BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 110001-EI ORDER NO. PSC-11-0579-FOF-EI ISSUED: December 16, 2011

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
EDUARDO E. BALBIS
JULIE I. BROWN

APPEARANCES:

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FINAL ORDER APPROVING EXPENDITURES AND TRUE-UP AMOUNTS FOR FUEL ADJUSTMENT FACTORS; GPIF TARGETS, RANGES, AND REWARDS; AND PROJECTED EXPENDITURES AND TRUE-UP AMOUNTS FOR CAPACITY COST RECOVERY FACTORS

BY THE COMMISSION:

Background

As part of our continuing fuel and purchased power cost recovery and generating performance incentive factor proceedings, a hearing was held on November 1, 2011, in this docket. The hearing addressed the issues set out in Order No. PSC-11-0508-PHO-EI, issued October 28, 2011, in this docket (Prehearing Order). Several of the positions on these issues were not contested by the parties and were presented to us for approval without objections, but some contested issues remained for our consideration.

We have jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

COMPANY-SPECIFIC FUEL COST RECOVERY ISSUES

Florida Power & Light Company

Hedging Activities for August 2010 through July 2011

We reviewed FPL's hedging activities for August 2010 through July 2011 and found its actions to mitigate the price volatility of natural gas, residual oil, and purchased power prices were reasonable and prudent.

Risk Management Plan for 2012

We reviewed FPL's 2012 Risk Management Plan and found that FPL's 2012 Risk Management Plan is consistent with the Hedging Guidelines.

Projected Fuel Savings Associated with West County Energy Center Unit 3

At the conclusion of FPL's prior rate proceeding, Docket No. 080677-EI, the parties to that proceeding entered a Stipulation and Settlement Agreement. We approved the Stipulation and Settlement Agreement on December 14, 2010.[1] Pursuant to that Agreement, FPL was permitted to recover its revenue requirements for the West County Energy Center Unit 3 through the fuel clause to the extent there were fuel savings associated with the unit. FPL has provided the amount of $186,895,413 as the projected 2012 jurisdictional fuel savings to compare with the projected West County Energy Center Unit 3 revenue requirements. We reviewed FPL's projected fuel savings Associated with West County Energy Center Unit 3 and approved the amount of $186,895,413.

Time-of-Use Fuel Factors

In its pre-filed testimony in this docket, FPL proposed a time-of-use rate for the period January 2012 through December 2012 that was calculated based on seasonally differentiated marginal fuel costs. We reviewed FPL's proposal and approve FPL's time-of-use fuel factors based on seasonally differentiated marginal fuel costs for 2012.

[1] Order No. PSC-11-0089-S-EI

Progress Energy Florida, Inc.

Hedging Activities for August 2010 through July 2011

We reviewed PEF's hedging activities for August 2010 through July 2011 and found its actions to mitigate the price volatility of natural gas, residual oil, and purchased power prices were reasonable and prudent.

Risk Management Plan for 2012

We reviewed PEF's 2012 Risk Management Plan and found that PEF's 2012 Risk Management Plan is consistent with the Hedging Guidelines.

Replacement Power Costs for Extended Outage at Crystal River Unit 3

Background of Extended Outage at Crystal River Unit 3

In the fall of 2009, during Refueling Outage 16, PEF replaced the Crystal River Unit 3 (CR3) nuclear power plant's existing steam generators. On October 2, 2009, PEF discovered a delamination (cracking of the layers of concrete) of a portion of CR3's containment building. CR3 was not returned to service in the timeframe planned by PEF for Refueling Outage 16 and the outage was extended.

During our 2010 fuel and purchased power cost recovery proceeding, PEF filed a motion to create a separate docket to investigate the prudence and reasonableness of PEF's actions concerning the delamination and to review the prudence of PEF's resulting fuel and purchased power replacement costs associated with the extended outage. We granted the motion and opened Docket No. 100437-EI. During the 2010 fuel and purchased power cost recovery proceeding, PEF requested our approval to recover the replacement power costs associated with the extended outage at CR3. By Order No. PSC-10-0734-FOF-EI, issued December 20, 2010, in Docket No. 100001-EI, (2010 Fuel Order), we permitted PEF to recover the entire amount of 2010's replacement power costs due to the CR3 outage, subject to refund, prior to the determination of prudence of such costs in Docket No. 100437-EI. The matter of replacement power costs was renewed in this year's proceeding because CR3 remains off-line and the extended outage continues.

Parties Arguments on Replacement Power Costs for CR3

As in 2010, PEF again seeks recovery of the replacement power costs associated with the CR3 extended outage. PEF requests recovery of the replacement power costs pending our determination of the prudence of its decisions in Docket No. 100437-EI. In its brief, PEF states the precedent established in the 2010 Fuel Order should guide us in resolving this issue.

PEF contends that our long-standing policy to allow utilities to recover their entire fuel cost concurrent with their expense, subject to a subsequent prudence review, is a paramount consideration in this issue. The Company specifically cites 2 orders that have direct relevance: Order No. PSC-07-0816-FOF-EI,[2] which states:

> Thus, "clause recovery is immediate. There is a trade-off, however, as a utility remains uncertain as to whether the Commission will ultimately determine its expenditures to be prudent. . . . [The Commission's] ability to review past expenditures by utilities is essentially a quid pro quo that was established in return for the benefit utilities receive."

Also, Order No. PSC-97-0608-FOF-EI[3] in part states:

> If we permit recovery now, we can later order a refund of these costs, with interest, if we determine the costs were imprudently incurred. . . . If we delay recovery of these costs until it is determined that all or a significant portion were prudently incurred, . . . we may be putting a significant burden on customers at some future period. That burden will be heightened by interest which will accumulate on the unrecovered costs."

In addition, PEF believes its projected costs are reasonable and recoverable. PEF witness Olivier filed testimony and provided E-Schedules that report 2011 actual and estimated fuel and capacity cost recovery information, and similar information to support PEF's proposed 2012 fuel and capacity cost recovery factors.

Pursuant to an insurance policy with the Nuclear Electric Insurance Limited (NEIL), in the event an unplanned outage of CR3 PEF is entitled to receive reimbursement payments for replacement power. The policy has a 12 week deductible period. PEF acknowledged that the plant has had two delamination events while off-line. PEF emphasized in its brief that the Company's assumptions regarding the NEIL insurance recovery are based on the best available information it has. Based on these assumptions, PEF has prepared its 2012 projections assuming that one delamination event occurred, and emphasized that it is in the midst of the claims process for a single event. PEF contends that it has demonstrated the reasonableness of its 2012 fuel cost projections, and thus should be permitted to recover these costs, subject to refund, pending the determination of prudence in Docket No. 100437-EI. PEF states that the Consumer Intervenors'[4] argument is exactly opposite to this policy.

The Consumer Intervenors did not sponsor any witnesses in this proceeding, but participated in the discovery process and in cross examination of PEF witnesses during the hearing. Collectively, the Consumer Intervenors assert that we should deny in full, or in substantial part, PEF's request for cost recovery for replacement fuel or capacity until after the conclusion of the prudence review in Docket No. 100437-EI.

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[2] See pages 6-7 of Order No. PSC-07-0816-FOF-EI, issued October 10, 2007, in Docket No. 060658-EI, In re: Petition on behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to refund $143 million.

[3] Order No. PSC-97-0608-FOF-EI, issued May 28, 1997 in Docket No. 970001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.

[4] OPC, FIPUG, FRF, and FEA filed a joint brief; PCS filed a brief separately but made similar arguments. These five parties are referred to as Consumer Intervenors as they each represent ratepayers.

The Consumer Intervenors believe the decisions rendered in the 2010 Fuel Order were made based on the facts at hand in 2010. These parties believe that circumstances have dramatically changed and argue the following:

- First, the plant is not expected to return to service in the projection year (2012), and in fact, it may not return until 2014. The Consumer Intervenors contend that the recovery allowed in 2010 was approved based on the Company's assertion that CR3 would return to service in 2011;

- Second, the Consumer Intervenors dispute PEF's assertion that allowing cost recovery will avoid a future rate shock for consumers. The consumers believe Exhibit 90 ("Residential Rate Comparisons for 2008 and 2009") demonstrates that PEF has imposed rates on its customers in the past that were several times greater than those in this issue. The Consumer Intervenors contend that rate shock is not a credible argument. They state that PEF's monthly 1000 kWh bill at the end of 2008 was $110.59, and that the bill increased to $137.87 at the beginning of 2009. PEF witness Olivier acknowledged this as rate shock;

- Third, any recovery should recognize the additional insurance proceeds PEF would realize for two delamination event claims, not one. The Consumer Intervenors point out that a net difference of $70 million is at issue in the "one versus two" events matter, and that Exhibit 89 supports the contention that two delamination events occurred; and

- Fourth, the question of prudence in Docket No 100437-EI has been scheduled for hearing in June, 2012, and an order should be issued in September. The Consumer Intervenors believe approval of recovery prior to a prudency finding would violate due process.

