standard of review for EGS's Pontchartrain and SGDS long-term natural gas contracts does not reflect the circumstances in existence at the time the contracts were entered into and accordingly it is not a reasonable standard by which to assess the reasonableness of the contracts' price terms

100. A margin of $0.15/MMBtu, as proposed by Cities, does not account for the degree of swing and flexibility in EGS's long-term contracts with Pontchartrain and SGDS

101. EGS had approximately $94,552,504 in total eligible coal costs during the reconciliation period.

102. Of its total eligible coal costs, roughly two-thirds or $60,845,303 of EGS's coal costs were attributable to coal burned at EGS's Nelson Station, Unit 6, a coal-fired generating unit The remainder of $33,707,201 in EGS's eligible coal costs were attributable to Big Cajun II, Unit 3, coal and displaced power costs.

103. The coal for EGS's coal-fired generating units is supplied under a long-term contract with Kerr-McGee Corporation (Kerr-McGee) from its mines in Wyoming EGS also purchased approximately 7,884 tons of spot coal from Kerr-McGee during the reconciliation period for its Nelson Station, Unit 6 generating unit.

104. EGS is also a party to a long-term transportation agreement with the Burlington Northern and the Kansas City Southern Railroads for delivery of the coal from Kerr-McGee's mines to EGS's coal-fired generating plants. Neither of these long-term transportation agreements was amended during the reconciliation period.

105. EGS purchased coal for its Big Cajun II, Unit 3, (Big Cajun) generating station under a long-term contract with the Triton Coal Company (Triton). The coal was transported to the Big Cajun station by rail and barge transportation during the reconciliation period.

106. EGS owns 42 percent of Big Cajun II, Unit 3, which is operated and owned in part by the Cajun Electric Power Cooperative, Inc., (CEPCO). EGS's 42 percent share accounts for approximately 227 MW of the total 540 MW rated generating capacity of Big Cajun II, Unit 3. CEPCO's remaining 58 percent share accounts for 313 MW.

107. On January 1, 1995, EGS changed its coal inventory accounting methodology from last in, first out, (LIFO) to the average cost method. EGS made this change to be consistent with Entergy's inventory accounting valuation methodology.

108. As a result of EGS's change to the average cost method, the value of EGS's coal inventory decreased by $996,109. The corresponding decrease in EGS's revenue requirement is a net reduction in Texas retail base rate revenues of $56,787.

109. EGS's change in coal inventory accounting methodology from LIFO to average cost resulted in fuel savings during the reconciliation period because the prices EGS paid for coal purchased during the first six months of 1995 were higher than the average price of all of the coal in its inventory.

110. Under the LIFO method, the cost of coal in EGS's inventory reflects the market price of coal. In contrast, under the average cost accounting method, the cost of the less expensive coal purchased by EGS in previous years and still in inventory decreases the overall average cost of the inventoried coal burned at EGS's power plants during the reconciliation period.

111. Therefore, the change in coal inventory accounting methodology from LIFO to average cost method did not have a significant adverse impact on ratepayers, but likely lowered the coal

costs they would have otherwise paid during the reconciliation period, had the change in inventory accounting valuation methods not been made

112. In October 1994, CEPCO advised EGS that CEPCO had expended all available funds for operating CEPCO's 30 percent share of the River Bend Nuclear Station (River Bend) CEPCO therefore advised that it would not make any further payments to EGS in 1994 for River Bend's operations, maintenance, or capital expenses.

113. Consequently, EGS ceased providing all power to CEPCO from River Bend and informed CEPCO that it would: (1) credit EGS's share of the expenses attributable to Big Cajun II, Unit 3, against amounts that CEPCO owed to EGS for operation of River Bend, and (2) seek to market CEPCO's share of the power from River Bend and apply the proceeds from that power against amounts that CEPCO owed to EGS.

114. Therefore, from November 2 through December 19, 1994, (the "displacement period"), CEPCO refused to provide EGS with EGS's share of the power from Big Cajun II, Unit 3

115. Because CEPCO withheld EGS's share of power from Big Cajun II, Unit 3, during the displacement period, EGS replaced the energy which would have been generated by Big Cajun II, Unit 3, with more expensive energy, specifically purchased power and power from the other EOCs ("replacement power").

