EXHIBIT NO. ___________

DOCKET NO: 000824-EI

PARTY: FLORIDA POWER CORPORATION

DESCRIPTION: COMPOSITE EXHIBIT: 1) RESPONSES TO STAFF'S INTERROGATORY NOS. 53, 54, 55, 56, 57, 58, 59, 60, 61, 62, 63, 64, 74, 77, 78, 79, 80, 82, 83, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 100, 101, 102, 103, 104, 105, 106, 107, 108, 121, 130, 133, 134, 135, 136, 137, 142, 150, 151, 152, 158; AND 2) RESPONSES TO STAFF'S PRODUCTION OF DOCUMENTS NOS. 1, 2, 3, 4, 5, 9, 10.

PROFERRED BY: STAFF

53. What is the change in retail revenues, plus or minus, as a result of FPC's participation in GridFlorida?

A. The change in retail revenue requirements for the first ten years is estimated to be as follows:

Year	Amount in Millions
2003	$25
2004	$25
2005	$26
2006	$27
2007	$27
2008	$23
2009	$26
2010	$29
2011	$32
2012	$35

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 54
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54. What is the change in retail expenses, plus or minus, as a result of FPC's participation in GridFlorida?

A. The estimated change in retail revenue requirements provided in the answer to No. 53 is predicated on the recovery of a like amount of retail expense responsibility.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 55
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55. On page 15, lines 10 and 11, of Mr. Southwick's Direct Testimony on behalf of FPC, he states that, "These rights are subject to limitations on transfers of control resulting from tax and other considerations." Please explain in detail this statement as it refers to the tax considerations.

A. The statement refers to the limitation imposed on GridFlorida's ability to request that additional transmission facilities be placed under GridFlorida's control, in accordance with Section 7.7.3 of the Participating Owners' Management Agreement ("POMA"). Under such provision, a Participating Owner ("PO") shall not be required to turn over Operational Control, as this term is defined in the GridFlorida Operating Protocol, of a facility if (a) the PO requested an unqualified opinion from nationally recognized bond counsel that transferring Operational Control over such facility is not expected to adversely affect the exclusion from gross income of interest on any bonds used to finance such facility, and (b) such nationally recognized bond counsel stated in writing that it is unable to provide such unqualified opinion, absent redemption of the bonds used to finance the facility or the taking of other remedial action with respect to such bonds. A PO relying on this provision must, within 30 days of receipt of the statement from bond counsel described in paragraph (b) above, seek an IRS ruling that turning over Operational Control would not adversely affect the exclusion from gross income of interest on any bonds used to finance such facility. If the IRS grants such a ruling the PO shall be required to turn over Operational Control of such facility as provided in this agreement.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

56. On page 24, Lines 1 and 2, of Mr. Southwick's Direct Testimony on behalf of FPC, he states that, "The POMA contains provisions protecting tax exempt debt." Please indicate what provisions of the POMA protect tax exempt debt and explain how they protect tax exempt debt.

A. The provision in question is Section 7.7.3 of the POMA. As described in the answer to interrogatory no. 55, this provision limits the ability of GridFlorida to request that additional transmission facilities be placed under the control of GridFlorida under certain circumstances where the transfer of control is expected to adversely affect the exclusion from gross income of interest on any bonds used to finance such facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

57. On page 8 of Ms. Dubin's Direct Testimony, she describes the proposed methodology of recovery for the transmission costs that are projected to be in excess of those currently allowed recovery through base rates. For FPC, please compare the tax consequences of transferring the transmission assets to GridFlorida versus maintaining ownership and transferring only control.

   a. What are the income tax consequences of divestiture versus transfer of control?

   b. What are the property tax consequences of divestiture versus transfer of control?

   c. What other tax consequences are anticipated?

   d. What are the consequences of divestiture versus transfer of control with respect to deferred taxes and excess deferred taxes associated with these assets?

   e. What are the consequences of divestiture versus transfer of control with respect to the investment tax credits that are associated with these assets?

   f. Under both circumstances, assuming a negative impact on ratepayers as a result of the income tax consequences, what provision(s) could be made to neutralize the negative impact such that the individual company and Florida ratepayers remain whole/unaffected?

A. As explained in my testimony, filed in this docket on August 15, 2001, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business. Those were the factors FPC considered when evaluating the form of its participation in GridFlorida. Therefore, no tax analysis was performed.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

58. On page 6, beginning at Line 13, the Joint Testimony of Mike Naeve, C. Martin Mennes, Henry Southwick and Greg Ramon states, "Use of a limited liability company to own the transmission facilities allows passive ownership interests in GridFlorida by divesting transmission owners to satisfy the Order No. 2000 independence standard, and offers favorable tax treatment." Please explain in detail how this favorable tax treatment is provided, citing relevant Internal Revenue Service (IRS) Code Sections and/or other applicable IRS statements.

A. FPC has not analyzed this issue, as it does not intend at this time to take passive ownership interests in GridFlorida once GridFlorida becomes operational.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

59. Provide a schedule which shows how the sources of capital (i.e., deferred taxes, investment tax credits, investor capital, etc.) associated with the transmission assets which are proposed to be assigned to GridFlorida will be removed from the capital structure of FPC. For purposes of this response, show the capital structure components, cost rates, and overall cost of capital of FPC before and after the removal of the capital associated with the transmission assets.

A. FPC is not proposing or planning to assign assets to (or divest of any transmission assets to) GridFlorida. Therefore, no impact on FPC's capital structure will occur due to assignment of or divestiture of assets.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

60. Discuss in detail how the removal of capital associated with the transmission assets will affect the overall cost of capital of FPC.

A. See response to interrogatory no. 59.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

61. What does FPC believe the total cost of capital will be for GridFlorida for the first year of operations? For purposes of this response, show the capital structure components, relative percentages, cost rates, and overall cost of capital.

A. FPC has not made such determination.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

62. What does FPC believe its share of the total cost of capital (amount and percentage) will be for GridFlorida's first year of operations?

A. FPC will be only be a customer of GridFlorida and not an owner that shares in the cost of capital.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

63. Referring to page 28 of FPC witness Southwick's direct testimony, provide a detailed explanation of the calculation of the "simple annual carrying charge." For purposes of this response, show the capital components, relative percentages, cost rates and overall cost used in the calculation and reconcile these amounts to FPC's relevant earnings surveillance report (ESR). If necessary, explain why the carrying charge cannot be reconciled to the ESR.

A. No calculation of the "simple annual carrying charge" has been developed as of this date. The testimony describes a concept that the Company plans to employ to separate its revenue requirements associated with existing facilities and new facilities. In particular, the Company wants to convey that, by employing this concept, the Company would not be over- or under-recovering its total revenue requirements by performing calculations separately for existing facilities and new facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 64
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64. Will any existing facilities be leased to GridFlorida? If so, please identify the facilities that will be leased, the amount of each lease, and an explanation for how each lease amount was determined.

A. No facilities will be leased by FPC.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

74. On page 20, lines 19 - 23, of his prefiled testimony, Witness Hoecker states that delays in implementation of Order No. 2000 may cost companies incentive ratemaking treatment. What is the cost to Florida ratepayers of delays in implementation of Order No. 2000?

A. Delaying implementation of an RTO in Florida would likely entail loss of the benefits to ratepayers that I describe in my testimony at pages 21-24. In addition, delays in RTO implementation could encourage the FERC to require development of an RTO in Florida or across the entire Southeast, which may not be entirely responsive to the specific needs of the ratepaying public in this state.

James J. Hoecker

77. Refer to page 25, lines 18 - 19, of Witness Hoecker's testimony. Will the elimination of pancaked rates through the administration of Florida's transmission system by a single RTO result in cost shifts? If so, identify the affected utilities and the amount of the cost shifts.

A. Yes. FPC would likely be affected. As explained in my testimony filed on August 15, 2001 in this docket, as a result of eliminating pancaking, rate charges will necessarily be higher since the costs of transmission facilities will be spread over less billing units. FPC's load is served predominantly from resources on FPC's existing transmission system, requiring little pancaking, and thus, the elimination of pancaking is likely to result in increased charges to FPC retail customers. The net cost impact to FPC retail customers for eliminating pancaking is estimated to be $2.5 million in the first year and over $10 million by year 10 of operation of GridFlorida. As also explained in my testimony, mitigation measures have been adopted to minimize the impact of cost shifts associated with the formation of GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

78. Refer to page 27, lines 11 - 12, of Witness Hoecker's testimony. Has FPC, or any entity known to FPC, calculated the approximate dollar benefit to Florida from an RTO? If FPC has made such a calculation, please provide the results of the calculation, stating all assumptions. If another entity known to FPC has made the calculation, please identify that entity and, if known, the results of its calculations.

A. The approximate dollar benefit has not been calculated by FPC or any entity known to it.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

79. Refer to page 10, line 2, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Identify and quantify those costs previously borne by out-of-state customers that customers in Florida may be required to bear.

A. The nature of the cost shifts would be similar to cost shifts GridFlorida addresses. Those cost shifts result from elimination of pancaking of transmission charges, Transmission Dependent Utility credits, and averaging low-cost and high-cost transmission providers together. An out-of-state RTO for the Southeast United States is too preliminary in its development, size, and scope to ascertain the cost shift impacts to Florida customers should the GridFlorida Companies participate, or even whether costs would be shifted into or out of Florida, i.e. whether Florida ratepayers would pay more or less for transmission.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

80. Is the initial use of FPL's control center dependent on the form of RTO created?

A. Yes. Consider two possible scenarios: (1) FPL divests its transmission assets to GridFlorida, or (2) FPL transfers operational control to an RTO. In the first scenario, GridFlorida will use FPL's control center for direct control of GridFlorida's facilities and indirect control of any Participating Owner's facilities. In the second scenario, FPL will use its control center as a control area operator under the direction of the RTO entity that has operational control.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

82. Refer to page 13, lines 6 - 8, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Witness Naeve states that the GridFlorida proposal eliminates pancaked rates for new transactions and depancakes existing transactions over a period of 10 years. Quantify both the benefits to FPC's ratepayers and to Florida associated with new transactions and the benefits associated with existing transactions. Could the benefits have been achieved regardless of the form of the RTO?

A. It is impossible to know what new transmission transactions will take place so it is not possible to quantify the benefits of eliminating pancaked rates associated with such transactions. The benefits of eliminating pancaked rates do not depend on the form of the RTO.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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83. Identify and quantify the benefits to FPC's ratepayers and to Florida associated with the Physical Transmission Rights model of congestion management included in the GridFlorida proposal. Could the benefits have been achieved regardless of the form of the RTO?

A. The benefits of market-based congestion management that is consistent with the FERC Order No. 2000 requirements include increased economical transactions and price signals to aid efficient expansion of generation and transmission (See answer to Interrogatories No. 119 and 156). FPC has not attempted to quantify those benefits, as they would depend on future markets, participants, and their market strategies. The Physical Transmission Rights model contained in the GridFlorida proposal is expected to achieve this benefit because it complies with and has been accepted by the FERC as compliant with Order No. 2000. Benefits of the proposal are not dependent on the form of the RTO.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

88. Refer to page 23, lines 7 - 9, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Will a transco that owns assets have greater financial strength and access to capital necessary to fund construction and maintenance at a lower cost than an ISO whose participants still own their assets? If yes, why? If no, why not?

A. A Transco that owns significant assets should have a greater financial strength and access to capital to fund construction and maintenance. An ISO, by definition, does not own transmission assets so finding construction and maintenance is not the issue. An ISO must try to get the transmission owning utilities or another entity to fund and construct the needed facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

89. Identify and quantify the costs and benefits associated with transferring ownership of transmission facilities to GridFlorida that FPC considered when evaluating its participation in GridFlorida.

A. As explained in my testimony in this docket, filed on August 15, 2001, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business. Those were the factors FPC considered when evaluating the form of its participation in GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

90. Identify and quantify the costs and benefits associated with transferring operational control of transmission facilities to GridFlorida that FPC considered when evaluating its participation in GridFlorida.

A. As explained in Mike Naeve's testimony in this docket, FPC did not believe that participation in an RTO was voluntary in the long run. Therefore, FPC did not conduct any evaluation of the costs or benefits of transferring control of its facilities to an RTO other than what is discussed in my testimony in this docket.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 91
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91. Will rates for retail transmission transactions be set by the FERC regardless of whether retail electric service rates are unbundled? Please explain your response.

A. No. FERC does not have jurisdiction over bundled retail rates, and therefore would not set the rate that retail customers would pay for bundled retail rates. If the retail rates are unbundled so that the transmission component is provided to the retail customer by GridFlorida, then FERC would have authority over the transmission rate. FERC has authority over the rates GridFlorida sets for services it will provide to FPC in securing transmission service for retail customers, just as FERC has authority over wholesale purchases of power made by FPC for resale to retail customers.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

92. Explain why the GridFlorida companies have selected a December 31, 2000, date to distinguish between the cost of existing transmission investment and new facilities.

A. There were a number of considerations by the applicants in establishing December 31, 2000, as the date to distinguish between the treatment of existing facilities and new facilities for cost recovery. FPC supported the date with the following primary considerations in mind:

(1) This date was the most recent completed calendar year for which cost data was available to establish the Company's transmission revenue requirements prior to GridFlorida becoming operational on December 15, 2001. The Company was hopeful of establishing its revenue requirements in pre-operational discussions with interested parties to mitigate litigation at FERC.

(2) By establishing a current date certain after which the cost of new facilities by a participating transmission owner would be recovered on a Grid-wide basis, transmission owners would not have an incentive to delay construction plans in order to effect such rate treatment by GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

93.

a. Do the transmission facilities that are owned by or under the control of GridFlorida have to be contiguous?

A. The GridFlorida proposal does not preclude the possibility that GridFlorida may own or control non-contiguous facilities.

b. If no, will the noncontiguous or strategic positioning of the transmission facilities have any impact on GridFlorida's ability to ensure the capability and reliability of the coordinated operation of the transmission systems?

A. GridFlorida will have Security Coordinator control over all transmission in the FRCC to ensure reliable and coordinated operation.

c. If yes, please identify the locations/layout of the contiguous transmission facilities as of June 30, 2001.

A. N/A

d. If mapping is not complete, please identify the areas of new facilities construction and projected dates of completion to achieve the desired results of GridFlorida.

A. N/A

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

94. Mr. Southwick's testimony, page 15, beginning with line 5, states that many of GridFlorida's systems will be new and will replace or overlay existing FPL, FPC and TECO systems. Further Mr. Southwick states that these costs are necessary to ensure that GridFlorida will meet its requirements.

a. For FPC, provide a list of the planned new systems, showing the location and expected service date.

b. For FPC, provide the estimated costs of these new systems and explain how were they developed.

A. The planned new systems referred to are those supporting the functional activities, i.e. system operations, market operations, commercial operations, etc. that GridFlorida will have in place when it commences operation. The blueprint design and cost estimates for creating GridFlorida are contained in Witness Holcombe's exhibits.

c. For FPC, provide a list of the systems being replaced, indicating the location, the planned retirement date, the dollar amounts associated with the systems to be retired, and the account number where the investments are currently located. Explain how the dollar amounts associated with the systems to be retired were determined.

A. After GridFlorida becomes fully operational, FPC will no longer perform a number of functions including: handling service requests, performing ATC and ATCWG calculations, and performing billing and settlement activities. The systems supporting these activities have little remaining book value. It is expected that net reductions of two full time employees will result in annual payroll loaded reductions of approximately $250,000.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

95. The joint testimony of Mr. Naeve, Mr. Mennes, Mr. Southwick and Mr. Ramon, pages 18 through 23, defines the demarcation between transmission and distribution facilities.

a. On page 19 regarding predominately distribution step down substations, lines 21 - 22 state that the "Transmission breakers in a ring bus that also serve as the protective device for a step down transformer are not deemed to be transmission facilities." However, lines 4- 6 on page 20 state that similar items in predominately transmission switching stations will be transferred to GridFlorida. Explain why the transmission breakers in predominately distribution step down substations will not be transferred to GridFlorida while those in predominately transmission switching stations will be transferred.

b. On page 22, lines 9-16, the GridFlorida Companies concluded that a uniform demarcation point for transmission facilities is a reasonable approach. Explain specifically what other factors and benefits referred to on line 15 outweigh any reason to attempt to undertake the reclassification of the 69 kV and above facilities as distribution.

A. a) The statement on page 19 is an error, all such breakers will be transferred to GridFlorida.

b) Please see the four specific factors detailed on pages 19 - 22, preceding the concluding statement in lines 9 - 16, page 22.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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96. Provide the estimated incremental cost impact of purchasing transmission service from GridFlorida to serve FPC retail customers.

A. This amount was estimated in the response to Interrogatory No. 53.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

97. Provide preliminary estimates of GridFlorida transmission costs including the impact on FPC's customers.

A. On a total retail MWH of sales basis, the most current cost of service for transmission service by FPC is \$3.13 per MWH. The change in revenue requirements for retail customers as estimated in the response to No. 53 results in additional charges in the range of \$0.54 to \$0.74 per MWH during the first ten years of operation of GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

100. Provide a listing of FPC's transmission facilities that will be under the operational control of GridFlorida. (Lee)

A. FPC plans to turn over operational control of all its transmission lines 69 kV and above to GridFlorida. Attached is a listing from a 2001 loadflow model from the FRCC databank of all FPC transmission lines by from bus to bus, and name. This loadflow and listing contains all FPC transmission lines. FPC notes that, while GridFlorida cannot have direct control of some of the breakers in some substations (primarily generator protection and synchronizing breakers), GridFlorida will nevertheless have Security Coordinator control over all transmission voltage equipment for reliability purposes.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

101. Provide a listing of FPC's transmission facilities that will not be under the operational control of GridFlorida.

A. GridFlorida will have operational control of all FPC transmission facilities either through direct or indirect control, or through Security Coordinator control in the case of generator synchronizing breakers as noted in answer to interrogatory no. 100.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

102. Explain how GridFlorida will maximize the efficient use of the Controlled Facilities.

A. GridFlorida has a contractual obligation, under Section 6.15 of the POMA, to seek to maximize the efficient use of the Controlled Facilities. In the event that GridFlorida fails to fulfill such obligation, FPC and other signatories of the POMA may take steps to enforce such obligation. As discussed in my testimony filed in this docket on August 15, 2001, the GridFlorida OATT and the POMA provide the standards and guidelines against which GridFlorida's operations will be measured.

The entire construct of the Planning and Operating Protocols is based upon providing GridFlorida the necessary responsibility and authority to operate and plan the use of the Controlled Facilities in optimum fashion. In particular, GridFlorida has full responsibility for ATC calculations and the facility ratings and databases used in ATC calculations, total responsibility for all transmission service over the Controlled Facilities, the responsibility to maintain reliability of service to levels no less than historic levels, the responsibility to manage any congestion on a least cost basis, and the authority to provide additional transmission service through redispatch to those customers willing to pay the costs. Finally, GridFlorida is responsible for considering alternatives including generation solutions in carrying out its responsibility for planning the expansion of the Controlled Facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

104. If a more vibrant wholesale market does not result from GridFlorida, what other benefits, if any, would be achieved, by GridFlorida?

A. Initially FPC does not believe the GridFlorida's control of FPC's facilities will significantly reduce FPC's existing transmission costs. However, in the event that FPC is able to eliminate costs as a result of experience with GridFlorida and its impact on FPC's operators, planners, etc., these cost reductions would be reflected in FPC's annual formula calculation its transmission revenue requirements the GridFlorida must collect. Thus, any cost savings automatically flow through GridFlorida's rates to transmission users. Upon approval by the FPSC of the pass through clause for incremental transmission cost recovery, which I proposed in my testimony, any cost savings reflected in GridFlorida rates to FPC would automatically flow through to FPC's retail customers.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

103. Refer to Mr. Southwick's testimony, page 28. Will the "simple annual carrying charge" contain a provision for depreciation? If so, what depreciation rate or rates are being assumed?

A. It is contemplated that the annual carrying charge will include a provision for depreciation. However, as indicated in the response to Interrogatory No. 63, the carrying charge has not yet been developed and, therefore, the depreciation component cannot yet be described.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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105. Over what period of time does FPC believe a more vibrant wholesale market will evolve to the point of resulting in significant residential customer savings?

A. FPC has no projection of when this will occur.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 106
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106. Provide the formula FPC proposes to use in the calculation of its transmission revenue requirements that GridFlorida must collect. Include in your response a discussion of each variable in the formula.

A. FPC has not developed as of this date the specific formula it anticipates employing for calculating its transmission revenue requirements for recovery from GridFlorida. FPC expects such a formula will be based on a traditional embedded cost of service calculation.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

107. Mr. Southwick's testimony, on page 33, lines 1 through 12, states that Seminole Electric Cooperative and its member systems, and the Florida Municipal Power Agency and its member participants (TDUs) are dependent upon FPC's transmission system for delivery of their power needs.

a. What will be the impact upon GridFlorida if the above TDUs opt not to participate?

A. GridFlorida would have fewer facilities under its control for providing unpancaked transmission service. However, the cost shift that FPC customers would otherwise be exposed to would be lessened. Operationally, GridFlorida would still have security coordinator authority of the facilities owned by the TDUs.

b. Will the TDU contractual agreements with FPC remain in effect after the formation of GridFlorida, and, if so, for how long?

A. FPC plans to amend these agreements for the purpose of converting the transmission service to be provided by GridFlorida under its OATT.

c. Since FPC is only giving GridFlorida operation control of its transmission facilities, can FPC enter into separate agreements with the TDUs? If so, what would be the revenue arrangement with GridFlorida and FPC?

A. FPC will no longer provide transmission service once it transfers operational control of its transmission facilities. All new transmission service utilizing Controlled Facilities will be provided through the GridFlorida OATT.

d. If the TDUs decide not to participate in GridFlorida, what other avenue would FPC have for facility cost recovery?

A. Whether the TDUs participate in GridFlorida or not, the TDUs must still obtain and transmission service from GridFlorida and pay GridFlorida for such service at a rate that will ensure the opportunity to recover facility cost for the GridFlorida Companies.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

108. Refer to page 6, lines 22 - 25 of the testimony of William R. Ashburn (filed in all three dockets). Explain in detail why each the following issues are problematic for GridFlorida pricing: 1) cost shifting that arises from adoption of average system rates; 2) providing revenue credits for facilities owned by transmission dependent utilities; and 3) eliminating pancaked rates.

A. Mr. Ashburn's testimony beginning at page 6 addresses the context in which GridFlorida's pricing policy was formulated. The testimony provides that the GridFlorida pricing policy was designed to comply with FERC's Order No. 2000 pricing requirements while providing a balanced and reasoned approach to certain issues that historically have provided impediments to RTO formation. The three issues listed above were addressed in the RTO proposal because they can increase the transmission cost of service for some utilities as a result of joining an RTO. While the generation benefits that are expected to accrue from a RTO are expected to be large but difficult to measure ex ante, these costs, while potentially much smaller, are certain and can be more easily measured. In the context of Order No. 2000, the mitigation measures relating to these issues that were accepted by FERC strike a reasonable balance between the interests of utilities to avoid or delay any adverse cost impacts as a result of joining an RTO and the interests of transmission users seeking to more immediately capture the benefits they will receive from the shifted cost burden.

A transition to average system rates for the GridFlorida region is problematic for the obvious reason that averaging of rates benefits those whose rates were higher while costing those whose rates were lower. Higher cost utilities sought shorter phase in periods or less zones, while the reverse was true for lower cost utilities.

Transmission Dependent Utility (TDU) credits was especially problematic, in part because of the cost shift and in part because the issue had been negotiated/litigated extensively at FERC. The issue is not revenue crediting, it is inclusion of the revenue requirements for those TDU facilities in the zonal revenue requirements of those two company's zonal rates.

Elimination of pancaked rates was particularly problematic given the many existing transmission agreements which must be addressed by the proposal and the concern to protect the rights and interests bargained for by parties on both sides of those agreements. As those agreements terminate, the party seeking service under those transactions will reap the benefits of non-pancaked rates from GridFlorida while the prior transmission provider will lose the source of revenue to benefit other users. The methodology utilized is finely tuned to the zonal rate phase out pricing approach to try and balance the interests of parties to both sides of the existing pancaked transactions.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

121. Refer to pages 39, line 23 through page 40, line 2 of the testimony of William R. Ashburn (filed in all three dockets).

a. Specifically identify the source of any reduced transmission costs, other than those associated with the elimination of pancaked rates, that will result by implementing the GridFlorida pricing protocol.

b. Specifically identify the source of any generation cost savings that would result from the implementation of the GridFlorida pricing protocol.

A.

a. As specified in section 8.1 of Attachment T to the Open Access Transmission Tariff (Exhibit No. CMN-1, p. 4180), existing pancaked transmission charges are eliminated only when the same customer bears transmission charges on 2 or more systems. If more than one customer pays multiple transmission charges to deliver the power from source to sink, the multiple charges will be reduced only if all parties to the transaction agree that the resulting reduction in transmission charges will go to benefit the load.

b. Generation costs would be reduced because of the increased area where generation can be sited without added transmission costs to deliver that generation to load. Generation costs would be reduced because purchased generation from generators located in areas where additional transmission charges have been imposed in the past will not have those charges imposed. One stop shopping and regional interconnection studies will encourage new generation resources to site in GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 130
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130. Under the GridFlorida Proposal should merchant plants have physical transmission rights if they do not currently serve a native load?

A. The GridFlorida proposal assigned physical transmission rights to Load Serving Entities (LSE's) within GridFlorida. These LSE's could transact with merchant plants on a non firm basis, or on a firm basis if they possessed enough physical rights.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
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133. Provide both the replacement and market value as of December 31, 2000 for those assets which will be under the operational control of GridFlorida. Explain in your response how each value was determined.

A. The replacement cost of FPC's transmission assets as of December 31, 2000 is estimated at $1,990,800,000. FPC employed a system that identified the vintage of its major transmission facilities, and applying Handy-Whitman Index factors, calculates a current replacement cost of such facilities. No analyses have been performed to estimate the market value of FPC's transmission assets.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

134. If FPC decides to divest its transmission assets to GridFlorida or any other entity at some future time, what ratepayer benefits would result if the transfer is at market value? At replacement cost? At net book value?

A. We have not decided to divest such assets and, thus, have not attempted to estimate the benefits at this time.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

135. Explain what, if any, steps FPC and/or GridFlorida have taken to ensure quality and reliability of transmission service to all retail ratepayers beyond the transition process as GridFlorida takes over the management and operation of FPC's transmission facilities.

A. As discussed in my testimony filed in this docket on August 15, 2001, the POMA and the Operating and Planning Protocols contain standards and requirements that will govern the management and operation of all facilities operated by GridFlorida. Particularly, see Section I.F of the Operating Protocol. As is also discussed by me, the Operating and Planning Protocols apply to all transmission facilities owned and/or operated by GridFlorida, which ensures that transmission service will be provided in a uniform manner. The POMA is extensively described in my testimony and is found in document 33, Volume VI of Exhibit CMN-1. The Operating and Planning Protocols are discussed in the Panel testimony and are also found in document 33, Volume VI of Exhibit CMN-1.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

136. The testimony of Henry I. Southwick, page 13, (filed August 15, 2001) describes how FPC will differentiate its revenue requirements for purposes of GridFlorida charges related to (a) existing facilities and (b) new facilities. Explain in detail how this description differs from the way FPC currently addresses the treatment of regulatory requirements.

A. Currently, in any ratemaking proceeding, FPC does not distinguish its revenue requirements as to existing facilities or new facilities. Since GridFlorida's pricing plan recovers the revenue requirements associated with existing facilities through zonal charges and the revenue requirements associated with new facilities through system wide charges, it is necessary to make this distinction. The Company's method of differentiating the revenue requirements ensures that total revenue requirements are the same as they would be if calculated in accordance with current methods.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

137. The testimony of Henry I. Southwick, p 3, (filed August 15, 2001) states that "RTO participation requires transfer of either control or ownership of transmission facilities. FPC views this choice as a business decision, not as a question of utility operations." If this is the case, what specific factors did FPC consider in its decision to transfer control, but not ownership of its transmission lines?

A. As explained in my testimony, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business. Those were the factors FPC considered when evaluating the form of its participation in GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

142. Did FPC ever consider divesting its transmission assets for the purpose of establishing a Florida RTO? Why or why not?

A. Yes, FPC gave some consideration to this option when FPL announced their proposed divestiture. As explained in my testimony, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

150. On Page 15 of the panel testimony, the panel states that "those owners who have divested their transmission assets to GridFlorida ("Divesting Owners") will have the option of operating their own "internal" control area that will be subject to GridFlorida's indirect control." Why do the Divesting Owners retain this option and, more specifically, why has FPC already decided to retain its internal control area?

A. Qualified parties have the right to form or merge control areas according to NERC's policies, and these rights are preserved under FERC's Order 2000. These rights are reflected in the GridFlorida market design in that both divesting and non-divesting transmission owners have the right to remain control area operators or to merge with the RTO control area. For this reason, the GridFlorida market is designed to be compatible with multiple control areas. FPC has decided for the present that it is in the best interests of its customers to remain a control area operator at least until the RTO has been established for some time, and future market operations are established and proven. This will give FPC the ability to effectively manage the complex interplay of resources necessary to meet the needs of its customers, including FPC's generation resources, demand side management, voltage reduction and others in much the same manner that it has in the past, while evaluating potential future changes. FPC and its customers will have the ability to fully participate in the RTO markets during this period to capture any and all available RTO market benefits. FPC believes that it is valuable to retain this flexibility.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

151. On Page 18 of the panel testimony, the panel describes the demarcation between transmission and distribution facilities. Why is land and/or right-of-way not defined as a transmission line segment within the scope of transmission facilities?

A. Land and land rights associated with most transmission facilities will continue to be essential to the provision of distribution services for retail customers such that the load-serving entities will grant to GridFlorida only those land access rights that are essential for the operation and maintenance of the transmission system while retaining control over all other land and land rights necessary or useful in the provision of retail electric service.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

152. On Page 23 of the panel testimony, the panel summarizes GridFlorida's planning function and mentions "in depth participation by all market participants, the Florida Public Utility Commission ("FPSC"), and other interested parties." Please describe FPC's view of the FPSC's role in assisting GridFlorida with the transmission planning function?

A. The FPSC would attend the regional planning meetings and participate in the planning process as any other entity, to the extent it chose to do so. The creation and operation of GridFlorida will not affect the FPSC's ability to participate in the FRCC's review of the plans and reliability assessment of the system. All proposed construction of transmission facilities subject to the FPSC's siting jurisdiction would be submitted to the FPSC for review and approval. Also, the FPSC has the right to review the studies (and supporting data) and to provide input to GridFlorida during the decision making process as to the need for new transmission facilities. To the extent that the FPSC lawfully orders a load-serving entity under its jurisdiction to construct transmission facilities, GridFlorida will build such facilities if the entity does not desire to do so. Please see Attachment N.1 to the Planning Protocol regarding the Annual Regional Transmission Planning Process.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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158. On page 38 of the panel testimony, the panel states that "GridFlorida will charge the average of the cost that it incurs to procure the [ancillary] services." Why is this charge based on an average and not on a time-based increment?

A. Due to the FERC finding that insufficient market data existed to support a market clearing price system, the GridFlorida proposal was modified to provide for cost based services by the GridFlorida Participants and other market entities. It is anticipated that these prices will be quite stable, and some, such as Black Start, should not vary by time anyway.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

1. Provide all completed studies concerning the current and future needs of FPC's transmission assets/facilities.

A. FPC's planning process is documented in an electronic information system termed THOR, which contains information on project alternatives, details on costs, project justifications, etc. THOR produces budget reports, project tracking, and data for planning models. While this data is too voluminous to print, all projects are included in the FRCC databank models that are filed in the annual FERC 715 report filed by the FRCC. The models include all transmission projects regardless of size, and all Point of Delivery (POD) projects. FPC has some studies completed for customers, as noted on FLOASIS. Any projects undertaken for customers as a result of either GIS or transmission service requests are listed in agreements filed with the FERC, and included in the next update of load flow models. In addition, FPC has completed a joint study of North Florida with SECI, Member Cooperatives and Tallahassee, a copy of which is attached.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

Transmission Reliability Workshop
Proposed Agenda
October 22, 1999
10am-5pm

- Planned FPC Bulk System improvements/facility upgrades

- Status of Predictive Maintenance Program & Databases
  - Bulk Power Maintenance Plan
  - Reliability Analysis

- Update on Maintenance Activities
  - Update of Previous Issues
  - Crew/Equipment Locations
  - Communications
  - Review of Specific Outages

- Introduce Seminole's Transmission Reliability Task Force

- Discussion of FPC-CPL Merger

Northwest Florida Transmission System Study

Introduction

The northwest Florida transmission includes the power systems of The City of Tallahassee (TAL), Florida Power Corporation (FPC), Suwannee Valley Electric Coop (SVEC), Talquin Electric Coop (TEC), and Tri-Country Electric Coop (TCEC) systems. The RUS cooperatives are members of Seminole Electric Cooperative, Inc.

All of the above entities are affected by the performance of the grid in this area. Accordingly, the parties have agreed to participate in a joint study of the system in order to identify the future needs for reliable and cost-effective electric supply.

Study Scope

FRCC load flow cases modeling 2000 summer and 2004 summer are used for the analysis. The study considers on and off peak time periods. The impact of power transfers, both state imports and exports are addressed using FRCC model assumptions.

High Import 3600 MW Southern to Florida Power at peak load
High Export 1900 MW Florida to Southern at 80 percent of peak load
Firm Import 1500 MW Southern to Florida at peak load

The intent of the study is to determine the future needs of the northwest peninsular Florida transmission system. Once determined, realistic and practical enhancements will be developed and tested to verify workability.

Methodology

The FRCC cases described above are modified to include:

- Three 15 Mvar capacitor installations: modeling mobile units installed at Havana, Miccoosukke and Perry North substations

- The capacity of the Hanson/Geenville/Aucilla 115 kV line section at 84/104 MVA.

- The addition of 69 kV bus tie breaker at FPC's Fort White.

- Modeled addition Ross Prairie 230/69 kV transformer substation in Marion County.

The analysis considers system operation flexibility such as pre and post contingency transmission line switching. Initial load flow screening is reviewed to determine line-switching options that reflect current operational procedures.

Base Case Analysis Summary

- The analysis indicates voltage and thermal weakness in the Gulf Power transmission system. This weakness is indicated when additional transmission lines are modeled linking the FPC system in the Northwest with the panhandle transmission system.
- Single contingency voltage concerns on the FPC system west of Tallahassee.
- Thermal concerns in Shultz and Woodruff areas.
- Thermal and voltage problems on contingency, along FPC's JQ 115 kV transmission

line as well as, lateral feeder transmission line source via the JQ.

System Improvements Considered

The following system enhancements were evaluated as separate solutions.

- Extension and interconnection with The City of Tallahassee of the Drifton to Waukeenah 115 kV transmission line.
- A 230 kV transmission line linking Thomasville to Tallahassee at Substation 7
- A 230 kV transmission line linking Thomasville to Drifton to Perry
- Addition of 230/115 kV transformer at Purdom.

Methodology

The study utilizes the 1998 FRCC Databank model. Power Technologies Incorporated PSS/E package and TAPWIN are used to perform the steady state analysis. PTI's PSS/E is an "industry standard" load flow software run on a PC platform. TAPWIN is a multiple contingency analysis package that utilizes PTI's PSS/E program.

Single contingency criteria is utilized to determine violations

Observations

In the 2000 timeframe, reactive additions and conductor capacity upgrades are required to maintain adequate system performance. Currently, mobile units recently installed at Havana, Miccosukkee and Perry North are providing additional reactive support for contingency scenarios. This needed support will be provided by permanent installations in this timeframe. Capacity increases are required at the FPC/Tallahassee interconnect on the West Side of the city. The nature of the capacity increase will be addressed bilaterally between Tallahassee and FPC.

The addition of the Waukeenah extension towards a Tallahassee interconnection significantly improves the robustness of the area's sub-transmission system, providing voltage support during contingency on the JQ 115 kV line and additional support to Drifton. This extension shall support additional points of delivery planned for the future. The extension also will integrate with the anticipated addition of a voltage source in the Drifton area. The 230 kV transmission line modeled in this study interconnecting Thomasville to Drifton to Perry is an example of the type of strong source anticipated. This project would be required in the 2000 to 2004 timeframe.

Cooperative facilities interconnected to the FPC grid at Miccosukkee exhibit voltage and thermal overloads in base case and contingency scenarios in the 2000 to 2004 timeframe and beyond. A tie connection between the JQ 115 kV line (near the Miccosukkee interconnection) and the proposed Wakeenah extension would provide critical contingency and load support. This proposal can be coordinated with cooperative needs described previously and would provide both FPC and cooperative system support for years to come. This component of a coordinated system plan will be discussed bilaterally with Seminole and the affected distribution cooperative.

Long term system enhancements required to maintain adequate performance are of the form:

A grid tie point in the central portion of the JQ 115 kV line. The Thomasville/Drifton/Perry 230 kV alternative is representative of this type of system addition.

A voltage upgrade of existing 69 kV facilities between Fort White, Perry and Drifton substations. This alternative was evaluated in past studies and was not considered in this evaluation.

By 2000;

Permanent 115 kV switched banks. Currently, FPC has three mobile capacitor bank installations to support voltage and minimize thermal loading on the transmission system in the area. These mobile units shall be replaced with 25 to 45 Mvars of switched banks and the location of these installations will be optimized.

Finalize Waukeenah extension configuration and west TAL interconnection capacity increase configuration. The termination of the Waukeenah extension and the increase of the FPC/Tallahassee tie involve bi-lateral coordination between FPC and Tallahassee. The need is in the 2000 to 2004 timeframe.

Between 2000 and 2004;

Energize Waukeenah extension western interconnection.

Coordinate northern lateral interconnection with JQ 115 kV line. A lateral "tie" between the existing JQ 115 kV line and the proposed Waukeenah extension is necessary for contingency support and to provide reliable load serving for both FPC and Cooperative load centers. Bi-lateral planning and design efforts between Seminole and FPC will be necessary to complete this effort.

Coordinate and finalize grid source in-service. The planning and conceptual configuration of grid upgrades (230 kV and up) should be finalized in this timeframe. This project(s) should coordinate with the earlier timeframe projects defined above. For example, a 230 kV loop through the Drifton area coupled with the Waukeenah extension will provide adequate load service for many years to come.

After 2004;

Energize 230 kV grid enhancement-Georgia connection-East West 230 kV line

Future Study Activity: Action Plan

Bi-lateral discussions with Seminole and Tallahasse will be conducted to implement the suggested system enhancements (or there equivalent). Projects defined for later time frames will be continually reviewed for refinement

Northwest Florida Joint Study

May 25, 1999

Load Flow Model Assumptions

- Florida Reliability Coordinating Council Transmission Model for FY1998
- Study Years 2000 and 2004
- Various Dispatch Scenarios
  - Firm Transactions
  - High Southern to Florida Import
  - High Florida to Southern Export

Study Criteria

- Single Contingency Analysis
- Selected Units Unavailable
- 0.95 to 1.05 Voltage Criteria for Load
- Rate A and Rate B Thermal Limits
- Remedial System Operations

Expansion Plan Summary

Florida Power Corporation

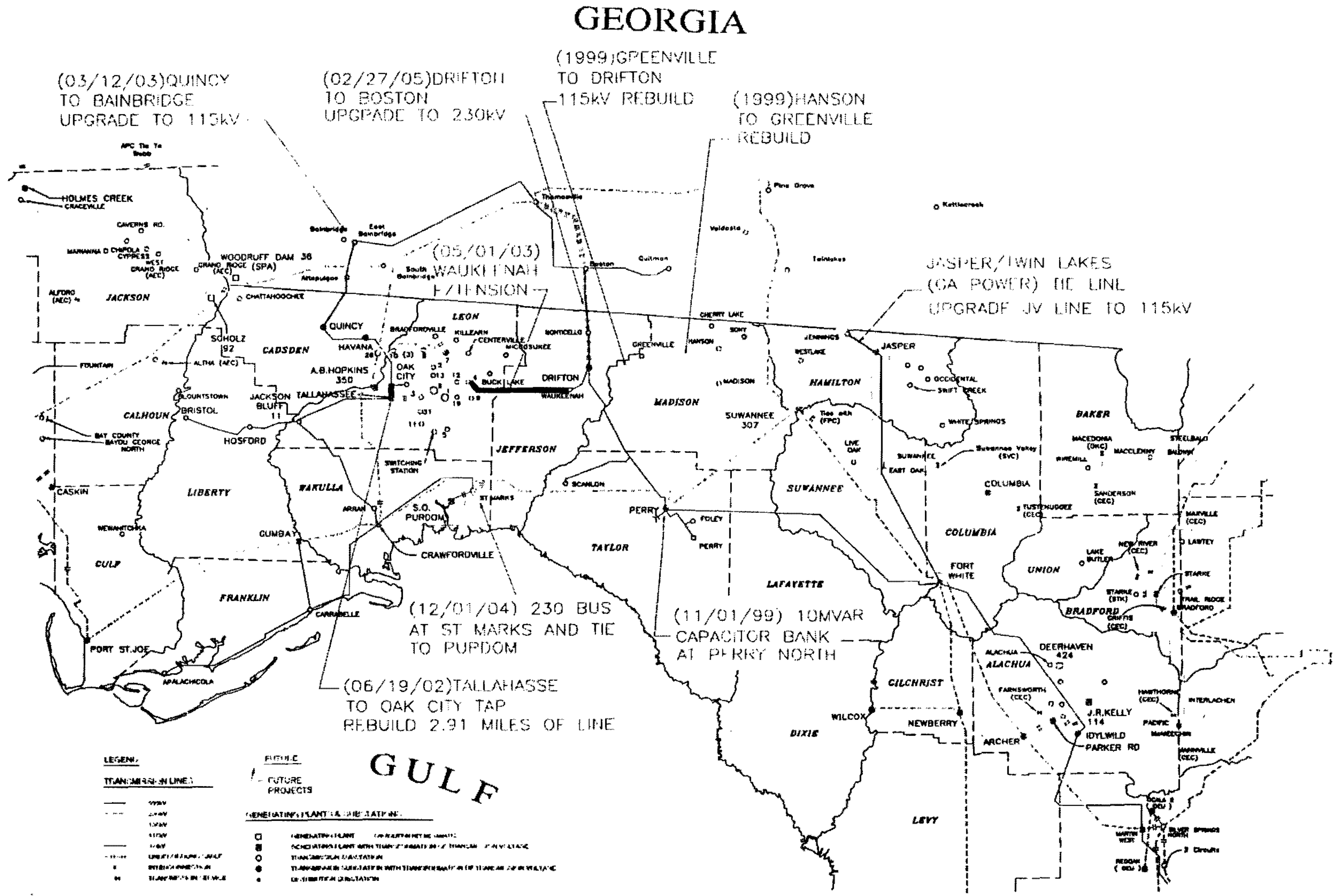
Project	In-service	Comments	Dollars	Budget #
in Budget				
10 MVAR Capacitor Bank at Perry North	11/01/99	Replaces mobile bank	177,000	1477
Greenville to Drifton 115 kV rebuild	06/01/99	Re-rate de-rated line to 104 MVA	507,000	1442
Hanson to Greenville rebuild	06/01/99	Re-rate de-rated line to 104 MVA	517,000	1442
Tallahasse to Oak City Line Rebuild 2.91 miles of line	06/19/02	Add Tall to Lk. Bradford to project	1,000,000	1214
Wakulla North 69 kV line	05/02/03	Possible Future Loop	1,500,000	1410
Drifton to Boston upgrade to 230 kV	05/27/05	Provides needed voltage source	4,200,000	1238
Quincy to Bainbridge upgrade to 115 kV	03/12/03	Currently 69kV	2,750,000	1236
Jasper/Twin Lakes (GA Power) Tie Line - Upgrade JV Line To 115 kV	06/01/06	Currently 69kV	3,100,000	1229
		sub total	13,751,000	
proposed, but not in Budget				
Waukeenah Extension	05/01/04	Continue effort with Tallahassee	3,000,000	
230 Bus Position at St. Marks	12/01/04	Contingent on Tallahassee Expansion	500,000	
		sub total	3,500,000	
		total	17,251,000	

0062

EXISTING NORTHWEST FLORIDA

0063

PROPOSED PROJECTS
NORTHWEST FLORIDA

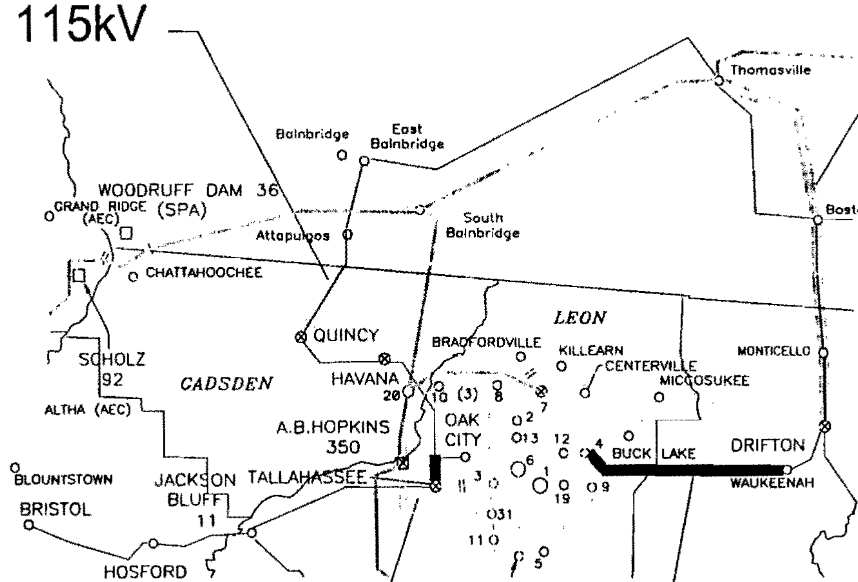


0064

NORTH TALLAHASSEE AREA

(03/12/03)
Quincy to Bainbridge
Upgrade to 115kV

(02/27/05) Drifton
To Boston
Upgrade To 230kV



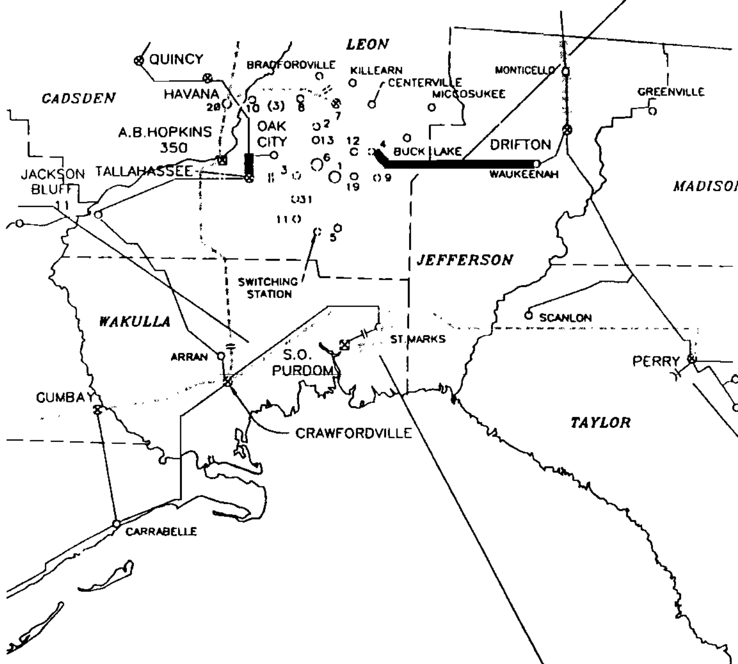
(06/19/02) Tallahasse
To Oak City Tap
Rebuild 2.91 Miles of Line

(05/01/03)
Waukeenah
Extension

0065

SOUTH TALLAHASSEE AREA

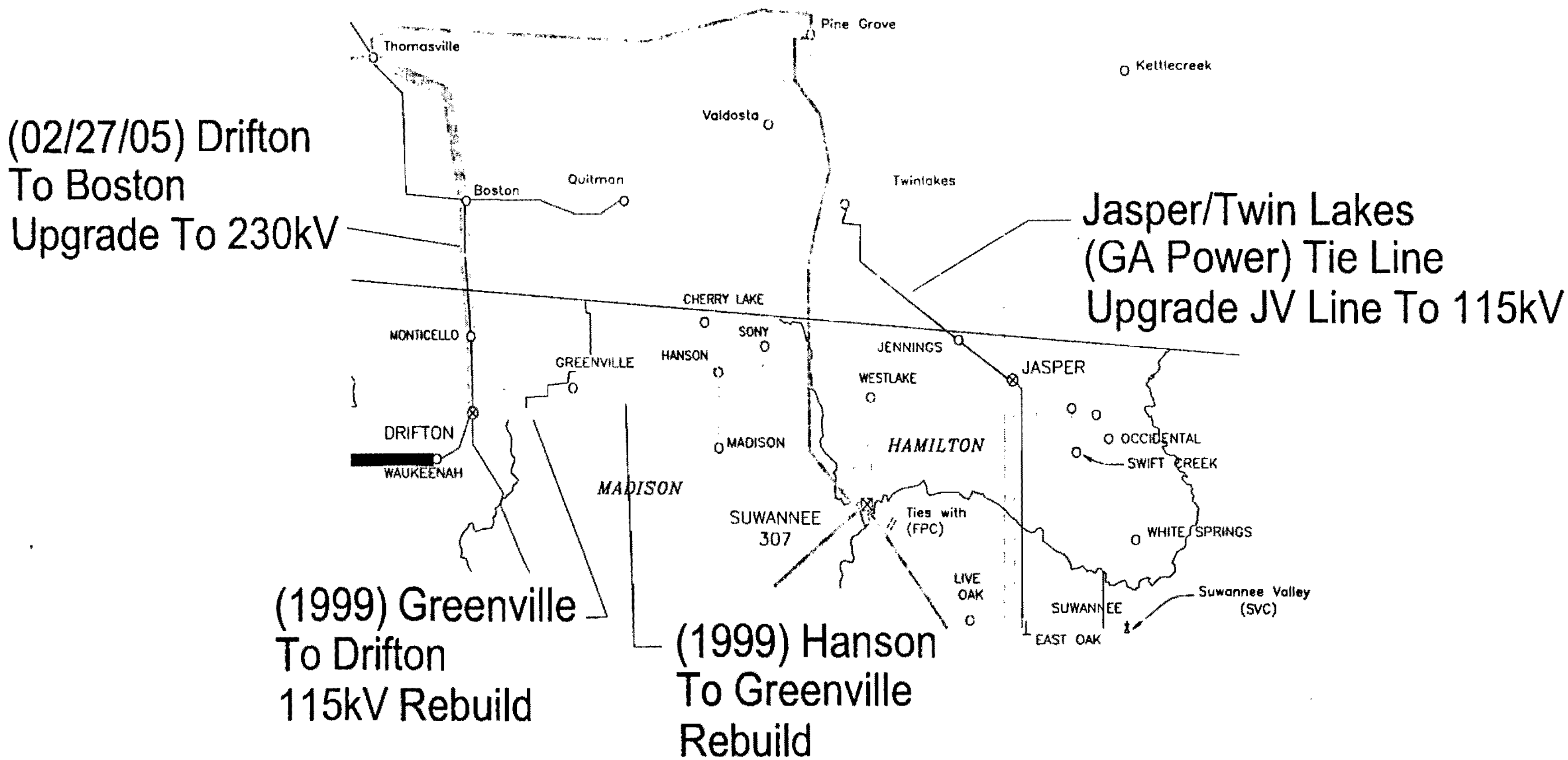
(05/01/03) Waukeenah Extension



(11/01/99) 10MVAR Capacitor Bank At Perry North

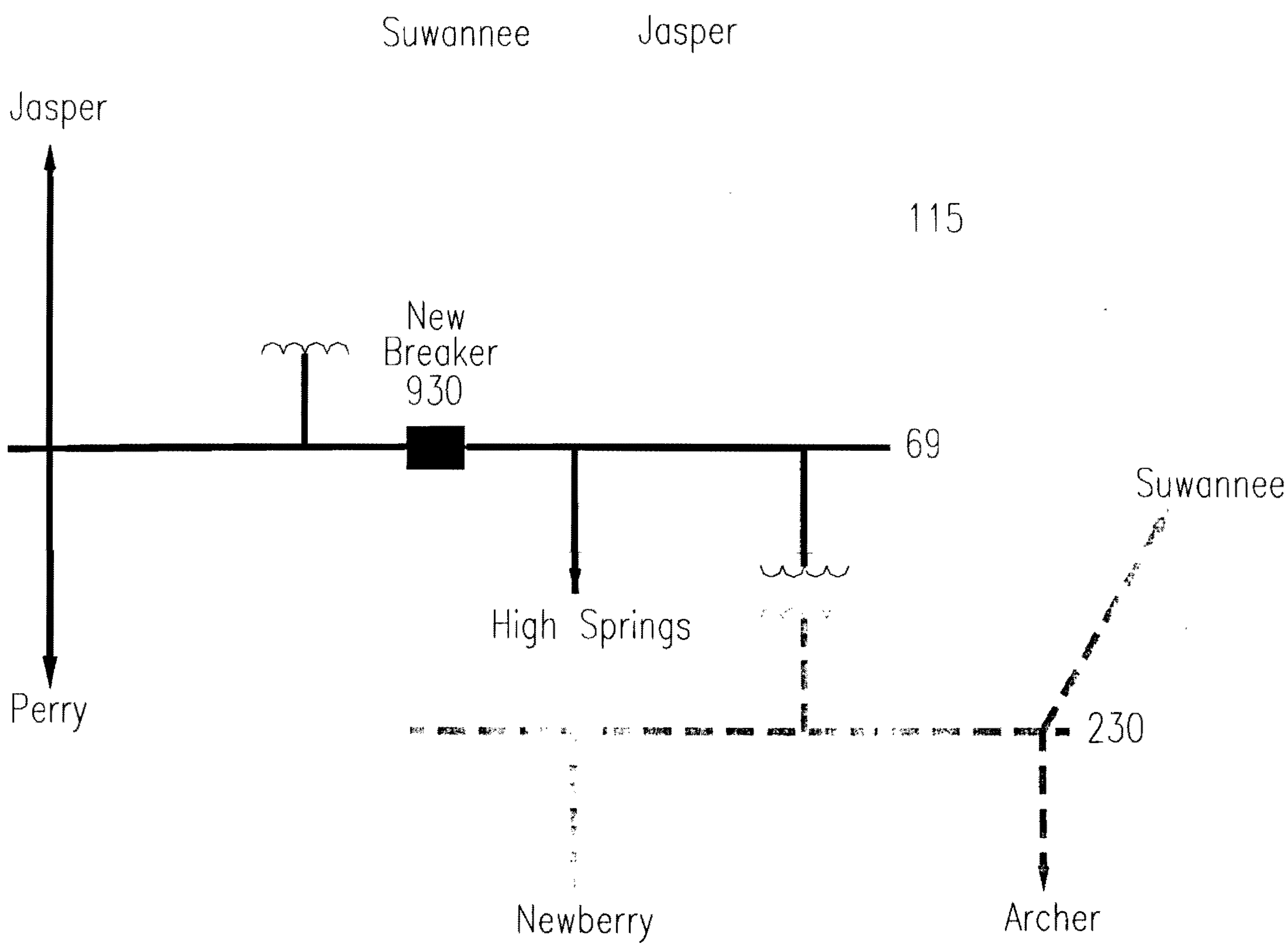
(12/01/04) 230 Bus At St Marks and Tie To Purdom

DRIFTON - SUWANNEE AREA

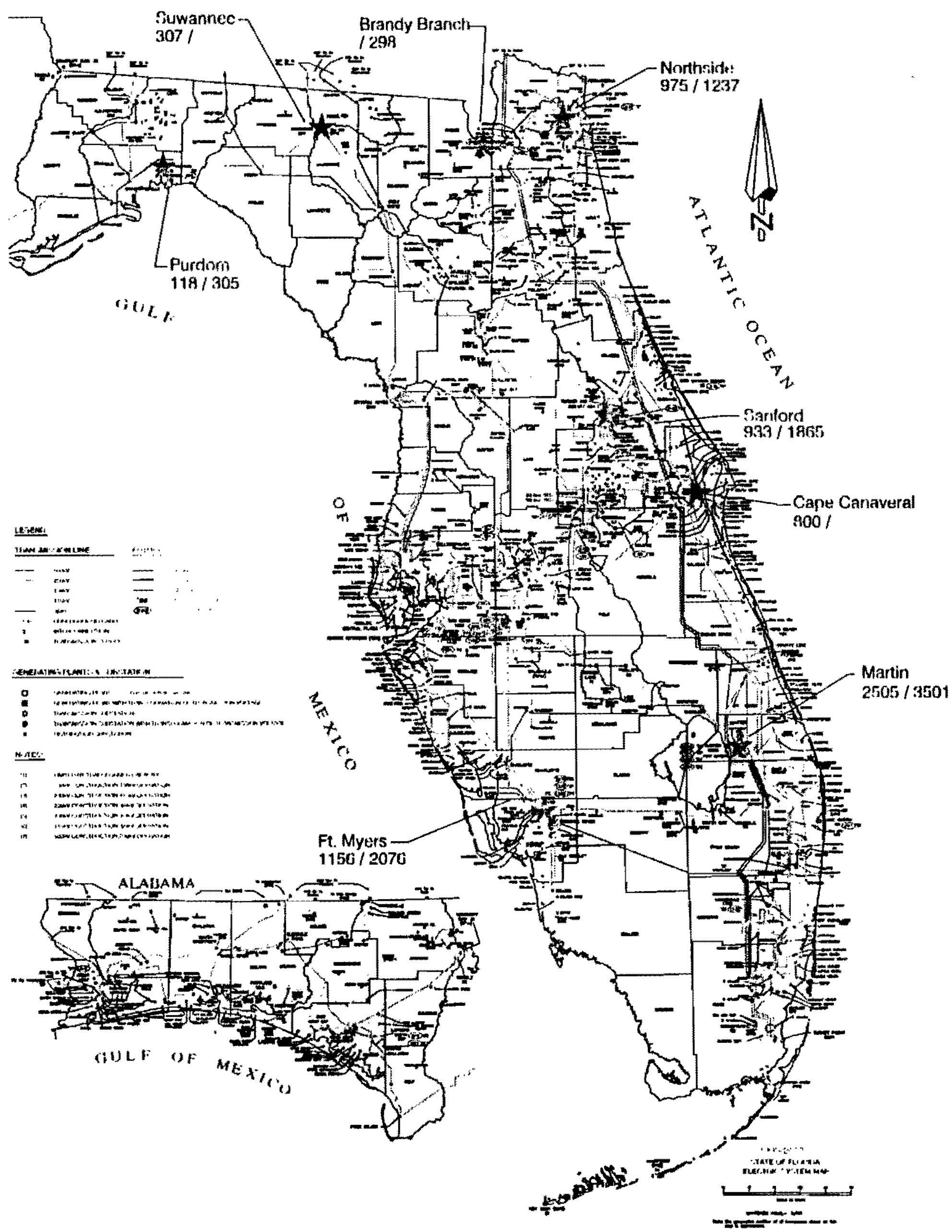


0067

FORT WHITE SUBSTATION



EXISTING FLORIDA

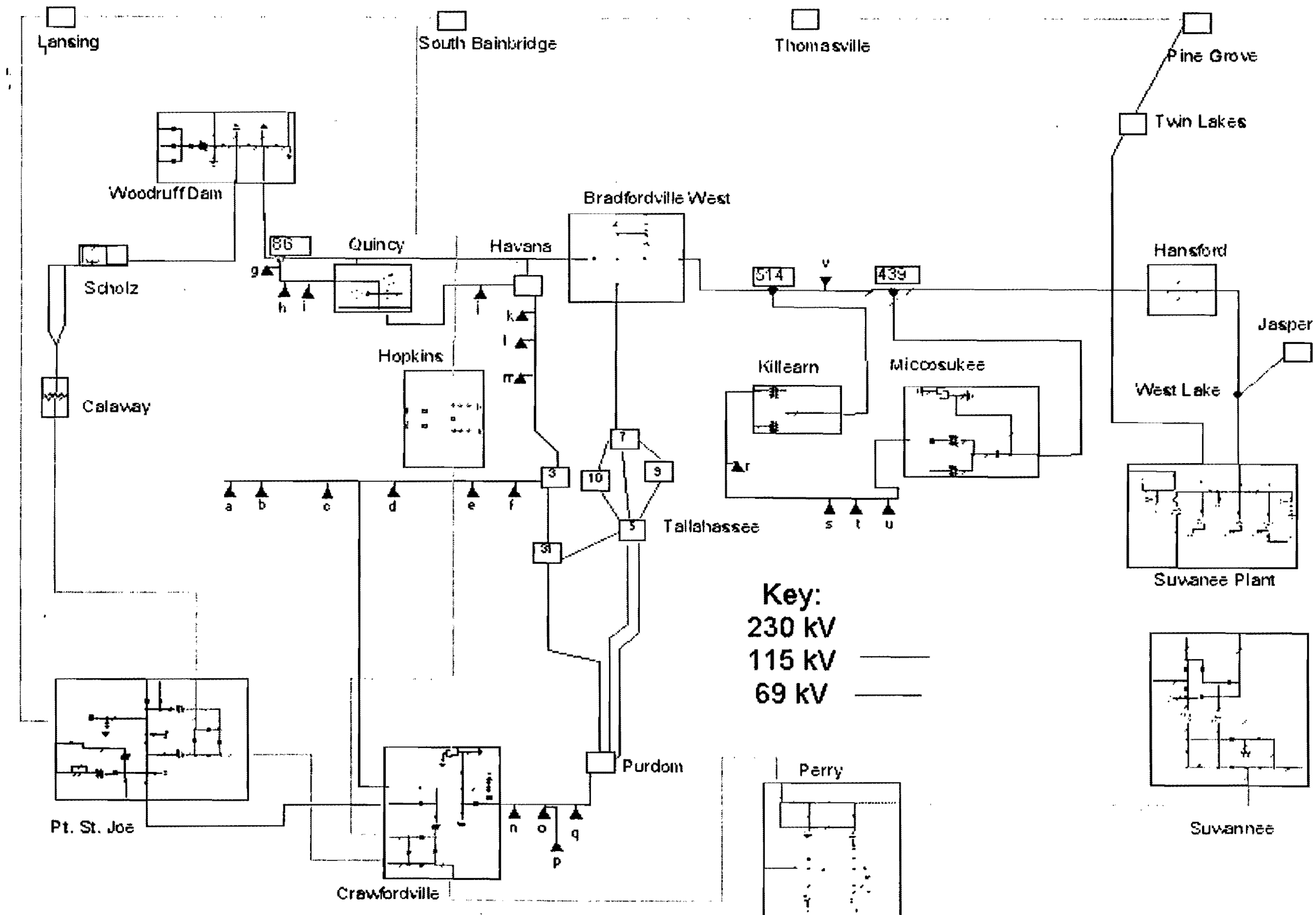


0069

Future Activity

- Continue Discussions with Tallahassee
- Initiate Discussions with Georgia
- Review Plan Subject to System Evolution
- Maintain Communication Seminole

EXISTING NORTHWEST FLORIDA SCHEMATIC



0071

2. Provide all documents used in evaluating the benefits and costs associated with participating in a transmission organization other than GridFlorida.

A. No documents were used.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 3

3. Provide all work papers and any other supporting documentation used to prepare Witness Holcombe's Exhibit BLH-3.

A. There is no such supporting documentation. The information provided for FPC in Exhibit No. BLH-3 is based on internal FPC discussions.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 4

4. Provide all documents referred to or relied upon in assuming a 30% contingency for Release 1 start up costs.

A. No specific documents are available. The contingency reflects Accenture's experience in working on projects of this nature where there are estimating uncertainties resulting from the fact that the project is early in the development cycle and GridFlorida requirements are not yet complete. The use of the 30% contingency is a standard component in Accenture's estimating models for projects of this nature at this stage in development.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
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STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 5

5. Provide all documents referred to or relied upon in determining that divested transmission assets should be transferred to GridFlorida at net book value.

A. FPC has no such documents.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 9

9. Please provide all lease agreements for existing facilities being leased to GridFlorida.

A. FPC has none.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 10

10. Please provide all documentation showing how FPC developed the dollar amounts associated with systems to be retired as a result of GridFlorida, as referenced in Interrogatory No. 94.

A. No such supporting documents exist. Please refer to the answer to Interrogatory No. 94

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

53. What is the change in retail revenues, plus or minus, as a result of FPC's participation in GridFlorida?

A. The change in retail revenue requirements for the first ten years is estimated to be as follows:

Year	Amount in Millions
2003	$25
2004	$25
2005	$26
2006	$27
2007	$27
2008	$23
2009	$26
2010	$29
2011	$32
2012	$35

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

54. What is the change in retail expenses, plus or minus, as a result of FPC's participation in GridFlorida?

A. The estimated change in retail revenue requirements provided in the answer to No. 53 is predicated on the recovery of a like amount of retail expense responsibility.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
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INTERROGATORY NO. 55
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55. On page 15, lines 10 and 11, of Mr. Southwick's Direct Testimony on behalf of FPC, he states that, "These rights are subject to limitations on transfers of control resulting from tax and other considerations." Please explain in detail this statement as it refers to the tax considerations.

A. The statement refers to the limitation imposed on GridFlorida's ability to request that additional transmission facilities be placed under GridFlorida's control, in accordance with Section 7.7.3 of the Participating Owners' Management Agreement ("POMA"). Under such provision, a Participating Owner ("PO") shall not be required to turn over Operational Control, as this term is defined in the GridFlorida Operating Protocol, of a facility if (a) the PO requested an unqualified opinion from nationally recognized bond counsel that transferring Operational Control over such facility is not expected to adversely affect the exclusion from gross income of interest on any bonds used to finance such facility, and (b) such nationally recognized bond counsel stated in writing that it is unable to provide such unqualified opinion, absent redemption of the bonds used to finance the facility or the taking of other remedial action with respect to such bonds. A PO relying on this provision must, within 30 days of receipt of the statement from bond counsel described in paragraph (b) above, seek an IRS ruling that turning over Operational Control would not adversely affect the exclusion from gross income of interest on any bonds used to finance such facility. If the IRS grants such a ruling the PO shall be required to turn over Operational Control of such facility as provided in this agreement.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

56. On page 24, Lines 1 and 2, of Mr. Southwick's Direct Testimony on behalf of FPC, he states that, "The POMA contains provisions protecting tax exempt debt." Please indicate what provisions of the POMA protect tax exempt debt and explain how they protect tax exempt debt.

A. The provision in question is Section 7.7.3 of the POMA. As described in the answer to interrogatory no. 55, this provision limits the ability of GridFlorida to request that additional transmission facilities be placed under the control of GridFlorida under certain circumstances where the transfer of control is expected to adversely affect the exclusion from gross income of interest on any bonds used to finance such facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

57. On page 8 of Ms. Dubin's Direct Testimony, she describes the proposed methodology of recovery for the transmission costs that are projected to be in excess of those currently allowed recovery through base rates. For FPC, please compare the tax consequences of transferring the transmission assets to GridFlorida versus maintaining ownership and transferring only control.

   a. What are the income tax consequences of divestiture versus transfer of control?

   b. What are the property tax consequences of divestiture versus transfer of control?

   c. What other tax consequences are anticipated?

   d. What are the consequences of divestiture versus transfer of control with respect to deferred taxes and excess deferred taxes associated with these assets?

   e. What are the consequences of divestiture versus transfer of control with respect to the investment tax credits that are associated with these assets?

   f. Under both circumstances, assuming a negative impact on ratepayers as a result of the income tax consequences, what provision(s) could be made to neutralize the negative impact such that the individual company and Florida ratepayers remain whole/unaffected?

A. As explained in my testimony, filed in this docket on August 15, 2001, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business. Those were the factors FPC considered when evaluating the form of its participation in GridFlorida. Therefore, no tax analysis was performed.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

58. On page 6, beginning at Line 13, the Joint Testimony of Mike Naeve, C. Martin Mennes, Henry Southwick and Greg Ramon states, "Use of a limited liability company to own the transmission facilities allows passive ownership interests in GridFlorida by divesting transmission owners to satisfy the Order No. 2000 independence standard, and offers favorable tax treatment." Please explain in detail how this favorable tax treatment is provided, citing relevant Internal Revenue Service (IRS) Code Sections and/or other applicable IRS statements.

A. FPC has not analyzed this issue, as it does not intend at this time to take passive ownership interests in GridFlorida once GridFlorida becomes operational.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

59. Provide a schedule which shows how the sources of capital (i.e., deferred taxes, investment tax credits, investor capital, etc.) associated with the transmission assets which are proposed to be assigned to GridFlorida will be removed from the capital structure of FPC. For purposes of this response, show the capital structure components, cost rates, and overall cost of capital of FPC before and after the removal of the capital associated with the transmission assets.

A. FPC is not proposing or planning to assign assets to (or divest of any transmission assets to) GridFlorida. Therefore, no impact on FPC's capital structure will occur due to assignment of or divestiture of assets.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

60. Discuss in detail how the removal of capital associated with the transmission assets will affect the overall cost of capital of FPC.

A. See response to interrogatory no. 59.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

61. What does FPC believe the total cost of capital will be for GridFlorida for the first year of operations? For purposes of this response, show the capital structure components, relative percentages, cost rates, and overall cost of capital.

A. FPC has not made such determination.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

62. What does FPC believe its share of the total cost of capital (amount and percentage) will be for GridFlorida's first year of operations?

A. FPC will be only be a customer of GridFlorida and not an owner that shares in the cost of capital.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

63. Referring to page 28 of FPC witness Southwick's direct testimony, provide a detailed explanation of the calculation of the "simple annual carrying charge." For purposes of this response, show the capital components, relative percentages, cost rates and overall cost used in the calculation and reconcile these amounts to FPC's relevant earnings surveillance report (ESR). If necessary, explain why the carrying charge cannot be reconciled to the ESR.

A. No calculation of the "simple annual carrying charge" has been developed as of this date. The testimony describes a concept that the Company plans to employ to separate its revenue requirements associated with existing facilities and new facilities. In particular, the Company wants to convey that, by employing this concept, the Company would not be over- or under-recovering its total revenue requirements by performing calculations separately for existing facilities and new facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

64. Will any existing facilities be leased to GridFlorida? If so, please identify the facilities that will be leased, the amount of each lease, and an explanation for how each lease amount was determined.

A. No facilities will be leased by FPC.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

74. On page 20, lines 19 - 23, of his prefiled testimony, Witness Hoecker states that delays in implementation of Order No. 2000 may cost companies incentive ratemaking treatment. What is the cost to Florida ratepayers of delays in implementation of Order No. 2000?

A. Delaying implementation of an RTO in Florida would likely entail loss of the benefits to ratepayers that I describe in my testimony at pages 21-24. In addition, delays in RTO implementation could encourage the FERC to require development of an RTO in Florida or across the entire Southeast, which may not be entirely responsive to the specific needs of the ratepaying public in this state.

James J. Hoecker

77. Refer to page 25, lines 18 - 19, of Witness Hoecker's testimony. Will the elimination of pancaked rates through the administration of Florida's transmission system by a single RTO result in cost shifts? If so, identify the affected utilities and the amount of the cost shifts.

A. Yes. FPC would likely be affected. As explained in my testimony filed on August 15, 2001 in this docket, as a result of eliminating pancaking, rate charges will necessarily be higher since the costs of transmission facilities will be spread over less billing units. FPC's load is served predominantly from resources on FPC's existing transmission system, requiring little pancaking, and thus, the elimination of pancaking is likely to result in increased charges to FPC retail customers. The net cost impact to FPC retail customers for eliminating pancaking is estimated to be $2.5 million in the first year and over $10 million by year 10 of operation of GridFlorida. As also explained in my testimony, mitigation measures have been adopted to minimize the impact of cost shifts associated with the formation of GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

78. Refer to page 27, lines 11 - 12, of Witness Hoecker's testimony. Has FPC, or any entity known to FPC, calculated the approximate dollar benefit to Florida from an RTO? If FPC has made such a calculation, please provide the results of the calculation, stating all assumptions. If another entity known to FPC has made the calculation, please identify that entity and, if known, the results of its calculations.

A. The approximate dollar benefit has not been calculated by FPC or any entity known to it.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

79. Refer to page 10, line 2, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Identify and quantify those costs previously borne by out-of-state customers that customers in Florida may be required to bear.

A. The nature of the cost shifts would be similar to cost shifts GridFlorida addresses. Those cost shifts result from elimination of pancaking of transmission charges, Transmission Dependent Utility credits, and averaging low-cost and high-cost transmission providers together. An out-of-state RTO for the Southeast United States is too preliminary in its development, size, and scope to ascertain the cost shift impacts to Florida customers should the GridFlorida Companies participate, or even whether costs would be shifted into or out of Florida, i.e. whether Florida ratepayers would pay more or less for transmission.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

80. Is the initial use of FPL's control center dependent on the form of RTO created?

A. Yes. Consider two possible scenarios: (1) FPL divests its transmission assets to GridFlorida, or (2) FPL transfers operational control to an RTO. In the first scenario, GridFlorida will use FPL's control center for direct control of GridFlorida's facilities and indirect control of any Participating Owner's facilities. In the second scenario, FPL will use its control center as a control area operator under the direction of the RTO entity that has operational control.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

82. Refer to page 13, lines 6 - 8, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Witness Naeve states that the GridFlorida proposal eliminates pancaked rates for new transactions and depancakes existing transactions over a period of 10 years. Quantify both the benefits to FPC's ratepayers and to Florida associated with new transactions and the benefits associated with existing transactions. Could the benefits have been achieved regardless of the form of the RTO?

A. It is impossible to know what new transmission transactions will take place so it is not possible to quantify the benefits of eliminating pancaked rates associated with such transactions. The benefits of eliminating pancaked rates do not depend on the form of the RTO.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

83. Identify and quantify the benefits to FPC's ratepayers and to Florida associated with the Physical Transmission Rights model of congestion management included in the GridFlorida proposal. Could the benefits have been achieved regardless of the form of the RTO?

A. The benefits of market-based congestion management that is consistent with the FERC Order No. 2000 requirements include increased economical transactions and price signals to aid efficient expansion of generation and transmission (See answer to Interrogatories No. 119 and 156). FPC has not attempted to quantify those benefits, as they would depend on future markets, participants, and their market strategies. The Physical Transmission Rights model contained in the GridFlorida proposal is expected to achieve this benefit because it complies with and has been accepted by the FERC as compliant with Order No. 2000. Benefits of the proposal are not dependent on the form of the RTO.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

88. Refer to page 23, lines 7 - 9, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Will a transco that owns assets have greater financial strength and access to capital necessary to fund construction and maintenance at a lower cost than an ISO whose participants still own their assets? If yes, why? If no, why not?

A. A Transco that owns significant assets should have a greater financial strength and access to capital to fund construction and maintenance. An ISO, by definition, does not own transmission assets so finding construction and maintenance is not the issue. An ISO must try to get the transmission owning utilities or another entity to fund and construct the needed facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

89. Identify and quantify the costs and benefits associated with transferring ownership of transmission facilities to GridFlorida that FPC considered when evaluating its participation in GridFlorida.

A. As explained in my testimony in this docket, filed on August 15, 2001, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business. Those were the factors FPC considered when evaluating the form of its participation in GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

90. Identify and quantify the costs and benefits associated with transferring operational control of transmission facilities to GridFlorida that FPC considered when evaluating its participation in GridFlorida.

A. As explained in Mike Naeve's testimony in this docket, FPC did not believe that participation in an RTO was voluntary in the long run. Therefore, FPC did not conduct any evaluation of the costs or benefits of transferring control of its facilities to an RTO other than what is discussed in my testimony in this docket.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 91
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91. Will rates for retail transmission transactions be set by the FERC regardless of whether retail electric service rates are unbundled? Please explain your response.

A. No. FERC does not have jurisdiction over bundled retail rates, and therefore would not set the rate that retail customers would pay for bundled retail rates. If the retail rates are unbundled so that the transmission component is provided to the retail customer by GridFlorida, then FERC would have authority over the transmission rate. FERC has authority over the rates GridFlorida sets for services it will provide to FPC in securing transmission service for retail customers, just as FERC has authority over wholesale purchases of power made by FPC for resale to retail customers.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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92. Explain why the GridFlorida companies have selected a December 31, 2000, date to distinguish between the cost of existing transmission investment and new facilities.

A. There were a number of considerations by the applicants in establishing December 31, 2000, as the date to distinguish between the treatment of existing facilities and new facilities for cost recovery. FPC supported the date with the following primary considerations in mind:

(1) This date was the most recent completed calendar year for which cost data was available to establish the Company's transmission revenue requirements prior to GridFlorida becoming operational on December 15, 2001. The Company was hopeful of establishing its revenue requirements in pre-operational discussions with interested parties to mitigate litigation at FERC.

(2) By establishing a current date certain after which the cost of new facilities by a participating transmission owner would be recovered on a Grid-wide basis, transmission owners would not have an incentive to delay construction plans in order to effect such rate treatment by GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

93.

a. Do the transmission facilities that are owned by or under the control of GridFlorida have to be contiguous?

A. The GridFlorida proposal does not preclude the possibility that GridFlorida may own or control non-contiguous facilities.

b. If no, will the noncontiguous or strategic positioning of the transmission facilities have any impact on GridFlorida's ability to ensure the capability and reliability of the coordinated operation of the transmission systems?

A. GridFlorida will have Security Coordinator control over all transmission in the FRCC to ensure reliable and coordinated operation.

c. If yes, please identify the locations/layout of the contiguous transmission facilities as of June 30, 2001.

A. N/A

d. If mapping is not complete, please identify the areas of new facilities construction and projected dates of completion to achieve the desired results of GridFlorida.

A. N/A

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

94. Mr. Southwick's testimony, page 15, beginning with line 5, states that many of GridFlorida's systems will be new and will replace or overlay existing FPL, FPC and TECO systems. Further Mr. Southwick states that these costs are necessary to ensure that GridFlorida will meet its requirements.

a. For FPC, provide a list of the planned new systems, showing the location and expected service date.

b. For FPC, provide the estimated costs of these new systems and explain how were they developed.

A. The planned new systems referred to are those supporting the functional activities, i.e. system operations, market operations, commercial operations, etc. that GridFlorida will have in place when it commences operation. The blueprint design and cost estimates for creating GridFlorida are contained in Witness Holcombe's exhibits.

c. For FPC, provide a list of the systems being replaced, indicating the location, the planned retirement date, the dollar amounts associated with the systems to be retired, and the account number where the investments are currently located. Explain how the dollar amounts associated with the systems to be retired were determined.

A. After GridFlorida becomes fully operational, FPC will no longer perform a number of functions including: handling service requests, performing ATC and ATCWG calculations, and performing billing and settlement activities. The systems supporting these activities have little remaining book value. It is expected that net reductions of two full time employees will result in annual payroll loaded reductions of approximately $250,000.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

95. The joint testimony of Mr. Naeve, Mr. Mennes, Mr. Southwick and Mr. Ramon, pages 18 through 23, defines the demarcation between transmission and distribution facilities.

a. On page 19 regarding predominately distribution step down substations, lines 21 - 22 state that the "Transmission breakers in a ring bus that also serve as the protective device for a step down transformer are not deemed to be transmission facilities." However, lines 4- 6 on page 20 state that similar items in predominately transmission switching stations will be transferred to GridFlorida. Explain why the transmission breakers in predominately distribution step down substations will not be transferred to GridFlorida while those in predominately transmission switching stations will be transferred.

b. On page 22, lines 9-16, the GridFlorida Companies concluded that a uniform demarcation point for transmission facilities is a reasonable approach. Explain specifically what other factors and benefits referred to on line 15 outweigh any reason to attempt to undertake the reclassification of the 69 kV and above facilities as distribution.

A. a) The statement on page 19 is an error, all such breakers will be transferred to GridFlorida.

b) Please see the four specific factors detailed on pages 19 - 22, preceding the concluding statement in lines 9 - 16, page 22.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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96. Provide the estimated incremental cost impact of purchasing transmission service from GridFlorida to serve FPC retail customers.

A. This amount was estimated in the response to Interrogatory No. 53.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

97. Provide preliminary estimates of GridFlorida transmission costs including the impact on FPC's customers.

A. On a total retail MWH of sales basis, the most current cost of service for transmission service by FPC is \$3.13 per MWH. The change in revenue requirements for retail customers as estimated in the response to No. 53 results in additional charges in the range of \$0.54 to \$0.74 per MWH during the first ten years of operation of GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

100. Provide a listing of FPC's transmission facilities that will be under the operational control of GridFlorida. (Lee)

A. FPC plans to turn over operational control of all its transmission lines 69 kV and above to GridFlorida. Attached is a listing from a 2001 loadflow model from the FRCC databank of all FPC transmission lines by from bus to bus, and name. This loadflow and listing contains all FPC transmission lines. FPC notes that, while GridFlorida cannot have direct control of some of the breakers in some substations (primarily generator protection and synchronizing breakers), GridFlorida will nevertheless have Security Coordinator control over all transmission voltage equipment for reliability purposes.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

101. Provide a listing of FPC's transmission facilities that will not be under the operational control of GridFlorida.

A. GridFlorida will have operational control of all FPC transmission facilities either through direct or indirect control, or through Security Coordinator control in the case of generator synchronizing breakers as noted in answer to interrogatory no. 100.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

102. Explain how GridFlorida will maximize the efficient use of the Controlled Facilities.

A. GridFlorida has a contractual obligation, under Section 6.15 of the POMA, to seek to maximize the efficient use of the Controlled Facilities. In the event that GridFlorida fails to fulfill such obligation, FPC and other signatories of the POMA may take steps to enforce such obligation. As discussed in my testimony filed in this docket on August 15, 2001, the GridFlorida OATT and the POMA provide the standards and guidelines against which GridFlorida's operations will be measured.

The entire construct of the Planning and Operating Protocols is based upon providing GridFlorida the necessary responsibility and authority to operate and plan the use of the Controlled Facilities in optimum fashion. In particular, GridFlorida has full responsibility for ATC calculations and the facility ratings and databases used in ATC calculations, total responsibility for all transmission service over the Controlled Facilities, the responsibility to maintain reliability of service to levels no less than historic levels, the responsibility to manage any congestion on a least cost basis, and the authority to provide additional transmission service through redispatch to those customers willing to pay the costs. Finally, GridFlorida is responsible for considering alternatives including generation solutions in carrying out its responsibility for planning the expansion of the Controlled Facilities.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

103. Refer to Mr. Southwick's testimony, page 28. Will the "simple annual carrying charge" contain a provision for depreciation? If so, what depreciation rate or rates are being assumed?