Analysis

Our practice in the fuel cost recovery clause process is to annually evaluate each investor owned utilities' fuel cost projections and expenditures through testimony, schedules, and monthly reports that are filed throughout the year to assess the reasonableness of those costs and expenditures. Historically, we have allowed these companies to recover their fuel cost expenses, unless specific instances are identified and investigated for a prudence determination. The fuel cost recovery clause was originally designed to allow a pass through of fuel costs, so the utility would be able to recover the costs as they are incurred. In Order 6357, we defined the purpose of the fuel cost recovery clause:

> The charge reflected on a customer's bill each month is designed only to provide for the recovery of fuel costs experienced by the utility in generating the customer's power. ... It should be emphasized that a utility does not make a profit on its fuel costs.[5]

[5] See page 3 of Order No. 6357, issued November 26, 1974, in Docket 74680-CI, In re: General investigation of fuel adjustment clauses of electric companies.

In Order No. 12645,[6] we established that a prudence review of costs in the annual fuel clause hearing will not be conducted unless prudence of a cost is raised as an issue ahead of time. Finding that a prudence investigation requires careful and often prolonged study, we ruled that we will not adjudicate the question until and unless all relevant facts are analyzed and placed before us.

Order No. PSC-07-0816-FOF-EI (Coal Refund Order),[7] contains a comprehensive review of the history of the development and implementation of todays fuel clause proceedings. Included in the Coal Refund Order is a discussion of a Florida Supreme Court decision acknowledging the operation of the fuel clause proceeding, Gulf Power Company v. Florida Public Service Commission, 487 So. 2d 1036 (Fla. 1986). On appeal from a Commission decision which required a refund to Gulf's customers because of a prior imprudent decision, Gulf raised several issues including whether the refund order constituted retroactive ratemaking. Id. The Florida Supreme Court affirmed our decision, holding that the order did not constitute retroactive ratemaking. Id. at 1037. The Court stated:

> [f]uel adjustment charges are authorized to compensate for utilities' fluctuating fuel expenses. The fuel adjustment proceeding is a continuous proceeding and operates to a utility's benefit by eliminating regulatory lag. This authorization to collect fuel costs close to the time they are incurred should not be used to divest the commission of the jurisdiction and power to review the prudence of these costs. The order was predicated on adjustments for 1980, 1981, and 1982. We find them to be permissible.

Id. Thus, our ability to review past expenditures by utilities is essentially a quid pro quo that was established in return for the benefit utilities receive. The fuel clause is not a prudence review but rather a comparison of a utility's projected fuel costs to the costs actually expended.

In Order No. PSC-10-0734-FOF-EI, issued December 20, 2010, in Docket No. 100001-EI, we rejected the argument that recovery should not be allowed without a prudence determination:

> Our practice in fuel clause proceedings has been to allow recovery of projected costs, which are then subject to true-up adjustments based on actual costs incurred. Subsequently, we may disallow costs based on a determination of prudence. This practice allows cost recovery in a timely manner while protecting ratepayers by conducting a separate review for potential disallowance, as demonstrated in the recent PEF coal refund case. See Order No. PSC-07-0816-FOF-EI. This practice allows the utilities relatively quick recovery of costs and allows them the cash flow to pay volatile fuel expenses. In exchange, we can

[6] Issued November 3, 1983, in Docket No. 830001-EU, In re: Investigation of Fuel Adjustment Clauses of Electric Utilities,
[7] Order No. PSC-07-0816-FOF-EI, issued October 10, 2007, in Docket No. 060658-EI, In re: Petition on behalf of Citizens of the State of Florida to require Progress Energy Florida, Inc. to refund customers $ 143 million, pp. 4-10, 15.

> conduct a prudence review of fuel costs going back a number of years without having established interim rates or holding money subject to refund.[8]

While historically we have allowed recovery of costs, subject to refund, our staff presented options to us that included deferrals because Order Nos. PSC-08-0494-PCO-EI[9] and PSC-08-0495-PCO-EI[10] clearly show that we have the discretion to defer all or a portion of the requested recovery amount prior to the determination of prudence. While we have the discretion to defer recovery of all or a portion of the costs, such deferral has been generally done to relieve rate shock associated with a large increase in fuel factors. In considering mid-course increases to fuel factors, we have deferred a portion of the increased costs from the middle of the current year to the beginning of the next year.[11] The appropriate goal in setting fuel factors is to minimize over-recoveries or under-recoveries (i.e. true-up amounts), by matching rates to costs as closely as possible, and to do so as the costs are being incurred. Otherwise, an under-recovery or deferral of costs coupled with rising fuel prices could exacerbate a future increase in fuel factors.

Although deferring 2011-2012 CR3 replacement power costs would keep rates in 2012 near their current level, rates for 2013 could be dramatically higher. For instance, if we were to determine in Docket No. 100437-EI that PEF's actions were prudent and we deferred replacement power costs to 2013, there would be a compounding effect in the 2013 fuel factors, with 2011, 2012 and 2013 replacement power costs all being included in the 2013 fuel factors. Furthermore, a deferral could compound an under-recovery of fuel cost or an increase in fuel prices – or both – and significantly increase customer bills in 2013.[12] This compounding effect could be further exacerbated if NEIL determines that the extended outage was only one delamination event. In that case the NEIL payments would end in August 2012 but PEF would continue to incur replacement power costs, as CR3 is not expected to return to service until 2014. Any 2013 replacement power PEF incurred under this scenario would not be offset by insurance payments, so the amount of replacement power PEF could potentially seek from customers could increase. Finally, a deferral of the replacement power cost could give customers an incorrect price signal because the 2013 fuel factors would be less representative of the cost PEF incurs to meet customer demand.

If we were to approve a partial or full deferral of the requested recovery amount, PEF's customers would also bear the burden of paying the carrying charges on the deferred amount if PEF is later deemed prudent. In considering possible deferrals for mid-course corrections, we

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[8] See page 17 of Order No. PSC-10-0734-FOF-EI, issued December 20, 2010, in Docket No. 100001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[9] See Order No. PSC-08-0494-PCO-EI, issued August 5, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[10] See pages 11 and 15 of Order No. PSC-08-0495-PCO-EI (2008 mid-course order) in docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. Commissioners McMurrian and Argenziano dissented from the majority's decision, with Commissioner McMurrian noting that the deferral of costs can increase the severity of a rate impact in the near future.
[11] See pages 11 through 13 of Order No. PSC-08-0495-PCO-EI (the 2008 mid-course order), issued August 5, 2008, in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[12] See pages 8 and 9 of the 2003 mid-course order cited above. See also Commissioner McMurrian's dissent on page 15 of the 2008 mid-course order cited below, which noted that the deferral of costs can increase the severity of a rate impact in the near future.

have noted that such deferrals would accrue interest.[13] Witness Olivier stated that deferrals incur interest at the commercial paper rate. She agreed that the current commercial paper rate is 0.09 percent. We note that while a deferral for one year would accrue interest, that amount would not be significant.

We also considered the Consumer Intervenors arguments that PEF's recovery should be based on the assumption that there were two delamination events and insurance proceeds would cover replacement power costs for both of those events. Consumer Intervenors assert that $70 million of ratepayer money is at stake in evaluating whether PEF should recover as if NEIL was paying insurance for two delamination events.

The Consumer Intervenors believe a PEF status report provides evidence of two delamination events in the Company's own words. Furthermore, the Consumer Intervenors attest that if a fresh claims process began on the second delamination event, the insurance proceeds from NEIL would reimburse PEF for future replacement fuel expense rather than ratepayers. In conclusion, the Consumer Intervenors believe the "one event" assumption that PEF is using for its 2012 projections is unreasonable based on the record evidence.

PEF witnesses acknowledge that two delamination events occurred, yet the Company contends it has prepared its schedules and projections for 2012 using insurance recovery from a single claim because that is "the best available information it has." Both witnesses emphasized that the Company and NEIL continue to work through the claims process for a single event.

PEF stated that "NEIL has not completed its review of the repair activities up to the March 2011 delamination." The Company provided similar evidence that NEIL is still reviewing the data from the first delamination, and "has not yet informed PEF whether it contends that the damage at CR3 arises from more than one 'event'."

Mathematically, two claims would yield more insurance proceeds than a single claim, and the Consumer Intervenors argue that PEF should have structured its projections around this assumption. We disagree with this contention. While the status report recognizes two delamination events occurred, PEF witnesses Garrett and Olivier clearly point out that its discussions with NEIL are on-going concerning whether the delamination is one event or two. We find that more facts surrounding the first delamination event are "known" than for the second, and that the Company was reasonable in using the insurance proceeds from the single claims process in building its 2012 projections that incorporate the "best known information."

We were also provided with information regarding investors' reaction to our decisions. Should we decide to defer some or all of the CR3 extended outage costs, the testimony and evidence suggests that rating agencies and Wall Street analysts may react negatively. As indicated in the Company's response to Interrogatory 108, "PEF anticipates that credit rating

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[13] See pages 11 and 15 of Order No. PSC-08-0495-PCO-EI (2008 mid-course order) in Docket No. 080001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. Commissioners McMurrian and Argenziano dissented from the majority's decision, with Commissioner McMurrian noting that the deferral of costs can increase the severity of a rate impact in the near future.

agencies would have an adverse reaction to the Commission taking such action. Indeed, in early July of this year Fitch lowered PEF's rating outlook from stable to negative based in large part on uncertainty regarding fuel and capital cost recovery associated with the CR3 extended outage."

The Florida Retail Federation asked Witness Garrett:

> Do you have an opinion as to what the capital market's perceptions would be of the differential risk between deferral of recovery until summer of 2012 as compared to the risk of disallowance and refund following the hearing that we anticipate next summer?

Witness Garrett responded:

> ...yes, I do have an opinion about that. I think it goes back to risk. I think if there is an appetite to defer costs, that it will indicate increased risk of recovery versus recovering those amounts subject to refund.