116. Instead of including the cost of this "replacement power" in its reconcilable fuel costs, EGS computed reconcilable fuel costs for the displacement period as if Big Cajun II, Unit 3 had continued to supply energy to EGS and as if the replacement power had not been purchased This displaced cost adjustment represents the difference between the more expensive replacement power and an estimate of what the power from Big Cajun II, Unit 3, would have cost EGS's ratepayers if it had been operated during the displacement period

117. In September 1994, EGS made an incorrect calculation, inflating the coal costs preceding the displacement period for Big Cajun II, Unit 3, and amounting to approximately $226,583 on a total company basis, or $90,653 on a Texas jurisdictional basis, meaning that EGS's coal costs should be adjusted downward by $90,653.

118. Had EGS calculated reconcilable coal costs for September 1994 utilizing the correct tonnage of coal actually burned at Big Cajun II, Unit 3, the total reconcilable coal costs for that month would have been $2,368,985 for coal stock purchases and transportation, instead of $2,594,568 which EGS requested. The difference is approximately $225,583 on a total company basis, or $90,653 on a Texas jurisdictional basis.

119. In making its displaced cost adjustment calculation to account for the cost of the replacement power for Big Cajun II, Unit 3, EGS relied on questionable coal inventory data provided by CEPCO, failed to take into account the effect of prior month true-ups, and did not adjust for a 50,000 ton coal inventory adjustment made by CEPCO; EGS's displaced cost adjustment calculation of the coal costs attributable to the pseudo-burn at Big Cajun II, Unit 3 were therefore based on unsound data.

120. In light of the fact that Big Cajun II, Unit 3, did not actually generate power for EGS during the displacement period, it was not possible for EGS to accurately predict what the heat rate and unit efficiency of Big Cajun II, Unit 3, would have been in order to accurately calculate the displaced power cost adjustment for the reconciliation period.

121. Because it was not possible to accurately predict what the heat rate or unit efficiency would have been for Big Cajun II, Unit 3, during the displacement period had it provided EGS's share of the output, the best cost estimate available is the price of power EGS relied upon in deciding whether or not to schedule power from Big Cajun II, Unit 3.

122. The replacement power costs for Big Cajun II, Unit 3, can best be calculated utilizing an approximate cost of $15/MWh, which is the cost EGS's own dispatchers use in determining

whether or not to schedule power from Big Cajun II, Unit 3. This cost is very close if not essentially the same as the $14.85/MWh cost of coal EGS utilized in its PROMOD computer runs to estimate the merger-related fuel savings for the reconciliation period.

123. Calculating the costs of generation or replacement power for Big Cajun II, Unit 3, during the displacement period based on a cost of $14.85/MWh, with 95.27 percent of that cost as reconcilable cost, results in a reconcilable cost of replacement power at Big Cajun II, Unit 3, of $14.15/MWh.

124. Therefore, $14.15/MWh is the cost that should be utilized to calculate the cost to EGS of replacement power for Big Cajun II, Unit 3, during the displacement period.

125. EGS had 255,300 MWh of displaced or replacement power at Big Cajun II, Unit 3, during the displacement period, resulting in reconcilable cost of generation for the reconciliation period of $3,612,495 ($14.15/MWh x 255,300 MWh = $3,612,495), which is $704,608 less, on a total company basis, than the $4,317,103 EGS charged or requested for this item in its application.

126. The foregoing methodology is an appropriate methodology of calculating the cost of replacement power for Big Cajun II, Unit 3, under the circumstances and eliminates the uncertainties and inaccuracies posed by EGS's methodology, which places too much reliance on unsound data from CEPCO's coal inventory and the unknown heat rate of the units at Big Cajun II.

127. Application of the foregoing methodology results in a reduction of $704,608 in reconcilable coal costs for EGS on a total company basis, or $226,447, with interest, on a Texas jurisdictional basis.

128. EGS's portion of the long-term coal consumed at Big Cajun during the reconciliation period was 1,599,232 tons or 25,943,427 MMBtu, representing total reconcilable coal expenses of $33,707,201.

129. The long-term coal supply for EGS's share of Big Cajun was purchased by CEPCO in conjunction with the Western Fuel Association (WFA). EGS's long-term coal expenses for its share of Big Cajun of $33,707,201, subject to any disallowances for the cost adjustments for Big Cajun II, Unit 3 during the displacement period, were reasonable.

130. EGS's portion of the long-term coal purchases at Nelson Unit 6 accounted for 2,383,251 tons or 40,231,501 MMBtu for the reconciliation period, representing total reasonable reconcilable long-term coal expenses of $60,812,584.