A. It is contemplated that the annual carrying charge will include a provision for depreciation. However, as indicated in the response to Interrogatory No. 63, the carrying charge has not yet been developed and, therefore, the depreciation component cannot yet be described.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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104. If a more vibrant wholesale market does not result from GridFlorida, what other benefits, if any, would be achieved, by GridFlorida?

A. Initially FPC does not believe the GridFlorida's control of FPC's facilities will significantly reduce FPC's existing transmission costs. However, in the event that FPC is able to eliminate costs as a result of experience with GridFlorida and its impact on FPC's operators, planners, etc., these cost reductions would be reflected in FPC's annual formula calculation its transmission revenue requirements the GridFlorida must collect. Thus, any cost savings automatically flow through GridFlorida's rates to transmission users. Upon approval by the FPSC of the pass through clause for incremental transmission cost recovery, which I proposed in my testimony, any cost savings reflected in GridFlorida rates to FPC would automatically flow through to FPC's retail customers.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

105. Over what period of time does FPC believe a more vibrant wholesale market will evolve to the point of resulting in significant residential customer savings?

A. FPC has no projection of when this will occur.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

106. Provide the formula FPC proposes to use in the calculation of its transmission revenue requirements that GridFlorida must collect. Include in your response a discussion of each variable in the formula.

A. FPC has not developed as of this date the specific formula it anticipates employing for calculating its transmission revenue requirements for recovery from GridFlorida. FPC expects such a formula will be based on a traditional embedded cost of service calculation.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

107. Mr. Southwick's testimony, on page 33, lines 1 through 12, states that Seminole Electric Cooperative and its member systems, and the Florida Municipal Power Agency and its member participants (TDUs) are dependent upon FPC's transmission system for delivery of their power needs.

a. What will be the impact upon GridFlorida if the above TDUs opt not to participate?

A. GridFlorida would have fewer facilities under its control for providing unpancaked transmission service. However, the cost shift that FPC customers would otherwise be exposed to would be lessened. Operationally, GridFlorida would still have security coordinator authority of the facilities owned by the TDUs.

b. Will the TDU contractual agreements with FPC remain in effect after the formation of GridFlorida, and, if so, for how long?

A. FPC plans to amend these agreements for the purpose of converting the transmission service to be provided by GridFlorida under its OATT.

c. Since FPC is only giving GridFlorida operation control of its transmission facilities, can FPC enter into separate agreements with the TDUs? If so, what would be the revenue arrangement with GridFlorida and FPC?

A. FPC will no longer provide transmission service once it transfers operational control of its transmission facilities. All new transmission service utilizing Controlled Facilities will be provided through the GridFlorida OATT.

d. If the TDUs decide not to participate in GridFlorida, what other avenue would FPC have for facility cost recovery?

A. Whether the TDUs participate in GridFlorida or not, the TDUs must still obtain and transmission service from GridFlorida and pay GridFlorida for such service at a rate that will ensure the opportunity to recover facility cost for the GridFlorida Companies.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

108. Refer to page 6, lines 22 - 25 of the testimony of William R. Ashburn (filed in all three dockets). Explain in detail why each the following issues are problematic for GridFlorida pricing: 1) cost shifting that arises from adoption of average system rates; 2) providing revenue credits for facilities owned by transmission dependent utilities; and 3) eliminating pancaked rates.

A. Mr. Ashburn's testimony beginning at page 6 addresses the context in which GridFlorida's pricing policy was formulated. The testimony provides that the GridFlorida pricing policy was designed to comply with FERC's Order No. 2000 pricing requirements while providing a balanced and reasoned approach to certain issues that historically have provided impediments to RTO formation. The three issues listed above were addressed in the RTO proposal because they can increase the transmission cost of service for some utilities as a result of joining an RTO. While the generation benefits that are expected to accrue from a RTO are expected to be large but difficult to measure ex ante, these costs, while potentially much smaller, are certain and can be more easily measured. In the context of Order No. 2000, the mitigation measures relating to these issues that were accepted by FERC strike a reasonable balance between the interests of utilities to avoid or delay any adverse cost impacts as a result of joining an RTO and the interests of transmission users seeking to more immediately capture the benefits they will receive from the shifted cost burden.

A transition to average system rates for the GridFlorida region is problematic for the obvious reason that averaging of rates benefits those whose rates were higher while costing those whose rates were lower. Higher cost utilities sought shorter phase in periods or less zones, while the reverse was true for lower cost utilities.

Transmission Dependent Utility (TDU) credits was especially problematic, in part because of the cost shift and in part because the issue had been negotiated/litigated extensively at FERC. The issue is not revenue crediting, it is inclusion of the revenue requirements for those TDU facilities in the zonal revenue requirements of those two company's zonal rates.

Elimination of pancaked rates was particularly problematic given the many existing transmission agreements which must be addressed by the proposal and the concern to protect the rights and interests bargained for by parties on both sides of those agreements. As those agreements terminate, the party seeking service under those transactions will reap the benefits of non-pancaked rates from GridFlorida while the prior transmission provider will lose the source of revenue to benefit other users. The methodology utilized is finely tuned to the zonal rate phase out pricing approach to try and balance the interests of parties to both sides of the existing pancaked transactions.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

121. Refer to pages 39, line 23 through page 40, line 2 of the testimony of William R. Ashburn (filed in all three dockets).

a. Specifically identify the source of any reduced transmission costs, other than those associated with the elimination of pancaked rates, that will result by implementing the GridFlorida pricing protocol.

b. Specifically identify the source of any generation cost savings that would result from the implementation of the GridFlorida pricing protocol.

A. a. As specified in section 8.1 of Attachment T to the Open Access Transmission Tariff (Exhibit No. CMN-1, p. 4180), existing pancaked transmission charges are eliminated only when the same customer bears transmission charges on 2 or more systems. If more than one customer pays multiple transmission charges to deliver the power from source to sink, the multiple charges will be reduced only if all parties to the transaction agree that the resulting reduction in transmission charges will go to benefit the load.

b. Generation costs would be reduced because of the increased area where generation can be sited without added transmission costs to deliver that generation to load. Generation costs would be reduced because purchased generation from generators located in areas where additional transmission charges have been imposed in the past will not have those charges imposed. One stop shopping and regional interconnection studies will encourage new generation resources to site in GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

130. Under the GridFlorida Proposal should merchant plants have physical transmission rights if they do not currently serve a native load?

A. The GridFlorida proposal assigned physical transmission rights to Load Serving Entities (LSE's) within GridFlorida. These LSE's could transact with merchant plants on a non firm basis, or on a firm basis if they possessed enough physical rights.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

133. Provide both the replacement and market value as of December 31, 2000 for those assets which will be under the operational control of GridFlorida. Explain in your response how each value was determined.

A. The replacement cost of FPC's transmission assets as of December 31, 2000 is estimated at $1,990,800,000. FPC employed a system that identified the vintage of its major transmission facilities, and applying Handy-Whitman Index factors, calculates a current replacement cost of such facilities. No analyses have been performed to estimate the market value of FPC's transmission assets.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

134. If FPC decides to divest its transmission assets to GridFlorida or any other entity at some future time, what ratepayer benefits would result if the transfer is at market value? At replacement cost? At net book value?

A. We have not decided to divest such assets and, thus, have not attempted to estimate the benefits at this time.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

135. Explain what, if any, steps FPC and/or GridFlorida have taken to ensure quality and reliability of transmission service to all retail ratepayers beyond the transition process as GridFlorida takes over the management and operation of FPC's transmission facilities.

A. As discussed in my testimony filed in this docket on August 15, 2001, the POMA and the Operating and Planning Protocols contain standards and requirements that will govern the management and operation of all facilities operated by GridFlorida. Particularly, see Section I.F of the Operating Protocol. As is also discussed by me, the Operating and Planning Protocols apply to all transmission facilities owned and/or operated by GridFlorida, which ensures that transmission service will be provided in a uniform manner. The POMA is extensively described in my testimony and is found in document 33, Volume VI of Exhibit CMN-1. The Operating and Planning Protocols are discussed in the Panel testimony and are also found in document 33, Volume VI of Exhibit CMN-1.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
DOCKET NO. 000824-EI
STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 53-158)
INTERROGATORY NO. 136
PAGE 1 of 1

136. The testimony of Henry I. Southwick, page 13, (filed August 15, 2001) describes how FPC will differentiate its revenue requirements for purposes of GridFlorida charges related to (a) existing facilities and (b) new facilities. Explain in detail how this description differs from the way FPC currently addresses the treatment of regulatory requirements.

A. Currently, in any ratemaking proceeding, FPC does not distinguish its revenue requirements as to existing facilities or new facilities. Since GridFlorida's pricing plan recovers the revenue requirements associated with existing facilities through zonal charges and the revenue requirements associated with new facilities through system wide charges, it is necessary to make this distinction. The Company's method of differentiating the revenue requirements ensures that total revenue requirements are the same as they would be if calculated in accordance with current methods.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

137. The testimony of Henry I. Southwick, p 3, (filed August 15, 2001) states that "RTO participation requires transfer of either control or ownership of transmission facilities. FPC views this choice as a business decision, not as a question of utility operations." If this is the case, what specific factors did FPC consider in its decision to transfer control, but not ownership of its transmission lines?

A. As explained in my testimony, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business. Those were the factors FPC considered when evaluating the form of its participation in GridFlorida.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

142. Did FPC ever consider divesting its transmission assets for the purpose of establishing a Florida RTO? Why or why not?

A. Yes, FPC gave some consideration to this option when FPL announced their proposed divestiture. As explained in my testimony, FPC has been successfully engaged in the transmission business for many years and sees no business reason to exit the transmission business.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

150. On Page 15 of the panel testimony, the panel states that "those owners who have divested their transmission assets to GridFlorida ("Divesting Owners") will have the option of operating their own "internal" control area that will be subject to GridFlorida's indirect control." Why do the Divesting Owners retain this option and, more specifically, why has FPC already decided to retain its internal control area?

A. Qualified parties have the right to form or merge control areas according to NERC's policies, and these rights are preserved under FERC's Order 2000. These rights are reflected in the GridFlorida market design in that both divesting and non-divesting transmission owners have the right to remain control area operators or to merge with the RTO control area. For this reason, the GridFlorida market is designed to be compatible with multiple control areas. FPC has decided for the present that it is in the best interests of its customers to remain a control area operator at least until the RTO has been established for some time, and future market operations are established and proven. This will give FPC the ability to effectively manage the complex interplay of resources necessary to meet the needs of its customers, including FPC's generation resources, demand side management, voltage reduction and others in much the same manner that it has in the past, while evaluating potential future changes. FPC and its customers will have the ability to fully participate in the RTO markets during this period to capture any and all available RTO market benefits. FPC believes that it is valuable to retain this flexibility.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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INTERROGATORY NO. 151
PAGE 1 of 1

151. On Page 18 of the panel testimony, the panel describes the demarcation between transmission and distribution facilities. Why is land and/or right-of-way not defined as a transmission line segment within the scope of transmission facilities?

A. Land and land rights associated with most transmission facilities will continue to be essential to the provision of distribution services for retail customers such that the load-serving entities will grant to GridFlorida only those land access rights that are essential for the operation and maintenance of the transmission system while retaining control over all other land and land rights necessary or useful in the provision of retail electric service.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

152. On Page 23 of the panel testimony, the panel summarizes GridFlorida's planning function and mentions "in depth participation by all market participants, the Florida Public Utility Commission ("FPSC"), and other interested parties." Please describe FPC's view of the FPSC's role in assisting GridFlorida with the transmission planning function?

A. The FPSC would attend the regional planning meetings and participate in the planning process as any other entity, to the extent it chose to do so. The creation and operation of GridFlorida will not affect the FPSC's ability to participate in the FRCC's review of the plans and reliability assessment of the system. All proposed construction of transmission facilities subject to the FPSC's siting jurisdiction would be submitted to the FPSC for review and approval. Also, the FPSC has the right to review the studies (and supporting data) and to provide input to GridFlorida during the decision making process as to the need for new transmission facilities. To the extent that the FPSC lawfully orders a load-serving entity under its jurisdiction to construct transmission facilities, GridFlorida will build such facilities if the entity does not desire to do so. Please see Attachment N.1 to the Planning Protocol regarding the Annual Regional Transmission Planning Process.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
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STAFF'S FOURTH SET OF INTERROGATORIES (NOS. 53-158)
INTERROGATORY NO. 158
PAGE 1 of 1

158. On page 38 of the panel testimony, the panel states that "GridFlorida will charge the average of the cost that it incurs to procure the [ancillary] services." Why is this charge based on an average and not on a time-based increment?

A. Due to the FERC finding that insufficient market data existed to support a market clearing price system, the GridFlorida proposal was modified to provide for cost based services by the GridFlorida Participants and other market entities. It is anticipated that these prices will be quite stable, and some, such as Black Start, should not vary by time anyway.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

1. Provide all completed studies concerning the current and future needs of FPC's transmission assets/facilities.

A. FPC's planning process is documented in an electronic information system termed THOR, which contains information on project alternatives, details on costs, project justifications, etc. THOR produces budget reports, project tracking, and data for planning models. While this data is too voluminous to print, all projects are included in the FRCC databank models that are filed in the annual FERC 715 report filed by the FRCC. The models include all transmission projects regardless of size, and all Point of Delivery (POD) projects. FPC has some studies completed for customers, as noted on FLOASIS. Any projects undertaken for customers as a result of either GIS or transmission service requests are listed in agreements filed with the FERC, and included in the next update of load flow models. In addition, FPC has completed a joint study of North Florida with SECI, Member Cooperatives and Tallahassee, a copy of which is attached.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

Transmission Reliability Workshop
Proposed Agenda
October 22, 1999
10am-5pm

- Planned FPC Bulk System improvements/facility upgrades

- Status of Predictive Maintenance Program & Databases
  - Bulk Power Maintenance Plan
  - Reliability Analysis

- Update on Maintenance Activities
  - Update of Previous Issues
  - Crew/Equipment Locations
  - Communications
  - Review of Specific Outages

- Introduce Seminole's Transmission Reliability Task Force

- Discussion of FPC-CPL Merger

Northwest Florida Transmission System Study

Introduction

The northwest Florida transmission includes the power systems of The City of Tallahassee (TAL), Florida Power Corporation (FPC), Suwannee Valley Electric Coop (SVEC), Talquin Electric Coop (TEC), and Tri-Country Electric Coop (TCEC) systems. The RUS cooperatives are members of Seminole Electric Cooperative, Inc.

All of the above entities are affected by the performance of the grid in this area. Accordingly, the parties have agreed to participate in a joint study of the system in order to identify the future needs for reliable and cost-effective electric supply.

Study Scope

FRCC load flow cases modeling 2000 summer and 2004 summer are used for the analysis. The study considers on and off peak time periods. The impact of power transfers, both state imports and exports are addressed using FRCC model assumptions.

High Import 3600 MW Southern to Florida Power at peak load
High Export 1900 MW Florida to Southern at 80 percent of peak load
Firm Import 1500 MW Southern to Florida at peak load

The intent of the study is to determine the future needs of the northwest peninsular Florida transmission system. Once determined, realistic and practical enhancements will be developed and tested to verify workability.

Methodology

The FRCC cases described above are modified to include:

- Three 15 Mvar capacitor installations: modeling mobile units installed at Havana, Miccoosukke and Perry North substations

- The capacity of the Hanson/Geenville/Aucilla 115 kV line section at 84/104 MVA.

- The addition of 69 kV bus tie breaker at FPC's Fort White.

- Modeled addition Ross Prairie 230/69 kV transformer substation in Marion County.

The analysis considers system operation flexibility such as pre and post contingency transmission line switching. Initial load flow screening is reviewed to determine line-switching options that reflect current operational procedures.

Base Case Analysis Summary

- The analysis indicates voltage and thermal weakness in the Gulf Power transmission system. This weakness is indicated when additional transmission lines are modeled linking the FPC system in the Northwest with the panhandle transmission system.
- Single contingency voltage concerns on the FPC system west of Tallahassee.
- Thermal concerns in Shultz and Woodruff areas.
- Thermal and voltage problems on contingency, along FPC's JQ 115 kV transmission

line as well as, lateral feeder transmission line source via the JQ.

System Improvements Considered

The following system enhancements were evaluated as separate solutions.

- Extension and interconnection with The City of Tallahassee of the Drifton to Waukeenah 115 kV transmission line.
- A 230 kV transmission line linking Thomasville to Tallahassee at Substation 7
- A 230 kV transmission line linking Thomasville to Drifton to Perry
- Addition of 230/115 kV transformer at Purdom.

Methodology

The study utilizes the 1998 FRCC Databank model. Power Technologies Incorporated PSS/E package and TAPWIN are used to perform the steady state analysis. PTI's PSS/E is an "industry standard" load flow software run on a PC platform. TAPWIN is a multiple contingency analysis package that utilizes PTI's PSS/E program.

Single contingency criteria is utilized to determine violations

Observations

In the 2000 timeframe, reactive additions and conductor capacity upgrades are required to maintain adequate system performance. Currently, mobile units recently installed at Havana, Miccosukkee and Perry North are providing additional reactive support for contingency scenarios. This needed support will be provided by permanent installations in this timeframe. Capacity increases are required at the FPC/Tallahassee interconnect on the West Side of the city. The nature of the capacity increase will be addressed bilaterally between Tallahassee and FPC.

The addition of the Waukeenah extension towards a Tallahassee interconnection significantly improves the robustness of the area's sub-transmission system, providing voltage support during contingency on the JQ 115 kV line and additional support to Drifton. This extension shall support additional points of delivery planned for the future. The extension also will integrate with the anticipated addition of a voltage source in the Drifton area. The 230 kV transmission line modeled in this study interconnecting Thomasville to Drifton to Perry is an example of the type of strong source anticipated. This project would be required in the 2000 to 2004 timeframe.

Cooperative facilities interconnected to the FPC grid at Miccosukkee exhibit voltage and thermal overloads in base case and contingency scenarios in the 2000 to 2004 timeframe and beyond. A tie connection between the JQ 115 kV line (near the Miccosukkee interconnection) and the proposed Wakeenah extension would provide critical contingency and load support. This proposal can be coordinated with cooperative needs described previously and would provide both FPC and cooperative system support for years to come. This component of a coordinated system plan will be discussed bilaterally with Seminole and the affected distribution cooperative.

Long term system enhancements required to maintain adequate performance are of the form:

A grid tie point in the central portion of the JQ 115 kV line. The Thomasville/Drifton/Perry 230 kV alternative is representative of this type of system addition.

A voltage upgrade of existing 69 kV facilities between Fort White, Perry and Drifton substations. This alternative was evaluated in past studies and was not considered in this evaluation.

By 2000;

Permanent 115 kV switched banks. Currently, FPC has three mobile capacitor bank installations to support voltage and minimize thermal loading on the transmission system in the area. These mobile units shall be replaced with 25 to 45 Mvars of switched banks and the location of these installations will be optimized.

Finalize Waukeenah extension configuration and west TAL interconnection capacity increase configuration. The termination of the Waukeenah extension and the increase of the FPC/Tallahassee tie involve bi-lateral coordination between FPC and Tallahassee. The need is in the 2000 to 2004 timeframe.

Between 2000 and 2004;

Energize Waukeenah extension western interconnection.

Coordinate northern lateral interconnection with JQ 115 kV line. A lateral "tie" between the existing JQ 115 kV line and the proposed Waukeenah extension is necessary for contingency support and to provide reliable load serving for both FPC and Cooperative load centers. Bi-lateral planning and design efforts between Seminole and FPC will be necessary to complete this effort.

Coordinate and finalize grid source in-service. The planning and conceptual configuration of grid upgrades (230 kV and up) should be finalized in this timeframe. This project(s) should coordinate with the earlier timeframe projects defined above. For example, a 230 kV loop through the Drifton area coupled with the Waukeenah extension will provide adequate load service for many years to come.

After 2004;

Energize 230 kV grid enhancement-Georgia connection-East West 230 kV line

Future Study Activity: Action Plan

Bi-lateral discussions with Seminole and Tallahasse will be conducted to implement the suggested system enhancements (or there equivalent). Projects defined for later time frames will be continually reviewed for refinement

Northwest Florida Joint Study

May 25, 1999

Load Flow Model Assumptions

- Florida Reliability Coordinating Council Transmission Model for FY1998
- Study Years 2000 and 2004
- Various Dispatch Scenarios
  - Firm Transactions
  - High Southern to Florida Import
  - High Florida to Southern Export

Study Criteria

- Single Contingency Analysis
- Selected Units Unavailable
- 0.95 to 1.05 Voltage Criteria for Load
- Rate A and Rate B Thermal Limits
- Remedial System Operations

Expansion Plan Summary

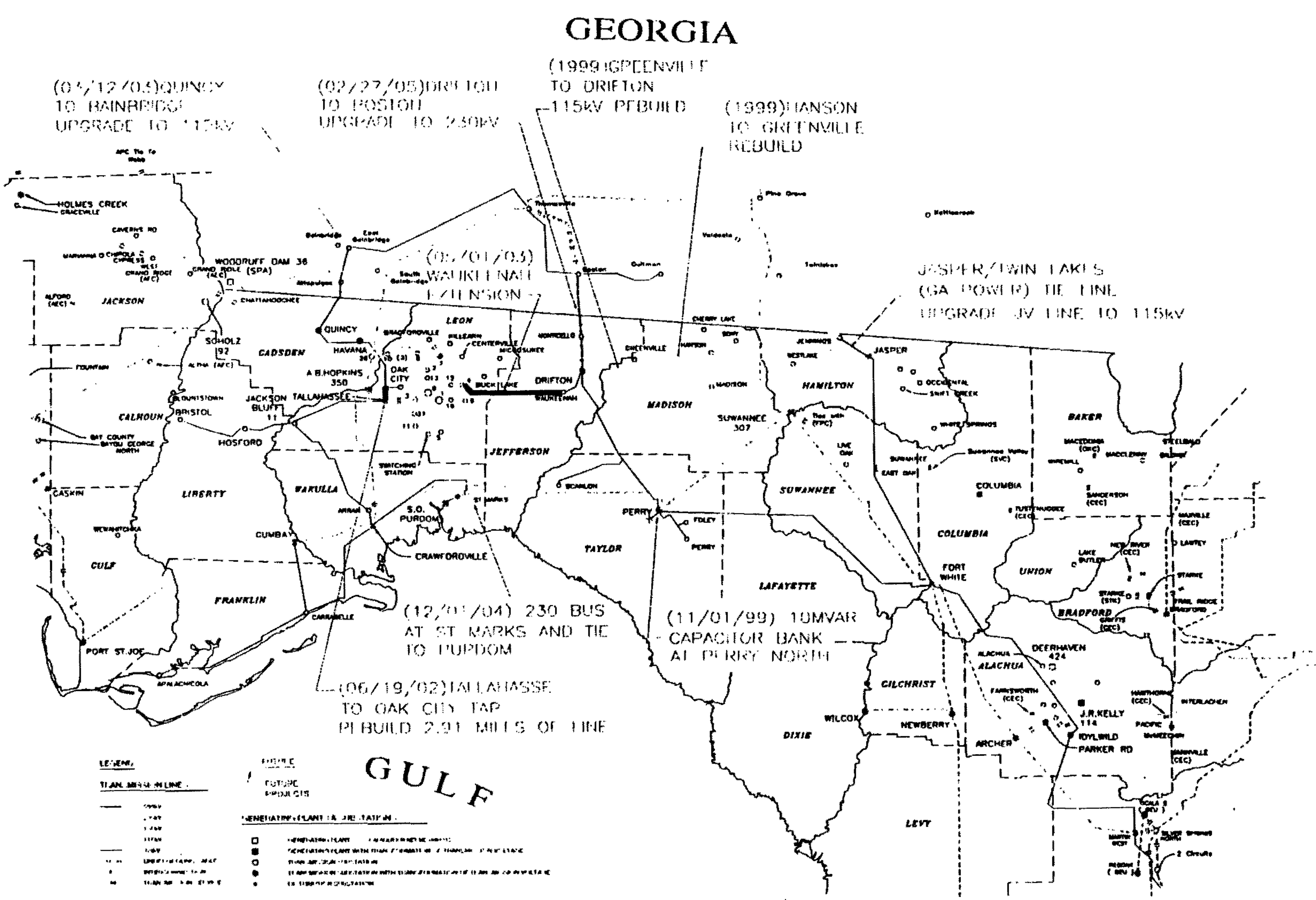
Florida Power Corporation

Project	In-service	Comments	Dollars	Budget #
in Budget				
10 MVAR Capacitor Bank at Perry North	11/01/99	Replaces mobile bank	177,000	1477
Greenville to Drifton 115 kV rebuild	06/01/99	Re-rate de-rated line to 104 MVA	507,000	1442
Hanson to Greenville rebuild	06/01/99	Re-rate de-rated line to 104 MVA	517,000	1442
Tallahasse to Oak City Line Rebuild 2.91 miles of line	06/19/02	Add Tall to Lk. Bradford to project	1,000,000	1214
Wakulla North 69 kV line	05/02/03	Possible Future Loop	1,500,000	1410
Drifton to Boston upgrade to 230 kV	05/27/05	Provides needed voltage source	4,200,000	1238
Quincy to Bainbridge upgrade to 115 kV	03/12/03	Currently 69kV	2,750,000	1236
Jasper/Twin Lakes (GA Power) Tie Line - Upgrade JV Line To 115 kV	06/01/06	Currently 69kV	3,100,000	1229
		sub total	13,751,000	
proposed, but not in Budget				
Waukeenah Extension	05/01/04	Continue effort with Tallahassee	3,000,000	
230 Bus Position at St. Marks	12/01/04	Contingent on Tallahassee Expansion	500,000	
		sub total	3,500,000	
		total	17,251,000	

EXISTING NORTHWEST FLORIDA

0140

PROPOSED PROJECTS
NORTHWEST FLORIDA

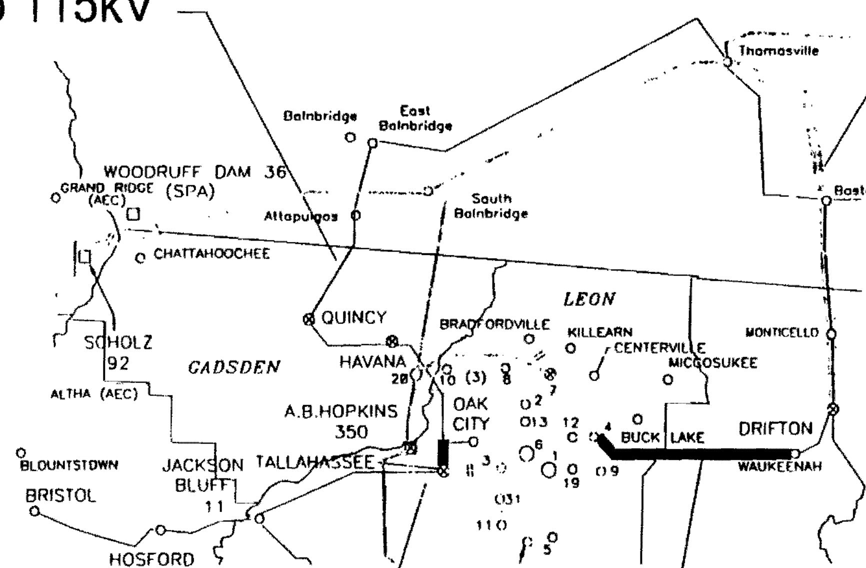


0141

NORTH TALLAHASSEE AREA

(03/12/03)
Quincy to Bainbridge
Upgrade to 115kV

(02/27/05) Drifton
To Boston
Upgrade To 230kV



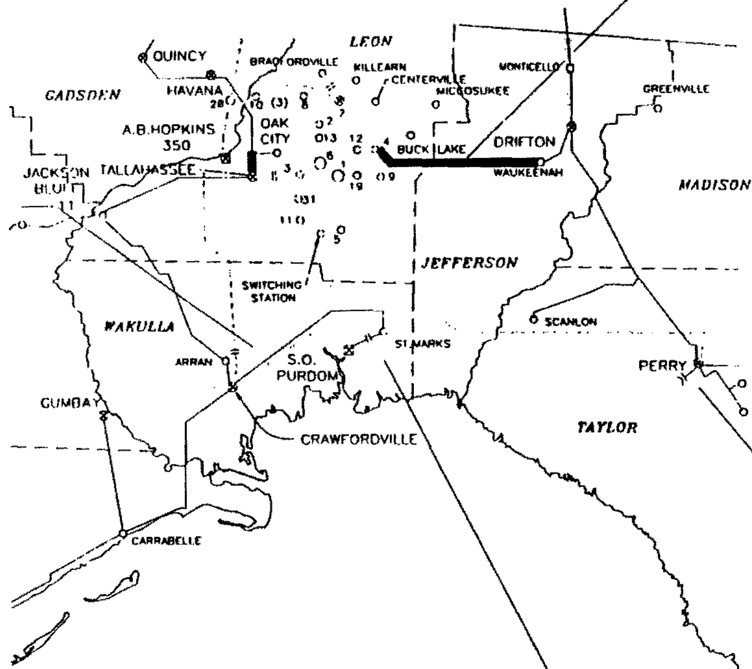
(06/19/02) Tallahasse
To Oak City Tap
Rebuild 2.91 Miles of Line

(05/01/03)
Waukeenah
Extension

0142

SOUTH TALLAHASSEE AREA

(05/01/03) Waukeenah Extension

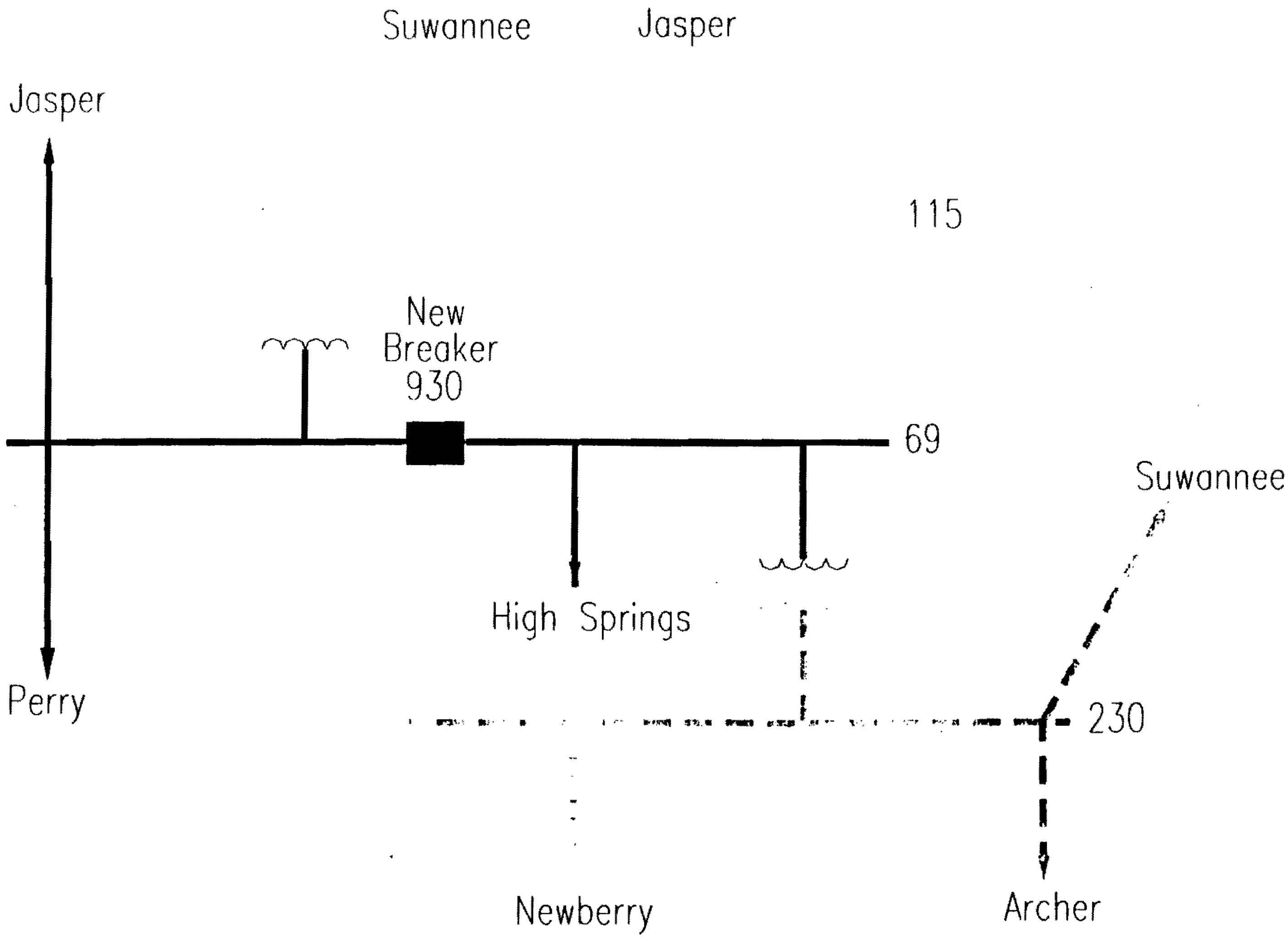


(11/01/99) 10MVAR Capacitor Bank At Perry North

(12/01/04) 230 Bus At St Marks and Tie To Purdom

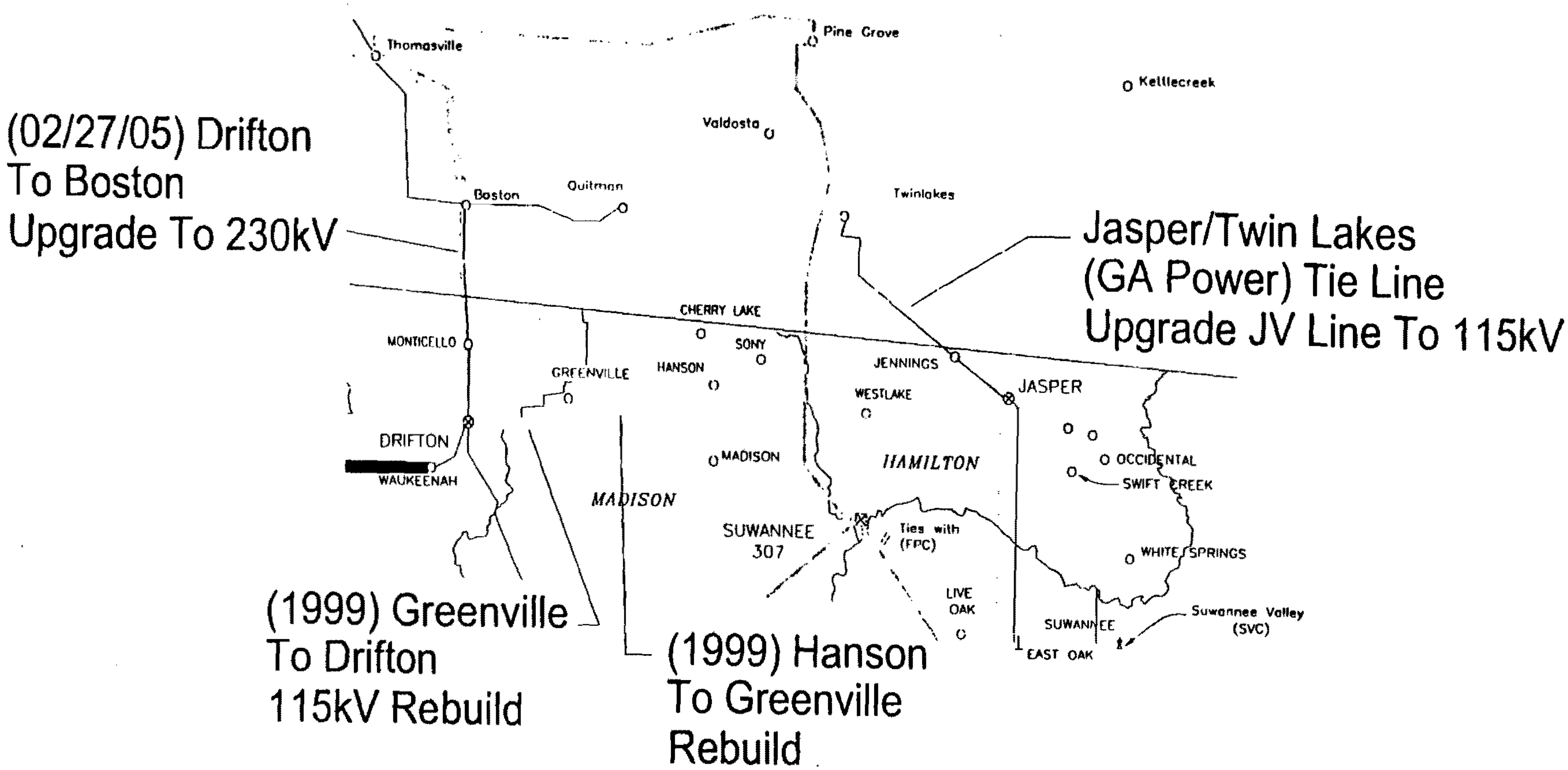
0143

FORT WHITE SUBSTATION



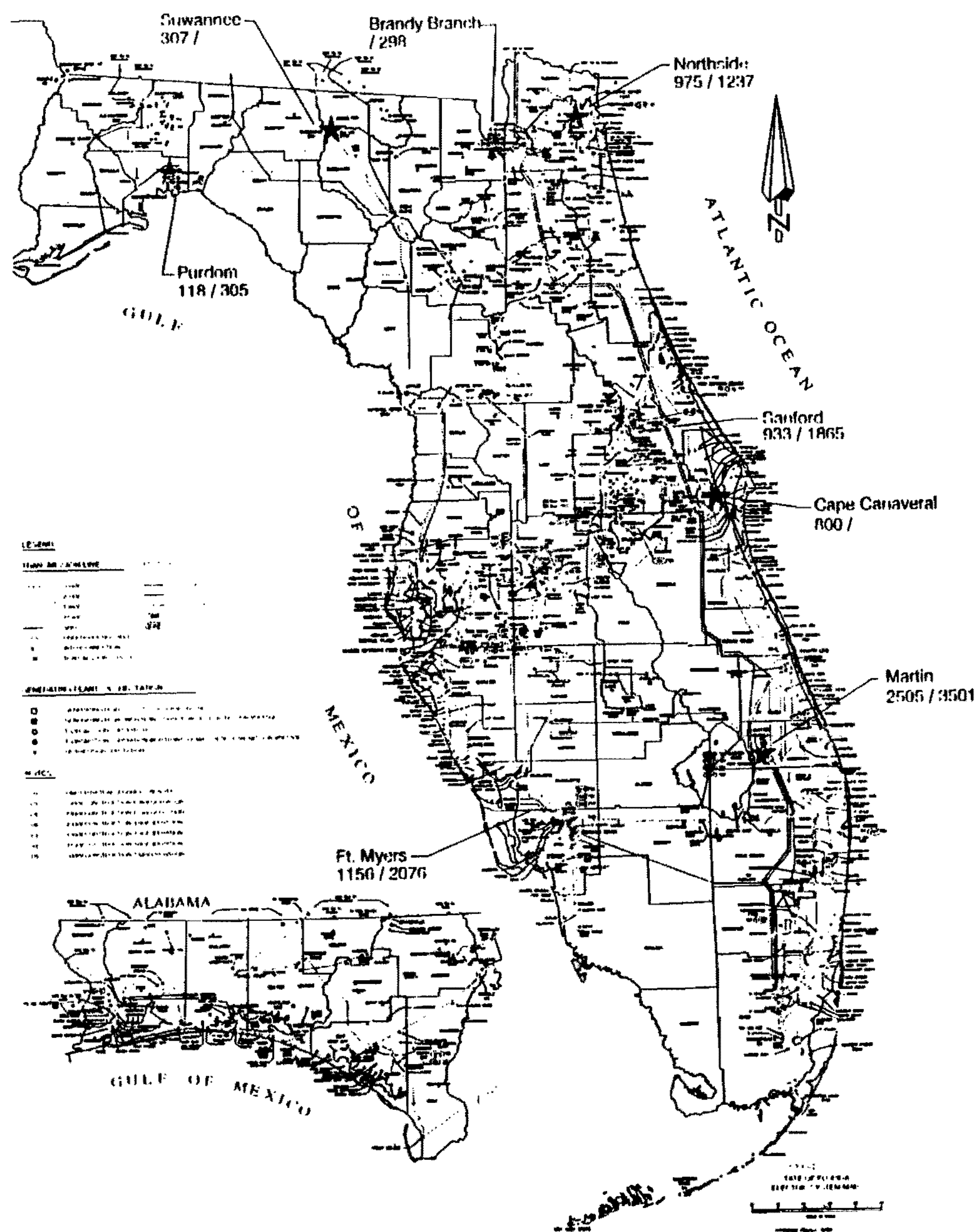
0145

DRIFTON - SUWANNEE AREA



0144

EXISTING FLORIDA

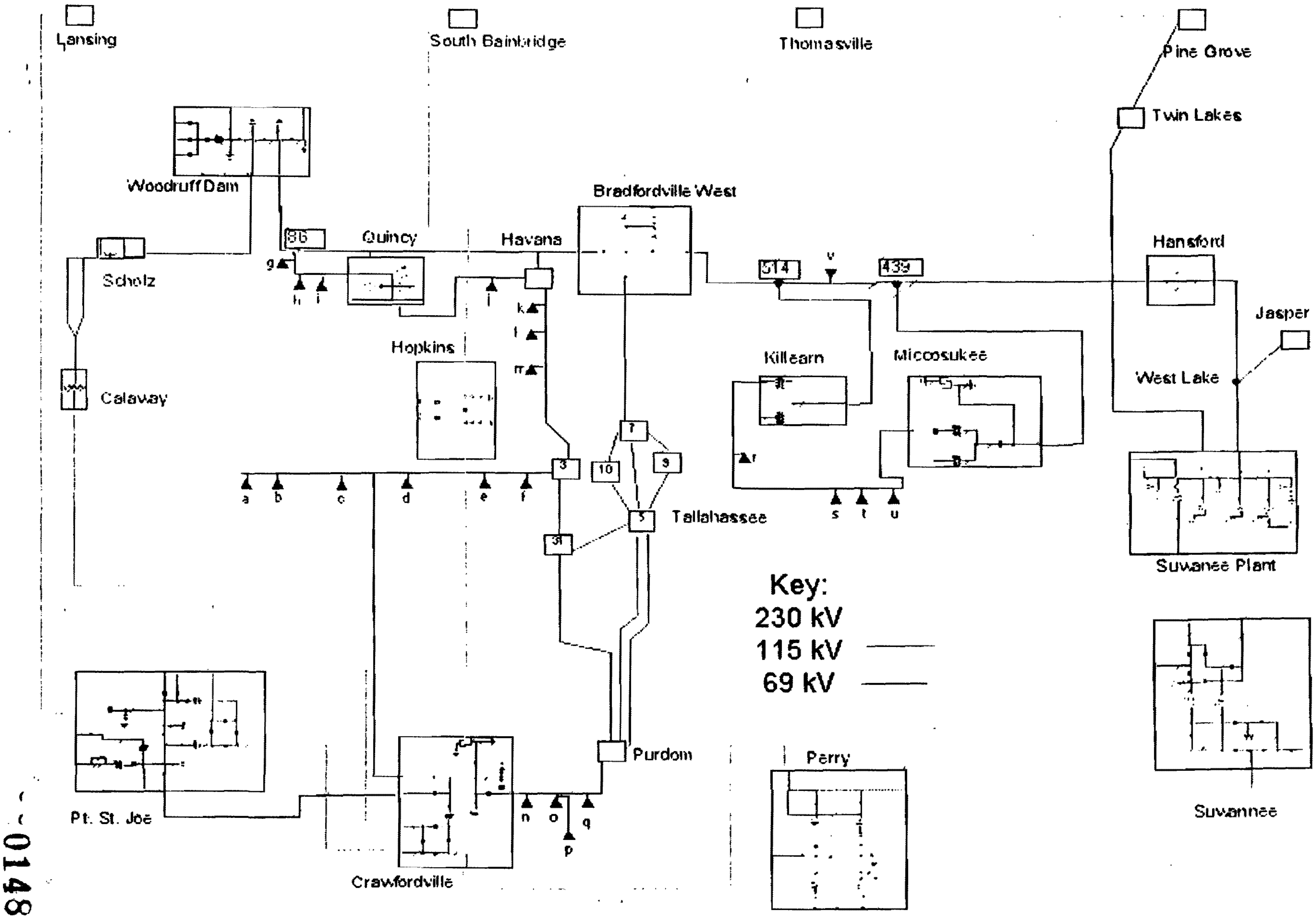


0146

Future Activity

- Continue Discussions with Tallahassee
- Initiate Discussions with Georgia
- Review Plan Subject to System Evolution
- Maintain Communication Seminole

EXISTING NORTHWEST FLORIDA SCHEMATIC



0148

2. Provide all documents used in evaluating the benefits and costs associated with participating in a transmission organization other than GridFlorida.

A. No documents were used.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 3

3. Provide all work papers and any other supporting documentation used to prepare Witness Holcombe's Exhibit BLH-3.

A. There is no such supporting documentation. The information provided for FPC in Exhibit No. BLH-3 is based on internal FPC discussions.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 4

4. Provide all documents referred to or relied upon in assuming a 30% contingency for Release 1 start up costs.

A. No specific documents are available. The contingency reflects Accenture's experience in working on projects of this nature where there are estimating uncertainties resulting from the fact that the project is early in the development cycle and GridFlorida requirements are not yet complete. The use of the 30% contingency is a standard component in Accenture's estimating models for projects of this nature at this stage in development.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 5

5. Provide all documents referred to or relied upon in determining that divested transmission assets should be transferred to GridFlorida at net book value.

A. FPC has no such documents.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

FLORIDA POWER CORPORATION
DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 9

9. Please provide all lease agreements for existing facilities being leased to GridFlorida.

A. FPC has none.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

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DOCKET NO. 000824-EI
STAFF'S SECOND REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 3-10)
REQUEST NO. 10

10. Please provide all documentation showing how FPC developed the dollar amounts associated with systems to be retired as a result of GridFlorida, as referenced in Interrogatory No. 94.

A. No such supporting documents exist. Please refer to the answer to Interrogatory No. 94

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

EXHIBIT NO. ___________

DOCKET NO: 010577-EI

PARTY: TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT: 1) RESPONSES TO STAFF'S INTERROGATORY NOS.7, 8, 11, 18, 19, 20, 21, 24, 28, 29, 30, 31, 32, 33A, 34, 35, 36, 37, 38, 39, 40, 41, 42, 43, 44, 50, 51, 52, 53, 54, 55, 57, 58, 59, 60, 61, 62, 63, 64, 65, 77, 82, 83, 88, 89, 90, 92, 93, 94, 95, 96, 97, 98, 101, 102, 103, 104, 105, 107, 108, 109, 110, 111, 112, 113, 122, 136, 137, 138, 139, 140, 142, 143, 144, 145, 146, 147, 148, 149, 150, 162; AND 2) RESPONSES TO STAFF'S PRODUCTION OF DOCUMENTS NOS. 2, 4, 5, 6, 7, 8, 14, 15.

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO. 2
COMPANY/
WITNESS. FPSC Staff
DATE: 10-3 - 5-01

7. How does TECO intend to treat any gain on the transferred assets above net book value?

A. The transfer of assets to GridFlorida is not expected to result in a gain since the assets are to be transferred at net book value.

8. What are the current annual revenue requirements associated with transmission services provided to:

a. Wholesale full and partial requirements customers;

b. Wholesale firm and non-firm interchange customers; and

c. Firm retail customers.

A. Based on a year 2000 cost of service study that reflects then current functionalization of plant to transmission and subtransmission functions (i.e., does not reflect any reclassification to production or distribution functions as a result of divestiture in a future period), the annual revenue requirements associated with transmission services provided to various classes of customers are as follows ($000):

a. Wholesale full and partial requirements customers: $ 1,824

b. Wholesale firm interchange customers: $ 328

These amounts represent the transmission revenue requirements associated with wholesale firm interchange customers for separated sales only. Revenue requirements are not specifically identified for firm interchange sales that are not required by the FPSC to be separated. No revenue requirements are associated with transmission services provided to non-firm interchange customers due to the variable nature of these transactions. Any transmission service revenues derived from non-firm interchange transactions have been revenue credited thereby reducing total revenue requirements.

c. Firm retail customers: $ 46,435

11. Please identify each service TECO will purchase from GridFlorida and the expected cost for each service.

A. Tampa Electric will purchase from GridFlorida the transmission services and ancillary services needed to serve its retail and wholesale native load and any other such services it may desire to purchase for its wholesale sales. The "cost" for such purchases will depend upon the GridFlorida rates for such services, which have not yet been determined. Tampa Electric expects the initial base transmission rates for the Tampa Electric zone to be similar to its existing cost of service. There will be an incremental cost assessed to Tampa Electric for the cost of implementing and operating GridFlorida which would be contained in the Grid Management Charge. The portion assessed to Tampa Electric will depend on its load ratio share, which depends upon which entities participate in GridFlorida as described in Interrogatory No. 3 above.

There should be a reduction in costs to Tampa Electric due to the elimination of wheeling costs paid to Florida Power and Florida Power & Light for purchases wheeled through their systems, depending on how many purchases are made. In addition, Tampa Electric expects to self-supply most of its own ancillary services initially, resulting in minimal change in costs, except that its participation in the balancing market (one of the ancillary services) is expected to result in reduced costs due to fuel savings realized in intra-hour economic dispatch.

18. If the GridFlorida rate, including the Grid Management charge and deferred start-up costs is greater than the revenue requirement associated with the divested assets, does TECO intend to recover the difference from retail ratepayers? If so, how?

A. If the total of the GridFlorida charges for transmission service is greater than the revenue requirement associated with the divested assets, Tampa Electric would anticipate at some point petitioning the FPSC to authorize recovery of the incremental costs. While all alternatives will be explored, one potential recovery mechanism would be a cost recovery clause.

19. Using a fully allocated cost of service study, please provide the amount of transmission expenses associated with each rate class.

A. Based on a year 2000 fully allocated retail cost of service study that reflects then current functionalization of plant to transmission and subtransmission functions (i.e., does not reflect any reclassification to production or distribution functions as a result of divestiture in a future period), the transmission revenue requirements associated with each rate class are as follows ($000):

RS	GS	GSD	GSLD & SBF	IS & SBI	SL & OL
$26,937	$3,306	$11,725	$4,157	$9,492	$310

20. What expenses, other than transmission investment does TECO intend to divest to GridFlorida? (*i.e., general, administration, operating,* land, debt service obligations?)

A. None.

21. Could a gain on sale result from the transfer of transmission assets to GridFlorida? If so, please identify the quantity and gain. If not, please explain why not.

A. No. See response to Interrogatory No. 7.

24. Transmission poles are assets that will be transferred to the RTO. Located on some transmission poles are pole attachments belonging to an entity other than the utility, such as CATV. Those pole attachments generate revenues. Please answer the following questions related to pole attachments.

a. What are the anticipated revenues from pole attachments which are located on transmission poles that will be transferred to the RTO?

b. How will any revenues lost from such pole attachments be reflected on TECO's books?

A. a. Tampa Electric estimates that approximately $166,000 in annual revenues from pole attachments which are located on transmission poles will be transferred to GridFlorida. This estimate was derived based on approximately 10,000 attachments related to CATV and telecommunication carriers priced at various FCC regulated and negotiated rates.

b. The revenues associated with these attachments will no longer be recorded on Tampa Electric's books, but will be revenue credited to the cost of service of GridFlorida.

28. Did TECO refunctionalize any transmission assets/facilities prior to their RTO filing of October 16, 2000? If so,

a. List the prior and current function of the assets/facilities transferred to the GridFlorida.

b. Provide the effective date of the change in function.

c. Provide the current and prior cost of the assets/facilities as it relates to the new and old function.

A. No.

29. What adjustments will be made to TECO's accounts to rectify any changes due to reclassification of assets/facilities under the operational control of the GridFlorida?

A. Based on the account balances of December 31, 2000, the adjustments to TECO's accounts would be:

Acct	Description	Debits	Credits
124	Other Investments	150,169	
101	Plant In Service - Classified		244,499
106	Completed Construction – Not Classified		11,601
107	Construction Work In Progress		1,830
114	Acquisition Adjustment		5,136
108	Accumulated Provision for Depreciation	90,196	
154	Plant Materials & Operating Supplies		2,867
255	Accumulated Deferred Investment Tax Credits	758	
281-3	Accumulated Deferred Income Taxes	24,810	

30. a. Is there any part of TECO's transmission system that will not be under the ownership and operational control of GridFlorida, but its usage will be necessary to effectuate functional control of the transmission facilities

b. If so, has a cost allocation plan been developed for the distribution of costs between TECO and GridFlorida?

A. a. Yes. There are components of the transmission system that will not be under the ownership and/or operational control of GridFlorida. This includes such facilities as dual use facilities (e.g., control house, remote terminal units, battery banks, etc.) in transmission-distribution stations that will be retained by the utility, land and land rights associated with transmission assets, generator main step-up transformers (GSUs), and the generator synchronizing breakers located in generator switchyards, which will be owned by GridFlorida, but will be controlled by the generator. A more detailed listing of the demarcation and the assets involved are included in Attachment Q, Sections 1-3, of GridFlorida's Open Access Transmission Tariff part of the compliance filing with the Federal Energy Regulatory Commission dated May 29, 2001.

In addition, in order to operate the transmission facilities that Tampa Electric has provisionally decided to contribute, GridFlorida will need to use a portion of Tampa Electric's telecommunications system. This system is required to operate both the transmission and distribution system and is the primary means of providing internal voice and data communication for Tampa Electric. Therefore, no portion of the telecommunications system will be transferred to GridFlorida. Instead, Tampa Electric will charge GridFlorida for the telecommunication services necessary to the operation of the transmission facilities transferred to GridFlorida by Tampa Electric. A cost allocation plan for the telecommunication services has not been fully developed. Tampa Electric is in the process of developing an appropriate methodology for accurately quantifying and allocating to GridFlorida the cost associated with the required telecommunications services.

b. A cost allocation plan is under review which will reimburse the asset owner for an allocable portion of the full costs to own, operate and maintain the assets.

31. Have any studies been completed on the current and future needs of TECO's transmission assets/facilities?

A. Yes.

32. a. Will TECO give ownership/operational control of any facilities currently classified as distribution, generation, or general plant facilities to GridFlorida as part of transmission system?

b. If so, identify the distribution, generation, or general plant assets that will be under the operational control of GridFlorida.

A. a. Yes.

b. Certain distribution substations that are served by 69 kV and above transmission have components that were originally classified as distribution that will be reclassified as transmission and divested to GridFlorida. These assets include, but are not limited to, high voltage buss, insulators and support structures, line sectionalizing switches, transmission breakers, and reactive devices connected to the high voltage buss.

33. a. Which transmission assets/facilities (proposed new and existing facilities) will be put under the operational control of GridFlorida?

b. Please list the new and existing facilities by the site and projected transfer date to GridFlorida.

A. a. Tampa Electric has provisionally decided to contribute all of the transmission facilities of 69 kV or above to GridFlorida as specified in the response to Interrogatory No. 33b. In addition, Tampa Electric will transfer assets and liabilities specifically attributable to the transmission function (e.g., materials & supplies). See the response to Interrogatory No. 29 for the adjustments to Tampa Electric's accounts that will result from those transfers.

b. Please see the attached list that details the transmission facilities to be transferred to GridFlorida. This list has not yet been finalized and may be revised if or when Tampa Electric resumes work on the GridFlorida RTO proposal. The facilities will be transferred to GridFlorida on the first day of GridFlorida commercial operation. Tampa Electric cannot project that date at the present time.

34. Under GridFlorida's transmission Pricing Protocol filed with FERC on October 16, 2000, "there will be a single system New Facilities Charge to recover the cost of any New Facilities constructed by any Participant that is not directly assigned to a particular customer."

a. Will TECO reclassify any distribution or generation facilities as transmission facilities?

b. If so, will these reclassified facilities be considered New Facilities or Existing Facilities under the Pricing protocol?

c. Does TECO project any cost recovery and the creation of schedules for reclassified facilities where the "New Facilities Charge" may apply?

A. a. Certain assets recorded in FERC Accounts 101, 106 and 108 will be reclassified between transmission, distribution and/or generation accounts in compliance with the line of demarcation for ownership/operational control of GridFlorida facilities and the GridFlorida Open Access Transmission Tariff filing. The attached schedule titled "Determination of RTO Investment" reflects the proposed reclassifications between functional areas.

b. All facilities that will be reclassified to transmission from other functional areas before the transfer to GridFlorida will be considered Existing Facilities under the Pricing protocol.

c. No. Since the reclassified facilities will not be considered New Facilities, no "New Facilities Charge" would apply.

REVISED: 05/18/01 update

DETERMINATION OF RTO INVESTMENT
AS OF DECEMBER, 31 2000.

ACCOUNT	DESCRIPTION	CURRENT PLANT IN SERVICE	CURRENT ACCUM DEPR.	CURRENT NET PLANT	ADJUSTMENTS DECREASE COST	ADJUSTMENTS DECREASE DEPR.	ADJUSTMENTS INCREASE COST	ADJUSTMENTS INCREASE DEPR.	ADJUSTED PLANT IN SERVICE	ADJUSTED ACCUM DEPR.	ADJUSTED NET PLANT	RTO NET INVESTMENT SUBSTATIONS	RTO NET INVESTMENT LINES	RTO ANNUAL DEPR.
	TRANSMISSION													
350000	LAND													
	SUBSTATION	2,496,015	(1,026)	2,494,989	(2,496,015)	1,026		0	0	0	0			0
	LINE	5,419,895	0	5,419,895	(5,419,895)	0			0	0	0			0
350010	EASEMENTS	6,384,704	(1,859,024)	4,525,680	(6,384,704)	1,859,024			0	0	0			0
352000	STRUCTURES	2,455,137	(481,339)	1,973,798	(782,041)	220,060	0	0	1,673,096	(261,279)	1,411,816	1,411,816		35,135
353000	SUBSTATIONS	125,872,859	(35,328,557)	90,544,302	(34,710,229)	12,527,043	9,357,377	(3,218,301)	100,520,007	(26,019,815)	74,500,191	74,500,191		2,311,960
354000	TOWERS	4,342,275	(2,963,941)	1,378,334	(344,415)	235,090			3,997,860	(2,728,851)	1,269,009		1,269,009	103,944
355000	POLES	71,012,248	(29,660,608)	41,351,640	(790,537)	330,194			70,221,711	(29,330,414)	40,891,297		40,891,297	2,668,425
356000	CONDUCTOR & DEVICES	67,887,397	(28,775,040)	39,112,357	(917,963)	389,092			66,969,434	(28,385,948)	38,583,486		38,583,486	2,276,961
356010	CLEAR RIGHTOF WAY	2,133,240	(960,417)	1,172,823					2,133,240	(960,417)	1,172,823		1,172,823	44,798
357000	CONDUIT-UNDERGROUND	3,540,428	(1,251,769)	2,288,659					3,540,428	(1,251,769)	2,288,659		2,288,659	67,268
358000	CONDUCTOR-UNDERGROUND	7,044,036	(1,257,501)	5,786,535					7,044,036	(1,257,501)	5,786,535		5,786,535	190,189
359000	ROADS & TRAILS	3,267,205	(832,700)	2,434,505	(3,267,205)	832,700			0	0	0		0	0
	TOTAL TRANSMISSION	301,855,439	(103,371,922)	198,483,517	(55,113,004)	16,394,229	9,357,377	(3,218,301)	256,099,811	(90,195,994)	165,903,817	75,912,008	89,991,809	7,698,680
	DISTRIBUTION													
350000	LAND													
	SUBSTATION	0	0	0	0	0	2,496,015	(1,026)	2,496,015	(1,026)	2,494,989			
	LINE	0	0	0	0	0	5,419,895		5,419,895	0	5,419,895			
350010	EASEMENTS	0	0	0		0	6,384,707	(1,859,024)	6,384,707	(1,859,024)	4,525,683			
359000	ROADS & TRAILS	0	0	0	0	0	3,187,028	(812,266)	3,187,028	(812,266)	2,374,762			
360000	LAND	5,027,537	0	5,027,537		0	0	0	5,027,537	0	5,027,537			
360010	EASEMENTS						0	0	0	0	0			
361000	STRUCTURES	863,883	(303,984)	559,899	0	0	782,041	(220,060)	1,645,924	(524,044)	1,121,880			
362000	SUBSTATIONS	112,946,109	(38,132,875)	74,813,234	(9,357,377)	3,218,301	15,370,496	(5,604,705)	118,959,228	(40,719,279)	78,239,949			
	OTHER DISTRIBUTION	1,016,614,484	(371,382,705)	645,231,779					1,016,614,484	(371,382,705)	645,231,779			
	TOTAL DISTRIBUTION	1,135,452,013	(409,619,564)	725,832,449	(9,357,377)	3,218,301	33,640,162	(8,497,081)	1,159,734,818	(415,298,344)	744,436,474			
	PRODUCTION													
35400	TOWERS						344,415	(235,090)	344,415	(235,090)	109,325			
35500	POLES						790,537	(330,194)	790,537	(330,194)	460,343			
35600	CONDUCTOR AND DEVICES						917,963	(389,092)	917,963	(389,092)	528,871			
35900	ROADS AND TRAILS						80,177	(20,434)	80,177	(20,434)	59,743			
35300	STEP-UP TRANSFORMERS						19,339,733	(6,722,338)	19,339,733	(6,722,338)	12,617,395			
	ENERGY SUPPLY	2,336,167,078	(1,079,542,575)	1,256,624,503					2,336,167,078	(1,079,542,575)	1,256,624,503			
	TOTAL ENERGY SUPPLY	2,336,167,078	(1,079,542,575)	1,256,624,503			21,472,825	(7,697,148)	2,357,639,903	(1,087,239,722)	1,270,400,180			
	GENERAL PLANT	248,157,103	(109,653,161)	138,503,942					248,157,103	(109,653,161)	138,503,942			
	INTANGIBLE PLANT	27,287,605	(6,651,476)	20,636,129					27,287,605	(6,651,476)	20,636,129			
	TOTAL PLANT	4,048,919,238	(1,709,038,698)	2,339,880,540	(64,470,381)	19,612,530	64,470,384	(19,612,530)	4,048,919,240	(1,709,038,698)	2,339,880,542			

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35. Will TECO conduct a physical inventory of the individual transmission assets to be transferred to GridFlorida?

a. If yes, when is the inventory planned?

b. If no, why not?

c. If a physical inventory has already been performed, provide the results.

A. a. No. However, Tampa Electric completed a physical inventory of all transmission pole assets on March 31, 2001.

b. A physical inventory of the remaining transmission assets (mainly conductors and station equipment) would have been unnecessarily time-consuming and expensive.

c. See the attached document. (Since the referenced document is voluminous, Tampa Electric has provided the Staff with a CD containing the document in question instead of a printed copy.)

36. a. Will TECO perform reconciliation between the results of the physical inventory and its Continuing Property Records for the transmission assets to be transferred?

b. If no, why not?

c. If yes, how will any resulting adjustments be handled?

d. If a reconciliation has already been performed, provide the accounting entries made.

A. a. No decision has been made as to whether a reconciliation will be done.

b. Not applicable.

c. No final decision has been made as to how any such adjustments will be handled.

d. Not applicable (a reconciliation is not completed).

37. Given that TECO will transfer its transmission assets to GridFlorida, explain in detail the process TECO will undertake to determine the investment and reserve of the individual assets to be transferred.

A. Tampa Electric's accounting and engineering departments have worked together to identify transmission assets to be transferred. The accounting department used the results of engineering's identification of asset units to run queries against the Continuing Property Record database to identify original cost and vintage for location assets. For mass assets (e.g. poles, towers and fixtures, conductor and devices) the overall reserve ratio was used to calculate the transmission line accumulated depreciation. For location assets (e.g. station equipment) where vintage records exist, the calculated accumulated depreciation is based on the theoretical reserve ratio approved in the company's last depreciation study. Since the definition of transmission lines includes all investment 69 kV and above, all transmission investment recorded in plant accounts 354,355,356,357 and 358 will be transferred with the exception of poles, towers and fixtures, conductor and devices associated with connecting individual generating units to the transmission grid (as described in Attachment Q of GridFlorida's Open Access Transmission Tariff). Assets in the station accounts 353 and 362 have historically been classified as transmission or distribution function based on the predominant function of the individual station. Based on the lines of demarcation and type of station, engineering identified the function of the assets in the Continuing Property Records database. Accounting used this identification field to prepare schedules of original cost by vintage by querying the database. The calculated theoretical reserve percent was then used to calculate accumulated depreciation. Generation Step-Up Transformers in account 353 will not be transferred because they serve individual generating units. The company decided not to transfer land or land rights in account 350 or roads and trails in account 359.

38. Explain in detail how the individual assets to be transferred to GridFlorida will be priced out.

A. See response to Interrogatory No. 37.

39. Will any assets be revalued before the transfer to GridFlorida? If so, please provide details regarding specific assets and the method of revaluation.

A. No.

40. a. Specifically, what facilities are being transferred to GridFlorida and how were they determined (list by line segment, switching station, and substation – show all physical and cost allocations between transmission and distribution?

b. What mechanism will be used to transfer the assets?

c. What is the original cost of the assets being transferred?

d. What is the current replacement value of the assets being transferred? In your response, please indicate the method used to determine this value.

e. What effect will the transfer of assets have on the overall earnings of the company?

A. a. See the response to Interrogatory No. 29 for all assets and liabilities that will be transferred to GridFlorida. A detailed listing of the demarcation and the assets involved are included in Attachment Q, Sections 1-3, of GridFlorida's Open Access Transmission Tariff part of the compliance filing with the Federal Energy Regulatory Commission dated May 29, 2001, and the response to Interrogatory No. 33b provides a list of the resulting transmission facilities that will be transferred. The response to Interrogatory No. 37 elaborates on the process for determining the investment and reserve for depreciation for those transmission facilities. The response to Interrogatory No. 34a provides the proposed reclassifications between transmission and distribution that will occur before, or concurrent with, the transfer of assets to GridFlorida, while the responses to Interrogatory Nos. 30b and 44 provide details of proposed cost allocations for the shared facilities or services after the transfer.

b. Tampa Electric would contribute its transmission assets in return for a passive ownership interest in GridFlorida.

c. See response to Interrogatory No. 29.

d. Since the contribution is anticipated to be at net book value, no replacement value has been determined.

e. Tampa Electric expects the effect of the transfer of assets to have a minimal impact on the overall earnings of the company. The company would no longer incur depreciation and carrying charges for the investment, which will be replaced by a charge from the RTO for the same equipment. Also, the RTO will charge the company for the cost of new investment and expenses that the company would have otherwise made absent the RTO.

41. a. What is the total original cost as of December 31, 2000, of the TECO facilities being transferred to GridFlorida? Designate these facilities by transmission, generation, distribution, or general plant.

b. What is the cumulative depreciation as a December 31, 2000, taken for tax purpose on the TECO facilities being transferred to GridFlorida?

c. What is the cumulative depreciation as of December 31, 2000, taken for regulatory purposes on the TECO facilities being transferred to GridFlorida? Designate these facilities by transmission, generation, distribution, or general plant.

d. What is the difference in cumulative depreciation as of December 31, 2000, allowed for retail ratemaking by the FPSC compared to what the FERC allows for wholesale ratemaking?

e. What would be the tax impact of selling the facilities directly to GridFlorida?

f. What alternatives have been considered to mitigate this tax impact?

g. Will a tax ruling from the IRS be requested? When could a final decision from the IRS be expected?

A. a. See response to Interrogatory No. 29; only transmission facilities are being transferred to GridFlorida.

b. The tax reserve at December 31, 2000 is $155,382,143.

c. See response to Interrogatory No. 29.

d. None.

e. If the assets were sold outright, any proceeds received in excess of tax basis would be taxable income.

f. The Edison Electric Institute has pursued, on behalf of its member companies, federal legislation that would provide tax relief in the event of an outright sale of transmission facilities to an RTO.

g. Our assumption is that TECO's plan to contribute assets in return for an ownership interest (GridFlorida) will not require a Private letter Ruling (PLR).

42. a. On what cost basis will the assets used to provide retail service and being transferred to GridFlorida be valued: net book cost, replacement cost, or some other cost basis?

b. What is the rationale for using the cost basis indicated in your response?

A. a. The assets transferred to GridFlorida will be transferred at net book cost.

b. Customers of Tampa Electric will be taking service in part under a zonal rate which the value of these assets will be used to derive. If they were transferred at a higher cost, that cost could be recovered through that zonal rate and thus increase the rate for service for Tampa Electric customers from the same assets.

43. Will the costs and revenues derived from non-electric utility activities associated with joint use of the divested facilities (such as telephone and cable pole attachments, dark fiber communications leasing, etc.) be transferred to the GridFlorida along with the transmission facilities? If yes, identify each activity and the annual cost and revenue associated with that activity.

A. Revenues derived from non-electric utility activities associated with joint use of transmission facilities contributed by Tampa Electric to GridFlorida shall be collected and retained by GridFlorida. However, such revenues should offset GridFlorida's cost of service.

Please see attached.

POLE ATTACHMENT REVENUE

ATTACHEES	# OF ATTACHMENTS	TOTAL REVENUE
Cable TV		
ADELPHIA	126	$693.00
COMCAST CABLEVISION	152	$836.00
MOFFAT COMMUNICATION	33	$156.42
TIME WARNER	5183	$24,567.42
Communications		
CSX	1	$18.53
GTE/VERIZON	4590	$137,700.00
INTERMEDIA COM	1	$20.00
SPRINT	82	$2,378.00
TOTAL REVENUE		**$166,369.37**

44. Will any TECO facilities and/or assets be leased or shared with GridFlorida? If so, please indicate how lease payments will be calculated or how cost allocations will be determined? What effect will lease payments have on the earnings of the company?

A. Some facilities may be shared with or leased to GridFlorida. GridFlorida will pay an appropriate fee for the use of any such shared or leased facility. For example, in a distribution substation with some transmission assets, Tampa Electric would own the land, fences and associated general plant and GridFlorida would pay a facilities fee to Tampa Electric for its use of those joint facilities. It has not been determined which, if any, assets will be leased to GridFlorida. Costs allocations for the shared services have not been determined. Analysis is under way to determine the most cost effective methodology.

50. What is the change in rate base, by component, as a result of TECO's participation in GridFlorida?

A. See the response to Production of Documents No. 4.

51. According to Exhibit BLH-3, page 2, line 14, the company will be charged a total of $770,000 for storm damage expense.

a. Explain how this amount was determined.

b. Explain why there is no cost offset on line 14, column 8.

A. a. FP&L estimated $7.7 million dollars of storm damage expense to cover their assets. For purposes of the Accenture estimate, Tampa Electric agreed that an appropriate estimate for its storm damage would be 10% of FPL's reserve ($7.7M x 10% = $770,000).

b. See Tampa Electric's response to Interrogatory No. 53. Tampa Electric believes it should continue to accrue the current amount of $4 million for storm damage related to its distribution system risk.

52. Will GridFlorida insure the transmission assets through an outside insurer or maintain a Storm Damage Reserve?

A. Tampa Electric does not know what decision the independent board and management of GridFlorida would make once GridFlorida begins commercial operation.

53. Will TECO propose a reduction in the annual storm accrual and targeted storm damage balance after the assets are transferred to GridFlorida?

A. No. In Order No. PSC-95-0255-FOF-EI issued February 23, 1995, the Commission ordered that Tampa Electric Company continue to accrue the sum of $4,000,000 annually to its storm damage reserve and further ordered that the target amount for the storm damage reserve fund be $55,000,000. In that hearing, Tampa Electric Company submitted a study that indicated that only 5.8% of the accrual and reserve related to transmission assets. This indicates that virtually all of the exposure was to the distribution system. The balance in the storm damage reserve as of August 31, 2001 is $30,666,666.36. Since the storm damage reserve balance is over $24 million short of the target amount, the company believes no change in the storm damage accrual is appropriate, especially given the distribution system risk.

54. How much will the company accrue from storm damage after the assets are transferred to GridFlorida?

A. The Company will continue its $4 million annual accrual.

55. What amount, if any, of TECO's storm damage reserve will be transferred to GridFlorida? Please explain how the appropriate amount of TECO's storm damage reserve to transfer to GridFlorida was determined.

A. None of Tampa Electric Company's storm damage reserves will be transferred to GridFlorida. (See response to Interrogatory No. 53.)

57. GridFlorida is a for-profit limited liability company (LLC). Please describe the nature of an LLC and its tax aspects.

A. For federal income tax purposes, an LLC can be treated as a partnership, by making an election under the check-the-box rules. Electing partnership status results in no taxation at the LLC level, avoiding double taxation when distributions are made to LLC members, and avoiding tax losses from being locked in at the LLC level. This means the members rather than the LLC, are directly taxed on the LLC's income, or the members directly recognize its tax losses. State tax treatment generally follows federal treatment.

58. On page 8 of Ms. Dubin's Direct Testimony, she describes the proposed methodology of recovery from the transmission costs that are projected to be in excess of those currently allowed recovery through base rates.

a. What are the income tax consequences of divesting these assets and using this methodology of recovery?

b. What are the property tax consequences of divesting these assets and using this methodology of recovery?

c. What other tax consequences are anticipated?

d. What will happen to the deferred taxes and excess deferred taxes associated with these assets that are divested?

e. What will happen to the investment tax credits that are associated with these assets that are divested?

f. Assuming a negative impact on ratepayers as a result of the income tax consequences, what provision could be made to neutralize the negative impact such that the individual company and Florida ratepayers remain whole/unaffected?

A. Ms. Dubin's testimony is not offered in Docket No. 010577-EI and Tampa Electric cannot comment on the tax consequences to FPL of divesting their assets.

59. On page 6, beginning at Line 13, the Joint Testimony of Mike Naeve, C. Martin Mennes, Henry Southwick and Greg Ramon states, "Use of a limited liability company to own the transmission facilities allows passive ownership interests in GridFlorida by divesting transmission owners to satisfy the Order No. 2000 independence standard, and offers favorable tax treatment." Please explain in detail how this favorable tax treatment is provided, citing relevant Internal Revenue Service (IRS) Code Sections and/or other applicable IRS statements.

A. Internal Revenue Service Regulation Section 301.7701-1, Regulation Section 301.7701-2 and Regulation Section 301.7701-3 are the "check-the-box" entity classification regulations. Under those regulations, a partnership is a business entity, with two or more members, that is not mandatorily classified as a corporation, and that has elected, or defaulted to, partnership tax status. When an LLC makes an election to be treated as a partnership for tax purposes, only the members and not the LLC are taxed on the entity's income. This is contrasted with the situation where GridFlorida would be a "corporation". The corporation would be taxed on its income, and the shareholders of the corporation would again be taxed when dividends are distributed to them. An LLC electing partnership status avoids this double taxation.

60. Provide a schedule which shows how the sources of capital (i.e., deferred taxes, investment tax credits, investor capital, etc.) associated with the transmission assets which are proposed to be transferred to GridFlorida will be removed from the capital structure of TECO. For purposes of this response, show the capital structure components, cost values, and overall cost of capital of TECO before and after the removal of the capital associated with the transmission assets.

A. Tampa Electric has not made a final determination of all sources of capital that may be transferred to GridFlorida. The Deferred Income Taxes and Investment Tax Credit will be reflected on the regulated books of GridFlorida along with the associated assets transferred. Tampa Electric has not made a final determination of all assets that may be transferred and therefore, the amounts of deferred income taxes and investment tax credits has not been determined.

61. Discuss in detail how the removal of capital associated with the transmission assets will affect the overall cost of capital of TECO.

A. See response to Interrogatory No. 60. Tampa Electric has not made this determination.

62. What does TECO believe the total cost of capital will be for GridFlorida for the first year of operations? For purposes of this response, show the capital structure components, relative percentages, cost rates, and overall cost of capital.

A. Tampa Electric has not made this determination.

63. What does TECO believe its share of the total cost of capital (amount and percentage) will be for GridFlorida's first year of operations?

A. Tampa Electric's share of the total capital of GridFlorida would be contingent on its share of the total investment in GridFlorida. Tampa Electric is uncertain of the amount of investment that FPL (and others, potentially) will contribute to the RTO, therefore, Tampa Electric cannot yet estimate its potential share.

64. For purposes of calculating the revenue requirements associated with the new facilities portion of the GridFlorida transmission charge, please explain in detail how the annual carrying charge applied to the accumulated new average investment balance is calculated. For purposes of the response, show the capital components, relative percentages, cost rates, and overall cost used in the calculation and reconcile these amounts to TECO's relevant earnings surveillance report (ESR). If necessary, discuss why the carrying charge cannot be reconciled to the ESR.

A. Tampa Electric has not calculated an expected annual carrying charge to be applied to new investments made at GridFlorida. Tampa Electric would not expect the carrying charge for GridFlorida to reconcile with Tampa Electric's retail cost of capital in its earnings surveillance report.

65. Will any existing facilities be leased to GridFlorida? If so, please identify the facilities that will be leased, the amount of each lease, and an explanation for how each lease amount was determined.

A. Tampa Electric does not plan to lease facilities to GridFlorida.

77. Refer to page 25, lines 18 - 19, of Witness Hoecker's testimony. Will the elimination of pancaked rates through the administration of Florida's transmission system by a single RTO results in cost shifts? If so, identify the affected utilities and the amount of the cost shifts.

A. Yes, the elimination of pancaked rates in the GridFlorida region as a result of the creation of the RTO will result in cost shifts. The cost shift that results from this elimination is mitigated by phasing in the elimination during the 10-year phase-in period provided in the GridFlorida tariff (see Attachment T, in particular Section 8.1 and 8.2).

All utilities that join GridFlorida will be affected by this elimination to some degree. Revenues will be lost by some from charges no longer imposed, and costs will be reduced for others from transmission charges no longer incurred. Most will have both effects.

It is difficult to determine the exact amount of cost shifts resulting from the elimination of pancaked rates because (i) it is not certain (other than FPL, FPC and Tampa Electric) which utilities will join GridFlorida and when (per the GridFlorida tariff, utilities that do not join are still subject to pancaked rates), (ii) future transactions between parties are hard to predict, and (iii) some mitigation measures (e.g. mitigation for loss of short-term transactions) are dependent on future unknown transactions within GridFlorida.

Tampa Electric provided an estimate of the loss of pancaked transmission revenues in response the Interrogatory No. 9, Staff's 1st Set based on FERC Form 1 Data for the year 2000 and assuming all the entities transacting business in that year joined GridFlorida.

82. Refer to page 13, lines 6 - 8, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Witness Naeve states that the GridFlorida proposal eliminates pancaked rates for new transactions and depancakes existing transactions over a period of 10 years. Quantify both the benefits to TECO's ratepayers and to Florida associated with new transactions and the benefits associated with existing transactions. Could the benefits have been achieved regardless of the form of the RTO?

A. It is impossible to know what new transactions will take place so it is not possible to quantify the benefits of eliminating pancakes associated with such transactions. For existing transactions, see response to Interrogatory No. 9, Staff's First Set. The benefits of eliminating pancaked rates do not depend on the form of the RTO.

83. Identify and quantify the benefits to TECO's ratepayers and to Florida associated with the Physical Transmission Rights model of congestion management included in the GridFlorida proposal. Could the benefits have been achieved regardless of the form of the RTO?

A. The benefits of market-based congestion management that is consistent with the FERC Order No. 2000 requirements include increased economical transactions and price signals to aid efficient expansion of generation and transmission (See answers to Interrogatories 128 and 173). Tampa Electric has not attempted to quantify those benefits, as they would depend on future markets, participants, and their market strategies. The Physical Transmission Rights model contained in the GridFlorida proposal is expected to achieve this benefit because it complies with and has been accepted by the FERC as compliant with Order No. 2000. Benefits of the proposal are not dependent on the form of the RTO.

88. Refer to page 23, lines 7 - 9, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Will a Transco that owns assets have greater financial strength and access to capital necessary to fund construction and maintenance at a lower cost that an ISO whose participants still own their assets? If yes, why? If no, why?

A. A Transco that owns significant assets should have a greater financial strength and access to capital to fund construction and maintenance. An ISO, by definition, does not own transmission assets so funding construction and maintenance is not the issue. An ISO must try to get the transmission owning utilities or another entity to fund and construct the needed facilities. Because the existing utilities do not have control over transmission rate design, they lack control over the recovery through transmission rates of the capital they invest in facility upgrades. This disconnect between control over capital investment and rate recovery will make it difficult for transmission owners operating under an ISO to raise capital at reasonable rates. Further, entities with significant assets tend to have better credit ratings than entities with no assets.

89. Identify and quantify the costs and benefits associated with transferring ownership of transmission facilities to GridFlorida that TECO considered when evaluating its participation in GridFlorida.

A. The benefits of Tampa Electric's participation are discussed in Hoecker, Naeve, and Hernandez, pp. 16-17, and costs are discussed in Holcombe, Southwick and the two Ashburn testimonies.

90. Identify and quantify the costs and benefits associated with transferring operational control of transmission facilities to GridFlorida that TECO considered when evaluating its participation in GridFlorida.

A. See response to Interrogatory No. 89, above.

92. Explain why the GridFlorida companies have selected a December 31, 2000, date to distinguish between the cost of existing transmission investment and new facilities.

A. There were several reasons for selecting that date. One reason was to correspond with the end of a calendar and fiscal year (in this case, the one just prior to the then expected startup date of GridFlorida – December, 2001) of the investor-owned utilities making the filing. This was done to facilitate accounting controls over which facilities would be in the existing investment revenue requirements filings and which would be in the new investment revenue requirement filings. Another reason was to pick a date close to the startup to minimize cost shifts at startup since the cost of existing facilities would be recovered through zonal rates and the cost of new facilities would be recovered through the system-wide rate. Still another reason was to correspond to the end of the expected test period for the Part 1 rates (which was expected to be calendar year 2000) in order to ensure no under or double counting of facilities. Finally, December 31, 2000 corresponded to the date which was associated with grandfathering of existing transmission agreements, including interconnection agreements.

93. a. Do the transmission facilities that are owned by or under the control of GridFlorida have to be contiguous?

b. If no, will the noncontiguous or strategic positioning of the transmission facilities have any impact on GridFlorida's ability to ensure the capability and reliability of the coordinated operation of the transmission systems?

c. If yes, please identify the locations/layout of the contiguous transmission facilities as of June 30, 2001.

d. If mapping is not complete, please identify the areas of new facilities construction and projected dates of completion to achieve the desired results of GridFlorida.