Although we are not compelled to follow the rating agencies' and Wall Street analysts' evaluations, we may consider their reports if we deem them relevant. An increase in regulatory risk could lead to an increase in the cost of capital to the Company and ultimately its customers. A downgrade of the Company's bonds could lead to an increase in the cost of debt.

Finally, Consumer Intervenors argue that the allowance of recovery of the fuel costs related to its replacement power due to the extended outage at CR3 prior to a determination of prudence violates the Florida Constitution's due process provision and property rights under Article I, Section 10 and Article 2, Section 1, of the Florida Constitution. Consumer Intervenors further argue that government, in this case, the Commission, must provide adequate notice and an opportunity to present objections, and be an impartial decision maker prior to a proposed taking of a citizen's life, liberty, or property. In this case, Consumer Intervenors argue, consumers will have the opportunity to be heard in the 2012 hearing in Docket No. 100437-EI, and allowing the utility to recover its costs by requiring consumers to pay now means that the consumers' property will be taken without notice and an opportunity to be heard.

PEF argues that the recovery of reasonable fuel costs, subject to refund, prior to a determination of prudence, comports with the requirements of due process because, in the fuel docket, consumers are provided the opportunity to participate in the proceedings prior to our determination including participating in discovery, calling witnesses and cross-examining the utility's witnesses. PEF argues that the fuel docket proceeding is not an eminent domain proceeding where the government "takes" property. PEF argues that the proceedings are not an action against the ratepayers but a setting of rates the utility may charge and to ensure that the fuel costs passed on to consumers are reasonable. Further, PEF argues that an obligation to pay money does not constitute a taking. See Commonwealth Edison Co. v. U.S., 271 F.3d 1327, 1340 (Fed. Cir. 2001) ("While a taking may occur when a specific fund of money is involved, the mere imposition of an obligation to pay money ... does not give rise to a claim under the Takings Clause of the Fifth Amendment").

It has long been established that, as any state agency, our powers, duties, and authority are those and only those that are conferred expressly or impliedly by statute. City of Cape Coral v. GAC Utilities, Inc., (281 So. 2d 493, 496 (Fla. 1973)); Florida Bridge Co. v. Bevis, (363 So. 2d 799, 802 (Fla. 1978)). Administrative agencies lack the power to consider or determine constitutional issues. Rice v. Dep't of Health and Rehabilitative Servs., (386 So. 2d 844, 848 (Fla. 1st DCA 1980)); Carrollwood State Bank v. Lewis, (362 So. 2d 110, 113-14 (Fla. 1st DCA 1978)); Fla. Hosp. (Adventist Health) v. Agency for Health Care Admin., (823 So. 2d 844 (Fla. 1st DCA 2002)).

We have previously specifically declined to rule on constitutional issues stating:

> ... [R]esolution of this suggested additional issue requires the interpretation of constitutional law; specifically the taking of property without just compensation. This Commission is a creature of statute, and Chapter 367 does not provide us the authority to resolve such constitutional questions. The appellate court, sitting in its review capacity, is the proper forum "to resolve this type of constitutional challenge because [it has] the power to . . . require any modifications in the administrative decision-making process necessary to render the final agency order constitutional." Key Haven Associated Enters., Inc. v. Board of Trustees of Internal Improvement Trust Fund, (427 So.2d 153, 158 (Fla. 1982)). [14]

Although our above discussion referred to Chapter 367, F.S., there is also no authority in Chapter 366, F.S., to resolve constitutional questions.

Consumer Intervenors have been given the opportunity, in this docket, to prepare a record upon which the Supreme Court can consider the constitutional issues *de novo*. Glendale Federal Savings and Loan Ass'n v. Florida Dep't of Ins., (485 So. 2d 1321, 1323 (Fla. 1st DCA 1986)), review denied, (494 So. 2d 1150 (Fla. 1986)). Thus, in accordance with Key Haven and the cited cases, we decline to determine the constitutional issues raised by the Consumer Intervenors. The issue of whether we can allow recovery of fuel costs, subject to refund, prior to a determination of prudence, can be resolved without resorting to a determination of the constitutional claims.

Ruling

Based on the foregoing, PEF may collect, subject to refund, the full amount, \$140,157,891, of net 2011-2012 replacement power costs due to the CR3 extended outage.

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[14] Order No. PSC-99-0664-PCO-WS, issued April 5, 1999, in Docket No. 950495-WS, In re: Application for rate increase and increase in service availability charges by Southern States Utilities, Inc. for Orange-Osceola Utilities, Inc. in Osceola County, and in Bradford, Brevard, Charlotte, Citrus, Clay, Collier, Duval, Highlands, Lake, Lee, Marion, Martin, Nassau, Orange, Pasco, Putnam, Seminole, St. Johns, St. Lucie, Volusia, and Washington Counties.

These costs shall be incorporated into the calculation of the 2012 fuel factor. Our general practice is to allow full recovery of replacement power costs subject to refund. The fuel clause was originally designed to allow a pass through of fuel costs, so the utility will be able to recover the costs as they are incurred. This manner of fuel cost recovery matches the time the cost is incurred with the time the cost is recovered and makes the fuel factors cost-based, which provides the appropriate price signals to customers. Deferring all or a portion of the 2011-2012 CR3 replacement power would reduce or eliminate an increase in the 2012 customer's bills. Deferring replacement power costs to 2013, however, could have a compounding effect with a potential future increase in fuel rates. A deferral, coupled with an increase in fuel prices, a significant under-recovery, or a one delamination event determination from NEIL could significantly increase the 2013 fuel factors and create rate shock for customers. Also, should we decide to defer some or all of the CR3 extended outage costs, rating agencies and Wall Street analysts could react negatively.

The prudence of replacement fuel and purchased power costs associated with the extended outage at CR3 will be explored in Docket No. 100437-EI, outside of the fuel cost recovery clause processes. We conclude, therefore, that because prudence will be examined in a separate proceeding and is not at issue in the fuel cost recovery clause, we will continue our past practice of allowing cost recovery of reasonable projected costs. By allowing recovery subject to refund, if replacement power costs are determined to be prudent in Docket No. 100437-EI, future customer bills will be more stable, because these costs will have already been recovered by the utility. Previously, in considering whether to defer a portion of increased fuel cost, we have considered bill stability to be an important factor. We will determine whether the replacement power costs are prudent in Docket No. 100437-EI.

Florida Public Utilities Company

Unbilled Revenues

In its testimony, FPUC proposed to include unbilled fuel revenues in its fuel factor calculations for both the Northwest and Northeast divisions. Based on the testimony in the record and the stipulation of our staff and FPUC, we agree that it is appropriate for FPUC to include unbilled fuel revenues in its fuel factor calculations for the Northwest and Northeast Divisions.

Proposed Methodology for Demand Allocation

FPUC's Argument

FPUC proposed a new methodology for allocating demand costs across its rate classes. Witness Martin testified that FPUC in previous fuel clause proceedings used the 12 Coincident Peak and 1/13 Average Demand (12 CP and 1/13) methodology[15] to allocate demand costs, but

[15] Under the 12 CP and 1/13 method, approximately 92 percent, or 12/13, of the cost are allocated on a 12 CP basis, and approximately eight percent, or 1/13, are allocated on an energy basis. CP is the maximum peak demand of the class at the time of the system peak. The term 12 CP refers to the average of each class's 12 monthly CP demands.

incorporated data from a 2007 FPL and from a 2006 Gulf load research study to allocate demand costs to the rate classes in the Northeast and Northwest Divisions respectively.

Witness Martin explained that FPUC does not have its own generation, and thus purchases all of its power from other providers. Specifically, FPUC purchases power from JEA for the Northeast Division, and from Gulf for the Northwest Division. Effective January 1, 2008, FPUC executed amended purchased power contracts with both providers. Witness Martin testified that prior to 2008, FPUC had some of the lowest fuel rates in the state. However, the amended contracts resulted in higher fuel rates that more closely reflected the then-current market conditions.

Witness Martin testified that as a result of higher fuel rates and the downturn in the economy, FPUC experienced significant usage reductions from its customer base. Witness Martin asserted that FPUC believes that the previous method of allocating demand costs to the rate classifications, which utilized FPL's and Gulf's load research data, is no longer the most accurate basis for this purpose.

FPUC engaged Christensen Associates Energy Consulting (Christensen Associates) to develop an FPUC-based customer usage method on which to allocate demand costs to the various rate classifications. Christensen Associates developed a report for FPUC (CA report) which was entered into the hearing as Exhibit 88. FPUC stated in its brief that the CA report concluded that a good indicator for each rate class' actual contribution to the coincident peak is the kWh usage of each rate class calculated as a percentage of the total kWh usage for the measurement period under each purchased power contract. For both divisions, FPUC used the three previous years (2008-2010) average kWhs to determine each rate classification's demand cost allocator.

FPUC recognizes that having its own load data would be the optimal means of allocating demand on its system. However, Witness Martin noted that FPUC does not have the necessary and costly monitoring equipment installed that would enable FPUC to conduct its own load research. Therefore, FPUC believes that substituting energy usage, as a proxy for demand, just makes sense for FPUC given its unique posture. FPUC asserts that in the absence of load data, including estimates of class peak demands, energy usage is the only observable means by which one can approximate coincident peak demand for FPUC's rate classes.