131. In December 1994, EGS purchased 7,884 tons of spot coal from Kerr-McGee for its Nelson Unit 6 at a price of $4.15/ton or $0.2413/MMBtu. Under the terms of the spot-coal letter agreement, Kerr-McGee agreed to deliver up to 150,000 tons of coal at the $4.15/ton price.

132. EGS did not seek bids from any coal suppliers other than Kerr-McGee for the December 1994 spot-coal purchase, relying instead on a reported spot bid of $4.43/ton for 1995 deliveries of coal to the Lower Colorado River Authority (LCRA) and because the Kerr-McGee bid was lower than the LCRA's.

133. EGS could have obtained a lower bid for spot-coal in December 1994 if it had solicited bids from other Wyoming coal producers. The October 3, 1994 issue of *Coal Week* reported that Grand Island Nebraska purchased spot coal from the Caballo Rojo Mine for $4.05/ton or $0.2411/MMBtu. Additionally, for October, November, and December 1994, *Coal Week* also reported that the marker price for 8,400 Btu/lb. coal from Wyoming was $4.05/ton.

134. EGS was not prudent in its decision to purchase the spot coal from Kerr-McGee in December 1994 without bidding and should have solicited bids from all of the coal suppliers served by the Burlington Northern Railroad in Wyoming and taken the lowest bid

135. EGS's December 1994 spot-coal purchase for Nelson Unit 6 should have reflected the lower market prices at the time of the purchase The market price for the total 7,884 ton spot-coal purchase for Nelson Unit 6 during the reconciliation period was $31,930 20, at a price of $4.05/ton. EGS paid approximately $32,719 for the spot-coal from Kerr-McGee at a price of $4.15/ton, or approximately $788 more than it should have paid for the spot coal at the time

136. EGS did not include any expenses of the Nelson Rail Spur, a rail spur that is being constructed to its Nelson Station. EGS originally intended to complete the spur in 1995, but delayed its completion because it believed that the lower transportation rate to justify the construction of the spur was not available from the railroad companies

137. Although EGS never received the equivalent of written bids containing rates used to justify the construction expense of the Nelson rail spur, it received verbal assurances from railroads that deliveries could be made over the Union Pacific/Southern Pacific railroads at a substantial savings over existing rates.

138. EGS's use of an estimated transportation rate during the reconciliation period to justify a several million dollar rail spur is not prudent management Unless and until EGS shows complete and credible documentation that the rail spur is a benefit to EGS's ratepayers, EGS should not include any of the expenses in its fuel reconciliation or future rate proceedings

139. EGS burned approximately 221,192 barrels of fuel oil or the equivalent of 1,396,899 MMBtu during the reconciliation period, resulting in total reconcilable fuel oil expenses of $4,028,017.

140. EGS burns small amounts of No. 2 fuel oil at its Sabine Station, Nelson Unit 6, and Big Cajun II, Unit 3, power plants for start-up and flame stabilization. Additionally, EGS maintains contingency supplies of No. 6 fuel oil in inventory at its Sabine, Willow Glen, and Nelson Stations in the event of gas curtailments during severe cold weather.

141. EGS purchased its fuel oil during the reconciliation period by soliciting bids from an approved qualified bidder's list. Accordingly, EGS's reconcilable fuel-oil expenses of $4,028,017 for the reconciliation period were reasonable and necessary.

142. EGS owns 70 percent of the River Bend Nuclear Station (RBNS), a General-Electric (GE) designed Boiling Water Reactor (BWR) nuclear power plant located near St. Francisville, Louisiana, which is approximately 24 miles north of Baton Rouge, Louisiana. CEPCO owns the remaining 30 percent share in RBNS. The plant is operated by Entergy Operations, Inc., since the merger of EGS with Entergy.

143. RBNS achieved commercial operation on June 16, 1986, and its nuclear reactor is rated at a capacity of 2,984 MWh, with its turbine generator rated at 936 MWe (Megawatts net electric).

144. Although RBNS' performance during the reconciliation period was comparatively low, based on its heat rate, capacity factor, and forced outage rates and those of other U.S. BWRs, Entergy's long-term goal of placing RBNS in the top quartile performers of national BWR nuclear power plants resulted in a substantial performance improvement during the reconciliation period.

145. RBNS' comparatively poor performance during the reconciliation period was due to an extended forced outage (FO-94-02) which started on September 8, 1994, and lasted approximately 42.7 days.