A. a. Nothing in the GridFlorida Proposal precludes noncontiguous facilities to be owned or under the control of GridFlorida.

b. GridFlorida will have Security Coordinator control over all transmission in the FRCC to ensure reliable and coordinated operation.

c. N/A

d. N/A

94. Mr. Southwick's testimony, page 15, beginning with line 5, states that many of GridFlorida's systems will be new and will replace or overlay existing FPL, FPC, and TECO systems. Further, Mr. Southwick states that these costs are necessary to ensure that GridFlorida will meet its requirements.

a. For TECO, provide a list of the planned new systems, showing the location and expected service date.

b. For TECO, provide the estimated costs of these new systems and explain how were they developed.

c. For TECO, provide a list of systems being replaced, indicating the location, the planned retirement date, the dollar amounts associated with the systems to be retired, and the account number where the investments are currently located. Explain how the dollar amounts associated with the systems to be retired were determined.

A. a. Such a list is not available because it's too early in the GridFlorida development process to identify the necessary planned new systems required to comply with FERC Order 2000. However, the Capability Model, as developed by Accenture and provided in Exhibit BLH-2 illustrates the capabilities necessary to ensure GridFlorida meets its requirements.

b. The specific systems have not been identified yet; therefore FPL can not provide the estimated costs of these systems.

c. For Tampa Electric, the specific systems being replaced have not been identified yet; therefore, Tampa Electric can not provide a list of these systems indicating the location, date and dollar amounts.

95. a. Did TECO consider transferring assets to GridFlorida at other than net book value?

b. If yes, what other alternatives were considered?

c. If no, explain why not.

d. Explain why net book value was determined to be the most appropriate valuation to transfer the divested assets.

A. a. No.

b. Not applicable.

c. See response d.

d. The Federal Energy Regulatory Commission Uniform System of Accounts promulgates the accounting for electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise. GridFlorida's accounting for the asset contribution would be governed by the accounting rules within the Uniform System of Accounts. Any amount that GridFlorida pays over and above the cost incurred by a contributing company, the person who first devoted the property to utility service, would be charged to Account 114 Electric Plant Acquisition Adjustments and amortized to Account 425 Miscellaneous Amortization. Items described as chargeable to Account 425 include Account Amortization of utility plant acquisition adjustments, or of intangibles included in utility plant in service **when not authorized to be included in utility operating expenses by the Commission** (emphasis added). Tampa Electric does not believe that its customer's rates should increase or decrease in the future as a result of transferring the assets at above or below net book value.

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96. The joint testimony of Mr. Naeve, Mr. Mennes, Mr. Southwick, and Mr. Ramon, pages 18 through 23, defines the demarcation between transmission and distribution facilities.

a. On page 19 regarding predominately distribution step down substations, lines 21 - 22 state that the "Transmission breakers in a ring bus that also serves as the protective device for a step down transformer are not deemed to be transmission facilities." However, lines 4 - 6 on page 20 state that similar items in predominately transmission switching stations will be transferred to GridFlorida. Explain why the transmission breakers in predominately transmission switching stations will be transferred.

b. On page 22, lines 9 - 16, the GridFlorida companies concluded that a uniform demarcation point for transmission facilities is a reasonable approach. Explain specifically what other factors and benefits referred to on line 15 outweigh any reason to attempt to undertake the reclassification of the 69 kV and above facilities and distribution.

A. a. The statement on page 19 is an error, all such breakers will be transferred to GridFlorida.

b. Please see the four specific factors detailed on pages 19 - 22, preceding the concluding statement in lines 9 - 16, page 22.

97. Provide the estimated incremental cost impact of purchasing transmission service from GridFlorida to serve TECO retail customers.

A. The estimated incremental cost impact of purchasing transmission service from GridFlorida to serve TECO retail customers is $13.1 million, all else held constant.

98. Provide preliminary estimates of GridFlorida transmission costs including the impact on TECO's customers.

A. The impact on TECO's customers from GridFlorida's transmission costs is estimated to be about $13.1 million, all else held constant.

101. Provide TECO's preliminary estimates of the payment to GridFlorida for transmission service purchased to serve retail load in 2003. In your response, identify the different charges (Zonal Charge, System Charge, Grid Management Charge and Scheduling Service Charges) making up the total estimated payment, and list and explain all assumptions making the estimates.

A. Tampa Electric does not have any preliminary estimates of proposed payments to GridFlorida for the year 2003. The estimated incremental cost impact to TECO's retail customers for the first full year of GridFlorida operations is $13.1 million.

102. Describe in detail how TECO proposes to ensure there is no double recovery of transmission costs in base rates. Please include in your response an explanation of all assumptions.

A. The current cost of transmission service associated with delivering power to customers using Tampa Electric-owned assets is recovered from wholesale and retail customers through base rates or through its Open Access Transmission Tariff (OATT) for transmission service through its system (wheeling). Revenues received for wheeling transactions are revenue credited to reduce the total cost of providing transmission service to wholesale and retail customers. The current cost of transmission service using the transmission systems of other entities that is associated with purchased power is recovered through the fuel and purchased power or capacity cost recovery clauses.

After GridFlorida is in operation, Tampa Electric's transmission assets will have been transferred to GridFlorida and will no longer be a "cost" to customers. Tampa Electric's O&M and A&G expenses associated with those assets will still be incurred by Tampa Electric for at least five years on behalf of GridFlorida, but those expenses will be fully reimbursed by GridFlorida under contract. Tampa Electric will then purchase transmission service from GridFlorida in order to serve the load of its customers and the charges from GridFlorida will replace the previous "cost" to customers.

Those costs can be recovered in three basic ways: base rates in total; in part through based rates with the incremental portion of the costs above the transmission costs already embedded in base rates recovered through a clause or other rate adder; or entirely through a clause with base rates reduced for the cost of transmission. As described in response to Interrogatory No. _99_, Tampa Electric has not determined what method will be chosen.

When Tampa Electric purchases power from resources within the GridFlorida RTO, there will be no additional transmission charges to deliver that power. When Tampa Electric purchases power from resources outside the GridFlorida RTO, there may be additional transmission charges which would continue to be recovered through the appropriate cost recovery clause.

In this way, there will be no double recovery of transmission costs in base rates or in any other way from customers.

103. Describe those services TECO anticipates having to temporarily perform on behalf of GridFlorida with respect to its divested facilities. What charges will be passed on to GridFlorida as a result of TECO's continued performance?

A. All planning, engineering, construction, and maintenance associated with the transmission assets transferred to GridFlorida will be temporarily performed by Tampa Electric Company. The company will also provide the communications and control equipment and services necessary for control of the transmission assets contributed to GridFlorida. All costs for providing these services will be charged to GridFlorida.

104. If a more vibrant wholesale market does not result from GridFlorida, what other benefits, if any, would be achieved by GridFlorida?

A. The other benefits that would result from GridFlorida are discussed at pages 7-10 and 13-17 of Mr. Naeve's testimony and pages 21-30 of Mr. Hoecker's testimony.

105. Over what period to time does TECO believe a more vibrant wholesale market will evolve to the point to resulting in significant residential customer savings?

A. The balancing energy and congestion management markets will provide benefits as soon as they are operational by providing the efficiencies of region-wide economic dispatch within each operating hour. Also, the addition of the new generation in the queues in Florida, much of which is planned to be operational within 1-2 years, in combination with the market design features of GridFlorida, will create the opportunity for reduced costs for wholesale power, which should result in increasing residential customer savings over time, beginning immediately upon implementation of the market design.

107. Mr. Hernandez states on page 20 of his testimony that TECO will not contribute any of its communications systems that are attached to its transmission assets. If the transmission assets are going to be a part of GridFlorida, will TECO pay GridFlorida for the attachments?

A. Yes.

108. Mr. Hernandez states on page 20 of this testimony that TECO will not transfer any land and land rights associated with its transmission facilities. However, on lines 4 through 10, he states "Therefore, *Tampa Electric will grant to GridFlorida only those* land access rights that are essential for the operation and maintenance of the contributed transmission assets while retaining ownership and control over all other land and land rights necessary or useful in the provision of retail electric service".

a. Does this constitute a transfer of land right assets?

b. If so, which land rights will be transferred and what criteria will be used to determine which ones will be transferred?

c. What is the associated investment and reserve as of December 31, 2000?

A. a. No. GridFlorida would be provided a license to enter upon lands owned or controlled by Tampa Electric, to enable GridFlorida to maintain and operate the transmission assets for their intended purpose. GridFlorida's rights would be non-exclusive but would include a priority for GridFlorida's use over any retained use that conflicted with GridFlorida's requirements except with regard to Tampa Electric's use of such land for the purpose of providing distribution and telecommunication service.

b. N/A

c. N/A

109. Are there any assets currently in Account 103, Experimental Electric Plant Unclassified, that will be transferred to GridFlorida? If so, provide the investment and associated depreciation reserve as of December 31, 2000, along with the company's plans for these assets, and the basis for why these assets should be transferred to GridFlorida.

A. No.

110. Are there any assets currently in Account 105, Electric Plant Held for Future Use, that will be transferred to GridFlorida? If so, provide the investment as of December 31, 2000, the company's plans for future use, and the basis for why these assets should be transferred to GridFlorida.

A. No.

111. Are there any assets currently in Account 106, Completed Construction Not Classified-Electric (Major Only), that will be transferred to GridFlorida? If so, provide the investment as of December 31, 2000, and the basis for why these assets should be transferred to GridFlorida.

A. Yes. The investment as of December 31, 2000 in Account 106, Completed Construction Not Classified-Electric (Major Only), that will be transferred to GridFlorida is $11,601,000 (see response to Interrogatory No. 29, Staff's 2nd Set of Interrogatories.) This represents projects that are in service but construction has not been completed and classified to Account 101, Electric Plant In Service. The basis for why these assets should be transferred to GridFlorida are the list of transmission facilities being contributed (see attachment to Interrogatory No. 33b, Staff's 2nd Set of Interrogatories) based on the listing of the demarcation and assets involved included in Attachment Q, Sections 1-3, of GridFlorida's Open Access Transmission Tariff.

112. Refer to page 6, lines 22-25 of the testimony of William R. Ashburn (filed in all three dockets) Explain in detail why each the following issues are problematic for GridFlorida pricing: 1) cost shifting that arises from adoption of average system rates; 2) providing revenue credits for facilities owned by transmission dependent utilities; and 3) eliminating pancaked rates.

A. Mr. Ashburn's testimony beginning at page 6 addresses the context in which GridFlorida's pricing policy was formulated. The testimony provides that the GridFlorida pricing policy was designed to comply with FERC's Order No. 2000 pricing requirements while providing a balanced and reasoned approach to certain issues that historically have provided impediments to RTO formation. The three issues listed above were addressed in the RTO proposal because they can increase the transmission cost of service for some utilities as a result of joining an RTO. While the generation benefits that are expected to accrue from a RTO are expected to be large but difficult to measure ex ante, these costs, while potentially much smaller, are certain and can be more easily measured. In the context of Order No. 2000, the mitigation measures relating to these issues that were accepted by FERC strike a reasonable balance between the interests of utilities to avoid or delay any adverse cost impacts as a result of joining an RTO and the interests of transmission users seeking to more immediately capture the benefits they will receive from the shifted cost burden.

A transition to average system rates for the GridFlorida region is problematic for the obvious reason that averaging of rates benefits those whose rates were higher while costing those whose rates were lower. Higher cost utilities sought shorter phase in periods or less zones, while the reverse was true for lower cost utilities.

Transmission Dependent Utility (TDU) credits was especially problematic, in part because of the cost shift and in part because the issue had been negotiated/litigated extensively at FERC. The issue is not revenue crediting, it is inclusion of the revenue requirements for those TDU facilities in the zonal revenue requirements of those two company's zonal rates.

Elimination of pancaked rates was particularly problematic given the many existing transmission agreements which must be addressed by the proposal and the concern to protect the rights and interests bargained for by parties on both sides of those agreements. As those agreements terminate, the party seeking service under those transactions will reap the benefits of non-pancaked rates from GridFlorida while the prior transmission provider will lose the source of revenue to benefit other users. The methodology utilized is finely tuned to the zonal rate phase out pricing approach to try and balance the interests of parties to both sides of the existing pancaked transactions.

113. Refer to page 7, lines 6-8, of the testimony of William R. Ashburn (filed in all three dockets). Define what is meant by "unreasonable additional costs" in general and with respect to each participating owner in GridFlorida.

A. In general, and with respect to the three GridFlorida applicant utilities, "unreasonable additional costs" refers to a rate design that would result in a swifter implementation of system-wide rates (including immediate inclusion of TDU facilities in those system-wide rates) and immediate elimination of existing rate pancakes and other existing transmission agreements than is necessary or appropriate to comply with the requirements of Order No. 2000.

122. Refer to page 17, lines 13-17 of the testimony of William R. Ashburn (filed in all three dockets) regarding zonal charges based on the revenue requirements of the transmission facilities forming the zone.

a. What is the revenue requirement for the transmission facilities provided by TECO?

b. What is the revenue requirement for the transmission facilities provided by FPC?

c. What is the revenue requirement for the transmission facilities provided by FPL?

A. As provided in the response to Interrogatory No. 19 of Staff's First Set of Interrogatories, Tampa Electric estimates its transmission revenue requirements to be $55.9 million based on year ended 2000 costs.

136. Regarding the divestiture of transmission assets, provide the detailed sample pro forma journal entries that track divestiture of the transmission assets from the regulated books of the company through all entities to their ultimate entity, ensuring that the entities are easily recognizable. The sample journal entries should also include entries to record the sale/purchase of the non-voting stock. Also, provide the assumptions used to develop the sample journal entries, the detailed account numbers and account descriptions, and summary of the income tax consequences to each entity.

A. The following sample pro forma journal entries assumes assets as of December 31, 2000, are transferred.

		$ 000	
Acct	Description	Debits	Credits
124	Other Investments	175,737	
101	Plant In Service – Classified		244,499
106	Completed Construction – Not Classified		11,601
107	Construction Work In Progress		1,830
114	Acquisition Adjustment		5,136
108	Accumulated Provision for Depreciation	90,196	
154	Plant Materials & Operating Supplies		2,867

To reflect the contribution of transmission assets to GridFlorida for Class B Common Stock on Tampa Electric Company's books. The contribution of assets is expected to be made tax free in exchange for a partnership interest in GridFlorida.

Acct	Description	Debits	Credits
101	Plant In Service – Classified	244,499	
106	Completed Construction – Not Classified	11,601	
107	Construction Work In Progress	1,830	
114	Acquisition Adjustment	5,136	
108	Accumulated Provision for Depreciation		90,196
154	Plant Materials & Operating Supplies	2,867	
201	Owner's Capital		175,737

To reflect the contribution of transmission assets from Tampa Electric Company for Class B Common Stock on GridFlorida's books.

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137. Provide detailed sample pro forma journal entries that track a sale of Class B stock along with recording the gain or loss, if any, ensuring that the entities are easily recognizable. Also, provide the assumptions used to develop the sample journal entries, the detailed account numbers and account descriptions, and summary of the income tax consequences to each entity.

A. The following sample pro forma journal entries assumes assets as of December 31, 2000, are transferred and a $10,000,000 gain or loss results on disposition.

		$ 000	
Acct	Description	Debits	Credits
131	Cash	185,737	
124	Other Investments		175,737
421	Miscellaneous Nonoperating Income		10,000
282	Accumulated Deferred Income Taxes	24,810	
236	Taxes Accrued		28,952
409	Current Tax Expense	28,952	
411	Deferred Tax Expense		24,810

To reflect a gain on the disposition of the investment in GridFlorida.

		$ 000	
Acct	Description	Debits	Credits
131	Cash	165,737	
124	Other Investments		175,737
426.5	Other Deductions	10,000	
282	Accumulated Deferred Income Taxes	24,810	
236	Taxes Accrued		20,953
409	Current Tax Expense	20,953	
411	Deferred Tax Expense		24,810

To reflect a loss on disposition of the investment in GridFlorida.

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138. At each stage described in the preceding two questions, provide pro forma balance sheets for each entity.

A.

Tampa Electric Company Balance Sheet	$ 000
Assets	
Other Investments	175,737
Liabilities	
Accumulated Deferred Investment Tax Credits	758
Accumulated Deferred Income Taxes	24,810

GridFlorida Balance Sheet	$ 000
Assets	
Plant In Service – Classified	244,499
Completed Construction – Not Classified	11,601
Construction Work In Progress	1,830
Acquisition Adjustment	5,136
Accumulated Provision for Depreciation	(90,196)
Plant Materials & Operating Supplies	2,867
Total Assets	175,737
Owner's Capital	175,737

Tampa Electric Company would have no items on its balance sheet after disposition of the investment in GridFlorida. GridFlorida's balance sheet would not be effected by Tampa Electric Company's disposition of its investment in GridFlorida.

139. How will the divested assets be reflected in the Earnings Surveillance Reports?

A. The investment in GridFlorida will be removed from the surveillance report as an "other income provided" item. Tampa Electric Company's rate base will be reduced by the divested assets and the resulting rate base will be reconciled to the capital structure in the traditional manner.

140. How will the Class B stock be reflected in the Earnings Surveillance Reports?

A. Please see the response to Interrogatory No. 139.

142. Provide the replacement value, market value, and reproduction cost as of December 31, 2000, for those assets being transferred to GridFlorida. Explain in your response how each value was determined.

A. For the reasons discussed in the response to Interrogatory No. 95d, Tampa Electric Company did not establish the replacement value, market value, and reproduction cost as of December 31, 2000, for those assets being transferred to GridFlorida.

143. Explain why the divested transmission assets should not be transferred to GridFlorida at reproduction cost, replacement cost, or market value.

A. Please see the response to Interrogatory No. 95d.

144. Pages 23-25 of Mr. Holcombe's Exhibit BLH-l, Business Blueprint Documents, Commercial Operations, state that metering and measurement is a required capability for the end state. Also, the primary purpose of this function is to ensure that meters connected to the GridFlorida system and/or providing meter data to GridFlorida for Settlements and Billings are certified and registered, in order to ensure the accuracy of the Settlements and Billings calculations.

a. Will TECO retain ownership of its meters?

b. If yes, what impact will this have upon GridFlorida's ability to certify and register meters for Settlement and Billing.

c. If GridFlorida has the ability to certify and register meters in order to ensure the Settlement and Billing results, regardless of meter ownership, would TECO establish a contributing agreement or invoke a charge for meter usage from GridFlorida.

A. a. Tampa Electric will not retain ownership of meters used for wholesale and interchange purposes.

b.-c. N/A

145. Does GridFlorida have any settlement and billing capabilities?

a. If no, which Transmission company will be performing this function?

b. Would this hamper GridFlorida's independence from the Transmission companies if the companies are providing the required functions?

c. In the development of GridFlorida, did the Transmission companies prioritize the required functions that were needed to make the RTO an independent functional organization? If yes, provide the prioritized list of required functions.

d. How will the Transmission companies maintain a segregation of duties and functions if they continue to provide GridFlorida administrative equipment and experience staff, facilities other than transmission, and other contributions to maintain functionality of GridFlorida?

A. GridFlorida does not have any settlement and billing capabilities at this time.

a. GridFlorida will have settlement and billing capability at start-up.
b. No.
c. No.
d. Depending on the type of support the participating companies provide GridFlorida, separation of duties may need to be maintained by instituting code of conduct rules.

146. Has FERC provided any guidance on the accounting procedures to be followed in transferring assets from the participating companies to GridFlorida? If so, please describe those procedures. If not, does TECO anticipate that such guidance will be requested or provided?

A. As discussed in response 95d, the FERC Uniform System of Accounts provides guidance for GridFlorida acquiring asset by any means.

147. Please identify and discuss the benefits and harms to ratepayers and stockholders if the divested transmission assets are transferred to GridFlorida at reproduction cost, replacement cost, market value, or net book value.

A. The transmission assets should be transferred at net book value. The rates charged to Tampa Electric's customers, both retail and wholesale, have been and are currently set using net book value. Tampa Electric does not believe that its customer's rates should increase or decrease in the future as a result of transferring the assets at above or below net book value.

148. Referring to the Class B Common Stock discussed on pages 5-6 of the joint testimony of witnesses Naeve, Mennes, Southwick, and Ramon, how will this stock be recorded on the books of the "divesting owners?" For example, will it be recorded on the books of TECO or TECO Energy?

A. Tampa Electric Company will record this stock in Account 124 — Other Investments.

149. What does Tampa Electric estimate the value of the Class B Common Stock received in exchange for divesting its transmission assets will be worth at the time of the transfer?

A. At the time of contribution, Tampa Electric Company expects the value of the Class B Common Stock received to be the value of the underlying transmission assets contributed based on the discounted future revenues equaling the investment under cost-based regulation.

150. For purposes of this question, assume that the Class B Common Stock is sold at some future date for a significant gain over its original value at the time it was acquired. Does TECO believe the FPSC would have any jurisdiction over the disposition of this gain? If not, please explain.

A. No. Once divested, this is merely an investment on the books of Tampa Electric Company. The success or failure and any related gain or loss is a risk borne by Tampa Electric Company's shareholders.

162. Pages 18-19 of the testimony of Thomas L. Hernandez describes TECO's alternatives other than the contribution of its transmission assets and states: "Tampa Electric also considered being a participating owner, where it would continue to own its transmission asset but would give up operational control of the assets to Grid Florida. While such a choice preserves some future options it also leases the utility with all of the risks of ownership without the ability to control the use or maintenance of the transmission assets." Specifically, what future options would TECO preserve and how would TECO pursue such options?

A. Tampa Electric does not intend to be a participating owner of GridFlorida, but those who take that approach could pursue contribution or sale of their assets to GridFlorida or another entity at a later date.

2. Provide all documentation used to evaluate the benefits and costs associated with participating in a transmission organization other than GridFlorida.

A. During the time the GridFlorida Companies were developing the GridFlorida RTO no other transmission organizations existed in the southeastern United States; therefore, Tampa Electric could not evaluate the benefits and costs associated with participation.

4. Provide a detailed Net Operating Income and Rate Base schedule (total company and retail) before and after the transfer of assets to GridFlorida?

A. The attached schedules come from analysis performed some time ago and do not match current estimates of value of assets to be transferred. They provide an example scenario of rate base and net operating income ("NOI") before and after the transfer of transmission assets. The expected NOI is very contingent on the amount charged from the RTO to the regulated utility. Tampa Electric does not have a reasonable estimate at this time of what that expense may be. However, the company has performed hypothetical scenario analysis, which is reflected in this response. The calculations in this response are very preliminary in nature.

RATE BASE	Before
Plant in Service (FPSCPS)	4,213,330
Accumulated Reserve(FPSCAR)	1,561,032
Net Plant (FPSCNP)	2,652,298
Property For Future Use (FPSCP3A)	31,362
CWIP (FPSCP9A)	58,070
Net Utility Plant (FPSCNUP)	2,741,730
Working Capital(FPSCWC)	(28,726)
Total Rate Base(TPFRB)	2,713,004
NET OPERATING INCOME	
Total Revenues-System (R8S)	962,170
Wholesale Sales (WOS)	(92,736)
Total Revenues-Retail (R8R)	869,434
Regulatory Adjustments (TFPSCAR)	(62,348)
Total Revenues-Retail (FPSCR)	807,086
Non Recoverable Fuel (FPSCE1)	11,927
O & M Other (FPSCE5)	238,849
Depreciation Expense (FPSCE6)	197,862
Other Taxes (FPSCE7)	55,527
Current Taxes (FPSCE8)	91,065
Deferred Taxes (FPSCE9)	(9,849)
ITC(FPSCEB)	(3,252)
Loss On Disposal (FPSCLOD)	0
Total Expenses (FPSCOE)	581,934
Jurisdictional NOI (FPSCNOI)	225,137

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	After
RATE BASE	
Plant in Service (FPSCPS)	3,913,783
Accumulated Reserve(FPSCAR)	1,463,963
Net Plant (FPSCNP)	2,449,820
Property For Future Use (FPSCP3A)	31,362
CWIP (FPSCP9A)	58,071
Net Utility Plant (FPSCNUP)	2,539,252
Working Capital(FPSCWC)	(28,726)
Total Rate Base(TPFRB)	2,510,526
NET OPERATING INCOME	
Total Revenues-System (R8S)	974,527
Wholesale Sales (WOS)	(92,736)
Total Revenues-Retail (R8R)	881,791
Regulatory Adjustments (TFPSCAR)	(62,561)
Total Revenues-Retail (FPSCR)	819,230
Non Recoverable Fuel (FPSCE1)	11,927
O & M Other (FPSCE5)	283,936
Depreciation Expense (FPSCE6)	189,027
Other Taxes (FPSCE7)	51,569
Current Taxes (FPSCE8)	87,173
Deferred Taxes (FPSCE9)	(9,807)
ITC(FPSCEB)	(3,252)
Loss On Disposal (FPSCLOD)	0
Total Expenses (FPSCOE)	610,378
Jurisdictional NOI (FPSCNOI)	208,838

5. In the testimony of William R. Ashburn filed in Docket No. 010577-EI, he references on page 4, lines 15-16, an actual year 2000 retail cost of service study. Provide a copy of that cost study.

A. Please see attached.

FL JURIS FACTORS (2000 ACTUAL LOAD RES) COST OF SERVICE STUDY

RATE OF RETURN SUMMARY - RORSUM

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #		Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Operating Revenues	718,462	396,546	50,535	161,728	56,995	25,957	26,703
2								
3	Operation Expenses:							
4	Power Transactions	11,746	5,215	668	3,228	1,324	1,190	120
5	O&M Expense	255,601	145,728	18,800	52,589	20,790	9,986	7,708
6	Depreciation Expense	147,232	83,258	9,889	32,093	11,716	3,284	6,991
7	Amortization Expense	0	0	0	0	0	0	0
8	Taxes Other than Income	43,697	24,880	3,014	9,482	3,507	1,171	1,643
9	Income Taxes	74,829	40,720	5,478	18,190	4,933	2,001	3,508
10	Other Expenses	(109)	(62)	(7)	(24)	(9)	(3)	(4)
11								
12	Total Operating Expenses	532,996	299,739	37,841	115,558	42,262	17,630	19,966
13								
14								
15	Net Operating Income	185,466	96,807	12,694	46,170	14,733	8,327	6,736
16								
17								
18								
19	Rate Base:							
20	Plant in Service	3,526,289	2,008,271	239,128	775,804	281,973	80,414	140,699
21	Plant Held for Future Use	32,045	17,071	1,994	6,711	2,558	3,515	196
22	Working Capital	(10,907)	(16,766)	(1,640)	1,996	1,702	6,201	(2,400)
23	Construction Work in Progress	54,436	32,072	3,712	12,849	4,900	774	129
24	Less: Depreciation Reserve	1,485,661	857,230	100,942	331,221	120,691	25,800	49,776
25	Less: Deferred Base	0	0	0	0	0	0	0
26								
27	Total Rate Base	2,116,202	1,183,418	142,251	466,140	170,441	65,104	88,848
28								
29								
30								
31	Rate of Return (%)	8.7641	8.1803	8.9233	9.9047	8.6439	12.7901	7.5817
32								
33	Percent of Overall Return	100	93	102	113	99	146	87

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OPERATING REVENUES - OPRREV

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Sales Revenue	REV	676,264	369,437	46,872	154,285	54,252	24,974	26,444
2									
3	Misc Acct. 451 Revenue	CUST	13,892	11,734	1,799	352	5	2	0
4									
5	Revenues: Rents Acct. 454								
6	Transmission	DEM	0	0	0	0	0	0	0
7	Subtransmission	DEM	0	0	0	0	0	0	0
8	Distribution Primary	DEM	12,594	7,614	909	2,871	1,031	35	134
9	Distribution Secondary	DEM	0	0	0	0	0	0	0
10	Rents: Plant Related	TOTAL	12,594	7,614	909	2,871	1,031	35	134
11									
12	Revenues: Acct. 456								
13	Production	DEM	275	165	18	66	25	0	0
14	Production	EGY	6	3	0	2	1	1	0
15	Transmission	DEM	1,471	817	92	336	129	95	2
16	Transmission-Wheeling	DEM	3,041	1,689	190	695	266	197	4
17	Subtransmission	DEM	23	14	2	5	2	0	0
18	Distribution Primary	DEM	71	42	5	16	6	1	1
19	Distribution Secondary	DEM	37	23	3	9	2	0	0
20	Distribution	CUST	36	24	5	6	1	1	0
21	Other	CUST	5	4	1	0	0	0	0
22	Revenues: Total Plant	TOTAL	4,965	2,780	316	1,135	431	295	8
23									
24	Revenues: Acct. 456 (Energy)								
25	Steam & Miscellaneous	EGY	3,420	1,519	195	940	386	347	35
26	Deferred Conservation	EGY	0	0	0	0	0	0	0
27	NonSales Rev. Subtotal	TOTAL	3,420	1,519	195	940	386	347	35
28	Collect Fee/Sales Tax	REV	14	2	2	2	2	2	2
29	Energy Power Sales	EGY	1,350	599	77	371	152	137	14
30	Unbilled Revenue	EGY	5,963	2,860	366	1,772	735	165	66
31	Sales Rev. Subtotal	TOTAL	7,327	3,462	446	2,145	889	304	82
32	Other Revenue	TOTAL	10,747	4,980	640	3,085	1,275	650	117
33									
34	Operating Revenues:								
35	Sales	REV	676,278	369,439	46,874	154,287	54,255	24,976	26,446
36	Production	DEM	275	165	18	66	25	0	0
37	Production	EGY	10,739	4,981	638	3,084	1,273	649	115
38	Transmission	DEM	4,512	2,506	282	1,031	394	293	7
39	Subtransmission	DEM	23	14	2	5	2	0	0
40	Distribution Primary	DEM	12,664	7,656	914	2,888	1,037	35	134
41	Distribution Secondary	DEM	37	23	3	9	2	0	0
42	Distribution	CUST	36	24	5	6	1	1	0
43	Other	CUST	13,897	11,738	1,799	352	5	2	0
44									
45	OPERATING REVENUES	TOTAL	718,462	396,546	50,535	161,728	56,995	25,957	26,703

OPERATION & MAINTENANCE EXPENSES - O&MEXP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Fuel & Power Transactions:								
2	Fuel Expense	EGY	11,107	4,931	632	3,052	1,252	1,125	113
3	Third Party Purchases	EGY	0	0	0	0	0	0	0
4	Net Interchange	EGY	0	0	0	0	0	0	0
5									
6	Net Firm Transactions	DEM	0	0	0	0	0	0	0
7	Net Firm Transactions	EGY	639	284	36	176	72	65	7
8	Net Firm Transactions	TOTAL	639	284	36	176	72	65	7
9									
10	Production	DEM	0	0	0	0	0	0	0
11	Production	EGY	11,746	5,215	668	3,228	1,324	1,190	120
12	Fuel & Power Transactions	TOTAL	11,746	5,215	668	3,228	1,324	1,190	120
13									
14									
15	Production O&M:								
16	Steam	DEM	23,206	13,903	1,555	5,593	2,131	0	24
17	Steam	EGY	54,972	24,408	3,127	15,108	6,198	5,571	561
18	Steam	TOTAL	78,179	38,311	4,682	20,701	8,329	5,571	585
19									
20	Other	DEM	17,887	10,716	1,199	4,311	1,642	0	18
21	Other	EGY	1,491	662	85	410	168	151	15
22	Other	TOTAL	19,377	11,378	1,284	4,721	1,810	151	34
23									
24	Production O&M	DEM	41,093	24,619	2,754	9,905	3,773	0	42
25	Production O&M	EGY	56,463	25,070	3,211	15,517	6,366	5,722	577
26	Production O&M	TOTAL	97,556	49,689	5,966	25,422	10,139	5,722	619
27									
28									
29	Transmission O&M:								
30	Step-Up Substations	DEM	1,838	1,086	122	447	171	10	3
31									
32	High-Volt Transmission								
33	Substations	DEM	0	0	0	0	0	0	0
34	Lines	DEM	669	372	42	153	59	43	1
35	High-Volt Transmission	TOTAL	669	372	42	153	59	43	1
36									
37	Subtransmission								
38	Substations Direct	DEM	238	0	0	0	0	238	0
39	Substations Common	DEM	3,440	2,047	244	772	294	47	36
40	Lines Direct	DEM	476	0	0	0	2	474	0
41	Lines Common	DEM	958	570	68	215	82	13	10
42	Subtrans/Dist. Transfer	DEM	225	136	16	51	18	1	2
43	Subtransmission	TOTAL	5,337	2,753	329	1,038	397	773	48

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OPERATION & MAINTENANCE EXPENSES - O&MEXP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
44	*Transmission O&M:*								
45	Step-Up Substations	DEM	1,838	1,086	122	447	171	10	3
46	Hi-Volt Transmission	DEM	669	372	42	153	59	43	1
47	*Subtransmission*	DEM	5,337	2,753	329	1,038	397	773	48
48									
49	Transmission O&M	TOTAL	7,845	4,211	493	1,638	626	826	52
50									
51									
52	Distribution O&M								
53	Supervision	CUST	1,506	663	108	80	8	5	642
54	Supervision Primary	DEM	6,739	4,000	480	1,553	573	62	70
55	Supervision Secondary	DEM	365	228	27	85	20	0	4
56	Supervision	TOTAL	8,609	4,891	616	1,718	601	68	716
57									
58	Substations Direct	DEM	109	0	0	0	16	93	0
59	Substations Common	DEM	2,495	1,508	180	569	204	7	26
60	Dist/Subtrans Transfer	DEM	162	97	12	36	14	2	2
61	Substations	TOTAL	2,767	1,605	192	605	234	102	28
62									
63	OH Lines Direct	CUST	636	0	18	44	6	0	567
64	OH Lines Primary	DEM	6,541	3,954	472	1,491	536	18	69
65	OH Lines Secondary	DEM	1,296	815	97	302	68	0	14
66	OH Lines	TOTAL	8,472	4,769	588	1,838	609	18	651
67									
68	UG Lines Direct	CUST	34	0	0	5	2	0	27
69	UG Lines Primary	DEM	1,296	763	93	312	115	0	13
70	UG Lines Secondary	DEM	0	0	0	0	0	0	0
71	UG Lines	TOTAL	1,331	763	93	317	117	0	40
72									
73	*Transformers Direct*	CUST	0	0	0	0	0	0	0
74	Transformers Line	DEM	234	146	17	55	13	0	3
75	Transformers	TOTAL	234	146	17	55	13	0	3
76									
77	Services	CUST	2,198	1,815	267	113	2	0	1
78	Meters	CUST	2,567	1,695	339	417	57	58	1
79	Installations	CUST	1,290	1,134	129	26	0	0	0
80	Street Lighting	CUST	2,357	0	0	0	0	0	2,357
81									
82	Distribution O&M:								
83	Distribution O&M	DEM	19,238	11,512	1,378	4,404	1,559	182	202
84	Distribution O&M	CUST	10,587	5,307	863	685	74	63	3,595
85									
86	Distribution O&M	TOTAL	29,825	16,819	2,241	5,089	1,634	245	3,797

OPERATION & MAINTENANCE EXPENSES - O&MEXP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
87	Prod, Trans & Dist O&M								
88	Production	DEM	41,093	24,619	2,754	9,905	3,773	0	42
89	Production	EGY	56,463	25,070	3,211	15,517	6,366	5,722	577
90	Transmission	DEM	2,507	1,458	164	599	229	53	4
91	Subtransmission	DEM	5,337	2,753	329	1,038	397	773	48
92	Distribution Primary	DEM	17,342	10,322	1,236	3,962	1,458	182	181
93	Distribution Secondary	DEM	1,895	1,190	142	442	101	0	21
94	Distribution	CUST	10,587	5,307	863	685	74	63	3,595
95	Other	CUST	0	0	0	0	0	0	0
96	Prod, Trans & Dist O&M	TOTAL	135,226	70,719	8,700	32,149	12,399	6,793	4,467
97									
98	Plus: Other Customer O&M								
99	Uncollectible	CUST	2,892	2,575	143	172	0	0	1
100	Billing & Misc.	CUST	18,897	15,806	2,113	579	278	115	4
101	Info Non-Recoverable	CUST	3,465	1,414	703	533	582	232	0
102	Sales	CUST	2,789	1,839	383	172	266	129	1
103	Other Customer O&M	TOTAL	28,042	21,635	3,343	1,456	1,126	476	6
104									
105	Plus: Admin & General O&M								
106	Production	DEM	33,917	20,320	2,273	8,175	3,114	0	35
107	Production	EGY	17,691	7,855	1,006	4,862	1,995	1,793	181
108	Transmission	DEM	2,053	1,193	134	491	188	44	3
109	Subtransmission	DEM	3,628	1,871	224	706	270	525	33
110	Distribution Primary	DEM	11,585	6,895	826	2,647	974	122	121
111	Distribution Secondary	DEM	4,310	2,705	322	1,005	230	0	47
112	Distribution	CUST	8,285	4,153	675	536	58	50	2,813
113	Other	CUST	10,865	8,382	1,295	564	436	184	2
114	Admin & General O&M	TOTAL	92,333	53,375	6,756	18,985	7,265	2,717	3,235
115									
116	Equals: O&M Expense <u>Less Fuel & Power Trans</u>								
117	Production	DEM	75,010	44,939	5,028	18,079	6,887	0	77
118	Production	EGY	74,154	32,925	4,218	20,379	8,361	7,514	757
119	Transmission	DEM	4,560	2,651	298	1,090	417	97	7
120	Subtransmission	DEM	8,966	4,624	552	1,744	667	1,298	81
121	Distribution Primary	DEM	28,927	17,218	2,062	6,608	2,432	304	302
122	Distribution Secondary	DEM	6,205	3,895	464	1,447	331	0	68
123	Distribution	CUST	18,872	9,460	1,538	1,222	132	113	6,407
124	Other	CUST	38,907	30,017	4,639	2,020	1,563	661	8
125			===========	===========	===========	===========	===========	===========	===========
126	O&M EXPENSE	TOTAL	255,601	145,728	18,800	52,589	20,790	9,986	7,708

DEPRECIATION EXPENSE - DEPRECEXP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Production Expense:								
2	Steam	DEM	39,241	23,510	2,630	9,458	3,603	0	40
3	Steam	EGY	7,465	3,314	425	2,051	842	756	76
4	Steam	TOTAL	46,706	26,824	3,055	11,510	4,444	756	117
5									
6	Other	DEM	25,535	15,298	1,712	6,155	2,344	0	26
7	Other	EGY	2,128	945	121	585	240	216	22
8	Other	TOTAL	27,663	16,243	1,833	6,739	2,584	216	48
9									
10	Production Total	DEM	64,776	38,808	4,342	15,613	5,947	0	67
11	Production Total	EGY	9,593	4,259	546	2,636	1,082	972	98
12									
13	Production Expense	TOTAL	74,369	43,067	4,887	18,249	7,029	972	165
14									
15									
16	Transmission Expense:								
17	Step-Up Substations	DEM	1,189	703	79	289	111	6	2
18									
19	High-Volt Transmission								
20	Substations	DEM	0	0	0	0	0	0	0
21	Lines	DEM	2,126	1,181	133	486	186	138	3
22	Hi-Volt Transmission	TOTAL	2,126	1,181	133	486	186	138	3
23									
24	Subtransmission								
25	Substations Direct	DEM	140	0	0	0	0	140	0
26	Substations Common	DEM	2,106	1,253	150	472	180	29	22
27	Lines Direct	DEM	799	0	0	0	4	795	0
28	Lines Common	DEM	1,671	994	119	375	143	23	17
29	Subtrans/Dist Transfer	DEM	138	83	10	31	11	0	1
30	Subtransmission	TOTAL	4,853	2,330	278	879	338	987	41
31									
32	Step-Up Substations	DEM	1,189	703	79	289	111	6	2
33	Hi-Volt Transmission	DEM	2,126	1,181	133	486	186	138	3
34	Subtransmission	DEM	4,853	2,330	278	879	338	987	41
35									
36	Transmission Expense	TOTAL	8,169	4,214	490	1,653	634	1,131	46

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DEPRECIATION EXPENSE - DEPRECEXP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
37	Distribution Expense:								
38	Substations Direct	DEM	143	0	0	0	21	122	0
39	Substations Common	DEM	3,265	1,974	236	744	267	9	35
40	Dist/Subtrans Transfer	DEM	212	126	15	48	18	3	2
41	Substations	TOTAL	3,621	2,101	251	792	307	134	37
42									
43	Poles Direct	CUST	667	0	6	15	2	0	644
44	Poles Primary	DEM	4,292	2,595	310	979	351	12	46
45	Poles Secondary	DEM	713	448	53	166	37	0	8
46	Poles	TOTAL	5,672	3,043	369	1,160	390	12	698
47									
48	OH Lines Direct	CUST	224	0	7	16	2	0	200
49	OH Lines Primary	DEM	4,568	2,762	330	1,042	374	13	49
50	OH Lines Secondary	DEM	1,027	645	77	239	54	0	11
51	OH Lines	TOTAL	5,819	3,407	413	1,296	430	13	260
52									
53	UG Lines Direct	CUST	127	0	2	20	6	0	99
54	UG Lines Primary	DEM	4,813	2,833	344	1,159	428	0	50
55	UG Lines Secondary	DEM	0	0	0	0	0	0	0
56	UG Lines	TOTAL	4,941	2,833	346	1,179	434	0	149
57									
58	Transformers Direct	CUST	0	0	0	0	0	0	0
59	Transformers Common	DEM	11,140	6,964	831	2,602	620	0	122
60	Transformers	TOTAL	11,140	6,964	831	2,602	620	0	122
61									
62	Services	CUST	3,221	2,660	392	165	2	0	1
63	Meters	CUST	1,154	762	152	187	26	26	0
64	Installations	CUST	0	0	0	0	0	0	0
65	Street Lighting	CUST	4,684	0	0	0	0	0	4,684
66									
67	Distribution Expense	DEM	30,173	18,348	2,195	6,978	2,172	158	322
68	Distribution Expense	CUST	10,077	3,422	558	404	38	26	5,630
69									
70	Distribution Expense	TOTAL	40,251	21,771	2,753	7,382	2,209	184	5,952
71									
72									
73									
74	Prod, Trans, & Dist Expense:								
75	Production	DEM	64,776	38,808	4,342	15,613	5,947	0	67
76	Production	EGY	9,593	4,259	546	2,636	1,082	972	98
77	Transmission	DEM	3,316	1,884	212	775	296	144	5
78	Subtransmission	DEM	4,853	2,330	278	879	338	987	41
79	Distribution Primary	DEM	17,294	10,290	1,234	3,971	1,460	158	181
80	Distribution Secondary	DEM	12,879	8,058	961	3,007	711	0	141
81	Distribution	CUST	10,077	3,422	558	404	38	26	5,630
82	Other	CUST	0	0	0	0	0	0	0
83									
84	Prod, Trans & Dist Expense	TOTAL	122,788	69,051	8,131	27,285	9,872	2,287	6,162

DEPRECIATION EXPENSE - DEPRECEXP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
85	Plus: Communication Equipment								
86	Production	DEM	2,252	1,349	151	543	207	0	2
87	Production	EGY	695	308	40	191	78	70	7
88	Transmission	DEM	1,225	696	78	286	110	53	2
89	Subtransmission	DEM	1,271	610	73	230	88	258	11
90	Distribution Primary	DEM	2,504	1,486	178	577	213	23	26
91	Distribution Secondary	DEM	23	15	2	5	1	0	0
92	Distribution	CUST	228	100	16	12	1	1	97
93	Other	CUST	509	426	57	16	8	3	0
94	Communication Equipment	TOTAL	8,707	4,991	595	1,860	706	409	146
95									
96	*Plus: Transportation Equipment*								
97	Production	DEM	0	0	0	0	0	0	0
98	Production	EGY	0	0	0	0	0	0	0
99	Transmission	DEM	0	0	0	0	0	0	0
100	Subtransmission	DEM	0	0	0	0	0	0	0
101	Distribution Primary	DEM	0	0	0	0	0	0	0
102	Distribution Secondary	DEM	0	0	0	0	0	0	0
103	Distribution	CUST	0	0	0	0	0	0	0
104	Other	CUST	0	0	0	0	0	0	0
105	Transportation Equipment	TOTAL	0	0	0	0	0	0	0
106									
107	*Plus: General & Tangible*								
108	Production	DEM	4,428	2,653	297	1,067	407	0	5
109	Production	EGY	4,378	1,944	249	1,203	494	444	45
110	Transmission	DEM	221	125	14	52	20	10	0
111	Subtransmission	DEM	474	228	27	86	33	96	4
112	Distribution Primary	DEM	1,440	855	103	332	122	13	15
113	Distribution Secondary	DEM	147	92	11	34	8	0	2
114	Distribution	CUST	1,438	633	103	76	7	5	613
115	Other	CUST	3,211	2,686	359	98	47	20	1
116	General & Tangible	TOTAL	15,737	9,216	1,163	2,949	1,138	588	684
117									
118	*Equals: Depreciation Expense (Factors 611 - 618)*								
119	Production	DEM	71,456	42,810	4,789	17,223	6,560	0	74
120	Production	EGY	14,665	6,511	834	4,030	1,653	1,486	150
121	Transmission	DEM	4,761	2,705	304	1,112	426	207	7
122	Subtransmission	DEM	6,598	3,168	378	1,195	460	1,342	55
123	Distribution Primary	DEM	21,238	12,631	1,515	4,880	1,796	194	222
124	Distribution Secondary	DEM	13,050	8,165	974	3,047	720	0	143
125	Distribution	CUST	11,744	4,156	678	492	46	32	6,340
126	Other	CUST	3,720	3,112	416	114	55	23	1
127			==========	==========	==========	==========	==========	==========	==========
128	DEPRECIATION EXPENSE	TOTAL	147,232	83,258	9,889	32,093	11,716	3,284	6,991

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TAXES OTHER THAN INCOME TAXES - TAXOTH

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Payroll Taxes:								
2	Production	DEM	2,700	1,618	181	651	248	0	3
3	Production	EGY	2,670	1,185	152	734	301	271	27
4	Transmission	DEM	164	95	11	39	15	3	0
5	Subtransmission	DEM	323	166	20	63	24	47	3
6	Distribution Primary	DEM	1,041	620	74	238	88	11	11
7	Distribution Secondary	DEM	223	140	17	52	12	0	2
8	Distribution	CUST	679	341	55	44	5	4	231
9	Other	CUST	1,401	1,081	167	73	56	24	0
10	Payroll Taxes	TOTAL	9,202	5,246	677	1,893	748	360	278
11									
12	Plus: Property Taxes								
13	Production	DEM	16,013	9,593	1,073	3,859	1,470	0	16
14	Production	EGY	2,800	1,243	159	770	316	284	29
15	Transmission	DEM	1,309	742	84	305	117	60	2
16	Subtransmission	DEM	1,884	905	108	341	131	383	16
17	Distribution Primary	DEM	5,470	3,247	390	1,261	465	50	57
18	Distribution Secondary	DEM	2,850	1,783	213	665	157	0	31
19	Distribution	CUST	2,754	1,212	198	146	14	10	1,174
20	Other	CUST	384	321	43	12	6	2	0
21	Property Taxes	TOTAL	33,464	19,047	2,268	7,359	2,676	789	1,325
22									
23	Proforma Revenue Tax Decrease								
24	Production	DEM	0	0	0	0	0	0	0
25	Production	EGY	0	0	0	0	0	0	0
26	Transmission	DEM	0	0	0	0	0	0	0
27	Subtransmission	DEM	0	0	0	0	0	0	0
28	Distribution Primary	DEM	0	0	0	0	0	0	0
29	Distribution Secondary	DEM	0	0	0	0	0	0	0
30	Distribution	CUST	0	0	0	0	0	0	0
31	Other	CUST	0	0	0	0	0	0	0
32	Revenue Tax Decrease	TOTAL	0	0	0	0	0	0	0
33									
34	Plus: Other Taxes								
35	Production	DEM	517	309	35	125	47	0	1
36	Production	EGY	79	35	5	22	9	8	1
37	Transmission	DEM	36	20	2	8	3	2	0
38	Subtransmission	DEM	52	25	3	9	4	11	0
39	Distribution Primary	DEM	167	99	12	38	14	2	2
40	Distribution Secondary	DEM	95	59	7	22	5	0	1
41	Distribution	CUST	85	38	6	5	0	0	36
42	Other	CUST	0	0	0	0	0	0	0
43	Other Taxes	TOTAL	1,031	586	70	229	83	22	41

TAXES OTHER THAN INCOME TAXES - TAXOTH

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
44	Equals: Non-Revenue Taxes								
45	Production	DEM	19,230	11,521	1,289	4,635	1,765	0	20
46	Production	EGY	5,549	2,464	316	1,525	626	562	57
47	Transmission	DEM	1,509	858	97	353	135	65	2
48	Subtransmission	DEM	2,259	1,096	131	413	159	441	19
49	Distribution Primary	DEM	6,678	3,966	476	1,537	567	63	70
50	Distribution Secondary	DEM	3,168	1,983	237	740	174	0	35
51	Distribution	CUST	3,519	1,591	259	194	19	14	1,441
52	Other	CUST	1,785	1,402	210	84	62	26	0
53	Non-Revenue Taxes	TOTAL	43,697	24,880	3,014	9,482	3,507	1,171	1,643
54									
55									
56	Actual Test Year Revenue Taxes								
57	Production	DEM	0	0	0	0	0	0	0
58	Production	EGY	0	0	0	0	0	0	0
59	Transmission	DEM	0	0	0	0	0	0	0
60	Subtransmission	DEM	0	0	0	0	0	0	0
61	Distribution Primary	DEM	0	0	0	0	0	0	0
62	Distribution Secondary	DEM	0	0	0	0	0	0	0
63	Distribution	CUST	0	0	0	0	0	0	0
64	Other	CUST	0	0	0	0	0	0	0
65	Actual Revenue Taxes	TOTAL	0	0	0	0	0	0	0
66									
67									
68	Equals: Taxes Other Than Income								
69	Production	DEM	19,230	11,521	1,289	4,635	1,765	0	20
70	Production	EGY	5,549	2,464	316	1,525	626	562	57
71	Transmission	DEM	1,509	858	97	353	135	65	2
72	Subtransmission	DEM	2,259	1,096	131	413	159	441	19
73	Distribution Primary	DEM	6,678	3,966	476	1,537	567	63	70
74	Distribution Secondary	DEM	3,168	1,983	237	740	174	0	35
75	Distribution	CUST	3,519	1,591	259	194	19	14	1,441
76	Other	CUST	1,785	1,402	210	84	62	26	0
77			==========	==========	==========	==========	==========	==========	==========
78	TAXES OTH. THAN INCOME	TOTAL	43,697	24,880	3,014	9,482	3,507	1,171	1,643

INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.
Federal Tax Rate = 35.00%
Fla State Tax Rate = 5.50%

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	First Step: Derivation of Operating Income								
2									
3	Total Operating Revenues:								
4	Sales	REV	676,278	369,439	46,874	154,287	54,255	24,976	26,446
5	Production	DEM	275	165	18	66	25	0	0
6	Production	EGY	10,739	4,981	638	3,084	1,273	649	115
7	Transmission	DEM	4,512	2,506	282	1,031	394	293	7
8	Subtransmission	DEM	23	14	2	5	2	0	0
9	Distribution Primary	DEM	12,664	7,656	914	2,888	1,037	35	134
10	Distribution Secondary	DEM	37	23	3	9	2	0	0
11	Distribution	CUST	36	24	5	6	1	1	0
12	Other	CUST	13,897	11,738	1,799	352	5	2	0
13	Total Operating Revenues	TOTAL	718,462	396,546	50,535	161,728	56,995	25,957	26,703
14									
15	Less: O&M Expense								
16	Production	DEM	75,010	44,939	5,028	18,079	6,887	0	77
17	Production	EGY	74,154	32,925	4,218	20,379	8,361	7,514	757
18	Transmission	DEM	4,560	2,651	298	1,090	417	97	7
19	Subtransmission	DEM	8,966	4,624	552	1,744	667	1,298	81
20	Distribution Primary	DEM	28,927	17,218	2,062	6,608	2,432	304	302
21	Distribution Secondary	DEM	6,205	3,895	464	1,447	331	0	68
22	Distribution	CUST	18,872	9,460	1,538	1,222	132	113	6,407
23	Other	CUST	38,907	30,017	4,639	2,020	1,563	661	8
24	O&M Expense	TOTAL	255,601	145,728	18,800	52,589	20,790	9,986	7,708
25									
26	Less: Fuel & Power Transacts								
27	Production	DEM	0	0	0	0	0	0	0
28	Production	EGY	11,746	5,215	668	3,228	1,324	1,190	120
29	Fuel & Power Transacts	TOTAL	11,746	5,215	668	3,228	1,324	1,190	120
30									
31	Less: Depreciation Expense								
32	Production	DEM	71,456	42,810	4,789	17,223	6,560	0	74
33	Production	EGY	14,665	6,511	834	4,030	1,653	1,486	150
34	Transmission	DEM	4,761	2,705	304	1,112	426	207	7
35	Subtransmission	DEM	6,598	3,168	378	1,195	460	1,342	55
36	Distribution Primary	DEM	21,238	12,631	1,515	4,880	1,796	194	222
37	Distribution Secondary	DEM	13,050	8,165	974	3,047	720	0	143
38	Distribution	CUST	11,744	4,156	678	492	46	32	6,340
39	Other	CUST	3,720	3,112	416	114	55	23	1
40	Depreciation Expense	TOTAL	147,232	83,258	9,889	32,093	11,716	3,284	6,991

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INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
41	Less: Amortization Expense								
42	Production	DEM	0						
43	Production	EGY	0						
44	Transmission	DEM	0						
45	Subtransmission	DEM	0						
46	Distribution Primary	DEM	0						
47	Distribution Secondary	DEM	0						
48	Distribution	CUST	0						
49	Other	CUST	0						
50	Amortization Expense	TOTAL	0	0	0	0	0	0	0
51									
52	Less: Taxes Other Than Income								
53	Production	DEM	19,230	11,521	1,289	4,635	1,765	0	20
54	Production	EGY	5,549	2,464	316	1,525	626	562	57
55	Transmission	DEM	1,509	858	97	353	135	65	2
56	Subtransmission	DEM	2,259	1,096	131	413	159	441	19
57	Distribution Primary	DEM	6,678	3,966	476	1,537	567	63	70
58	Distribution Secondary	DEM	3,168	1,983	237	740	174	0	35
59	Distribution	CUST	3,519	1,591	259	194	19	14	1,441
60	Other	CUST	1,785	1,402	210	84	62	26	0
61	Taxes Other Than Income	TOTAL	43,697	24,880	3,014	9,482	3,507	1,171	1,643
62									
63	Less: Loss on Disposition & Misc								
64	Production	DEM	(53)	(31)	(4)	(13)	(5)	0	(0)
65	Production	EGY	(9)	(4)	(1)	(3)	(1)	(1)	(0)
66	Transmission	DEM	(4)	(2)	(0)	(1)	(0)	(0)	(0)
67	Subtransmission	DEM	(6)	(3)	(0)	(1)	(0)	(1)	(0)
68	Distribution Primary	DEM	(18)	(11)	(1)	(4)	(2)	(0)	(0)
69	Distribution Secondary	DEM	(9)	(6)	(1)	(2)	(1)	0	(0)
70	Distribution	CUST	(9)	(4)	(1)	(0)	(0)	(0)	(4)
71	Other	CUST	(1)	(1)	(0)	(0)	(0)	(0)	(0)
72	Total Other Expenses		(109)	(62)	(7)	(24)	(9)	(3)	(4)
73									
74	Equals: Operating Income								
75	Sales	REV	676,278	369,439	46,874	154,287	54,255	24,976	26,446
76	Production	DEM	(165,368)	(99,073)	(11,084)	(39,858)	(15,182)	0	(170)
77	Production	EGY	(95,366)	(42,130)	(5,397)	(26,076)	(10,690)	(10,103)	(969)
78	Transmission	DEM	(6,315)	(3,705)	(417)	(1,524)	(583)	(76)	(10)
79	Subtransmission	DEM	(17,793)	(8,872)	(1,060)	(3,346)	(1,283)	(3,079)	(155)
80	Distribution Primary	DEM	(44,162)	(26,148)	(3,138)	(10,134)	(3,756)	(525)	(459)
81	Distribution Secondary	DEM	(22,377)	(14,013)	(1,671)	(5,223)	(1,224)	0	(246)
82	Distribution	CUST	(34,094)	(15,179)	(2,470)	(1,902)	(196)	(158)	(14,188)
83	Other	CUST	(30,514)	(22,792)	(3,466)	(1,866)	(1,674)	(707)	(10)
84	Operating Income	TOTAL	260,290	137,527	18,171	64,360	19,666	10,328	10,239
85									
86									
87	Next Step: Deductions from Operating Income								
88									
89									
90	Production Group Items:								
91	Production	DEM	2,578	1,545	173	621	237	0	3
92	Production	EGY	49,802	22,112	2,833	13,687	5,615	5,047	509
93	Production Group Items	TOTAL	52,381	23,657	3,005	14,308	5,852	5,047	511

INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
94	Plus: Plant Group Items								
95	Production	DEM	(7,784)	(4,663)	(522)	(1,876)	(715)	0	(8)
96	Production	EGY	(184)	(82)	(10)	(51)	(21)	(19)	(2)
97	Transmission	DEM	(515)	(292)	(33)	(120)	(46)	(23)	(1)
98	Subtransmission	DEM	(740)	(355)	(42)	(134)	(52)	(150)	(6)
99	Distribution Primary	DEM	(2,298)	(1,364)	(164)	(530)	(195)	(21)	(24)
100	Distribution Secondary	DEM	(1,208)	(756)	(90)	(282)	(67)	0	(13)
101	Distribution	CUST	(1,168)	(514)	(84)	(62)	(6)	(4)	(498)
102	Other	CUST	(163)	(136)	(18)	(5)	(2)	(1)	(0)
103	Plant Group Items	TOTAL	(14,059)	(8,162)	(964)	(3,059)	(1,103)	(219)	(552)
104									
105	Plus: Tax Deprec. Over Book								
106	Production	DEM	408	245	27	98	37	0	0
107	Production	EGY	7	3	0	2	1	1	0
108	Transmission	DEM	22	13	1	5	2	1	0
109	Subtransmission	DEM	28	13	2	5	2	6	0
110	Distribution Primary	DEM	90	54	6	21	8	1	1
111	Distribution Secondary	DEM	52	33	4	12	3	0	1
112	Distribution	CUST	45	16	3	2	0	0	24
113	Other	CUST	6	5	1	0	0	0	0
114	Tax Deprec. Over Book	TOTAL	659	381	44	146	53	8	26
115									
116	Plus: Interest Expense								
117	Production	DEM	26,516	15,886	1,777	6,391	2,434	0	27
118	Production	EGY	2,596	1,153	148	714	293	263	27
119	Transmission	DEM	2,155	1,225	138	504	193	92	3
120	Subtransmission	DEM	3,369	1,608	192	606	234	701	28
121	Distribution Primary	DEM	9,198	5,451	655	2,126	785	85	96
122	Distribution Secondary	DEM	4,511	2,822	337	1,053	249	0	50
123	Distribution	CUST	4,671	2,069	337	246	24	17	1,978
124	Other	CUST	660	552	74	20	10	4	0
125	Interest Expense	TOTAL	53,676	30,766	3,657	11,660	4,222	1,161	2,209
126									
127	Plus: Other Deductions								
128	Production	DEM	(3,606)	(2,160)	(242)	(869)	(331)	0	(4)
129	Production	EGY	(341)	(151)	(19)	(94)	(38)	(35)	(3)
130	Transmission	DEM	(280)	(163)	(18)	(67)	(26)	(6)	(0)
131	Subtransmission	DEM	(444)	(229)	(27)	(86)	(33)	(64)	(4)
132	Distribution Primary	DEM	(1,216)	(724)	(87)	(278)	(102)	(13)	(13)
133	Distribution Secondary	DEM	(596)	(374)	(45)	(139)	(32)	0	(7)
134	Distribution	CUST	(617)	(309)	(50)	(40)	(4)	(4)	(210)
135	Other	CUST	(87)	(67)	(10)	(5)	(4)	(1)	(0)
136	Other Deductions	TOTAL	(7,188)	(4,179)	(499)	(1,578)	(570)	(123)	(240)

0101

INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
137	Equals: Deducts. From Operating Income								
138	Production	DEM	18,113	10,852	1,214	4,366	1,663	0	19
139	Production	EGY	51,881	23,035	2,951	14,258	5,850	5,257	530
140	Transmission	DEM	1,382	783	88	322	123	63	2
141	Subtransmission	DEM	2,213	1,037	124	391	152	492	18
142	Distribution Primary	DEM	5,774	3,417	411	1,339	495	52	60
143	Distribution Secondary	DEM	2,758	1,725	206	644	153	0	30
144	Distribution	CUST	2,931	1,261	205	147	14	9	1,295
145	Other	CUST	416	354	46	11	4	2	0
146	Deducts. From Oper. Income	TOTAL	85,468	42,464	5,244	21,478	8,454	5,875	1,954
147									
148									
149	Next Step: Calculation of Florida Income Taxes Payable After Deductions								
150									
151									
152	Operating Income Less Deductions								
153	Sales	REV	676,278	369,439	46,874	154,287	54,255	24,976	26,446
154	Production	DEM	(183,481)	(109,925)	(12,298)	(44,224)	(16,845)	0	(189)
155	Production	EGY	(147,246)	(65,165)	(8,347)	(40,334)	(16,540)	(15,361)	(1,499)
156	Transmission	DEM	(7,697)	(4,489)	(505)	(1,846)	(707)	(139)	(12)
157	Subtransmission	DEM	(20,006)	(9,908)	(1,183)	(3,736)	(1,434)	(3,571)	(173)
158	Distribution Primary	DEM	(49,935)	(29,565)	(3,549)	(11,473)	(4,251)	(577)	(519)
159	Distribution Secondary	DEM	(25,135)	(15,738)	(1,877)	(5,867)	(1,377)	0	(276)
160	Distribution	CUST	(37,025)	(16,440)	(2,675)	(2,048)	(210)	(167)	(15,484)
161	Other	CUST	(30,930)	(23,145)	(3,511)	(1,877)	(1,678)	(709)	(10)
162	Operating Inc. Less Deduct.	TOTAL	174,822	95,063	12,927	42,882	11,212	4,453	8,285
163									
164	Less: Florida Income Adjustments								
165	Production	DEM	(14,137)	(8,470)	(948)	(3,407)	(1,298)	0	(15)
166	Production	EGY	(4,846)	(2,152)	(276)	(1,332)	(546)	(491)	(49)
167	Transmission	DEM	(1,405)	(799)	(90)	(329)	(126)	(60)	(2)
168	Subtransmission	DEM	(2,197)	(1,049)	(125)	(395)	(153)	(457)	(18)
169	Distribution Primary	DEM	(5,999)	(3,555)	(427)	(1,386)	(512)	(55)	(62)
170	Distribution Secondary	DEM	(2,942)	(1,841)	(220)	(687)	(162)	0	(32)
171	Distribution	CUST	(3,047)	(1,349)	(220)	(161)	(16)	(11)	(1,290)
172	Other	CUST	(431)	(361)	(48)	(13)	(6)	(3)	(0)
173	Florida Income Adjustments	TOTAL	(35,004)	(19,575)	(2,353)	(7,710)	(2,819)	(1,077)	(1,470)

INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
174	Equals: Florida Taxable Income								
175	Sales	REV	676,278	369,439	46,874	154,287	54,255	24,976	26,446
176	Production	DEM	(169,344)	(101,456)	(11,351)	(40,816)	(15,547)	0	(174)
177	Production	EGY	(142,400)	(63,014)	(8,072)	(39,002)	(15,993)	(14,870)	(1,449)
178	Transmission	DEM	(6,292)	(3,690)	(415)	(1,517)	(581)	(79)	(10)
179	Subtransmission	DEM	(17,809)	(8,860)	(1,058)	(3,341)	(1,281)	(3,114)	(154)
180	Distribution Primary	DEM	(43,937)	(26,010)	(3,122)	(10,087)	(3,739)	(522)	(457)
181	Distribution Secondary	DEM	(22,193)	(13,897)	(1,658)	(5,180)	(1,215)	0	(244)
182	Distribution	CUST	(33,978)	(15,090)	(2,456)	(1,888)	(195)	(156)	(14,193)
183	Other	CUST	(30,499)	(22,785)	(3,463)	(1,864)	(1,672)	(706)	(10)
184	Florida Taxable Income	TOTAL	209,826	114,638	15,280	50,592	14,031	5,530	9,755
185									
186	Results: Florida Income Tax @	5.50%							
187	Sales	REV	37,182	20,312	2,577	8,483	2,983	1,373	1,454
188	Production	DEM	(9,311)	(5,578)	(624)	(2,244)	(855)	0	(10)
189	Production	EGY	(7,829)	(3,464)	(444)	(2,144)	(879)	(818)	(80)
190	Transmission	DEM	(346)	(203)	(23)	(83)	(32)	(4)	(1)
191	Subtransmission	DEM	(979)	(487)	(58)	(184)	(70)	(171)	(8)
192	Distribution Primary	DEM	(2,416)	(1,430)	(172)	(555)	(206)	(29)	(25)
193	Distribution Secondary	DEM	(1,220)	(764)	(91)	(285)	(67)	0	(13)
194	Distribution	CUST	(1,868)	(830)	(135)	(104)	(11)	(9)	(780)
195	Other	CUST	(1,677)	(1,253)	(190)	(102)	(92)	(39)	(1)
196	Florida Income Tax	TOTAL	11,536	6,303	840	2,782	771	304	536
197									
198									
199	Next Step: Calculation of Federal Income Taxes Payable After Deductions and Before Tax Adjustments								
200									
201									
202	Operating Income After Florida Tax								
203	Sales	REV	639,096	349,128	44,297	145,805	51,272	23,603	24,992
204	Production	DEM	(160,033)	(95,878)	(10,726)	(38,572)	(14,693)	0	(165)
205	Production	EGY	(134,571)	(59,549)	(7,628)	(36,858)	(15,114)	(14,052)	(1,370)
206	Transmission	DEM	(5,946)	(3,487)	(392)	(1,434)	(549)	(75)	(9)
207	Subtransmission	DEM	(16,830)	(8,373)	(1,000)	(3,157)	(1,211)	(2,943)	(146)
208	Distribution Primary	DEM	(41,521)	(24,580)	(2,950)	(9,532)	(3,534)	(493)	(432)
209	Distribution Secondary	DEM	(20,973)	(13,133)	(1,566)	(4,895)	(1,148)	0	(231)
210	Distribution	CUST	(32,110)	(14,261)	(2,321)	(1,784)	(184)	(148)	(13,413)
211	Other	CUST	(28,822)	(21,532)	(3,273)	(1,761)	(1,580)	(667)	(9)
212	Oper Inc After Florida Tax	TOTAL	198,290	108,335	14,440	47,811	13,260	5,226	9,219

INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
213	Less: Federal Income Adjustments								
214	Production	DEM	0	0	0	0	0	0	0
215	Production	EGY	0	0	0	0	0	0	0
216	Transmission	DEM	0	0	0	0	0	0	0
217	Subtransmission	DEM	0	0	0	0	0	0	0
218	Distribution Primary	DEM	0	0	0	0	0	0	0
219	Distribution Secondary	DEM	0	0	0	0	0	0	0
220	Distribution	CUST	0	0	0	0	0	0	0
221	Other	CUST	0	0	0	0	0	0	0
222	Federal Income Adjustments	TOTAL	0	0	0	0	0	0	0
223									
224	Equals: Federal Taxable Income								
225	Sales	REV	639,096	349,128	44,297	145,805	51,272	23,603	24,992
226	Production	DEM	(160,033)	(95,878)	(10,726)	(38,572)	(14,693)	0	(165)
227	Production	EGY	(134,571)	(59,549)	(7,628)	(36,858)	(15,114)	(14,052)	(1,370)
228	Transmission	DEM	(5,946)	(3,487)	(392)	(1,434)	(549)	(75)	(9)
229	Subtransmission	DEM	(16,830)	(8,373)	(1,000)	(3,157)	(1,211)	(2,943)	(146)
230	Distribution Primary	DEM	(41,521)	(24,580)	(2,950)	(9,532)	(3,534)	(493)	(432)
231	Distribution Secondary	DEM	(20,973)	(13,133)	(1,566)	(4,895)	(1,148)	0	(231)
232	Distribution	CUST	(32,110)	(14,261)	(2,321)	(1,784)	(184)	(148)	(13,413)
233	Other	CUST	(28,822)	(21,532)	(3,273)	(1,761)	(1,580)	(667)	(9)
234	Federal Taxable Income	TOTAL	198,290	108,335	14,440	47,811	13,260	5,226	9,219
235									
236	Results: Federal Income Tax @	35.00%							
237	Sales	REV	223,684	122,195	15,504	51,032	17,945	8,261	8,747
238	Production	DEM	(56,012)	(33,557)	(3,754)	(13,500)	(5,142)	0	(58)
239	Production	EGY	(47,100)	(20,842)	(2,670)	(12,900)	(5,290)	(4,918)	(479)
240	Transmission	DEM	(2,081)	(1,220)	(137)	(502)	(192)	(26)	(3)
241	Subtransmission	DEM	(5,890)	(2,930)	(350)	(1,105)	(424)	(1,030)	(51)
242	Distribution Primary	DEM	(14,532)	(8,603)	(1,033)	(3,336)	(1,237)	(173)	(151)
243	Distribution Secondary	DEM	(7,341)	(4,597)	(548)	(1,713)	(402)	0	(81)
244	Distribution	CUST	(11,239)	(4,991)	(812)	(624)	(64)	(52)	(4,695)
245	Other	CUST	(10,088)	(7,536)	(1,145)	(616)	(553)	(234)	(3)
246	Federal Income Tax	TOTAL	69,401	37,917	5,054	16,734	4,641	1,829	3,226

INCOME TAXES - INCTAX

This section performs the calculation of Income Taxes.

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
247	Presentation of Adjustments to Income Taxes Prior to Totaling								
248									
249	Adjustments to Income Taxes:								
250	Production	DEM	(2,988)	(1,790)	(200)	(720)	(274)	0	(3)
251	Production	EGY	(298)	(132)	(17)	(82)	(34)	(30)	(3)
252	Transmission	DEM	(248)	(141)	(16)	(58)	(22)	(11)	(0)
253	Subtransmission	DEM	(387)	(186)	(22)	(70)	(27)	(79)	(3)
254	Distribution Primary	DEM	(1,057)	(627)	(75)	(244)	(90)	(10)	(11)
255	Distribution Secondary	DEM	(518)	(324)	(39)	(121)	(29)	0	(6)
256	Distribution	CUST	(537)	(236)	(39)	(28)	(3)	(2)	(229)
257	Other	CUST	(76)	(63)	(8)	(2)	(1)	(0)	(0)
258	Adjustment to Income Taxes	TOTAL	(6,109)	(3,500)	(416)	(1,325)	(479)	(132)	(255)
259									
260									
261	Final Step: Totaling of All Income Taxes								
262	(Florida Tax + Federal Tax + Adjustments)								
263									
264	Income Taxes:								
265	Sales	REV	260,865	142,506	18,081	59,514	20,928	9,634	10,201
266	Production	DEM	(68,311)	(40,926)	(4,579)	(16,465)	(6,272)	0	(70)
267	Production	EGY	(55,227)	(24,439)	(3,131)	(15,127)	(6,203)	(5,766)	(562)
268	Transmission	DEM	(2,675)	(1,564)	(176)	(643)	(246)	(42)	(4)
269	Subtransmission	DEM	(7,257)	(3,603)	(430)	(1,359)	(521)	(1,280)	(63)
270	Distribution Primary	DEM	(18,005)	(10,660)	(1,280)	(4,134)	(1,532)	(211)	(187)
271	Distribution Secondary	DEM	(9,079)	(5,685)	(678)	(2,119)	(497)	0	(100)
272	Distribution	CUST	(13,643)	(6,057)	(986)	(756)	(78)	(62)	(5,704)
273	Other	CUST	(11,840)	(8,852)	(1,344)	(721)	(646)	(273)	(4)
274			==========	==========	==========	==========	==========	==========	==========
275	INCOME TAXES	TOTAL	74,829	40,720	5,478	18,190	4,933	2,001	3,508

0105

PLANT IN SERVICE - PLTSVC

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Production Plant:								
2	Steam	DEM	1,075,574	644,386	72,092	259,241	98,748	0	1,106
3	Steam	EGY	204,600	90,843	11,637	56,229	23,069	20,733	2,089
4	Steam	TOTAL	1,280,174	735,229	83,729	315,471	121,817	20,733	3,195
5									
6	Other	DEM	562,232	336,838	37,684	135,512	51,618	0	578
7	Other	EGY	46,853	20,803	2,665	12,876	5,283	4,748	478
8	Other	TOTAL	609,084	357,641	40,349	148,389	56,901	4,748	1,057
9									
10	Production Plant	DEM	1,637,806	981,225	109,776	394,754	150,366	0	1,685
11	Production Plant	EGY	251,453	111,646	14,301	69,106	28,352	25,481	2,567
12									
13	Production Plant	TOTAL	1,889,259	1,092,870	124,078	463,859	178,718	25,481	4,252
14									
15									
16	Transmission Plant:								
17	Step-Up Substations	DEM	40,542	23,951	2,696	9,849	3,770	215	62
18									
19	High-Volt Transmission								
20	Substations	DEM	0	0	0	0	0	0	0
21	Lines	DEM	72,474	40,252	4,530	16,553	6,335	4,700	104
22	Hi-Volt Transmission	TOTAL	72,474	40,252	4,530	16,553	6,335	4,700	104
23									
24	Subtransmission								
25	Substations Direct	DEM	4,770	0	0	0	0	4,770	0
26	Substations Common	DEM	71,768	42,700	5,100	16,102	6,137	984	744
27	Lines Direct	DEM	27,224	0	0	0	128	27,096	0
28	Lines Common	DEM	56,944	33,880	4,047	12,776	4,870	781	590
29	Subtrans/Dist Transfer	DEM	4,692	2,837	339	1,070	384	13	50
30	Subtransmission	TOTAL	165,398	79,417	9,486	29,948	11,520	33,643	1,384
31									
32	Step-Up Substations	DEM	40,542	23,951	2,696	9,849	3,770	215	62
33	Hi-Volt Transmission	DEM	72,474	40,252	4,530	16,553	6,335	4,700	104
34	Subtransmission	DEM	165,398	79,417	9,486	29,948	11,520	33,643	1,384
35									
36	Transmission Plant	TOTAL	278,414	143,619	16,711	56,350	21,625	38,558	1,551

0106

PLANT IN SERVICE - PLTSVC

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
37	Distribution Plant:								
38	Substations Direct	DEM	4,551	0	0	0	679	3,872	0
39	Substations Common	DEM	103,961	62,852	7,502	23,702	8,514	287	1,104
40	Dist/Subtrans Transfer	DEM	6,760	4,022	480	1,517	578	93	70
41	Substations	TOTAL	115,272	66,874	7,983	25,219	9,771	4,252	1,174
42									
43	Poles Direct	CUST	15,910	0	139	369	38	0	15,364
44	Poles Primary	DEM	102,316	61,857	7,384	23,327	8,379	283	1,087
45	Poles Secondary	DEM	16,995	10,684	1,273	3,959	892	0	187
46	Poles	TOTAL	135,221	72,542	8,795	27,655	9,309	283	16,638
47									
48	OH Lines Direct	CUST	6,064	0	176	424	55	0	5,409
49	OH Lines Primary	DEM	123,622	74,738	8,921	28,185	10,124	342	1,313
50	OH Lines Secondary	DEM	27,780	17,465	2,081	6,471	1,458	0	306
51	OH Lines	TOTAL	157,466	92,203	11,178	35,079	11,637	342	7,028
52									
53	UG Lines Direct	CUST	4,974	0	71	786	232	0	3,885
54	UG Lines Primary	DEM	188,314	110,842	13,451	45,332	16,744	0	1,945
55	UG Lines Secondary	DEM	0	0	0	0	0	0	0
56	UG Lines	TOTAL	193,288	110,842	13,522	46,118	16,976	0	5,830
57									
58	Transformers Direct	CUST	0	0	0	0	0	0	0
59	Transformers Common	DEM	255,917	159,997	19,091	59,782	14,239	0	2,807
60	Transformers	TOTAL	255,917	159,997	19,091	59,782	14,239	0	2,807
61									
62	Services	CUST	108,952	89,985	13,243	5,591	84	0	50
63	Meters	CUST	43,789	28,923	5,787	7,113	970	984	12
64	Installations	CUST	0	0	0	0	0	0	0
65	Street Lighting	CUST	90,409	0	0	0	0	0	90,409
66									
67	Distribution Plant	DEM	830,216	502,457	60,183	192,274	61,606	4,876	8,820
68	Distribution Plant	CUST	270,099	118,908	19,416	14,283	1,379	984	115,129
69									
70	Distribution Plant	TOTAL	1,100,315	621,364	79,600	206,557	62,985	5,860	123,949
71									
72									
73									
74	Prod, Trans, & Dist Plant:								
75	Production	DEM	1,637,806	981,225	109,776	394,754	150,366	0	1,685
76	Production	EGY	251,453	111,646	14,301	69,106	28,352	25,481	2,567
77	Transmission	DEM	113,016	64,202	7,226	26,402	10,105	4,915	167
78	Subtransmission	DEM	165,398	79,417	9,486	29,948	11,520	33,643	1,384
79	Distribution Primary	DEM	529,525	314,311	37,739	122,063	45,018	4,876	5,518
80	Distribution Secondary	DEM	300,692	188,146	22,445	70,211	16,588	0	3,301
81	Distribution	CUST	270,099	118,908	19,416	14,283	1,379	984	115,129
82	Other	CUST	0	0	0	0	0	0	0
83									
84	Prod, Tran, & Dist Plant	TOTAL	3,267,988	1,857,854	220,389	726,766	263,328	69,899	129,752

PLANT IN SERVICE - PLTSVC

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
85	Plus: Communication Equipment								
86	Production	DEM	23,885	14,310	1,601	5,757	2,193	0	25
87	Production	EGY	7,368	3,271	419	2,025	831	747	75
88	Transmission	DEM	12,991	7,215	812	2,967	1,136	842	19
89	Subtransmission	DEM	13,478	6,471	773	2,440	939	2,741	113
90	Distribution Primary	DEM	26,560	15,766	1,893	6,123	2,258	245	277
91	Distribution Secondary	DEM	248	155	19	58	14	0	3
92	Distribution	CUST	2,421	1,066	174	128	12	9	1,032
93	Other	CUST	5,401	4,518	604	166	80	33	1
94	Communication Equipment	TOTAL	92,352	52,772	6,294	19,663	7,462	4,617	1,544
95									
96	Plus: Transportation Equipment								
97	Production	DEM	2,252	1,349	151	543	207	0	2
98	Production	EGY	2,252	1,000	128	619	254	228	23
99	Transmission	DEM	1,264	718	81	295	113	55	2
100	Subtransmission	DEM	2,721	1,307	156	493	190	554	23
101	Distribution Primary	DEM	8,342	4,951	595	1,923	709	77	87
102	Distribution Secondary	DEM	860	538	64	201	47	0	9
103	Distribution	CUST	8,326	3,666	599	440	43	30	3,549
104	Other	CUST	8,678	7,259	971	266	128	53	2
105	Transportation Equipment	TOTAL	34,695	20,787	2,744	4,780	1,690	997	3,697
106									
107	Plus: General & Intangible								
108	Production	DEM	36,935	22,128	2,476	8,902	3,391	0	38
109	Production	EGY	36,515	16,213	2,077	10,035	4,117	3,700	373
110	Transmission	DEM	1,841	1,046	118	430	165	80	3
111	Subtransmission	DEM	3,957	1,900	227	716	276	805	33
112	Distribution Primary	DEM	12,011	7,130	856	2,769	1,021	111	125
113	Distribution Secondary	DEM	1,229	769	92	287	68	0	13
114	Distribution	CUST	11,998	5,282	863	634	61	44	5,114
115	Other	CUST	26,769	22,391	2,994	821	394	163	6
116	General & Intangible	TOTAL	131,255	76,858	9,701	24,595	9,493	4,902	5,705
117									
118	Equals: Plant in Service								
119	Production	DEM	1,700,877	1,019,011	114,004	409,956	156,157	0	1,750
120	Production	EGY	297,588	132,130	16,925	81,785	33,553	30,156	3,039
121	Transmission	DEM	129,112	73,181	8,236	30,095	11,518	5,892	190
122	Subtransmission	DEM	185,553	89,095	10,642	33,597	12,924	37,743	1,553
123	Distribution Primary	DEM	576,438	342,158	41,082	132,877	49,006	5,308	6,007
124	Distribution Secondary	DEM	303,029	189,608	22,619	70,757	16,717	0	3,327
125	Distribution	CUST	292,844	128,921	21,052	15,486	1,495	1,066	124,824
126	Other	CUST	40,847	34,168	4,568	1,252	602	248	9
127			===========	===========	===========	===========	===========	===========	===========
128	PLANT IN SERVICE	TOTAL	3,526,289	2,008,271	239,128	775,804	281,973	80,414	140,699

0108

PLANT HELD FOR FUTURE USE - PLTHFFU

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Plant Held For Future Use:								
2	Production	DEM	1,794	1,075	120	432	165	0	2
3	Production	EGY	150	66	9	41	17	15	2
4	Transmission	DEM	10,119	5,749	647	2,364	905	440	15
5	Subtransmission	DEM	14,809	7,111	849	2,681	1,031	3,012	124
6	Distribution Primary	DEM	5,172	3,070	369	1,192	440	48	54
7	Distribution Secondary	DEM	0	0	0	0	0	0	0
8	Distribution	CUST	0	0	0	0	0	0	0
9	Other	CUST	0	0	0	0	0	0	0
10									
11	PLT HELD FOR FUTURE USE	TOTAL	32,045	17,071	1,994	6,711	2,558	3,515	196