FPUC's purchased power contracts include energy and demand costs. Energy costs are allocated to the rate classes based on each class's projected energy, or kWh, consumption. Load research done by investor-owned electric utilities, such as FPL and Gulf provides the coincident peak (CP) demand of the major rate classes. Due to its size, FPUC is not required to do load research pursuant to Rule 25-6.0437, Florida Administrative Code (F.A.C.).[16] The purpose of Rule 25-6.0437, F.A.C., is contained in subsection (2) of the rule, which states that this rule is to require load research to support cost of service studies used in ratemaking proceedings to

[16] Rule 25-6.0437(1), F.A.C., applies to investor-owned electric utilities which provide electric service to more than 50,000 retail customers. In deposition, Witness Martin stated that FPUC's Northwest Division has 15,172 customers, and the Northeast Division 15,829 customers.

reasonably assure that tariffs are equitable and reflect the true costs of serving each class of customer. In the absence of load research data specific to FPUC, FPUC has historically relied on actual load research collected by FPL for the Northeast Division and by Gulf for the Northwest Division to allocate its demand related costs. Pursuant to Rule 25-6.0437(7), F.A.C., FPL and Gulf are required to perform a complete load research study no less often than every three years.

FPUC relied on the CA Report that concluded that using kWh usage as an indicator of each rate class' contribution to coincident peak is appropriate. The author of the report, Mr. Camfield, is not a witness in this proceeding. FPUC stated in its brief that the CA Report trended customer consumption patterns over a ten year period. However, there is no showing in the CA Report that a reduction in overall energy consumption translates into reduced demand during the system peak. Furthermore, FPUC argues that Christensen Associates also studied price elasticities for each division and developed models for gauging energy consumption with respect to changes in several variables, including price, weather, and income. The CA Report's regression analysis using price or weather to determine energy usage appears appropriate, but the regression analysis does not show how the results of the analysis is related to peak demand. Finally, FPUC stated in its brief that the CA Report ultimately concludes a good indicator of each rate class' actual contribution to the coincident peak is the kWh usage of each rate class calculated as a percentage of the total kWh usage. Again, the CA Report's conclusions are not supported by any quantitative analysis linking kWh usage to coincident peak demand.

Witness Martin testified that FPUC believes that it is different, geographically and economically, from FPL and Gulf. In response to discovery, FPUC responded that the load shapes for classes of customers served by other utilities may not readily fit FPUC because of a) differences in gas saturation, b) differences in temperature patterns, c) differences in class definitions, d) differences in the economic sector of commercial/industrial customers served, e) differences in rate levels and rate design, and f) differences in income and employment levels. However, Witness Martin has provided no quantitative analysis to support the conclusion that FPUC is different from FPL or Gulf.

Analysis

We agree with FPUC that there does not appear to be a Commission order specifically approving FPUC's current demand allocation method. However, FPUC's reliance on FPL and Gulf actual load research has been accepted for many years. We also agree with FPUC that there is no evidence in the record of this proceeding that indicates whether FPL and Gulf are appropriate load proxies for FPUC. However, we disagree with FPUC's assertion that this issue only requires FPUC to demonstrate that its proposal methodology is reasonable and appropriate for FPUC. Since we have relied upon the use of actual load research data for many years in finding that FPUC's fuel factors are appropriate, FPUC shall also be required to show that the use of the 12CP and 1/13 method that incorporates FPL's and Gulf's load research data is no longer appropriate for FPUC. Witness Martin argued that even the historical 12CP and 1/13 methodology includes kWh usage as a component of the calculation to allocate demand. That is true, however, this method allocates most costs (12/13) to the rate classes based on their contribution to the 12 monthly system peaks, and only 1/13 to the rate classes based on a kWh, or energy, basis. FPUC's proposal to allocate its demand-related purchased power costs on a 100 percent energy basis represents a significant change in demand cost allocation methodology.

FPUC cited Order No. PSC-93-1845-FOF-EG,[17] which approved the allocation of FPUC's conservation program cost on an energy basis. However, this order states that FPUC has no dispatchable demand-side management (DSM) programs for which allocation on the 12CP and 1/13 basis would be more appropriate. The order further states on page 13 that "the same rationale discussed for FPL is applicable to FPUC." In the discussion on FPL, the order finds that FPL shall allocate only the costs of its dispatchable conservation programs using the 12 CP and 1/13 method, and that FPL shall continue to allocate the costs of its remaining programs on an energy basis. The order describes dispatchable programs as heavily demand-related, as they can be called upon by the utilities at times of system peak demand. Based upon a review of the order, we do not believe it provides a basis for an energy allocation of demand related purchased power costs.

FPUC's proposed demand allocation method, when compared to the current method, impacts customer bills. Under FPUC's proposed method, residential customers would see lower bills. For the Northwest Division, the 1,000 kWh residential bill for 2011 is $137.53. Under FPUC's proposed allocation methodology, the 2012 bill would be $133.19. Using the existing allocation methodology the 2012 bill would be $139.28, which is $6.09 higher than if we were to use FPUC's proposed allocation methodology. For the Northeast Division, the 1,000 kWh residential bill for 2011 is $132.34. Under FPUC's proposed allocation methodology, the 2012 bill would be $125.10. Using the existing allocation methodology the 2012 bill would be $129.07, which is $3.97 higher than if we were to use FPUC's proposed allocation methodology.

Small commercial General Service (GS) customers would see lower fuel factors under FPUC's proposed method in the Northwest Division, and higher fuel factors in the Northeast Division. The remaining commercial and industrial classes (GSD, GSLD) would see higher fuel factors in both divisions under FPUC's proposed method. Lighting customers would also see higher fuel factors under FPUC's proposed method. While lowering residential bills is a desirable goal, it is not appropriate to increase commercial bills at the same time without a reasonable cost basis.

In deposition, Witness Martin explained that FPUC revisited its demand allocation methodology as a result of new management and the recent merger. Witness Martin further stated that as a result of FPUC's recent price increases that faced their electric customers, FPUC continues to look for ways to mitigate the impact and see if there is anything FPUC can do to reduce the price increases that their customers are facing. However, changing the demand cost allocation methodology does not mitigate FPUC's total purchased power costs. Thus, changing the allocation methodology does not support FPUC's desire to reduce overall fuel costs, only costs to mainly residential customers. Changing cost allocation methodology should not be used to mitigate rate impacts, absent a showing that the current methodology is inappropriate.

[17] Order No. PSC-93-1845-FOF-EG, issued December 29, 1993, in Docket No. 930759-EG, In re: Investigation into appropriate method for allocation and recovery of costs associated with conservation programs.

Ruling

Based on the foregoing, we find that FPUC has not demonstrated that going to an energy only allocation for demand related costs is appropriate. FPUC should continue to use the 12 CP and 1/13 demand allocation method incorporating the actual load research data provided by FPL for the Northeast Division and Gulf for the Northwest Division. If FPUC wishes to rely on another approach, it should adequately support that alternative methodology with quantitative studies showing the relationship between kWh usage and peak demand. However, we are not requiring that FPUC incur the expense of conducting its own load research. The impact of FPUC's proposed demand allocation methodology on the rate classes is significant, and we therefore have reservations about such a change without adequate data and a more thorough analysis to support the change. Since the fuel and purchased power cost recovery clause is an on-going docket, FPUC and our staff can continue to analyze this issue.

Gulf Power Company

Hedging Activities for August 2010 through July 2011

We reviewed Gulf's hedging activities for August 2010 through July 2011 and found Gulf's actions to mitigate the price volatility of natural gas, residual oil and purchased power prices were reasonable and prudent.

Risk Management Plan for 2012

We reviewed Gulf's 2012 Risk Management Plan and found that Gulf's 2012 Risk Management Plan is consistent with the Hedging Guidelines.

Litigation Costs Associated with Breach of Coal Contract Suit

We conducted continuing discovery and an audit regarding the litigation between Gulf Power Company and Coalsales II, LLC for a breach of contract for coal sales. We find that it is prudent for a utility to commence and continue litigation for breach of contract to the benefit of ratepayers. Accordingly, it is appropriate to include the costs of litigation in the fuel and purchased power cost recovery clause. Those costs are as shown in Table 4-C below:

Summary of Litigation Costs			
Year	**Outside Legal Fees ($)**	**Administrative Costs ($)**	**Total ($)**
2005	0.00	0.00	0.00
2006	89,906.47	2,746.31	92,652.78
2007	64,506.92	67.35	64,574.27
2008	356,264.64	5,139.12	361,403.76
2009	286,753.44	0.00	286,753.44
2010	395,806.46	0.00	395,806.46
2011	(9,191.73)	0.00	(9,191.73)
Estimated 2012	100,000.00	0.00	100,000.00

Table 4-C

Tampa Electric Company

Hedging Activities for August 2010 through July 2011

We reviewed TECO's hedging activities for August 2010 through July 2011 and found that TECO's actions to mitigate the price volatility of natural gas, residual oil and purchased power prices were reasonable and prudent.

Risk Management Plan for 2012

We reviewed TECO's 2012 Risk Management Plan and found that TECO's 2012 Risk Management Plan is consistent with the Hedging Guidelines.

GENERIC FUEL COST RECOVERY ISSUES

Shareholder Incentive Benchmarks

The actual benchmark levels for calendar year 2011 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI were uncontested by the parties. After reviewing the testimony and exhibits, we concurred with the utilities' positions. Accordingly, we approve the actual benchmark levels for calendar year 2011 as follows:

FPL: $10,707,967
Gulf: $ 1,004,362
PEF: $ 1,138,637
TECO: $ 2,719,531

The estimated benchmark levels for the calendar year 2012 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to Order No. PSC-00-1744-PAA-EI were uncontested by the parties. After reviewing the testimony and exhibits, we concurred with the utilities' positions. Accordingly, we approve the estimated benchmark levels for calendar year 2012 as follows:

FPL:	$6,763,028
Gulf:	$ 868,270
PEF:	$ 905,703
TECO:	$2,482,588

Each investor-owned electric utility presented evidence regarding the appropriate final fuel adjustment true-up for their company for 2010. Based on the testimony and exhibits in the record, we approve the following as the appropriate final fuel adjustment true-up amounts for the period of January 2010 through December 2010:

FPL:	$45,498,494	under-recovery.
FPUC Northwest Division:	$ 885,786	over-recovery.
FPUC Northeast Division:	$ 856,166	over-recovery.
Gulf:	$ 3,609,728	under-recovery.
PEF:	$158,825,721	under-recovery.
TECO:	$ 5,086,991	over-recovery.

Each investor-owned electric utility presented evidence regarding the appropriate estimated/actual fuel adjustment true-up amounts for their company for 2011. Based on the evidence in the record, we approve the following as the appropriate estimated/actual fuel adjustment true-up amounts for the period of January 2011 through December 2011:

FPL:	$109,641,629	under-recovery.
FPUC Northwest Division:	$ 682,002	over-recovery.
FPUC Northeast Division:	$ 2,292,856	over-recovery.
Gulf:	$ 8,441,457	under-recovery.
PEF:	$ 35,666,520	over-recovery.
TECO:	$ 42,726,419	over-recovery.

Each investor-owned electric utility presented evidence regarding the appropriate total fuel adjustment true-up amounts to be collected or refunded from January 2012 to December 2012. Based on the evidence in the record, we approve the following as the appropriate fuel adjustment true-up amounts to be collected or refunded from January 2012 through December 2012:

FPL:	$155,140,123	under-recovery.
FPUC Northwest Division:	$ 1,567,788	over-recovery.
FPUC Northeast Division:	$ 3,149,022	over-recovery.
PEF:	$123,159,202	under-recovery.
Gulf:	$ 12,051,185	under-recovery.
TECO:	$ 47,813,410	over-recovery.

Each investor-owned electric utility presented evidence regarding the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2012 through December 2012. Based on the evidence in the record, the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2012 through December 2012 are:

FPL:	$4,068,064,280	excluding True-Up, Revenue Taxes, GPIF.
FPUC Northwest Division:	$ 34,443,981	excluding True-Up, Revenue Taxes, GPIF.
FPUC Northeast Division:	$ 40,276,293	excluding True-Up, Revenue Taxes, GPIF.
Gulf:	$ 568,620,732	excluding True-Up, Revenue Taxes, GPIF.
PEF:	$ 1,786,078,923	excluding True-Up, Revenue Taxes, GPIF.
TECO:	$ 841,805,228	excluding True-Up, Revenue Taxes, GPIF.

COMPANY-SPECIFIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

Tampa Electric Company

TECO submitted corrected revised testimony and exhibits of its witness Brian Buckley seeking to re-establish its GPIF targets and ranges for 2011. Accordingly, TECO's GPIF targets and ranges for 2011 shall be re-established, based on the corrected revised testimony and exhibit of TECO's witness Brian Buckley filed in this docket on April 11, 2011. The revised targets and ranges for 2011 are set forth in the tables below:

Revised 2011 GPIF Targets and Ranges for TECO						
EQUIVALENT AVAILABILITY						
Plant/ Unit	Weighting Factor (%)	EAF Target (%)	EAF Range		Max Fuel Savings ($000)	Max Fuel Loss ($000)
			Maximum (%)	Minimum (%)		
Big Bend 1	4.79%	67.9	73.5	56.8	1,359.3	(5,657.4)
Big Bend 2	6.23%	62.4	66.3	54.5	1,765.3	(1,487.8)
Big Bend 3	6.47%	83.5	85.8	78.9	1,833.9	(1,379.9)
Big Bend 4	8.25%	77.9	81.3	71.0	2,339.2	(2,354.1)
Polk 1	0.70%	88.6	90.0	85.9	198.2	(455.9)
Bayside 1	1.40%	78.2	79.4	75.9	397.4	(821.4)
Bayside 2	0.33%	94.4	95.0	93.3	93.8	(280.8)
GPIF System	28.17%					

AVERAGE NET OPERATING HEAT RATE							
Plant/ Unit	Weighting Factor (%)	ANOHR Target (BTU/ KWH)	NOF	ANOHR Range		Max Fuel Savings ($000)	Max Fuel Loss ($000)
				Minimum (BTU/ KWH)	Maximum (BTU/ KWH)		
Big Bend 1	13.09%	10,469	91.3	10,176	11,123	3,710.3	(3,710.3)
Big Bend 2	7.71%	10,379	91.2	10,025	10,733	2,469.7	(2469.7)
Big Bend 3	10.13%	10,602	86.9	10,265	10,939	2,871.4	(2,871.4)
Big Bend 4	10.62%	10,599	90.8	10,286	10,911	3,012.5	(3,012.5)
Polk 1	16.31%	9,820	97.5	9,117	10,522	4,624.5	(4,624.5)
Bayside 1	5.15%	7,212	86.6	7,120	7,305	1,459.8	(1,459.8)
Bayside 2	7.82%	7,311	84.7	7,222	7,400	2,218.6	(2,218.6)
GPIF System 71.83%							

GENERATING PERFORMANCE INCENTIVE FACTOR

Based on the testimony and evidence submitted in this docket, the appropriate generation performance incentive factor (GPIF) reward or penalty for performance achieved during the period January 2010 through December 2010 for each investor-owned electric utility subject to the GPIF shall be as follows:

FPL: A reward in the amount of $6,571,449.
Gulf: A reward in the amount of $ 645,511.
PEF: A penalty in the amount of $2,980,090.
TECO: A reward in the amount of $ 2,054,696.

Based on the testimony and evidence submitted in this docket, the GPIF targets/ranges for the period January 2012 through December 2012 for each investor-owned electric utility subject to the GPIF shall be as follows:

FPL: The GPIF targets and ranges should be as shown in Table 17-1 below:
Gulf: The GPIF targets and ranges should be as shown in Table 17-2 below:
PEF: The GPIF targets and ranges should be as shown in Table 17-3 below:
TECO: The GPIF targets and ranges should be as shown in Table 17-4 below:

2012 GPIF Targets and Ranges for FPL		
Plant / Unit	**EAF Target (%)**	**Heat Rate Target (BTU / KWH)**
Ft. Myers 2	91.6	7,105
Martin 8	91.4	7,025
Manatee 3	93.9	6,930
Sanford 4	92.5	7,252
Scherer 4	72.5	9,948
St. Lucie 1	68.7	10,771
St. Lucie 2	60.1	10,724
Turkey Point 3	49.9	10,875
Turkey Point 4	78.0	11,263
Turkey Point 5	92.6	6,936

Table 17-1

2012 GPIF Targets and Ranges for Gulf				
Unit	**EAF**	**POF**	**EUOF**	**Heat Rate**
Crist 4	97.7	0.0	2.3	11,479
Crist 5	97.9	0.0	2.1	11,471
Crist 6	74.8	19.7	5.6	11,457
Crist 7	72.6	21.6	5.9	10,683
Smith 1	93.6	0.0	6.4	10,628
Smith 2	87.7	6.3	6.0	10,533
Daniel 1	84.1	10.1	5.8	10,703
Daniel 2	93.4	0.0	6.6	10,630
EAF = Equivalent Availability Factor (%) POF = Planned Outage factor (%) EUOF = Equivalent Unplanned Outage factor (%)				

Table 17-2

2012 GPIF Targets and Ranges for PEF

Plant/ Unit	Weighting Factor (%)	EAF Target (%)	EAF Range		Max Fuel Savings ($000)	Max Fuel Loss ($000)
			Max (%)	Min (%)		
Bartow 4	9.63	81.81	85.95	73.42	7,684	(22,307)
CR 4	9.38	90.50	94.92	81.71	7,483	(21,288)
CR 5	5.54	85.12	87.62	80.06	4,419	(8,549)
Hines 1	3.12	84.31	87.29	78.37	2,488	(5,132)
Hines 2	2.93	86.26	88.74	81.17	2,335	(4,371)
Hines 3	1.97	79.62	80.98	76.79	1,575	(2,748)
Hines 4	2.60	82.61	84.69	78.32	2,076	(3,387)
GPIF System	35.16				28,060	(67,782)

Plant/ Unit	Weighting Factor (%)	ANOHR Target (BTU/ KWH)	NOF	ANOHR Range		Max Fuel Savings ($000)	Max Fuel Loss ($000)
				Minimum (BTU/ KWH)	Maximum (BTU/ KWH)		
Bartow 4	18.97	7,428	68.0	6,999	7,856	15,143	(15,143)
CR 4	12.29	9,947	83.5	9,334	10,560	9,808	(9,808)
CR 5	10.36	9,937	88.5	9,407	10,467	8,265	(8,265)
Hines 1	4.47	7,291	83.6	7,054	7,528	3,565	(3,565)
Hines 2	5.60	7,158	79.0	6,885	7,431	4,467	(4,467)
Hines 3	6.48	7,167	88.4	6,856	7,477	5,171	(5,171)
Hines 4	6.67	6,961	88.7	6,658	7,263	5,325	(5,325)
GPIF System	64.84					51,744	(51,744)