0109

ACCUMULATED RESERVE FOR DEPRECIATION - ARFDEPREC

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Production Reserve:								
2	Steam	DEM	682,892	409,127	45,772	164,595	62,696	0	702
3	Steam	EGY	56,908	25,267	3,237	15,640	6,416	5,767	581
4	Steam	TOTAL	739,799	434,394	49,008	180,234	69,112	5,767	1,283
5									
6	Other	DEM	133,428	79,938	8,943	32,160	12,250	0	137
7	Other	EGY	11,119	4,937	632	3,056	1,254	1,127	114
8	Other	TOTAL	144,547	84,875	9,576	35,215	13,504	1,127	251
9									
10	Production Reserve	DEM	816,319	489,065	54,715	196,754	74,946	0	840
11	Production Reserve	EGY	68,027	30,204	3,869	18,695	7,670	6,893	695
12									
13	Production Reserve	TOTAL	884,346	519,269	58,584	215,450	82,616	6,893	1,534
14									
15									
16	*Transmission Reserve:*								
17	Step-Up Substations	DEM	12,081	7,137	803	2,935	1,123	64	19
18									
19	*High-Volt Transmission*								
20	Substations	DEM	0	0	0	0	0	0	0
21	Lines	DEM	30,366	16,865	1,898	6,936	2,654	1,969	44
22	Hi-Volt.Transmission	TOTAL	30,366	16,865	1,898	6,936	2,654	1,969	44
23									
24	Subtransmission								
25	Substations Direct	DEM	1,440	0	0	0	0	1,440	0
26	Substations Common	DEM	13,811	8,217	981	3,099	1,181	189	143
27	Lines Direct	DEM	8,217	0	0	0	39	8,178	0
28	Lines Common	DEM	21,225	12,628	1,508	4,762	1,815	291	220
29	Subtrans/Dist Transfer	DEM	8,360	5,054	603	1,906	685	23	89
30	Subtransmission	TOTAL	53,054	25,900	3,093	9,767	3,720	10,122	452
31									
32	Step-Up Substations	DEM	12,081	7,137	803	2,935	1,123	64	19
33	Hi-Volt Transmission	DEM	30,366	16,865	1,898	6,936	2,654	1,969	44
34	Subtransmission	DEM	53,054	25,900	3,093	9,767	3,720	10,122	452
35									
36	Transmission Reserve	TOTAL	95,501	49,902	5,795	19,637	7,497	12,155	514

ACCUMULATED RESERVE FOR DEPRECIATION - ARFDEPREC

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
37	Distribution Reserve:								
38	Substations Direct	DEM	1,522	0	0	0	227	1,295	0
39	Substations Common	DEM	34,764	21,017	2,509	7,926	2,847	96	369
40	Dist/Subtrans Transfer	DEM	2,261	1,345	161	507	193	31	23
41	Substations	TOTAL	38,546	22,362	2,669	8,433	3,267	1,422	393
42									
43	Poles Direct	CUST	6,053	0	53	140	14	0	5,845
44	Poles Primary	DEM	38,925	23,533	2,809	8,875	3,188	108	413
45	Poles Secondary	DEM	6,466	4,065	484	1,506	339	0	71
46	Poles	TOTAL	51,444	27,598	3,346	10,521	3,541	108	6,330
47									
48	OH Lines Direct	CUST	2,883	0	84	202	26	0	2,572
49	OH Lines Primary	DEM	58,778	35,535	4,242	13,401	4,814	162	624
50	OH Lines Secondary	DEM	13,208	8,304	989	3,077	693	0	146
51	OH Lines	TOTAL	74,869	43,839	5,315	16,679	5,533	162	3,342
52									
53	UG Lines Direct	CUST	1,255	0	18	198	59	0	981
54	UG Lines Primary	DEM	47,531	27,977	3,395	11,442	4,226	0	491
55	UG Lines Secondary	DEM	0	0	0	0	0	0	0
56	UG Lines	TOTAL	48,786	27,977	3,413	11,640	4,285	0	1,472
57									
58	Transformers Direct	CUST	0	0	0	0	0	0	0
59	Transformers Common	DEM	98,561	61,619	7,353	23,024	5,484	0	1,081
60	Transformers	TOTAL	98,561	61,619	7,353	23,024	5,484	0	1,081
61									
62	Services	CUST	36,813	30,404	4,475	1,889	28	0	17
63	Meters	CUST	16,397	10,830	2,167	2,664	363	368	5
64	Installations	CUST	0	0	0	0	0	0	0
65	Street Lighting	CUST	31,011	0	0	0	0	0	31,011
66									
67	Distribution Reserve	DEM	302,014	183,395	21,941	69,756	22,011	1,692	3,219
68	Distribution Reserve	CUST	94,412	41,234	6,796	5,093	491	368	40,430
69									
70	Distribution Reserve	TOTAL	396,426	224,629	28,737	74,849	22,502	2,060	43,649
71									
72									
73									
74	Prod, Trans, & Dist Reserve:								
75	Production	DEM	816,319	489,065	54,715	196,754	74,946	0	840
76	Production	EGY	68,027	30,204	3,869	18,695	7,670	6,893	695
77	Transmission	DEM	42,447	24,002	2,701	9,871	3,778	2,033	62
78	Subtransmission	DEM	53,054	25,900	3,093	9,767	3,720	10,122	452
79	Distribution Primary	DEM	183,779	109,407	13,115	42,150	15,495	1,692	1,921
80	Distribution Secondary	DEM	118,235	73,988	8,826	27,606	6,516	0	1,298
81	Distribution	CUST	94,412	41,234	6,796	5,093	491	368	40,430
82	Other	CUST	0	0	0	0	0	0	0
83									
84	Prod, Tran, & Dist Reserve	TOTAL	1,376,273	793,799	93,116	309,936	112,615	21,109	45,698

ACCUMULATED RESERVE FOR DEPRECIATION - ARFDEPREC

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
85	Plus: Communication Equipment								
86	Production	DEM	14,785	8,858	991	3,564	1,357	0	15
87	Production	EGY	4,561	2,025	259	1,253	514	462	47
88	Transmission	DEM	8,042	4,466	503	1,837	703	521	12
89	Subtransmission	DEM	8,343	4,006	478	1,511	581	1,697	70
90	Distribution Primary	DEM	16,442	9,759	1,172	3,790	1,398	151	171
91	Distribution Secondary	DEM	154	96	11	36	8	0	2
92	Distribution	CUST	1,499	660	108	79	8	5	639
93	Other	CUST	3,345	2,798	374	103	49	20	1
94	Communication Equipment	TOTAL	57,170	32,669	3,897	12,172	4,619	2,858	956
95									
96	Plus: Transportation Equipment								
97	Production	DEM	878	526	59	212	81	0	1
98	Production	EGY	878	390	50	241	99	89	9
99	Transmission	DEM	493	280	32	115	44	21	1
100	Subtransmission	DEM	1,061	509	61	192	74	216	9
101	Distribution Primary	DEM	3,252	1,931	232	750	277	30	34
102	Distribution Secondary	DEM	335	210	25	78	19	0	4
103	Distribution	CUST	3,246	1,429	233	172	17	12	1,384
104	Other	CUST	3,385	2,831	379	104	50	21	1
105	Transportation Equipment	TOTAL	13,529	8,106	1,070	1,864	659	389	1,442
106									
107	Plus: General & Intangible								
108	Production	DEM	10,886	6,522	730	2,624	999	0	11
109	Production	EGY	10,762	4,778	612	2,958	1,213	1,091	110
110	Transmission	DEM	543	308	35	127	49	24	1
111	Subtransmission	DEM	1,166	560	67	211	81	237	10
112	Distribution Primary	DEM	3,540	2,101	252	816	301	33	37
113	Distribution Secondary	DEM	362	227	27	85	20	0	4
114	Distribution	CUST	3,536	1,557	254	187	18	13	1,507
115	Other	CUST	7,893	6,603	883	242	116	48	2
116	General & Intangible	TOTAL	38,689	22,656	2,860	7,249	2,798	1,445	1,682
117									
118	Equals: Depreciation Reserve								
119	Production	DEM	842,869	504,970	56,495	203,153	77,383	0	867
120	Production	EGY	84,228	37,397	4,790	23,148	9,497	8,535	860
121	Transmission	DEM	51,524	29,057	3,270	11,949	4,573	2,600	75
122	Subtransmission	DEM	63,624	30,975	3,699	11,681	4,456	12,272	540
123	Distribution Primary	DEM	207,014	123,198	14,771	47,506	17,470	1,906	2,163
124	Distribution Secondary	DEM	119,086	74,520	8,890	27,805	6,563	0	1,308
125	Distribution	CUST	102,693	44,880	7,391	5,531	533	398	43,959
126	Other	CUST	14,623	12,232	1,635	448	215	89	3
127			==========	==========	==========	==========	==========	==========	==========
128	DEPRECIATION RESERVE	TOTAL	1,485,661	857,230	100,942	331,221	120,691	25,800	49,776

WORKING CAPITAL - WORKCAP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Materials & Supplies								
2	Production	DEM	23,671	14,181	1,587	5,705	2,173	0	24
3	Production	EGY	3,634	1,614	207	999	410	368	37
4	Transmission	DEM	1,560	884	100	364	139	71	2
5	Subtransmission	DEM	2,279	1,094	131	413	159	464	19
6	Distribution Primary	DEM	7,297	4,331	520	1,682	620	67	76
7	Distribution Secondary	DEM	4,144	2,593	309	968	229	0	45
8	Distribution	CUST	3,722	1,639	268	197	19	14	1,587
9	Other	CUST	0	0	0	0	0	0	0
10	Materials & Supplies	TOTAL	46,307	26,336	3,120	10,327	3,749	984	1,791
11									
12	Plus: Cash								
13	Production	DEM	(432)	(259)	(29)	(104)	(40)	0	(0)
14	Production	EGY	(441)	(196)	(25)	(121)	(50)	(45)	(5)
15	Transmission	DEM	(22)	(13)	(1)	(5)	(2)	(1)	(0)
16	Subtransmission	DEM	(48)	(23)	(3)	(9)	(3)	(10)	(0)
17	Distribution Primary	DEM	(146)	(87)	(10)	(34)	(12)	(1)	(2)
18	Distribution Secondary	DEM	(15)	(9)	(1)	(3)	(1)	0	(0)
19	Distribution	CUST	(146)	(64)	(10)	(8)	(1)	(1)	(62)
20	Other	CUST	(325)	(272)	(36)	(10)	(5)	(2)	(0)
21	Cash	TOTAL	(1,576)	(923)	(117)	(294)	(114)	(59)	(69)
22									
23	Plus: Net Additions								
24	Production	DEM	87,568	52,463	5,869	21,106	8,040	0	90
25	Production	EGY	1,974	876	112	543	223	200	20
26	Transmission	DEM	5,958	3,377	380	1,389	532	271	9
27	Subtransmission	DEM	8,573	4,117	492	1,552	597	1,744	72
28	Distribution Primary	DEM	24,886	14,772	1,774	5,737	2,116	229	259
29	Distribution Secondary	DEM	12,966	8,113	968	3,028	715	0	142
30	Distribution	CUST	12,530	5,516	901	663	64	46	5,341
31	Other	CUST	1,748	1,462	195	54	26	11	0
32	Additions	TOTAL	156,203	90,696	10,691	34,070	12,312	2,500	5,934
33									
34	Less: Net Deductions								
35	Production	DEM	159,275	95,423	10,676	38,389	14,623	0	164
36	Production	EGY	3,591	1,594	204	987	405	364	37
37	Transmission	DEM	10,836	6,143	691	2,526	967	493	16
38	Subtransmission	DEM	15,594	7,487	894	2,823	1,086	3,172	131
39	Distribution Primary	DEM	45,265	26,868	3,226	10,434	3,848	417	472
40	Distribution Secondary	DEM	23,584	14,757	1,760	5,507	1,301	0	259
41	Distribution	CUST	22,791	10,034	1,638	1,205	116	83	9,715
42	Other	CUST	3,179	2,659	356	97	47	19	1
43	Deductions	TOTAL	284,114	164,965	19,446	61,969	22,393	4,548	10,793
44									
45	Plus: Fuel Inventory								
46	Production	EGY	72,273	32,089	4,111	19,862	8,149	7,324	738
47	Fuel Inventory	TOTAL	72,273	32,089	4,111	19,862	8,149	7,324	738
48									
49	Equals: Working Capital								
50	Production	DEM	(48,469)	(29,038)	(3,249)	(11,682)	(4,450)	0	(50)
51	Production	EGY	73,850	32,789	4,200	20,296	8,327	7,484	754
52	Transmission	DEM	(3,341)	(1,894)	(213)	(779)	(298)	(152)	(5)
53	Subtransmission	DEM	(4,789)	(2,300)	(275)	(867)	(334)	(974)	(40)
54	Distribution Primary	DEM	(13,228)	(7,852)	(943)	(3,049)	(1,125)	(122)	(138)
55	Distribution Secondary	DEM	(6,489)	(4,060)	(484)	(1,515)	(358)	0	(71)
56	Distribution	CUST	(6,684)	(2,943)	(481)	(353)	(34)	(24)	(2,849)
57	Other	CUST	(1,756)	(1,469)	(196)	(54)	(26)	(11)	(0)
58			==========	==========	==========	==========	==========	==========	==========
59	WORKING CAPITAL	TOTAL	(10,907)	(16,766)	(1,640)	1,996	1,702	6,201	(2,400)

0113

CONSTRUCTION WORK IN PROGRESS - CWIP

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Production CWIP:								
2	Steam	DEM	7,945	4,760	533	1,915	729	0	8
3	Steam	EGY	662	294	38	182	75	67	7
4	Steam	TOTAL	8,607	5,054	570	2,097	804	67	15
5									
6	Other	DEM	33,166	19,870	2,223	7,994	3,045	0	34
7	Other	EGY	2,764	1,227	157	760	312	280	28
8	Other	TOTAL	35,930	21,097	2,380	8,754	3,357	280	62
9									
10	Production CWIP	DEM	41,111	24,630	2,756	9,909	3,774	0	42
11	Production CWIP	EGY	3,426	1,521	195	942	386	347	35
12									
13	Production CWIP	TOTAL	44,537	26,151	2,950	10,850	4,161	347	77
14									
15	Transmission CWIP:								
16	Step-Up Substations	DEM	162	96	11	39	15	1	0
17	Hi-Volt Transmission	DEM	290	161	18	66	25	19	0
18	Subtransmission Direct	DEM	128	0	0	0	0	128	0
19	Subtransmission Common	DEM	534	318	38	120	46	7	6
20									
21	Transmission CWIP	TOTAL	1,115	575	67	226	86	155	6
22									
23	Distribution CWIP:								
24	Distribution Primary	DEM	556	330	40	128	47	5	6
25	Distribution Secondary	DEM	316	197	24	74	17	0	3
26	Distribution	CUST	0	0	0	0	0	0	0
27									
28	Distribution CWIP	TOTAL	871	527	63	202	65	5	9
29									
30									
31	Prod, Tran, & Dist CWIP:								
32	Production	DEM	41,111	24,630	2,756	9,909	3,774	0	42
33	Production	EGY	3,426	1,521	195	942	386	347	35
34	Transmission	DEM	453	257	29	106	40	20	1
35	Subtransmission	DEM	663	318	38	120	46	135	6
36	Distribution Primary	DEM	556	330	40	128	47	5	6
37	Distribution Secondary	DEM	316	197	24	74	17	0	3
38	Distribution	CUST	0	0	0	0	0	0	0
39	Other	CUST	0	0	0	0	0	0	0
40									
41	Prod, Tran, & Dist CWIP	TOTAL	46,524	27,254	3,080	11,278	4,312	507	93
42									
43	Plus: General CWIP								
44	Production	DEM	2,226	1,334	149	537	204	0	2
45	Production	EGY	2,201	977	125	605	248	223	22
46	Transmission	DEM	111	62	7	25	10	7	0
47	Subtransmission	DEM	239	142	17	54	20	3	2
48	Distribution Primary	DEM	724	430	52	167	62	7	6
49	Distribution Secondary	DEM	74	46	6	17	4	0	1
50	Distribution	CUST	723	478	96	117	16	16	0
51	Other	CUST	1,614	1,350	180	49	24	10	0
52	General CWIP	TOTAL	7,912	4,818	631	1,572	588	266	36
53									
54	Equals: Total CWIP								
55	Production	DEM	43,338	25,964	2,905	10,446	3,979	0	45
56	Production	EGY	5,627	2,498	320	1,546	634	570	57
57	Transmission	DEM	564	319	36	131	50	27	1
58	Subtransmission	DEM	901	460	55	173	66	139	8
59	Distribution Primary	DEM	1,280	760	91	295	109	12	13
60	Distribution Secondary	DEM	390	244	29	91	21	0	4
61	Distribution	CUST	723	478	96	117	16	16	0
62	Other	CUST	1,614	1,350	180	49	24	10	0
63									
64	CWIP	TOTAL	54,436	32,072	3,712	12,849	4,900	774	129

CLASS RATE OF RETURN

DERIVATION OF D-E-C COSTS - DEC_COSTS

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Functionalized Revenue Requirements:								
2	Production	DEM	$278,884	$162,853	$18,912	$71,300	$25,548	$0	$271
3	Production	EGY	109,272	46,125	6,110	30,809	11,954	13,243	1,032
4	Transmission	DEM	18,186	9,918	1,182	4,636	1,618	806	25
5	Subtransmission	DEM	37,742	17,019	2,124	7,089	2,538	8,686	286
6	Distribution Primary	DEM	93,990	53,838	6,778	23,281	7,977	1,207	908
7	Distribution Secondary	DEM	46,713	28,376	3,545	11,748	2,564	0	479
8	Distribution	CUST	57,548	25,713	4,345	3,431	326	294	23,438
9	Other	CUST	33,946	25,598	3,877	1,992	1,728	740	10
10									
11	TOTAL BASE REVENUE REQUIREMENTS		$676,281	$369,439	$46,874	$154,287	$54,255	$24,976	$26,449
12									
13									
14	Aggregated Revenue Reqs:								
15	TOTAL DEMAND		$475,515	$272,004	$32,542	$118,054	$40,247	$10,699	$1,969
16	TOTAL ENERGY		109,272	46,125	6,110	30,809	11,954	13,243	1,032
17	TOTAL CUSTOMER		91,494	51,311	8,222	5,424	2,054	1,034	23,449
18									
19	Tot Base Revenue Requirements		$676,281	$369,439	$46,874	$154,287	$54,255	$24,976	$26,449
20									
21									
22	Billing Units (Annual) Except:								
23	For KW Class 69KV&HIKV-KW/10		10,584,427	7,350,569	941,579	1,090,300	403,451	629,489	169,039
24	For KW Class 13KV - KW/10		10,584,427	7,350,569	941,579	1,090,300	403,451	629,489	169,039
25	For KW Class LOKV - KW/10		9,954,938	7,350,569	941,579	1,090,300	403,451	0	169,039
26	Energy - Total Company - MWH		16,634,654	7,350,569	941,579	4,553,125	1,887,990	1,732,352	169,039
27	For Bills - 12 Mos. Bills/10		983,516	590,478	67,438	13,520	208	85	311,788
28									
29			<—Demand in Cents/KWH—			<—Demand in $/KW—		—>	
30	Functionalized Unit Costs:								
31	Prod-D; GS(L)D, IS- $/KW; c/KWH		1.68	2.22	2.01	6.54	6.33	0.00	0.16
32	Prod-E; All Classes; c/KWH		0.66	0.63	0.85	0.88	0.63	0.76	0.61
33	HIKV-D;GS(L)D,IS-$/KW; c/KWH		0.11	0.13	0.13	0.43	0.40	0.13	0.01
34	69KV-D;GS(L)D,IS-$/KW; c/KWH		0.23	0.23	0.23	0.65	0.63	1.38	0.17
35	13KV-D;GS(L)D,IS-$/KW; c/KWH		0.57	0.73	0.72	2.14	1.98	0.19	0.54
36	LOKV-D;GS(L)D,IS-$/KW; c/KWH		0.28	0.39	0.38	1.08	0.84	0.00	0.28
37	Dist Cust——$/Bill		5.85	4.35	6.44	25.38	157.00	344.91	7.52
38	Other Cust——$/Bill		3.45	4.34	5.75	14.74	832.39	868.56	0.00
39									
40	Aggregated Mo. Unit Costs:								
41	DEMAND; GS(L)D,IS-$/KW; c/KWH		2.86	3.70	3.46	10.63	9.98	1.70	1.16
42	ENERGY—— c/KWH		0.66	0.63	0.65	0.68	0.63	0.76	0.61
43	CUSTOMER——$/Bill		9.30	8.69	12.19	40.12	989.39	-	7.52
44									
45	Production - Dem; All Classes - $/KW		[redacted]						
46	Production - Energy; All Classes - $/KW								
47	Transmission - Dem; All Classes - $/KW								
48	Total - Dem & Energy; All Classes - $/KW								

DERIVATION OF D-E-C COSTS - DEC_COSTS

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

This section calculates Functionalized Revenue
Requirement for Demand, Energy, Cust Costs

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
1	Rate Base								
2	Production	DEM	854,672	512,042	57,286	205,998	78,467	0	879
3	Production	EGY	292,986	130,087	16,664	80,520	33,034	29,690	2,992
4	Transmission	DEM	84,929	48,297	5,436	19,862	7,602	3,608	125
5	Subtransmission	DEM	132,851	63,391	7,572	23,904	9,232	27,648	1,104
6	Distribution Primary	DEM	362,649	214,938	25,828	83,809	30,980	3,340	3,773
7	Distribution Secondary	DEM	177,843	111,271	13,274	41,528	9,818	0	1,952
8	Distribution	CUST	184,190	81,576	13,275	9,719	944	660	78,016
9	Other	CUST	26,081	21,816	2,917	800	384	158	6
10									
11	Total Rate Base		2,116,202	1,183,418	142,251	466,140	170,441	65,104	88,848
12									
13	Multiplied by ROR		8.76%	8.18%	8.92%	9.90%	8.64%	12.79%	7.58%
14									
15	Equals Return on Rate Base								
16	Production	DEM	74,251	41,886	5,112	20,403	6,783	0	67
17	Production	EGY	26,983	10,641	1,487	7,975	2,855	3,797	227
18	Transmission	DEM	7,531	3,951	485	1,967	657	461	9
19	Subtransmission	DEM	12,647	5,186	676	2,368	796	3,536	84
20	Distribution Primary	DEM	31,578	17,583	2,305	8,301	2,676	427	286
21	Distribution Secondary	DEM	15,397	9,102	1,185	4,113	849	0	148
22	Distribution	CUST	14,901	6,673	1,185	963	82	84	5,915
23	Other	CUST	2,178	1,785	260	79	33	20	0
24									
25	Total Return on Rate Base		185,468	96,807	12,694	46,170	14,733	8,327	6,736
26									
27	Plus: Adjustments to Income Taxes								
28	Production	DEM	(2,988)	(1,790)	(200)	(720)	(274)	0	(3)
29	Production	EGY	(298)	(132)	(17)	(82)	(34)	(30)	(3)
30	Transmission	DEM	(248)	(141)	(16)	(58)	(22)	(11)	(0)
31	Subtransmission	DEM	(387)	(186)	(22)	(70)	(27)	(79)	(3)
32	Distribution Primary	DEM	(1,057)	(627)	(75)	(244)	(90)	(10)	(11)
33	Distribution Secondary	DEM	(518)	(324)	(39)	(121)	(29)	0	(6)
34	Distribution	CUST	(537)	(236)	(39)	(26)	(3)	(2)	(229)
35	Other	CUST	(76)	(63)	(8)	(2)	(1)	(0)	(0)
36									
37	Total Adjustments to Income Taxes		(6,109)	(3,500)	(416)	(1,325)	(479)	(132)	(255)
38									
39	Less: Deductions from Operating Income								
40	Production	DEM	18,113	10,852	1,214	4,366	1,663	0	19
41	Production	EGY	51,881	23,035	2,951	14,258	5,850	5,257	530
42	Transmission	DEM	1,382	783	88	322	123	63	2
43	Subtransmission	DEM	2,213	1,037	124	391	152	492	18
44	Distribution Primary	DEM	5,774	3,417	411	1,339	495	52	60
45	Distribution Secondary	DEM	2,758	1,725	206	644	153	0	30
46	Distribution	CUST	2,931	1,261	205	147	14	9	1,295
47	Other	CUST	416	354	46	11	4	2	0
48									
49	Total Deductions from Oper Income		85,468	42,464	5,244	21,478	8,454	5,875	1,954
50									
51	Less: Fla Inc Adjustments								
52	Production	DEM	(14,137)	(8,470)	(948)	(3,407)	(1,298)	0	(15)
53	Production	EGY	(4,846)	(2,152)	(276)	(1,332)	(548)	(491)	(49)
54	Transmission	DEM	(1,405)	(799)	(90)	(329)	(126)	(60)	(2)
55	Subtransmission	DEM	(2,197)	(1,049)	(125)	(395)	(153)	(457)	(18)
56	Distribution Primary	DEM	(5,999)	(3,555)	(427)	(1,386)	(512)	(55)	(62)
57	Distribution Secondary	DEM	(2,942)	(1,841)	(220)	(687)	(162)	0	(32)
58	Distribution	CUST	(3,047)	(1,349)	(220)	(161)	(16)	(11)	(1,290)
59	Other	CUST	(431)	(361)	(48)	(13)	(6)	(3)	(0)
60									
61	Total Fla Income Adjustments		(35,004)	(19,575)	(2,353)	(7,710)	(2,819)	(1,077)	(1,470)

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DERIVATION OF D-E-C COSTS - DEC_COSTS

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

This section calculates Functionalized Revenue
Requirement for Demand, Energy, Cust Costs

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
62	Less: Federal Income Adjustments								
63	Production	DEM	0	0	0	0	0	0	0
64	Production	EGY	0	0	0	0	0	0	0
65	Transmission	DEM	0	0	0	0	0	0	0
66	Subtransmission	DEM	0	0	0	0	0	0	0
67	Distribution Primary	DEM	0	0	0	0	0	0	0
68	Distribution Secondary	DEM	0	0	0	0	0	0	0
69	Distribution	CUST	0	0	0	0	0	0	0
70	Other	CUST	0	0	0	0	0	0	0
71									
72	Total Federal Income Adjustments		0	0	0	0	0	0	0
73									
74	Equals Operating Income After FIT								
75	Production	DEM	67,286	37,714	4,645	18,725	6,143	0	59
76	Production	EGY	(20,349)	(10,374)	(1,205)	(5,033)	(2,481)	(999)	(256)
77	Transmission	DEM	7,306	3,826	471	1,916	637	447	9
78	Subtransmission	DEM	12,244	5,012	655	2,302	772	3,423	81
79	Distribution Primary	DEM	30,746	17,093	2,246	8,105	2,603	421	278
80	Distribution Secondary	DEM	15,062	8,894	1,160	4,035	829	0	144
81	Distribution	CUST	14,480	6,525	1,161	948	81	84	5,681
82	Other	CUST	2,118	1,728	254	79	35	21	0
83									
84	Total Operating Inc After FIT		128,893	70,418	9,386	31,077	8,619	3,397	5,996
85									
86	Plus FIT @ 35.00%								
87	Production	DEM	36,231	20,308	2,501	10,083	3,308	0	32
88	Production	EGY	(10,957)	(5,586)	(649)	(2,710)	(1,336)	(538)	(138)
89	Transmission	DEM	3,934	2,060	254	1,032	343	241	5
90	Subtransmission	DEM	6,593	2,699	353	1,240	416	1,843	43
91	Distribution Primary	DEM	16,555	9,204	1,209	4,364	1,402	227	149
92	Distribution Secondary	DEM	8,110	4,789	624	2,173	446	0	78
93	Distribution	CUST	7,797	3,513	625	511	43	45	3,059
94	Other	CUST	1,140	931	137	43	19	11	0
95									
96	Total Fed. Inc. Tax @ 35.00%		69,404	37,917	5,054	16,734	4,641	1,829	3,229
97									
98	Equals Operating Income Before FIT								
99	Production	DEM	103,518	58,021	7,146	28,807	9,451	0	92
100	Production	EGY	(31,306)	(15,960)	(1,854)	(7,743)	(3,817)	(1,537)	(395)
101	Transmission	DEM	11,240	5,886	725	2,947	981	687	14
102	Subtransmission	DEM	18,837	7,710	1,008	3,542	1,188	5,266	124
103	Distribution Primary	DEM	47,301	26,298	3,455	12,469	4,005	648	427
104	Distribution Secondary	DEM	23,172	13,683	1,784	6,207	1,275	0	222
105	Distribution	CUST	22,277	10,038	1,786	1,459	124	130	8,740
106	Other	CUST	3,258	2,659	391	122	53	32	1
107									
108	Total Oper Income Before FIT		198,296	108,335	14,440	47,811	13,260	5,226	9,225

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DERIVATION OF D-E-C COSTS - DEC_COSTS

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

This section calculates Functionalized Revenue Requirement for Demand, Energy, Cust Costs

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
109	Plus Adjustments for FIT								
110	Production	DEM	0	0	0	0	0	0	0
111	Production	EGY	0	0	0	0	0	0	0
112	Transmission	DEM	0	0	0	0	0	0	0
113	Subtransmission	DEM	0	0	0	0	0	0	0
114	Distribution Primary	DEM	0	0	0	0	0	0	0
115	Distribution Secondary	DEM	0	0	0	0	0	0	0
116	Distribution	CUST	0	0	0	0	0	0	0
117	Other	CUST	0	0	0	0	0	0	0
118									
119	Total Adjustments for FIT		0	0	0	0	0	0	0
120									
121	Equals Operating Income After Fla Tax								
122	Production	DEM	103,518	58,021	7,146	28,807	9,451	0	92
123	Production	EGY	(31,306)	(15,960)	(1,854)	(7,743)	(3,817)	(1,537)	(395)
124	Transmission	DEM	11,240	5,886	725	2,947	981	687	14
125	Subtransmission	DEM	18,837	7,710	1,008	3,542	1,188	5,266	124
126	Distribution Primary	DEM	47,301	26,298	3,455	12,469	4,005	648	427
127	Distribution Secondary	DEM	23,172	13,683	1,784	6,207	1,275	0	222
128	Distribution	CUST	22,277	10,038	1,786	1,459	124	130	8,740
129	Other	CUST	3,258	2,659	391	122	53	32	1
130									
131	Total Oper. Income After Fla Tax		198,296	108,335	14,440	47,811	13,260	5,226	9,225
132									
133	Plus SIT @ 5.50%								
134	Production	DEM	6,023	3,376	416	1,676	550	0	5
135	Production	EGY	(1,821)	(929)	(108)	(450)	(222)	(89)	(23)
136	Transmission	DEM	654	342	42	171	57	40	1
137	Subtransmission	DEM	1,096	449	59	206	69	306	7
138	Distribution Primary	DEM	2,752	1,530	201	725	233	38	25
139	Distribution Secondary	DEM	1,348	796	104	361	74	0	13
140	Distribution	CUST	1,296	584	104	85	7	8	508
141	Other	CUST	190	155	23	7	3	2	0
142									
143	Total State Inc. Tax @ 5.50%		11,537	6,303	840	2,782	771	304	537
144									
145	Equals Oper. Income Before Fla Tax								
146	Production	DEM	109,540	61,397	7,562	30,483	10,001	0	97
147	Production	EGY	(33,128)	(16,889)	(1,962)	(8,193)	(4,039)	(1,626)	(418)
148	Transmission	DEM	11,894	6,228	767	3,119	1,038	727	15
149	Subtransmission	DEM	19,933	8,159	1,066	3,748	1,257	5,572	131
150	Distribution Primary	DEM	50,053	27,828	3,656	13,195	4,238	686	452
151	Distribution Secondary	DEM	24,520	14,479	1,888	6,568	1,350	0	235
152	Distribution	CUST	23,573	10,622	1,889	1,544	131	137	9,249
153	Other	CUST	3,447	2,814	414	129	56	34	1
154									
155	Total Oper. Income Before Fla Tax		209,833	114,838	15,280	50,592	14,031	5,530	9,762
156									
157	Plus Adjustments for Fla Tax								
158	Production	DEM	(14,137)	(8,470)	(948)	(3,407)	(1,298)	0	(15)
159	Production	EGY	(4,846)	(2,152)	(276)	(1,332)	(546)	(491)	(49)
160	Transmission	DEM	(1,405)	(799)	(90)	(329)	(126)	(60)	(2)
161	Subtransmission	DEM	(2,197)	(1,049)	(125)	(395)	(153)	(457)	(18)
162	Distribution Primary	DEM	(5,999)	(3,555)	(427)	(1,386)	(512)	(55)	(62)
163	Distribution Secondary	DEM	(2,942)	(1,841)	(220)	(687)	(162)	0	(32)
164	Distribution	CUST	(3,047)	(1,349)	(220)	(161)	(16)	(11)	(1,290)
165	Other	CUST	(431)	(361)	(48)	(13)	(6)	(3)	(0)
166									
167	Total Adjustments for Fla Tax		(35,004)	(19,575)	(2,353)	(7,710)	(2,819)	(1,077)	(1,470)

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DERIVATION OF D-E-C COSTS - DEC_COSTS

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

This section calculates Functionalized Revenue
Requirement for Demand, Energy, Cust Costs

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
168	Plus Deductions from Oper Income								
169	Production	DEM	18,113	10,852	1,214	4,366	1,663	0	19
170	Production	EGY	51,881	23,035	2,951	14,258	5,850	5,257	530
171	Transmission	DEM	1,382	783	88	322	123	63	2
172	Subtransmission	DEM	2,213	1,037	124	391	152	492	18
173	Distribution Primary	DEM	5,774	3,417	411	1,339	495	52	60
174	Distribution Secondary	DEM	2,758	1,725	206	644	153	0	30
175	Distribution	CUST	2,931	1,261	205	147	14	9	1,295
176	Other	CUST	416	354	46	11	4	2	0
177									
178	Total Deductions from Oper Income		85,468	42,464	5,244	21,478	8,454	5,875	1,954
179									
180	Equals Operating Income Before Taxes								
181	Production	DEM	113,516	63,779	7,828	31,442	10,366	0	101
182	Production	EGY	13,907	3,994	713	4,733	1,264	3,140	63
183	Transmission	DEM	11,871	6,213	765	3,112	1,035	731	15
184	Subtransmission	DEM	19,949	8,147	1,065	3,743	1,256	5,607	131
185	Distribution Primary	DEM	49,828	27,689	3,640	13,147	4,221	682	449
186	Distribution Secondary	DEM	24,337	14,363	1,874	6,526	1,341	0	233
187	Distribution	CUST	23,458	10,534	1,875	1,530	130	135	9,254
188	Other	CUST	3,432	2,807	411	127	54	33	1
189									
190	Total Oper. Income Before Taxes		260,297	137,527	18,171	64,360	19,666	10,328	10,247
191									
192	Plus Taxes Other Than Income								
193	Production	DEM	19,230	11,521	1,289	4,635	1,765	0	20
194	Production	EGY	5,549	2,464	316	1,525	626	562	57
195	Transmission	DEM	1,509	858	97	353	135	65	2
196	Subtransmission	DEM	2,259	1,096	131	413	159	441	19
197	Distribution Primary	DEM	6,678	3,966	476	1,537	567	63	70
198	Distribution Secondary	DEM	3,168	1,983	237	740	174	0	35
199	Distribution	CUST	3,519	1,591	259	194	19	14	1,441
200	Other	CUST	1,785	1,402	210	84	62	26	0
201									
202	Total Taxes Other Than Income		43,697	24,880	3,014	9,482	3,507	1,171	1,643
203									
204	Plus Deprec. & Amort. Expense								
205	Production	DEM	71,456	42,810	4,789	17,223	6,560	0	74
206	Production	EGY	14,665	6,511	834	4,030	1,653	1,486	150
207	Transmission	DEM	4,761	2,705	304	1,112	426	207	7
208	Subtransmission	DEM	6,598	3,168	378	1,195	460	1,342	55
209	Distribution Primary	DEM	21,238	12,631	1,515	4,880	1,796	194	222
210	Distribution Secondary	DEM	13,050	8,165	974	3,047	720	0	143
211	Distribution	CUST	11,744	4,156	678	492	46	32	6,340
212	Other	CUST	3,720	3,112	416	114	55	23	1
213									
214	Total Deprec. & Amort. Expense		147,232	83,258	9,889	32,093	11,716	3,284	6,991
215									
216	Plus Other Expenses								
217	Production	DEM	(53)	(31)	(4)	(13)	(5)	0	(0)
218	Production	EGY	(9)	(4)	(1)	(3)	(1)	(1)	(0)
219	Transmission	DEM	(4)	(2)	(0)	(1)	(0)	(0)	(0)
220	Subtransmission	DEM	(6)	(3)	(0)	(1)	(0)	(1)	(0)
221	Distribution Primary	DEM	(18)	(11)	(1)	(4)	(2)	(0)	(0)
222	Distribution Secondary	DEM	(9)	(6)	(1)	(2)	(1)	0	(0)
223	Distribution	CUST	(9)	(4)	(1)	(0)	(0)	(0)	(4)
224	Other	CUST	(1)	(1)	(0)	(0)	(0)	(0)	(0)
225									
226	Total Other Expenses		(109)	(62)	(7)	(24)	(9)	(3)	(4)
227									
228	Plus Oper. & Maint. Expense								
229	Production	DEM	75,010	44,939	5,028	18,079	6,887	0	77
230	Production	EGY	74,154	32,925	4,218	20,379	8,361	7,514	757
231	Transmission	DEM	4,560	2,651	298	1,090	417	97	7
232	Subtransmission	DEM	8,966	4,624	552	1,744	667	1,298	81
233	Distribution Primary	DEM	28,927	17,218	2,062	6,608	2,432	304	302
234	Distribution Secondary	DEM	6,205	3,895	464	1,447	331	0	68
235	Distribution	CUST	18,872	9,460	1,538	1,222	132	113	6,407
236	Other	CUST	38,907	30,017	4,639	2,020	1,563	661	8
237									
238	Total Oper. & Maint. Expense		255,601	145,728	18,800	52,589	20,790	9,986	7,708

DERIVATION OF D-E-C COSTS - DEC_COSTS

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

This section calculates Functionalized Revenue
Requirement for Demand, Energy, Cust Costs

Line #			Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible IS & SBI	Lighting SL & OL
239	Plus: Fuel & Power Transactions								
240	Production	DEM	0	0	0	0	0	0	0
241	Production	EGY	11,746	5,215	668	3,228	1,324	1,190	120
242									
243	Total Fuel & Power Transactions		11,746	5,215	668	3,228	1,324	1,190	120
244									
245	Equals Total Rev. Less Rev. Taxes								
246	Production	DEM	279,159	163,017	18,931	71,366	25,574	0	271
247	Production	EGY	120,011	51,105	6,748	33,893	13,227	13,892	1,146
248	Transmission	DEM	22,698	12,424	1,464	5,667	2,013	1,099	31
249	Subtransmission	DEM	37,765	17,033	2,126	7,094	2,540	8,686	286
250	Distribution Primary	DEM	106,654	61,493	7,692	26,169	9,015	1,243	1,043
251	Distribution Secondary	DEM	46,751	28,400	3,548	11,757	2,566	0	479
252	Distribution	CUST	57,583	25,737	4,350	3,437	327	295	23,438
253	Other	CUST	47,843	37,336	5,676	2,345	1,733	742	10
254									
255	Total Rev. Less Rev. Taxes		718,465	396,546	50,535	161,728	56,995	25,957	26,705
256									
257	Plus Revenue Taxes								
258	Production	DEM	0	0	0	0	0	0	0
259	Production	EGY	0	0	0	0	0	0	0
260	Transmission	DEM	0	0	0	0	0	0	0
261	Subtransmission	DEM	0	0	0	0	0	0	0
262	Distribution Primary	DEM	0	0	0	0	0	0	0
263	Distribution Secondary	DEM	0	0	0	0	0	0	0
264	Distribution	CUST	0	0	0	0	0	0	0
265	Other	CUST	0	0	0	0	0	0	0
266									
267	Total Revenue Taxes		0	0	0	0	0	0	0
268									
269	Equals Total Revenues								
270	Production	DEM	279,159	163,017	18,931	71,366	25,574	0	271
271	Production	EGY	120,011	51,105	6,748	33,893	13,227	13,892	1,146
272	Transmission	DEM	22,698	12,424	1,464	5,667	2,013	1,099	31
273	Subtransmission	DEM	37,765	17,033	2,126	7,094	2,540	8,686	286
274	Distribution Primary	DEM	106,654	61,493	7,692	26,169	9,015	1,243	1,043
275	Distribution Secondary	DEM	46,751	28,400	3,548	11,757	2,566	0	479
276	Distribution	CUST	57,583	25,737	4,350	3,437	327	295	23,438
277	Other	CUST	47,843	37,336	5,676	2,345	1,733	742	10
278									
279	Total Revenues		718,465	396,546	50,535	161,728	56,995	25,957	26,705
280									
281	Less Rev. Other than Sales								
282	Production	DEM	275	165	18	66	25	0	0
283	Production	EGY	10,739	4,981	638	3,084	1,273	649	115
284	Transmission	DEM	4,512	2,506	282	1,031	394	293	7
285	Subtransmission	DEM	23	14	2	5	2	0	0
286	Distribution Primary	DEM	12,664	7,656	914	2,888	1,037	35	134
287	Distribution Secondary	DEM	37	23	3	9	2	0	0
288	Distribution	CUST	36	24	5	6	1	1	0
289	Other	CUST	13,897	11,738	1,799	352	5	2	0
290									
291	Total Rev. Other than Sales		42,184	27,106	3,661	7,441	2,740	980	256
292									
293	Equals Sales Revenue (Functionalized Revenue Requirement)								
294	Production	DEM	278,884	162,853	18,912	71,300	25,548	0	271
295	Production	EGY	109,272	46,125	6,110	30,809	11,954	13,243	1,032
296	Transmission	DEM	18,186	9,918	1,182	4,636	1,618	806	25
297	Subtransmission	DEM	37,742	17,019	2,124	7,089	2,538	8,686	286
298	Distribution Primary	DEM	93,990	53,836	6,778	23,281	7,977	1,207	908
299	Distribution Secondary	DEM	46,713	28,376	3,545	11,748	2,564	0	479
300	Distribution	CUST	57,548	25,713	4,345	3,431	326	294	23,438
301	Other	CUST	33,946	25,598	3,877	1,992	1,728	740	10
302									
303	Total Sales Revenue		676,281	369,439	46,874	154,287	54,255	24,976	26,449
304	(Functionalized Revenue Requirements)								

ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
PLTSVC	2	Steam	DEM	1,075,574	Allocation Factor #	101	12 Coincident Peak (No I/S)
PLTSVC	3	Steam	EGY	204,600	Allocation Factor #	201	MWH at Generation
PLTSVC	6	Other	DEM	562,232	Allocation Factor #	101	12 Coincident Peak (No I/S)
PLTSVC	7	Other	EGY	46,853	Allocation Factor #	201	MWH at Generation
PLTSVC	17	Step-Up Subst.	DEM	40,542	Allocation Factor #	121	12 Coinc. Peak & 1/13th (I/S-1/13th)
PLTSVC	20	Substations	DEM	0	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
PLTSVC	21	Lines	DEM	72,474	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
PLTSVC	25	Subst. Direct	DEM	4,770	Allocation Factor #	107	Subtrans. Subst. - Dir. Alloc.
PLTSVC	26	Subst. Common	DEM	71,768	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
PLTSVC	27	Lines Direct	DEM	27,224	Allocation Factor #	108	Subtrans Lines - Dir. Alloc.
PLTSVC	28	Lines Common	DEM	56,944	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
PLTSVC	29	Subtrans/Dist Trans	DEM	4,692	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
PLTSVC	38	Subst. Direct	DEM	4,551	Allocation Factor #	109	Dist. Subst. Demand - Dir. Alloc.
PLTSVC	39	Subst. Common	DEM	103,961	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
PLTSVC	40	Dist/Subtrans Trans	DEM	6,760	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
PLTSVC	43	Poles Direct	CUST	15,910	Allocation Factor #	303	Specific Poles - Dir. Alloc.
PLTSVC	44	Poles Primary	DEM	102,316	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
PLTSVC	45	Poles Secondary	DEM	16,995	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
PLTSVC	48	OH Lines Direct	CUST	6,064	Allocation Factor #	304	Specific OH Lines - Dir. Alloc.
PLTSVC	49	OH Lines Primary	DEM	123,622	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
PLTSVC	50	OH Lines Secondary	DEM	27,780	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
PLTSVC	53	UG Lines Direct	CUST	4,974	Allocation Factor #	305	Specific UG Lines - Dir. Alloc.
PLTSVC	54	UG Lines Primary	DEM	188,314	Allocation Factor #	110	Underground Lines Dmd - Dir. Alloc.
PLTSVC	55	UG Lines Secondary	DEM	0	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
PLTSVC	58	Transformers Direct	CUST	0	Allocation Factor #	306	Specific Transformers - Dir. Alloc.
PLTSVC	59	Transformers Common	DEM	255,917	Allocation Factor #	111	Transformers Dmd - Dir. Alloc.
PLTSVC	62	Services	CUST	108,952	Allocation Factor #	307	Weighted Services - Customer
PLTSVC	63	Meters	CUST	43,789	Allocation Factor #	308	Weighted Meters - Customer
PLTSVC	64	Installations	CUST	0	Allocation Factor #	309	Installations - Dir. Alloc.
PLTSVC	65	Street Lighting	CUST	90,409	Allocation Factor #	310	Street Lighting - Dir. Alloc.
PLTSVC	82	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
PLTSVC	86	Production	DEM	23,885	Allocation Factor #	101	12 Coincident Peak (No I/S)
PLTSVC	87	Production	EGY	7,368	Allocation Factor #	201	MWH at Generation
PLTSVC	88	Transmission	DEM	12,991	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
PLTSVC	89	Subtransmission	DEM	13,478	Allocation Factor #	904	PTD Plant - Subtrans. Demand
PLTSVC	90	Distribution Primary	DEM	26,560	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
PLTSVC	91	Distribution Secondary	DEM	248	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
PLTSVC	92	Distribution	CUST	2,421	Allocation Factor #	907	PTD Plant - Distr. Customer
PLTSVC	93	Other	CUST	5,401	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
PLTSVC	97	Production	DEM	2,252	Allocation Factor #	901	PTD Plant - Prod. Demand
PLTSVC	98	Production	EGY	2,252	Allocation Factor #	201	MWH at Generation
PLTSVC	99	Transmission	DEM	1,264	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
PLTSVC	100	Subtransmission	DEM	2,721	Allocation Factor #	904	PTD Plant - Subtrans. Demand
PLTSVC	101	Distribution Primary	DEM	8,342	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
PLTSVC	102	Distribution Secondary	DEM	860	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
PLTSVC	103	Distribution	CUST	8,326	Allocation Factor #	907	PTD Plant - Distr. Customer
PLTSVC	104	Other	CUST	8,678	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
PLTSVC	108	Production	DEM	36,935	Allocation Factor #	901	PTD Plant - Prod. Demand
PLTSVC	109	Production	EGY	36,515	Allocation Factor #	201	MWH at Generation
PLTSVC	110	Transmission	DEM	1,841	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
PLTSVC	111	Subtransmission	DEM	3,957	Allocation Factor #	904	PTD Plant - Subtrans. Demand
PLTSVC	112	Distribution Primary	DEM	12,011	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
PLTSVC	113	Distribution Secondary	DEM	1,229	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
PLTSVC	114	Distribution	CUST	11,998	Allocation Factor #	907	PTD Plant - Distr. Customer
PLTSVC	115	Other	CUST	26,769	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.

ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
PLTHFFU	2	Production	DEM	1,794	Allocation Factor #	101	12 Coincident Peak (No I/S)
PLTHFFU	3	Production	EGY	150	Allocation Factor #	201	MWH at Generation
PLTHFFU	4	Transmission	DEM	10,119	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
PLTHFFU	5	Subtranmission	DEM	14,809	Allocation Factor #	904	PTD Plant - Subtrans. Demand
PLTHFFU	6	Distribution Primary	DEM	5,172	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
PLTHFFU	7	Distribution Secondary	DEM	0	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
PLTHFFU	8	Distribution	CUST	0	Allocation Factor #	907	PTD Plant - Distr. Customer
PLTHFFU	9	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
CWIP	2	Steam	DEM	7,945	Allocation Factor #	101	12 Coincident Peak (No I/S)
CWIP	3	Steam	EGY	662	Allocation Factor #	221	MWH at Generation - No Resale
CWIP	6	Other	DEM	33,166	Allocation Factor #	101	12 Coincident Peak (No I/S)
CWIP	7	Other	EGY	2,764	Allocation Factor #	221	MWH at Generation - No Resale
CWIP	16	Step-Up Subst.	DEM	162	Allocation Factor #	121	12 Coinc. Peak & 1/13th (I/S-1/13th)
CWIP	17	Hi-Volt Transmission	DEM	290	Allocation Factor #	122	12 Coinc. Peak & 1/13th (Incl. I/S)
CWIP	18	Subtransmission Direct	DEM	128	Allocation Factor #	107	Subtrans. Subst. - Dir. Alloc.
CWIP	19	Subtransmisson Common	DEM	534	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
CWIP	24	Distribution Primary	DEM	556	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
CWIP	25	Distribution Secondary	DEM	316	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
CWIP	26	Distribution	CUST	0	Allocation Factor #	308	Weighted Meters - Customer
CWIP	27	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
CWIP	44	Production	DEM	2,226	Allocation Factor #	101	12 Coincident Peak (No I/S)
CWIP	45	Production	EGY	2,201	Allocation Factor #	221	MWH at Generation - No Resale
CWIP	46	Transmission	DEM	111	Allocation Factor #	122	12 Coinc. Peak & 1/13th (Incl. I/S)
CWIP	47	Subtransmission	DEM	239	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
CWIP	48	Distribution Primary	DEM	724	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
CWIP	49	Distribution Secondary	DEM	74	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
CWIP	50	Distribution	CUST	723	Allocation Factor #	308	Weighted Meters - Customer
CWIP	51	Other	CUST	1,614	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
WORKCAP	2	Production	DEM	23,671	Allocation Factor #	101	12 Coincident Peak (No I/S)
WORKCAP	3	Production	EGY	3,634	Allocation Factor #	201	MWH at Generation
WORKCAP	4	Transmission	DEM	1,560	Allocation Factor #	943	Plt. in Service - StepUp & HiVolt Dem
WORKCAP	5	Subtranmission	DEM	2,279	Allocation Factor #	944	Plt. in Service - Subtrans. Demand
WORKCAP	6	Distribution Primary	DEM	7,297	Allocation Factor #	945	Plt. in Service - Distr. Pri. Demand
WORKCAP	7	Distribution Secondary	DEM	4,144	Allocation Factor #	946	Plt. in Service - Distr. Sec. Demand
WORKCAP	8	Distribution	CUST	3,722	Allocation Factor #	947	Plt. in Service - Distr. Customer
WORKCAP	9	Other	CUST	0	Allocation Factor #	948	Plt. in Service - Other Customer
WORKCAP	13	Production	DEM	(432)	Allocation Factor #	101	12 Coincident Peak (No I/S)
WORKCAP	14	Production	EGY	(441)	Allocation Factor #	201	MWH at Generation
WORKCAP	15	Transmission	DEM	(22)	Allocation Factor #	943	Plt. in Service - StepUp & HiVolt Dem
WORKCAP	16	Subtranmission	DEM	(48)	Allocation Factor #	944	Plt. in Service - Subtrans. Demand
WORKCAP	17	Distribution Primary	DEM	(146)	Allocation Factor #	945	Plt. in Service - Distr. Pri. Demand
WORKCAP	18	Distribution Secondary	DEM	(15)	Allocation Factor #	946	Plt. in Service - Distr. Sec. Demand
WORKCAP	19	Distribution	CUST	(146)	Allocation Factor #	947	Plt. in Service - Distr. Customer
WORKCAP	20	Other	CUST	(325)	Allocation Factor #	948	Plt. in Service - Other Customer
WORKCAP	24	Production	DEM	87,568	Allocation Factor #	911	Total Plant - Prod. Demand
WORKCAP	25	Production	EGY	1,974	Allocation Factor #	912	Total Plant - Prod. Energy
WORKCAP	26	Transmission	DEM	5,958	Allocation Factor #	913	Total Plant - StepUp & Hi-Volt Dem
WORKCAP	27	Subtranmission	DEM	8,573	Allocation Factor #	914	Total Plant - Subtrans. Demand
WORKCAP	28	Distribution Primary	DEM	24,886	Allocation Factor #	915	Total Plant - Distr. Pri. Demand
WORKCAP	29	Distribution Secondary	DEM	12,966	Allocation Factor #	916	Total Plant - Distr. Sec. Demand
WORKCAP	30	Distribution	CUST	12,530	Allocation Factor #	917	Total Plant - Distr. Customer
WORKCAP	31	Other	CUST	1,748	Allocation Factor #	918	Total Plant - Other Customer
WORKCAP	35	Production	DEM	159,275	Allocation Factor #	911	Total Plant - Prod. Demand
WORKCAP	36	Production	EGY	3,591	Allocation Factor #	912	Total Plant - Prod. Energy
WORKCAP	37	Transmission	DEM	10,836	Allocation Factor #	913	Total Plant - StepUp & Hi-Volt Dem
WORKCAP	38	Subtranmission	DEM	15,594	Allocation Factor #	914	Total Plant - Subtrans. Demand
WORKCAP	39	Distribution Primary	DEM	45,265	Allocation Factor #	915	Total Plant - Distr. Pri. Demand
WORKCAP	40	Distribution Secondary	DEM	23,584	Allocation Factor #	916	Total Plant - Distr. Sec. Demand
WORKCAP	41	Distribution	CUST	22,791	Allocation Factor #	917	Total Plant - Distr. Customer
WORKCAP	42	Other	CUST	3,179	Allocation Factor #	918	Total Plant - Other Customer
WORKCAP	46	Production	EGY	72,273	Allocation Factor #	201	MWH at Generation

FL JURIS FACTORS (2000 ACTUAL LOAD RES) COST OF SERVICE STUDY

ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
ARFDEPRC	2	Steam	DEM	682,692	Allocation Factor #	101	12 Coincident Peak (No I/S)
ARFDEPRC	3	Steam	EGY	56,908	Allocation Factor #	201	MWH at Generation
ARFDEPRC	6	Other	DEM	133,428	Allocation Factor #	101	12 Coincident Peak (No I/S)
ARFDEPRC	7	Other	EGY	11,119	Allocation Factor #	201	MWH at Generation
ARFDEPRC	17	Step-Up Subst.	DEM	12,081	Allocation Factor #	121	12 Coinc. Peak & 1/13th (I/S-1/13th)
ARFDEPRC	20	Substations	DEM	0	Allocation Factor #	102	Incl. I/S)
ARFDEPRC	21	Lines	DEM	30,366	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
ARFDEPRC	25	Substations Direct	DEM	1,440	Allocation Factor #	107	Subtrans. Subst. - Dir. Alloc.
ARFDEPRC	26	Substations Common	DEM	13,811	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
ARFDEPRC	27	Lines Direct	DEM	8,217	Allocation Factor #	108	Subtrans Lines - Dir. Alloc.
ARFDEPRC	28	Lines Common	DEM	21,225	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
ARFDEPRC	29	Subtrans/Dist Transfer	DEM	8,360	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
ARFDEPRC	38	Substations Direct	DEM	1,522	Allocation Factor #	109	Dist. Subst. Demand - Dir. Alloc.
ARFDEPRC	39	Substations Common	DEM	34,764	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
ARFDEPRC	40	Dist/Subtrans Transfer	DEM	2,261	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
ARFDEPRC	43	Poles Direct	CUST	6,053	Allocation Factor #	303	Specific Poles - Dir. Alloc.
ARFDEPRC	44	Poles Primary	DEM	38,925	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
ARFDEPRC	45	Poles Secondary	DEM	6,466	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
ARFDEPRC	48	OH Lines Direct	CUST	2,883	Allocation Factor #	304	Specific OH Lines - Dir. Alloc.
ARFDEPRC	49	OH Lines Primary	DEM	58,776	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
ARFDEPRC	50	OH Lines Secondary	DEM	13,208	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
ARFDEPRC	53	UG Lines Direct	CUST	1,255	Allocation Factor #	305	Specific UG Lines - Dir. Alloc.
ARFDEPRC	54	UG Lines Primary	DEM	47,531	Allocation Factor #	110	Underground Lines Dmd - Dir. Alloc.
ARFDEPRC	55	UG Lines Secondary	DEM	0	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
ARFDEPRC	58	Transformers Direct	CUST	0	Allocation Factor #	306	Specific Transformers - Dir. Alloc.
ARFDEPRC	59	Transformers Common	DEM	98,561	Allocation Factor #	111	Transformers Dmd - Dir. Alloc.
ARFDEPRC	62	Services	CUST	36,813	Allocation Factor #	307	Weighted Services - Customer
ARFDEPRC	63	Meters	CUST	16,397	Allocation Factor #	308	Weighted Meters - Customer
ARFDEPRC	64	Installations	CUST	0	Allocation Factor #	309	Installations - Dir. Alloc.
ARFDEPRC	65	Street Lighting	CUST	31,011	Allocation Factor #	310	Street Lighting - Dir. Alloc.
ARFDEPRC	82	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
ARFDEPRC	86	Production	DEM	14,785	Allocation Factor #	101	12 Coincident Peak (No I/S)
ARFDEPRC	87	Production	EGY	4,561	Allocation Factor #	201	MWH at Generation
ARFDEPRC	88	Transmission	DEM	8,042	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
ARFDEPRC	89	Subtranmission	DEM	8,343	Allocation Factor #	904	PTD Plant - Subtrans. Demand
ARFDEPRC	90	Distribution Primary	DEM	16,442	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
ARFDEPRC	91	Distribution Secondary	DEM	154	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
ARFDEPRC	92	Distribution	CUST	1,499	Allocation Factor #	907	PTD Plant - Distr. Customer
ARFDEPRC	93	Other	CUST	3,345	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
ARFDEPRC	97	Production	DEM	878	Allocation Factor #	101	12 Coincident Peak (No I/S)
ARFDEPRC	98	Production	EGY	878	Allocation Factor #	201	MWH at Generation
ARFDEPRC	99	Transmission	DEM	493	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
ARFDEPRC	100	Subtranmission	DEM	1,061	Allocation Factor #	904	PTD Plant - Subtrans. Demand
ARFDEPRC	101	Distribution Primary	DEM	3,252	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
ARFDEPRC	102	Distribution Secondary	DEM	335	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
ARFDEPRC	103	Distribution	CUST	3,246	Allocation Factor #	907	PTD Plant - Distr. Customer
ARFDEPRC	104	Other	CUST	3,385	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
ARFDEPRC	108	Production	DEM	10,886	Allocation Factor #	101	12 Coincident Peak (No I/S)
ARFDEPRC	109	Production	EGY	10,762	Allocation Factor #	201	MWH at Generation
ARFDEPRC	110	Transmission	DEM	543	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
ARFDEPRC	111	Subtranmission	DEM	1,166	Allocation Factor #	904	PTD Plant - Subtrans. Demand
ARFDEPRC	112	Distribution Primary	DEM	3,540	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
ARFDEPRC	113	Distribution Secondary	DEM	362	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
ARFDEPRC	114	Distribution	CUST	3,536	Allocation Factor #	907	PTD Plant - Distr. Customer
ARFDEPRC	115	Other	CUST	7,893	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
OPRREV	1	Sales Revenue	REV	676,264	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
OPRREV	3	Misc Acct. 451 Revenue	CUST	13,892	Allocation Factor #	502	Service Charges - Dir. Alloc.
OPRREV	6	Transmission	DEM	0	Allocation Factor #	122	12 Coinc. Peak & 1/13th (Incl. I/S)
OPRREV	7	Subtransmission	DEM	0	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
OPRREV	8	Distribution Primary	DEM	12,594	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
OPRREV	9	Distribution Secondary	DEM	0	Allocation Factor #	111	Transformers Dmd - Dir. Alloc.
OPRREV	13	Production	DEM	275	Allocation Factor #	101	12 Coincident Peak (No I/S)
OPRREV	14	Production	EGY	6	Allocation Factor #	221	MWH at Generation - No Resale
OPRREV	15	Transmission	DEM	1,471	Allocation Factor #	122	12 Coinc. Peak & 1/13th (Incl. I/S)
OPRREV	15	Transmission-Wheeling	DEM	3,041	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
OPRREV	16	Subtranmission	DEM	23	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
OPRREV	17	Distribution Primary	DEM	71	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
OPRREV	18	Distribution Secondary	DEM	37	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
OPRREV	19	Distribution	CUST	36	Allocation Factor #	308	Weighted Meters - Customer
OPRREV	20	Other	CUST	5	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
OPRREV	24	Steam & Miscellaneous	EGY	3,420	Allocation Factor #	221	MWH at Generation - No Resale
OPRREV	25	Deferred Conservation	EGY	0	Allocation Factor #	221	MWH at Generation - No Resale
OPRREV	27	Collect Fee/Sales Tax	REV	14	Allocation Factor #	505	Collect Fee/Sales Tax - Dir. Alloc.
OPRREV	28	Energy Power Sales	EGY	1,350	Allocation Factor #	201	MWH at Generation
OPRREV	29	Unbilled Revenue	EGY	5,963	Allocation Factor #	504	Unbilled Revenue - Dir. Alloc.

ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
O\MEXP	2	Fuel Expense	EGY	11,107	Allocation Factor #	201	MWH at Generation
O\MEXP	3	Third Party Purchases	EGY	0	Allocation Factor #	202	Third Party Purchases - Dir. Alloc.
O\MEXP	4	Net Interchange	EGY	0	Allocation Factor #	201	MWH at Generation
O\MEXP	6	Net Firm Transactions	DEM	0	Allocation Factor #	101	12 Coincident Peak (No I/S)
O\MEXP	7	Net Firm Transactions	EGY	639	Allocation Factor #	201	MWH at Generation
O\MEXP	16	Steam	DEM	23,206	Allocation Factor #	101	12 Coincident Peak (No I/S)
O\MEXP	17	Steam	EGY	54,972	Allocation Factor #	201	MWH at Generation
O\MEXP	20	Other	DEM	17,887	Allocation Factor #	101	12 Coincident Peak (No I/S)
O\MEXP	21	Other	EGY	1,491	Allocation Factor #	201	MWH at Generation
O\MEXP	30	Step-Up Subst.	DEM	1,838	Allocation Factor #	121	12 Coinc. Peak & 1/13th (I/S-1/13th)
O\MEXP	33	Substations	DEM	0	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
O\MEXP	34	Lines	DEM	669	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
O\MEXP	38	Substations Direct	DEM	238	Allocation Factor #	107	Subtrans. Subst. - Dir. Alloc.
O\MEXP	39	Substations Common	DEM	3,440	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
O\MEXP	40	Lines Direct	DEM	476	Allocation Factor #	108	Subtrans Lines - Dir. Alloc.
O\MEXP	41	Lines Common	DEM	958	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
O\MEXP	42	Subtrans/Dist Transfer	DEM	225	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
O\MEXP	53	Supervision	CUST	1,506	Allocation Factor #	917	Total Plant - Distr. Customer
O\MEXP	54	Supervision Primary	DEM	6,739	Allocation Factor #	915	Total Plant - Distr. Pri. Demand
O\MEXP	55	Supervision Secondary	DEM	365	Allocation Factor #	916	Total Plant - Distr. Sec. Demand
O\MEXP	58	Substations Direct	DEM	109	Allocation Factor #	109	Dist. Subst. Demand - Dir. Alloc.
O\MEXP	59	Substations Common	DEM	2,495	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
O\MEXP	60	Dist/Subtrans Transfer	DEM	162	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
O\MEXP	63	OH Lines Direct	CUST	636	Allocation Factor #	304	Specific OH Lines - Dir. Alloc.
O\MEXP	64	OH Lines Primary	DEM	6,541	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
O\MEXP	65	OH Lines Secondary	DEM	1,296	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
O\MEXP	68	UG Lines Direct	CUST	34	Allocation Factor #	305	Specific UG Lines - Dir. Alloc.
O\MEXP	69	UG Lines Primary	DEM	1,296	Allocation Factor #	110	Underground Lines Dmd - Dir. Alloc.
O\MEXP	70	UG Lines Secondary	DEM	0	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
O\MEXP	73	Transformers Direct	CUST	0	Allocation Factor #	306	Specific Transformers - Dir. Alloc.
O\MEXP	74	Transformers Lines	DEM	234	Allocation Factor #	111	Transformers Dmd - Dir. Alloc.
O\MEXP	77	Services	CUST	2,198	Allocation Factor #	307	Weighted Services - Customer
O\MEXP	78	Meters	CUST	2,567	Allocation Factor #	308	Weighted Meters - Customer
O\MEXP	79	Installations	CUST	1,290	Allocation Factor #	309	Installations - Dir. Alloc.
O\MEXP	80	Street Lighting	CUST	2,357	Allocation Factor #	310	Street Lighting - Dir. Alloc.
O\MEXP	95	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
O\MEXP	99	Uncollectible	CUST	2,892	Allocation Factor #	503	Bad Debt Expense
O\MEXP	100	Billing & Misc.	CUST	18,897	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
O\MEXP	101	Info Non-Recoverable	CUST	3,465	Allocation Factor #	313	Serv. & Info. Expense - Dir. Alloc.
O\MEXP	102	Sales	CUST	2,789	Allocation Factor #	312	Sales Expense - Dir. Alloc.
O\MEXP	106	Production	DEM	33,917	Allocation Factor #	601	PTD O&M Expense - Prod. Demand
O\MEXP	107	Production	EGY	17,691	Allocation Factor #	602	PTD O&M Expense - Prod. Energy
O\MEXP	108	Transmission	DEM	2,053	Allocation Factor #	603	PTD O&M Exp. Step-Up&Hi-Volt Dem.
O\MEXP	109	Subtranmission	DEM	3,628	Allocation Factor #	604	PTD O&M Exp. - Subtrans. Demand
O\MEXP	110	Distribution Primary	DEM	11,585	Allocation Factor #	605	PTD O&M Exp. - Distr. Pri. Demand
O\MEXP	111	Distribution Secondary	DEM	4,310	Allocation Factor #	606	PTD O&M Exp. - Distr. Sec. Demand
O\MEXP	112	Distribution	CUST	8,285	Allocation Factor #	607	PTD O&M Exp. - Distr. Customer
O\MEXP	113	Other	CUST	10,865	Allocation Factor #	608	O&M Expense - Other Customer
RORSUM	10	Other Expenses		(109)	Allocation Factor #	910	Total Plant - Total Company

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ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
DEPRECEXP	2	Steam	DEM	39,241	Allocation Factor #	101	12 Coincident Peak (No I/S)
DEPRECEXP	3	Steam	EGY	7,465	Allocation Factor #	201	MWH at Generation
DEPRECEXP	6	Other	DEM	25,535	Allocation Factor #	101	12 Coincident Peak (No I/S)
DEPRECEXP	7	Other	EGY	2,128	Allocation Factor #	201	MWH at Generation
DEPRECEXP	17	Step-Up Subst.	DEM	1,189	Allocation Factor #	121	12 Coinc. Peak & 1/13th (I/S-1/13th)
DEPRECEXP	20	Substations	DEM	0	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
DEPRECEXP	21	Lines	DEM	2,126	Allocation Factor #	102	12 Coinc. Peak & 1/13th (Incl. I/S)
DEPRECEXP	25	Substations Direct	DEM	140	Allocation Factor #	107	Subtrans. Subst. - Dir. Alloc.
DEPRECEXP	26	Substations Common	DEM	2,106	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
DEPRECEXP	27	Lines Direct	DEM	799	Allocation Factor #	108	Subtrans Lines - Dir. Alloc.
DEPRECEXP	28	Lines Common	DEM	1,671	Allocation Factor #	103	Class Non-Coincident Pk - Subtrans
DEPRECEXP	29	Subtrans/Dist Transfer	DEM	138	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
DEPRECEXP	38	Substations Direct	DEM	143	Allocation Factor #	109	Dist. Subst. Demand - Dir. Alloc.
DEPRECEXP	39	Substations Common	DEM	3,265	Allocation Factor #	104	Class Non-Coincident Pk - Distr. Subst.
DEPRECEXP	40	Dist/Subtrans Transfer	DEM	212	Allocation Factor #	123	Class Non-Coincident Pk - 69KV
DEPRECEXP	43	Poles Direct	CUST	667	Allocation Factor #	303	Specific Poles - Dir. Alloc.
DEPRECEXP	44	Poles Primary	DEM	4,292	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
DEPRECEXP	45	Poles Secondary	DEM	713	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
DEPRECEXP	48	OH Lines Direct	CUST	224	Allocation Factor #	304	Specific OH Lines - Dir. Alloc.
DEPRECEXP	49	OH Lines Primary	DEM	4,568	Allocation Factor #	105	Class Non-Coincident Pk - Distr. Pri.
DEPRECEXP	50	OH Lines Secondary	DEM	1,027	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
DEPRECEXP	53	UG Lines Direct	CUST	127	Allocation Factor #	305	Specific UG Lines - Dir. Alloc.
DEPRECEXP	54	UG Lines Primary	DEM	4,813	Allocation Factor #	110	Underground Lines Dmd - Dir. Alloc.
DEPRECEXP	55	UG Lines Secondary	DEM	0	Allocation Factor #	106	Class Non-Coincident Pk - Distr. Sec.
DEPRECEXP	58	Transformers Direct	CUST	0	Allocation Factor #	306	Specific Transformers - Dir. Alloc.
DEPRECEXP	59	Transformers Common	DEM	11,140	Allocation Factor #	111	Transformers Dmd - Dir. Alloc.
DEPRECEXP	62	Services	CUST	3,221	Allocation Factor #	307	Weighted Services - Customer
DEPRECEXP	63	Meters	CUST	1,154	Allocation Factor #	308	Weighted Meters - Customer
DEPRECEXP	64	Installations	CUST	0	Allocation Factor #	309	Installations - Dir. Alloc.
DEPRECEXP	65	Street Lighting	CUST	4,684	Allocation Factor #	310	Street Lighting - Dir. Alloc.
DEPRECEXP	82	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
DEPRECEXP	86	Production	DEM	2,252	Allocation Factor #	101	12 Coincident Peak (No I/S)
DEPRECEXP	87	Production	EGY	695	Allocation Factor #	201	MWH at Generation
DEPRECEXP	88	Transmission	DEM	1,225	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
DEPRECEXP	89	Subtranmission	DEM	1,271	Allocation Factor #	904	PTD Plant - Subtrans. Demand
DEPRECEXP	90	Distribution Primary	DEM	2,504	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
DEPRECEXP	91	Distribution Secondary	DEM	23	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
DEPRECEXP	92	Distribution	CUST	228	Allocation Factor #	907	PTD Plant - Distr. Customer
DEPRECEXP	93	Other	CUST	509	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
DEPRECEXP	97	Production	DEM	0	Allocation Factor #	101	12 Coincident Peak (No I/S)
DEPRECEXP	98	Production	EGY	0	Allocation Factor #	201	MWH at Generation
DEPRECEXP	99	Transmission	DEM	0	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
DEPRECEXP	100	Subtranmission	DEM	0	Allocation Factor #	904	PTD Plant - Subtrans. Demand
DEPRECEXP	101	Distribution Primary	DEM	0	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
DEPRECEXP	102	Distribution Secondary	DEM	0	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
DEPRECEXP	103	Distribution	CUST	0	Allocation Factor #	907	PTD Plant - Distr. Customer
DEPRECEXP	104	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
DEPRECEXP	108	Production	DEM	4,428	Allocation Factor #	101	12 Coincident Peak (No I/S)
DEPRECEXP	109	Production	EGY	4,378	Allocation Factor #	201	MWH at Generation
DEPRECEXP	110	Transmission	DEM	221	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
DEPRECEXP	111	Subtranmission	DEM	474	Allocation Factor #	904	PTD Plant - Subtrans. Demand
DEPRECEXP	112	Distribution Primary	DEM	1,440	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
DEPRECEXP	113	Distribution Secondary	DEM	147	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
DEPRECEXP	114	Distribution	CUST	1,438	Allocation Factor #	907	PTD Plant - Distr. Customer
DEPRECEXP	115	Other	CUST	3,211	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.

ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
TAXOTH	2	Production	DEM	2,700	Allocation Factor #	101	12 Coincident Peak (No I/S)
TAXOTH	3	Production	EGY	2,670	Allocation Factor #	201	MWH at Generation
TAXOTH	4	Transmission	DEM	164	Allocation Factor #	603	PTD O&M Exp. Step-Up&Hi-Volt Dem.
TAXOTH	5	Subtranmission	DEM	323	Allocation Factor #	604	PTD O&M Exp. - Subtrans. Demand
TAXOTH	6	Distribution Primary	DEM	1,041	Allocation Factor #	605	PTD O&M Exp. - Distr. Pri. Demand
TAXOTH	7	Distribution Secondary	DEM	223	Allocation Factor #	606	PTD O&M Exp. - Distr. Sec. Demand
TAXOTH	8	Distribution	CUST	679	Allocation Factor #	607	PTD O&M Exp. - Distr. Customer
TAXOTH	9	Other	CUST	1,401	Allocation Factor #	608	O&M Expense - Other Customer
TAXOTH	13	Production	DEM	16,013	Allocation Factor #	101	12 Coincident Peak (No I/S)
TAXOTH	14	Production	EGY	2,800	Allocation Factor #	201	MWH at Generation
TAXOTH	15	Transmission	DEM	1,309	Allocation Factor #	913	Total Plant - StepUp & Hi-Volt Dem
TAXOTH	16	Subtranmission	DEM	1,884	Allocation Factor #	914	Total Plant - Subtrans. Demand
TAXOTH	17	Distribution Primary	DEM	5,470	Allocation Factor #	915	Total Plant - Distr. Pri. Demand
TAXOTH	18	Distribution Secondary	DEM	2,850	Allocation Factor #	916	Total Plant - Distr. Sec. Demand
TAXOTH	19	Distribution	CUST	2,754	Allocation Factor #	917	Total Plant - Distr. Customer
TAXOTH	20	Other	CUST	384	Allocation Factor #	918	Total Plant - Other Customer
TAXOTH	24	Production	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	25	Production	EGY	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	26	Transmission	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	27	Subtranmission	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	28	Distribution Primary	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	29	Distribution Secondary	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	30	Distribution	CUST	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	31	Other	CUST	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	35	Production	DEM	517	Allocation Factor #	101	12 Coincident Peak (No I/S)
TAXOTH	36	Production	EGY	79	Allocation Factor #	201	MWH at Generation
TAXOTH	37	Transmission	DEM	36	Allocation Factor #	903	PTD Plant - Step-Up & Hi-Volt Dem.
TAXOTH	38	Subtranmission	DEM	52	Allocation Factor #	904	PTD Plant - Subtrans. Demand
TAXOTH	39	Distribution Primary	DEM	167	Allocation Factor #	905	PTD Plant - Distr. Pri. Demand
TAXOTH	40	Distribution Secondary	DEM	95	Allocation Factor #	906	PTD Plant - Distr. Sec. Demand
TAXOTH	41	Distribution	CUST	85	Allocation Factor #	907	PTD Plant - Distr. Customer
TAXOTH	42	Other	CUST	0	Allocation Factor #	311	Billing & Misc. - Dir. Alloc.
TAXOTH	57	Production	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	58	Production	EGY	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	59	Transmission	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	60	Subtranmission	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	61	Distribution Primary	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	62	Distribution Secondary	DEM	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	63	Distribution	CUST	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.
TAXOTH	64	Other	CUST	0	Allocation Factor #	501	Revenue from Sales - Dir. Alloc.