Table 17-3

2012 GPIF Targets and Ranges for TECO

EQUIVALENT AVAILABILITY

Plant/ Unit	Weighting Factor (%)	EAF Target (%)	EAF Range		Max Fuel Savings ($000)	Max Fuel Loss ($000)
			Maximum (%)	Minimum (%)		
Big Bend 1	0.30%	81.9	84.6	76.3	89.3	(936.3)
Big Bend 2	5.09%	76.2	80.1	68.4	1,512.2	(122.3)
Big Bend 3	9.20%	80.0	83.0	73.9	2,734.4	(1,685.0)
Big Bend 4	6.50%	77.4	80.9	70.3	1,932.3	(1,553.3)
Polk 1	0.81%	85.5	86.8	83.0	241.1	(84.9)
Bayside 1	1.35%	94.8	95.2	93.8	401.1	(1,665.7)
Bayside 2	0.95%	80.0	81.4	77.1	280.9	(224.1)
GPIF System	24.19%					

AVERAGE NET OPERATING HEAT RATE

Plant/ Unit	Weighting Factor (%)	ANOHR Target (BTU/ KWH)	NOF	ANOHR Range		Max Fuel Savings ($000)	Max Fuel Loss ($000)
				Minimum (BTU/ KWH)	Maximum (BTU/ KWH)		
Big Bend 1	19.20%	10,468	92.9	9,836	11,101	5,705.6	(5,705.6)
Big Bend 2	12.41%	10,272	92.9	9,862	10,682	3,688.3	(3,688.3)
Big Bend 3	12.03%	10,614	86.1	10,209	11,018	3,576.1	(3,576.1)
Big Bend 4	11.77%	10,549	88.0	10,157	10,941	3,499.1	(3,499.1)
Polk 1	6.81%	10,220	94.2	9,915	10,525	2,023.9	(2,023.9)
Bayside 1	6.86%	7,248	82.6	7,120	7,377	2,040.2	(2,040.2)
Bayside 2	6.73%	7,316	83.2	7,189	7,442	1,998.9	(1,998.9)
GPIF System	75.81%						

Table 17-4

FUEL FACTOR CALCULATION ISSUES

Based on the testimony and exhibits presented in this docket, the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2012 through December 2012 shall be as follows:

FPL:	$4,232,816,559
FPUC Northwest Division:	$ 34,443,981
FPUC Northeast Division:	$ 40,276,293
Gulf:	$ 581,735,512
PEF:	$1,907,632,686
TECO:	$ 796,618,188

Based on the testimony and exhibits presented in this docket, the appropriate revenue tax factor to be applied in calculating each investor-owned electric utility's levelized fuel factor for the projection period January 2012 through December 2012 is:

FPL:	1.00072
FPUC Northwest Division:	1.00072
FPUC Northeast Division:	1.00072
Gulf:	1.00072
PEF:	1.00072
TECO:	1.00072

Based on the testimony and exhibits presented in this docket, the appropriate levelized fuel cost recovery factors for the period January 2012 through December 2012 are:

FPL:	4.131 cents/kWh.
FPUC Northwest Division:	6.544 cents/kWh.
FPUC Northeast Division:	5.961 cents/kWh.
Gulf:	4.943 cents/kWh.
PEF:	5.168 cents/ kWh
TECO:	4.183 cents/kWh.

Based on the evidence submitted in this docket, the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class shall be as follows:

FPL: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Tables 21-1 through 21-3 below:

Gulf: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Table 21-4 below:

PEF: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Table 21-5 below:

TECO: The appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class/delivery voltage level class are shown in Table 21-6 below:

Fuel Recovery Line Loss Multipliers for FPL		
FUEL RECOVERY FACTORS – BY RATE GROUP (Adjusted for Line / Transformation Losses) FOR THE PERIOD JANUARY 2012 – DECEMBER 2012		
GROUP	RATE SCHEDULE	FUEL RECOVERY LOSS MULTIPLIER
A	RS-1 first 1,000kWh	1.00233
	RS-1 all additional kWh	1.00233
A	GS-1, SL-2, GSCU-1, WIES-1	1.00233
A-1*	SL-1, OL-1, PL-1	1.00233
B	GSD-1	1.00225
C	GSLD-1 & CS-1	1.00107
D	GSLD-2, CS-2, OS-2, MET	0.98972
E	GSLD-3, CS-3	0.95828
* Weighted Average 16 % on-Peak and 84 % off-Peak		

Table 21-1

Fuel Recovery Line Loss Multipliers for FPL			
FPL - TIME OF USE FUEL RECOVERY FACTORS – BY RATE GROUP (Adjusted for Line / Transformation Losses) FOR THE PERIOD JANUARY 2012 – DECEMBER 2012			
GROUP	RATE SCHEDULE		FUEL RECOVERY LOSS MULTIPLIERS
A	RST-1, GST-1	On / Off Peak	1.00233
B	GSDT-1, CILC-1 (G), HLFT-1	On / Off Peak	1.00224
C	GSLDT-1, CST-1, HLFT-2	On / Off Peak	1.00110
D	GSLDT-2, CST-2, HLFT-3	On / Off Peak	0.99111
E	GSLDT-3, CST-3, CILC1(T), ISST-1(T)	On / Off Peak	0.95828
F	CILC-1(D), ISST-1(D)	On / Off Peak	0.98992

Table 21-2

Fuel Recovery Line Loss Multipliers for FPL		
FPL - DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR) FUEL RECOVERY FACTORS ON-PEAK: JUNE 2012 THROUGH SEPTEMBER 2012 – WEEKDAYS 3:00 PM TO 6:00 PM OFF-PEAK: ALL OTHER HOURS		
GROUP	OTHERWISE APPLICABLE RATE SCHEDULE	FUEL RECOVERY LOSS MULTIPLIERS
B	GSD(T)-1 On-Peak	1.00225
	GSD(T)-1 Off-Peak	1.00225
C	GSLD(T)-1 On-Peak	1.00114
	GSLD(T)-1 Off-Peak	1.00114
D	GSLD(T)-2 On-Peak	0.99154
	GSLD(T)-2Off-Peak	0.99154

Table 21-3

Fuel Recovery Line Loss Multipliers for Gulf		
Group	Rate Schedules	Line Loss Multipliers
A	RS, RSVP, GS, GSD, GSDT, GSTOU, OSIII, SBS(1)	1.00525921
B	LP, LPT, SBS(2)	0.98890061
C	PX, PXT, RTP, SBS(3)	0.98062822
D	OS I / II	1.00529485
(1) Includes SBS customers with a contract demand in the range of 100 to 499 KW (2) Includes SBS customers with a contract demand in the range of 500 to 7,499 KW (3) Includes SBS customers with a contract demand over 7,499 KW.		

Table 21-4

Fuel Recovery Line Loss Multipliers for PEF		
Group	Delivery Voltage Level	Line Loss Multipliers
A	Transmission	0.9800
B	Distribution Primary	0.9900
C	Distribution Secondary	1.000
D	Lighting Service	1.000

Table 21-5

Fuel Recovery Line Loss Multipliers for TECO	
Metering Voltage Schedule	Line Loss Multiplier
Distribution Secondary	1.0000
Distribution Primary	0.9900
Transmission	0.9800
Lighting Service	1.0000

Table 21-6

Based on the evidence in the record, we find that the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses shall be as follows:

FPL: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-1 through 22-4 below:
FPUC Northwest Division: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-5 through 22-6 below:
FPUC Northeast Division: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 22-7:
Gulf: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-8 below:
PEF: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-9 below:
TECO: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Table 22-10 below:

FPL - FUEL RECOVERY FACTORS – BY RATE GROUP (Adjusted for Line / Transformation Losses) FOR THE PERIOD JANUARY 2012 – DECEMBER 2012				
		JANUARY - DECEMBER		
GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS-1 first 1,000kWh	4.131	1.00233	3.796
	RS-1 all additional kWh	4.131	1.00233	4.796
A	GS-1, SL-2, GSCU-1, WIES-1	4.131	1.00233	4.141
A-1*	SL-1, OL-1, PL-1	3.966	1.00233	3.975
B	GSD-1	4.131	1.00225	4.140
C	GSLD-1 & CS-1	4.131	1.00107	4.135
D	GSLD-2, CS-2, OS-2, MET	4.131	0.98972	4.089
E	GSLD-3, CS-3	4.131	0.95828	3.959
* Weighted Average 16 % on-Peak and 84 % off-Peak				

Table 22-1

FPL - SEASONALLY DIFFERENTIATED TIME OF USE FUEL RECOVERY FACTORS – BY RATE GROUP (Adjusted for Line / Transformation Losses) FOR THE PERIOD JANUARY 2012 – DECEMBER 2012				
		JANUARY – MARCH and NOVEMBER - DECEMBER		
GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RST-1, GST-1 On-Peak	4.974	1.00233	4.986
	RST-1, GST-1 Off-Peak	3.821	1.00233	3.830
B	GSDT-1, CILC-1 G On-Peak	4.974	1.00224	4.985
	HLFT-1 (21-499 kW) Off-Peak	3.821	1.00224	3.830
C	GSLDT-1, CST-1 On-Peak	4.974	1.00110	4.979
	HLFT-2 (500-1,999 kW) Off-Peak	3.821	1.00110	3.825
D	GSLDT-2, CST-2 On-Peak	4.974	0.99111	4.930
	HLFT-3 (2,000+ kW) Off-Peak	3.821	0.99111	3.787
E	GSLDT-3, CST-3 On-Peak	4.974	0.95828	4.767
	CILC-1(T), ISST-1(T) Off-Peak	3.821	0.95828	3.662
F	CILC-1(D), ISST-1(D) On-Peak	4.974	0.98992	4.924
	Off-Peak	3.821	0.98992	3.782