ALLOCATION ASSIGNMENT REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Report	Line #	Line Title		Amount	Method of Assignment		
INCTAX	91	Production	DEM	2,578	Allocation Factor #	101	12 Coincident Peak (No I/S)
INCTAX	92	Production	EGY	49,802	Allocation Factor #	201	MWH at Generation
INCTAX	95	Production	DEM	(7,784)	Allocation Factor #	101	12 Coincident Peak (No I/S)
INCTAX	96	Production	EGY	(184)	Allocation Factor #	201	MWH at Generation
INCTAX	97	Transmission	DEM	(515)	Allocation Factor #	943	Plt. in Service - StepUp & HiVolt Dem
INCTAX	98	Subtranmission	DEM	(740)	Allocation Factor #	944	Plt. in Service - Subtrans. Demand
INCTAX	99	Distribution Primary	DEM	(2,298)	Allocation Factor #	945	Plt. in Service - Distr. Pri. Demand
INCTAX	100	Distribution Secondary	DEM	(1,208)	Allocation Factor #	946	Plt. in Service - Distr. Sec. Demand
INCTAX	101	Distribution	CUST	(1,168)	Allocation Factor #	947	Plt. in Service - Distr. Customer
INCTAX	102	Other	CUST	(163)	Allocation Factor #	948	Plt. in Service - Other Customer
INCTAX	106	Production	DEM	408	Allocation Factor #	611	Deprec. Expense - Prod. Demand
INCTAX	107	Production	EGY	7	Allocation Factor #	612	Deprec. Expense - Prod. Energy
INCTAX	108	Transmission	DEM	22	Allocation Factor #	613	Deprec. Exp. - Step-Up&Hi-Volt Dem.
INCTAX	109	Subtranmission	DEM	28	Allocation Factor #	614	Deprec. Expense - Subtrans. Demand
INCTAX	110	Distribution Primary	DEM	90	Allocation Factor #	615	Deprec. Expense - Distr. Pri. Demand
INCTAX	111	Distribution Secondary	DEM	52	Allocation Factor #	616	Deprec. Expense - Distr. Sec. Demand
INCTAX	112	Distribution	CUST	45	Allocation Factor #	617	Deprec. Expense - Distr. Customer
INCTAX	113	Other	CUST	6	Allocation Factor #	618	Deprec. Expense - Other Customer
INCTAX	117	Production	DEM	26,516	Allocation Factor #	931	Rate Base - Prod. Demand
INCTAX	118	Production	EGY	2,596	Allocation Factor #	932	Rate Base - Prod. Energy
INCTAX	119	Transmission	DEM	2,155	Allocation Factor #	933	Rate Base - StepUp & Hi-Volt Dem.
INCTAX	120	Subtranmission	DEM	3,369	Allocation Factor #	934	Rate Base - Subtrans. Demand
INCTAX	121	Distribution Primary	DEM	9,198	Allocation Factor #	935	Rate Base - Distr. Pri. Demand
INCTAX	122	Distribution Secondary	DEM	4,511	Allocation Factor #	936	Rate Base - Distr. Sec. Demand
INCTAX	123	Distribution	CUST	4,671	Allocation Factor #	937	Rate Base - Distr. Customer
INCTAX	124	Other	CUST	660	Allocation Factor #	938	Rate Base - Other Customer
INCTAX	128	Production	DEM	(3,606)	Allocation Factor #	601	PTD O&M Expense - Prod. Demand
INCTAX	129	Production	EGY	(341)	Allocation Factor #	602	PTD O&M Expense - Prod. Energy
INCTAX	130	Transmission	DEM	(280)	Allocation Factor #	603	PTD O&M Exp. Step-Up&Hi-Volt Dem.
INCTAX	131	Subtranmission	DEM	(444)	Allocation Factor #	604	PTD O&M Exp. - Subtrans. Demand
INCTAX	132	Distribution Primary	DEM	(1,216)	Allocation Factor #	605	PTD O&M Exp. - Distr. Pri. Demand
INCTAX	133	Distribution Secondary	DEM	(596)	Allocation Factor #	606	PTD O&M Exp. - Distr. Sec. Demand
INCTAX	134	Distribution	CUST	(617)	Allocation Factor #	607	PTD O&M Exp. - Distr. Customer
INCTAX	135	Other	CUST	(87)	Allocation Factor #	608	O&M Expense - Other Customer
INCTAX	135	Other	CUST	0	Allocation Factor #	308	Weighted Meters - Customer
INCTAX	165	Production	DEM	(14,137)	Allocation Factor #	931	Rate Base - Prod. Demand
INCTAX	166	Production	EGY	(4,846)	Allocation Factor #	932	Rate Base - Prod. Energy
INCTAX	167	Transmission	DEM	(1,405)	Allocation Factor #	933	Rate Base - StepUp & Hi-Volt Dem.
INCTAX	168	Subtranmission	DEM	(2,197)	Allocation Factor #	934	Rate Base - Subtrans. Demand
INCTAX	169	Distribution Primary	DEM	(5,999)	Allocation Factor #	935	Rate Base - Distr. Pri. Demand
INCTAX	170	Distribution Secondary	DEM	(2,942)	Allocation Factor #	936	Rate Base - Distr. Sec. Demand
INCTAX	171	Distribution	CUST	(3,047)	Allocation Factor #	937	Rate Base - Distr. Customer
INCTAX	172	Other	CUST	(431)	Allocation Factor #	938	Rate Base - Other Customer
INCTAX	214	Production	DEM	0	Allocation Factor #	931	Rate Base - Prod. Demand
INCTAX	215	Production	EGY	0	Allocation Factor #	932	Rate Base - Prod. Energy
INCTAX	216	Transmission	DEM	0	Allocation Factor #	933	Rate Base - StepUp & Hi-Volt Dem.
INCTAX	217	Subtranmission	DEM	0	Allocation Factor #	934	Rate Base - Subtrans. Demand
INCTAX	218	Distribution Primary	DEM	0	Allocation Factor #	935	Rate Base - Distr. Pri. Demand
INCTAX	219	Distribution Secondary	DEM	0	Allocation Factor #	936	Rate Base - Distr. Sec. Demand
INCTAX	220	Distribution	CUST	0	Allocation Factor #	937	Rate Base - Distr. Customer
INCTAX	221	Other	CUST	0	Allocation Factor #	938	Rate Base - Other Customer
INCTAX	250	Production	DEM	(2,988)	Allocation Factor #	101	12 Coincident Peak (No I/S)
INCTAX	251	Production	EGY	(298)	Allocation Factor #	201	MWH at Generation
INCTAX	252	Transmission	DEM	(248)	Allocation Factor #	943	Plt. in Service - StepUp & HiVolt Dem
INCTAX	253	Subtranmission	DEM	(387)	Allocation Factor #	944	Plt. in Service - Subtrans. Demand
INCTAX	254	Distribution Primary	DEM	(1,057)	Allocation Factor #	945	Plt. in Service - Distr. Pri. Demand
INCTAX	255	Distribution Secondary	DEM	(518)	Allocation Factor #	946	Plt. in Service - Distr. Sec. Demand
INCTAX	256	Distribution	CUST	(537)	Allocation Factor #	947	Plt. in Service - Distr. Customer
INCTAX	257	Other	CUST	(76)	Allocation Factor #	948	Plt. in Service - Other Customer

ALLOCATION FACTOR REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Factor #	Name	Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible I/S & SBI	Lighting SL & OL
101	12 Coincident Peak (No I/S)	2,851,733	1,708,500	191,142	687,342	261,817	0	2,933
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
102	12 Coinc. Peak & 1/13th (Incl. I/S)	2,961,632	1,644,870	185,122	676,431	258,892	192,049	4,267
	% of Total Company	100.0000%	55.5393%	6.2507%	22.8398%	8.7415%	6.4846%	0.1441%
103	Class Non-Coincident Pk - Subtrans	3,712,053	2,208,583	263,804	832,841	317,448	50,892	38,486
	% of Total Company	100.0000%	59.4976%	7.1067%	22.4361%	8.5518%	1.3710%	1.0368%
104	Class Non-Coincident Pk - Distr. Subst.	3,591,486	2,171,302	259,175	818,821	294,124	9,924	38,140
	% of Total Company	100.0000%	60.4569%	7.2164%	22.7990%	8.1895%	0.2763%	1.0619%
105	Class Non-Coincident Pk - Distr. Pri.	3,591,486	2,171,302	259,175	818,821	294,124	9,924	38,140
	% of Total Company	100.0000%	60.4569%	7.2164%	22.7990%	8.1895%	0.2763%	1.0619%
106	Class Non-Coincident Pk - Distr. Sec.	3,363,104	2,114,300	251,900	783,340	176,464	0	37,100
	% of Total Company	100.0000%	62.8675%	7.4901%	23.2922%	5.2471%	0.0000%	1.1031%
107	Subtrans. Subst. - Dir. Alloc.	4,770	0	0	0	0	4,770	0
	% of Total Company	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
108	Subtrans Lines - Dir. Alloc.	27,224	0	0	0	128	27,096	0
	% of Total Company	100.0000%	0.0000%	0.0000%	0.0000%	0.4712%	99.5288%	0.0000%
109	Dist. Subst. Demand - Dir. Alloc.	4,551	0	0	0	679	3,872	0
	% of Total Company	100.0000%	0.0000%	0.0000%	0.0000%	14.9168%	85.0832%	0.0000%
110	Underground Lines Dmd - Dir. Alloc.	193,288,170	113,769,253	13,806,645	46,529,882	17,186,060	0	1,996,329
	% of Total Company	100.0000%	58.8599%	7.1430%	24.0728%	8.8914%	0.0000%	1.0328%
111	Transformers Dmd - Dir. Alloc.	255,916,530	159,996,610	19,091,187	59,782,238	14,239,007	0	2,807,489
	% of Total Company	100.0000%	62.5191%	7.4599%	23.3601%	5.5639%	0.0000%	1.0970%
121	12 Coinc. Peak & 1/13th (I/S-1/13th)	2,784,355	1,644,870	185,122	676,431	258,892	14,773	4,267
	% of Total Company	100.0000%	59.0754%	6.6487%	24.2940%	9.2981%	0.5306%	0.1532%
122	12 Coinc. Peak & 1/13th (Incl. I/S)	2,961,632	1,644,870	185,122	676,431	258,892	192,049	4,267
	% of Total Company	100.0000%	55.5393%	6.2507%	22.8398%	8.7415%	6.4846%	0.1441%
123	Class Non-Coincident Pk - 69KV	3,712,053	2,208,583	263,804	832,841	317,448	50,892	38,486
	% of Total Company	100.0000%	59.4976%	7.1067%	22.4361%	8.5518%	1.3710%	1.0368%
201	MWH at Generation	17,387,819	7,720,242	988,933	4,778,618	1,960,491	1,761,995	177,540
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%
202	Third Party Purchases - Dir. Alloc.	1	0	0	0	0	1	0
	% of Total Company	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%	0.0000%
203	MWH at Meter	16,634,654	7,350,569	941,579	4,553,125	1,887,990	1,732,352	169,039
	% of Total Company	100.0000%	44.1883%	5.6603%	27.3713%	11.3497%	10.4141%	1.0162%
204	Net Firm Transacts - Demand	5	1	1	1	1	0	1
	% of Total Company	100.0000%	20.0000%	20.0000%	20.0000%	20.0000%	0.0000%	20.0000%
205	Net Firm Transacts - Energy	6	1	1	1	1	1	1
	% of Total Company	100.0000%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%
221	MWH at Generation - No Resale	17,387,819	7,720,242	988,933	4,778,618	1,960,491	1,761,995	177,540
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%

ALLOCATION FACTOR REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Factor #	Name	Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible I/S & SBI	Lighting SL & OL
301	Avg. Custs. Thru Pri. Excl. Lights	560,100	492,065	56,198	11,383	173	71	210
	% of Total Company	100.0000%	87.8531%	10.0336%	2.0323%	0.0309%	0.0127%	0.0375%
302	Avg. Custs. Thru Sec. Incl. Lights	819,477	492,065	56,198	11,267	124	0	259,823
	% of Total Company	100.0000%	60.0462%	6.8578%	1.3749%	0.0152%	0.0000%	31.7060%
303	Specific Poles - Dir. Alloc.	15,910	0	139	369	38	0	15,364
	% of Total Company	100.0000%	0.0000%	0.8736%	2.3193%	0.2388%	0.0000%	96.5683%
304	Specific OH Lines - Dir. Alloc.	6,064	0	176	424	55	0	5,409
	% of Total Company	100.0000%	0.0000%	2.9024%	6.9921%	0.9070%	0.0000%	89.1985%
305	Specific UG Lines - Dir. Alloc.	4,974	0	71	786	232	0	3,885
	% of Total Company	100.0000%	0.0000%	1.4274%	15.8019%	4.6642%	0.0000%	78.1066%
306	Specific Transformers - Dir. Alloc.	6	1	1	1	1	1	1
	% of Total Company	100.0000%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%
307	Weighted Services - Customer	384,979	317,958	46,794	19,755	298	0	175
	% of Total Company	100.0000%	82.5910%	12.1548%	5.1314%	0.0773%	0.0000%	0.0454%
308	Weighted Meters - Customer	49,094	32,426	6,489	7,975	1,087	1,103	14
	% of Total Company	100.0000%	66.0498%	13.2167%	16.2440%	2.2151%	2.2463%	0.0282%
309	Installations - Dir. Alloc.	560,100	492,065	56,198	11,383	173	71	210
	% of Total Company	100.0000%	87.8531%	10.0336%	2.0323%	0.0309%	0.0127%	0.0375%
310	Street Lighting - Dir. Alloc.	1	0	0	0	0	0	1
	% of Total Company	100.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	100.0000%
311	Billing & Misc. - Dir. Alloc.	20,381,228	17,048,354	2,279,461	624,809	300,280	123,850	4,474
	% of Total Company	100.0000%	83.6473%	11.1841%	3.0656%	1.4733%	0.6077%	0.0220%
312	Sales Expense - Dir. Alloc.	2,804,518	1,848,970	385,193	172,475	267,583	129,744	553
	% of Total Company	100.0000%	65.9283%	13.7347%	6.1499%	9.5411%	4.6263%	0.0197%
313	Serv. & Info. Expense - Dir. Alloc.	3,354,087	1,368,855	680,897	515,889	563,230	224,870	345
	% of Total Company	100.0000%	40.8116%	20.3005%	15.3809%	16.7924%	6.7044%	0.0103%
314	Reserved Future Use - Dir. Alloc.	6	1	1	1	1	1	1
	% of Total Company	100.0000%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%
401	Demand Billing Determinant	10,584,427	7,350,569	941,579	1,090,300	403,451	629,489	169,039
	% of Total Company	100.0000%	69.4470%	8.8959%	10.3010%	3.8117%	5.9473%	1.5971%
402	Pri. Demand Billing Determinant	10,584,427	7,350,569	941,579	1,090,300	403,451	629,489	169,039
	% of Total Company	100.0000%	69.4470%	8.8959%	10.3010%	3.8117%	5.9473%	1.5971%
403	Sec. Demand Billing Determinant	9,954,938	7,350,569	941,579	1,090,300	403,451	0	169,039
	% of Total Company	100.0000%	73.8384%	9.4584%	10.9523%	4.0528%	0.0000%	1.6980%
404	Energy Billing Determinant	16,634,654	7,350,569	941,579	4,553,125	1,887,990	1,732,352	169,039
	% of Total Company	100.0000%	44.1883%	5.6603%	27.3713%	11.3497%	10.4141%	1.0162%
405	Customer Billing Determinant	9,835,159	5,904,780	674,376	135,199	2,076	852	3,117,876
	% of Total Company	100.0000%	60.0375%	6.8568%	1.3746%	0.0211%	0.0087%	31.7013%

ALLOCATION FACTOR REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Deferred Revenue 0
(Allocated on MWh% - Factor 203)

Factor #	Name	Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible I/S & SBI	Lighting SL & OL
501	Revenue from Sales - Dir. Alloc.	676,264	369,437	46,872	154,285	54,252	24,974	26,444
	% of Total Company	100.0000%	54.6291%	6.9310%	22.8143%	8.0224%	3.6929%	3.9103%
502	Service Charges - Dir. Alloc.	9,968,983	8,420,349	1,290,661	252,654	3,717	1,602	0
	% of Total Company	100.0000%	84.4655%	12.9468%	2.5344%	0.0373%	0.0161%	0.0000%
503	Bad Debt Expense	3,753,139	3,342,556	186,205	223,022	0	0	1,357
	% of Total Company	100.0000%	89.0603%	4.9613%	5.9423%	0.0000%	0.0000%	0.0361%
504	Unbilled Revenue - Dir. Alloc.	5,963	2,860	366	1,772	735	165	66
	% of Total Company	100.0000%	47.9629%	6.1439%	29.7094%	12.3193%	2.7616%	1.1030%
505	Collect Fee/Sales Tax - Dir. Alloc.	6	1	1	1	1	1	1
	% of Total Company	100.0000%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%	16.6667%
601	PTD O&M Expense - Prod. Demand	41,093	24,619	2,754	9,905	3,773	0	42
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
602	PTD O&M Expense - Prod. Energy	56,463	25,070	3,211	15,517	6,366	5,722	577
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%
603	PTD O&M Exp. Step-Up&Hi-Volt Dem.	2,507	1,458	164	599	229	53	4
	% of Total Company	100.0000%	58.1316%	6.5424%	23.9059%	9.1496%	2.1197%	0.1508%
604	PTD O&M Exp. - Subtrans. Demand	5,337	2,753	329	1,038	397	773	48
	% of Total Company	100.0000%	51.5787%	6.1606%	19.4500%	7.4346%	14.4770%	0.8991%
605	PTD O&M Exp. - Distr. Pri. Demand	17,342	10,322	1,236	3,962	1,458	182	181
	% of Total Company	100.0000%	59.5205%	7.1296%	22.8453%	8.4090%	1.0504%	1.0451%
606	PTD O&M Exp. - Distr. Sec. Demand	1,895	1,190	142	442	101	0	21
	% of Total Company	100.0000%	62.7674%	7.4814%	23.3117%	5.3381%	0.0000%	1.1014%
607	PTD O&M Exp. - Distr. Customer	10,587	5,307	863	685	74	63	3,595
	% of Total Company	100.0000%	50.1254%	8.1514%	6.4740%	0.6990%	0.5979%	33.9523%
608	O&M Expense - Other Customer	28,042	21,635	3,343	1,456	1,126	476	6
	% of Total Company	100.0000%	77.1502%	11.9226%	5.1908%	4.0167%	1.6980%	0.0218%
611	Deprec. Expense - Prod. Demand	71,456	42,810	4,789	17,223	6,560	0	74
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
612	Deprec. Expense - Prod. Energy	14,665	6,511	834	4,030	1,653	1,486	150
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%
613	Deprec. Exp. - Step-Up&Hi-Volt Dem.	4,761	2,705	304	1,112	426	207	7
	% of Total Company	100.0000%	56.8078%	6.3935%	23.3615%	8.9412%	4.3487%	0.1474%
614	Deprec. Expense - Subtrans. Demand	6,598	3,168	378	1,195	460	1,342	55
	% of Total Company	100.0000%	48.0158%	5.7351%	18.1064%	6.9649%	20.3409%	0.8369%
615	Deprec. Expense - Distr. Pri. Demand	21,238	12,631	1,515	4,880	1,796	194	222
	% of Total Company	100.0000%	59.4743%	7.1335%	22.9775%	8.4554%	0.9151%	1.0443%
616	Deprec. Expense - Distr. Sec. Demand	13,050	8,165	974	3,047	720	0	143
	% of Total Company	100.0000%	62.5662%	7.4640%	23.3509%	5.5211%	0.0000%	1.0979%
617	Deprec. Expense - Distr. Customer	11,744	4,156	678	492	46	32	6,340
	% of Total Company	100.0000%	35.3881%	5.7727%	4.1898%	0.3926%	0.2723%	53.9844%

ALLOCATION FACTOR REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Factor #	Name	Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible I/S & SBI	Lighting SL & OL
901	PTD Plant - Prod. Demand	1,637,806	981,225	109,776	394,754	150,366	0	1,685
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
903	PTD Plant - Step-Up & Hi-Volt Dem.	113,016	64,202	7,226	26,402	10,105	4,915	167
	% of Total Company	100.0000%	56.8078%	6.3935%	23.3615%	8.9412%	4.3487%	0.1474%
904	PTD Plant - Subtrans. Demand	165,398	79,417	9,486	29,948	11,520	33,643	1,384
	% of Total Company	100.0000%	48.0158%	5.7351%	18.1064%	6.9649%	20.3409%	0.8369%
905	PTD Plant - Distr. Pri. Demand	529,525	314,311	37,739	122,063	45,018	4,876	5,518
	% of Total Company	100.0000%	59.3572%	7.1269%	23.0514%	8.5016%	0.9208%	1.0421%
906	PTD Plant - Distr. Sec. Demand	300,692	188,146	22,445	70,211	16,588	0	3,301
	% of Total Company	100.0000%	62.5709%	7.4644%	23.3499%	5.5167%	0.0000%	1.0979%
907	PTD Plant - Distr. Customer	270,099	118,908	19,416	14,283	1,379	984	115,129
	% of Total Company	100.0000%	44.0237%	7.1886%	5.2880%	0.5106%	0.3642%	42.6248%
910	Total Plant - Total Company	3,558,334	2,025,342	241,122	782,516	284,530	83,929	140,895
	% of Total Company	100.0000%	56.9183%	6.7763%	21.9911%	7.9962%	2.3587%	3.9596%
911	Total Plant - Prod. Demand	1,702,672	1,020,087	114,124	410,388	156,322	0	1,751
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
912	Total Plant - Prod. Energy	297,738	132,196	16,934	81,826	33,570	30,171	3,040
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%
913	Total Plant - StepUp & Hi-Volt Dem	139,231	78,929	8,883	32,459	12,423	6,332	205
	% of Total Company	100.0000%	56.6895%	6.3801%	23.3128%	8.9226%	4.5480%	0.1470%
914	Total Plant - Subtrans. Demand	200,363	96,206	11,491	36,279	13,955	40,756	1,677
	% of Total Company	100.0000%	48.0158%	5.7351%	18.1064%	6.9649%	20.3409%	0.8369%
915	Total Plant - Distr. Pri. Demand	581,611	345,228	41,451	134,070	49,446	5,356	6,061
	% of Total Company	100.0000%	59.3572%	7.1269%	23.0514%	8.5016%	0.9208%	1.0421%
916	Total Plant - Distr. Sec. Demand	303,029	189,608	22,619	70,757	16,717	0	3,327
	% of Total Company	100.0000%	62.5709%	7.4644%	23.3499%	5.5167%	0.0000%	1.0979%
917	Total Plant - Distr. Customer	292,844	128,921	21,052	15,486	1,495	1,066	124,824
	% of Total Company	100.0000%	44.0237%	7.1886%	5.2880%	0.5106%	0.3642%	42.6248%
918	Total Plant - Other Customer	40,847	34,168	4,568	1,252	602	248	9
	% of Total Company	100.0000%	83.6473%	11.1841%	3.0656%	1.4733%	0.6077%	0.0220%
930	Rate Base - Total Company	2,116,202	1,183,418	142,251	466,140	170,441	65,104	88,848
	% of Total Company	100.0000%	55.9218%	6.7220%	22.0272%	8.0541%	3.0764%	4.1985%
931	Rate Base - Prod. Demand	854,672	512,042	57,286	205,998	78,467	0	879
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
932	Rate Base - Prod. Energy	292,986	130,087	16,664	80,520	33,034	29,690	2,992
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%
933	Rate Base - StepUp & Hi-Volt Dem.	84,929	48,297	5,436	19,862	7,602	3,608	125
	% of Total Company	100.0000%	56.8677%	6.4002%	23.3861%	8.9506%	4.2479%	0.1475%
934	Rate Base - Subtrans. Demand	132,851	63,391	7,572	23,904	9,232	27,648	1,104
	% of Total Company	100.0000%	47.7158%	5.6995%	17.9933%	6.9489%	20.8112%	0.8313%
935	Rate Base - Distr. Pri. Demand	362,649	214,938	25,828	83,809	30,960	3,340	3,773
	% of Total Company	100.0000%	59.2688%	7.1221%	23.1103%	8.5372%	0.9210%	1.0405%
936	Rate Base - Distr. Sec. Demand	177,843	111,271	13,274	41,528	9,818	0	1,952
	% of Total Company	100.0000%	62.5669%	7.4641%	23.3507%	5.5204%	0.0000%	1.0979%
937	Rate Base - Distr. Customer	184,190	81,576	13,275	9,719	944	660	78,016
	% of Total Company	100.0000%	44.2891%	7.2073%	5.2766%	0.5126%	0.3583%	42.3562%
938	Rate Base - Other Customer	26,081	21,816	2,917	800	384	158	6
	% of Total Company	100.0000%	83.6473%	11.1841%	3.0656%	1.4733%	0.6077%	0.0220%

ALLOCATION FACTOR REPORT

TAMPA ELECTRIC COMPANY
ELECTRIC UTILITY COST OF SERVICE STUDY
FOR THE YEAR ENDING 12/31/00 IN ($000)
EXCLUDING FUEL

Per Book Study
12CP & 1/13th Avg. Demand
Electric Cost of Service

Factor #	Name	Total Company	Residential RS	Small GS	Medium GSD	Large GSLD & SBF	Interruptible I/S & SBI	Lighting SL & OL
941	Plt. in Service - Prod. Demand	1,700,877	1,019,011	114,004	409,956	156,157	0	1,750
	% of Total Company	100.0000%	59.9109%	6.7026%	24.1026%	9.1810%	0.0000%	0.1029%
942	Plt. in Service - Prod. Energy	297,588	132,130	16,925	81,785	33,553	30,156	3,039
	% of Total Company	100.0000%	44.4003%	5.6875%	27.4826%	11.2751%	10.1335%	1.0211%
943	Plt. in Service - StepUp & HiVolt Dem	129,112	73,181	8,236	30,095	11,518	5,892	190
	% of Total Company	100.0000%	56.6802%	6.3791%	23.3090%	8.9211%	4.5636%	0.1470%
944	Plt. in Service - Subtrans. Demand	185,553	89,095	10,642	33,597	12,924	37,743	1,553
	% of Total Company	100.0000%	48.0158%	5.7351%	18.1064%	6.9649%	20.3409%	0.8369%
945	Plt. in Service - Distr. Pri. Demand	576,438	342,158	41,082	132,877	49,006	5,308	6,007
	% of Total Company	100.0000%	59.3572%	7.1269%	23.0514%	8.5016%	0.9208%	1.0421%
946	Plt. in Service - Distr. Sec. Demand	303,029	189,608	22,619	70,757	16,717	0	3,327
	% of Total Company	100.0000%	62.5709%	7.4644%	23.3499%	5.5167%	0.0000%	1.0979%
947	Plt. in Service - Distr. Customer	292,844	128,921	21,052	15,486	1,495	1,066	124,824
	% of Total Company	100.0000%	44.0237%	7.1886%	5.2880%	0.5106%	0.3642%	42.6248%
948	Plt. in Service - Other Customer	40,847	34,168	4,568	1,252	602	248	9
	% of Total Company	100.0000%	83.6473%	11.1841%	3.0656%	1.4733%	0.6077%	0.0220%

6. Provide the land use agreement that will allow GridFlorida access to access TECO's and land and land rights.

A. No such agreements yet have been entered into. In as much as the company plans to retain ownership of its land and land rights, but make access available to GridFlorida for operations, the company expects to enter into such an agreement sometime prior to the commencement of commercial operations.

7. Provide all documents referred to or relied upon in assuming a 30% contingency for Release 1 start up costs.

A. No specific documents are available. The contingency reflects Accenture's experience in working on projects of this nature where there are estimating uncertainties resulting from the fact that the project is early in the development cycle and GridFlorida requirements are not yet complete. The use of the 30% contingency is a standard component in Accenture's estimating models for projects of this nature at this stage in development.

8. Provide all documents referred to or relied upon in determining that divested transmission assets should be transferred to GridFlorida at net book value.

A. See the response to Production of Documents No. 14.

14. Please provide all documentation of any accounting procedures suggested or provided by FERC related to transferring assets from the participating companies to GridFlorida.

A. Excerpts from the Uniform System of Accounts 18CFR Ch.1 Pt.101 (emphasis added)

Electric Plant Instructions

2. Electric Plant To Be Recorded at Cost.

A. ***All amounts included in the accounts for electric plant acquired as an operating unit or system,*** *except as otherwise provided in the texts of the intangible plant accounts,* ***shall be stated at the cost incurred by the person who first devoted the property to utility service.*** *All other electric plant shall be included in the accounts at the cost incurred by the utility, except for property acquired by lease which qualifies as capital lease property under General Instruction 19.*

5. Electric Plant Purchased or Sold.

A. When electric plant constituting an operating unit or system is acquired by purchase, merger, consolidation, liquidation, or otherwise, after the effective date of this system of accounts, the costs of acquisition, including expenses incidental thereto properly includible in electric plant, shall be charged to account 102, Electric Plant Purchased or Sold.

B. The accounting for the acquisition shall then be completed as follows:

(1) The original cost of plant, estimated if not known, shall be credited to account 102, Electric Plant Purchased or Sold, and concurrently charged to the appropriate electric plant in service accounts and to account 104, Electric Plant Leased to Others, account 105, Electric Plant Held for Future Use, and account 107, Construction Work in Progress--Electric, as appropriate.

(2) The depreciation and amortization applicable to the original cost of the properties purchased shall be charged to account 102, Electric Plant Purchased or Sold, and concurrently credited to the appropriate account for accumulated provision for depreciation or amortization.

(3) The cost to the utility of any property includible in account 121, Nonutility Property, shall be transferred thereto.

(4) The amount remaining in account 102, Electric Plant Purchased or Sold, shall then be closed to account 114, Electric Plant Acquisition Adjustments.

C. If property acquired in the purchase of an operating unit or system is in such physical condition when acquired that it is necessary substantially to rehabilitate it in order to bring the property up to the standards of the utility, the cost of such work, except replacements, shall be accounted for as a part of the purchase price of the property.

D. When any property acquired as an operating unit or system includes duplicate or other plant which will be retired by the accounting utility in the reconstruction of the acquired property or its consolidation with previously owned property, the proposed accounting for such property shall be presented to the Commission.

E. In connection with the acquisition of electric plant constituting an operating unit or system, the utility shall procure, if possible, all existing records relating to the property acquired, or certified copies thereof, and shall preserve such records in conformity with regulations or practices governing the preservation of records of its own construction.

F. When electric plant constituting an operating unit or system is sold, conveyed, or transferred to another by sale, merger, consolidation, or otherwise, the book cost of the property sold or transferred to another shall be credited to the appropriate utility plant accounts, including amounts carried in account 114, Electric Plant Acquisition Adjustments. The amounts (estimated if not known) carried with respect thereto in the accounts for accumulated provision for depreciation and amortization and in account 252, Customer Advances for Construction, shall be charged to such accounts and contra entries made to account 102, Electric Plant Purchased or Sold. Unless otherwise ordered by the Commission, the difference, if any, between (1) the net amount of debits and credits and (2) the consideration received for the property (less commissions and other expenses of making the sale) shall be included in account 421.1. Gain on Disposition of Property, or account 421.2, Loss on Disposition of Property. (See account 102, Electric Plant Purchased or Sold.)

Note: In cases where existing utilities merge or consolidate because of financial or operating reasons or statutory requirements rather than as a means of transferring title of purchased properties to a new owner, the accounts of the constituent utilities, with the approval of the Commission, may be combined. In the event original cost has not been determined, the resulting utility shall proceed to determine such cost as outlined herein.

102. Electric plant purchased or sold.

A. This account shall be charged with the cost of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and shall be credited with the selling price of like property transferred to others pending the distribution to appropriate accounts in accordance with electric plant instruction 5.

B. Within six months from the date of acquisition or sale of property recorded herein, the utility shall file with the Commission the proposed journal entries to clear from this account the amounts recorded herein.

114. Electric plant acquisition adjustments.

A. This account shall include the difference between (1) the cost to the accounting utility of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and (2) the original cost, estimated, if not known, of such property, less the amount or amounts credited by the accounting utility at the time of acquisition to accumulated provisions for depreciation and amortization and contributions in aid of construction with respect to such property...

C. Debit amounts recorded in this account related to plant and land acquisition may be amortized to account 425, Miscellaneous Amortization, over a period not longer than the estimated remaining life of the properties to which such amounts relate.

425. Miscellaneous amortization.

This account shall include amortization charges not includible in other accounts which are properly deductible in determining the income of the utility before interest charges. Charges includible herein, if significant in *amount, must be in accordance with an orderly and systematic amortization program.*

ITEMS

1. *Amortization of utility plant acquisition adjustments, or of intangibles included in utility plant in service when not authorized to be included in utility operating expenses by the Commission.*

2. *Other miscellaneous amortization charges allowed to be included in this account by the Commission.*

15. Please provide any and all agreements between TECO and GridFlorida concerning attachments (e.g., communications systems, etc.) to TECO's transmission assets.

A. No such agreements yet have been entered into.

EXHIBIT NO. 3

DOCKET NO: 001148-EI

PARTY: FLORIDA POWER & LIGHT COMPANY

DESCRIPTION: COMPOSITE EXHIBIT: 1) RESPONSES TO STAFF'S INTERROGATORY NOS. 9, 10, 11 (Attachment only), 14B, 14D, 14F (w/o Attachment), 15, 20, 21, 24, 26, 27, 61-64, 73-81, 84-106, 110, 118-121, 123, 124, 129-131, 133-140, 157-160, 163, 173, 175-180, 182-195; AND 2) RESPONSES TO STAFF'S PRODUCTION OF DOCUMENTS NOS. 2, 6-9, AND 12-15.

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-Hutez EXHIBIT NO. 3
COMPANY/
WITNESS. FPSC Staff
DATE: 10-3-5-00

Q. Will FPL be responsible for paying any of the FLARTO start up costs? If so, describe how they will be paid, i.e., up front, over time, recovered on a flat rate basis, bundled in transmission rates, etc. What is FPL budgeting over the first three years of FLARTO operations for payment of start up costs?

A. It would be expected that, to the extent the recovery of start-up costs for GridFlorida is approved by the FERC and included in rates charged, FPL would be responsible for payment of those costs. Specific issues as to the recovery of such start-up costs up front, over time, etc, have not yet been determined.

The amounts of start-up costs which GridFlorida may include in its rates and charges have not yet been determined and FPL, therefore, has no budget for payment of such amounts at this time.

Q. Identify costs incurred to date for FPL's participation in forming the FLARTO. How will FPL recover these costs from its customers?

A. Costs captured to date for FPL's participation in forming GridFloridainclude only costs for out-of-pocket consultant and legal fees. To the extent that FPL is able to recover these costs from the RTO as start-up costs, GridFlorida will reimburse FPL for said costs. All such start-up costs will be included in GridFlorida's Grid Management Charge (see response to Interrogatory No. 9). Please see response to Interrogatory No. 20 for a description of recovery of RTO costs.

Q. **What will the rate and revenue impact be on FPL due to the elimination of pancaked transmission rates? Please show the annual impact over twenty years. Please show the cumulative present value impact for each utility for a twenty-year period.**

A. **Identify the current annual revenue requirements for transmission services.**

B. **Restate the current revenue requirements for transmission services using the expected transco rates for transmission.**

C. **Identify any anticipated increase in transmission usage associated with using the expected transco transmission rates**

A. FPL is in the process of analyzing this issue in conjunction with the GridFlorida Pricing Committee. Cost shifting results from many factors, including the elimination of pancaked rates, averaging of rates, and crediting of transmission systems owned by municipal power agencies and electric cooperatives. The rate impact estimation reflects data and assumptions provided by the Committee members including FPL. The current assumptions include 1998 revenue requirements based on traditional allocated FERC cost of service methodology, and assume that JEA, Gainesville, and Tallahassee, who did not provide data, do not participate in the RTO.

The annual impact for each utility over 20 years, as well as the cumulative present value, has not been determined.

Based on the base case preliminary estimates, the worksheets attached to the response to 11A below calculate that for FPL the net impact resulting from the loss of pancaked transmission revenues is an increase, i.e., a reduced credit, to transmission revenue requirements of $12.8 million.

A. See attached worksheet from the GridFlorida RTO Pricing Committee for the utilities and other participants that have submitted data calculating an annual rate and revenue impact based on estimates for 1998. Page 4 of the attached worksheet shows an FPL estimate for 1998 annual transmission revenue requirements of approximately $288.7 million.

B. The necessary rates, terms and conditions for transmission and ancillary services to be provided by GridFlorida in order to calculate such a restatement of current revenue requirements are not yet available.

C. At this time, FPL has not identified any significant increase in transmission usage due to the adoption of GridFlorida's transmission rates.

RTO Pricing Committee Data Sheet
Changes made for this version

Changes in version 082800

Item	
1	SECI retail load divided into FPL and FPC groupings
2	SECI revenue requirements reduced by $0.3 million
3	SECI type 3 transaction set to "0". SECI contends use of their transmission facilities by their own generation does not constitue a pancaked transaction.
4	FMPA retail loads divided into EAST and WEST groupings
5	FMPA data supports retail load by EAST and WEST. FPL type 3 showing 496 MW of network load adjusted to match FMPA 191 MW of zonals transfers. FPC type 3 showing 496 MW of network load adjusted to match FMPA 319 MW of zonals transfers.

Changes in version 082900

6	Insert ZONE worksheet summarizing Zone 1 and Zone 2 rates over 6 year period

Additional Note from Pat McGovern 8/30 (below analysis NOT shown on attached sheets)

The calculations in the spreadsheet V082900, phase out the IPP/Cogen transmission transactions over 5 years.
The sensitivity you requested crediting IPP/Cogen transmission revenues to the TO/POs' revenue requirements results in the following:

Zone
Year 6 State wide avg rate ($/kW-mo)
Year 5 - 100% elimination of unpancaking
Year 4 - 80% reduction of unpancaking
Year 3 - 60% reduction of unpancaking
Year 2 - 40% reduction of unpancaking
Year 1- 20% reduction of unpancaking

Change from base case
Year 6 State wide avg rate
Year 5 - 100% elimination of unpancaking
Year 4 - 80% reduction of unpancaking
Year 3 - 60% reduction of unpancaking
Year 2 - 40% reduction of unpancaking
Year 1- 20% reduction of unpancaking

Florida Transco
Pricing Committee
Analysis of Zones

	Zone 1		Zone 2	
	FPL-TECO-SECI(FPL)-FMPA(East)-LWU-HST-FREC		FPC- SECI (FPC) - OUC - FMPA (West) -LKL - KUA - RCID - St Cld - NSB	
	Charge $ / kW-mo			
Year 6 - State wide avg rate	$1.55	($0.06)	$1.55	$0.11
Year 5 - 100% elimination of unpancaking	$1.60	$0.02	$1.44	$0.02
Year 4 - 80% reduction of unpancaking	$1.59	$0.02	$1.41	$0.02
Year 3 - 60% reduction of unpancaking	$1.57	$0.02	$1.39	$0.02
Year 2 - 40% reduction of unpancaking	$1.55	$0.02	$1.37	$0.02
Year 1- 20% reduction of unpancaking	$1.54	$0.02	$1.34	$0.02
Year 0 - 0% reduction of unpancaking	$1.52		$1.32	

By Load

Entity	Retail Load	Access Charges: Present	Access Charges: Postage stamp	Access Charges: Difference	Impact: Benefit from reduce expenses from unpancaking	Impact: Lower / (Higher) expenses for average Transmission (Postage Stamp) rate	Impact: Net Benefit/ (Costs)
		($/kw-mo)			($ millions)		
Aggregate Total	28,616	$1.45	$1.55	($0.09)	$ 31.8	$ (31.8)	$ (0.0)
FP&L - Retail	14,770	$1.47	$1.55	($0.07)	$ 0.1	$ (12.9)	$ (12.8)
FPC - Retail	6,020	$1.20	$1.55	($0.35)	$ 1.6	$ (25.1)	$ (23.5)
TECO	2,804	$1.31	$1.55	($0.24)	$ 0.5	$ (8.0)	$ (7.5)
SECI (FPC)	1,261	$1.37	$1.55	($0.17)	$ -	$ (2.6)	$ (2.6)
SECI (FPL)	878	$2.82	$1.55	$1.28	$ 2.5	$ 13.5	$ 15.9
OUC	752	$1.18	$1.55	($0.36)	$ 1.3	$ (3.3)	$ (2.0)
FMPA (ARP-EAST)	526	$2.11	$1.55	$0.56	$ 8.8	$ 3.5	$ 12.4
Lakeland	465	$1.73	$1.55	$0.18	$ -	$ 1.0	$ 1.0
FMPA (ARP-WEST)	319	$2.08	$1.55	$0.53	$ -	$ 2.0	$ 2.0
KUA	189	$2.45	$1.55	$0.90	$ 0.4	$ 2.0	$ 2.4
RCID	152	$1.75	$1.55	$0.21	$ 1.3	$ 0.4	$ 1.6
FPC-AR	124	$1.20	$1.55	($0.35)	$ 0.0	$ (0.5)	$ (0.5)
FREC	102	$1.47	$1.55	($0.07)	$ -	$ (0.1)	$ (0.1)
LWU	70	$0.13	$1.55	($1.42)	$ 0.4	$ (1.2)	$ (0.8)
St Cld	66	$2.67	$1.55	$1.13	$ 0.1	$ 0.9	$ 1.0
NSB	65	$1.41	$1.55	($0.13)	$ 0.7	$ (0.1)	$ 0.6
HST	53	$0.45	$1.55	($1.09)	$ 0.3	$ (0.7)	$ (0.4)
IPP/ Cogen	-	$1.45	$1.55	($0.09)	$ 7.0	$ -	$ 7.0
Non-RTO Sales	-	$1.20	$1.55	($0.34)	$ -	$ (0.8)	$ (0.8)
Unidentifed S-T sales	-		$0.00		$ 6.8	$ -	$ 6.8

By Net Benefit

Entity	Retail Load	Access Charges: Present	Access Charges: Postage stamp	Access Charges: Difference	Impact: Benefit from reduce expenses from unpancaking	Impact: Lower / (Higher) expenses for average Transmission (Postage Stamp) rate	Impact: Net Benefit/ (Costs)
		($/kw-mo)			($ millions)		
Aggregate Total	28,616	$1.45	$1.55	($0.09)	$ 31.8	$ (31.8)	$ (0.0)
SECI (FPL)	878	$2.82	$1.55	$1.28	$ 2.5	$ 13.5	$ 15.9
FMPA (ARP-EAST)	526	$2.11	$1.55	$0.56	$ 8.8	$ 3.5	$ 12.4
IPP/ Cogen	-	$1.45	$1.55	($0.09)	$ 7.0	$ -	$ 7.0
Unidentifed S-T sales	-	$0.00	$1.55	($1.55)	$ 6.8	$ -	$ 6.8
KUA	189	$2.45	$1.55	$0.90	$ 0.4	$ 2.0	$ 2.4
FMPA (ARP-WEST)	319	$2.08	$1.55	$0.53	$ -	$ 2.0	$ 2.0
RCID	152	$1.75	$1.55	$0.21	$ 1.3	$ 0.4	$ 1.6
Lakeland	465	$1.73	$1.55	$0.18	$ -	$ 1.0	$ 1.0
St Cld	66	$2.67	$1.55	$1.13	$ 0.1	$ 0.9	$ 1.0
NSB	65	$1.41	$1.55	($0.13)	$ 0.7	$ (0.1)	$ 0.6
FREC	102	$1.47	$1.55	($0.07)	$ -	$ (0.1)	$ (0.1)
HST	53	$0.45	$1.55	($1.09)	$ 0.3	$ (0.7)	$ (0.4)
FPC-AR	124	$1.20	$1.55	($0.35)	$ 0.0	$ (0.5)	$ (0.5)
Non-RTO Sales	-	$1.20	$1.55	($0.34)	$ -	$ (0.8)	$ (0.8)
LWU	70	$0.13	$1.55	($1.42)	$ 0.4	$ (1.2)	$ (0.8)
OUC	752	$1.18	$1.55	($0.36)	$ 1.3	$ (3.3)	$ (2.0)
SECI (FPC)	1,261	$1.37	$1.55	($0.17)	$ -	$ (2.6)	$ (2.6)
TECO	2,804	$1.31	$1.55	($0.24)	$ 0.5	$ (8.0)	$ (7.5)
FP&L - Retail	14,770	$1.47	$1.55	($0.07)	$ 0.1	$ (12.9)	$ (12.8)
FPC - Retail	6,020	$1.20	$1.55	($0.35)	$ 1.6	$ (25.1)	$ (23.5)

This document is for discussion purposes only and does not necessarily reflect the view of any participant in the Florida RTO development effort.

RTO Pricing Committee Data Sheet

Transmission Delivery System (TDS):	ZONE 1 FPL-TECO-SECI(FPL)-FMPA(East)-LWU-HST-FREC	ZONE 2 FPC-SECI (FPC)-OUC-FMPA (West)-LKL-KUA-RCID-St Cld-NSB	Aggregate Total	FP&L	FPC	TECO	SECI (FPL)	SECI (FPC)	OUC	FMPA (ARP-EAST)	FMPA (ARP-WEST)	Lakeland	KUA	RCID	FREC	LWU	St Cld	NSB	HST
Estimated Data for 12 months ending				12/31/98	12/31/98	12/31/98	1998	1998	10/31/98	12/31/98	12/31/98	9/30/98	3/31/00	9/30/99		12/31/98		12/31/98	12/31/98
I. Tranmission Facilities Investment ($Millions):																			
Gross Transmission Plant In Service (Avg BOY/EOY):			$3,774.7	$2,048.5	$858.0	$205.7	$200.8		$138.0	$82.8	$19.3	$58.5	$40.3	$17.0	$0.0	$0.8	$15.4	$8.2	$2.4
II. Annual Revenue Requirements ($Millions):																			
Total Transmission Facilities Annual Revenue Requirement			$536.5	$288.7	$120.0	$53.1	$18.5	$2.6	$15.8	$9.9	$2.3	$10.5	$8.3	$3.2	$0.0	$0.1	$2.1	$1.1	$0.3
Less: Revenues received from short term transactions			$11.7	$7.1	$2.0	$1.7	$0.3	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Equals: Revenues required from long-term transactions	$361.4	$163.4 (155.8)	$524.8	$281.6	$118.0	$51.3	$18.1	$2.6	$15.2	$9.9	$2.3	$10.5	$8.3	$3.2	$0.0	$0.1	$2.1	$1.1	$0.3
III. Summary of Billing Determinants for Long-Term Transactions:																			
Average 12 CP Demand (MW)																			
a Total Retail & ARS Load	19,203	9,413	28,616	14,770	6,144	2,804	878	1,261	752	526	319	465	189	152	102	70	66	65	53
b Zonal Transfers	-	0	0	950	1,580		(657)	(1,261)		(191)	(319)			-	(102)				-
c Total Type 1 + Type 2 Transactions	19,203 (19,358)	9,413 (9,558)	28,616	15,720	7,724	2,804	221	-	752	335	-	465	189	152	-	70	66	65	53
Average Month Contract Demand MW																			
d Transaction Type 3	582	860	1,442	183	410	418	-	-	315	-	-	40	85	-	-	-	-	-	-
e Transaction Type 4	84	90	174	40	69	44	-	-	7	-	14	-	-	-	-	-	-	-	-
f TOTAL ALL TRANSACTIONS (Total c+d+e)	19,869	10,363	30,232	15,923	8,203	3,267	221	-	1,074	335	14	505	284	152	-	70	66	65	53
IV. Charge ($/kW-mo) per long term transactions	$1.52	$1.31	$1.45	$1.47	$1.20	$1.31	$6.84	$1.20	$1.18	$2.47	$13.95	$1.73	$2.45	$1.75	$1.47	$0.13	$2.67	$1.41	$0.45
Difference from Aggregate Total																			
$/kW-month				$0.03	($0.25)	($0.14)	$5.39		($0.26)	$1.02	$12.51	$0.28	$1.00	$0.31		($1.32)	NA	($0.03)	($0.99)
Annual revenue ($ Millions)				$5.2	($24.4)	($5.4)	$14.3		($3.4)	$4.1	$2.1	$1.7	$3.4	$0.6		($1.1)	NA	($0.0)	($0.6)

RTO Pricing Committee Data Sheet - ELIMINATION OF PANCAKED TRANSACTIONS

Transmission Delivery System (TDS):			Aggregate Total	FP&L	FPC	TECO	SECI (FPL)	SECI (FPC)	OUC	FMPA (ARP-EAST)	FMPA (ARP-	Lakeland	KUA	RCID	FREC	LWU	St Cld	NSB	HST
Estimated Data for 12 months ending:				12/31/98	12/31/98	12/31/98	1998	1998	10/31/98	12/31/98	12/31/98	9/30/98	3/31/00	9/30/99		12/31/98		12/31/98	12/31/98
I. Tranmission Facilities Investment ($Millions):																			
Gross Transmission Plant In Service (Avg. BOY/EOY):			$3,774.7	$2,046.5	$858.0	$285.7	$200.8		$138.0	$82.8	$19.3	$58.5	$40.3	$17.0	$0.0	$0.9	$15.4	$9.2	$2.4
II. Annual Revenue Requirements ($Millions):																			
Total Transmission Facilities Annual Revenue Requirement			$536.5	$288.7	$120.0	$53.1	$18.5	$2.6	$15.8	$9.9	$2.3	$10.5	$8.3	$3.2	$0.0	$0.1	$2.1	$1.1	$0.3
Less: Revenues received from short term transactions			$2.1	$1.1	$0.7	NA	$0.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Equals: Revenues required from long-term transactions	$369.1	$165.3	$534.4	$287.6	$119.3	$53.1	$18.1	$2.6	$15.8	$9.9	$2.3	$10.5	$8.3	$3.2	$0.0	$0.1	$2.1	$1.1	$0.3
III. Summary of Billing Determinants for Long-Term Transactions:																			
		Average 12 CP Demand (MW)																	
a. Total Type 1 + Type 2 Transactions	19,203	9,413	28,616	15,720	7,724	2,804	221	-	752	335	-	465	189	152	-	70	66	65	53
			Average Month Contract Demand MW																
e. Transaction Type 3	4	180	184	4	180	-	-	-	-	-	-	-	-	-		-	-	-	-
f. Transaction Type 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	-	-
g. TOTAL ALL TRANSACTIONS (Total Transmission Load Reqts)	**19,207**	**9,593**	**28,800**	**15,724**	**7,904**	**2,804**	**221**	-	**752**	**335**	-	**465**	**189**	**152**	-	**70**	**66**	**65**	**53**
IV. CHARGE ($/kW-mo) PER LONG TERM TRANSACTION	$1.60	$1.44	$1.55	$1.52	$1.26	$1.58	$6.84	NA	$1.75	$2.47	NA	$1.88	$3.68	$1.75	NA	$0.13	$2.67	$1.41	$0.45

This document is for discussion purposes only and does not necessarily reflect the view of any participant in the Florida RTO development effort.

Line		Aggregate Total	FP&L - Retail	FPC - Retail	FPC-AR	TECO	SECI (FPL)	SECI (FPC)	OUC	FMPA (ARP-EAST)	FMPA (ARP-WEST)	Lakeland	KUA	RCID	FREC	LWU	St Cld	NSB	HST	IPP/Cogen	Non-RTO Sales
1	Retail Load (12 CP)	28,800	14,770	6,020	124	2,804	878	1,261	752	526	319	465	189	152	102	70	66	65	53	-	184
2	PART I Retail Firm Access Transmission Charges																				
3	Current Retail cost responsibility for owned transmission		$1.47	$1.20	$1.20	$1.31	$1.72	$0.17	$1.18	$1.57	$0.60	$1.73	$2.45	$1.75	$0.00	$0.13	$2.67	$1.41	$0.45	$0.00	$1.20
4	Current charges for zonal transmission						$1.10	$1.20		$0.54	$1.47				$1.47					$1.45	
5	Current total charges for transmission	$1.45	$1.47	$1.20	$1.20	$1.31	$2.82	$1.37	$1.18	$2.11	$2.08	$1.73	$2.45	$1.75	$1.47	$0.13	$2.67	$1.41	$0.45	$1.45	$1.20
6	Average unpancaked transmission	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$1.55	$0.00	$1.55
7	Difference	$0.09	($0.07)	($0.35)	($0.35)	($0.24)	$1.28	($0.17)	($0.36)	$0.56	$0.53	$0.18	$0.90	$0.21	($0.07)	($1.42)	$1.13	($0.13)	($1.09)	$1.45	($0.34)
8	**Retail Benefit / (Costs)**	($31.8)	($12.9)	($25.1)	($0.5)	($8.0)	$13.5	($2.6)	($3.3)	$3.5	$2.0	$1.0	$2.0	$0.4	($0.1)	($1.2)	$0.9	($0.1)	($0.7)	$0.0	($0.8)
9																					
10	PART II Beneficiaries of unpancaking																				
11	Unpancaked benefits by utility	$25.0	$0.1	$1.6	$0.0	$0.5	$2.5		$1.3	$8.8		$0.0	$0.4	$1.3	$0.0	$0.4	$0.1	$0.7	$0.3	$7.0	$0.0
12	Short term tranactions & Others	$6.8																			
13	Total	$31.8																			
14																					
15	PART III TOTAL RETAIL BENEFIT/COST		($12.8)	($23.5)	($0.5)	($7.5)	$13.3		($2.0)	$14.4		$1.0	$2.4	$1.6	($0.1)	($0.8)	$1.0	$0.6	($0.4)	$7.0	($0.8)
16																					
17	Short-term (S-T) transactions																				
18	S-T FPL	$0.1		$0.1																	
19	S-T FPC	$0.9	$0.4			$0.3			$0.2												
20	S-T TECO	$0.5		$0.5																	
21	S-T OUC	$0.2		$0.2																	
22	[redacted]																				
23	IPPS/Cogen	$7.0	$1.1	$2.7		$2.4						$0.8									
24	FPL	$0.0																			
25	FPC	$0.7				$0.7															
26	TECO	$0.0																			
27	SECI	$2.5		$0.0		$2.4															
28	OUC	$1.1	$0.9	$0.2																	
29	FMPA (ARP)	$8.8	$0.7	$0.0		$1.0			$4.3				$2.8								
30	Lakeland	$0.0																			
31	KUA	$0.4	$0.1	$0.1					$0.3												
32	RCID	$1.3		$0.8		$0.4															
33	St Cloud	$0.1				$0.1															
34	New Smyrna Beach	$0.7	$0.1	$0.4		$0.2															
35	Homestead/Lake Worth	$0.7	$0.7																		
36	Non-RTO sales	($1.1)							$0.0												($0.8)
37	Revenues loss w/o pancaking	$31.8	$9.6	$5.6		$9.0		$0.0	$5.1		$0.0	$0.8	$2.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0		($[illegible])

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Q. If ownership of transmission facilities and assets will be transferred to the FLARTO:

A. Specifically, what facilities are being transferred and how were they determined (list by line segment, switching station, and substation -- show all physical and cost allocations between transmission and distribution)?

B. What mechanism will be used to transfer the assets?

C. What is the original cost of the assets being transferred?

D. Will any debt associated with the assets also be transferred?

E. What is the current replacement value of the assets being transferred?

F. What effect will the transfer of assets have on the overall earnings of the company?

A. A. **Transmission Line segments:** FPL currently plans to transfer all overhead transmission line segments 69 kV and above, including the structures, foundations, line switches, metering equipment, conductors, insulators, overhead ground wire, bonding, and other hardware, but not the land and/or right-of-way. All underground transmission line segments including the cable and pipe, and any cooling equipment associated with the underground cable, but not the land and/or right-of way.

Transmission switching stations (type T): All equipment associated with a transmission switching station.

Generator switchyards (type GT): All equipment associated with the generator switchyards with the exception of the generator step up transformers and coolers, the generator synchronizing breakers and associated bus-work, switches and motor operators, plus the protective equipment associated with these devices.

Generator switchyards that also serve distribution load (type GTD): All equipment associated with the generator switchyards will be transferred to GridFlorida with the exception of the following assets: the generator step up transformers and coolers, the generator synchronizing breakers and associated bus-work, switches and motor operators, plus the protective equipment associated with these devices. The step down transformers, its associated protective devices, plus all equipment rated below 69 kV that's associated with serving the retail or generator auxiliary load will remain with the Load Serving Entity (LSE) or generator.

Distribution step down substations (type D): The high voltage bus and all above grade equipment associated with the high voltage bus including: bus support structures, line sectionalizing switches, motor operators, and/or transmission breakers, insulators, reactive devices, plus any equipment used for protection of the transmission line or bus. Assets remaining with the utility include, but are not limited to, transformer fault interrupting devices, foundations, conduits, control cable, ground grid, remote communication equipment, telemetry, battery bank and charger, plus all other equipment less than 69 kV.

Combination transmission switching stations and step down substations: Predominately distribution step down substations (type DT) - All assets will remain with the utility except for autotransformers, the transmissionbus(es) and all above grade equipment associated with the high voltage bus including: bus support structures, line sectionalizing switches, motor operators, and/or transmission breakers, insulators, reactive devices, plus any equipment used for protection of the transmission line or bus. Transmission breakers in a ring bus that also serve as the protective device for a step down transformer will remain with the utility.

Predominately transmission switching stations (type TD) - All assets will be transferred to GridFlorida with the exception of the step down transformers, its associated protective devices, plus all equipment rated below 69 kV that's associated with serving the retail load. Transmission breakers in a ring bus that also serve as the protective device for a step down transformer will be transferred to GridFlorida.

Determination: The determination of the GridFlorida boundaries on the supply and demand side is as follows. On the demand side boundary, the high voltage bus inside the distribution step down substation provides two functions. It provides continuity to move bulk power, and also serves as a tap point for the step down transformers. It's critical that GridFlorida own and operate the entire length of the transmission line to provide bulk power. To provide reliable service, it's essential that GridFlorida own and operate the line sectionalizing switches and any transmission reactive devices used for voltage support inside the distribution substation. On the supply side boundary, since the generator breakers are controlled and operated by the production facility, and to be consistent with new merchant plants, the generator step up transformer, string bus and high side synchronizing breakers will not be transferred to GridFlorida. All land will remain with the utility to reduce transition costs and simplify the asset transfer. GridFlorida will enter into a land use agreement with the divesting utility(s).

B. Property journal vouchers at the retirement unit level will be prepared to transfer all assets from the utility to GridFlorida using a separate company code identification for the new company All attributes associated with each retirement unit (i.e., FERC account, CPR location, In Service Year, etc.) will be maintained in the transfer.

C. Please refer to the attached schedule.

D. It is FPL's intent to transfer relevant debt to GridFlorida. However, at this time, FPL has not determined the amount of debt to be transferred to GridFlorida. Once FPL has finalized the assets to be transferred it will be able to identify the associated debt.

E. Please refer to the attached schedule.

F. FPL has not estimated the effect on the overall earnings of the company from transferring its transmission facilities and assets to GridFlorida. The earnings impact will be influenced by the assets transferred, rates GridFlorida will be able to charge, and FPL's recovery of additional costs associated with the formation of GridFlorida, if any.

Florida Power & Light Company
Estimated Assets to be Transferred to GridFlorida
As of December 31, 1999

NOTE: These amounts are not yet final and represent estimates based on FERC account balances and don't include property in other FERC Functions such as Intangible or General Plant. In addition, equipment which may be excluded from or included in the property to be transferred continues to be identified.

		($000's)		
		Original Cost Book Basis	Accumulated Book Depreciation	Replacement Value (Handy Whitman)
Transmission Plant				
352	Structures & Improvements	43,533	15,551	70,964
353	Station Equipment	781,063	250,044	1,326,579
354	Towers & Fixtures	272,460	179,158	413,013
355	Poles & Fixtures	367,728	178,308	849,244
356	Overhead Conductors & Devices	427,516	234,557	724,566
357	Underground Conduit	32,659	17,477	83,401
358	Underground Conductors & Devices	37,110	24,826	122,600
359	Roads & Trails	72,431	20,410	106,840
Less:				
353	Generator Step-Ups & Cooling	(97,742)	(23,453)	(165,287)
Distribution Plant				
362	Capacitor Banks (Transmission Use)	2,409	611	
Transmission Plant Held for Future Use				
352	Structures & Improvements	1,136	51	
353	Station Equipment	152	3	
357	Underground Conduit	1,046	0	
	Total	1,941,501	897,543	3,531,920

Notes:

Land and Land Rights are assumed to remain at FPL with a use agreement between FPL and GridFlorida.
Replacement cost estimates are based upon the Handy Whitman Index.

Q. If transmission facilities and assets will not be transferred, or only partially transferred to the FLARTO, will they be leased to the FLARTO? Ifso, how will lease payments be calculated? What effect will lease payments have on the earnings of the company?

A. Essentially, all transmission facilities and assets will be transferred to GridFlorida as detailed in response to Interrogatory No. 14A. As explained in response to Interrogatory No. 14C, the transmission rights of way will not be transferred to GridFlorida. The payments for use of the rights of way have not been determined. The use fees will be priced at cost and therefore should not impact earnings.

Q. Identify each service FPL will purchase from the FLARTO. What are the expected costs for each service and how will those costs be recovered from FPL's customers?

A. FPL will purchase, at a minimum, Network Integration Transmission Service, Scheduling and Dispatch Service, Grid Management, Reactive Supply and Voltage Control from Generation Source Service, and System Black Start Service. The costs of these services has not yet been determined.

In addition to these services, FPL may rely on GridFlorida's Ancillary Services and Installed Capacity and Energy Markets to procure other services as needed. The Ancillary Services are: Regulation and Frequency Response Service, Energy Balancing Service, and Operating Reserves. FPL may under the GridFlorida transmission tariff self-provide or purchase these services.

The costs of the market based ancillary services will be determined based on the market prices of those services at the time of procurement.

FPL plans on pursuing recovery of its payments to GridFlorida by subtracting the transmission revenue requirement embedded in retail base rates from the GridFlorida charge and passing the difference through a recovery clause.

Q. **What, if any, regulatory adjustments need to be made to avoid the double recovery of transmission costs which are currently embedded in base rates or recovered through the capacity cost recovery clause?**

A. No adjustments will be necessary if payments to GridFlorida are recovered as explained in the response to Interrogatory No. 20. That approach would eliminate the potential for any double recovery.

Florida Power & Light Company
Docket No. 001148-EI
Staff's First Set of Interrogatories
Interrogatory No. 23
Attachment

Florida Power & Light Company
Estimated Assets to be Transferred to GridFlorida
As of December 31, 1999

NOTE: These amounts are not yet final and represent estimates based on FERC account balances and don't include property in other FERC Functions such as Intangible or General Plant. In addition, equipment which may be excluded from or included in the property to be transferred continues to be identified.

		($000's) Original Cost Book Basis	Accumulated Book Depreciation	Replacement Value (Handy Whitman)
Transmission Plant				
352	Structures & Improvements	43,533	15,551	70,964
353	Station Equipment	781,063	250,044	1,326,579
354	Towers & Fixtures	272,460	179,158	413,013
355	Poles & Fixtures	367,728	178,308	849,244
356	Overhead Conductors & Devices	427,516	234,557	724,566
357	Underground Conduit	32,659	17,477	83,401
358	Underground Conductors & Devices	37,110	24,826	122,600
359	Roads & Trails	72,431	20,410	106,840
Less:				
353	Generator Step-Ups & Cooling	(97,742)	(23,453)	(165,287)
Distribution Plant				
362	Capacitor Banks (Transmission Use)	2,409	611	
Transmission Plant Held for Future Use				
352	Structures & Improvements	1,136	51	
353	Station Equipment	152	3	
357	Underground Conduit	1,046	0	
	Total	1,941,501	897,543	3,531,920

Notes:
Land and Land Rights are assumed to remain at FPL with a use agreement between FPL and GridFlorida.
Replacement cost estimates are based upon the Handy Whitman Index.

Q. On what cost basis will the transmission assets used to provide retail service and being transferred to the FLARTO be valued: net book cost, replacement cost, or some other cost basis?

A. What would be the tax affect of valuing the transferred transmission assets at some other basis than net book cost?

B. If the assets are transferred at a premium over net book, should the premium be reflected on the retail books?

C. If the assets are transferred at less than net book, should the shortfall be reflected on the retail books?

D. Should any premium or shortfall have an immediate impact on retail rates or be absorbed by the company in earnings reported for surveillance?

E. What would the cumulative net present value savings to retail ratepayers be (net book transfer and lower FLARTO rates vs. replacement cost transfer and higher FLARTO rates)?

F. Could a gain on sale result from the transfer of transmission assets to the FLARTO in exchange for Class B stock in the FLARTO? If not, why not?

G. Please identify any anticipated gain on sale from the exchange of transmission assets for Class B stock of the FLARTO.

H. If the utility does not believe a sale will result from the exchange of transmission assets for Class B stock of the FLARTO, please explain what measures FPL will implement to allow regulatory tracking of the value of transmission assets transferred to the FLARTO?

A. Net book cost.

A. It depends on whether there is a contribution of capital of the assets or a sale of the assets to GridFlorida. If there is a contribution of capital, the basis used for valuing assets is not likely to have a direct tax effect, but there may be some indirect impacts if changes in value change allocations among members. If there is a sale of assets to GridFlorida, tax gain or loss is measured relative to tax basis, and any change in value will impact these items in a taxable sale. Valuation changes merely increase or decrease gain or loss if the transaction is a current taxable event.

B. Yes. The portion of the 500 kv line that was allowed accelerated depreciation through the Oil Backout Cost Recovery Clause would be transferred to GridFlrorida as though only straight-line depreciation had been recorded based on FPSC approved transmission account depreciation rates. The difference between the amount of accelerated depreciation allowed and the depreciation that would have been recorded using the straight-line depreciation rates as approved by the FPSC, if any, will be recorded as a gain on the transfer of the transmission property. The gain should be amortized over the estimated remaining life the Oil Backout 500 kv line. The amortization of the gain could be used to offset the higher charge from GridFlorida resulting from its larger rate base and higher depreciation expense.

C. FPL is not contemplating transferring the assets at less than net book value.

D. If the FPSC allows recovery of the payments to GridFlorida through a clause as described in the response to Interrogatory No. 20, then the amortization of the premium would be included in that clause.

E. FPL has not estimated the net present value savings or additional costs to retail ratepayers that may result from transferring transmission assets at net book, replacement or other cost. FPL does not currently know all of the ultimate assets being transferred to GridFlorida, its final structure, or the rates FERC will approve for transmission and ancillary services.

F. FPL is planning to contribute transmission assets to GridFlorida in exchange for a passive ownership interest in GridFlorida. This contribution of transmission assets, which would be at net book value except for the OBO project (see the response to Interrogatory No. 24G), will not result in a gain or loss on the transfer. FPL is not considering exchanging its transmission assets for Class B stock.

G. Since FPL plans to contribute transmission assets to GridFlorida for a passive ownership interest in GridFlorida, the only gain anticipated is for the portion of the 500 kv line that was allowed accelerated depreciation through the Oil Backout Cost Recovery Clause. This portion of the 500 kv line would be transferred to GridFlorida as though only straight-line depreciation had been recorded based on FPSC approved transmission-account depreciation rates. The difference between the amount of accelerated depreciation allowed and the depreciation that would have been recorded using the straight-line depreciation rates as approved by the FPSC, if any, will be recorded as a gain on the transfer of the transmission property.

H. GridFlorida will be a regulated public utility subject to FERC jurisdiction and will maintain a property records system in accordance with the FERC Uniform System of Accounts. This property records system will track the value of all assets owned by GridFlorida.

Q. Will the costs and revenues derived from non-electric utility activities associated with joint use of the divested transmission facilities (such as telephone and cable pole attachments, dark fiber communications leasing, etc.) be transferred to the FLARTO along with the transmission facilities? If yes, identify each activity and the annual cost and revenue associated with that activity.

A. Yes. The only costs associated with the joint use of the divested transmission facilities would be the administration of the joint use activities, e.g., surveying the number of poles and attachments, billings, collections, accounting, etc. These activities and their associated costs have not been separately tracked to date and, therefore, are not available. However, FPL expects these costs to be less than $100,000 per year. The associated revenues associated with these facilities for 2000 are estimated to be approximately $580,000 (telephone - $353,000, CATV - $35,000, and other attachments - $192,000).

Q. How should retail ratepayers be compensated for the loss of revenues resulting from such transfers? Should lost revenues be calculated on a present value basis over the life of the activity? If so, how should future market value and growth be calculated?

A. In general, it is expected that the calculation of rates for GridFlorida would continue to recognize such revenues as a credit, i.e., a reduction to revenue requirements. The specific information necessary to calculate such an impact is still under development.

Q. Provide a detailed breakdown of anticipated Transition costs (clearly identify any severance payments).

A. The table below sets forth all costs expected to be incurred by Florida Power and Light Company to achieve the estimated merger savings. These estimates include severance or separation payments and transition costs such as the use of outside professional firms to assist in the integration of the combined company, travel expenses for the transition team, facilities refurbishment and leasehold improvements. Estimates of costs to achieve are inherently uncertain and there can be no assurance as to the accuracy of these estimates.

$ Thousands	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Total
Separation programs	$20,270	$7,576	$5,571	$0	$0	$0	$0	$0	$0	$0	$33,418
Executive separation	1,783	0	0	0	0	0	0	0	0	0	1,783
Separation assistance	2,260	0	0	0	0	0	0	0	0	0	2,260
Change in control	51,685	0	0	0	0	0	0	0	0	0	51,685
Retention costs	26,346	0	0	0	0	0	0	0	0	0	26,346
System integration costs	4,843	8,068	12,831	13,273	13,359	10,123	6,620	2,446	2,461	2,505	76,529
Transaction costs	20,242	0	0	0	0	0	0	0	0	0	20,242
Relocation costs	8,473	0	0	0	0	0	0	0	0	0	8,473
D&O liability tail coverage	599	577	572	552	545	0	0	0	0	0	2,846
Regulatory process cost	7,245	0	0	0	0	0	0	0	0	0	7,245
Customer/supplier/employee education expenses	9,415	0	0	0	0	0	0	0	0	0	9,415
Transition costs	4,327	4,166	0	0	0	0	0	0	0	0	8,493
Back office consolidation	1,615	1,560	1,552	1,504	1,488	170	173	172	174	173	8,580
Facilities integration	1,883	1,813	0	0	0	0	0	0	0	0	3,696
	$160,986	$23,759	$20,526	$15,329	$15,392	$10,293	$6,793	$2,618	$2,636	$2,678	$261,010

Q. If FPL's transmission assets are transferred to GridFlorida at net book value, for what purpose would the replacement value of the transferred assets be used?

A. None. FPL determined and provided replacement value estimates in order to respond to Staff's First Set of Interrogatories, No. 14E.

Q. **Provide an update to the response to Staff's First Set of Interrogatories, Item Nos. 14 C and E, and 23 A and C as of December 31, 2000.**

A. Please refer to the schedule below:

Florida Power & Light Company
Estimated Assets to be Transferred to GridFlorida
As of December 31, 2000

NOTE: These amounts are not yet final and represent estimates based on FERC account balances and do not include property in other FERC Functions such as Intangible or General Plant. In addition, equipment which may be excluded from or included in the property to be transferred to GridFlorida continues to be identified.

		($000's)		
		Original Cost Book Basis	Accumulated Book Depreciation Reserve	Replacement Value (Handy Whitman)
Transmission Plant				
352	Structures and Improvements	45,952	16,332	74,504
353	Station Equipment	810,544	255,926	1,354,175
354	Towers & Fixtures	272,511	182,982	422,173
355	Poles & Fixtures	388,237	187,738	849,775
356	Overhead Conductors & Devices	432,634	240,834	728,880
357	Underground Conduit	35,622	20,084	85,964
358	Underground Conductors & Devices	40,310	27,432	122,954
Less:				
353	Generator Step-ups and Cooling	(112,127)	(24,679)	(187,331)
Transmission Plant Held for Future Use				
352	Structures and Improvements	1,136	51	1,414
353	Station Equipment	152	3	192
357	Underground Conduit	1,046	0	1,161
	Total	1,916,017	906,703	3,453,861

Notes:
Land and Land Rights and Roads and Trails are assumed to remain at FPL with a use agreement between FPL and GridFlorida.
Capacitor Banks to be used for Transmission use have been reclassified to Account 353, Station Equipment, as of December 31, 2000.
Replacement cost estimates are based upon the Handy-Whitman Index.

Q. Provide the December 31, 2000, difference between the accelerated depreciation and the straight line depreciation associated with FPL's 500 KV transmission line.

A. As of December 31, 2000 accelerated depreciation on the Oil Backout 500 KV line exceeded straight line depreciation by $170.9 million, not including $19.9 million related to Land and Land Rights and Roads and Trails.

Q. Provide the remaining life development for the 500 KV line measured at December 31, 2000. This should include all calculations made and assumptions used in determining age, service life, and curve shape.

A. Based on the average service life and mortality characteristics approved by the Florida Public Service Commission as the result of the 1997 Comprehensive Depreciation Study filed by Florida Power & Light Company (FPSC Docket No. 971660-EI, Order PSC-99-0073-FOF-EI), the composite remaining life of the Oil Backout 500 KV line is approximately 27 years. See Request No. 2 of Staff's Second Request for Production of Documents for the documents used to determine the remaining life.

Q. Which merger-related costs, if any, does FPL intend to include as expenses in its monthly surveillance reports?

A. FPL's expected merger related costs, as shown on the Company's response to Interrogatory No. 31 of Staff's First Set of Interrogatories will be included, when incurred, in its monthly surveillance reports. Please note that the costs shown on that schedule for 2002 are costs that will be incurred during the period from 2000 through 2002 inclusive.

Q. Did FPL refunctionalize any transmission assets/facilities prior to its RTO filing of October 16, 2000? If so,

a. List the prior and current function of the assets/facilities transferred to the GridFlorida.

b. Provide the effective date of the change in function.

c. Provide the current and prior cost of the assets/facilities as it relates to the new and old function.

d. What adjustments will be made to FPL's accounts to rectify any changes due to reclassification of assets/facilities under the operational control and ownership of GridFlorida?

A. No. FPL did not refunctionalize any transmission assets/facilities prior to its RTO filing of October 16, 2000.

Q. a. Is there any part of FPL's transmission system that will not be under the ownership and operational control of GridFlorida, but its usage will be necessary to effectuate functional control of the transmission facilities?

b. If so, has a cost allocation plan been developed for distribution of costs between FPL and GridFlorida?

A. a. Yes. Were FPL to divest, there would be several components of the transmission system that would not be under the ownership and/or operational control of GridFlorida. Examples include (1) certain dual use facilities (e.g., control house, remote terminal units, battery banks, etc.) in transmission-distribution ("T-D") stations that are owned by the load serving entity, (2) land and land rights associated with transmission assets, also being retained by the load serving entity (3) generator main step-up transformers (GSUs), also being retained by the load serving entity, and, (4) at generation-transmission ("GT1") substations, the generator synchronizing breakers located in the generator switchyard, will be owned by GridFlorida, but will be controlled by the generator. A more detailed listing of the demarcation and the assets involved are included in Attachment Q, Sections 1-3, of GridFlorida's Open Access Transmission Tariff part of the compliance filing with Federal Energy Regulatory Commission dated May 29, 2001.

b. A cost allocation plan to reimburse the asset owner for an allocable portion of the full costs to own, operate and maintain the assets is being developed but has not been finalized.

Q. Have any studies been completed concerning the current and future needs of FPL's transmission assets/facilities?

A. Yes.

Q. a. Will FPL transfer ownership/operational control of any facilities currently classified as distribution, generation, or general plant facilities to GridFlorida as part of the transmission system?

b. If so, identify the distribution, generation, or general plant assets that will be under the operational control of GridFlorida.

A. a. In the event FPL elects to divest its transmission assets to GridFlorida, certain distribution, generation, and general plant facilities may be transferred to or be under the operational control of GridFlorida as part of the transmission system.

b. Certain distribution substations that are served by 69 kV and above transmission have components that were originally classified as distribution and which may be re-classified as transmission if these assets are divested to GridFlorida. These assets include, but are not limited to, high voltage buss, insulators and support structures, line sectionalizing switches, transmission breakers, reactive devices connected to the high voltage buss, etc. FPL cannot, at this time, identify any generation assets that may be reclassified as transmission or possibly placed under the control of GridFlorida. FPL intends to retain ownership of general plant assets. However, some general plant assets may be under the operational control of GridFlorida and may include office space and equipment leased by FPL to GridFlorida.

Q. Under GridFlorida's transmission Pricing Protocol filed with FERC on October 16, 2000, "there will be a single system New Facilities Charge to recover the cost of any New Facilities constructed by any Participant that is not directly assigned to a particular customer".

a. Will FPL reclassify any distribution or generation facilities as transmission facilities?

b. If so, will these reclassified facilities be considered New Facilities or Existing Facilities under the Pricing Protocol?

c. Does FPL project any cost recovery for reclassified facilities where the "New Facilities Charge" may apply?

A. a. Please see response 76b.

b. Under the Pricing Proposal, an asset is classified as New Facility or Existing Facility based on its in-service date. If a distribution asset was in-service prior to January 1, 2001 and reclassified as a transmission facility after January 1, 2001, the newly defined transmission asset will be classified as an Existing Facility. An asset placed into service on or after January 1, 2001 and reclassified to a transmission asset account will be classified as New Facility.

c. FPL has not analyzed assets placed in-service on or after January 1, 2001, to determine whether there may be reclassifications that would result in recovery under the "New Facilities Charge".

Q. a. Will FPL conduct a physical inventory of the individual transmission assets to be transferred to GridFlorida?

b. If yes, when is the inventory planned?

c. If no, why not?

d. If a physical inventory has already been performed, provide the results.

A. a. No.

b. N/A

c. A physical inventory would be an expensive and time consuming effort and, at this time, is unnecessary. There is still some question as to whether FPL will transfer its transmission assets to GridFlorida. Should FPL transfer these assets, GridFlorida may elect to conduct its own physical inventory of these assets. In addition, FPL's property records system and associated databases have been developed over a number of years in accordance with FPSC requirements and accurately reflect the physical attributes, and financial information associated with these assets. The financial information associated with these assets is within the scope of the annual audit conducted by independent accountants.

d. N/A

Q. a. Will FPL perform a reconciliation between the results of the physical inventory and its Continuing Property Records for the transmission assets to be transferred?

b. If no, why not?

c. If yes, how will any resulting adjustments be handled?

d. If a reconciliation has already been performed, provide the accounting entries made.

A. a. No

b. At this time, FPL does not intend to perform a reconciliation because FPL is not planning on conducting a physical inventory.

c. N/A

d. N/A

Q. Given that FPL will transfer its transmission assets to GridFlorida, explain in detail the process FPL will undertake to determine the investment and reserve of the individual assets to be transferred.

A. If FPL transfers assets to GridFlorida, where assets do not comprise the complete FERC plant account, FPL is pricing out its investment in the assets to be transferred to GridFlorida at the retirement unit level. This information is maintained in FPL's Continuing Property Records System by vintage year. From the retirement unit and vintage year the depreciation reserve associated with each retirement unit is calculated based on the depreciation rates approved over the life of the retirement unit by the FPSC. The result is a calculation of the net book value of each retirement unit that will be transferred.

Q. Explain in detail how the individual assets to be transferred to GridFlorida will be priced out.

A. The assets will be transferred at net book value (see response to No. 80) except for the portion on the 500 Kv line that was recovered through the Oil Backout Cost Recovery Clause (Clause). The FPSC allowed FPL to recover accelerated depreciation from its retail customers through the Clause. Since the accelerated depreciation was only allowed in retail rates these assets will be transferred to GridFlorida as though only straight line depreciation, based on depreciation rates approved by the FPSC, had been recorded. The accelerated depreciation in excess of straight line depreciation, if any, at the time of the transfer will be recorded as a gain and amortized to the benefit of the retail customers over the average remaining life of the Oil Backout assets.

Q. Did FPL evaluate the benefits and costs associated with participating in a transmission organization other than GridFlorida?

A. Under FERC Order 2000 an RTO has to meet some very specific guidelines as to characteristics and functions to be approved by the FERC. The GridFlorida Companies worked with a broad range of constituents and interested parties in a robust collaborative process that considered a variety of issues related to scope, asset divestiture, structure, and governance. As a result of this effort, the GridFlorida Companies were able to develop and file a GridFlorida RTO proposal that has been provisionally approved by the FERC. During the time the GridFlorida Companies were developing the GridFlorida RTO no other transmission organizations existed in the Southeastern United States; therefore, FPL could not have evaluated the benefits and costs associated with participation.

A FERC's recent order initiated mediation proceedings to establish a larger Southeastern RTO. FPL, although not required to participate, is involved in the FERC mediation proceedings. We do not know what proposal may arise out of that mediation, how FERC will react to any such proposal, or whether the FPL and other GridFlorida Companies would agree to join the larger RTO. However, FPL is participating in the FERC mediation for the same reason that FPL believed that it was prudent to develop the GridFlorida proposal in the first place. We are concerned that someday we may be ordered by FERC to become part of the Southeastern RTO and, even if that is not the case, a Southeastern RTO will have a significant impact on the Florida market. By participating actively in the Southeastern RTO discussion, the FPL and the other GridFlorida Companies already have been able to influence the process, and it appears that the parties are likely to agree to many of the same features that are in the GridFlorida proposal. FPL hopes that by participating we can make the proposed RTO as efficient and effective as possible and otherwise protect Florida ratepayers. Of course, FPL would consult with the FPSC prior to making any decisions about Southeastern RTO participation.

Q. What is the change in retail revenues, plus or minus, as a result of FPL's participation in GridFlorida?

A. Kory Dubin's Exhibit KMD-1, page 1 of 6, line 16, illustrates a rough estimate of FPL's retail revenues increasing by $60.4 million in the first full year of GridFlorida's operations.

Q. What is the change in retail expenses, plus or minus, as a result of FPL's participation in GridFlorida?

A. The change of total expenses, including the return on investment, would mirror the increase in FPL revenues. If the actual incremental costs equals the amount illustrated by Kory Dubin's Exhibit KMD-1, page 1 of 6, line 16, of $60.4 million, then retail expenses would increase by $60.4 million.

Q. According to Exhibit BLH-3, page 2, line 13, the company will be charged a total of $7.700 million for storm damage expense ($7.130 million retail), with an offset of $4.259 million to retail expense , for a net increase of $2.870 million retail.

a. Explain how these amounts were determined.

b. Why will the company experience an increase in storm damage expense?

A. a FPL targeted an estimate of the appropriate stand-alone fund needed to cover potential storm damage to FPL's transmission facilities that may be divested to GridFlorida. The target reserve balance for this fund was $30 million to be accrued over a number of years. In the early years, the difference between the fund balance and the $30 million target will be secured through purchasing lines of credit for the unfunded amount. Thus, the first year cost of $7.7 million had two components. The first component, a $7.5 million accrual, comprising of two elements: $4.6 million accrual for expected storm damage to transmission assets and $2.9 million additional accrual to build the core reserve fund. The second component, $0.2 million line of credit fees to supplement the accruals to provide for the $30 million desired coverage.

The $7.130 million retail represents that portion of the $7.700 million annual expenses that were allocated to retail load based on forecasted 2003 load ratio share (based on 12 month coincident peak load MW).

The $4.600 million total cost off-set represents an estimate of the transmission portion of FPL'S annual projected future storm funding requirements.

The $4.259 million cost off-set to retail expense represents that portion of the $4.600 million total cost off-set that was allocated to retail load based on forecasted 2003 load ratio share (based on 12 month Coincident Peak Load MW).

The $2.870 million retail represents the difference between the $7.130 million and the $4.259 million retail cost off-set.

b FPL targeted an estimate of the appropriate stand-alone fund needed to cover potential storm damage to FPL'S transmission facilities that may be divested to GridFlorida. The target reserve balance for this fund was $30 million to be accrued over a number of years. The $2.870 million net increase retail reflects the decision to accrue the fund over a number of years. As outlined above, FPL budgeted an accrual of $2.9 million to build the core reserve fund and $0.2 million line of credit fees to supplement the first year accrual. The $2.870 million represents the retail portion of these two items allocated to retail load based on forecasted 2003 load ratio share (based on 12 month coincident peak load MW).

Q. **Will GridFlorida insure the transmission assets through an outside insurer or maintain a Storm Damage Reserve?**

A. FPL annually evaluates insurance markets and has determined that outside insurance is not currently a cost-effective means of controlling risk. It is anticipated that GridFlorida will follow a similar annual evaluation process. At this time, FPL has assumed that GridFlorida will maintain a storm damage reserve fund as a risk management vehicle for FPL'S transmission facilities that may be divested to GridFlorida.

Q. Will FPL propose a reduction in its annual storm accrual and targeted storm damage reserve balance after the assets are transferred to GridFlorida?

A. At this time, FPL does not plan to propose changes in its annual storm accrual and targeted storm damage reserve balance due to the potential transfer of assets to GridFlorida.

Q. On page 3 of Ms. Dubin's Direct Testimony, she describes GridFlorida as a for-profit limited liability company (LLC). Please elaborate and discuss the tax aspects of an LLC.

A. For federal income tax purposes, an LLC can be treated as a partnership, by making an election under the check-the-box rules. Electing partnership status results in no taxation at the LLC level, avoiding double taxation when distributions are made to LLC members, and avoiding tax losses from being locked in at the LLC level. This means the members rather than the LLC, are directly taxed on the LLC's income, or the members directly recognize its tax losses. State tax treatment generally follows federal treatment.

Q. On page 8 of Ms. Dubin's Direct Testimony, she describes the proposed methodology of recovery for the transmission costs that are projected to be in excess of those currently allowed recovery through base rates.

A. What are the income tax consequences of divesting these assets and using this methodology of recovery?

B. What are the property tax consequences of divesting these assets and using this methodology of recovery?

C. What other tax consequences are anticipated?

D. What will happen to the deferred taxes and excess deferred taxes associated with the assets that are divested?

E. What will happen to the investment tax credits that are associated with these assets that are divested?

F. Assuming a negative impact on ratepayers as a result of the income tax consequences, what provision could be made to neutralize the negative impact such that the individual company and Florida ratepayers remain whole/unaffected?

A. A. Since it is the "transfer, sale or contribution" of assets which triggers tax consequences, and not per se "recovery of transmission costs," for purposes of this answer it was assumed that the interrogatory intended to cover tax consequences from a "transfer, sale or contribution" of assets. It is also noted, to the extent Ms. Dubin's testimony was referred to, it was assumed that the interrogatory was referring to the page containing "page 7" as the printed page number.

Except as otherwise noted, the transfer of assets from a utility to GridFlorida should generally be tax free. This is not considered as a "divestiture" for tax purposes. For tax purposes, the divestiture occurs when FPL, at a future date transfers to a third party, the ownership interests it initially receives in GridFlorida in exchange for the assets contributed in a "tax-free" transfer to GridFlorida.

Based on previously issued IRS rulings, the Federal tax law mandates the tax treatment described below for the assets, when they are transferred as a capital contribution to a corporation. However, Grid Florida is an LLC, which is treated as a partnership for federal tax purposes. It is anticipated that the same treatment as required for corporations, will be required for GridFlorida, which is an LLC, but the IRS has not specifically ruled on such a transfer to an LLC, which can cause some uncertainty in the form of the IRS requiring some other type of treatment. The anticipated tax consequences are:

The tax attributes related to the transferred property, transfer over from the utility to GridFlorida, including tax depreciation reserves, tax lives, and methods of depreciation. This means that GridFlorida would continue to depreciate the transferred assets using the remaining tax basis at the time of transfer, and using the same life and method of depreciation that FPL was using. This is essentially a continuity of tax treatment or a carryover of treatment from FPL to GridFlorida.

The transferred assets should be removed from utility's books of account and no part of such deferred tax reserve may be used to reduce the utility's rate base or cost of service (or treated as no-cost capital) after the transfer.

B. From a Property Tax perspective, this LLC will fall under FERC regulation and we would value the assets for this organization as we do for our other regulated assets. Depending on the level of record keeping that will be attainable from this new organization will drive which methodology is used in the valuation process.

C. We anticipate no other material tax issues

D. The deferred tax reserve attributable to the transferred assets that will be reflected in GridFlorida's books may, for ratemaking purposes, be used to reduce its rate base or treated as no-cost capital only in accordance with the existing normalization provisions.

E. The balance of the unamortized investment tax credit with respect to the transferred property may be removed from the utility's books to reflect the assignment of the property, and no portion of such unamortized investment tax credit may be used to reduce the utility's cost of service or rate base.

GridFlorida must account for the unamortized investment tax credit allocable to the transferred assets only in accordance with an ITC normalization method acceptable under Federal tax law.

But also note that the deferred tax liabilities, like the current tax provisions, will be that of the utilities, not GridFlorida. Since an LLC is a "pass-through" entity for federal income tax purposes, the tax consequences are recognized at the member level.

F. Negative tax income tax consequences are not foreseen at this time.

Q. On page 9 of Ms. Dubin's Direct Testimony, she describes a proposed adjustment for the Oil Backout.

a. What are the income tax consequences of this proposed adjustment?

b. What are the property tax consequences of this proposed adjustment?

c. What other tax consequences are anticipated?

d. Where will each of the identified tax consequences be reflected (i.e., in the Capacity Cost Recovery Clause, base rates, etc.)?

A. The tax impact should follow revenue changes, which may result from the adjustment. An "adjustment for Oil Backout" generates no special tax consequences, except to the extent the adjustment causes a normal change in revenue.

Q. On page 10 of Ms. Dubin's Direct Testimony, Ms. Dubin uses a revenue tax multiplier of 1.01597 to adjust costs in the Capacity Cost Recovery Clause. Please explain how the 1.01597 tax multiplier was calculated.

A. The tax multiplier of 1.01597 is made up of the following:

Gross Receipts Tax in accordance with Florida Statute 203.1 of 1.5%
Regulatory Assessment Fee per Order No. PSC-98-1660-FOF-EI, in Docket No. 980276-EI, issued 12/9/98 of 0.072%

	100.000%
less Gross Receipt Tax -	1.500%
less Regulatory Assessment Fee -	0.072%
	98.428%

Tax Multiplier Equals: 1.00000 divided by 98.428% = 1.01597

Q. On pages 9 and 10 of Mr. Mennes' Direct Testimony, he states that the estimated cost off-set associated with O & M on transferred assets is approximately $57 million of which $20 million is for property tax on tangible property, poles, and wires, estimated based on 1999 data.

A. Provide a detailed calculation of the $20 million.

B. Provide the retail and wholesale portions of the $20 million and provide a calculation of the retail and wholesale portions.

A. A. FPL's estimate of $20 million was based upon the actual tangible personal property taxes paid by FPL on transmission lines and stations to each respective county for 1999. The approximate amounts paid by FPL were $11,100,000 (transmission stations) and $8,100,000 (transmission lines). The sum was rounded up to $20 million to accommodate asset growth and for the budgetary forecast.

B. In order to estimate the retail and wholesale portions, FPL allocated the $20 million estimate of tangible personal property tax on transmission lines and stations between retail and wholesale portions based on forecasted load, as shown on Exhibit BLH-1, Appendix 1, ratio share (based on 12 month coincident peak load MW). The calculation is as follows:

Retail estimate = $20 million x 93% =	$18.5 million
Wholesale estimate = $20 million x 7% =	$ 1.5 million
	$ 20.0 million

Q. **On page 10 of Mr. Mennes' Direct Testimony, he states that the estimated cost off-set associated with salaries and benefits is $2.733 million.**

A. **Provide a detailed breakdown of the $2.733 million between actual payroll costs and each benefit, including FICA, FUTA, SUTA, etc.**

B. **Provide supporting calculations for each item listed in response to part A of this interrogatory.**

A. A. FPL identified functions that FPL is currently providing that may be transferred or performed by GridFlorida in the future. FPL estimated that 27 full time skilled personnel currently perform these functions at FPL. The salary and benefits estimate for each of these positions was based upon the assumptions developed by Accenture as part of the "blueprint engagement". The salary assumption was $75,000 annually per employee plus 35% loading for employee benefits, payroll taxes, insurance, etc.

B. All of the available detail used in these calculations is described above.

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Q. On pages 10 through 12 of Mr. Mennes' Direct Testimony, he refers to cost off-sets associated with the following: lease back arrangements; control center facilities and building services; disaster recovery facility; storm fund; telecommunications; meetings, travel and seminars; employee training budget; and FERC fees. Provide a list of any and all tax consequences related to the above cost off-sets, separated into retail and wholesale.

A. These items will generally receive normal tax treatment, which means a deductible income tax expense for the party making the payment, and taxable income for the party receiving the payment. With regard to payments relating to the use of real property, there is a possibility that these payments could be subject to Florida sales tax. FPL plans to seek clarification from the Florida Legislature that these payments are not subject to sales tax. FPL has not calculated the tax consequences associated with the items listed above.

Q. **On page 6, beginning at Line 13, the Joint Testimony of Mike Naeve, C. Martin Mennes, Henry Southwick and Greg Ramon states, "Use of a limited liability company to own the transmission facilities allows passive ownership interests in GridFlorida by divesting transmission owners to satisfy the Order No. 2000 independence standard, and offers favorable tax treatment." Please explain in detail how this favorable tax treatment is provided, citing relevant Internal Revenue Service (IRS) Code Sections and/or other applicable IRS statements.**

A. Internal Revenue Service Regulation Section 301.7701-1, Regulation Section 301.7701-2 and Regulation Section 301.7701-3 are the "check-the-box" entity classification regulations. Under those regulations, a partnership is a business entity, with two or more members, that is not mandatorily classified as a corporation, and that has elected, or defaulted to, partnership tax status. When an LLC makes an election to be treated as a partnership for tax purposes, only the members and not the LLC are taxed on the entity's income. This is contrasted with the situation where GridFlorida would be a "corporation." The corporation would be taxed on its income, and the shareholders of the corporation would again be taxed when dividends are distributed to them. An LLC electing partnership status avoids this double taxation.

Q. Provide a schedule which shows how the sources of capital (i.e., deferred taxes, investment tax credits, investor capital, etc.) associated with the transmission assets which are proposed to be transferred to GridFlorida will be removed from the capital structure of FPL. For purposes of this response, show the capital structure components, costs rates, and overall cost of capital of FPL before and after the removal of the capital associated with the transmission assets.

A. FPL has not made a final determination of all sources of capital that may be transferred to GridFlorida. The Deferred Income Taxes and Investment Tax Credit will be reflected on the regulated books of GridFlorida along with the associated assets transferred. FPL has not made a final determination of all assets that may be transferred and therefore, the amounts of deferred income taxes and investment tax credits has not been determined.

Q. **Discuss in detail how the removal of capital associated with the transmission assets will affect the overall cost of capital of FPL.**

A. See response to Interrogatory Number 98. FPL has not made this determination.

Q. What does FPL believe the total cost of capital will be for GridFlorida for the first year of operations? For purposes of this response, show the capital structure components, relative percentages, cost rates, and overall cost of capital.

A. FPL has not made this determination. Please see response to Interrogatory #102 in reference to the carrying charge rate used for illustrative purposes in Exhibit KMD-1.

Q. What does FPL believe its share of the total cost of capital (amount and percentage) will be for GridFlorida's first year of operations?

A. FPL has not made this determination. Please see response to Interrogatory Number 98.

Q. For purposes of calculating the revenue requirements associated with the new facilities portion of the GridFlorida transmission charge, explain in detail how the annual carrying charge applied to the accumulated new average investment balance is calculated. In your response, show the capital components, relative percentages, cost rates and overall cost used in the calculation and reconcile these amounts to FPL's relevant earnings surveillance report (ESR). If necessary discuss why the carrying charge cannot be reconciled to the ESR.

A. The annual carrying charge applied to the accumulated new average investment balance as shown in Kory Dubin's Exhibit KMD-1, page 6 of 6, line 18, illustrates the magnitude of the revenue requirement impact of new facilities charge. A carrying charge rate could vary significantly given the range of factors that would influence the rate.. The actual carrying charge rate GridFlorida would experience is beyond the control and scope of the issues and matters FPL and the other Joint applicants' have in establishing GridFlorida. The capital structure, depreciation rates, and other revenue requirement components will be GridFlorida decisions subject to the approval of the Federal Energy Regulatory Commission.

The selection of 18.5% carrying charge rate for illustrative purpose was based on examining the following ranges of input factors:

Capital Structure:

	%	Cost Rate
Debt	45% - 50%	6.5% - 7%
Equity	55% - 50%	11.8% - 12%

Income Tax rates
Federal 35%
State 5.5%

Depreciation rates: 2.3% - 3.1%

O&M expenses 2.1% - 4.1%

Resulting Carrying Charge rate 17% - 20%

A reconciliation between the 18.5% illustrative carrying charge rate used in Exhibit KMD-1 to FPL's relevant earnings surveillance report has not been performed.

Q. Mr. Holcombe's testimony states that the GridFlorida start up and operating cost estimates assume, among other things, that GridFlorida initially will lease the FPL control center. Will FPL need a control center to fulfill other FPL utility needs?

A. Yes, although FPL will not need a control center as elaborate or large as FPL's existing control center. Assuming FPL leases its existing control center to GridFlorida, FPL will need a smaller facility to carry out non-transmission functions such as generator dispatch and distribution operations.

Q. Will GridFlorida lease the communications equipment located in FPL's control center to operate GridFlorida? If yes, provide the lease price and explain how that price was determined.

A. Yes. In the event FPL divests its transmission assets to GridFlorida, GridFlorida will lease the portion of the communications equipment located in FPL's control center that is allocated to the transmission function. The estimate for the telecommunications is $750,000 per year and was determined from a functional allocation of all the communications equipment located at FPL's control center based on generation, distribution, transmission and common functionality.

Q. Please explain how the estimated land use fees between FPL and GridFlorida were developed. In your response, please provide a calculation of these fees and list and explain all assumptions.

A. The estimates developed for land use fees constitute reimbursement of the full costs incurred by FPL to own, operate and maintain the assets. The components of the estimate and the calculation is as follows:

Description	Rounded Amounts
Amortization of Land Rights	$ 3,000,000
Property Taxes	3,000,000
Carrying Charge	15,000,000
Total Estimate	$21,000,000

Assumptions:
Amortization of Land Rights - based on amortization recorded for the year ended December 31, 2000 for Account 350.2 Easements in the amount of $2.5 million. Property Taxes based on real property taxes paid for 1999 on transmission stations in the amount of $1.2 million and on transmission right-of way in the amount of $1.7 million. Carrying Charge based on FPL's pre-tax weighted average cost of capital for 12/31/99 which was approximately 12% and asset base of approximately $125 million (estimated net-book-value of assets).

Q. **What amount, if any, of FPL's storm damage reserve will be transferred to GridFlorida? Explain how the appropriate amount of FPL's storm damage reserve to transfer to GridFlorida was determined.**

A. FPL does not plan on transferring any of its existing storm damage reserve to GridFlorida.

Q. **Would FERC have considered a detailed explanation of state oversight of retail transmission an acceptable reason for a public utility not to make a filing to participate in a regional transmission organization?**

A. To FPL's knowledge, no utility advanced this reason for not making a filing, nor is this reason mentioned in Order No. 2000, so FPL does not know how FERC would have reacted. However, it seems unlikely that state oversight over retail transmission would have been deemed an acceptable reason by FERC for not participating in an RTO. Order No. 2000 was directed principally towards creating large transmission organizations that could provide service across several transmission systems at non-pancaked rates and at ensuring that control over those organizations was independent of market participants. State oversight of individual utility retail transmission does not achieve either of these results.

Q. **Refer to page 25, lines 18 - 19, of Witness Hoecker's testimony. Will the elimination of pancaked rates through the administration of Florida's transmission system by a single RTO result in cost shifts? If so, identify the affected utilities and the amount of the cost shifts.**

A. Yes, the elimination of pancaked rates in the GridFlorida region as a result of the creation of the RTO will result in cost shifts. The cost shift that results from this elimination is mitigated by phasing in the elimination during the 10-year phase-in period provided in the GridFlorida tariff (see Attachment T, in particular Section 8.1 and 8.2).

All utilities that join GridFlorida will be affected by this elimination to some degree. Revenues will be lost by some from charges no longer imposed, and costs will be reduced for others from transmission charges no longer incurred. Most will have both effects.

It is difficult to determine the exact amount of cost shifts resulting from the elimination of pancaked rates because (i) it is not certain (other than FPL, FPC and Tampa Electric) which utilities will join GridFlorida and when (per the GridFlorida tariff, utilities that do not join are still subject to pancaked rates), (ii) future transactions between parties are hard to predict, and (iii) some mitigation measures (e.g. mitigation for loss of short-term transactions) are dependent on future unknown transactions within GridFlorida.

Please refer to Florida Power and Light's worksheets provided in response to Staff's First Set of Interrogatories, Interrogatory Number 11, "What will the rate and revenue impact be on FPL due to the elimination of pancaked transmission rates?" Page 3 of 6 in the Attachment identifies the individual utilities providing information to the GridFlorida RTO Pricing Committee and quantifies cost shifts among them.

Q. **Refer to page 27, lines 11 - 12, of Witness Hoecker's testimony. Has FPL, or any entity known to FPL, calculated the approximate dollar benefit to Florida from an RTO? If FPL has made such a calculation, please provide the results of the calculation, stating all assumptions. If another entity known to FPL has made the calculation, please identify that entity and, if known, the results of its calculations.**

A. No.

Q. Refer to page 10, line 2, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Identify and quantify those costs previously borne by out-of-state customers that customers in Florida may be required to bear.

A. The nature of the cost shifts would be similar to cost shifts GridFlorida addresses. Those cost shifts result from elimination of pancaking of transmission charges, Transmission Dependent Utility credits, and averaging low-cost and high-cost transmission providers together. An out-of-state RTO for the Southern United States is too preliminary in its development, size, and scope to ascertain the cost shift impacts to Florida customers should the GridFlorida Companies participate, or even whether costs would be shifted into or out of Florida, i.e. whether Florida ratepayers would pay more or less for transmission.

Q. Is the initial use of FPL's control center dependent on the form of RTO created?

A. Yes. Consider two possible scenarios, (1) FPL divests its transmission assets to GridFlorida Transco, or (2) FPL transfers operational control to an RTO. In the first scenario, GridFlorida will use FPL'S control center for direct control of GridFlorida's facilities and indirect control of any Participating Owner's facilities. In the second scenario, FPL will use its control center as a control area operator under the direction of the RTO entity that has operational control.

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Q. Refer to page 13, lines 6 - 8, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Witness Naeve states that the GridFlorida proposal eliminates pancaked rates for new transactions and depancakes existing transactions over a period of 10 years. Quantify both the benefits to FPL's ratepayers and to Florida associated with new transactions and the benefits associated with existing transactions. Could the benefits have been achieved regardless of the form of the RTO?

A. It is impossible to know what new transmission transactions will take place so it is not possible to quantify the benefits of eliminating pancaked rates associated with such transactions. The benefits of eliminating pancaked rates do not depend on the form of the RTO.

Q. Identify and quantify the benefits to FPL's ratepayers and to Florida associated with the Physical Transmission Rights model of congestion management included in the GridFlorida proposal. Could the benefits have been achieved regardless of the form of the RTO?

A. FPL believes the results of the Flowgate Work Group (available on the GridFlorida web site) demonstrates that several flowgates exist in the grid, and that assigning physical rights to existing users assures equity to FPL's ratepayers. Each LSE will be required to operate and schedule within its allocation of rights, or secure rights from others in the marketplace, or pay for either buy through rights or the congestion it causes. The Physical Transmission Rights model contained in the GridFlorida proposal is expected to achieve this benefit because it complies with and has been accepted by the FERC as compliant with Order No. 2000. The benefits of the proposal are not dependent on the form of the RTO.

Q. **Refer to page 23, lines 7 - 9, of Witness Naeve's testimony (filed August 15, 2001 in all three dockets). Will a transco that owns assets have greater financial strength and access to capital necessary to fund construction and maintenance at a lower cost than an ISO whose participants still own their assets? If yes, why? If no, why not?**

A. A Transco that owns significant assets should have a greater financial strength and access to capital to fund construction and maintenance. An ISO, by definition, does not own transmission assets so funding construction and maintenance is not the issue. An ISO must try to get the transmission owning utilities or another entity to fund and construct the needed facilities. Because the existing utilities do not have control over transmission rate design, they lack control over the recovery through transmission rates of the capital they invest in facility upgrades. This disconnect between control over capital investment and rate recovery will make it difficult for transmission owners operating under a non-asset owning ISO to raise capital at reasonable rates. Further, entities with significant assets tend to have better credit ratings than entities with no assets.

Lack of control over revenue recovery will not be an issue for non-divesting owners in GridFlorida because they are guaranteed revenue requirement recovery. GridFlorida, who has all the rate design authority, also bears all of the risk for revenue requirement recovery.

By contrast, ISOs, which do not have significant assets, must transfer the risk of revenue underrecovery back to the transmission owner, which is why the disconnect between ownership and rate design is a problem for ISOs and not GridFlorida.

Q. Identify and quantify the costs and benefits associated with transferring ownership of transmission facilities to GridFlorida that FPL considered when evaluating its participation in GridFlorida.

A. FPL did not identify and quantify the costs and benefits associated with transferring ownership of transmission facilities to GridFlorida.

Q. Identify and quantify the costs and benefits associated with transferring operational control of transmission facilities to GridFlorida that FPL considered when evaluating its participation in GridFlorida.

A. FPL did not identify and quantify the costs and benefits associated with transferring operational control of its transmission facilities to GridFlorida.

Q. Explain why the GridFlorida companies have selected a December 31, 2000, date to distinguish between the cost of existing transmission investment and new facilities.

A. There were several reasons for selecting that date. One reason was to correspond with the end of a calendar and fiscal year (in this case, the one just prior to the then expected startup date of GridFlorida December, 2001) of the investor-owned utilities making the filing. This was done to facilitate accounting controls over which facilities would be in the existing investment revenue requirements filings and which would be in the new investment revenue requirement filings. Another reason was to pick a date close to the startup to minimize cost shifts at startup since the cost of existing facilities would be recovered through zonal rates and the cost of new facilities would be recovered through the system-wide rate. Still another reason was to correspond to the end of the expected test period for the Part 1 rates (which was expected to be calendar year 2000) in order to ensure no under or double counting of facilities. Finally, December 31, 2000 corresponded to the date which was associated with grandfathering of existing transmission agreements, including interconnection agreements.

Q. **a.** **Do the transmission facilities that are owned by or under the control of GridFlorida have to be contiguous?**

b. **If no, will the noncontiguous or strategic positioning of the transmission facilities have any impact on GridFlorida's ability to ensure the capability and reliability of the coordinated operation of the transmission systems?**

c. **If yes, please identify the locations/layout of the contiguous transmission facilities as of June 30, 2001.**

d. **If mapping is not complete, please identify the areas of new facilities construction and projected dates of completion to achieve the desired results of GridFlorida.**

A. a. Nothing in the GridFlorida proposal precludes non-contiguous transmission facilities to be under the control GridFlorida.

b. Grid Florida will have Security Coordinator control over all transmission in the FRCC to ensure reliable and coordinated operation.

c. N/A.

d. The areas of new facilities construction and projected dates of construction were provided to the Commission as part of the answer to Staff's Third Request for Production of Documents No. 4.

Q. Mr. Southwick's testimony, page 15, beginning with line 5, states that many of GridFlorida's systems will be new and will replace or overlay existing FPL, FPC and TECO systems. Further Mr. Southwick states that these costs are necessary to ensure that GridFlorida will meet its requirements.

a. For FPL, provide a list of the planned new systems, showing the location and expected service date.

b. For FPL, provide the estimated costs of these new systems and explain how were they developed.

c. For FPL, provide a list of the systems being replaced, indicating the location, the planned retirement date, the dollar amounts associated with the systems to be retired, and the account number where the investments are currently located. Explain how the dollar amounts associated with the systems to be retired were determined.

A. a. Such a list is not available because it's too early in the GridFlorida development process to identify the necessary planned new systems required to comply with FERC Order 2000. However, the Capability Model, as developed by Accenture and provided in Exhibit BLH-2 illustrates the capabilities necessary to ensure GridFlorida meets its requirements.

b. The specific systems have not been identified yet; therefore FPL can not provide the estimated costs of these systems.

c. For FPL, the specific systems being replaced have not been identified yet; therefore FPL can not provide a list of these systems indicating the location, date and dollar amounts.

Q. A. Did FPL consider transferring assets to GridFlorida at other than net book value?

B. If yes, what other alternatives were considered?

C. If no, explain why not.

D. Explain why net book value was determined to be the most appropriate valuation to transfer the divested assets.

A. A. No.

Except for the accelerated recovery of the 500kV line allowed by the FPSC through the Oil Backout Clause, the transmission assets should be transferred at net book value (see response to Staff's First Set of Interrogatories No. 24). The rates charged to FPL's customers, both retail and wholesale, have been and are currently set using net book value.

B. Not applicable.

C. See response D.

D The Federal Energy Regulatory Commission Uniform System of Accounts promulgates the accounting for electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise. GridFlorida's accounting for the asset contribution would be governed by the accounting rules within the Uniform System of Accounts. Any amount that GridFlorida pays over and above the cost incurred by a contributing company, the person who first devoted the property to utility service, would be charged to Account 114 Electric Plant Acquisition Adjustments and amortized to Account 425 Miscellaneous Amortization. Items described as chargeable to Account 425 include Account Amortization of utility plant acquisition adjustments, or of intangibles included in utility plant in service when not authorized to be included in utility operating expenses by the Commission (emphasis added). FPL does not believe that its customer's rates should increase or decrease in the future as a result of transferring the assets at above or below net book value.

Q. **The joint testimony of Mr. Naeve, Mr. Mennes, Mr. Southwick and Mr. Ramon, pages 18 through 23, defines the demarcation between transmission and distribution facilities.**

A. **On page 19 regarding predominately distribution step down substations, lines 21 - 22 state that the "Transmission breakers in a ring bus that also serve as the protective device for a step down transformer are not deemed to be transmission facilities." However, lines 4- 6 on page 20 state that similar items in predominately transmission switching stations will be transferred to GridFlorida. Explain why the transmission breakers in predominately distribution step down substations will not be transferred to GridFlorida while those in predominately transmission switching stations will be transferred.**

B. **On page 22, lines 9-16, the GridFlorida Companies concluded that a uniform demarcation point for transmission facilities is a reasonable approach. Explain specifically what other factors and benefits referred to on line 15 outweigh any reason to attempt to undertake the reclassification of the 69 kV and above facilities as distribution.**

A. A. The statement on page 19 is an error, all such breakers will be transferred to GridFlorida.

B. There is little benefit to reclassify the small portion of 69 kV and above facilities that may be eligible for reclassification as distribution. There are certain 69 kV and above facilities that act like distribution facilities in that they are radial in nature and can not carry any bulk power. Such facilities were candidates for reclassification, but the future functionality of these facilities could be changed to transmission merely by connecting the radial feed to another source in the transmission network. It was decided that the uniform demarcation point should be at 69 kV to facilitate the initial and future asset transfer.

Q. **Are there any assets currently in Account 103, Experimental Electric Plant Unclassified, that will be transferred to GridFlorida? If so, for each asset provide the investment and associated depreciation reserve as of December 31, 2000, along with the company's plans for these assets and the basis for why these assets should be transferred to GridFlorida.**

A. No.

Q. Are there any assets currently in Account 105, Electric Plant Held for Future Use, that will be transferred to GridFlorida? If so, for each asset provide the investment as of December 31, 2000, the company's plans for future use and the basis for why these assets should be transferred to GridFlorida.

A.

Yes. Please see below. This account includes the original cost of electric plant owned and held for future use in electric service under a definite plan for such use. Assets are continually constructed and placed in service or help for future use to address the needs of growth and system reliability. The assets include some of the more recent additions for these purposes and comprise an integral part of the transmission system

		($000's) General Ledger 105
Transmission Plant Held For Future Use		
352	Structures and Improvements	1,136
353	Station Equipment	152
357	Underground Conduit	1,046
	Total Future Use	2,334

NOTES: These amounts are not yet final and represent estimates based on FERC account balances and do not include property in other FERC Functions such as Intangible or General Plant. In addition, equipment which may be excluded from or included in the property to be transferred to GridFlorida continues to be identified.
Land, Land Rights and Roads and Trails are assumed to remain at FPL with a use agreement between FPL and GridFlorida.
Capacitor Banks to be used for Transmission use have been reclassified to Account 353, Station Equipment as of December 31, 2000.
Replacement cost estimates are based upon the Handy-Whitman Index.

Q. Are there any assets currently in Account 106, Completed Construction Not Classified-Electric (Major Only), that will be transferred to GridFlorida? If so, for each asset provide the investment as of December 31, 2000, and the basis for why these assets should be transferred to GridFlorida.

A. Yes. Please see below. This includes the total of the balance of work orders for tangible transmission electric plant which has been completed and placed in service but which work orders have not been transferred to the detailed electric plant accounts. Assets are continually constructed and placed in service for purposes of growth and maintaining system reliability. The assets in this account include some of the more recent additions for these purposes and comprise an integral part of the transmission system.

			($000's)	
		General Ledger 101	General Ledger 106	Total Original Cost Book Basis
Transmission Plant				
352	Structures and Improvements	45,657	295	45,952
353	Station Equipment	803,746	6,798	810,544
354	Towers & Fixtures	272,440	71	272,511
355	Poles & Fixtures	375,455	12,782	388,237
356	Overhead Conductors & Devices	422,767	9,867	432,634
357	Underground Conduit	35,341	281	35,622
358	Underground Conductors & Devices	39,948	362	40,310
Less:				
353	Generator Step-ups and Cooling	(112,047)	(80)	(112,127)
	Total (Excluding Future Use)	1,883,307	30,376	1,913,683

NOTES: These amounts are not yet final and represent estimates based on FERC account balances and do not include property in other FERC Functions such as Intangible or General Plant. In addition, equipment which may be excluded from or included in the property to be transferred to GridFlorida continues to be identified.
Land, Land Rights and Roads and Trails are assumed to remain at FPL with a use agreement between FPL and GridFlorida.
Capacitor Banks to be used for Transmission use have been reclassified to Account 353, Station Equipment as of December 31, 2000.
Replacement cost estimates are based upon the Handy-Whitman Index.

Q. Mr. Mennes' testimony, on pages 7 - 8, describes the GridFlorida Facilities Project costs and the overall amount of FPL's offsets. Does FPL consider its total offset of $635,000 to be a significant offset? Why or why not?

A. FPL's objective was to develop the most cost-effective means to comply with FERC Order No. 2000 while fully considering the needs of the customers of Florida as drivers in the development of GridFlorida. FPL recognized that certain of its existing assets could facilitate start up of the RTO. FPL chose to incorporate those assets within the overall implementation plan for GridFlorida. FPL's cost off-sets are a manifestation of that strategy and are a significant element in minimizing cost.

Q. Does FPL's offset of $107,607 for building lease fees associated with the leasing of 11,000 sq. ft. of the FPL control center reflect fair market value? Please explain your response.

A. The fair market value of the facility is unknown. The building lease fees constitute reimbursement of the full costs incurred by FPL to own, operate and maintain the assets. That cost is $39 per square foot.

Q. Does FPL's offset of $495,000 for building lease fees associated with the leasing of office space at the FPL control center for 12 months prior to commercial operations reflect fair market value? Please explain your response.

A. The fair market value of the facility is unknown. The building lease fees constitute reimbursement of the full costs incurred by FPL to own, operate and maintain the office space associated with the control center. That cost is $39 per square foot.

Q. **Does FPL's offset of $32,000 for building lease fees associated with the leasing of the disaster control facility for 12 months prior to commercial operations reflect fair market value? Please explain your response.**

A. The fair market value of a disaster control center is unknown. The building lease fees constitute reimbursement of the full costs incurred by FPL to own, operate and maintain the assets. That cost is $27 per square foot.

Q. Mr. Mennes' testimony, on page 12, describes FPL's estimated cost offset associated with telecommunications. Once GridFlorida becomes operational, who will own the telecommunications equipment on FPL's transmission towers?

A. Several years ago FPL created a separate subsidiary, Fibernet, and transferred the FPL owned telecommunications equipment on FPL's transmission towers to Fibernet. Once GridFlorida becomes operational, Fibernet will continue to own the telecommunications equipment on the transmission towers. In addition, all telecommunications equipment owned by third parties, such as wireless antennas, will continue to be owned by such third parties once GridFlorida becomes operational."

Q. Under the GridFlorida Proposal should merchant plants have physical transmission rights if they do not currently serve a native load?

A. The GridFlorida proposal assigned physical transmission rights to Load Serving Entities (LSE's) within GridFlorida. These LSE's could transact with merchant plants on a non firm basis, or on a firm basis if they possessed enough physical rights.

Q. What is FPL's proposed treatment of revenues associated with pole attachments where those attachments are located on transmission assets transferred to the RTO? What proportion of total pole attachment revenues are derived from attachments to transmission poles?

A. In the event that FPL elects to divest its transmission assets to GridFlorida, revenues associated with attachments to transmission assets would be recognized by GridFlorida in the FPL zonal revenue requirements. Based on 2000 actual results, revenues from attachments to transmission assets accounted for approximately 3% of total attachment revenues. ($583,298 / $18,076,249).

Q. Regarding the divestiture of transmission assets, provide detailed sample pro forma journal entries that track divestiture of the transmission assets from the regulated books of the company through all entities to their ultimate entity, ensuring that the entities are easily recognizable. The sample journal entries should also include entries to record the sale/purchase of the non-voting stock. Also, provide the assumptions used to develop the sample journal entries, the detailed account numbers and account descriptions, and summary of the income tax consequences to each entity.

A. FPL has not prepared nor has the information available.

Q. Provide detailed sample pro forma journal entries that track a sale of Class B stock along with recording the gain or loss, if any, ensuring that the entities are easily recognizable. Also, provide the assumptions used to develop the sample journal entries, the detailed account numbers and account descriptions, and summary of the income tax consequences to each entity.

A. FPL has neither prepared nor has the information requested.

Q. **At each stage described in the preceding two questions, provide pro forma balance sheets for each entity.**

A. FPL has neither prepared nor has the information requested.

Q. How will the divested transmission assets be reflected in FPL's Earnings Surveillance Reports?

A. The divested transmission assets would be recorded as an investment in GridFlorida and reflected as such in the preparation of the Earnings Surveillance Reports.

Q. How will the Class B stock be reflected in FPL's Earnings Surveillance Reports?

A. FPL would contribute its assets for an ownership interest in GridFlorida. This ownership interest would be recorded as an investment in GridFlorida, see response to interrogatory 179, this set.

Q. Provide the reproduction, replacement, and market value as of December 31, 2000, for those assets being transferred to GridFlorida.

A. Given the current level of uncertainty, it would be difficult to develop a credible and defendable estimate of true market value for these assets.

In response to Staff's Second Set of Interrogatories, Question Number 62, FPL previously provided the following estimates of replacement value, based on the Handy-Whitman Index as of December 31, 2000, by FERC plant accounts:

Replacement Value	$(000)'s
352 Structures and Improvements	74,504
353 Station Equipment	1,354,175
354 Towers & Fixtures	422,173
355 Poles & Fixtures	849,775
356 Overhead Conducters & Devices	728,880
357 Underground Conduit	85,964
358 Underground Conducters & Device	122,954
Less:	
353 Generator Step-ups and Cooling	(187,331)
Transmission Plant Held for Future Use	
352 Structures and Improvements	1,414
353 Station Equipment	192
357 Underground Conduit	1,161

NOTES: These amounts are not yet final and represent estimates based on FERC account balances and do not include property in other FERC Functions such as Intangible or General Plant. In addition, equipment which may be excluded from or included in the property to be transferred to GridFlorida continues to be identified.
Land, Land Rights and Roads and Trails are assumed to remain at FPL with a use agreement between FPL and GridFlorida.
Capacitor Banks to be used for Transmission use have been reclassified to Account 353, Station Equipment as of December 31, 2000.
Replacement cost estimates are based upon the Handy-Whitman Index.

Q. In response to Interrogatory No. 14B from Staff's First Set of Interrogatories to Florida Power & Light Company in this docket, FPL states that "property journal vouchers at the retirement unit level will be prepared to transfer all assets from the utility to GridFlorida using a separate company code identification for the new company." Does this mean that FPL will maintain these assets on its books with a new company code? If so, what will be contained in GridFlorida Property Records System?

A. FPL will not maintain the assets of GridFlorida on its books. The property records system will be used to identify and facilitate the transfer of the ownership of the assets from FPL to the new company. The new company code will be established in the property records system for this purpose and the new company will not be on the books and records of FPL. For a limited period of time, the utility may maintain the identification and reporting of the assets for GridFlorida . All attributes associated with each retirement unit (FERC account, in service year, location, etc.) will be maintained for in the property records system of GridFlorida.

Q. **Has FERC provided any guidance on the accounting procedures to be followed in transferring assets from the participating companies to GridFlorida? If so, please describe those procedures. If not, does FPL anticipate that such guidance will be requested or provided?**

A. FERC has not provided any guidance on the transfer of any assets to a RTO.

Q. Explain why the divested transmission assets should not be transferred to GridFlorida at reproduction cost, replacement cost, or market value.

A. The Federal Energy Regulatory Commission Uniform System of Accounts promulgates the accounting for electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise. GridFlorida's accounting for the asset contribution would be governed by the accounting rules within the Uniform System of Accounts. Any amount that GridFlorida pays over and above the cost incurred by a contributing company, the person who first devoted the property to utility service, would be charged to Account 114 Electric Plant Acquisition Adjustments and amortized to Account 425 Miscellaneous Amortization. Items described as chargeable to Account 425 include Account Amortization of utility plant acquisition adjustments, or of intangibles included in utility plant in service when not authorized to be included in utility operating expenses by the Commission. To the extent assets are transferred above book value, GridFlorida rates would increase. Any gain would need to be amortized to offset the increased transmission rates. FPL does not believe that its customer's rates should increase or decrease in the future as a result of transferring the assets at above or below net book value.

Q. Please identify and discuss the benefits and harms to ratepayers and stockholders if the divested transmission assets are transferred to GridFlorida at reproduction cost, replacement cost, market value, or net book value.

A. Except for the accelerated recovery of the 500kV line allowed by the FPSC through the Oil Backout Clause, the transmission assets should be transferred at net book value (see response to Staff's First Set of Interrogatories No. 24). The rates charged to FPL's customers, both retail and wholesale, have been and are currently set using net book value. FPL does not believe that its customer rates should increase or decrease in the future as a result of transferring the assets at above or below net book value.

Q. A. In its response to Interrogatory No. 23D from Staff's First Set of Interrogatories to Florida Power & Light Company in this docket, FPL states that the FPSC and FERC transmission account depreciation rates are the same and the accumulated depreciation is the same for both, except for that portion of the 500 kV line for which the FPSC allowed accelerated depreciation through the Oil Backout Cost Recovery Clause. Please provide the latest FERC approved transmission depreciation rates, by account, and the FPL's investment and accumulated depreciation by FERC transmission account as of December 31, 2000.

b. Will FPL retain ownership of the land and land rights associated with the 500 kV line recovered through the Oil Backout Cost Recovery Clause? If yes, please provide the total accelerated depreciation expense booked for this investment along with the associated investment and depreciation reserve as of December 31, 2000.

A. A. Below are the plant and reserve balances as of December 31, 2000 and the depreciation rates approved by the FERC in the company's settlement agreement.

Transmission Plant	Plant in Service	Reserve Balance	Depr. Rates
350.2 Easements	$ 138,069,450	$ 49,615,234	2.2%
352.0 Structures & Improve.	45,952,070	16,332,409	2.2%
353.0 Station Equipment	810,544,344	255,926,099	2.2%
354.0 Towers & Fixtures	272,510,655	182,982,175	2.6%
355.0 Poles & Fixtures	388,237,031	187,738,211	3.5%
356.0 Overhead Cond. & Devices	432,633,685	240,834,411	3.4%
357.0 Underground Conduit	35,622,265	20,083,894	1.8%
358.0 Underground Cond. & Dev	40,309,990	27,431,587	2.0%
359.0 Roads & Trails	72,693,655	21,760,931	2.1%
Total	$2,236,573,145	1,002,704,951	

Paragraph A, Section VII, of the FERC settlement agreement states that "For the period from January 1, 1998, until the settlement rates established hereby are superseded, FPL's depreciation and amortization rates for wholesale services shall be the same as the depreciation and amortization rates approved by the FPSC;". The depreciation rates shown above are the latest approved for use by the FPSC (Docket No. 971660-EI).

The accumulated reserve balance includes the accelerated depreciation associated with the 500 kV line that the FPSC allowed FPL to recover through the Oil Back out Cost Recovery Clause. The gain that would be recorded by FPL upon the transfer of the assets is the difference between the accelerated depreciation taken on all the transmission assets recoverable under the Oil back out Recovery Clause compared to the depreciation calculated under the straight-line method using approved rates. The difference between the accelerated depreciation and what would have been recorded under a straight-line method is not maintained at the FERC account level. As of December 31, 2000, this amount is $190,454,184, which is based on all the transmission assets recoverable under the Oil Back out Cost Recovery Clause. If the transfer of assets excludes land, land rights and road and trails, the gain related to the difference in accelerated depreciation reported and as calculated using the straight-line method with approved rates is $170,594,190 (See interrogatory request 191).

The plant in service balance and the accumulated reserve used for establishing jurisdictional cost for wholesale customers as of December 31, 2000 is:

	Plant in Service	Reserve Balance
Transmission Plant	$2,236,573,145	$812,250,767

B. FPL will retain ownership of the land, land rights and road and trails associated with the 500 kV line recovered through the Oil Backout Cost Recovery Clause. The Florida Public Service Commission froze the investment in the oil back out recovery clause effective in 1987. The investment, depreciation reserve and accelerated depreciation expense for the land, land right and road and trails as of December 31,2000 is as follows:

Account-Description	Investment	Reserve	Accelerated Depreciation
350.0 - Land	$ 8,182,316	NA	NA
350.2 - Land Rights	$22,956,074	$22,124,557	$19,157,345
359.0 - Road & Trails	$ 6,361,251	$ 6,199,426	$ 5,377,196

The reserve amount is the combination of the straight line amounts allocated to land right and roads and trails, based on the investment in these accounts to the total depreciable plant recoverable under the oil back out recovery clause plus the accelerated depreciation taken.

Q. What would be the impact on FPL ratepayers if the 500 kV line were transferred to the RTO including the accelerated depreciation?

A. Other utilities as well as FPL's retail customers would receive the benefit of the accelerated depreciation, i.e., the greatly reduced rate base investment associated with the 500kV line, which was only included in the existing FPL retail rates. Therefore, FPL's retail customers who paid 100% of the retail cost would lose that portion, and the benefit that would flow to other utilities should the transmission assets transfer including the accelerated depreciation.

Q. In its response to Interrogatory No. 12B from Staff's First Set of Interrogatories to Florida Power & Light Company in this docket, FPL states that the difference between the amount of accelerated depreciation allowed and the depreciation that would have been recorded using the straight-line depreciation rates as approved by the FPSC, if any, will be recorded as a gain on the transfer of the transmission property, and that the gain should be amortized over the estimated remaining life of the 500 kV line recovered through the Oil Backout Cost Recovery Clause. Why was the remaining life selected for the amortization period rather than a shorter period of time?

A. Retail rates would be set using the investment and depreciation expense as though only straight-line depreciation had been recorded. This change in investment and depreciation expense would result in an increase in retail rates over the remaining life of the Oil Backout property. To offset the increase in rates, the gain should be amortized back to the benefit of the retail customers over the same period. See response to Staff's First Set of Interrogatories Number 24.

Q. Explain why FPL decided to retain ownership of the land and land rights associated with its transmission assets?

A. Currently, FPL has a full-time professional staff charged with the responsibility of acquiring, maintaining and administering a portfolio of land and land rights. A minority of these land and land rights are associated with transmission assets, but the bulk of these legal documents involve only non-transmission assets, or are dual-use (primarily distribution and transmission assets). By retaining all of the land and land rights, in addition to simplifying the divestiture, FPL is able to continue to realize economies of scale in their administration of the land and land rights. This effectively mitigates any need for GridFlorida to duplicate these services, and provides for the future needs of FPL's distribution customers.

Q. Provide by FERC account number the total book reserve separated between the amount accumulated under straight-line depreciation and the amount of accelerated depreciation and the anticipated gain associated with the 500 kv line as mentioned in FPL's response to Interrogatory No. 25B and 25G from Staff's First Set of Interrogatories to Florida Power & Light Company in this docket. Please provide this data as of December 31, 2000, and as of the expected date of transfer to the RTO.

A. The investment assigned to the oil back out recovery clause was frozen by the Florida Public Service Commission at $334,662,558 (including land of $8,182,316) in 1987. This was the amount used to determine the total depreciation to be collected under the oil back out clause.

The difference between the accumulated depreciation calculated on a straight-line basis and the amount of accelerated depreciation allowed under the oil back out recovery clause is not maintained at the FERC Account level. The depreciation expense calculated under the straight-line method using rates approved by the Florida Public Service Commission, as compared to the depreciation expense actually recorded using these same rates on the FERC portion of the assets, is used to adjust the amount of accelerated depreciation that will be considered as the gain when the assets are transferred. Accumulated straight-line depreciation, accelerated depreciation and anticipated gain as of December 31, 2000 are as follows:

Accumulated Straight line Depreciation	$ 38,340,895
Accelerated Depreciation	$257,258,715
Gain Associated with the 500 kv line	$170,594,190

The above amounts are based on the assets expected to be transferred and do not include the accumulated depreciation associated with Land Rights (Account 350.2) or Roads and Trails (Account 359.0). The accumulated straight line depreciation was allocated to the assets being transferred based on the original cost of the assets being transferred to the total assets recoverable under the oil back out recovery clause times the total amount of straight line depreciation recorded prior to September 1989 and the depreciation expense recorded on the remaining FERC portion of the assets.

Accelerated depreciation recorded under the Oil backout Cost Recovery Clause was maintained at the FERC Account level. These amounts are as follows:

Account - Description	Accelerated Depreciation
352.0 - Structures & Improvements	$ 4,191,985
353.0 - Station Equipment	67,133,007
354.0 - Towers & Fixtures	112,640,708
355.0 - Poles & Fixtures	1,761,402
356.0 - Overhead conductors & Devices	71,531,613
Total	257,258,715

Q. The following questions refer to FPL's response to Staff's Second Request for Production of Documents, Request No. 1, in this docket:

a. It would appear that there are numerous negative investments on the document entitled "Insurable Value Analysis as of 12/31/99." Please explain what each negative investment represents. Explain the logic of the negative investment.

b. How was the original cost, column a, and the accumulated depreciation amount, column b, determined as shown on the document entitled "Net Book Cost for GSU's and GSU Cooling Banks?"

A. a. The negative investment items listed on the document entitled "Insurable Value Analysis as of 12/31/99" represent contra accounts recorded as contributions in aid of construction. These amounts represent payments recorded from Qualifying Facilities to interconnect to the transmission system. These amounts are recorded in compliance with the Code of Federal Regulation, Part 101.

b. The original cost, column a, was determined from a review of FPL's Property Record System (PRS) which maintains the original cost of Generator Step-up transformers, the transformer installations and the transformer cooling banks by property unit number, property unit description and a unique asset number. The information in the system contains the asset location, original cost and the in service year of the asset.

FPL does not calculate the depreciation expense or maintain the depreciation reserve at the property unit level (property unit number). Therefore, the accumulated depreciation amount, column b, was calculated on an annual basis for each ledger year of each property unit's life by multiplying its original cost by the approved depreciation rate in effect for each year in service. The resulting annual depreciation expense was then accumulated and provided in column b.

Q. Referring to the Class B Common Stock discussed on pages 5 - 6 of the joint testimony of witnesses Naeve, Mennes, Southwick, and Ramon, how will this stock be recorded on the books of the "divesting owners?" For example, will it be recorded on the books of FPL or FPL Group?

A. FPL has not made a final determination of where the Class B Common Stock will be recorded.

Florida Power & Light Company
Docket No. 001148-EI
Staff's Fourth Set of Interrogatories
Question No. 194

Revised 09/28/2001

Q. What does FPL estimate the value of the Class B Common Stock received in exchange for divesting its transmission assets will be worth at the time of the transfer?

A. At the time of contribution, Florida Power & Light expects the value of the Class B Common Stock received to be the value of the underlying transmission assets contributed based on the discounted future cash flows equaling the investment under cost-based regulation.

Q. For purposes of this question, assume that the Class B Common Stock is sold at some future date for a significant gain over its original value at the time it was acquired. Does FPL believe the FPSC would have any jurisdiction over the disposition of this gain? If not, please explain.

A. No. FPL will receive a membership interest in GridFlorida valued on the basis of the net book value of the assets it contributes to GridFlorida. Thus, there is no gain to FPL on the transfer. Consistent with the net book value transfer, GridFlorida will earn a return on the net book value of the assets. To the extent that the assets were transferred at a value greater than book, the extent to which the amount over book is recoverable through rates would be subject to the approval of the relevant ratemaking authorities. Of course, if the premium over net book value is recoverable, this will result in higher rates to retail customers.

At some point, in order to raise capital to fund its business, GridFlorida will issue stock to the public. Depending on market conditions, the stock price may be above or below book value. This is exactly the same risk that all companies face when they issue stock. FPL Group, for example, has, at different times in its history, issued stock at prices both above and below book value. There is no impact on ratepayers; rather it is the existing shareholders who bear the risk.

If ever FPL chooses to sell its interest in GridFlorida, it must convert its membership interest into non-voting stock of GridFlorida. That stock can then be sold in public markets. As with any stock transaction, the share purchase price would reflect the expectation of future earnings associated with the stock as well as market conditions at the time. Thus the share purchase price may be above or below book value. In recent utility acquisitions the purchasing entity has typically paid a premium over and above net book value for the utility. When utilities are sold for a premium over net book value, those premiums belong to the shareholders of the selling entity. By the same token, shareholders take the risk that the price paid is lower than book or lower than the price they paid to purchase the shares originally.

Q. Provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14 E.

A. The attached documents (Bates numbered 000001 through 000081) were used in developing the current replacement value of the assets being transferred:

* Reconciliation of Transmission Plant
* Insurable Value Analysis as of 12/31/99, which represents replacement values based on the The Handy-Whitman Index of Public Utility Construction Costs
* Net Book Cost for Generator Step-Ups ("GSU's") and GSU Cooling Banks

In addition, FPL used The Handy-Whitman Index of Public Utility Construction Costs, but FPL has not reproduced and attached that document because of copyright considerations. FPL will produce The Handy-Whitman Index of Public Utility Construction Costs in its Tallahassee office at a mutually agreeable time.

Reconciliation of Transmission Plant

G/L	Plt. Acct.	Original Cost	Replacement Cost
101	352	$42,225,613.99	$68,290,859.71
106	352	$1,307,539.22	1,312,845.75
105	352		1,360,313.28
Total		$43,533,153.21	$70,964,018.74
101	353	$766,552,054.37	1,311,889,029.38
106	353	$14,511,174.55	190,563.59
	353		14,499,801.95
Total		$781,063,228.92	1,326,579,394.92
101	354	$272,359,792.97	412,911,957.41
106	354	$100,420.73	100,420.73
Total		$272,460,213.70	413,012,378.14
101	355	$357,265,197.73	838,791,181.72
106	355	$10,463,281.34	10,452,690.31
Total		$367,728,479.07	849,243,872.03
101	356	$419,114,436.74	716,266,029.22
106	356	$8,401,910.08	8,299,540.11
Total		$427,516,346.82	724,565,569.33
101	357	$30,774,969.57	80,375,645.09
106	357	$1,884,263.72	1,884,354.53
105	357		1,140,609.15
Total		$32,659,233.29	83,400,608.77
101	358	$36,637,351.55	122,127,581.59
106	358	$472,746.81	472,764.97
Total		$37,110,098.36	122,600,346.56
101	359	$71,582,397.59	105,992,008.93
106	359	$848,544.45	848,544.45
Total		$72,430,942.04	106,840,553.38

105	352	$1,136,140.83
	353	$152,029.70
	354	$0.00
	355	$0.00
	356	$0.00
	357	$1,046,430.41
	358	$0.00
	359	$0.00
		$2,334,600.94

Florida Power Light Co.
Insurable value analysis as of 12/31/99
Total Property Cost

	Gen. Ldgr.	Cpr. Location	Description	Plant Acc.	Original Cost	Replacement Cost
01	101000	1010741120	KINGSLEY METERING STATION (CLAY CO-OP)	352	$4,670.98	$24,102.26
01	101000	1011309000	BUNNELL	352	$861,359.88	$1,075,112.08
01	101000	1012916080	CRILL	352	$30,000.00	$33,900.00
01	101000	1012927900	FRANCIS (CLAY CO-OP)	352	$18,879.02	$23,598.78
01	101000	1012950800	MELROSE (CLAY CO-OP)	352	$8,033.74	$9,640.49
01	101000	1012964240	PACIFIC SUB	352	$352.04	$422.45
01	101000	1012964260	PACIFIC TAP	352	$2,737.69	$4,024.40
01	101000	1012965000	PUTNAM PLANT 115KV SWITCH YARD	352	$91,350.94	$144,745.80
01	101000	1012965500	PALATKA	352	$43,027.60	$210,261.75
01	101000	1012973600	PUTNAM PLANT 230KV SWITCHYARD	352	$161,228.74	$419,929.77
01	101000	1012973620	PUTNAM (OBO)-INST TWO 240KV CAP BANKS & RELAY	352	$65,289.72	$95,975.89
01	101000	1012974960	RICE (NON-OBO)	352	$11,295.28	$11,973.00
01	101000	1012974970	RICE (OBO)	352	$1,299,270.96	$1,909,928.31
01	101000	1013255400	MILLCREEK	352	$493,472.81	$542,820.09
01	101000	1013283850	ST. JOHN'S SWITCHING STATION	352	$287,939.02	$422,378.06
01	101000	1013287520	TOCOI	352	$297,207.97	$436,209.93
01	101000	1013618500	DAYTONA BEACH	352	$2,835.10	$4,609.98
01	101000	1013619750	DELAND	352	$23,945.37	$123,558.11
01	101000	1013663000	ORMOND	352	$81,698.99	$216,451.04
01	101000	1013691750	VOLUSIA	352	$105,695.43	$279,134.75
01	101000	1013691760	VOLUSIA (OBO)-INST THREE 240KV CAP BANK	352	$43,380.69	$60,299.16
01	101000	1020402880	BARNA TRANSMISSION SUBSTATION	352	$770,642.17	$847,706.39
01	101000	1020407750	BREVARD	352	$102,071.68	$321,592.79
01	101000	1020410250	C-5 COMPLEX	352	$11,416.59	$41,412.42
01	101000	1020410750	CAPE CANAVERAL PLANT SWITCH YARD	352	$169,029.92	$328,718.18
01	101000	1020421750	EAU GALLIE	352	$15,790.11	$57,779.49
01	101000	1020433160	HARRIS SUBSTATION	352	$9,858.02	$10,449.50
01	101000	1020447750	MALABAR	352	$46,143.46	$133,810.42
01	101000	1020459150	NORRIS	352	$180,148.80	$356,474.97
01	101000	1020459160	NORRIS (OBO)-INST ONE 240KV CAP BANK	352	$3,945.40	$5,799.74
01	101000	1020459250	NORTH CAPE	352	$7,288.45	$26,701.75
01	101000	1020463250	ORSINO	352	$8,832.14	$32,784.51
01	101000	1020481650	624-A COMPLEX - COCOA	352	$8,928.24	$9,604.72
01	101000	1020482500	SOUTH CAPE	352	$7,962.31	$20,345.15
01	101000	1020482650	CAPE CANAVERAL - USAF ROCC	352	$28,901.98	$28,901.98
01	101000	1022669590	POINSETT (NON-OBO)	352	$106,574.52	$125,879.45
01	101000	1022669600	POINSETT (OBO)	352	$1,638,807.33	$2,277,942.19
01	101000	1023179250	SANFORD	352	$9,263.27	$47,798.47

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Florida Power Light Co.
Insurable value analysis as of 12/31/99
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01	101000	1023620320	DELTONA	352	$27,794.22	$28,628.05
01	101000	1023678500	SANFORD PLANT SWITCH YARD	352	$286,097.43	$651,076.31
01	101000	1030307530	BRADFORD	352	$206,777.40	$450,472.35
01	101000	1030914000	COLUMBIA	352	$120,175.15	$221,052.18
01	101000	1030946250	LIVE OAK TAP STATION	352	$23,078.71	$27,694.45
01	101000	1031202500	BALDWIN SWITCHING STATION	352	$75,180.56	$239,810.31
01	101000	1031221070	DUVAL (OBO)	352	$991,188.50	$1,457,047.10
01	101000	1031221080	DUVAL	352	$323,790.80	$552,283.56
01	101000	1032409860	CALLAHAN TAP	352	$872.72	$2,818.89
01	101000	1042208230	BRIDGE	352	$767,777.56	$921,333.07
01	101000	1042235140	HOBE SUBSTATION	352	$754,113.07	$982,116.70
01	101000	1042238600	INDIANTOWN SUBSTATION	352	$200,740.00	$564,754.89
01	101000	1042249290	MARTIN PLANT SWITCHYARD	352	$1,601,344.34	$2,274,262.85
01	101000	1042249310	MARTIN (OBO)-ADD BAY #4-RELOC TRAPS BAYS #1&3	352	$72,486.47	$106,555.11
01	101000	1042277890	SANDPIPER	352	$315,239.00	$418,834.23
01	101000	1042292130	WARFIELD	352	($89,193.31)	($100,788.44)
01	101000	1042561000	OKEECHOBEE	352	$45,606.04	$88,566.68
01	101000	1042580950	SHERMAN	352	$388,028.99	$692,973.86
01	101000	1042800300	ALEXANDER SUB NEW CPR UNDER ER 0128-09-307	352	$4,604.41	$4,742.54
01	101000	1042810980	CEDAR (OBO)-INST ONE 138KV CAP BANK	352	$40,404.14	$54,545.59
01	101000	1042810990	CEDAR	352	$469,235.57	$680,381.70
01	101000	1042814550	CORBETT SWITCHING STATION	352	$4,184,276.20	$5,215,095.60
01	101000	1042863640	OSCEOLA (OKEELANTA COOP)	352	$372.51	$409.76
01	101000	1042869500	PLUMOSUS	352	$1,042,317.23	$1,251,193.89
01	101000	1042872000	PRATT & WHITNEY	352	$2,016.16	$2,540.36
01	101000	1042874250	RANCH SUBSTATION	352	$112,356.44	$414,857.40
01	101000	1042874270	RANCH (OBO)-INST ONE 240KV CAP BANK	352	$53,693.43	$74,633.87
01	101000	1042874650	RECWAY	352	$115.75	$144.69
01	101000	1042875500	RIVIERA PLANT STO	352	$2,606.70	$12,981.37
01	101000	1042875750	RIVIERA PLANT SWITCH YARD	352	$100,374.22	$185,553.55
01	101000	1042882250	SOUTH BAY	352	$53,007.34	$242,413.97
01	101000	1042893250	WEST PALM BEACH	352	$109,146.44	$401,020.05
01	101000	1042897000	YAMATO SWITCHING STATION	352	$129,903.03	$359,047.93
01	101000	1042897010	YAMATO (OBO)-INST ONE 138KV CAP BANK	352	$29,228.54	$40,627.67
01	101000	1043323150	EMERSON	352	$455,356.58	$631,448.97
01	101000	1043337050	ST LUCIE PLANT SWITCHYARD	352	$720,059.29	$1,417,394.74
01	101000	1043354960	MIDWAY (OBO)-ADD POINSETT TERMINAL	352	$308,502.15	$320,411.49
01	101000	1043354970	MIDWAY SUBSTATION (FORMERLY ST. LUCIE SUB)	352	$967,974.33	$1,596,744.97
01	101000	1043389060	TURNPIKE #2 (SITE)	352	$234.02	$280.82

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01	101000	1050611250	CHARLOTTE	352	$151,083.32	$310,190.19
01	101000	1050673250	PUNTA GORDA	352	$9,842.38	$50,786.68
01	101000	1050813600	COLLIER	352	$238,365.02	$418,262.95
01	101000	1051194830	WHIDDEN SUBSTATION	352	$351,718.15	$516,344.57
01	101000	1051900280	ALICO SWITCHING STATION	352	$441,650.20	$664,223.71
01	101000	1051908700	BUCKINGHAM SW STA	352	$24,738.21	$72,730.34
01	101000	1051909880	CALUSA	352	$121,008.58	$181,512.87
01	101000	1051926500	FORT MYERS PLANT SWITCH YARD	352	$182,329.20	$267,027.20
01	101000	1051962450	ORANGE RIVER	352	$233,956.42	$466,355.09
01	101000	1052014750	CORTEZ	352	$120,434.72	$204,739.02
01	101000	1052028500	FRUIT INDUSTRIES	352	$26,693.60	$32,032.32
01	101000	1052029850	GILLETTE SWITCHING STATION	352	$7,071.71	$36,490.02
01	101000	1052039800	JOHNSON	352	$361,331.89	$587,722.83
01	101000	1052040550	KEENTOWN SUBSTATION	352	$535,003.43	$737,034.37
01	101000	1052047800	MANATEE PLANT SWITCH YARD	352	$285,397.11	$590,741.02
01	101000	1052096500	CRAWLEY TAP	352	$17,539.07	$17,539.07
01	101000	1053036870	HOWARD	352	$317,310.49	$399,811.22
01	101000	1053043770	LAURELWOOD	352	$372,211.09	$575,873.27
01	101000	1053057350	MYAKKA SWITCHING STATION	352	$227,220.16	$323,495.51
01	101000	1053075000	RINGLING	352	$165,828.51	$392,120.08
01	101000	1053091000	VENICE	352	$26,828.81	$91,931.30
01	101000	1070500500	ANDYTOWN TRANSMISSION SUB	352	$1,576,062.62	$3,127,430.88
01	101000	1070500510	ANDYTOWN (OBO)-ADD TWO 240KV CAP BANKS	352	$294,601.83	$409,496.54
01	101000	1070501650	ASHMONT	352	$3,617.98	$4,341.58
01	101000	1070508500	BROWARD	352	$354,233.03	$1,065,718.69
01	101000	1070508560	BROWARD (OBO)-INST TWO 138KV CAP BANKS	352	$18,955.60	$26,348.28
01	101000	1070514030	CONSERVATION 500KV-230-23KV	352	$4,064,419.95	$4,469,216.41
01	101000	1070519500	DEERFIELD BEACH	352	$76,651.24	$129,488.34
01	101000	1070526000	SISTRUNK SUB (FORMERLY FT. LAUDERDALE SUB)	352	$230,408.67	$478,014.41
01	101000	1070536000	HOLLYWOOD	352	$26,621.46	$72,526.64
01	101000	1070543200	LAUDANIA	352	$97,652.61	$240,144.70
01	101000	1070543500	LAUDERDALE PLANT SWITCH YARD	352	$1,793,850.29	$2,612,687.05
01	101000	1070560500	OAKLAND PARK	352	$59,826.19	$188,132.24
01	101000	1070570750	PORT EVERGLADES PLANT SWITCH YARD	352	$182,055.85	$372,770.58
01	101000	1070587880	TRADEWINDS	352	$2,270.55	$2,506.36
01	101000	1081001500	ARCH CREEK	352	$3,067.43	$3,987.66
01	101000	1081013500	COCONUT GROVE	352	$612,820.03	$908,578.53
01	101000	1081016250	CUTLER PLANT SWITCH YARD	352	$58,472.69	$172,903.11
01	101000	1081017250	DADE	352	$76,826.90	$212,826.41

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01	101000 1081018250	DAVIS	352	$86,976.77	$254,613.35
01	101000 1081021050	DUMFOUNDLING	352	$2.00	$6.46
01	101000 1081022600	8TH STREET CABLE TERMINAL - MIAMI	352	$24,119.59	$69,433.17
01	101000 1081024500	FLAGAMI	352	$192,068.18	$644,371.63
01	101000 1081025500	FLORIDA CITY	352	$79,463.63	$218,154.15
01	101000 1081027750	40TH STREET - MIAMI BEACH	352	$227,666.42	$892,897.70
01	101000 1081031010	GRAHAM NORTH SUB	352	$497,777.79	$690,197.76
01	101000 1081031020	GRAHAM SOUTH SUB	352	$357,111.20	$482,100.12
01	101000 1081032000	GRATIGNY	352	$92,215.58	$341,388.72
01	101000 1081032500	GREYNOLDS	352	$209,057.41	$645,616.87
01	101000 1081038000	INDIAN CREEK	352	$623,647.39	$1,896,105.02
01	101000 1081044850	LEVEE SUBSTATION	352	$1,837,897.81	$2,865,251.52
01	101000 1081045500	LITTLE RIVER	352	$143,489.69	$427,746.15
01	101000 1081049250	MARKET	352	$35,371.64	$113,701.05
01	101000 1081052000	MIAMI BEACH	352	$207,097.60	$226,121.13
01	101000 1081053250	MIAMI SUB (FORMERLY MIAMI PLANT SWITCH YARD)	352	$442,581.87	$737,208.06
01	101000 1081054250	MIAMI SHORES	352	$205,560.75	$577,970.60
01	101000 1081059000	NORMANDY BEACH	352	$95,900.25	$408,178.65
01	101000 1081067610	PERIMETER SOUTH TERMINAL	352	$8,119.00	$12,178.50
01	101000 1081075250	RIVERSIDE	352	$19,895.83	$76,180.15
01	101000 1081076650	RONEY	352	$87,791.03	$89,546.85
01	101000 1081083250	SOUTH MIAMI	352	$17,865.80	$21,438.96
01	101000 1081089000	TURKEY POINT PLANT SWITCH YARD	352	$325,377.25	$944,542.88
01	101000 1081099900	SYSTEM RELAY OPERATIONS	352	$40,574.97	$209,366.85
01	101000 1090099900	UNKNOWN	352	$52.91	$273.02
01	101000 1991283870	ST. JOHNS RIVER PARK SWITCHYARD (JEA)	352	$171,617.90	$222,371.75
01	101000 1997090010	SCHERER (SWITCHING STA FOR GA POWER)	352	$490,178.25	$581,075.30
			352 Total	**$42,225,613.99**	**$68,290,859.71**
01	101000 1010741120	KINGSLEY METERING STATION (CLAY CO-OP)	353	$45,584.18	$182,012.98
01	101000 1010788000	TRAIL RIDGE	353	$14,186.41	$23,171.49
01	101000 1011309000	BUNNELL	353	$3,176,267.10	$5,681,529.59
01	101000 1012916080	CRILL	353	$262,717.11	$288,513.61
01	101000 1012921490	PUTNAM DOLLAR MOVED TO 1012973600	353	$43,557.68	$61,944.32
01	101000 1012927900	FRANCIS (CLAY CO-OP)	353	$38,045.84	$50,817.17
01	101000 1012932270	GREENLAND (JEA)	353	$2,318.79	$3,446.73
01	101000 1012950800	MELROSE (CLAY CO-OP)	353	$52,884.84	$66,905.71
01	101000 1012964260	PACIFIC TAP	353	$71,032.84	$105,491.45
01	101000 1012965000	PUTNAM PLANT 115KV SWITCH YARD	353	$3,208,683.50	$8,202,842.76
01	101000 1012965500	PALATKA	353	$17,991.11	$79,662.15

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Florida Power Light Co.
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01	101000	1012969900	POMONA PARK (CLAY CO-OP)	353	$25,802.48	$76,101.36
01	101000	1012973600	PUTNAM PLANT 230KV SWITCHYARD	353	$6,735,648.66	$11,619,392.44
01	101000	1012973620	PUTNAM (OBO)-INST TWO 240KV CAP BANKS & RELAY	353	$221,027.20	$289,677.55
01	101000	1012974960	RICE (NON-OBO)	353	$263,614.27	$456,695.29
01	101000	1012974970	RICE (OBO)	353	$16,496,532.27	$24,774,467.73
01	101000	1013255400	MILLCREEK	353	$2,289,285.33	$4,112,414.56
01	101000	1013283750	ST. AUGUSTINE	353	$2,108.31	$8,538.66
01	101000	1013283850	ST. JOHN'S SWITCHING STATION	353	$3,184,479.45	$4,828,872.58
01	101000	1013287520	TOCOI	353	$1,642,489.23	$3,113,864.47
01	101000	1013602810	BARBERVILLE (F.P.C.)	353	$28,545.36	$43,103.49
01	101000	1013618500	DAYTONA BEACH	353	$289,273.31	$678,164.18
01	101000	1013619750	DELAND	353	$362,365.96	$1,124,101.87
01	101000	1013622250	EDGEWATER	353	$174,501.63	$181,037.23
01	101000	1013629750	GENERAL ELECTRIC	353	$25,518.21	$48,229.42
01	101000	1013644500	LEHIGH ACRES (LEE CO-OP)	353	$62,956.10	$287,080.24
01	101000	1013663000	ORMOND	353	$289,586.43	$951,010.21
01	101000	1013691750	VOLUSIA	353	$8,083,797.95	$16,399,320.37
01	101000	1013691760	VOLUSIA (OBO)-INST THREE 240KV CAP BANK	353	$1,402,539.25	$2,111,007.76
01	101000	1020090000	RESERVE - NORTHEASTERN DIV-NORTH CENTRAL AREA	353	$2,329,822.94	$5,473,115.75
01	101000	1020402880	BARNA TRANSMISSION SUBSTATION	353	$4,372,447.57	$4,624,993.39
01	101000	1020407750	BREVARD	353	$8,615,585.17	$13,579,861.17
01	101000	1020407760	BREVARD (OBO)-RELAYING FOR POINSETT LINE	353	$308,409.43	$462,614.15
01	101000	1020410250	C-5 COMPLEX	353	$368,784.12	$891,741.55
01	101000	1020410750	CAPE CANAVERAL PLANT SWITCH YARD	353	$9,710,701.82	$19,486,093.70
01	101000	1020412750	COCOA BEACH	353	$379,899.56	$975,656.52
01	101000	1020421750	EAU GALLIE	353	$840,451.97	$1,878,554.26
01	101000	1020433160	HARRIS SUBSTATION	353	$733,094.68	$780,827.43
01	101000	1020447750	MALABAR	353	$5,253,194.36	$13,279,442.48
01	101000	1020459150	NORRIS	353	$3,139,279.95	$7,973,708.32
01	101000	1020459160	NORRIS (OBO)-INST ONE 240KV CAP BANK	353	$78,605.06	$118,450.71
01	101000	1020459250	NORTH CAPE	353	$313,161.21	$906,568.94
01	101000	1020463250	ORSINO	353	$413,438.14	$891,097.36
01	101000	1020481650	624-A COMPLEX - COCOA	353	$317,590.83	$935,572.19
01	101000	1020482500	SOUTH CAPE	353	$1,082,571.25	$3,232,338.19
01	101000	1020489200	SOUTH UNITED STATES AIR FORCE (USAF)	353	$40,282.23	$40,282.23
01	101000	1022669590	POINSETT (NON-OBO)	353	$2,425,762.48	$3,056,825.55
01	101000	1022669600	POINSETT (OBO)	353	$20,793,578.23	$31,061,873.04
01	101000	1023160230	NORTH LONGWOOD (FPC)	353	$21,622.72	$40,866.94
01	101000	1023179250	SANFORD	353	$78,451.53	$91,515.27

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01	101000	1023620320	DELTONA	353	$226,677.58	$235,744.68
01	101000	1023678500	SANFORD PLANT SWITCH YARD	353	$7,179,231.25	$22,919,149.33
01	101000	1023689070	TURNER PLANT (FPC)	353	$7,648.20	$29,292.61
01	101000	1030090000	RESERVE - NORTHERN DIVISION-LAKE CITY AREA	353	$11,078,210.48	$11,470,715.78
01	101000	1030119510	DEERHAVEN PLANT (GVL)	353	$32,913.32	$48,711.71
01	101000	1030247030	MACEDONIA TAP (OKC)	353	$4,215.15	$5,058.18
01	101000	1030307530	BRADFORD	353	$5,485,732.86	$9,459,958.85
01	101000	1030358500	NEW RIVER (CLAY CO-OP)	353	$292,702.01	$1,381,770.64
01	101000	1030384250	STARKE	353	$694,868.86	$1,729,405.14
01	101000	1030914000	COLUMBIA	353	$1,099,299.08	$2,420,309.86
01	101000	1030946250	LIVE OAK TAP STATION	353	$313,169.58	$462,936.86
01	101000	1031202500	BALDWIN SWITCHING STATION	353	$2,210,561.76	$4,152,011.08
01	101000	1031221070	DUVAL (OBO)	353	$16,637,514.70	$25,208,548.35
01	101000	1031221080	DUVAL	353	$11,472,003.51	$17,948,644.96
01	101000	1032409860	CALLAHAN TAP	353	$30,909.87	$113,177.66
01	101000	1032441140	KINGSLAND (GA. POWER)	353	$17,943.91	$33,913.99
01	101000	1032980030	SEMINOLE PLANT (SEC)	353	$49,384.23	$74,570.19
01	101000	1033286130	SWITZERLAND (JEA)	353	$37,085.27	$43,018.91
01	101000	1033486010	SUWANNEE RIVER PLANT (FPC)	353	$27,711.90	$36,302.59
01	101000	1040090000	RESERVE - EASTERN DIVISION	353	$8,082,978.48	$10,237,462.78
01	101000	1041612500	CLEWISTON	353	$1,376.27	$2,380.95
01	101000	1041612510	MONTURA	353	($15,225.13)	($16,747.64)
01	101000	1041634100	HENDRY (CITY OF CLEWISTON)	353	$102,844.37	$125,458.78
01	101000	1041689890	U.S. SUGAR CORP.	353	$0.01	$0.01
01	101000	1041838510	INDIAN RIVER MONITOR-ORLANDO UTILITIES COMM	353	$23,623.56	$51,260.91
01	101000	1041892190	WEST (CITY OF VERO BCH)	353	$26,745.70	$48,654.13
01	101000	1042208230	BRIDGE	353	$3,104,695.70	$3,626,987.44
01	101000	1042235140	HOBE SUBSTATION	353	$3,860,113.82	$5,827,658.48
01	101000	1042238600	INDIANTOWN SUBSTATION	353	$4,009,594.35	$5,714,127.87
01	101000	1042249290	MARTIN PLANT SWITCHYARD	353	$67,609,524.74	$90,400,736.09
01	101000	1042249310	MARTIN (OBO)-ADD BAY #4-RELOC TRAPS BAYS #1&3	353	$3,084,585.48	$4,657,724.07
01	101000	1042277890	SANDPIPER	353	$2,789,667.72	$4,075,001.20
01	101000	1042292130	WARFIELD	353	$62.14	($312.13)
01	101000	1042557210	MORRIS (GEC CO-GEN)	353	$34,586.16	$42,540.98
01	101000	1042561000	OKEECHOBEE	353	$485,609.24	$934,050.01
01	101000	1042580950	SHERMAN	353	$3,059,093.00	$7,286,406.27
01	101000	1042800300	ALEXANDER SUB NEW CPR UNDER ER 0128-09-307	353	$396,994.36	$412,874.13
01	101000	1042805500	BOCA RATON	353	$51,064.52	$232,554.61
01	101000	1042808640	BRYANT (USSC)	353	$50,712.95	$72,971.77

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01	101000 1042810980	CEDAR (OBO)-INST ONE 138KV CAP BANK	353	$533,714.27	$789,897.12
01	101000 1042810990	CEDAR	353	$9,642,356.03	$14,202,365.55
01	101000 1042814550	CORBETT SWITCHING STATION	353	$31,684,107.63	$40,131,587.16
01	101000 1042837320	HYPOLUXO ROAD (LAKE WORTH UTILITY)	353	$15,293.27	$32,694.44
01	101000 1042863640	OSCEOLA (OKEELANTA COOP)	353	($15,818.39)	($16,767.49)
01	101000 1042863660	OKEELANTA (OKEELANTA COOP)	353	$75,587.67	$92,609.55
01	101000 1042864500	PAHOKEE	353	$65,073.70	$76,238.44
01	101000 1042869500	PLUMOSUS	353	$5,761,438.19	$6,825,860.93
01	101000 1042872000	PRATT & WHITNEY	353	$322,288.09	$533,128.29
01	101000 1042874250	RANCH SUBSTATION	353	$8,138,043.50	$17,609,469.26
01	101000 1042874270	RANCH (OBO)-INST ONE 240KV CAP BANK	353	$593,047.51	$889,571.27
01	101000 1042874650	RECWAY	353	($390,142.73)	($538,396.97)
01	101000 1042875750	RIVIERA PLANT SWITCH YARD	353	$6,933,346.28	$17,040,332.30
01	101000 1042882250	SOUTH BAY	353	$1,479,369.06	$4,881,738.80
01	101000 1042893250	WEST PALM BEACH	353	$3,237,278.96	$9,112,161.53
01	101000 1042897000	YAMATO SWITCHING STATION	353	$6,465,803.18	$9,987,062.52
01	101000 1042897010	YAMATO (OBO)-INST ONE 138KV CAP BANK	353	$237,708.74	$356,563.11
01	101000 1043323150	EMERSON	353	$3,584,193.38	$5,360,854.56
01	101000 1043333200	HARTMAN (CITY OF FT. PIERCE)	353	$18,658.25	$39,659.05
01	101000 1043337050	ST LUCIE PLANT SWITCHYARD	353	$23,526,969.68	$34,759,843.42
01	101000 1043354960	MIDWAY (OBO)-ADD POINSETT TERMINAL	353	$5,320,555.61	$7,335,839.47
01	101000 1043354970	MIDWAY SUBSTATION (FORMERLY ST. LUCIE SUB)	353	$22,172,305.20	$41,066,095.32
01	101000 1043389060	TURNPIKE #2 (SITE)	353	$1,400,050.08	$1,624,058.09
01	101000 1050090000	RESERVE - WESTERN DIVISION	353	$3,193,049.54	$4,610,514.95
01	101000 1050611250	CHARLOTTE	353	$7,328,638.12	$14,824,504.25
01	101000 1050673250	PUNTA GORDA	353	$74,677.47	$306,021.03
01	101000 1050813600	COLLIER	353	$8,123,655.61	$13,021,721.61
01	101000 1050882150	SOLANA	353	$1,202.94	$2,081.09
01	101000 1051101250	ARCADIA	353	$53.53	$244.10
01	101000 1051194830	WHIDDEN SUBSTATION	353	$2,115,656.33	$4,426,539.15
01	101000 1051711400	CHILDS (GLADES CO-OP)	353	$98,057.53	$162,857.82
01	101000 1051900280	ALICO SWITCHING STATION	353	$6,406,051.77	$9,098,054.81
01	101000 1051908700	BUCKINGHAM SW STA	353	$202,893.33	$759,099.11
01	101000 1051908710	LAZY ACRES	353	($54,903.96)	($55,425.75)
01	101000 1051909880	CALUSA	353	$1,265,137.13	$2,527,980.63
01	101000 1051926500	FORT MYERS PLANT SWITCH YARD	353	$13,629,354.32	$32,752,102.84
01	101000 1051926510	FT MYERS PLT (OBO)-INST ONE 138KV CAP BANK	353	$227,185.80	$340,778.70
01	101000 1051927000	FT MYERS SUBSTATION	353	$700,306.04	$716,970.16
01	101000 1051944360	LEE (LEE CO-OP)	353	$50,801.65	$58,929.91

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01	101000	1051962450	ORANGE RIVER	353	$12,201,666.96	$21,678,388.99
01	101000	1052003000	BEKER	353	$18,132.71	$82,685.16
01	101000	1052014750	CORTEZ	353	$1,088,702.30	$1,621,167.44
01	101000	1052028500	FRUIT INDUSTRIES	353	$99,598.78	$83,735.95
01	101000	1052029850	GILLETTE SWITCHING STATION	353	$5,480.21	$8,275.12
01	101000	1052039800	JOHNSON	353	$6,402,553.78	$9,013,247.63
01	101000	1052040550	KEENTOWN SUBSTATION	353	$2,161,875.22	$4,067,318.14
01	101000	1052047800	MANATEE PLANT SWITCH YARD	353	$10,461,012.17	$19,288,684.02
01	101000	1052096500	CRAWLEY TAP	353	$268,865.59	$268,865.59
01	101000	1053036870	HOWARD	353	$3,502,228.72	$5,460,045.69
01	101000	1053043770	LAURELWOOD	353	$6,978,993.18	$11,990,501.13
01	101000	1053057350	MYAKKA SWITCHING STATION	353	$2,895,394.14	$4,587,939.17
01	101000	1053075000	RINGLING	353	$7,550,195.98	$18,381,864.01
01	101000	1053091000	VENICE	353	$829,464.72	$2,679,712.85
01	101000	1053704740	BIG BEND (TEC)	353	$51,909.92	$77,864.88
01	101000	1053777170	RUSKIN (TEC)	353	$7,252.05	$20,668.34
01	101000	1070090000	RESERVE - SOUTHEASTERN DIVISION	353	$2,763,730.98	$3,989,508.00
01	101000	1070500500	ANDYTOWN TRANSMISSION SUB	353	$29,077,041.09	$50,367,867.76
01	101000	1070500510	ANDYTOWN (OBO)-ADD TWO 240KV CAP BANKS	353	$2,483,402.27	$3,693,525.96
01	101000	1070501650	ASHMONT	353	($1,877.14)	($3,933.00)
01	101000	1070508500	BROWARD	353	$7,384,062.69	$18,679,468.57
01	101000	1070508560	BROWARD (OBO)-INST TWO 138KV CAP BANKS	353	$375,334.59	$563,001.89
01	101000	1070514030	CONSERVATION 500KV-230-23KV	353	$15,562,409.49	$17,100,321.30
01	101000	1070519500	DEERFIELD BEACH	353	$576,326.53	$1,313,415.89
01	101000	1070525730	FORT LAUDERDALE PORTABLES	353	$122,455.94	$134,701.53
01	101000	1070526000	SISTRUNK SUB (FORMERLY FT. LAUDERDALE SUB)	353	$2,214,936.00	$5,406,578.79
01	101000	1070536000	HOLLYWOOD	353	$293,037.57	$660,244.82
01	101000	1070543200	LAUDANIA	353	$971,857.75	$2,747,005.12
01	101000	1070543500	LAUDERDALE PLANT SWITCH YARD	353	$53,363,279.19	$84,808,286.56
01	101000	1070560500	OAKLAND PARK	353	$918,494.59	$1,861,512.52
01	101000	1070570250	POMPANO	353	$17.38	$83.60
01	101000	1070570500	PORT	353	$20,776.25	$39,267.11
01	101000	1070570750	PORT EVERGLADES PLANT SWITCH YARD	353	$17,955,078.86	$33,421,315.86
01	101000	1070587880	TRADEWINDS	353	$135,009.69	$181,356.24
01	101000	1080090000	RESERVE - SOUTHERN DIVISION	353	$2,717,090.14	$3,940,493.16
01	101000	1081000250	AIRPORT	353	$138,630.50	$426,487.38
01	101000	1081001500	ARCH CREEK	353	$413,762.19	$784,263.83
01	101000	1081007060	BOYSTOWN-WEST	353	$24,581.98	$28,515.10
01	101000	1081007070	BOYSTOWN-EAST	353	$24,581.99	$28,515.11

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01	101000	1081010920	CARD SOUND METERING STATION	353	$16,501.59	$37,953.66
01	101000	1081013500	COCONUT GROVE	353	$513,662.21	$1,123,769.23
01	101000	1081016250	CUTLER PLANT SWITCH YARD	353	$4,225,010.87	$9,408,952.04
01	101000	1081017250	DADE	353	$5,717,480.22	$14,926,235.32
01	101000	1081017260	DADE (OBO)-INST TWO 138KV CAP BANKS	353	$931,259.55	$1,378,264.13
01	101000	1081018250	DAVIS	353	$5,593,083.76	$18,603,566.47
01	101000	1081020660	DORAL (RESOURCE RECOVERY - DADE COUNTY)	353	$37,600.53	$52,805.33
01	101000	1081022600	8TH STREET CABLE TERMINAL - MIAMI	353	$90,931.01	$233,469.39
01	101000	1081024500	FLAGAMI	353	$7,540,726.42	$21,501,513.78
01	101000	1081025500	FLORIDA CITY	353	$4,216,747.94	$6,641,902.39
01	101000	1081027750	40TH STREET - MIAMI BEACH	353	$1,820,592.11	$3,982,657.92
01	101000	1081031010	GRAHAM NORTH SUB	353	$349,685.80	$522,176.58
01	101000	1081031020	GRAHAM SOUTH SUB	353	$276,973.65	$409,921.00
01	101000	1081032000	GRATIGNY	353	$1,296,015.42	$2,964,951.13
01	101000	1081032500	GREYNOLDS	353	$2,376,248.65	$7,347,611.19
01	101000	1081038000	INDIAN CREEK	353	$1,473,814.77	$3,125,373.74
01	101000	1081044850	LEVEE SUBSTATION	353	$27,064,063.22	$42,134,966.15
01	101000	1081045500	LITTLE RIVER	353	$2,428,955.07	$6,133,994.35
01	101000	1081046450	LUCY (CITY OF HOMESTEAD)	353	$9,899.24	$11,898.39
01	101000	1081049250	MARKET	353	$696,408.97	$2,102,709.60
01	101000	1081052000	MIAMI BEACH	353	$2,017,110.07	$4,151,241.66
01	101000	1081053250	MIAMI SUB (FORMERLY MIAMI PLANT SWITCH YARD)	353	$10,144,882.94	$22,886,988.05
01	101000	1081054250	MIAMI SHORES	353	$2,584,782.81	$3,856,226.52
01	101000	1081059000	NORMANDY BEACH	353	$1,252,921.55	$3,930,914.47
01	101000	1081067080	PENNSUCO	353	$488,161.73	$493,043.35
01	101000	1081067610	PERIMETER SOUTH TERMINAL	353	$62,684.46	$108,444.12
01	101000	1081074000	RAILWAY	353	$244,083.50	$447,604.99
01	101000	1081074760	RESERVE REPAIR - ER8150	353	$3,385,803.85	$6,077,564.75
01	101000	1081075250	RIVERSIDE	353	$1,059,393.33	$3,477,548.79
01	101000	1081076650	RONEY	353	$74,726.56	$112,521.97
01	101000	1081081380	SIMPSON (BRICKELL SITE)	353	$790.46	$1,169.88
01	101000	1081083250	SOUTH MIAMI	353	$615,089.43	$782,895.55
01	101000	1081086580	TAMIAMI	353	$5,122.30	$24,638.26
01	101000	1081089000	TURKEY POINT PLANT SWITCH YARD	353	$28,526,716.64	$47,408,054.46
01	101000	1081090500	VENETIAN	353	$45,280.11	$68,825.77
01	101000	1081099900	SYSTEM RELAY OPERATIONS	353	$15,253.29	$54,301.71
01	101000	1082347950	MARATHON (FLA KEYS CO-OP)	353	$31,140.73	$44,531.24
01	101000	1090099900	UNKNOWN	353	$573.11	$2,613.38
01	101000	1980000000	SUSPENSE-SUBSTATIONS	353	($2,892.20)	($2,153.66)