Table 22-2

FPL - SEASONALLY DIFFERENTIATED TIME OF USE FUEL RECOVERY FACTORS – BY RATE GROUP (Adjusted for Line / Transformation Losses) FOR THE PERIOD APRIL 2012 – OCTOBER 2012				
		APRIL - OCTOBER		
GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RST-1, GST-1 On-Peak	6.577	1.00233	6.592
	RST-1, GST-1 Off-Peak	3.404	1.00233	3.412
B	GSDT-1, CILC-1 G On-Peak	6.577	1.00224	6.592
	HLFT-1 (21-499 kW) Off-Peak	3.404	1.00224	3.412
C	GSLDT-1, CST-1 On-Peak	6.577	1.00110	6.584
	HLFT-2 (500-1,999 kW) Off-Peak	3.404	1.00110	3.408
D	GSLDT-2, CST-2 On-Peak	6.577	0.99111	6.519
	HLFT-3 (2,000+ kW) Off-Peak	3.404	0.99111	3.374
E	GSLDT-3, CST-3 On-Peak	6.577	0.95828	6.303
	CILC-1(T), ISST-1(T) Off-Peak	3.404	0.95828	3.262
F	CILC-1(D), ISST-1(D) On-Peak	6.577	0.98992	6.511
	Off-Peak	3.404	0.98992	3.370

Table 22-3

FPL - DETERMINATION OF SEASONAL DEMAND TIME OF USE RIDER (SDTR) FUEL RECOVERY FACTORS ON-PEAK: JUNE 2012 THROUGH SEPTEMBER 2012 – WEEKDAYS 3:00 PM TO 6:00 PM OFF-PEAK: ALL OTHER HOURS				
		APRIL - OCTOBER		
GROUP	OTHERWISE APPLICABLE RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	SDTR FUEL RECOVERY FACTOR
B	GSD(T)-1 On-Peak	7.361	1.00225	7.378
	Off-Peak	3.540	1.00225	3.548
C	GSLD(T)-1 On-Peak	7.361	1.00114	7.369
	Off-Peak	3.540	1.00114	3.544
D	GSLD(T)-2 On-Peak	7.361	0.99154	7.299
	Off-Peak	3.540	0.99154	3.510

Table 22-4

FPUC - NORTHWEST DIVISION FUEL COST RECOVERY FACTORS ADJUSTED FOR LINE LOSS	
Rate Schedule	Fuel Factor ($/kWh)
RS	$0.10667
GS	$0.10305
GSD	$0.09803
GSLD	$0.09443
OL, OL-2	$0.08055
SL1-2, AND SL-3	$0.08078
Step rate for RS	
RS with less than 1,000 kWh/month	$0.10307
RS with more than 1,000 kWh/month	$0.11307

Table 22-5

FPUC -NORTHWEST DIVISION / Time of Use / Interruptible FUEL COST RECOVERY FACTORS ADJUSTED FOR LINE LOSS		
Rate Schedule	Fuel Factor On Peak	Fuel Factor Off-Peak
RS	$0.18707	$0.06407
GS	$0.14305	$0.05305
GSD	$0.13803	$0.06553
GSLD	$0.15443	$0.06443
Interruptible	$0.07943	$0.09443

Table 22-6

FPUC - NORTHEAST DIVISION FUEL COST RECOVERY FACTORS ADJUSTED FOR LINE LOSS	
Rate Schedule	Fuel Factor
RS	$0.09654
GS	$0.08830
GSD	$0.08736
GSLD	$0.08753
OL, OL-2	$0.06270
SL1-2, SL-3	$0.06251
Step rate for RS	
RS with less than 1,000 kWh/month	$0.09311
RS with more than 1,000 kWh/month	$0.10311

Table 22-7

Gulf - Fuel Cost Recovery Factors Adjusted For Line Losses					
Group	**Rate Schedules**	**Line Loss Multipliers**	**Fuel Cost Factors cents/KWH**		
			Standard	**TOU (Peak)**	**TOU (Off-Peak)**
A	RS, RSVP, GS,GSD,GSDT, GSTOU, OSIII, SBS(1)	1.00525921	4.969	5.828	4.612
B	LP, LPT, SBS(2)	0.98890061	4.888	5.733	4.537
C	PX, PXT,RTP, SBS(3)	0.98062822	4.847	5.685	4.499
D	OS I / II	1.00529485	4.917	N/A	N/A
The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: (1) customers with a contract demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; (2) customers with a contract demand in the range of 500 to 7,499 KW will use the recovery factor applicable for Rate Schedule LP; and (3) customers with a contract demand over 7,499 KW will use the recovery factor applicable to rate Schedule PX.					

Table 22-8

PEF - Fuel Cost Recovery Factors (cents/kWh) Adjusted for Line Losses						
					Time of Use	
Group	Delivery Voltage Level	First Tier Factor	Second Tier Factors	Levelized Factors	On-Peak	Off-Peak
A	Transmission	--	--	5.072	7.238	4.027
B	Distribution Primary	--	--	5.123	7.311	4.068
C	Distribution Secondary	4.860	5.860	5.175	7.385	4.109
D	Lighting	--	--	4.722	--	--

Table 22-9

TECO - Fuel Cost Recovery Factors Adjusted For Line Losses	
Metering Voltage Schedule	**Fuel Charge Factors (cents per kWh)**
Secondary	4.190
Tier I (Up to 1,000 kWh)	3.840
Tier II (Over 1,000 kWh)	4.840
Distribution Primary	4.148
Transmission	4.106
Lighting Service	4.129
Distribution Secondary	4.580 (On-Peak)
	4.036 (Off-Peak)
Distribution Primary	4.534 (On-Peak)
	3.996 (Off-Peak)
Transmission	4.488 (On-Peak)
	3.955 (Off-Peak)

Table 22-10

COMPANY-SPECIFIC CAPACITY COST RECOVERY FACTOR ISSUES

Florida Power & Light Company

Nuclear Cost Recovery

FPL presented evidence in the record to support its nuclear cost recovery amount to be recovered. Based on the Commission's vote at the October 24, 2011 special agenda conference in Docket No. 110009-EI, the nuclear cost recovery amount to be recovered in FPL's 2012 capacity cost recovery clause factors is $196,088,824.

Non-fuel Revenue Requirements Associated with West County Energy Center Unit 3

As discussed above, FPL's 2008 rate case was the subject of a Stipulation and Settlement Agreement between the parties which was approved by us. Pursuant to that Agreement, FPL was permitted to recover its revenue requirements for the West County Energy Center Unit 3 through the fuel clause to the extent there were fuel savings associated with the unit. We have approved the amount of $186,895,413 as the projected 2012 jurisdictional fuel savings to compare with the projected West County Energy Center Unit 3 revenue requirements.

Based on the evidence in the record, the appropriate projected jurisdictional non-fuel revenue requirements associated with WCEC-3 for the period January 2012 through December 2012 are $166,860,714. FPL has included $166,860,714 of jurisdictional non-fuel revenue requirements associated with WCEC-3 for recovery in the capacity cost recovery clause. This amount is the lesser of the projected 2012 WCEC-3 jurisdictional non-fuel revenue requirements and the projected 2012 WCEC-3 jurisdictional fuel savings. Accordingly, we approve FPL's recovery of $166,860,714 through the capacity cost recovery clause for the revenue requirements associated with WCEC-3

Progress Energy Florida, Inc.

We set the nuclear cost recovery amount at the October 24, 2011 Agenda Conference for Docket No. 110009-EI. We approved an amount of $85,951,036 to be recovered by PEF in its 2012 capacity cost recovery factors. PEF witness Olivier filed supplemental testimony along with revised capacity cost recovery factors reflecting our vote. Accordingly, $85,951,036 shall be included in PEF's 2012 capacity cost recovery factors.

Tampa Electric Company

In its projection testimony, TECO included $295,465 of incremental cybersecurity costs in the capacity cost recovery clause. Upon stipulation of the parties, TECO agreed to withdraw its proposal to charge incremental cybersecurity costs in the amount of $295,465 (the full amount requested). That withdrawal is reflected in the revised testimony and exhibit pages and prehearing statement positions.

The effect of this withdrawal of incremental cybersecurity costs is a reduction in Tampa Electric's capacity cost recovery factors for January 2012 through December 2012, as reflected in the revised schedules. We approve this withdrawal.

GENERIC CAPACITY COST RECOVERY FACTOR ISSUES

Based on the testimony and exhibits in the record, the appropriate capacity cost recovery true-up amounts for the period January 2010 through December 2010 are:

FPL:	$ 3,364,670	over-recovery.
GULF:	$ 1,217,382	over-recovery.
PEF:	$14,684,019	over-recovery.
TECO:	$ 461,060	under-recovery.