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01	101000	1991259110	NORMANDY (JEA)	353	$48,542.01	$85,022.29
01	101000	1991283870	ST. JOHNS RIVER PARK SWITCHYARD (JEA)	353	$4,747,719.82	$6,590,012.00
01	101000	1993729350	GANNON PLANT (TEC)	353	$8,972.02	$49,884.43
01	101000	1997090010	SCHERER (SWITCHING STA FOR GA POWER)	353	$14,512,636.58	$16,227,787.68
				353 Total	$766,552,054.37	$1,311,889,029.38
01	101000	2011325075	DUVAL-POINSETT 500KV (OBO) (FLAGLER CO)	354	$7,473,389.85	$10,612,213.59
01	101000	2011325076	POINSETT-RICE 500KV (OBO) (FLAGLER CO)	354	$7,701,554.09	$10,936,206.81
01	101000	2012925039	DUVAL-POINSETT 500KV (OBO) (PUTNAM CO)	354	$7,317,231.88	$10,390,469.27
01	101000	2012925040	DUVAL-POINSETT 500KV (OBO)-ST.JOHNS RIVER XNG	354	$188,061.23	$267,046.95
01	101000	2012925041	DUVAL-RICE 500KV (OBO) (PUTNAM CO)	354	$1,888,212.40	$2,681,261.61
01	101000	2012925042	POINSETT-RICE 500KV (OBO) (PUTNAM CO)	354	$4,710,677.48	$6,689,162.02
01	101000	2012925043	POINSETT-RICE 500KV (OBO) (ST.JOHNS RIVER)	354	$273,470.25	$388,327.76
01	101000	2013625109	DUVAL-POINSETT 500KV (OBO) (VOLUSIA)	354	$6,688,511.49	$9,497,686.32
01	101000	2013625110	POINSETT-RICE 500KV (OBO) (VOLUSIA CO)	354	$6,180,120.00	$8,775,770.40
01	101000	2022623168	BREVARD-W LAKE WALES 230KV (OBO) PURCH FM FPC	354	$80,089.67	$113,727.33
01	101000	2022625001	MARTIN-POINSETT 500KV (OBO) (ORANGE CO)	354	$638,900.20	$907,238.28
01	101000	2022625002	MIDWAY-POINSETT 500KV (OBO) (ORANGE CO)	354	$566,041.49	$781,137.26
01	101000	2022625160	DUVAL-POINSETT 500KV (OBO) (ORANGE CO)	354	$4,464,053.38	$6,338,955.80
01	101000	2022625161	POINSETT-RICE 500KV (OBO) (ORANGE CO)	354	$3,830,629.59	$5,439,494.02
01	101000	2023125144	DUVAL-POINSETT 500KV (OBO) (SEMINOLE CO)	354	$3,473,875.33	$4,932,902.97
01	101000	2023125145	POINSETT-RICE 500KV (OBO) (SEMINOLE CO)	354	$3,127,716.03	$4,441,356.76
01	101000	2030725007	DUVAL-POINSETT 500KV (OBO) (CLAY CO)	354	$7,077,351.65	$10,049,839.34
01	101000	2030725008	DUVAL-RICE 500KV (OBO) (CLAY CO)	354	$6,530,703.71	$9,273,599.27
01	101000	2031225001	DUVAL-HATCH (GP) #1 500KV (OBO) (DUVAL CO)	354	$6,480.61	$9,720.92
01	101000	2031225002	DUVAL-POINSETT 500KV (OBO) (DUVAL CO)	354	$1,639,602.92	$2,328,236.15
01	101000	2031225003	DUVAL-RICE 500KV (OBO) (DUVAL CO)	354	$1,417,041.91	$2,012,199.51
01	101000	2031250001	DUVAL-HATCH (GP) #2 500KV (OBO) (DUVAL CO)	354	$6,491.90	$9,737.85
01	101000	2032425008	DUVAL-HATCH (GP) #1 500KV (OBO) (NASSAU CO)	354	$25,771.85	$38,657.78
01	101000	2032450008	DUVAL-HATCH (GP) #2 500KV (OBO) (NASSAU CO)	354	$25,762.61	$38,643.92
01	101000	2041825043	MARTIN-POINSETT 500KV (OBO) (INDIAN RIVER CO)	354	$7,651,540.35	$10,865,187.30
01	101000	2041825044	MIDWAY-POINSETT 500KV (OBO) (INDIAN RIVER CO)	354	$5,135,918.31	$7,087,567.27
01	101000	2042225001	MARTIN-MIDWAY 500KV (MARTIN CO)	354	$2,394,364.09	$3,735,207.98
01	101000	2042225024	CORBETT-MIDWAY 500KV (MARTIN CO)	354	$5,603,530.15	$6,539,728.45
01	101000	2042225077	CORBETT-MARTIN 500KV (MARTIN CO.)	354	$2,413,774.65	$2,913,012.27
01	101000	2042225078	CORBETT-MARTIN 500KV (OBO)	354	$353,724.33	$527,049.25
01	101000	2042225079	ANDYTOWN-MARTIN 500KV #1 (MARTIN CO.)	354	$2,277,609.84	$3,447,481.29
01	101000	2042225082	MARTIN-MIDWAY 500KV (OBO) (MARTIN CO)	354	$105,047.30	$156,520.48
01	101000	2042225100	MARTIN-POINSETT 500KV (OBO) (MARTIN CO)	354	$3,041,672.85	$4,319,175.45
01	101000	2042250079	ANDYTOWN-MARTIN 500KV #2 (MARTIN CO)	354	$1,646,582.46	$2,457,177.84

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01	101000 2042804088	RIVIERA-WEST PALM BEACH	354	$19,837.41	$97,401.68
01	101000 2042818058	BELLE GLADE-SO.BAY	354	$113.91	$674.35
01	101000 2042819056	RANCH-RIVIERA (3 CKTS)	354	$28,892.85	$159,884.09
01	101000 2042819099	RIVIERA (STEEL TOWERS)	354	$12,894.14	$72,336.13
01	101000 2042825001	CORBETT-MIDWAY 500KV (PALM BCH.CO)	354	$5,207,326.88	$6,613,305.14
01	101000 2042825002	CORBETT-MARTIN 500KV (PALM BCH CO.)	354	$7,314,902.60	$8,412,137.99
01	101000 2042825016	CONSERVATION-CORBETT 500KV (PALM BEACH CO.)	354	$19,637,953.43	$21,012,610.17
01	101000 2042825023	ANDYTOWN-MARTIN 500KV #1 (PALM BCH CO.)	354	$11,734,891.79	$18,306,431.19
01	101000 2042825036	ANDYTOWN-ORANGE RIVER 500KV LN (PALM BCH CO)	354	$1,534,003.24	$3,881,028.20
01	101000 2042850023	ANDYTOWN-MARTIN 500KV #2 (PALM BCH CO)	354	$11,545,206.26	$18,010,521.77
01	101000 2043304107	INDIAN RIVER XING @ ST LUCIE PLT #1 240KV	354	$1,715,609.09	$4,340,491.00
01	101000 2043325013	MARTIN-MIDWAY 500KV (ST.LUCIE CO)	354	$4,239,921.54	$5,576,480.50
01	101000 2043325022	CORBETT-MIDWAY 500KV (ST. LUCIE CO.)	354	$3,236,182.03	$4,186,701.72
01	101000 2043325071	MARTIN-POINSETT 500KV (OBO) (ST. LUCIE CO)	354	$8,588,647.94	$12,195,880.07
01	101000 2043325072	MIDWAY-POINSETT 500KV (OBO) (ST.LUCIE CO)	354	$4,938,741.72	$6,815,463.57
01	101000 2043329107	INDIAN RIVER XING @ ST LUCIE PLT-#2 240KV	354	$1,696,018.78	$4,290,927.51
01	101000 2043354107	INDIAN RIVER XING @ ST LUCIE PLT-#3	354	$1,696,018.78	$4,290,927.51
01	101000 2050825068	ANDYTOWN-ORANGE RIVER 500KV LN (COLLIER CO)	354	$3,552,707.57	$8,988,350.15
01	101000 2051625043	ANDYTOWN-ORANGE RIVER 500KV LN (HENDRY CO)	354	$4,807,961.26	$12,158,972.45
01	101000 2051913052	FT MYERS-BUCKINGHAM AIR FIELD	354	$13.18	$78.03
01	101000 2051913096	BUCKINGHAM 69KV TAP	354	$98.86	$585.25
01	101000 2051913183	FT MYERS SUB-NAPLES TAP (OLD)	354	$19.77	$117.04
01	101000 2051925087	ANDYTOWN-ORANGE RIVER 500KV LN (LEE CO)	354	$3,716,530.48	$9,402,822.11
01	101000 2070503001	LAUDERDALE-PINEHURST-POMPANO-PALM BCH CO.	354	$263.18	$1,558.03
01	101000 2070503170	LAUDERDALE-PORT EVERGLADES #1-4 240KV LINES	354	$1,995,275.44	$11,649,094.20
01	101000 2070525001	ANDYTOWN-ORANGE RIVER 500KV LN (BROWARD CO)	354	$8,502,272.60	$21,400,941.64
01	101000 2070525002	ANDYTOWN-MARTIN 500KV #1 (BROWARD CO.)	354	$1,460,037.89	$2,277,659.11
01	101000 2070525012	ANDYTOWN-LEVEE 500KV (BROWARD CO)	354	$1,498,784.63	$2,637,860.95
01	101000 2070525016	CONSERVATION-CORBETT 500KV (BROWARD CO.)	354	$17,244,638.49	$18,451,763.18
01	101000 2070525034	ANDYTOWN-MARTIN 500KV #1 (SWAMP)	354	$3,898,695.80	$6,081,965.45
01	101000 2070550001	ANDYTOWN-MARTIN 500KV #2 (BROWARD CO)	354	$1,503,661.52	$2,345,711.97
01	101000 2070550012	ANDYTOWN-LEVEE #2 500KV LINE (BROWARD CO.)	354	$5,655,676.67	$7,522,049.97
01	101000 2070550035	ANDYTOWN-MARTIN #2 500KV (SWAMP)	354	$4,096,832.64	$6,391,058.92
01	101000 2081001024	BISCAYNE-MIAMI SHORES	354	$254.33	$1,505.63
01	101000 2081001036	HIALEAH-RIVER (OLD)	354	$12.06	$71.40
01	101000 2081025001	ANDYTOWN-LEVEE 500KV (DADE CO)	354	$2,437,862.21	$4,290,637.49
01	101000 2081050001	ANDYTOWN-LEVEE #2 500KV LINE (DADE CO.)	354	$76,092.35	$101,202.83
01	101000 2992725003	MARTIN-POINSETT 500KV (OBO) (OSCEOLA CO)	354	$10,816,744.31	$15,359,776.92
01	101000 2992725004	MIDWAY-POINSETT 500KV (OBO) (OSCEOLA CO)	354	$11,689,406.54	$16,131,381.03

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01	101000 2993699500	EMERGENCY 500KV TRANSMISSION STRUCTURES	354	$303,282.95	$451,891.60
			354 Total	**$272,359,792.97**	**$412,911,957.41**
01	101000 2010709034	MELROSE TAP-STARKE (CLAY CO.SECT)	355	$34,879.56	$52,240.91
01	101000 2010709091	STARKE-TRAILRIDGE TAP (CLAY CO)	355	$12,335.49	$61,307.39
01	101000 2010709155	BRADFORD-PUTNAM 240KV YARD (CLAY CO.)	355	$247,605.20	$981,167.04
01	101000 2010709185	HUDSON-TITANIUM 240KV (CLAY)	355	$44,942.88	$158,004.42
01	101000 2010710040	TRAIL RIDGE TAP (OLD)	355	$9,181.25	$38,840.95
01	101000 2011308054	FLAGLER BCH - ST JOE	355	$542,827.61	$1,222,519.98
01	101000 2011308067	ST JOE - ST JOHNS CO LINE	355	$314,669.20	$637,800.16
01	101000 2011308095	LEHIGH TAP	355	($1,128.38)	($2,019.80)
01	101000 2011310048	BUNNELL-PALATKA #2 115KV (FLAGLER CO.)	355	$320,297.24	$1,430,679.04
01	101000 2011310097	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	355	$925,059.16	$2,337,785.88
01	101000 2011325075	DUVAL-POINSETT 500KV (OBO) (FLAGLER CO)	355	$610,384.39	$1,007,134.24
01	101000 2011325076	POINSETT-RICE 500KV (OBO) (FLAGLER CO)	355	$766,594.70	$1,264,881.26
01	101000 2011335048	PUTNAM-VOLUSIA #1 240KV (FLAGLER CO.)	355	$675,171.83	$3,145,198.39
01	101000 2011335073	PUTNAM-VOLUSIA #1 240KV (FLAGLER COUNTY0)	355	$708,774.22	$2,483,226.44
01	101000 2011360073	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	355	$651,075.18	$1,637,471.58
01	101000 2012907055	CRESCENT CITY-VOLUSIA CO.LINE	355	$120,269.53	$222,663.59
01	101000 2012907062	CRESCENT CITY-POMONA PARK LOOP	355	$151,775.24	$302,271.39
01	101000 2012907069	POMONA PARK LOOP	355	$42,306.33	$168,378.08
01	101000 2012907070	PALATKA SES-POMONA PARK LOOP	355	$626,301.86	$1,031,997.65
01	101000 2012907085	PALATKA SES-PALATKA SUB	355	$57,497.87	$111,440.56
01	101000 2012907088	PUTNAM - ST JOHNS CO. LINE	355	$348,701.02	$1,619,712.57
01	101000 2012907121	PALATKA SES-PUTNAM 240KV YARD	355	$24,959.08	$122,269.06
01	101000 2012907131	PALATKA PLT-EAST PALATKA 115KV RADIAL	355	$17,322.61	$28,062.63
01	101000 2012909001	PALATKA-MCMEEKIN TAP	355	$675,563.97	$2,498,517.53
01	101000 2012909004	FRANCIS TAP	355	$71,259.82	$88,887.73
01	101000 2012909012	MANVILLE TAP (CLAY CO.CO-OP)	355	$6,585.98	$28,978.31
01	101000 2012909023	MCMEEKIN TAP	355	$132,430.61	$441,698.35
01	101000 2012909025	MCMEEKIN TAP-CLAY CO.LINE	355	$148,880.52	$289,554.16
01	101000 2012909033	MELROSE TAP	355	$150,261.13	$186,323.80
01	101000 2012909129	HUDSON TAP	355	$35,792.15	$207,147.89
01	101000 2012909133	BRADFORD-PUTNAM 240KV YARD (PUTNAM CO.)	355	$775,756.93	$3,013,279.25
01	101000 2012909139	BRADORD-PUTNAM 240 KV YARD (ST JOHNS RIVER X	355	$431,189.56	$1,779,541.58
01	101000 2012909146	BRADFORD-PUTNAM 240KV (OBO)-EXT TO RICE	355	$86,030.39	$144,531.06
01	101000 2012909175	HUDSON-TITANIUM 240KV (PUTNAM)	355	$653,130.30	$1,555,770.44
01	101000 2012909178	HUDSON-TITANIUM 240KV (OBO)-TO SEMINOLE ELECT	355	$7,976.85	$38,129.34
01	101000 2012909188	BLANK CREEK-PUTNAM #1(OBO)-EXT TO SEMINOLE	355	$255,938.63	$435,095.67
01	101000 2012909325	PACIFIC SUB TAP (GP)	355	$96,930.64	$171,916.80

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01	101000 2012909362	PUTNAM-CRILL 115KV	355	$753,717.25	$829,088.98
01	101000 2012910001	PALATKA-ST AUGUSTINE (PUTNAM CO.)	355	$187,449.19	$517,257.36
01	101000 2012910044	BUNNELL-PALATKA #2 115KV (PUTNAM CO.)	355	$73,918.50	$240,489.89
01	101000 2012910093	PUTNAM-VOLUSIA #2 240KV (PUTNAM CO.)	355	$214,192.53	$487,294.70
01	101000 2012925039	DUVAL-POINSETT 500KV (OBO) (PUTNAM CO)	355	$719,046.50	$1,186,426.73
01	101000 2012925041	DUVAL-RICE 500KV (OBO) (PUTNAM CO)	355	$252,205.59	$416,139.22
01	101000 2012925042	POINSETT-RICE 500KV (OBO) (PUTNAM CO)	355	$524,429.31	$865,308.36
01	101000 2012934133	PUTNAM-TITANIUM 240KV	355	$1,095,710.21	$2,138,317.84
01	101000 2012934188	BLACK CREEK-PUTNAM #2 (OBO)-EXT TO SEMINOLE	355	$256,087.06	$435,348.00
01	101000 2012935044	PUTNAM-VOLUSIA #1 240KV (PUTNAM CO.)	355	$181,668.05	$573,436.84
01	101000 2013207099	ST JOHNS RIVER XING @ ORANGEDALE	355	$392,047.06	$1,853,818.82
01	101000 2013207102	ORANGEDALE-GREENLAND (JACKSONVILLE ELECT AUTH	355	$286,848.38	$830,401.40
01	101000 2013208075	ST AUGUSTINE-FLAGLER CO. LINE	355	$1,722,563.27	$2,877,372.15
01	101000 2013208114	ST. AUGUSTINE-93H8 (NORTH LINE)	355	$415,709.59	$755,974.41
01	101000 2013208134	LEWIS LOOP	355	$182,292.13	$800,522.55
01	101000 2013208144	LEWIS-TOLOMATO 115KV	355	$825,309.79	$957,359.36
01	101000 2013208150	MILLCREEK-TOLOMATO 115KV	355	$2,031,275.73	$2,153,152.27
01	101000 2013210009	PALATKA-ST AUGUSTINE (ST JOHNS CO.)	355	$894,570.09	$1,174,351.91
01	101000 2013210027	SAN SEBASTIAN RIVER-27J5 (ST AUGUSTINE)	355	$190,465.74	$260,938.06
01	101000 2013210028	SAN SEBASTIAN RIVER XING	355	$115,959.28	$201,548.36
01	101000 2013210029	ST AUGUSTINE-F.E.C. SHOPS (OLD)	355	$7,545.64	$55,913.19
01	101000 2013210121	ST. JOHN'S-TOCOI 240KV	355	$834,279.61	$1,418,275.34
01	101000 2013600009	T" EDGEWATER-SMYRNA 115KV "	355	$519,336.84	$514,143.47
01	101000 2013601109	TRANS EASEMENT	355	$1,587.04	$1,555.30
01	101000 2013606072	SANFORD-TURNER (FLA POWER CORP)	355	$79,411.42	$342,807.51
01	101000 2013606152	EDGEWATER-NORRIS 115KV (VOLUSIA CO.)	355	$105,868.37	$122,807.31
01	101000 2013607001	SANFORD SES-DELAND	355	$604,457.57	$1,749,657.80
01	101000 2013607020	DELAND-PUTNAM CO.LINE (S/O CRESCENT CITY)	355	$1,730,791.92	$2,075,120.98
01	101000 2013607025	DELAND NAS RELOCATION (N/O DELAND)	355	$426,447.14	$500,555.98
01	101000 2013608001	DELAND-SMYRNA	355	$258,003.01	$969,148.18
01	101000 2013608012	PORT ORANGE-TAYLOR	355	$262,388.83	$401,980.11
01	101000 2013608016	TAYLOR-SMYRNA	355	$923,058.19	$1,469,385.88
01	101000 2013608022	PORT ORANGE-SO.DAYTONA TAP (DISTR)	355	$21,943.01	$101,419.06
01	101000 2013608026	DAYTONA-SO.DAYTONA TAP	355	$211,713.64	$575,278.62
01	101000 2013608029	DAYTONA (DOUBLE CKT WEST)	355	$174,557.42	$287,816.19
01	101000 2013608030	MISSION CITY 66KV TAP (OLD)	355	$1,862.08	$13,798.01
01	101000 2013608035	DAYTONA-ORMOND-FLAGLER CO.LINE	355	$847,620.13	$1,850,429.33
01	101000 2013608099	SOUTH DAYTONA TAP	355	$226,997.37	$454,538.99
01	101000 2013608102	HOLLY HILL LOOP	355	$189,720.45	$499,119.72

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01	101000	2013608108	VOLUSIA TIE LINES	355	$165,520.63	$236,961.85
01	101000	2013608109	GENERAL ELECTRIC-VOLUSIA	355	$51,226.26	$186,894.79
01	101000	2013608111	DAYTONA-VOLUSIA	355	$192,744.38	$693,017.41
01	101000	2013608117	EDGEWATER TAP	355	$298,720.64	$1,210,496.01
01	101000	2013608123	BULOW LOOP	355	$118,982.46	$430,602.20
01	101000	2013608124	PORT ORANGE-SOUTH DAYTONA	355	$203,738.85	$804,337.29
01	101000	2013608128	HOLLY HILL-FLEMING-ORMOND	355	$227,248.19	$1,041,505.23
01	101000	2013608132	ORMOND-VOLUSIA #2	355	$57,662.67	$168,139.75
01	101000	2013623053	SANFORD-SR 40 (E/O DELAND)	355	$668,187.41	$2,744,442.45
01	101000	2013623070	VOLUSIA-SR 40(E/O DELAND)	355	$429,530.45	$2,262,472.60
01	101000	2013623119	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	355	$1,009,499.47	$4,358,030.78
01	101000	2013623143	VOLUSIA - 148X2	355	$680,056.64	$1,657,521.08
01	101000	2013623148	SUGAR MILL-148X3	355	$505,028.96	$1,265,057.25
01	101000	2013623152	SUGAR MILL-PORT ORANGE	355	$96,722.32	$252,445.26
01	101000	2013623171	VOLUSIA-SMYRNA #2 115KV	355	$839,519.19	$1,224,086.19
01	101000	2013625109	DUVAL-POINSETT 500KV (OBO) (VOLUSIA)	355	$674,388.13	$1,112,740.41
01	101000	2013625110	POINSETT-RICE 500KV (OBO) (VOLUSIA CO)	355	$640,341.76	$1,056,563.90
01	101000	2013635088	PUTNAM-VOLUSIA #1 240KV (VOLUSIA CO.)	355	$258,991.93	$968,540.34
01	101000	2013648053	SANFORD-VOLUSIA #2	355	$1,052,337.28	$3,257,007.00
01	101000	2013660088	PUTNAM-VOLUSIA #2 240KV (VOLUSIA COUNTY)	355	$308,137.36	$722,139.49
01	101000	2020400014	T" C-5 - 624 EXTEND TO BARNA "	355	$208,345.33	$212,512.24
01	101000	2020405034	WABASSO SUB-MICCO SUB (SEBASTIAN RIVER XING)	355	$110,095.25	$177,968.44
01	101000	2020405035	WABASSO SUB-MICCO SUB (BREVARD CO.)	355	$355,742.49	$879,220.96
01	101000	2020405038	MICCO SUB-51E2A (PALM BAY)	355	$1,405,622.15	$3,112,021.02
01	101000	2020405051	MELBOURNE-MALABAR LOOP (N/O PALM BAY)	355	$238,606.16	$759,504.31
01	101000	2020405056	EAU GALLIE-MELBOURNE	355	$382,572.34	$1,204,835.83
01	101000	2020405063	EAU GALLIE-ROCKLEDGE	355	$494,471.61	$1,889,408.57
01	101000	2020405079	BREVARD-ROCKLEDGE	355	$1,654,821.95	$2,180,707.65
01	101000	2020405083	COCOA-SYKES CREEK LOOP	355	$791,279.85	$1,440,206.64
01	101000	2020405084	INDIAN RIVER CROSSING @ COCOA	355	$830,293.53	$1,054,948.59
01	101000	2020405086	SYKES CREEK LOOP	355	$87,750.47	$96,525.52
01	101000	2020405087	COCOA BEACH-SYKES CREEK LOOP	355	$641,655.78	$949,643.88
01	101000	2020405089	BANANA RIVER CROSSING @ COCOA BEACH	355	$85,545.06	$259,876.54
01	101000	2020405092	COCOA BEACH-SOUTH CAPE	355	$575,160.11	$1,373,212.51
01	101000	2020405100	EAU GALLIE-INDIAN HARBOUR	355	$464,310.75	$865,235.78
01	101000	2020405101	INDIAN RIVER CROSSING @ EAU GALLIE	355	$544,609.64	$977,683.31
01	101000	2020405103	INDIAN HARBOR-PATRICK	355	$450,895.94	$991,302.27
01	101000	2020405109	MALABAR-PALM BAY (SO.H-FRAME)	355	$761,192.44	$1,715,389.70
01	101000	2020405116	AURORA-EAU GALLIE	355	$131,598.57	$454,757.21

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01	101000 2020405119	AURORA-HIBISCUS-MALABAR	355	$347,096.68	$1,309,506.00
01	101000 2020405129	COCOA BEACH-SOUTH COCOA BEACH	355	$618,592.59	$1,290,845.45
01	101000 2020405132	BANANA RIVER SUB-SOUTH COCOA BEACH	355	$294,007.72	$944,251.38
01	101000 2020405136	BANANA RIVER SUB-PATRICK	355	$609,104.36	$951,568.02
01	101000 2020405140	PALM BAY TAP	355	$87,478.65	$449,713.50
01	101000 2020405143	INDIAN RIVER CROSSING @ HOLLAND PARK	355	$152,882.80	$805,211.73
01	101000 2020405145	HOLLAND PARK-INDIAN HARBOR	355	$359,416.23	$1,576,607.63
01	101000 2020405158	BREVARD-EAU GALLIE EXT TO SUNTREE	355	$543,457.08	$756,793.09
01	101000 2020406001	CLEARLAKE-COCOA	355	$98,366.84	$435,368.25
01	101000 2020406003	BREVARD-CITY POINT TAP-CLEARLAKE	355	$121,857.77	$307,492.42
01	101000 2020406005	CITY POINT TAP	355	$309,517.49	$753,658.55
01	101000 2020406007	CAPE CANAVERAL SES-CITY POINT	355	$788,523.13	$1,374,266.77
01	101000 2020406012	CAPE CANAVERAL SES-INDIAN RIVER SUB	355	$330,700.70	$1,073,427.88
01	101000 2020406020	INDIAN RIVER-TITUSVILLE	355	$125,404.23	$442,727.17
01	101000 2020406025	MIMS-TITUSVILLE	355	$221,536.41	$821,547.13
01	101000 2020406031	MIMS-VOLUSIA CO LINE	355	$268,599.15	$925,148.70
01	101000 2020406077	BREVARD-COCOA	355	$1,185,568.67	$1,865,576.03
01	101000 2020406082	BREVARD-CITY POINT TAP	355	$461,095.10	$548,621.98
01	101000 2020406084	BREVARD-COCOA	355	$18,774.33	$134,782.37
01	101000 2020406086	CITY POINT-SOUTH CAPE	355	$2,884,047.59	$4,386,556.47
01	101000 2020406093	CAPE CANAVERAL SES-GRISSOM TAP	355	$1,162,420.66	$1,560,277.25
01	101000 2020406099	GRISSOM TAP-ORSINO-C-5 COMPLEX	355	$818,670.85	$1,594,612.38
01	101000 2020406108	C-5 STRING BUS (2 TRANSM STRUCTURES)	355	$18,771.39	$19,146.82
01	101000 2020406109	SOUTH CAPE-C-5 COMPLEX	355	$1,772,085.01	$1,921,543.94
01	101000 2020406131	LINDE-MIMS	355	$82,931.03	$281,940.73
01	101000 2020406134	GRISSOM LOOP	355	$167,005.98	$194,459.59
01	101000 2020406135	FRONTENAC TAP	355	$17,042.76	$31,774.13
01	101000 2020406136	CAPE CANAVERAL SES-START-UP TAP	355	$31,216.69	$137,353.44
01	101000 2020406142	EDGEWATER-NORRIS 15KV (BREVARD CO.)	355	$1,317,093.80	$1,527,828.81
01	101000 2020406154	CAPE -NORRIS 115KV LOOP TO BARNA	355	$792,519.41	$840,070.57
01	101000 2020406158	C-5 - 624 EXTEND TO BARNA	355	$1,804,532.04	$1,840,622.68
01	101000 2020406163	RIVER CROSSING C-5 624 EXTEND TO BARNA	355	$130,715.77	$133,330.09
01	101000 2020422086	BREVARD-RANCH (BREVARD CO.)	355	$1,478,659.60	$3,827,490.95
01	101000 2020423001	BREVARD-SANFORD (BREVARD CO.)	355	$274,334.97	$1,023,477.28
01	101000 2020423080	BREVARD-CAPE CANAVERAL (3 CKTS)	355	$1,157,047.09	$4,494,260.48
01	101000 2020423088	CAPE CANAVERAL-INDIAN RIVER (ORLANDO U.C.)	355	$14,286.43	$17,765.86
01	101000 2020423091	CAPE CANAVERAL-VOLUSIA (BREVARD CO)	355	$1,332,681.97	$5,156,064.63
01	101000 2020423180	CAPE-NORRIS 230KV LOOP TO BARNA	355	$720,693.56	$757,478.26
01	101000 2020430109	MALABAR-PALM BAY (NO. H-FRAME)	355	$844,407.69	$1,153,282.65

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01	101000 2020447086	BREVARD-RANCH 2ND CKT (BREVARD CO.)	355	$906,587.06	$3,806,930.56
01	101000 2020448001	BREVARD-WEST LAKE WALES (FLA.POWER CORP)	355	$237,355.53	$817,515.21
01	101000 2020455109	MALABAR-PALM BAY-INDIAN RIVER CROSSING	355	$183,968.65	$531,185.29
01	101000 2022606067	SANFORD SUB-ST JOHNS RIVER XING	355	$1,132.00	$6,588.24
01	101000 2022606074	LAUREL-SANFORD SUB	355	$832.00	$5,037.81
01	101000 2022623006	BREVARD-SANFORD (ORANGE CO.)	355	$667,211.23	$2,198,617.72
01	101000 2022623160	BREVARD-POINSETT #1 240 KV (OBO) (ORANGE CO)	355	$399,789.10	$654,518.29
01	101000 2022623168	BREVARD-W LAKE WALES 230KV (OBO) PURCH FM FPC	355	$146,670.43	$158,935.59
01	101000 2022623270	POINSETT-SANFORD EXT TO CHULUOTA (ORANGE CO)	355	$318,348.52	$369,284.28
01	101000 2022625001	MARTIN-POINSETT 500KV (OBO) (ORANGE CO)	355	$217,446.09	$358,786.05
01	101000 2022625002	MIDWAY-POINSETT 500KV (OBO) (ORANGE CO)	355	$60,601.63	$99,992.69
01	101000 2022625160	DUVAL-POINSETT 500KV (OBO) (ORANGE CO)	355	$366,691.16	$605,040.41
01	101000 2022625161	POINSETT-RICE 500KV (OBO) (ORANGE CO)	355	$343,993.48	$567,589.24
01	101000 2022648160	POINSETT-WEST LAKE WALES #2 (OBO) (ORANGE CO)	355	$46,793.03	$72,074.77
01	101000 2023106045	LAUREL-VOLUSIA CO. LINE	355	$756,222.97	$2,921,836.84
01	101000 2023106067	SANFORD SUB-ST JOHNS RIVER XING	355	$242,722.98	$628,118.38
01	101000 2023106070	ST JOHNS RIVER XING AT SANFORD SES	355	$188,955.31	$341,654.76
01	101000 2023106074	LAUREL-SANFORD SUB	355	$138,739.87	$527,385.77
01	101000 2023107123	SANFORD-NORTH LONGWOOD (FPC)(SEMINOLE CO)	355	$788,836.02	$1,758,644.48
01	101000 2023123030	BREVARD-SANFORD (SEMINOLE CO)	355	$1,273,193.03	$4,530,155.28
01	101000 2023123272	POINSET-SANFORD EXT TO CHULUOTA (SEMINOLE CO)	355	$427,897.41	$496,361.00
01	101000 2023125144	DUVAL-POINSETT 500KV (OBO) (SEMINOLE CO)	355	$270,223.38	$445,868.58
01	101000 2023125145	POINSETT-RICE 500KV (OBO) (SEMINOLE CO)	355	$252,182.77	$416,101.57
01	101000 2023606036	CELERY-MIMS (VOLUSIA CO.)	355	$273,231.88	$1,079,745.29
01	101000 2023606070	ST JOHNS RIVER XING @ SANFORD SES	355	$10,530.42	$72,387.83
01	101000 2023606071	SANFORD SES-ST JOHNS RIVER XING	355	$53,204.36	$108,419.97
01	101000 2023607123	SANFORD-NORTH LONGWOOD (FPC)(VOLOSIA CO)	355	$228,642.22	$652,179.00
01	101000 2023623052	BREVARD-SANFORD (VOLUSIA CO.)	355	$38,422.83	$86,352.72
01	101000 2023623116	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	355	$145,933.43	$776,016.20
01	101000 2023623165	DELTONA TAP 240KV	355	$306,832.82	$506,274.15
01	101000 2030209124	BALDWIN-MACCLENNY (BAKER CO.)	355	$100,566.66	$309,837.25
01	101000 2030217066	COLUMBIA-MACCLENNY (BAKER CO.)	355	$621,421.08	$1,851,915.47
01	101000 2030217099	WIREMILL SUB TAP LINE	355	$98,637.28	$214,403.55
01	101000 2030309036	STARKE-CLAY CO. LINE	355	$410,688.47	$806,131.85
01	101000 2030309051	BALDWIN - STARKE (BRADFORD)	355	$596,523.80	$905,995.78
01	101000 2030309089	STARKE-TRAIL RIDGE TAP (BRADFORD CO)	355	$55,293.17	$287,910.88
01	101000 2030309161	BRADFORD-PUTNAM 240KV YARD (BRADFORD CO.)	355	$227,795.79	$1,004,306.72
01	101000 2030309167	BRADFORD-STARKE	355	$182,640.32	$710,852.59
01	101000 2030309168	GRIFFIS LOOP TAP	355	$4,276.38	$18,816.07

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01	101000 2030309190	BRADFORD-DUVAL 240KV LN (BRADFORD CO)	355	$587,473.07	$1,519,971.75
01	101000 2030309234	NEW RIVER TAP #2	355	$223,579.61	$520,305.52
01	101000 2030309348	BRADFORD-DEERHAVEN (GRU) (FPL OWNERSHIP)	355	$377,962.86	$613,467.72
01	101000 2030309361	PUTNAM-STARKE - EXTEND TO BRADFORD	355	$184,730.78	$203,203.86
01	101000 2030310043	LAWTEY TAP	355	$52,878.57	$159,396.26
01	101000 2030317001	STARKE-NEW RIVER TAP	355	$97,381.75	$350,386.88
01	101000 2030317008	NEW RIVER TAP #1	355	$4,566.14	$16,001.01
01	101000 2030317009	LAKE BUTLER-NEW RIVER TAP (BRADFORD CO.)	355	$52,581.26	$228,841.87
01	101000 2030709216	BRADFORD-DUVAL 240KV LN (CLAY CO.)	355	$275,999.48	$654,431.12
01	101000 2030709242	BLACK CREEK-TITANIUM 240KV	355	$1,421,662.87	$2,744,073.63
01	101000 2030709260	BLACK CREEK-DUVAL 240KV (CLAY COUNTY)	355	$532,763.37	$1,036,251.83
01	101000 2030725007	DUVAL-POINSETT 500KV (OBO) (CLAY CO)	355	$372,945.29	$615,359.73
01	101000 2030725008	DUVAL-RICE 500KV (OBO) (CLAY CO)	355	$494,117.61	$815,294.06
01	101000 2030917027	COLUMBIA-LAKE BUTLER (COLUMBIA CO.)	355	$219,472.61	$315,896.43
01	101000 2030917040	COLUMBIA-LIVE OAK TAP SECTION	355	$1,107,999.78	$1,505,328.07
01	101000 2030917052	LIVE OAK TAP STA-EAST OAK (COLUMBIA CO.)	355	$205,161.47	$205,530.70
01	101000 2030917084	COLUMBIA-MACCLENNY (COLUMBIA CO.)	355	$384,837.43	$944,985.77
01	101000 2031209067	BALDWIN (OLD)-BRADFORD CO. LINE	355	$234,657.41	$1,139,527.09
01	101000 2031209069	MAXVILLE TAP (CLAY CO. CO-OP)	355	$5,187.10	$17,480.53
01	101000 2031209078	BALDWIN (OLD)-NORMANDY (JACKSONVILLE ELECT AU	355	$47,632.49	$148,266.47
01	101000 2031209120	BALDWIN-MACCLENNY (DUVAL CO)	355	$73,511.60	$268,423.30
01	101000 2031209224	BRADFORD-DUVAL 240 KV LN (DUVAL CO)	355	$241,672.92	$586,108.23
01	101000 2031209231	STEELBALD SUB TAP LINE	355	$109,737.26	$173,336.73
01	101000 2031209232	BALDWIN-DUVAL 240KV LINE	355	$164,393.44	$397,876.44
01	101000 2031209233	DUVAL-NORMANDY (JEA)	355	$20,575.64	$53,496.66
01	101000 2031209268	BLACK CREEK-DUVAL 240KV (DUVAL COUNTY)	355	$483,470.00	$931,244.25
01	101000 2031209276	DUVAL-CALLAHAN 240KV (DUVAL CO)	355	$911,207.53	$1,950,658.55
01	101000 2031225002	DUVAL-POINSETT 500KV (OBO) (DUVAL CO)	355	$203,505.40	$335,783.91
01	101000 2031225003	DUVAL-RICE 500KV (OBO) (DUVAL CO)	355	$254,884.84	$420,559.99
01	101000 2032409178	CALLAHAN SUB-YULEE SUB 240KV (NASSAU CO)	355	$944,959.71	$2,235,544.28
01	101000 2032409287	DUVAL-CALLAHAN 240KV (NASSAU CO)	355	$933,832.27	$1,991,865.04
01	101000 2032409314	YULEE-KINGSLAND 240KV (GPC)	355	$669,724.76	$1,425,471.74
01	101000 2032450008	DUVAL-HATCH (GP) #2 500KV (OBO) (NASSAU CO)	355	($23.13)	($37.47)
01	101000 2033417055	LIVE OAK TAP STA-EAST OAK (SUWANNEE CO.)	355	$650,872.44	$1,009,854.60
01	101000 2033417061	EAST OAK-SUWANNEE TAP	355	$184,865.75	$257,089.28
01	101000 2033417063	LIVE OAK-SUWANNEE TAP	355	$27,878.41	$38,193.42
01	101000 2033417102	LIVE OAK-SUWANNEE PLT (FPC) 115KV	355	$1,315,672.33	$1,963,469.67
01	101000 2033517014	LAKE BUTLER-NEW RIVER TAP (UNION CO.)	355	$82,496.88	$329,321.29
01	101000 2033517019	COLUMBIA-LAKE BUTLER (UNION CO.)	355	$190,477.99	$755,322.62

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01	101000 2041621044	FT. MYERS-RANCH 138KV (HENDRY CO.)	355	$519,843.47	$821,433.72
01	101000 2041646044	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	355	$660,347.03	$2,347,980.86
01	101000 2041712012	CHILDS-OKEECHOBEE (HIGHLANDS CO.)	355	$1,450,078.36	$1,521,403.67
01	101000 2041805011	FT. PIERCE-OSLO (INDIAN RIVER CO.)	355	$169,977.37	$418,504.66
01	101000 2041805013	OSLO-WEST SUB (VERO BEACH)	355	$589,881.73	$1,305,696.85
01	101000 2041805019	WEST SUB (VERO BEACH)-WABASSO SUB	355	$718,199.69	$1,775,659.34
01	101000 2041805027	WABASSO-MICCO (INDIAN RIVER CO.)	355	$625,130.65	$1,497,471.11
01	101000 2041822067	BREVARD-RANCH (INDIAN RIVER CO.)	355	$818,502.31	$4,369,598.85
01	101000 2041825043	MARTIN-POINSETT 500KV (OBO) (INDIAN RIVER CO)	355	$338,945.86	$559,260.67
01	101000 2041825044	MIDWAY-POINSETT 500KV (OBO) (INDIAN RIVER CO)	355	$302,561.80	$499,226.97
01	101000 2041847067	BREVARD-RANCH 2ND CKT (INDIAN RIVER CO.)	355	$1,063,744.40	$5,115,355.07
01	101000 2042204028	PORT SEWALL-PALM BCH.CO.LINE	355	$1,297,179.32	$3,162,649.24
01	101000 2042204044	PORT SEWALL-ST. LUCIE CO. LINE	355	$478,977.32	$833,748.15
01	101000 2042204118	SANDPIPER-TURNPIKE 240 KV (MARTIN CO.)	355	$191,497.77	$310,226.39
01	101000 2042204138	TURNPIKE-CRANE 230KV (MARTIN CO)	355	$399,094.07	$526,804.17
01	101000 2042204142	RIO LOOP	355	$339,495.04	$420,973.85
01	101000 2042204164	CRANE-BRIDGE	355	$2,410,731.50	$2,779,919.61
01	101000 2042204174	BRIDGE-ALEXANDER (MARTIN CO.)	355	$573,240.56	$664,959.05
01	101000 2042204203	HOBE-COVE 138KV RADIAL LINE	355	$1,236,610.67	$1,360,271.74
01	101000 2042204210	HOBE-HILLS 138KV RADIAL LINE	355	$849,002.68	$933,902.95
01	101000 2042215009	SHERMAN SW STA-MARTIN PLANT (MARTIN CO.)	355	$582,133.41	$1,308,397.35
01	101000 2042215017	MARTIN PLANT-PAHOKEE (MARTIN CO.)	355	$743,682.03	$1,472,157.86
01	101000 2042222024	BREVARD-RANCH (MARTIN CO.)	355	$577,202.98	$2,483,858.69
01	101000 2042222146	FLORIDA STEEL TAP	355	$7,856.04	$12,904.40
01	101000 2042222155	FLA STEEL-MARTIN PLT 240KV LINE	355	$154,039.47	$402,043.02
01	101000 2042222160	HOBE-INDIANTOWN 240KV	355	$1,382,917.09	$2,340,761.54
01	101000 2042222179	INDIANTOWN-MARTIN #1-INDIANTOWN-FLA. STEEL	355	$663,837.84	$728,627.04
01	101000 2042222186	INDIANTOWN-MARTIN #1-FLA.STEEL-MARTIN SECT	355	$185,828.48	$204,411.33
01	101000 2042225001	MARTIN-MIDWAY 500KV (MARTIN CO)	355	$320,238.19	$627,666.85
01	101000 2042225024	CORBETT-MIDWAY 500KV (MARTIN CO)	355	$357,954.93	$398,002.50
01	101000 2042225077	CORBETT-MARTIN 500KV (MARTIN CO.)	355	$322,999.03	$377,374.09
01	101000 2042225078	CORBETT-MARTIN 500KV (OBO)	355	$74,327.30	$124,869.86
01	101000 2042225079	ANDYTOWN-MARTIN 500KV #1 (MARTIN CO.)	355	$333,749.55	$597,162.48
01	101000 2042225082	MARTIN-MIDWAY 500KV (OBO) (MARTIN CO)	355	$49,105.14	$82,496.64
01	101000 2042225100	MARTIN-POINSETT 500KV (OBO) (MARTIN CO)	355	$293,940.02	$485,001.03
01	101000 2042247024	BREVARD-RANCH 2ND CKT (MARTIN CO.)	355	$694,785.88	$2,612,390.46
01	101000 2042247179	INDIANTOWN-MARTIN #2-INDIANTOWN-WARFIELD SECT	355	$10,561.71	$10,561.71
01	101000 2042247186	INDIANTOWN-MARTIN #2-WARFIELD-MARTIN SECT	355	$434,857.70	$477,926.19
01	101000 2042250079	ANDYTOWN-MARTIN 500KV #2 (MARTIN CO)	355	$362,202.40	$622,992.92

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01	101000 2042511035	OKEECHOBEE-34K14	355	$178,498.51	$345,024.77
01	101000 2042511059	MIDWAY SHERMAN(OKEECHOBEE CO.)	355	$393,083.89	$827,846.03
01	101000 2042511066	OKEECHOBEE-SHERMAN #2	355	$523,489.21	$772,838.11
01	101000 2042511069	OKEECHOBEE-SHERMAN #1 EXT. TO SWEATT SUB	355	$954,743.23	$1,050,217.55
01	101000 2042512001	CHILDS-OKEECHOBEE (OKEECHOBEE CO.)	355	$703,450.16	$1,083,642.71
01	101000 2042515001	OKEECHOBEE (34K14)-SHERMAN SW STA)	355	$181,070.35	$429,865.86
01	101000 2042515002	SHERMAN SW STA-MARTIN PLANT (OKEECHOBEE CO.)	355	$490,014.90	$1,068,780.00
01	101000 2042803027	LAUDERDALE SES-WEST PALM BEACH	355	$171,308.64	$1,249,658.81
01	101000 2042803045	GREENACRES TAP	355	$285,190.25	$978,327.25
01	101000 2042803048	GREENACRES-MILITARY TRAIL	355	$691,350.75	$1,176,686.72
01	101000 2042803051	MILITARY TRAIL-WEST PALM BEACH	355	$371,887.81	$1,037,539.98
01	101000 2042803057	BOCA RATON TAP (OLD)	355	$30,571.46	$211,009.29
01	101000 2042803060	BOYNTON LOOP (OLD)	355	$14,930.44	$108,202.79
01	101000 2042803065	DELRAY BEACH TAP (REBUILT FOR BROWARD-RANCH #	355	$117,954.53	$287,420.11
01	101000 2042803088	LINTON-YAMATO	355	$495,206.20	$1,465,888.07
01	101000 2042803093	IBM-YAMATO	355	$484,608.14	$820,809.78
01	101000 2042803095	IBM-BOCA RATON TAP (OLD)	355	$153,262.55	$427,504.71
01	101000 2042803100	BOCA RATON-BROWARD CO. LINE	355	$182,540.00	$528,368.10
01	101000 2042803103	BOCA RATON-ATLANTIC LOOP	355	$195,430.17	$692,616.28
01	101000 2042803106	ATLANTIC LOOP-106C27 (SIO IBM)	355	$31,564.42	$57,849.72
01	101000 2042803107	CEDAR-LINTON 138KV	355	$804,889.10	$1,606,543.97
01	101000 2042803112	BOYNTON-CEDAR 138KV	355	$276,168.22	$493,618.70
01	101000 2042803113	BOYNTON-LANTANA	355	$437,524.93	$778,512.45
01	101000 2042803116	LANTANA-RANCH	355	$1,300,540.65	$2,153,248.40
01	101000 2042803150	ATLANTIC LOOP	355	$135,391.33	$553,125.59
01	101000 2042803151	MILITARY TRAIL-RANCH	355	$341,424.40	$1,408,874.07
01	101000 2042803166	NORTON TAP	355	$184,796.10	$861,297.02
01	101000 2042803168	BROWARD-YAMATO 240KV (PALM BCH CO.)	355	$913,567.45	$3,481,792.79
01	101000 2042803195	CEDAR-DELTRAIL 240KV	355	$535,154.13	$862,027.71
01	101000 2042803200	DELTRAIL-YAMATO 240KV	355	$1,023,496.85	$1,623,495.91
01	101000 2042803214	RANCH-WPB #1 138KV JOG-MILITARY TRAIL SECTION	355	$345,467.37	$456,016.93
01	101000 2042803224	CEDAR-STR 120C3	355	$490,438.30	$664,382.17
01	101000 2042803227	CEDAR-JOG (CEDAR-FOUNTAIN SECTION)	355	$1,208,012.32	$1,474,580.39
01	101000 2042803233	CEDAR-JOG (FOUNTAIN-STR B131C17 SECTION)	355	$838,049.89	$1,039,181.86
01	101000 2042803240	CALDWELL - YAMATO 138KV	355	$881,116.42	$1,048,528.54
01	101000 2042804001	WEST PALM BEACH-DATURA TAP #1	355	$130,872.23	$324,058.74
01	101000 2042804002	RIVIERA-DATURA TAP #1	355	$9,021.31	$9,923.44
01	101000 2042804008	PLUMOSUS-RIVIERA #2	355	$1,193,314.74	$4,567,802.36
01	101000 2042804022	PLUMOSUS-MARTIN CO. LINE	355	$646,721.97	$1,311,379.24

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01	101000	2042804069	PLUMOSUS-RIVIERA #1	355	$1,700,417.30	$2,662,602.27
01	101000	2042804081	WEST PALM BEACH-STUART (OLD)	355	$10,202.67	$75,601.78
01	101000	2042804084	RIVIERA TIE (#1 CKT)	355	$18,446.48	$132,790.86
01	101000	2042804085	RIVIERA TIE (#2 CKT)	355	$32,457.11	$131,731.68
01	101000	2042804086	DATURA TAP #1 (SOUTH)	355	$149,429.70	$185,831.00
01	101000	2042804087	DATURA TAP #2 (NORTH)	355	$86,526.45	$185,334.87
01	101000	2042804088	RIVIERA-WEST PALM BEACH	355	$916,067.09	$4,413,949.09
01	101000	2042804144	RANCH-RIVIERA #2 EXTEND TO TERMINAL SUB	355	$652,257.00	$756,618.12
01	101000	2042804147	TERMINAL - NORTHWOOD	355	$204,979.90	$237,776.68
01	101000	2042804179	BRIDGE-ALEXANDER (PALM BEACH CO.)	355	$356,744.77	$411,373.70
01	101000	2042804182	ALEXANDER-PLUMOSUS	355	$2,645,123.95	$3,068,343.78
01	101000	2042804217	ALEXANDER-TRIGAS 230KV RADIAL	355	$458,148.84	$453,567.35
01	101000	2042815023	OKEECHOBEE (34K14)-PAHOKEE (PALM BEACH CO.)	355	$578,793.04	$1,244,187.85
01	101000	2042815035	BRYANT SUB TAP	355	$30,379.44	$54,527.89
01	101000	2042815048	BELLE GLADE-QUAKER OATS TAP-STR 64P9	355	$556,758.24	$766,251.48
01	101000	2042815056	QUAKER OATS TAP (DOUBLE CKT)	355	$280,000.70	$383,600.96
01	101000	2042815058	PAHOKEE-SOUTH BAY	355	$706,805.98	$2,457,194.63
01	101000	2042815072	S0. BAY-PAHOKEE RADIAL	355	$136,836.30	$294,198.05
01	101000	2042818058	BELLE GLADE-SO.BAY	355	$249,989.41	$609,269.42
01	101000	2042819030	LAUDERDALE-RANCH (PALM BEACH CO.)	355	$655,727.35	$1,750,754.74
01	101000	2042819056	RANCH-RIVIERA (3 CKTS)	355	$1,463,418.37	$5,201,099.42
01	101000	2042819099	RIVIERA (STEEL TOWERS)	355	$5,396.16	$7,122.93
01	101000	2042819100	RANCH-BROWARD #2 240KV (PALM BEACH CO.)	355	$1,655,859.34	$6,514,321.46
01	101000	2042819183	RANCH-RIVIERA #3 RECWAY TAP	355	$4,838.42	$7,209.25
01	101000	2042819186	RANCH-WEST PALM BEACH #3	355	$1,092,763.35	$1,447,662.48
01	101000	2042821062	FT.MYERS-RANCH 138KV (PALM BEACH CO.)	355	$1,585,074.66	$3,112,622.03
01	101000	2042821109	BROWARD-RANCH #2 CORBETT EXTENSION	355	$4,195,024.40	$6,108,652.59
01	101000	2042821121	ORANGE RIVER-RANCH CORBETT EXTENSION	355	$679,207.75	$1,012,019.55
01	101000	2042821124	CLEWISTON-SO. BAY - LOOP TO OKEELANTA	355	$727,096.11	$770,721.88
01	101000	2042821130	RANCH-SOUTH BAY - LOOP TO OSCEOLA PLANT	355	$0.01	$0.01
01	101000	2042822001	BREVARD-RANCH (PALM BEACH CO.)	355	$706,816.31	$2,995,928.69
01	101000	2042822128	APIX-PRATT & WHITNEY	355	$1.15	$8.52
01	101000	2042825001	CORBETT-MIDWAY 500KV (PALM BCH.CO)	355	$301,387.24	$449,066.99
01	101000	2042825002	CORBETT-MARTIN 500KV (PALM BCH CO.)	355	$160,196.08	$176,215.69
01	101000	2042825023	ANDYTOWN-MARTIN 500KV #1 (PALM BCH CO.)	355	$1,112,325.24	$2,180,157.47
01	101000	2042829022	HOBE-PLUMOSUS #2 230KV	355	$18,692.67	$21,683.50
01	101000	2042844030	CEDAR-LAUDERDALE (PALM BEACH CO.)	355	$1,109,883.68	$4,750,723.59
01	101000	2042844046	CEDAR-RANCH (PALM BEACH CO.)	355	$1,148,092.33	$1,986,809.39
01	101000	2042846062	ORANGE RIVER-RANCH 240KV (PALM BEACH CO.)	355	$1,585,199.47	$4,864,266.72

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01	101000 2042846109	CORBETT-RANCH #1 & CORBETT-CEDAR 240KV	355	$1,547,919.25	$2,027,628.85
01	101000 2042847001	BREVARD-RANCH 2ND CKT (PALM BEACH CO.)	355	$964,980.59	$3,613,462.81
01	101000 2042850023	ANDYTOWN-MARTIN 500KV #2 (PALM BCH CO)	355	$1,256,973.17	$2,463,667.41
01	101000 2042853131	RANCH-WPB #1 138KV RANCH-JOG SECTION	355	$569,679.05	$751,093.32
01	101000 2043304053	WHITE CITY-MARTIN CO. LINE	355	$974,068.67	$2,319,269.31
01	101000 2043304062	FT PIERCE-WHITE CITY	355	$727,489.96	$1,557,980.22
01	101000 2043304098	MIDWAY-WHITE CITY	355	$345,865.88	$1,299,582.05
01	101000 2043304108	ST LUCIE PLANT-MIDWAY #1 240KV	355	$1,375,177.80	$3,908,992.39
01	101000 2043304119	SANDPIPER-TURNPIKE 240KV (ST. LUCIE CO.)	355	$1,133,175.02	$1,746,052.59
01	101000 2043304125	MIDWAY-TURNPIKE 240KV (ST. LUCIE CO.)	355	$1,179,860.07	$1,902,369.77
01	101000 2043304134	TURNPIKE-CRANE 230KV (ST LUCIE CO)	355	$635,507.05	$838,869.31
01	101000 2043305001	FT PIERCE-OSLO (ST LUCIE CO.)	355	$1,100,912.39	$2,758,494.20
01	101000 2043311001	FT. PIERCE-MIDWAY	355	$1,087,733.78	$2,693,743.68
01	101000 2043311010	MIDWAY-OKEECHOBEE CO.LINE	355	($90.95)	($673.94)
01	101000 2043311039	MIDWAY-SHERMAN (ST. LUCIE CO.)	355	$2,002,550.25	$4,293,898.41
01	101000 2043322042	BREVARD-RANCH (ST LUCIE C.)	355	$1,252,646.30	$3,761,310.83
01	101000 2043322176	EMERSON-MIDWAY TAP STR 64W5	355	$559,632.24	$923,393.20
01	101000 2043325013	MARTIN-MIDWAY 500KV (ST.LUCIE CO)	355	$221,922.58	$306,584.84
01	101000 2043325022	CORBETT-MIDWAY 500KV (ST. LUCIE CO.)	355	$111,226.12	$184,818.71
01	101000 2043325071	MARTIN-POINSETT 500KV (OBO) (ST. LUCIE CO)	355	$636,540.62	$1,050,292.02
01	101000 2043325072	MIDWAY-POINSETT 500KV (OBO) (ST.LUCIE CO)	355	$200,007.93	$330,013.08
01	101000 2043329108	ST LUCIE PLANT-MIDWAY #2	355	$1,354,732.92	$3,856,880.20
01	101000 2043347042	BREVARD-RANCH 2ND CKT (ST LUCIE CO.)	355	$1,225,548.06	$3,734,596.66
01	101000 2043354108	ST LUCIE PLANT-MIDWAY #3 240KV	355	$1,129,960.39	$3,182,031.49
01	101000 2050612265	MYAKKA-ROTUNDA 138KV (CHARLOTTE CO.)	355	$565,254.06	$880,730.66
01	101000 2050612270	ENGLEWOOD TO ROTONDA 138KV (CHARLOTTE CO.)	355	$694,670.73	$687,724.02
01	101000 2050612275	ENGLEWOOD TO ROTONDA 138KV (SARASOTA CO.)	355	$115,318.50	$114,165.32
01	101000 2050613017	CHARLOTTE-NOCATEE (CHARLOTTE CO.)	355	$168,413.90	$500,326.93
01	101000 2050613022	CHARLOTTE-PUNTA GORDA (NO. CKT)	355	$521,375.15	$710,513.94
01	101000 2050613030	LEE-PUNTA GORDA (E. CKT-CHARLOTTE CO.)	355	$70,509.56	$350,103.33
01	101000 2050613057	LEE-PUNTA GORDA (W.CKT-CHARLOTTE CO.)	355	$46,633.19	$123,025.62
01	101000 2050613199	CHARLOTTE-PUNTA GORDA (SO.CKT)	355	$281,289.00	$661,355.26
01	101000 2050613235	DORRFIELD TAP-CHARLOTTE (CHARLOTTE CO.)	355	$418,152.41	$986,524.72
01	101000 2050614001	PUNTA GORDA-MURDOCK-SARASOTA CO. LINE	355	$1,069,468.87	$2,963,122.01
01	101000 2050614002	PEACE RIVER CROSSING @ PUNTA GORDA	355	$214,370.21	$1,357,139.39
01	101000 2050624054	CHARLOTTE-RINGLING 138KV (CHARLOTTE CO.)	355	$469,555.53	$1,726,470.97
01	101000 2050624063	CHARLOTTE-CALUSA-FT. MYERS (CHARLOTTE CO.)	355	$443,241.25	$1,216,280.64
01	101000 2050624151	CHARLOTTE-LAURELWOOD 240KV (CHARLOTTE C.)	355	$1,037,783.17	$2,328,728.49
01	101000 2050624155	PEACE RIVER XING @ CHARLOTTE SUB	355	$576,856.86	$1,944,007.62

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01	101000 2050624160	FT. MYERS-CHARLOTTE (CHARLOTTE CO.)	355	$708,902.41	$2,080,140.06
01	101000 2050649054	FT. MYERS-RINGLING #1 240KV (CHARLOTTE CO.)	355	$858,291.93	$2,499,796.49
01	101000 2050813083	NAPLES-SOLANA-LEE CO. LINE	355	$605,122.73	$1,100,923.22
01	101000 2050813137	FT. MYERS-COLLIER (COLLIER CO.)	355	$342,390.22	$1,014,862.39
01	101000 2050813145	COLLIE-NAPLES	355	$177,802.83	$514,360.17
01	101000 2050813153	ALLIGATOR-COLLIER	355	$267,403.20	$452,781.86
01	101000 2050813155	ALLIGATOR TAP	355	$20,989.37	$83,979.96
01	101000 2050813156	ALLIGATOR-BELLE MEADE	355	$737,531.29	$1,396,654.99
01	101000 2050813163	CAPRI TAP	355	$51,724.29	$80,077.69
01	101000 2050813258	ALICO-COLLIER (COLLIER CO.)	355	$1,180,109.90	$2,913,416.00
01	101000 2050813280	CAPRI-GOLDEN GATE-COLLIER 138KV	355	$1,537,282.56	$2,606,816.61
01	101000 2050813299	ALICO-NAPLES/ALICO-COLLIER TIE LINE	355	$638,694.44	$843,076.66
01	101000 2051112046	ARCADIA-CHILDS (DE SOTO CO.)	355	$683,747.99	$853,604.34
01	101000 2051112066	WHIDDEN TAP 69KV	355	$49,408.80	$78,875.75
01	101000 2051113001	ARCADIA-NOCATEE 69KV	355	$188,267.54	$750,098.63
01	101000 2051113009	CHARLOTTE-NOCATEE (DE SOTO CO.)	355	$576,984.31	$1,411,020.02
01	101000 2051113218	DORRFIELD TAP-CHARLOTTE (DE SOTO CO.)	355	$1,644,714.64	$4,007,335.13
01	101000 2051114231	KEENTOWN-WHIDDEN 240KV (DE SOTO CO.)	355	$1,540,071.08	$2,501,886.59
01	101000 2051124052	CHARLOTTE-RINGLING 138KV (DE SOTO CO.)	355	$10,939.68	$49,164.06
01	101000 2051124149	CHARLOTTE-LAURELWOOD (DE SOTO CO.)	355	$16,449.00	$56,138.28
01	101000 2051149052	FT. MYERS-RINGLING #1 240KV (DE SOTO CO.)	355	$32,793.08	$198,624.48
01	101000 2051621015	FT. MYERS-RANCH 138KV (HENDRY CO.)	355	$503,903.29	$1,601,560.44
01	101000 2051646015	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	355	$770,352.89	$3,236,367.15
01	101000 2051712032	ARCADIA-CHILDS (HIGHLANDS CO.)	355	$632,710.01	$653,149.03
01	101000 2051913042	LEE-PUNTA GORDA (EAST CKT. LEE CO.)	355	$8,348.06	$31,437.62
01	101000 2051913046	FT MYERS TAP CROSSOVER-LEE	355	$24,497.00	$51,900.56
01	101000 2051913049	CALOOSAHATCHEE RIVER XING #1 LINE	355	$108.95	$770.05
01	101000 2051913050	FT MYERS TAP	355	$98,238.30	$182,014.43
01	101000 2051913052	FT MYERS-BUCKINGHAM AIR FIELD	355	$25,559.22	$65,796.40
01	101000 2051913064	LEE-PUNTA GORDA (WEST CKT.LEE CO.)	355	$7,756.99	$32,056.64
01	101000 2051913067	FT MYERS TAP-LEE	355	$29,562.88	$87,234.21
01	101000 2051913068	CALOOSAHATCHEE RIVER XING #2 LINE	355	$4,165.87	$12,493.72
01	101000 2051913075	ALICO-COLONIAL TAP	355	$342,326.61	$455,961.00
01	101000 2051913078	ALICO-BONITA SPRINGS-COLLIER LINE VIA ESTERO	355	$492,221.37	$795,251.22
01	101000 2051913091	FT.MYERS SES-FT MYERS (SINGLE POLE SECT)	355	$54,659.47	$107,346.01
01	101000 2051913092	FT.MYERS SES-FT MYERS (DOUBLE CKT SECT)	355	$706,026.78	$1,228,944.84
01	101000 2051913096	BUCKINGHAM 69KV TAP	355	$85,314.79	$178,896.39
01	101000 2051913098	IONA TAP	355	$438,117.95	$700,235.40
01	101000 2051913105	FT MYERS SES-BUCKINGHAM	355	$216,677.54	$530,386.68

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01	101000 2051913110	COLONIAL TAP	355	$137,574.13	$671,935.65
01	101000 2051913113	FT MYERS-COLLIER (LEE CO.)	355	$1,357,038.24	$4,106,620.45
01	101000 2051913164	COLONIAL-IONA	355	$418,039.73	$1,511,626.07
01	101000 2051913178	BUCKINGHAM-COLONIAL TAP	355	$1,100,422.64	$2,436,403.09
01	101000 2051913183	FT MYERS SUB-NAPLES TAP (OLD)	355	$262,292.13	$372,577.87
01	101000 2051913204	ALICO-FT MYERS #2	355	$92,751.34	$156,641.66
01	101000 2051913208	ALICO-SR 45	355	$161,203.58	$204,527.55
01	101000 2051913212	FT MYERS PLT-ORANGE RIVER 240KV TIE LINE	355	$436,940.48	$1,254,604.56
01	101000 2051913215	FT MYERS PLT STRING BUS	355	$2,665.02	$6,955.70
01	101000 2051913241	ALICO-245M7	355	$1,895,932.57	$4,727,265.89
01	101000 2051913245	COLLIER-ORANGE RIVER (LEE CO.)	355	$2,367,122.30	$4,261,388.04
01	101000 2051913328	ALICO-BUCKINGHAM 138KV - IONA-BUCKINGHAM SECT	355	$439,665.76	$435,269.10
01	101000 2051921001	FT. MYERS-RANCH 138KV (LEE CO.)	355	$544,809.39	$2,802,237.36
01	101000 2051924080	CHARLOTTE-CALUSA-FT. MYERS (LEE CO.)	355	$219,086.64	$577,935.06
01	101000 2051924085	FT MYERS SES-BAYSHORE	355	$134.95	$785.41
01	101000 2051924086	FT MYERS-LEE (LEE CO.)	355	$18,717.82	$63,079.05
01	101000 2051924176	FT MYERS-CHARLOTTE 240KV (LEE CO.)	355	$381,021.74	$1,209,187.38
01	101000 2051924181	CALOOSAHATCHEE RIVER XING @ FT MYERS PLT.	355	$231,591.62	$780,463.76
01	101000 2051938098	ALICO-GLADIOLUS-BUCKINGHAM 138KV	355	$430,316.82	$438,923.16
01	101000 2051938212	FT MYERS PLT-ORANGE RIVER #2 240KV	355	$632,203.37	$1,586,830.46
01	101000 2051938241	ALICO-COLLIER 138KV	355	$375,522.69	$465,352.94
01	101000 2051946001	ORANGE RIVER-RANCH 240KV (LEE CO.)	355	$486,727.59	$1,676,750.04
01	101000 2051949080	FT MYERS-RINGLING #1 240KV (LEE CO.)	355	$295,140.68	$679,631.47
01	101000 2051974085	CALUSA-FT. MYERS	355	$178,239.75	$716,295.24
01	101000 2052014022	BUCKEYE TAP #1 NORTH	355	$83,178.74	$133,917.77
01	101000 2052014056	CORTEZ TAP-WHITFIELD-SARASOTA CO. LINE	355	$275,022.44	$762,880.62
01	101000 2052014060	CORTEZ TAP-FRUIT INDUSTRIES TAP	355	$20,720.57	$120,053.84
01	101000 2052014071	BRADENTON-CASTLE	355	$420,457.37	$1,128,882.08
01	101000 2052014075	BRADENTON-CASTLE(BRADEN RIVER CROSSING)	355	$297,685.79	$413,112.89
01	101000 2052014076	CASTLE-RUBONIA	355	$816,672.15	$1,248,893.10
01	101000 2052014077	CASTLE-TAMPA ELECTRIC(MANATEE RIVER CROSSING)	355	$189,964.23	$447,947.78
01	101000 2052014078	RUBONIA-TAMPA ELECTRIC(BIG BEND)	355	$960,655.22	$1,389,859.77
01	101000 2052014083	CORTEZ TAP	355	$491,083.54	$807,707.12
01	101000 2052014088	CASTLE-RINGLING (W CKT, MANATEE CO.)	355	$431,702.83	$1,525,421.96
01	101000 2052014111	CORTEZ-PALMA SOLA-BRADENTON	355	$405,162.07	$1,391,420.46
01	101000 2052014121	BORDEN TAP #1 (NORTH)	355	$227,798.96	$562,441.11
01	101000 2052014125	FRUIT INDUSTRIES TAP	355	$216,884.64	$1,031,590.99
01	101000 2052014135	RINGLING-MANATEE #1 240KV (MANATEE CO.)	355	$2,961,225.31	$8,089,690.24
01	101000 2052014144	RINGLING-MANATEE #240KV-MANATEE RIVER XING	355	$222,467.59	$749,715.78

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01	101000 2052014150	MANATEE-TAMPA #1 240KV (MANATEE CO.)	355	$1,176,612.95	$2,830,462.13
01	101000 2052014171	CORTEZ-JOHNSON 138KV	355	$1,169,175.81	$2,276,635.08
01	101000 2052014187	KEENTOWN-MANATEE 240KV	355	$1,844,413.63	$3,043,328.19
01	101000 2052014229	BEKER-KEENTOWN TAP 69KV	355	$27,557.59	$46,847.90
01	101000 2052014253	KEENTOWN-WHIDDEN 240KV (MANATEE CO.)	355	$1,012,672.08	$1,679,086.56
01	101000 2052014270	MANATEE-BIG BEND #2 240KV (TECO)	355	$721,846.77	$1,212,702.57
01	101000 2052024001	CASTLE-RINGLING (MANATEE CO.)	355	$671,724.49	$1,381,913.42
01	101000 2052024033	CHARLOTTE-RINGLING 138KV (MANATEE CO.)	355	$355,619.25	$707,683.89
01	101000 2052039022	BUCKEYE TAP #2 SOUTH	355	$78,114.17	$125,763.81
01	101000 2052039121	BORDEN TAP #2 (SOUTH)	355	$206,508.53	$536,055.99
01	101000 2052039135	RINGLING-MANATEE #2 240KV (MANATEE CO.)	355	$2,874,763.17	$7,427,786.49
01	101000 2052049033	FT MYERS-RINGLING #1 240KV (MANATEE CO.)	355	$123,036.30	$339,265.26
01	101000 2052064135	RINGLING-MANATEE #3 240KV (MANATEE CO.)	355	$2,880,734.16	$6,827,293.12
01	101000 2052064144	RINGLING-MANATEE #3 240KV-MANATEE RIVER WING	355	$182,395.27	$434,100.74
01	101000 2053012263	MYAKKA-ROTUNDA 138KV (SARASOTA CO.)	355	$177,677.51	$293,167.89
01	101000 2053014012	VENICE-ENGLEWOOD-CHARLOTTE CO.LINE	355	$1,790,072.74	$4,109,226.69
01	101000 2053014034	CLARK-VENICE	355	$1,285,908.71	$1,797,322.61
01	101000 2053014047	CLARK-HYDE PARK-RINGLING	355	$1,032,131.28	$2,126,992.66
01	101000 2053014053	MANATEE CO. LINE-53N11 (E/O SARASOTA)	355	$251,151.94	$846,662.84
01	101000 2053014068	SARASOTA & PAYNE LOOPS	355	$918,898.74	$1,588,121.30
01	101000 2053014096	CASTLE-RINGLING (W CKT. SARASOTA CO.)	355	$151,660.24	$674,348.78
01	101000 2053014102	RINGLING-TUTTLE AVE. (DOUBLE CKT)	355	$124,908.96	$597,384.68
01	101000 2053014108	RINGLING-54N2	355	$118,418.86	$147,344.60
01	101000 2053014126	PHILLIPPI LOOP	355	$271,152.16	$1,340,382.28
01	101000 2053014131	RINGLING-MANATEE #1 240KV (SARASOTA CO.)	355	$248,260.18	$803,964.98
01	101000 2053014166	LAURELWOOD TAP 138KV	355	$523,472.03	$1,212,681.18
01	101000 2053014180	PHILLIPPI LOOP EXTENSION (NORTH)	355	$317,524.10	$562,069.16
01	101000 2053014183	PHILLIPPI LOOP EXTENSION (SOUTH)	355	$362,751.13	$647,854.25
01	101000 2053014206	LAURELWOOD-MYAKKA 240KV	355	$1,483,090.11	$2,625,965.69
01	101000 2053024009	CASTLE-RINGLING (SARASOTA CO.)	355	$387,608.22	$678,375.18
01	101000 2053024013	CHARLOTTE-RINGLING 138KV (SARASOTA CO.)	355	$2,090,247.42	$6,914,821.65
01	101000 2053024087	RINGLING-VENICE #2	355	$2,491,922.66	$3,454,784.11
01	101000 2053024107	LAURELWOOD-RINGLING #1	355	$998,144.26	$2,900,289.48
01	101000 2053024128	CHARLOTTE-LAURELWOOD (SARASOTA CO.)	355	$1,070,271.17	$2,745,367.70
01	101000 2053024182	LAURELWOOD-RINGLILNG #2 240KV	355	$1,353,643.54	$2,274,121.15
01	101000 2053039131	RINGLING-MANATEE #2 240KV (SARASOTA CO.)	355	$594,781.30	$1,546,431.38
01	101000 2053039144	RINGLING-MANATEE #2 240KV-MANATEE RIVER XING	355	$95,900.24	$249,340.62
01	101000 2053039166	HOWARD-LAURELWOOD (LAURELWOOD LOOP SECT)	355	$817,374.24	$968,926.17
01	101000 2053049013	FT MYERS-RINGLING #1 240KV (SARASOTA CO.)	355	$1,390,066.28	$3,819,264.33

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01	101000 2053064131	RINGLING-MANATEE #3 240KV (SARASOTA CO.)	355	$723,138.08	$1,684,168.99
01	101000 2070500920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (BROWAR	355	$57.57	$402.99
01	101000 2070501028	LAUDERDALE SES-COUNTY LINE	355	$1,034,191.27	$3,059,104.53
01	101000 2070501106	BEVERLY LOOP	355	$11,638.49	$72,524.38
01	101000 2070501242	GARDEN-LAUDERDALE (BROWARD CO.)	355	$146,132.50	$917,289.02
01	101000 2070502030	COUNTY LINE TAP-32B8 (S/O LAUDERDALE)	355	$330,208.90	$937,853.21
01	101000 2070502033	LAUDERDALE-32B8 (TO FULFORD)	355	$219,736.70	$1,048,369.00
01	101000 2070502034	LAUDERDALE-HOLLYWOOD	355	$1,389,190.60	$2,272,511.92
01	101000 2070502036	HOLLYWOOD (N/O)-RAVENSWOOD (E/O)	355	$66,833.14	$249,224.72
01	101000 2070502037	HOLLYWOOD 138KV TAP	355	$63,572.69	$211,287.81
01	101000 2070502038	LAUDERDALE SES-HOLLYWOOD TIE	355	$130,434.22	$416,287.78
01	101000 2070502039	PLAYLAND TAP	355	$125,574.60	$197,924.23
01	101000 2070502043	GRANT STREET TIE LINE	355	$13,297.83	$46,898.36
01	101000 2070502044	HALLANDALE-HOLLYWOOD	355	$232,233.86	$851,612.54
01	101000 2070502049	HALLANDALE-DADE CO. LINE	355	$51,705.97	$280,345.01
01	101000 2070502058	LAUDERDALE-HOLLYWOOD (STIRLING RD SECT)	355	$250,195.35	$352,875.41
01	101000 2070502059	HOLLYWOOD-STIRLING	355	$270,562.39	$1,237,177.61
01	101000 2070502066	PORT SUB-RAVENSWOOD (OLD DANIA TAP)	355	$1,067,053.79	$2,356,200.03
01	101000 2070502073	BEVERLY TIE LINES	355	$14,293.13	$86,826.96
01	101000 2070502078	STIRING RD TIE	355	$8,295.58	$20,665.45
01	101000 2070502079	STIRLING RD (W/O STIRLING)-PEMBROKE-DADE CO L	355	$187,838.04	$1,135,093.79
01	101000 2070502091	DANIA-HOLLYWOOD	355	$55,064.69	$185,568.01
01	101000 2070502092	MELALEUCA-TRACE 240KV LINE	355	$460,312.27	$749,190.45
01	101000 2070502096	ANDYTOWN-TRACE 240KV	355	$1,273,662.35	$1,881,527.67
01	101000 2070503001	LAUDERDALE-PINEHURST-POMPANO-PALM BCH CO.	355	$2,920,461.45	$8,145,110.27
01	101000 2070503024	BROWARD-YAMATO (BROWARD CO.)	355	$356,619.00	$1,002,030.26
01	101000 2070503025	CRYSTAL TAP #2 - DEERFIELD BCH	355	$403,879.64	$944,225.39
01	101000 2070503067	LAUDERDALE SES-1C13	355	$197,814.11	$251,036.09
01	101000 2070503068	OAKLAND PARK LOOP	355	$88,450.63	$408,815.62
01	101000 2070503069	FAIRMONT-FT LAUDERDALE	355	$301,208.40	$444,403.56
01	101000 2070503072	VERENA-72C4 (OLD VERENA TAP)	355	$100,612.73	$309,751.42
01	101000 2070503074	PINEHURST-PT.EVERGLADES	355	$70,271.49	$389,430.90
01	101000 2070503079	BROWARD-SAMPLE RD	355	$478,217.02	$1,408,692.13
01	101000 2070503097	SAMPLE-DEERFIELD-PALM BCH CO.LINE	355	$334,047.80	$988,415.72
01	101000 2070503135	BROWARD-LYONS-HOLY CROSS-OAKLAND PARK	355	$951,479.77	$2,839,313.35
01	101000 2070503154	OAKLAND PARK-VERENA	355	$128,417.89	$735,926.59
01	101000 2070503158	FT LAUDERDALE-72C4	355	$6,254.45	$19,756.45
01	101000 2070503159	FT LAUDERDALE-PORT SUB	355	$338,139.17	$655,859.53
01	101000 2070503170	LAUDERDALE-PORT EVERGLADES #1-4 240KV LINES	355	$5,326.67	($50,080.92)

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01	101000 2070503187	BROWARD-YAMATO #| 240KV	355	$154,769.58	$268,719.41
01	101000 2070503213	BROWARD-TRADEWINDS	355	$54,411.23	$72,214.62
01	101000 2070518062	LAUDERDALE-DAVIE	355	$1,036,089.92	$1,630,367.47
01	101000 2070518067	DAVIE-JACARANDA-MOTOROLA	355	$520,040.02	$1,280,042.31
01	101000 2070518072	MOTOROLA-SPRINGTREE-77S3	355	$749,373.70	$1,421,672.39
01	101000 2070518078	HIATUS-SPRING TREE TAP 230KV LINE BRD CO	355	$190,832.03	$309,147.89
01	101000 2070518081	HIATUS-MELALEUCA	355	$1,210,992.01	$1,783,613.78
01	101000 2070519001	FAIRMONT-LAUDERDALE	355	$519,031.92	$1,218,657.54
01	101000 2070519009	LAUDERDALE-RANCH (BROWARD CO.)	355	$1,370,393.37	$6,399,523.06
01	101000 2070519073	BROWARD LOOP	355	$265,683.05	$1,212,189.40
01	101000 2070519083	BROWARD-FT.LAUDERDALE	355	$1,579,401.76	$2,790,191.28
01	101000 2070519118	RANCH-BROWARD #2 240KV (BROWARD CO.)	355	$846,304.25	$3,389,368.26
01	101000 2070519130	BROWARD-LAUDERDALE #2 240KV	355	$5,403,550.46	$15,908,076.84
01	101000 2070519154	ANDYTOWN-LAUDERDALE #2 & #3 240KV	355	$1,090,335.30	$4,916,848.29
01	101000 2070519167	WESTINGHOUSE 138KV LOOP	355	$253,194.38	$1,199,407.69
01	101000 2070519171	ANDYTOWN-LAUDERDALE #1 240KV	355	$1,296,718.47	$3,171,682.48
01	101000 2070519194	LAUDERDALE-ASHMONT 138KV	355	$30,693.46	$40,515.37
01	101000 2070520051	DADE-GRATIGNY-LAUDERDALE (BROWARD CO.)	355	$777,552.77	$1,829,950.37
01	101000 2070520084	DADE-PORT EVERGLADES (BROWARD CO.)	355	$686,454.89	$2,421,973.16
01	101000 2070520103	DADE-LAUDERDALE #3 & #4 (BROWARD CO.)	355	$1,526,938.17	$7,437,170.15
01	101000 2070520161	DADE-LAUDERDALE (ANDYTOWN EXTENSION)	355	$850,097.51	$1,387,356.62
01	101000 2070520166	FLAGAMI LAUDERDALE (ANDYTOWN EXTENSION)	355	$950,835.56	$1,551,797.18
01	101000 2070520219	ANDYTOWN-BASSCREEK-ANDYTOWN 230KV	355	$605,771.05	$702,447.27
01	101000 2070525001	ANDYTOWN-ORANGE RIVER 500KV LN (BROWARD CO)	355	$69,457.65	$70,846.82
01	101000 2070525034	ANDYTOWN-MARTIN 500KV #1 (SWAMP)	355	$171,233.38	$335,617.42
01	101000 2070544009	CEDAR-LAUDERDALE (BROWARD CO.)	355	$472,211.87	$697,176.80
01	101000 2070550012	ANDYTOWN-LEVEE #2 500KV LINE (BROWARD CO.)	355	$212,729.97	$342,495.25
01	101000 2070550035	ANDYTOWN-MARTIN #2 500KV (SWAMP)	355	$266,853.18	$523,032.23
01	101000 2070570111	GRATIGNY-LAUDERDALE #2 138KV	355	$331,613.84	$853,783.23
01	101000 2081000000	MIAMI ELECTRIC AND POWER (1925)	355	$1,321.32	$9,790.98
01	101000 2081000011	T" AVOCADO-FLA CITY 138KV "	355	$1,745,420.04	$1,710,511.64
01	101000 2081000903	MIAMI BEACH-DEAUVILLE 69KV CABLE	355	$2,324.13	$17,221.80
01	101000 2081000907	UG-MIAMI-LAWRENCE 138KV CABLE	355	$1,904.25	$14,110.49
01	101000 2081000911	HAULOVER-NORMANDY 138KV CABLE	355	$417.82	$2,924.74
01	101000 2081001001	MIAMI-RAILWAY #1 (OLD)	355	$559,577.68	$1,283,264.54
01	101000 2081001004	MASTER-SEABOARD 138KV	355	$126,157.43	$247,268.56
01	101000 2081001012	RAILWAY-HIALEAH (OLD)	355	$16,617.50	$123,135.68
01	101000 2081001015	AIRPORT-RIVERSIDE (AIRPORT-FRONTON SECTION)	355	$139,197.32	$489,164.19
01	101000 2081001016	AIRPORT-DADE (AIRPORT-HIALEAH SECTION)	355	$218,723.50	$523,497.09

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01	101000 2081001018	HIALEAH SUB-GLADEVIEW TAP-DADE LITTLE RIVER	355	$456,236.48	$1,360,917.45
01	101000 2081001021	LITTLE RIVER-21A23 (S/O LITTLE RIVER)	355	$381,833.54	$655,629.98
01	101000 2081001023	LAUDERDALE SES-HIALEAH (OLD)	355	$152,011.26	$1,118,438.36
01	101000 2081001024	BISCAYNE-MIAMI SHORES	355	$144,839.91	$429,194.64
01	101000 2081001034	MARKET-BUENA VISTA-21A23 (S/O LITTLE RIVER)	355	$552,288.37	$1,783,001.53
01	101000 2081001036	HIALEAH-RIVER (OLD)	355	$121,896.61	$675,283.28
01	101000 2081001039	MERCHANDISE-WESTSIDE	355	$12,081.88	$80,153.12
01	101000 2081001040	FLAGAMI-RIVERSIDE #2	355	$176,610.10	$386,514.32
01	101000 2081001042	DADE-WESTSIDE (OLD)	355	$2,997.37	$21,811.36
01	101000 2081001045	GRAPELAND-RIVERSIDE	355	$306,860.00	$1,095,153.52
01	101000 2081001047	OPA LOCKA TAP	355	$25,394.70	$121,471.57
01	101000 2081001048	CUTLER-HIALEAH (OLD)	355	$804.50	$5,961.35
01	101000 2081001049	49A18 (E/O FIU CAMPUS)-54A14B (E/O DAVIS)	355	$1,453,433.57	$2,395,102.11
01	101000 2081001054	CORAL REEF-54A15 (E/O DAVIS)	355	$248,487.98	$621,800.28
01	101000 2081001057	FRONTON-57A1 (S/O INDUSTRIAL)	355	$18,206.49	$49,417.67
01	101000 2081001058	AIRPORT-RIVERSIDE (FRONTON-LEJEUNE SECTION)	355	$343,237.23	$751,215.51
01	101000 2081001061	CORAL REEF-PERRINE	355	$97,398.13	$373,699.25
01	101000 2081001062	GOULDS-PERRINE	355	$194,926.35	$593,295.46
01	101000 2081001063	GOULDS-PRINCETON	355	$82,107.33	$293,798.50
01	101000 2081001066	62ND AVE-66A1 (W/O RIVERSIDE)	355	$126,736.06	$562,222.71
01	101000 2081001067	62ND AVE-BIRD-KENDALL-SUNLAND-74A17	355	$756,532.59	$1,446,045.32
01	101000 2081001075	CUTLER-75A5 (W/O CUTLER 3 CKTS)	355	$42,856.12	$91,414.93
01	101000 2081001076	75A5 (W/O CUTLER)-76A20 (SW 87 AVE &152 ST)	355	$12,190.35	$36,144.74
01	101000 2081001077	CORAL REEF-76A20 (SW 87 AVE & 152 ST)	355	$352,306.15	$1,466,973.62
01	101000 2081001078	CUTLER-SOUTH MIAMI-COCONUT GROVE	355	$703,891.35	$1,418,197.20
01	101000 2081001084	SOUTH MIAMI-68A25 (N/O SO. MIAMI)	355	$239,881.34	$467,031.71
01	101000 2081001085	FRONTON-INDUSTRIAL-HIALEAH	355	$203,972.49	$544,076.88
01	101000 2081001088	GLADEVIEW TAPS	355	$35,293.47	$92,156.22
01	101000 2081001091	FLAGAMI-92A5 (E/O FLAGAMI)	355	$73,792.43	$161,128.41
01	101000 2081001094	CORAL REEF (OLD)-HIALEAH	355	$3,355.59	$19,710.40
01	101000 2081001095	DADE-HIALEAH-21A23 (S/O LITTLE RIVER)	355	$178,710.36	$245,423.13
01	101000 2081001097	DADE-LITTLE RIVER	355	$1,125,836.22	$2,416,043.03
01	101000 2081001107	PRINCETON-109A9 (W/O HOMESTEAD)	355	$92,493.62	$231,776.19
01	101000 2081001109	HOMESTEAD-109A9 (W/O HOMESTEAD)	355	$60,977.96	$91,159.40
01	101000 2081001111	FLAGAMI-TROPICAL	355	$70,286.97	$117,343.81
01	101000 2081001115	FLORIDA CITY-KEYS ELEC CO-OP	355	$3,040,437.02	$3,861,534.79
01	101000 2081001119	VILLAGE GREEN-120A18 (W/O V.G)	355	$30,231.02	$210,363.29
01	101000 2081001120	KROME-120A18 (W/O VILLAGE GREEN)	355	$110,318.25	$210,455.15
01	101000 2081001125	FLORIDA CITY-109A9 (W/O HOMESTEAD)	355	$362,951.42	$501,344.15