Based on the testimony and exhibits in the record, the appropriate capacity cost recovery actual/estimated true-up amounts for the period January 2011 through December 2011 are:

FPL:	$ 25,243,602	over-recovery.
GULF:	$ 7,179,724	over-recovery.
PEF:	$ 14,684,019	over-recovery.
TECO:	$ 31,477	over-recovery.

Based on the testimony and exhibits in the record, the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January 2012 through December 2012 are:

FPL:	$ 28,608,272	over-recovery.
GULF:	$ 8,397,106	over-recovery.
PEF:	$ 20,667,503	over-recovery.
TECO:	$ 429,583	under-recovery.

The appropriate projected total capacity cost recovery amounts for the period January 2012 through December 2012 are:

FPL: $ 546,891,268, excluding the amounts approved for nuclear cost recovery and for the revenue requirements associated with WCEC-3.
GULF: $ 46,396,792.
PEF: $ 373,845,099. This does not include the amount approved for recovery of nuclear costs. Nuclear costs are included in the recovery factors for the period January 2012 through December 2012.
TECO: $ 44,720,668.

Based on the evidence in the record, the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January 2012 through December 2012 are as follows and are calculated as indicated in Table 31-1 below:

FPL: $ 518,656,160, excluding the amounts under Issue 24A (nuclear cost recovery) and Issue 24C (revenue requirements associated with WCEC-3).
GULF: $ 38,027,046.
PEF: $ 353,431,884, excluding the amounts under Issue 23A (nuclear cost recovery)
TECO: $ 44,995,474.

	FPL	TECO	GULF	PEF
Total true-up (Issue 29)	-$28,608,272	$429,583	-$8,397,106	-$20,667,503
2012 projected recovery (Issue 30)	$546,891,268	$44,533,518	$46,396,792	$373,845,099
SUM	$518,282,996	$44,963,101	$37,999,686	$353,177,596
REVENUE TAX MULTIPLIER	1.00072	1.00072	1.00072	1.00072
Amount of Purchased Power Capacity to be included in 2012 factors (Issue 31)	**$518,656,160**	**$44,995,474**	**$38,027,046**	**$353,431,884**

Table 31-1 Purchased Power Capacity in 2012 Factors

In addition, the nuclear cost recovery amounts for FPL and PEF and the WCEC-3 revenue requirements for FPL are also to be included in the recovery factors. With these amounts included, the total costs to be included in FPL and PEF's capacity cost recovery factors for the period January 2012 through December 2012 are $881,746,882 for FPL and $439,444,805 for PEF, respectively, and are calculated as illustrated in Table 31-2.

Revenue Required (including taxes)	FPL	PEF
Purchased Power Capacity in 2012 Factors	$518,656,160	$353,431,884
Nuclear cost recovery	$196,230,008	$86,012,921
WCEC-3	$166,860,714	N / A
Total Capacity in 2012 Factors	**$881,746,882**	**$439,444,805**

Table 31-2 Total Capacity in 2012 Factors

Based on the evidence in the record, the appropriate jurisdictional separation factors for capacity revenues and costs to be included in the recovery factor for the period January 2012 through December 2012 should be as follows:

FPL:	FPSC	98.01395%.
	FERC	1.98605%.
GULF:		96.44582%.
PEF:	Base	92.792%.
	Intermediate	72.541%.
	Peaking	91.972%.
TECO:		99.58152%.

Based on the evidence in the record, the appropriate capacity cost recovery factors for the period January 2012 through December 2012 should be as follows:

FPL: The appropriate capacity cost recovery factors for the period January 2012 through December 2012 are shown in Tables 33-1 and 33-2 below:
Gulf: The appropriate capacity cost recovery factors for the period January 2012 through December 2012 are shown in Table 33-3 below:
PEF: The appropriate capacity cost recovery factors for the period January 2012 through December 2012 are shown in Table 33-4 below:
TECO: The appropriate capacity cost recovery factors for the period January 2012 through December 2012 are shown in Table 33-5 below:

FPL - Capacity Cost Recovery Factors January 2012 through December 2012						
Rate Schedule	**Jan 2012 – Dec 2012 Capacity Recovery Factor**		**WCEC-3 Capacity Recovery Factor**		**Total Capacity Recovery Factor Jan 2012 – Dec 2012**	
	$ / KW	**$ / kWh**	**$ / KW**	**$ / kWh**	**$ / KW**	**$ / kWh**
RS1 / RST1	--	0.00800	--	0.00169	--	0.00969
GS1 / GST1	--	0.00622	--	0.00186	--	0.00808
GSD1 / GSDT1 / HLFT1 (21-499 Kw)	2.11	--	0.55	--	2.66	--
OS2	--	0.00312	--	0.00175	--	0.00487
GSLD1 / GSLDT1 / CS1 / CST1 / HLFT2 (500-1,999 kW)	2.45	--	0.63	--	3.08	--
GSLD2 / GSLDT2 / CS2 / CST2 / HLFT3 (2,000 + kW)	2.39	--	0.58	--	2.97	--
GSLD3 / GSLDT3 / CS3 / CST3	2.84	--	0.79	--	3.63	--
ISST1D	**	--	**	--	**	--
ISST1T	**	--	**	--	**	--
SST1T	**	--	**	--	**	--
SST1D1 / SST1D2 / SST1D3	**	--	**	--	**	--
CILCD / CILCG	2.39	--	0.72	--	3.11	--
CILC T	2.35	--	0.73	--	3.08	--
MET	2.67	--	0.77	--	3.44	--
OL1 / SL1 / PL1	--	0.00062	--	0.00067	--	0.00129
SL2 /GSCU1	--	0.00482	--	0.00093	--	0.00575

Table 33-1

FPL - Capacity Cost Recovery Factors For Standby Rates January 2012 through December 2012						
Rate Schedule	**Jan 2012 – Dec 2012 Capacity Recovery Factor**		**WCEC-3 Capacity Recovery Factor**		**Total Capacity Recovery Factor Jan 2012 – Dec 2012**	
	RDC **$ / KW	**SDD **$ / kWh**	**RDC **$ / KW**	**SDD **$ / kWh**	**RDC **$ / KW**	**SDD **$ / kWh**
ISST1D	$0.32	$0.15	$0.08	$0.04	$0.40	$0.19
ISST1T	$0.32	$0.15	$0.07	$0.04	$0.39	$0.19
SST1T	$0.32	$0.15	$0.07	$0.04	$0.39	$0.19
SST1D1 / SST1D2 / SST1D3	$0.32	$0.15	$0.08	$0.04	$0.40	$0.19

Table 33-2

Gulf - Capacity Cost Recovery Factors	
Rate Class	**Capacity Cost Recovery Factors (cents per kWh)**
RS, RSVP	0.378
GS	0.345
GSD,GSDT, GSTOU	0.298
LP, LPT	0.260
PX, PXT,RTP, SBS	0.232
OS-I / II	0.138
OS III	0.224

Table 33-3

PEF - Capacity Cost Recovery Factors	
Rate Class	**Capacity Cost Recovery Factors (cents per kWh)**
Residential	1.460
General Service Non-Demand	1.064
At Primary Voltage	1.053
At Transmission Voltage	1.043
General Service 100% Load Factor	0.767
General Service Demand	0.949
At Primary Voltage	0.940
At Transmission Voltage	0.930
Curtailable	0.873
At Primary Voltage	0.864
At Transmission Voltage	0.856
Interruptible	0.765
At Primary Voltage	0.757
At Transmission Voltage	0.750
Lighting	0.223

Table 33-4

TECO - Capacity Cost Recovery Factors		
Rate Class and Metered Voltage	**Capacity Cost Recovery Factors (dollars per kWh)**	**Capacity Cost Recovery Factors (dollars per KW)**
RS Secondary	0.00276	
GS and TS Secondary	0.00256	
GSD, SBF Standard		
Secondary		0.86
Primary		0.85
Transmission		0.84
GSD Optional		
Secondary	0.00203	
Primary	0.00201	
IS, SBI		
Primary		0.68
Transmission		0.68
LS1 Secondary	0.0064	

Table 33-5

EFFECTIVE DATE

The new factors shall be effective beginning with the first billing cycle for January 2012. The first billing cycle may start before January 1,2012, and thereafter the fuel adjustment factors and the capacity cost recovery factors should remain in effect until modified by us.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the findings set forth in the body of this Order are hereby approved. It is further

ORDERED that Florida Power & Light Company, Florida Public Utilities Company, Gulf Power Company, Progress Energy Florida, Inc., and Tampa Electric Company, are hereby authorized to apply the fuel cost recovery factors set forth herein during the period January 2012 through December 2012. It is further

ORDERED the estimated true-up amounts contained in the fuel cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that Florida Power & Light Company, Progress Energy Florida, Inc., Gulf Power Company, and Tampa Electric Company are hereby authorized to apply the capacity cost recovery factors as set forth herein during the period January 2012 through December 2012. It is further

ORDERED that the estimated true-up amounts contained in the capacity cost recovery factors approved herein are hereby authorized subject to final true-up and further subject to proof of the reasonableness and prudence of the expenditures upon which the amounts are based. It is further

ORDERED that the Fuel and Purchased Power Cost Recovery Clause With Generating Performance Incentive Factor docket is an on-going docket and shall remain open.

By ORDER of the Florida Public Service Commission this 16th day of December, 2011.

Hong Wang

HONG WANG
Chief Deputy Commission Clerk
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LCB

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.