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01	101000 2081001130	AIRPORT-DADE (DADE-HIALEAH SECTION)	355	$222,957.74	$410,436.09
01	101000 2081001132	OPA LOCKA-GOLDEN GLADES-134A15	355	$133,949.15	$304,616.33
01	101000 2081001135	N W 179ST TIE (E/O GARDEN)	355	$13,079.10	$39,686.09
01	101000 2081001136	137TH AVE TAP	355	$15,556.66	$25,554.79
01	101000 2081001139	GARDEN-134A15 (E/O GARDEN)	355	$49,015.80	$109,546.21
01	101000 2081001141	SEABOARD-140A1 (S/O SEABOARD)	355	$87,764.54	$139,865.49
01	101000 2081001143	LITTLE RIVER-S/O MIAMI SHORES	355	$110,003.51	$555,686.07
01	101000 2081001144	CORAL-REEF-144A24 (S/W 117 AV)	355	$224,276.44	$546,505.73
01	101000 2081001145	144A24-145A25 (S/O DAVIS)	355	$103,276.40	$233,098.06
01	101000 2081001146	HAINLIN-146A4 (S/O DAVIS)	355	$491,985.14	$753,673.57
01	101000 2081001151	FLORIDA CITY-HAINLIN	355	$464,473.19	$1,117,004.48
01	101000 2081001162	DAVIS-144A24 (W/O CORAL REEF)	355	$141,295.41	$264,984.51
01	101000 2081001164	DAVIS-KROME (INCLUDES TAMIAMI DIP)	355	($1.27)	($7.39)
01	101000 2081001165	AVOCADO-DAVIS (BOYSTOWN E.-BOYSTOWN W. UG)	355	$20,512.39	$32,040.96
01	101000 2081001171	CORAL REEF-75A5 (W/O CUTLER)	355	$274,043.62	$827,905.31
01	101000 2081001177	FLAGAMI-62ND AVE AND RIVERSIDE (SW 4ST BETW	355	$191,785.85	$818,999.55
01	101000 2081001179	FLAGAMI-137TH AVE	355	$565,769.58	$1,239,262.19
01	101000 2081001183	TROPICAL-49A20 (E/O FIU CAMPUS)	355	$91,063.66	$420,258.55
01	101000 2081001185	DADE-WESTSIDE	355	$578,517.92	$1,005,834.82
01	101000 2081001188	LAWRENCE-RIVERSIDE	355	$260,222.58	$1,019,258.13
01	101000 2081001191	AIRPORT-RIVERSIDE (RIVERSIDE-LEJEUNE SECTION)	355	$46,439.44	$211,154.21
01	101000 2081001193	FLAGAMI-RIVERSIDE	355	$719,298.53	$1,539,439.21
01	101000 2081001198	INDUSTRIAL-SEABOARD TAP	355	$60,258.72	$279,895.27
01	101000 2081001199	LITTLE RIVER-MIAMI SHORES	355	$52,676.86	$95,463.53
01	101000 2081001200	LITTLE RIVER-SEABOARD	355	$167,148.53	$710,447.50
01	101000 2081001203	DADE-HIALEAH #3	355	$269,317.43	$479,813.73
01	101000 2081001205	CUTLER-74A17 (SW 77 AVE & 140 ST)	355	$105,087.10	$588,282.88
01	101000 2081001206	FLAGAMI-PALMETTO XWAY	355	$78,967.40	$235,296.49
01	101000 2081001208	DAVIS-145A25 (S/O DAVIS)	355	$40,255.85	$115,413.73
01	101000 2081001209	DAVIS-146A4 (S/O DAVIS)	355	$17,541.54	$45,791.70
01	101000 2081001210	MASTER-OPA LOCKA	355	$322,910.86	$1,571,153.05
01	101000 2081001212	GRATIGNY-MASTER	355	$148,987.20	$431,800.63
01	101000 2081001218	MARKET-MIRAMAR-16TH ST CABLE TERMINAL	355	$133,839.77	$555,853.73
01	101000 2081001233	BISCAYNE-OPA LOCKA TAP	355	$34,231.06	$186,156.13
01	101000 2081001234	BISCAYNE-COUNTY LINE	355	$292,883.98	$1,041,104.69
01	101000 2081001236	GALLOWAY LOOP	355	$36,971.58	$149,950.82
01	101000 2081001237	FLAGAMI-MERCHANDISE	355	$232,291.10	$751,935.10
01	101000 2081001239	GARDEN-LAUDERDALE (DADE CO.)	355	$236,623.66	$1,502,497.75
01	101000 2081001246	FLAGAMI-8TH ST TERMINAL	355	$174,268.37	$919,494.64

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01	101000 2081001249	LITTLE RIVER-LEMON CITY	355	$71,644.57	$356,073.95
01	101000 2081001250	DADELAND TAPS	355	$182,294.60	$693,575.01
01	101000 2081001252	CORAL REEF DR @ SW 89 AV-WHISPERING PINES	355	$265,438.21	$835,049.65
01	101000 2081001255	WHISPERING PINES-PRINCETON	355	$848,384.81	$1,978,341.97
01	101000 2081001264	FLA CITY-KEYS COOP 138KV LINE	355	$1,356,945.37	$3,506,337.00
01	101000 2081001278	FLORIDA CITY-TURKEY POINT 240KV LINE	355	$440,622.52	$546,857.48
01	101000 2081001286	DADE-MIAMI SHORES 240KV	355	$1,129,135.28	$1,849,573.53
01	101000 2081002001	MIAMI BEACH-RAILWAY (OLD)	355	$18,890.34	$134,471.46
01	101000 2081002006	MIAMI BEACH-FULFORD (OLD)	355	$78,235.72	$515,783.84
01	101000 2081002017	DEAUVILLE-NORMANDY	355	$95,937.74	$186,593.12
01	101000 2081002022	GREYNOLDS-HAULOVER	355	$1,072,877.22	$1,931,684.57
01	101000 2081002026	GREYNOLDS-FULFORD	355	$127,947.55	$699,230.98
01	101000 2081002028	FULFORD-COUNTY LINE TAP	355	$599,823.49	$1,638,300.68
01	101000 2081002040	ARCH CREEK-ULETA	355	$113,936.82	$398,111.10
01	101000 2081002051	DUMBFOUNDLING-BROWARD CO. LINE	355	$579,560.37	$1,411,714.59
01	101000 2081002055	DUMBFOUNDLING-GREYNOLDS	355	$46,533.36	$118,046.68
01	101000 2081002072	COUNTY LINE TAP	355	$40,593.31	$194,992.41
01	101000 2081002074	ARCH CREEK-GREYNOLDS	355	$207,662.85	$1,175,659.06
01	101000 2081002084	GREYNOLDS-IVES-BROWARD CO. LINE	355	$243,776.37	$1,424,365.64
01	101000 2081020001	CUTLER-DAVIS LOOPS	355	$244,351.85	$571,768.18
01	101000 2081020005	FLAGAMI-DAVIS LOOPS	355	$971,173.15	$3,801,362.02
01	101000 2081020015	DADE-FLAGAMI (H FRAME SECT)	355	$1,094,539.11	$2,846,685.78
01	101000 2081020041	DADE-GRATIGNY-LAUDERDALE (DADE CO.)	355	$474,273.68	$1,372,849.08
01	101000 2081020067	DADE-PORT EVERGLADES (DADE CO.)	355	$940,553.09	$2,408,374.49
01	101000 2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	355	$1,318,210.92	$5,004,253.21
01	101000 2081020116	DAVIS-TURKEY POINT (7 CIRCUITS)	355	$4,768,194.59	$24,441,052.81
01	101000 2081020133	DAVIS LOOP (FROM CUTLER & FLAGAMI)	355	$894,631.87	$4,587,184.91
01	101000 2081020137	MAULE LOOP	355	$367,469.38	$1,580,613.00
01	101000 2081020140	DADE-LEVEE #1 & 2	355	$374,030.92	$2,383,227.82
01	101000 2081020144	DAVIS-144U1	355	$1,836,803.03	$7,067,692.36
01	101000 2081020158	FLAGAMI-LEVEE 240KV (LEVEE EXTENSION)	355	$253,709.51	$545,475.45
01	101000 2081020180	AVOCADO-DAVIS (BOYSTOWN EAST-DAVIS SECT)	355	$283,604.11	$311,964.52
01	101000 2081020183	AVOCADO-DAVIS (AVOCADO-BOYSTOWN WEST SECT)	355	$1,051,798.97	$1,156,978.87
01	101000 2081020194	DAVIS-LEVEE #3 (DAVIS-NEWTON SECT) 230KV	355	$2,343,142.17	$2,718,035.41
01	101000 2081020209	DAVIS-LEVEE #3 (LEVEE-NEWTON SECT) 230KV	355	$1,885,311.83	$2,186,961.72
01	101000 2081025001	ANDYTOWN-LEVEE 500KV (DADE CO)	355	$508,676.81	$1,093,655.14
01	101000 2081045158	DAVIS_LEVEE #1 & 2 (LEVEE EXTENSION)	355	$306,116.90	$675,344.48
01	101000 2081050001	ANDYTOWN-LEVEE #2 500KV LINE (DADE CO.)	355	$44,468.57	$71,594.40
01	101000 2081070133	DAVIS-SW 117 AVE (BETW CORAL REEF & MARION)	355	$55,041.02	$280,917.54

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01	101000 2081070158	DADE-LEVEE #2 (LEVEE EXTENSION)	355	$133,705.68	$224,625.54
01	101000 2081095158	LEVEE-TURKEY PT #1 (LEVEE EXTENSION)	355	$220,939.41	$371,291.64
01	101000 2980000000	SUSPENSE-TRANSM LINES	355	$0.00	($18.39)
01	101000 2991514250	KEENTOWN-WHIDDEN 240KV (HARDEE CO)	355	$256,978.37	$431,723.66
01	101000 2992723162	BREVARD-POINSETT #1 240KV (OBO) (OSCEOLA CO)	355	$191,771.01	$316,422.17
01	101000 2992725003	MARTIN-POINSETT 500KV (OBO) (OSCEOLA CO)	355	$666,700.20	$1,100,055.33
01	101000 2992725004	MIDWAY-POINSETT 500KV (OBO) (OSCEOLA CO)	355	$269,473.76	$444,631.70
01	101000 2992748162	POINSETT-WEST LAKE WALES #2 (OBO) (OSCEOLA C)	355	$9,718.82	$16,036.05
01	101000 2993714082	CASTLE-TAMPA ELECT. CO. (HILLSBOROUGH CO.)	355	$17,447.30	$29,311.46
01	101000 2993714280	MANATEE-BIG BEND #2 (TEC) (HILLSBOROUGH CO.)	355	$31,301.47	$52,586.47
01	101000 2993714293	MANATEE BIG BEND #2 240KV (HILLSBOROUGH CO.)	355	$1,754,216.04	$2,894,456.47
01	101000 2999999911	TRANSMISSION-HOLDING LOCN 11	355	($120,404.88)	($857,013.89)
			355 Total	$357,265,197.73	$838,791,181.72
01	101000 2010709034	MELROSE TAP-STARKE (CLAY CO.SECT)	356	$42,340.22	$66,680.21
01	101000 2010709091	STARKE-TRAILRIDGE TAP (CLAY CO)	356	$24,481.44	$90,091.70
01	101000 2010709155	BRADFORD-PUTNAM 240KV YARD (CLAY CO.)	356	$202,797.30	$632,697.45
01	101000 2010709185	HUDSON-TITANIUM 240KV (CLAY)	356	$63,428.40	$211,850.86
01	101000 2010710040	TRAIL RIDGE TAP (OLD)	356	$7,270.67	$22,790.87
01	101000 2011308054	FLAGLER BCH - ST JOE	356	$488,456.39	$692,923.57
01	101000 2011308067	ST JOE - ST JOHNS CO LINE	356	$380,412.75	$552,068.42
01	101000 2011310048	BUNNELL-PALATKA #2 115KV (FLAGLER CO.)	356	$228,632.64	$777,791.08
01	101000 2011310097	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	356	$789,194.62	$1,697,014.64
01	101000 2011325075	DUVAL-POINSETT 500KV (OBO) (FLAGLER CO)	356	$5,722,807.00	$7,897,473.66
01	101000 2011325076	POINSETT-RICE 500KV (OBO) (FLAGLER CO)	356	$4,825,726.60	$6,659,502.71
01	101000 2011335048	PUTNAM-VOLUSIA #1 240KV (FLAGLER CO.)	356	$526,066.48	$1,753,080.22
01	101000 2011335073	PUTNAM-VOLUSIA #1 240KV (FLAGLER COUNTY0)	356	$511,484.88	$1,488,445.85
01	101000 2011360073	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	356	$487,911.85	$1,020,427.55
01	101000 2012907055	CRESCENT CITY-VOLUSIA CO.LINE	356	$133,389.89	$175,174.37
01	101000 2012907062	CRESCENT CITY-POMONA PARK LOOP	356	$343,878.13	$403,748.20
01	101000 2012907069	POMONA PARK LOOP	356	$79,180.62	$250,788.82
01	101000 2012907070	PALATKA SES-POMONA PARK LOOP	356	$823,055.89	$1,037,173.36
01	101000 2012907085	PALATKA SES-PALATKA SUB	356	$30,829.92	$44,912.01
01	101000 2012907088	PUTNAM - ST JOHNS CO. LINE	356	$269,609.54	$1,148,269.39
01	101000 2012907121	PALATKA SES-PUTNAM 240KV YARD	356	$25,901.51	$111,900.78
01	101000 2012907131	PALATKA PLT-EAST PALATKA 115KV RADIAL	356	$12,490.62	$17,469.80
01	101000 2012909001	PALATKA-MCMEEKIN TAP	356	$1,075,106.93	$2,165,240.17
01	101000 2012909004	FRANCIS TAP	356	$110,663.47	$116,617.83
01	101000 2012909012	MANVILLE TAP (CLAY CO.CO-OP)	356	$18,457.79	$48,072.31
01	101000 2012909023	MCMEEKIN TAP	356	$220,585.22	$872,677.80

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01	101000	2012909025	MCMEEKIN TAP-CLAY CO.LINE	356	$202,957.43	$337,669.20
01	101000	2012909033	MELROSE TAP	356	$108,651.81	$112,997.88
01	101000	2012909129	HUDSON TAP	356	$42,625.55	$235,248.81
01	101000	2012909133	BRADFORD-PUTNAM 240KV YARD (PUTNAM CO.)	356	$654,810.94	$1,986,113.14
01	101000	2012909139	BRADORD-PUTNAM 240 KV YARD (ST JOHNS RIVER X	356	$124,209.56	$252,848.40
01	101000	2012909146	BRADFORD-PUTNAM 240KV (OBO)-EXT TO RICE	356	$111,781.63	$143,806.49
01	101000	2012909175	HUDSON-TITANIUM 240KV (PUTNAM)	356	$936,816.19	$1,688,594.49
01	101000	2012909178	HUDSON-TITANIUM 240KV (OBO)-TO SEMINOLE ELECT	356	$7,552.64	$18,027.22
01	101000	2012909188	BLANK CREEK-PUTNAM #1(OBO)-EXT TO SEMINOLE	356	$170,910.54	$240,983.86
01	101000	2012909325	PACIFIC SUB TAP (GP)	356	$121,714.31	$173,954.36
01	101000	2012909362	PUTNAM-CRILL 115KV	356	$307,837.11	$317,072.22
01	101000	2012910001	PALATKA-ST AUGUSTINE (PUTNAM CO.)	356	$251,621.21	$459,151.77
01	101000	2012910044	BUNNELL-PALATKA #2 115KV (PUTNAM CO.)	356	$72,045.73	$150,970.57
01	101000	2012910093	PUTNAM-VOLUSIA #2 240KV (PUTNAM CO.)	356	$98,865.54	$190,811.57
01	101000	2012925039	DUVAL-POINSETT 500KV (OBO) (PUTNAM CO)	356	$5,735,877.70	$7,915,511.23
01	101000	2012925040	DUVAL-POINSETT 500KV (OBO)-ST.JOHNS RIVER XNG	356	$214,113.36	$295,476.44
01	101000	2012925041	DUVAL-RICE 500KV (OBO) (PUTNAM CO)	356	$1,265,740.59	$1,746,722.01
01	101000	2012925042	POINSETT-RICE 500KV (OBO) (PUTNAM CO)	356	$2,824,326.50	$3,897,570.57
01	101000	2012925043	POINSETT-RICE 500KV (OBO) (ST.JOHNS RIVER)	356	$119,744.94	$165,248.02
01	101000	2012934133	PUTNAM-TITANIUM 240KV	356	$500,937.10	$780,517.07
01	101000	2012934188	BLACK CREEK-PUTNAM #2 (OBO)-EXT TO SEMINOLE	356	$172,287.62	$242,925.54
01	101000	2012935044	PUTNAM-VOLUSIA #1 240KV (PUTNAM CO.)	356	$80,956.07	$283,779.90
01	101000	2013207099	ST JOHNS RIVER XING @ ORANGEDALE	356	$332,492.45	$1,405,650.89
01	101000	2013207102	ORANGEDALE-GREENLAND (JACKSONVILLE ELECT AUTH	356	$196,616.04	$487,769.75
01	101000	2013208075	ST AUGUSTINE-FLAGLER CO. LINE	356	$1,296,479.38	$1,773,073.37
01	101000	2013208114	ST. AUGUSTINE-93H8 (NORTH LINE)	356	$112,513.44	$247,109.47
01	101000	2013208134	LEWIS LOOP	356	$110,681.56	$356,964.53
01	101000	2013208144	LEWIS-TOLOMATO 115KV	356	$571,385.77	$605,668.92
01	101000	2013208150	MILLCREEK-TOLOMATO 115KV	356	$1,110,182.07	$1,054,265.53
01	101000	2013210009	PALATKA-ST AUGUSTINE (ST JOHNS CO.)	356	$724,395.64	$821,220.90
01	101000	2013210027	SAN SEBASTIAN RIVER-27J5 (ST AUGUSTINE)	356	$48,019.70	$66,370.40
01	101000	2013210028	SAN SEBASTIAN RIVER XING	356	$15,643.02	$16,738.03
01	101000	2013210029	ST AUGUSTINE-F.E.C. SHOPS (OLD)	356	$7,130.48	$36,650.67
01	101000	2013210121	ST. JOHN'S-TOCOI 240KV	356	$436,526.71	$615,502.66
01	101000	2013600009	T" EDGEWATER-SMYRNA 115KV "	356	$643,329.65	$591,863.28
01	101000	2013606072	SANFORD-TURNER (FLA POWER CORP)	356	$17,977.80	$74,027.55
01	101000	2013606152	EDGEWATER-NORRIS 115KV (VOLUSIA CO.)	356	$108,781.36	$115,308.24
01	101000	2013607001	SANFORD SES-DELAND	356	$513,226.52	$1,123,501.16
01	101000	2013607020	DELAND-PUTNAM CO.LINE (S/O CRESCENT CITY)	356	$1,366,827.09	$1,521,096.29

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01	101000 2013607025	DELAND NAS RELOCATION (N/O DELAND)	356	$179,033.33	$200,083.93
01	101000 2013608001	DELAND-SMYRNA	356	$187,713.83	$459,381.24
01	101000 2013608012	PORT ORANGE-TAYLOR	356	$139,737.78	$155,380.48
01	101000 2013608016	TAYLOR-SMYRNA	356	$464,321.16	$556,394.68
01	101000 2013608022	PORT ORANGE-SO.DAYTONA TAP (DISTR)	356	$4,863.71	$10,934.12
01	101000 2013608026	DAYTONA-SO.DAYTONA TAP	356	$154,037.34	$286,404.92
01	101000 2013608029	DAYTONA (DOUBLE CKT WEST)	356	$253,384.28	$318,368.33
01	101000 2013608030	MISSION CITY 66KV TAP (OLD)	356	$5,276.37	$27,120.54
01	101000 2013608035	DAYTONA-ORMOND-FLAGLER CO.LINE	356	$629,479.65	$1,400,230.90
01	101000 2013608099	SOUTH DAYTONA TAP	356	$187,288.66	$361,168.48
01	101000 2013608102	HOLLY HILL LOOP	356	$97,051.87	$342,764.23
01	101000 2013608108	VOLUSIA TIE LINES	356	$65,754.68	$75,216.40
01	101000 2013608109	GENERAL ELECTRIC-VOLUSIA	356	$113,481.31	$148,802.52
01	101000 2013608111	DAYTONA-VOLUSIA	356	$154,507.17	$277,498.44
01	101000 2013608117	EDGEWATER TAP	356	$218,363.63	$923,658.63
01	101000 2013608123	BULOW LOOP	356	$98,150.34	$299,385.48
01	101000 2013608124	PORT ORANGE-SOUTH DAYTONA	356	$216,402.56	$581,863.49
01	101000 2013608128	HOLLY HILL-FLEMING-ORMOND	356	$152,918.07	$455,555.07
01	101000 2013608132	ORMOND-VOLUSIA #2	356	$83,030.12	$260,658.32
01	101000 2013623053	SANFORD-SR 40 (E/O DELAND)	356	$450,914.11	$1,389,875.76
01	101000 2013623070	VOLUSIA-SR 40(E/O DELAND)	356	$432,048.80	$1,591,565.95
01	101000 2013623119	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	356	$682,175.41	$2,577,955.49
01	101000 2013623143	VOLUSIA - 148X2	356	$595,316.14	$832,946.97
01	101000 2013623148	SUGAR MILL-148X3	356	$336,222.81	$524,559.30
01	101000 2013623152	SUGAR MILL-PORT ORANGE	356	$37,688.20	$82,914.04
01	101000 2013623171	VOLUSIA-SMYRNA #2 115KV	356	$601,709.57	$658,771.00
01	101000 2013625109	DUVAL-POINSETT 500KV (OBO) (VOLUSIA)	356	$5,701,911.36	$7,868,637.68
01	101000 2013625110	POINSETT-RICE 500KV (OBO) (VOLUSIA CO)	356	$3,870,287.10	$5,340,996.20
01	101000 2013635088	PUTNAM-VOLUSIA #1 240KV (VOLUSIA CO.)	356	$194,323.02	$588,199.07
01	101000 2013648053	SANFORD-VOLUSIA #2	356	$1,007,821.00	$2,606,103.90
01	101000 2013660088	PUTNAM-VOLUSIA #2 240KV (VOLUSIA COUNTY)	356	$238,680.36	$462,201.00
01	101000 2020400014	T" C-5 - 624 EXTEND TO BARNA "	356	$69,513.36	$64,647.42
01	101000 2020405034	WABASSO SUB-MICCO SUB (SEBASTIAN RIVER XING)	356	$28,351.99	$89,934.59
01	101000 2020405035	WABASSO SUB-MICCO SUB (BREVARD CO.)	356	$176,220.47	$325,414.63
01	101000 2020405038	MICCO SUB-51E2A (PALM BAY)	356	$1,017,180.64	$1,706,877.91
01	101000 2020405051	MELBOURNE-MALABAR LOOP (N/O PALM BAY)	356	$132,655.40	$383,026.24
01	101000 2020405056	EAU GALLIE-MELBOURNE	356	$262,420.76	$895,808.67
01	101000 2020405063	EAU GALLIE-ROCKLEDGE	356	$518,766.01	$2,226,193.13
01	101000 2020405079	BREVARD-ROCKLEDGE	356	$1,126,679.50	$1,309,198.22

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01	101000 2020405083	COCOA-SYKES CREEK LOOP	356	$455,051.03	$627,160.15
01	101000 2020405084	INDIAN RIVER CROSSING @ COCOA	356	$281,063.02	$355,458.65
01	101000 2020405086	SYKES CREEK LOOP	356	$155,442.31	$200,951.35
01	101000 2020405087	COCOA BEACH-SYKES CREEK LOOP	356	$472,551.48	$523,077.46
01	101000 2020405089	BANANA RIVER CROSSING @ COCOA BEACH	356	$45,311.40	$51,689.78
01	101000 2020405092	COCOA BEACH-SOUTH CAPE	356	$543,922.84	$1,213,320.90
01	101000 2020405100	EAU GALLIE-INDIAN HARBOUR	356	$361,620.41	$643,615.64
01	101000 2020405101	INDIAN RIVER CROSSING @ EAU GALLIE	356	$159,175.64	$236,312.15
01	101000 2020405103	INDIAN HARBOR-PATRICK	356	$505,166.68	$869,595.42
01	101000 2020405109	MALABAR-PALM BAY (SO.H-FRAME)	356	$493,082.41	$925,129.57
01	101000 2020405116	AURORA-EAU GALLIE	356	$68,054.94	$267,597.57
01	101000 2020405119	AURORA-HIBISCUS-MALABAR	356	$178,530.73	$729,307.66
01	101000 2020405129	COCOA BEACH-SOUTH COCOA BEACH	356	$354,741.20	$633,329.36
01	101000 2020405132	BANANA RIVER SUB-SOUTH COCOA BEACH	356	$281,928.26	$378,688.86
01	101000 2020405136	BANANA RIVER SUB-PATRICK	356	$511,456.01	$658,152.80
01	101000 2020405140	PALM BAY TAP	356	$50,143.51	$134,021.89
01	101000 2020405143	INDIAN RIVER CROSSING @ HOLLAND PARK	356	$200,453.79	$461,658.54
01	101000 2020405145	HOLLAND PARK-INDIAN HARBOR	356	$510,256.46	$820,052.59
01	101000 2020405158	BREVARD-EAU GALLIE EXT TO SUNTREE	356	$373,950.58	$407,368.97
01	101000 2020406001	CLEARLAKE-COCOA	356	$40,950.13	$90,037.85
01	101000 2020406003	BREVARD-CITY POINT TAP-CLEARLAKE	356	$61,251.63	$172,530.08
01	101000 2020406005	CITY POINT TAP	356	$143,477.25	$265,483.13
01	101000 2020406007	CAPE CANAVERAL SES-CITY POINT	356	$352,632.13	$401,780.87
01	101000 2020406012	CAPE CANAVERAL SES-INDIAN RIVER SUB	356	$309,194.11	$753,298.14
01	101000 2020406020	INDIAN RIVER-TITUSVILLE	356	$237,644.54	$568,361.86
01	101000 2020406025	MIMS-TITUSVILLE	356	$393,912.61	$856,472.07
01	101000 2020406031	MIMS-VOLUSIA CO LINE	356	$259,673.16	$458,051.40
01	101000 2020406077	BREVARD-COCOA	356	$581,018.48	$782,995.84
01	101000 2020406082	BREVARD-CITY POINT TAP	356	$473,022.18	$520,324.40
01	101000 2020406084	BREVARD-COCOA	356	$25,673.69	$130,704.74
01	101000 2020406086	CITY POINT-SOUTH CAPE	356	$840,948.64	$2,413,716.98
01	101000 2020406093	CAPE CANAVERAL SES-GRISSOM TAP	356	$282,352.86	$643,926.03
01	101000 2020406099	GRISSOM TAP-ORSINO-C-5 COMPLEX	356	$282,778.57	$893,799.46
01	101000 2020406108	C-5 STRING BUS (2 TRANSM STRUCTURES)	356	$43,799.90	$40,733.91
01	101000 2020406109	SOUTH CAPE-C-5 COMPLEX	356	$725,071.10	$1,568,783.09
01	101000 2020406131	LINDE-MIMS	356	$68,724.81	$156,695.91
01	101000 2020406134	GRISSOM LOOP	356	$115,523.42	$199,210.82
01	101000 2020406135	FRONTENAC TAP	356	$9,350.23	$19,923.99
01	101000 2020406136	CAPE CANAVERAL SES-START-UP TAP	356	$29,799.44	$97,444.17

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01	101000	2020406142	EDGEWATER-NORRIS 15KV (BREVARD CO.)	356	$891,967.23	$945,485.26
01	101000	2020406154	CAPE -NORRIS 115KV LOOP TO BARNA	356	$465,484.73	$442,148.57
01	101000	2020406158	C-5 - 624 EXTEND TO BARNA	356	$1,634,530.65	$1,520,113.50
01	101000	2020406163	RIVER CROSSING C-5 624 EXTEND TO BARNA	356	$17,424.60	$16,204.88
01	101000	2020422086	BREVARD-RANCH (BREVARD CO.)	356	$950,943.64	$1,731,017.60
01	101000	2020423001	BREVARD-SANFORD (BREVARD CO.)	356	$460,132.36	$1,040,808.92
01	101000	2020423080	BREVARD-CAPE CANAVERAL (3 CKTS)	356	$714,471.76	$2,010,230.36
01	101000	2020423088	CAPE CANAVERAL-INDIAN RIVER (ORLANDO U.C.)	356	$33,581.06	$111,734.90
01	101000	2020423091	CAPE CANAVERAL-VOLUSIA (BREVARD CO)	356	$1,055,374.81	$2,953,537.48
01	101000	2020423180	CAPE-NORRIS 230KV LOOP TO BARNA	356	$703,642.43	$666,162.02
01	101000	2020430109	MALABAR-PALM BAY (NO. H-FRAME)	356	$396,676.71	$678,870.41
01	101000	2020447086	BREVARD-RANCH 2ND CKT (BREVARD CO.)	356	$650,332.10	$1,939,200.29
01	101000	2020448001	BREVARD-WEST LAKE WALES (FLA.POWER CORP)	356	$181,343.72	$470,759.66
01	101000	2020455109	MALABAR-PALM BAY-INDIAN RIVER CROSSING	356	$230,780.53	$535,275.26
01	101000	2022623006	BREVARD-SANFORD (ORANGE CO.)	356	$736,254.47	$1,831,878.46
01	101000	2022623160	BREVARD-POINSETT #1 240 KV (OBO) (ORANGE CO)	356	$269,709.88	$371,740.79
01	101000	2022623168	BREVARD-W LAKE WALES 230KV (OBO) PURCH FM FPC	356	$150,357.96	$178,740.43
01	101000	2022623270	POINSETT-SANFORD EXT TO CHULUOTA (ORANGE CO)	356	$637,291.86	$675,529.37
01	101000	2022625001	MARTIN-POINSETT 500KV (OBO) (ORANGE CO)	356	$732,763.66	$1,011,213.85
01	101000	2022625002	MIDWAY-POINSETT 500KV (OBO) (ORANGE CO)	356	$468,538.30	$646,582.85
01	101000	2022625160	DUVAL-POINSETT 500KV (OBO) (ORANGE CO)	356	$3,503,613.17	$4,834,986.17
01	101000	2022625161	POINSETT-RICE 500KV (OBO) (ORANGE CO)	356	$2,365,857.78	$3,264,883.74
01	101000	2022648160	POINSETT-WEST LAKE WALES #2 (OBO) (ORANGE CO)	356	$15,318.44	$20,680.59
01	101000	2023106045	LAUREL-VOLUSIA CO. LINE	356	$965,880.37	$2,300,185.02
01	101000	2023106067	SANFORD SUB-ST JOHNS RIVER XING	356	$242,205.51	$604,594.47
01	101000	2023106070	ST JOHNS RIVER XING AT SANFORD SES	356	$19,106.30	$48,015.97
01	101000	2023106074	LAUREL-SANFORD SUB	356	$148,444.75	$387,070.79
01	101000	2023107123	SANFORD-NORTH LONGWOOD (FPC)(SEMINOLE CO)	356	$329,513.50	$905,919.45
01	101000	2023123030	BREVARD-SANFORD (SEMINOLE CO)	356	$959,437.51	$3,088,270.19
01	101000	2023123272	POINSET-SANFORD EXT TO CHULUOTA (SEMINOLE CO)	356	$767,362.95	$813,404.73
01	101000	2023125144	DUVAL-POINSETT 500KV (OBO) (SEMINOLE CO)	356	$2,769,794.46	$3,822,316.35
01	101000	2023125145	POINSETT-RICE 500KV (OBO) (SEMINOLE CO)	356	$1,825,992.42	$2,519,869.54
01	101000	2023606036	CELERY-MIMS (VOLUSIA CO.)	356	$270,885.36	$499,546.69
01	101000	2023606070	ST JOHNS RIVER XING @ SANFORD SES	356	$7,682.01	$20,198.93
01	101000	2023606071	SANFORD SES-ST JOHNS RIVER XING	356	$57,328.32	$113,137.91
01	101000	2023607123	SANFORD-NORTH LONGWOOD (FPC)(VOLOSIA CO)	356	$127,064.51	$212,750.58
01	101000	2023623052	BREVARD-SANFORD (VOLUSIA CO.)	356	$122,323.80	$167,873.08
01	101000	2023623116	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	356	$78,545.11	$325,514.34
01	101000	2023623165	DELTONA TAP 240KV	356	$314,095.67	$390,967.66

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01	101000 2030209124	BALDWIN-MACCLENNY (BAKER CO.)	356	$56,938.39	$161,051.56
01	101000 2030217066	COLUMBIA-MACCLENNY (BAKER CO.)	356	$367,304.58	$1,486,063.12
01	101000 2030217099	WIREMILL SUB TAP LINE	356	$90,496.54	$169,988.41
01	101000 2030309036	STARKE-CLAY CO. LINE	356	$436,705.68	$871,321.99
01	101000 2030309051	BALDWIN - STARKE (BRADFORD)	356	$852,846.35	$990,930.51
01	101000 2030309089	STARKE-TRAIL RIDGE TAP (BRADFORD CO)	356	$64,354.30	$242,322.98
01	101000 2030309161	BRADFORD-PUTNAM 240KV YARD (BRADFORD CO.)	356	$196,672.95	$656,887.65
01	101000 2030309167	BRADFORD-STARKE	356	$89,259.20	$289,300.43
01	101000 2030309168	GRIFFIS LOOP TAP	356	$12,878.68	$42,113.28
01	101000 2030309190	BRADFORD-DUVAL 240KV LN (BRADFORD CO)	356	$285,321.91	$685,903.50
01	101000 2030309234	NEW RIVER TAP #2	356	$208,889.35	$392,246.36
01	101000 2030309348	BRADFORD-DEERHAVEN (GRU) (FPL OWNERSHIP)	356	$500,281.83	$690,388.93
01	101000 2030309361	PUTNAM-STARKE - EXTEND TO BRADFORD	356	$252,946.29	$260,534.68
01	101000 2030310043	LAWTEY TAP	356	$100,574.47	$133,831.09
01	101000 2030317001	STARKE-NEW RIVER TAP	356	$152,923.97	$559,835.08
01	101000 2030317008	NEW RIVER TAP #1	356	$3,490.16	$13,213.18
01	101000 2030317009	LAKE BUTLER-NEW RIVER TAP (BRADFORD CO.)	356	$40,993.90	$61,905.75
01	101000 2030709216	BRADFORD-DUVAL 240KV LN (CLAY CO.)	356	$203,566.86	$432,511.31
01	101000 2030709242	BLACK CREEK-TITANIUM 240KV	356	$671,030.44	$1,035,089.41
01	101000 2030709260	BLACK CREEK-DUVAL 240KV (CLAY COUNTY)	356	$254,759.56	$397,424.91
01	101000 2030725007	DUVAL-POINSETT 500KV (OBO) (CLAY CO)	356	$5,204,054.75	$7,181,595.56
01	101000 2030725008	DUVAL-RICE 500KV (OBO) (CLAY CO)	356	$4,260,273.69	$5,879,177.69
01	101000 2030917027	COLUMBIA-LAKE BUTLER (COLUMBIA CO.)	356	$184,822.09	$184,074.06
01	101000 2030917040	COLUMBIA-LIVE OAK TAP SECTION	356	$859,770.40	$919,035.37
01	101000 2030917052	LIVE OAK TAP STA-EAST OAK (COLUMBIA CO.)	356	$253,127.57	$260,369.25
01	101000 2030917084	COLUMBIA-MACCLENNY (COLUMBIA CO.)	356	$238,751.04	$726,061.79
01	101000 2031209067	BALDWIN (OLD)-BRADFORD CO. LINE	356	$476,439.19	$1,307,321.57
01	101000 2031209069	MAXVILLE TAP (CLAY CO. CO-OP)	356	$13,858.29	$44,900.86
01	101000 2031209078	BALDWIN (OLD)-NORMANDY (JACKSONVILLE ELECT AU	356	$75,162.94	$119,378.46
01	101000 2031209120	BALDWIN-MACCLENNY (DUVAL CO)	356	$36,262.93	$146,467.31
01	101000 2031209224	BRADFORD-DUVAL 240 KV LN (DUVAL CO)	356	$187,706.56	$394,078.33
01	101000 2031209231	STEELBALD SUB TAP LINE	356	$132,093.98	$155,689.41
01	101000 2031209232	BALDWIN-DUVAL 240KV LINE	356	$82,461.05	$157,949.96
01	101000 2031209233	DUVAL-NORMANDY (JEA)	356	$14,431.81	$27,709.08
01	101000 2031209268	BLACK CREEK-DUVAL 240KV (DUVAL COUNTY)	356	$253,964.05	$392,407.70
01	101000 2031209276	DUVAL-CALLAHAN 240KV (DUVAL CO)	356	$758,468.49	$1,328,942.21
01	101000 2031225001	DUVAL-HATCH (GP) #1 500KV (OBO) (DUVAL CO)	356	$5,743.28	$8,098.02
01	101000 2031225002	DUVAL-POINSETT 500KV (OBO) (DUVAL CO)	356	$1,258,439.65	$1,736,646.72
01	101000 2031225003	DUVAL-RICE 500KV (OBO) (DUVAL CO)	356	$1,028,219.10	$1,418,942.36

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01	101000	2031250001	DUVAL-HATCH (GP) #2 500KV (OBO) (DUVAL CO)	356	$5,759.06	$8,120.27
01	101000	2032409178	CALLAHAN SUB-YULEE SUB 240KV (NASSAU CO)	356	$1,078,751.66	$2,012,317.71
01	101000	2032409287	DUVAL-CALLAHAN 240KV (NASSAU CO)	356	$837,429.86	$1,447,690.23
01	101000	2032409314	YULEE-KINGSLAND 240KV (GPC)	356	$576,210.61	$960,576.79
01	101000	2032425008	DUVAL-HATCH (GP) #1 500KV (OBO) (NASSAU CO)	356	$22,604.77	$31,872.73
01	101000	2032450008	DUVAL-HATCH (GP) #2 500KV (OBO) (NASSAU CO)	356	$22,597.99	$31,863.37
01	101000	2033417055	LIVE OAK TAP STA-EAST OAK (SUWANNEE CO.)	356	$707,631.47	$742,842.85
01	101000	2033417061	EAST OAK-SUWANNEE TAP	356	$302,047.32	$324,937.35
01	101000	2033417063	LIVE OAK-SUWANNEE TAP	356	$49,502.02	$52,967.16
01	101000	2033417102	LIVE OAK-SUWANNEE PLT (FPC) 115KV	356	$695,857.88	$766,142.67
01	101000	2033517014	LAKE BUTLER-NEW RIVER TAP (UNION CO.)	356	$33,612.69	$78,475.89
01	101000	2033517019	COLUMBIA-LAKE BUTLER (UNION CO.)	356	$334,064.68	$1,185,827.23
01	101000	2041621044	FT. MYERS-RANCH 138KV (HENDRY CO.)	356	$443,772.07	$694,958.74
01	101000	2041646044	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	356	$412,781.05	$1,267,421.20
01	101000	2041712012	CHILDS-OKEECHOBEE (HIGHLANDS CO.)	356	$1,028,776.50	$1,099,767.70
01	101000	2041805011	FT. PIERCE-OSLO (INDIAN RIVER CO.)	356	$106,440.37	$192,402.21
01	101000	2041805013	OSLO-WEST SUB (VERO BEACH)	356	$468,024.73	$620,145.84
01	101000	2041805019	WEST SUB (VERO BEACH)-WABASSO SUB	356	$447,926.75	$777,800.18
01	101000	2041805027	WABASSO-MICCO (INDIAN RIVER CO.)	356	$413,026.03	$719,448.74
01	101000	2041822067	BREVARD-RANCH (INDIAN RIVER CO.)	356	$676,447.64	$2,283,567.31
01	101000	2041825043	MARTIN-POINSETT 500KV (OBO) (INDIAN RIVER CO)	356	$4,155,894.03	$5,735,133.76
01	101000	2041825044	MIDWAY-POINSETT 500KV (OBO) (INDIAN RIVER CO)	356	$3,839,662.84	$5,298,734.72
01	101000	2041847067	BREVARD-RANCH 2ND CKT (INDIAN RIVER CO.)	356	$718,262.38	$2,921,042.31
01	101000	2042204028	PORT SEWALL-PALM BCH.CO.LINE	356	$490,986.55	$1,345,768.48
01	101000	2042204044	PORT SEWALL-ST. LUCIE CO. LINE	356	$461,789.71	$1,057,294.79
01	101000	2042204118	SANDPIPER-TURNPIKE 240 KV (MARTIN CO.)	356	$266,458.19	$325,583.80
01	101000	2042204138	TURNPIKE-CRANE 230KV (MARTIN CO)	356	$329,212.73	$334,991.16
01	101000	2042204142	RIO LOOP	356	$366,291.40	$380,943.06
01	101000	2042204164	CRANE-BRIDGE	356	$2,019,459.57	$2,132,614.44
01	101000	2042204174	BRIDGE-ALEXANDER (MARTIN CO.)	356	$490,999.73	$520,459.71
01	101000	2042204203	HOBE-COVE 138KV RADIAL LINE	356	$1,211,171.31	$1,240,025.20
01	101000	2042204210	HOBE-HILLS 138KV RADIAL LINE	356	$534,495.88	$550,530.76
01	101000	2042215009	SHERMAN SW STA-MARTIN PLANT (MARTIN CO.)	356	$516,872.42	$909,088.65
01	101000	2042215017	MARTIN PLANT-PAHOKEE (MARTIN CO.)	356	$459,593.26	$646,848.47
01	101000	2042222024	BREVARD-RANCH (MARTIN CO.)	356	$653,833.59	$1,835,914.12
01	101000	2042222146	FLORIDA STEEL TAP	356	$2,479.65	$5,224.38
01	101000	2042222155	FLA STEEL-MARTIN PLT 240KV LINE	356	$12,223.69	$23,694.97
01	101000	2042222160	HOBE-INDIANTOWN 240KV	356	$1,101,794.94	$1,553,059.95
01	101000	2042222179	INDIANTOWN-MARTIN #1-INDIANTOWN-FLA. STEEL	356	$1,135,996.43	$1,170,076.32

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01	101000 2042222186	INDIANTOWN-MARTIN #1-FLA.STEEL-MARTIN SECT	356	$561,528.98	$578,374.85
01	101000 2042225001	MARTIN-MIDWAY 500KV (MARTIN CO)	356	$1,639,267.10	$2,557,256.68
01	101000 2042225024	CORBETT-MIDWAY 500KV (MARTIN CO)	356	$3,948,512.19	$4,090,865.08
01	101000 2042225077	CORBETT-MARTIN 500KV (MARTIN CO.)	356	$1,839,161.90	$1,947,344.83
01	101000 2042225078	CORBETT-MARTIN 500KV (OBO)	356	$416,752.27	$549,987.95
01	101000 2042225079	ANDYTOWN-MARTIN 500KV #1 (MARTIN CO.)	356	$862,965.12	$1,210,557.33
01	101000 2042225082	MARTIN-MIDWAY 500KV (OBO) (MARTIN CO)	356	$101,242.50	$133,640.10
01	101000 2042225100	MARTIN-POINSETT 500KV (OBO) (MARTIN CO)	356	$1,867,506.87	$2,577,159.48
01	101000 2042247024	BREVARD-RANCH 2ND CKT (MARTIN CO.)	356	$990,213.30	$2,327,319.54
01	101000 2042247186	INDIANTOWN-MARTIN #2-WARFIELD-MARTIN SECT	356	$453,924.21	$467,541.94
01	101000 2042250079	ANDYTOWN-MARTIN 500KV #2 (MARTIN CO)	356	$880,896.03	$1,146,768.34
01	101000 2042511028	MIDWAY-34K14 (OKEECHOBEE CO.)	356	$2,418.56	$2,660.42
01	101000 2042511035	OKEECHOBEE-34K14	356	$338,637.57	$382,459.64
01	101000 2042511059	MIDWAY SHERMAN(OKEECHOBEE CO.)	356	$300,154.69	$523,440.36
01	101000 2042511066	OKEECHOBEE-SHERMAN #2	356	$391,620.35	$430,488.81
01	101000 2042511069	OKEECHOBEE-SHERMAN #1 EXT. TO SWEATT SUB	356	$816,446.02	$840,939.40
01	101000 2042512001	CHILDS-OKEECHOBEE (OKEECHOBEE CO.)	356	$323,867.46	$383,691.16
01	101000 2042515001	OKEECHOBEE (34K14)-SHERMAN SW STA)	356	$101,716.93	$125,344.52
01	101000 2042515002	SHERMAN SW STA-MARTIN PLANT (OKEECHOBEE CO.)	356	$340,807.15	$599,820.58
01	101000 2042803027	LAUDERDALE SES-WEST PALM BEACH	356	$22,311.44	$111,740.79
01	101000 2042803045	GREENACRES TAP	356	$281,670.78	$666,012.69
01	101000 2042803048	GREENACRES-MILITARY TRAIL	356	$438,492.41	$687,485.82
01	101000 2042803051	MILITARY TRAIL-WEST PALM BEACH	356	$368,263.83	$922,657.09
01	101000 2042803057	BOCA RATON TAP (OLD)	356	$7,561.91	$38,868.22
01	101000 2042803060	BOYNTON LOOP (OLD)	356	$9,228.57	$47,434.85
01	101000 2042803065	DELRAY BEACH TAP (REBUILT FOR BROWARD-RANCH #	356	$83,399.07	$184,161.24
01	101000 2042803088	LINTON-YAMATO	356	$361,860.48	$1,000,112.24
01	101000 2042803093	IBM-YAMATO	356	$247,147.87	$415,810.52
01	101000 2042803095	IBM-BOCA RATON TAP (OLD)	356	$107,523.94	$214,659.45
01	101000 2042803100	BOCA RATON-BROWARD CO. LINE	356	$106,147.04	$349,529.05
01	101000 2042803103	BOCA RATON-ATLANTIC LOOP	356	$220,308.31	$574,855.13
01	101000 2042803106	ATLANTIC LOOP-106C27 (SIO IBM)	356	$26,352.00	$57,041.31
01	101000 2042803107	CEDAR-LINTON 138KV	356	$496,118.32	$930,308.62
01	101000 2042803112	BOYNTON-CEDAR 138KV	356	$236,682.43	$339,680.59
01	101000 2042803113	BOYNTON-LANTANA	356	$210,424.61	$535,817.73
01	101000 2042803116	LANTANA-RANCH	356	$729,713.13	$1,304,278.69
01	101000 2042803150	ATLANTIC LOOP	356	$123,421.88	$425,848.77
01	101000 2042803151	MILITARY TRAIL-RANCH	356	$208,499.89	$783,603.98
01	101000 2042803166	NORTON TAP	356	$149,572.32	$478,177.38

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01	101000 2042803168	BROWARD-YAMATO 240KV (PALM BCH CO.)	356	$700,153.53	$1,733,603.42
01	101000 2042803195	CEDAR-DELTRAIL 240KV	356	$479,446.40	$572,182.67
01	101000 2042803200	DELTRAIL-YAMATO 240KV	356	$767,271.42	$955,878.02
01	101000 2042803214	RANCH-WPB #1 138KV JOG-MILITARY TRAIL SECTION	356	$389,989.68	$413,389.06
01	101000 2042803224	CEDAR-STR 120C3	356	$439,302.16	$473,233.74
01	101000 2042803227	CEDAR-JOG (CEDAR-FOUNTAIN SECTION)	356	$1,309,680.87	$1,357,234.60
01	101000 2042803233	CEDAR-JOG (FOUNTAIN-STR B131C17 SECTION)	356	$849,322.21	$883,295.10
01	101000 2042803240	CALDWELL - YAMATO 138KV	356	$380,740.77	$418,312.04
01	101000 2042804001	WEST PALM BEACH-DATURA TAP #1	356	$142,389.72	$235,980.52
01	101000 2042804002	RIVIERA-DATURA TAP #1	356	$3,619.17	$3,727.75
01	101000 2042804008	PLUMOSUS-RIVIERA #2	356	$986,838.16	$2,706,617.46
01	101000 2042804022	PLUMOSUS-MARTIN CO. LINE	356	$400,664.73	$1,085,996.21
01	101000 2042804069	PLUMOSUS-RIVIERA #1	356	$2,141,424.84	$2,280,663.75
01	101000 2042804084	RIVIERA TIE (#1 CKT)	356	$8,485.62	$42,970.94
01	101000 2042804085	RIVIERA TIE (#2 CKT)	356	$18,137.99	$39,588.56
01	101000 2042804086	DATURA TAP #1 (SOUTH)	356	$118,737.71	$123,487.22
01	101000 2042804087	DATURA TAP #2 (NORTH)	356	$101,263.84	$129,477.64
01	101000 2042804088	RIVIERA-WEST PALM BEACH	356	$713,902.96	$2,718,173.50
01	101000 2042804144	RANCH-RIVIERA #2 EXTEND TO TERMINAL SUB	356	$665,625.78	$705,563.33
01	101000 2042804147	TERMINAL - NORTHWOOD	356	$129,296.00	$137,053.76
01	101000 2042804179	BRIDGE-ALEXANDER (PALM BEACH CO.)	356	$382,568.32	$403,365.12
01	101000 2042804182	ALEXANDER-PLUMOSUS	356	$2,412,378.66	$2,556,290.76
01	101000 2042804217	ALEXANDER-TRIGAS 230KV RADIAL	356	$253,332.88	$233,066.25
01	101000 2042815023	OKEECHOBEE (34K14)-PAHOKEE (PALM BEACH CO.)	356	$411,617.77	$650,608.52
01	101000 2042815035	BRYANT SUB TAP	356	$23,357.64	$39,428.97
01	101000 2042815048	BELLE GLADE-QUAKER OATS TAP-STR 64P9	356	$529,788.24	$569,378.79
01	101000 2042815056	QUAKER OATS TAP (DOUBLE CKT)	356	$377,990.82	$404,450.18
01	101000 2042815058	PAHOKEE-SOUTH BAY	356	$505,038.24	$1,901,574.81
01	101000 2042815072	S0. BAY-PAHOKEE RADIAL	356	$142,139.15	$246,513.32
01	101000 2042818058	BELLE GLADE-SO.BAY	356	$242,186.71	$403,905.96
01	101000 2042819030	LAUDERDALE-RANCH (PALM BEACH CO.)	356	$410,298.66	$1,773,267.13
01	101000 2042819056	RANCH-RIVIERA (3 CKTS)	356	$753,951.02	$3,708,608.90
01	101000 2042819099	RIVIERA (STEEL TOWERS)	356	$53,139.91	$73,473.61
01	101000 2042819100	RANCH-BROWARD #2 240KV (PALM BEACH CO.)	356	$2,960,035.20	$7,123,326.05
01	101000 2042819183	RANCH-RIVIERA #3 RECWAY TAP	356	($6,127.02)	($6,739.72)
01	101000 2042819186	RANCH-WEST PALM BEACH #3	356	$1,186,580.78	$1,258,958.43
01	101000 2042821062	FT.MYERS-RANCH 138KV (PALM BEACH CO.)	356	$832,932.15	$1,629,576.64
01	101000 2042821109	BROWARD-RANCH #2 CORBETT EXTENSION	356	$3,933,591.71	$4,284,356.83
01	101000 2042821121	ORANGE RIVER-RANCH CORBETT EXTENSION	356	$457,213.87	$502,935.26

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01	101000 2042821124	CLEWISTON-SO. BAY - LOOP TO OKEELANTA	356	$653,974.76	$621,276.02
01	101000 2042821130	RANCH-SOUTH BAY - LOOP TO OSCEOLA PLANT	356	$22,721.37	$22,721.38
01	101000 2042822001	BREVARD-RANCH (PALM BEACH CO.)	356	$1,259,532.59	$2,878,399.42
01	101000 2042822128	APIX-PRATT & WHITNEY	356	$0.43	$2.21
01	101000 2042825001	CORBETT-MIDWAY 500KV (PALM BCH.CO)	356	$3,234,798.33	$3,558,278.16
01	101000 2042825002	CORBETT-MARTIN 500KV (PALM BCH CO.)	356	$5,244,090.32	$5,401,413.03
01	101000 2042825016	CONSERVATION-CORBETT 500KV (PALM BEACH CO.)	356	$12,814,695.80	$11,915,977.60
01	101000 2042825023	ANDYTOWN-MARTIN 500KV #1 (PALM BCH CO.)	356	$3,577,135.84	$5,580,331.91
01	101000 2042825036	ANDYTOWN-ORANGE RIVER 500KV LN (PALM BCH CO)	356	$603,519.00	$1,671,747.63
01	101000 2042829022	HOBE-PLUMOSUS #2 230KV	356	$15,102.54	$16,008.69
01	101000 2042844030	CEDAR-LAUDERDALE (PALM BEACH CO.)	356	$572,510.53	$2,722,146.88
01	101000 2042844046	CEDAR-RANCH (PALM BEACH CO.)	356	$817,661.40	$1,176,824.45
01	101000 2042846062	ORANGE RIVER-RANCH 240KV (PALM BEACH CO.)	356	$774,495.20	$1,786,510.18
01	101000 2042846109	CORBETT-RANCH #1 & CORBETT-CEDAR 240KV	356	$2,024,700.92	$2,112,785.85
01	101000 2042847001	BREVARD-RANCH 2ND CKT (PALM BEACH CO.)	356	$1,669,476.34	$3,694,774.53
01	101000 2042850023	ANDYTOWN-MARTIN 500KV #2 (PALM BCH CO)	356	$3,597,124.14	$5,611,513.66
01	101000 2042853131	RANCH-WPB #1 138KV RANCH-JOG SECTION	356	$796,679.77	$843,053.40
01	101000 2043304053	WHITE CITY-MARTIN CO. LINE	356	$1,003,061.83	$2,190,186.69
01	101000 2043304062	FT PIERCE-WHITE CITY	356	$545,510.05	$1,179,845.69
01	101000 2043304098	MIDWAY-WHITE CITY	356	$230,163.63	$806,200.13
01	101000 2043304107	INDIAN RIVER XING @ ST LUCIE PLT #1 240KV	356	$490,991.49	$945,346.95
01	101000 2043304108	ST LUCIE PLANT-MIDWAY #1 240KV	356	$926,050.46	$2,064,189.22
01	101000 2043304119	SANDPIPER-TURNPIKE 240KV (ST. LUCIE CO.)	356	$635,686.57	$810,046.30
01	101000 2043304125	MIDWAY-TURNPIKE 240KV (ST. LUCIE CO.)	356	$870,094.23	$1,136,592.65
01	101000 2043304134	TURNPIKE-CRANE 230KV (ST LUCIE CO)	356	$552,515.73	$564,019.45
01	101000 2043305001	FT PIERCE-OSLO (ST LUCIE CO.)	356	$615,786.38	$1,066,971.01
01	101000 2043311001	FT. PIERCE-MIDWAY	356	$448,292.11	$907,204.45
01	101000 2043311039	MIDWAY-SHERMAN (ST. LUCIE CO.)	356	$1,009,281.08	$1,775,909.31
01	101000 2043322042	BREVARD-RANCH (ST LUCIE C.)	356	$937,294.60	$2,228,345.82
01	101000 2043322176	EMERSON-MIDWAY TAP STR 64W5	356	$206,495.58	$284,963.90
01	101000 2043325013	MARTIN-MIDWAY 500KV (ST.LUCIE CO)	356	$3,153,573.18	$3,855,202.09
01	101000 2043325022	CORBETT-MIDWAY 500KV (ST. LUCIE CO.)	356	$2,192,779.23	$2,603,680.16
01	101000 2043325071	MARTIN-POINSETT 500KV (OBO) (ST. LUCIE CO)	356	$4,553,628.37	$6,284,007.15
01	101000 2043325072	MIDWAY-POINSETT 500KV (OBO) (ST.LUCIE CO)	356	$3,454,754.45	$4,767,561.14
01	101000 2043329107	INDIAN RIVER XING @ ST LUCIE PLT-#2 240KV	356	$510,243.26	$1,101,601.61
01	101000 2043329108	ST LUCIE PLANT-MIDWAY #2	356	$878,284.35	$2,188,155.22
01	101000 2043347042	BREVARD-RANCH 2ND CKT (ST LUCIE CO.)	356	$2,115,242.27	$3,727,761.28
01	101000 2043354107	INDIAN RIVER XING @ ST LUCIE PLT-#3	356	$510,249.79	$1,101,607.83
01	101000 2043354108	ST LUCIE PLANT-MIDWAY #3 240KV	356	$162,905.64	$154,119.57

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01	101000 2050612265	MYAKKA-ROTUNDA 138KV (CHARLOTTE CO.)	356	$464,801.85	$630,944.68
01	101000 2050612270	ENGLEWOOD TO ROTONDA 138KV (CHARLOTTE CO.)	356	$357,770.62	$329,148.97
01	101000 2050612275	ENGLEWOOD TO ROTONDA 138KV (SARASOTA CO.)	356	$70,547.73	$64,903.91
01	101000 2050613017	CHARLOTTE-NOCATEE (CHARLOTTE CO.)	356	$118,433.71	$383,689.01
01	101000 2050613022	CHARLOTTE-PUNTA GORDA (NO. CKT)	356	$502,732.05	$570,616.37
01	101000 2050613030	LEE-PUNTA GORDA (E. CKT-CHARLOTTE CO.)	356	$46,370.96	$205,513.53
01	101000 2050613057	LEE-PUNTA GORDA (W.CKT-CHARLOTTE CO.)	356	$21,447.47	$43,704.78
01	101000 2050613199	CHARLOTTE-PUNTA GORDA (SO.CKT)	356	$364,166.02	$533,302.28
01	101000 2050613235	DORRFIELD TAP-CHARLOTTE (CHARLOTTE CO.)	356	$171,489.03	$297,158.10
01	101000 2050614001	PUNTA GORDA-MURDOCK-SARASOTA CO. LINE	356	$890,652.17	$2,185,183.78
01	101000 2050614002	PEACE RIVER CROSSING @ PUNTA GORDA	356	$75,427.28	$270,997.84
01	101000 2050624054	CHARLOTTE-RINGLING 138KV (CHARLOTTE CO.)	356	$167,636.01	$282,819.64
01	101000 2050624063	CHARLOTTE-CALUSA-FT. MYERS (CHARLOTTE CO.)	356	$667,800.58	$1,174,833.64
01	101000 2050624151	CHARLOTTE-LAURELWOOD 240KV (CHARLOTTE C.)	356	$580,625.50	$1,027,406.69
01	101000 2050624155	PEACE RIVER XING @ CHARLOTTE SUB	356	$61,163.06	$124,714.05
01	101000 2050624160	FT. MYERS-CHARLOTTE (CHARLOTTE CO.)	356	$832,362.84	$1,677,839.62
01	101000 2050649054	FT. MYERS-RINGLING #1 240KV (CHARLOTTE CO.)	356	$251,105.83	$660,606.26
01	101000 2050813083	NAPLES-SOLANA-LEE CO. LINE	356	$295,506.58	$432,857.63
01	101000 2050813137	FT. MYERS-COLLIER (COLLIER CO.)	356	$178,682.14	$728,811.48
01	101000 2050813145	COLLIE-NAPLES	356	$109,739.51	$344,722.48
01	101000 2050813153	ALLIGATOR-COLLIER	356	$223,321.18	$368,384.69
01	101000 2050813155	ALLIGATOR TAP	356	$8,444.26	$27,612.73
01	101000 2050813156	ALLIGATOR-BELLE MEADE	356	$221,528.09	$663,600.00
01	101000 2050813163	CAPRI TAP	356	$44,293.46	$52,865.12
01	101000 2050813258	ALICO-COLLIER (COLLIER CO.)	356	$1,056,663.34	$1,633,691.78
01	101000 2050813280	CAPRI-GOLDEN GATE-COLLIER 138KV	356	$879,219.95	$1,239,183.54
01	101000 2050813299	ALICO-NAPLES/ALICO-COLLIER TIE LINE	356	$549,305.26	$581,980.90
01	101000 2050825068	ANDYTOWN-ORANGE RIVER 500KV LN (COLLIER CO)	356	$1,169,288.44	$3,238,928.98
01	101000 2051112046	ARCADIA-CHILDS (DE SOTO CO.)	356	$819,895.15	$872,761.24
01	101000 2051112066	WHIDDEN TAP 69KV	356	$51,262.85	$67,666.96
01	101000 2051113001	ARCADIA-NOCATEE 69KV	356	$181,285.09	$640,475.65
01	101000 2051113009	CHARLOTTE-NOCATEE (DE SOTO CO.)	356	$349,777.56	$812,869.57
01	101000 2051113218	DORRFIELD TAP-CHARLOTTE (DE SOTO CO.)	356	$815,627.63	$1,402,996.63
01	101000 2051114231	KEENTOWN-WHIDDEN 240KV (DE SOTO CO.)	356	$1,118,636.96	$1,465,122.55
01	101000 2051124052	CHARLOTTE-RINGLING 138KV (DE SOTO CO.)	356	$10,181.79	$30,058.88
01	101000 2051124149	CHARLOTTE-LAURELWOOD (DE SOTO CO.)	356	$20,004.17	$38,160.61
01	101000 2051149052	FT. MYERS-RINGLING #1 240KV (DE SOTO CO.)	356	$214,717.98	$1,084,854.46
01	101000 2051621015	FT. MYERS-RANCH 138KV (HENDRY CO.)	356	$333,315.35	$720,522.25
01	101000 2051625043	ANDYTOWN-ORANGE RIVER 500KV LN (HENDRY CO)	356	$1,596,237.93	$4,349,364.99

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01	101000 2051646015	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	356	$870,924.04	$2,240,812.16
01	101000 2051712032	ARCADIA-CHILDS (HIGHLANDS CO.)	356	$345,460.83	$317,881.09
01	101000 2051913042	LEE-PUNTA GORDA (EAST CKT. LEE CO.)	356	$18,209.68	$84,750.18
01	101000 2051913046	FT MYERS TAP CROSSOVER-LEE	356	$10,419.32	$24,306.60
01	101000 2051913049	CALOOSAHATCHEE RIVER XING #1 LINE	356	$180.07	$895.85
01	101000 2051913050	FT MYERS TAP	356	$59,899.36	$110,891.81
01	101000 2051913052	FT MYERS-BUCKINGHAM AIR FIELD	356	$16,524.57	$46,457.00
01	101000 2051913064	LEE-PUNTA GORDA (WEST CKT.LEE CO.)	356	$6,562.20	$28,894.49
01	101000 2051913067	FT MYERS TAP-LEE	356	$14,532.22	$38,774.29
01	101000 2051913068	CALOOSAHATCHEE RIVER XING #2 LINE	356	$24.97	$119.38
01	101000 2051913075	ALICO-COLONIAL TAP	356	$531,017.59	$788,508.27
01	101000 2051913078	ALICO-BONITA SPRINGS-COLLIER LINE VIA ESTERO	356	$802,253.35	$1,110,748.46
01	101000 2051913091	FT.MYERS SES-FT MYERS (SINGLE POLE SECT)	356	$48,648.23	$99,617.01
01	101000 2051913092	FT.MYERS SES-FT MYERS (DOUBLE CKT SECT)	356	$506,076.73	$933,244.93
01	101000 2051913096	BUCKINGHAM 69KV TAP	356	$55,083.64	$145,764.83
01	101000 2051913098	IONA TAP	356	$591,244.75	$623,405.37
01	101000 2051913105	FT MYERS SES-BUCKINGHAM	356	$78,039.87	$301,170.97
01	101000 2051913110	COLONIAL TAP	356	$48,997.18	$114,287.42
01	101000 2051913113	FT MYERS-COLLIER (LEE CO.)	356	$1,167,369.27	$2,828,542.40
01	101000 2051913164	COLONIAL-IONA	356	$300,614.45	$1,161,023.64
01	101000 2051913178	BUCKINGHAM-COLONIAL TAP	356	$1,034,151.35	$1,637,785.10
01	101000 2051913183	FT MYERS SUB-NAPLES TAP (OLD)	356	$223,981.08	$286,495.87
01	101000 2051913204	ALICO-FT MYERS #2	356	$67,529.17	$145,576.90
01	101000 2051913208	ALICO-SR 45	356	$168,531.44	$235,482.36
01	101000 2051913212	FT MYERS PLT-ORANGE RIVER 240KV TIE LINE	356	$240,399.03	$557,733.93
01	101000 2051913241	ALICO-245M7	356	$1,241,914.41	$1,789,861.70
01	101000 2051913245	COLLIER-ORANGE RIVER (LEE CO.)	356	$2,222,883.82	$3,148,473.70
01	101000 2051913328	ALICO-BUCKINGHAM 138KV - IONA-BUCKINGHAM SECT	356	$305,538.82	$281,095.71
01	101000 2051921001	FT. MYERS-RANCH 138KV (LEE CO.)	356	$252,175.86	$475,473.78
01	101000 2051924080	CHARLOTTE-CALUSA-FT. MYERS (LEE CO.)	356	$466,541.26	$918,190.39
01	101000 2051924086	FT MYERS-LEE (LEE CO.)	356	$4,144.74	$13,428.96
01	101000 2051924176	FT MYERS-CHARLOTTE 240KV (LEE CO.)	356	$549,061.34	$849,402.30
01	101000 2051924181	CALOOSAHATCHEE RIVER XING @ FT MYERS PLT.	356	$163,580.69	$195,855.42
01	101000 2051925087	ANDYTOWN-ORANGE RIVER 500KV LN (LEE CO)	356	$1,244,297.97	$3,441,161.19
01	101000 2051938098	ALICO-GLADIOLUS-BUCKINGHAM 138KV	356	$264,291.04	$245,790.67
01	101000 2051938212	FT MYERS PLT-ORANGE RIVER #2 240KV	356	$90,804.29	$162,539.68
01	101000 2051938241	ALICO-COLLIER 138KV	356	$474,495.36	$493,475.85
01	101000 2051946001	ORANGE RIVER-RANCH 240KV (LEE CO.)	356	$458,001.54	$1,062,537.54
01	101000 2051949080	FT MYERS-RINGLING #1 240KV (LEE CO.)	356	$144,979.92	$435,707.69

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01	101000	2051974085	CALUSA-FT. MYERS	356	$24,979.39	$68,632.53
01	101000	2052014022	BUCKEYE TAP #1 NORTH	356	$57,825.07	$81,259.54
01	101000	2052014056	CORTEZ TAP-WHITFIELD-SARASOTA CO. LINE	356	$198,578.60	$605,230.47
01	101000	2052014060	CORTEZ TAP-FRUIT INDUSTRIES TAP	356	$2,367.56	$12,143.44
01	101000	2052014071	BRADENTON-CASTLE	356	$161,643.30	$582,673.79
01	101000	2052014075	BRADENTON-CASTLE(BRADEN RIVER CROSSING)	356	$41,878.36	$59,145.45
01	101000	2052014076	CASTLE-RUBONIA	356	$473,751.96	$819,842.57
01	101000	2052014077	CASTLE-TAMPA ELECTRIC(MANATEE RIVER CROSSING)	356	$19,307.40	$42,129.78
01	101000	2052014078	RUBONIA-TAMPA ELECTRIC(BIG BEND)	356	$570,621.55	$865,107.04
01	101000	2052014083	CORTEZ TAP	356	$285,472.72	$703,905.75
01	101000	2052014088	CASTLE-RINGLING (W CKT, MANATEE CO.)	356	$263,951.06	$949,144.19
01	101000	2052014111	CORTEZ-PALMA SOLA-BRADENTON	356	$385,251.23	$1,254,546.03
01	101000	2052014121	BORDEN TAP #1 (NORTH)	356	$94,887.85	$263,008.68
01	101000	2052014125	FRUIT INDUSTRIES TAP	356	$173,796.97	$510,103.97
01	101000	2052014135	RINGLING-MANATEE #1 240KV (MANATEE CO.)	356	$2,215,753.05	$4,222,432.94
01	101000	2052014144	RINGLING-MANATEE #240KV-MANATEE RIVER XING	356	$114,783.67	$263,708.61
01	101000	2052014150	MANATEE-TAMPA #1 240KV (MANATEE CO.)	356	$441,285.06	$845,855.23
01	101000	2052014171	CORTEZ-JOHNSON 138KV	356	$1,028,492.20	$1,346,604.43
01	101000	2052014187	KEENTOWN-MANATEE 240KV	356	$1,355,514.79	$1,775,805.28
01	101000	2052014229	BEKER-KEENTOWN TAP 69KV	356	$92,487.51	$123,185.23
01	101000	2052014253	KEENTOWN-WHIDDEN 240KV (MANATEE CO.)	356	$797,615.13	$1,048,990.86
01	101000	2052014270	MANATEE-BIG BEND #2 240KV (TECO)	356	$604,919.97	$798,494.36
01	101000	2052024001	CASTLE-RINGLING (MANATEE CO.)	356	$422,861.52	$957,685.24
01	101000	2052024033	CHARLOTTE-RINGLING 138KV (MANATEE CO.)	356	$52,711.24	$154,676.10
01	101000	2052039022	BUCKEYE TAP #2 SOUTH	356	$55,100.95	$77,364.05
01	101000	2052039121	BORDEN TAP #2 (SOUTH)	356	$86,762.74	$268,054.87
01	101000	2052039135	RINGLING-MANATEE #2 240KV (MANATEE CO.)	356	$1,213,759.56	$2,295,717.37
01	101000	2052049033	FT MYERS-RINGLING #1 240KV (MANATEE CO.)	356	$53,583.48	$183,748.01
01	101000	2052064135	RINGLING-MANATEE #3 240KV (MANATEE CO.)	356	$1,898,754.99	$3,586,716.46
01	101000	2052064144	RINGLING-MANATEE #3 240KV-MANATEE RIVER WING	356	$123,508.69	$233,431.42
01	101000	2053012263	MYAKKA-ROTUNDA 138KV (SARASOTA CO.)	356	$120,938.85	$166,895.61
01	101000	2053014012	VENICE-ENGLEWOOD-CHARLOTTE CO.LINE	356	$1,365,512.94	$3,828,089.05
01	101000	2053014034	CLARK-VENICE	356	$785,053.38	$905,061.61
01	101000	2053014047	CLARK-HYDE PARK-RINGLING	356	$892,011.22	$1,166,283.56
01	101000	2053014053	MANATEE CO. LINE-53N11 (E/O SARASOTA)	356	$152,314.17	$483,515.31
01	101000	2053014068	SARASOTA & PAYNE LOOPS	356	$408,889.45	$945,284.56
01	101000	2053014096	CASTLE-RINGLING (W CKT. SARASOTA CO.)	356	$126,107.73	$498,392.80
01	101000	2053014102	RINGLING-TUTTLE AVE. (DOUBLE CKT)	356	$143,000.21	$646,300.12
01	101000	2053014108	RINGLING-54N2	356	$77,959.57	$81,509.28

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01	101000	2053014126	PHILLIPPI LOOP	356	$220,702.72	$845,652.88
01	101000	2053014131	RINGLING-MANATEE #1 240KV (SARASOTA CO.)	356	$324,256.75	$771,207.68
01	101000	2053014166	LAURELWOOD TAP 138KV	356	$425,624.52	$671,063.15
01	101000	2053014180	PHILLIPPI LOOP EXTENSION (NORTH)	356	$217,956.60	$311,256.34
01	101000	2053014183	PHILLIPPI LOOP EXTENSION (SOUTH)	356	$237,360.75	$340,153.06
01	101000	2053014206	LAURELWOOD-MYAKKA 240KV	356	$1,054,590.15	$1,497,079.22
01	101000	2053024009	CASTLE-RINGLING (SARASOTA CO.)	356	$115,188.12	$251,319.75
01	101000	2053024013	CHARLOTTE-RINGLING 138KV (SARASOTA CO.)	356	$1,323,712.97	$3,229,970.67
01	101000	2053024087	RINGLING-VENICE #2	356	$2,413,122.40	$2,736,177.32
01	101000	2053024107	LAURELWOOD-RINGLING #1	356	$587,986.73	$1,607,667.45
01	101000	2053024128	CHARLOTTE-LAURELWOOD (SARASOTA CO.)	356	$1,115,295.57	$2,104,991.14
01	101000	2053024182	LAURELWOOD-RINGLILNG #2 240KV	356	$1,801,358.08	$2,202,283.82
01	101000	2053039131	RINGLING-MANATEE #2 240KV (SARASOTA CO.)	356	$353,537.60	$592,851.95
01	101000	2053039144	RINGLING-MANATEE #2 240KV-MANATEE RIVER XING	356	$48,646.74	$92,953.92
01	101000	2053039166	HOWARD-LAURELWOOD (LAURELWOOD LOOP SECT)	356	$542,548.35	$596,803.19
01	101000	2053049013	FT MYERS-RINGLING #1 240KV (SARASOTA CO.)	356	$469,869.52	$2,191,944.26
01	101000	2053064131	RINGLING-MANATEE #3 240KV (SARASOTA CO.)	356	$351,462.48	$664,264.09
01	101000	2070500920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (BROWAR	356	$76.36	$386.38
01	101000	2070501028	LAUDERDALE SES-COUNTY LINE	356	$500,965.86	$1,310,943.65
01	101000	2070501106	BEVERLY LOOP	356	$10,317.29	$35,728.61
01	101000	2070501242	GARDEN-LAUDERDALE (BROWARD CO.)	356	$196,257.92	$818,077.95
01	101000	2070502030	COUNTY LINE TAP-32B8 (S/O LAUDERDALE)	356	$167,641.42	$440,940.89
01	101000	2070502033	LAUDERDALE-32B8 (TO FULFORD)	356	$142,983.23	$633,959.62
01	101000	2070502034	LAUDERDALE-HOLLYWOOD	356	$797,597.52	$1,190,578.89
01	101000	2070502036	HOLLYWOOD (N/O)-RAVENSWOOD (E/O)	356	$150,102.00	$324,572.22
01	101000	2070502037	HOLLYWOOD 138KV TAP	356	$21,472.78	$74,111.63
01	101000	2070502038	LAUDERDALE SES-HOLLYWOOD TIE	356	$125,596.80	$383,863.51
01	101000	2070502039	PLAYLAND TAP	356	$162,492.28	$251,867.76
01	101000	2070502043	GRANT STREET TIE LINE	356	$8,669.24	$28,233.32
01	101000	2070502044	HALLANDALE-HOLLYWOOD	356	$134,809.53	$432,576.89
01	101000	2070502049	HALLANDALE-DADE CO. LINE	356	$42,307.42	$206,905.77
01	101000	2070502058	LAUDERDALE-HOLLYWOOD (STIRLING RD SECT)	356	$222,470.82	$307,710.42
01	101000	2070502059	HOLLYWOOD-STIRLING	356	$88,973.08	$390,390.32
01	101000	2070502066	PORT SUB-RAVENSWOOD (OLD DANIA TAP)	356	$467,954.32	$737,250.86
01	101000	2070502073	BEVERLY TIE LINES	356	$15,219.42	$60,414.13
01	101000	2070502078	STIRING RD TIE	356	$1,391.08	$4,548.83
01	101000	2070502079	STIRLING RD (W/O STIRLING)-PEMBROKE-DADE CO L	356	$167,758.09	$690,015.80
01	101000	2070502091	DANIA-HOLLYWOOD	356	$58,629.92	$178,366.83
01	101000	2070502092	MELALEUCA-TRACE 240KV LINE	356	$466,181.97	$586,522.65

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01	101000	2070502096	ANDYTOWN-TRACE 240KV	356	$1,172,726.81	$1,263,345.14
01	101000	2070503001	LAUDERDALE-PINEHURST-POMPANO-PALM BCH CO.	356	$1,911,937.99	$4,276,397.31
01	101000	2070503024	BROWARD-YAMATO (BROWARD CO.)	356	$266,270.99	$450,475.45
01	101000	2070503025	CRYSTAL TAP #2 - DEERFIELD BCH	356	$320,667.21	$553,951.49
01	101000	2070503067	LAUDERDALE SES-1C13	356	$277,848.05	$306,062.13
01	101000	2070503068	OAKLAND PARK LOOP	356	$152,216.78	$469,056.06
01	101000	2070503069	FAIRMONT-FT LAUDERDALE	356	$87,105.74	$168,232.53
01	101000	2070503072	VERENA-72C4 (OLD VERENA TAP)	356	$78,490.80	$305,523.50
01	101000	2070503074	PINEHURST-PT.EVERGLADES	356	$63,262.63	$197,535.47
01	101000	2070503079	BROWARD-SAMPLE RD	356	$334,124.39	$869,154.18
01	101000	2070503097	SAMPLE-DEERFIELD-PALM BCH CO.LINE	356	$153,483.60	$425,545.71
01	101000	2070503135	BROWARD-LYONS-HOLY CROSS-OAKLAND PARK	356	$674,156.59	$2,174,434.67
01	101000	2070503154	OAKLAND PARK-VERENA	356	$125,110.64	$495,393.97
01	101000	2070503158	FT LAUDERDALE-72C4	356	$19,054.51	$33,257.04
01	101000	2070503159	FT LAUDERDALE-PORT SUB	356	$261,595.04	$465,475.92
01	101000	2070503170	LAUDERDALE-PORT EVERGLADES #1-4 240KV LINES	356	$1,277,451.86	$6,577,159.44
01	101000	2070503187	BROWARD-YAMATO #| 240KV	356	$200,991.29	$245,131.45
01	101000	2070503213	BROWARD-TRADEWINDS	356	$40,614.76	$43,122.78
01	101000	2070518062	LAUDERDALE-DAVIE	356	$824,276.66	$1,054,800.91
01	101000	2070518067	DAVIE-JACARANDA-MOTOROLA	356	$548,672.22	$900,353.25
01	101000	2070518072	MOTOROLA-SPRINGTREE-77S3	356	$1,196,687.91	$1,520,612.96
01	101000	2070518078	HIATUS-SPRING TREE TAP 230KV LINE BRD CO	356	$281,816.34	$333,779.34
01	101000	2070518081	HIATUS-MELALEUCA	356	$925,859.80	$969,115.12
01	101000	2070519001	FAIRMONT-LAUDERDALE	356	$178,124.58	$385,909.81
01	101000	2070519009	LAUDERDALE-RANCH (BROWARD CO.)	356	$813,605.99	$3,666,628.13
01	101000	2070519073	BROWARD LOOP	356	$130,189.43	$466,440.44
01	101000	2070519083	BROWARD-FT.LAUDERDALE	356	$1,080,053.79	$1,520,329.66
01	101000	2070519118	RANCH-BROWARD #2 240KV (BROWARD CO.)	356	$566,259.53	$1,116,180.76
01	101000	2070519130	BROWARD-LAUDERDALE #2 240KV	356	$4,236,252.00	$8,681,175.80
01	101000	2070519154	ANDYTOWN-LAUDERDALE #2 & #3 240KV	356	$694,776.25	$1,240,893.50
01	101000	2070519167	WESTINGHOUSE 138KV LOOP	356	$245,426.48	$793,230.88
01	101000	2070519171	ANDYTOWN-LAUDERDALE #1 240KV	356	$836,844.11	$1,441,007.67
01	101000	2070520051	DADE-GRATIGNY-LAUDERDALE (BROWARD CO.)	356	$513,631.79	$909,495.88
01	101000	2070520084	DADE-PORT EVERGLADES (BROWARD CO.)	356	$563,349.05	$2,051,645.32
01	101000	2070520103	DADE-LAUDERDALE #3 & #4 (BROWARD CO.)	356	$1,296,216.73	$3,183,598.59
01	101000	2070520161	DADE-LAUDERDALE (ANDYTOWN EXTENSION)	356	$693,052.37	$858,572.12
01	101000	2070520166	FLAGAMI LAUDERDALE (ANDYTOWN EXTENSION)	356	$971,802.26	$1,340,085.00
01	101000	2070520219	ANDYTOWN-BASSCREEK-ANDYTOWN 230KV	356	$587,842.92	$623,113.50
01	101000	2070525001	ANDYTOWN-ORANGE RIVER 500KV LN (BROWARD CO)	356	$3,293,494.62	$8,829,758.43

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01	101000 2070525002	ANDYTOWN-MARTIN 500KV #1 (BROWARD CO.)	356	$540,117.58	$840,844.82
01	101000 2070525012	ANDYTOWN-LEVEE 500KV (BROWARD CO)	356	$830,651.96	$1,461,947.45
01	101000 2070525016	CONSERVATION-CORBETT 500KV (BROWARD CO.)	356	$11,505,911.41	$10,698,177.87
01	101000 2070525034	ANDYTOWN-MARTIN 500KV #1 (SWAMP)	356	$1,032,206.18	$1,610,241.64
01	101000 2070544009	CEDAR-LAUDERDALE (BROWARD CO.)	356	$165,748.99	$201,739.57
01	101000 2070550001	ANDYTOWN-MARTIN 500KV #2 (BROWARD CO)	356	$517,003.63	$806,525.66
01	101000 2070550012	ANDYTOWN-LEVEE #2 500KV LINE (BROWARD CO.)	356	$1,985,610.10	$2,839,422.44
01	101000 2070550035	ANDYTOWN-MARTIN #2 500KV (SWAMP)	356	$1,046,595.41	$1,632,688.84
01	101000 2070570111	GRATIGNY-LAUDERDALE #2 138KV	356	$259,313.41	$601,079.25
01	101000 2081000011	T" AVOCADO-FLA CITY 138KV "	356	$715,571.98	$644,014.78
01	101000 2081000903	MIAMI BEACH-DEAUVILLE 69KV CABLE	356	$1,203.93	$6,188.20
01	101000 2081000907	UG-MIAMI-LAWRENCE 138KV CABLE	356	$1,786.23	$9,181.22
01	101000 2081001001	MIAMI-RAILWAY #1 (OLD)	356	$349,892.74	$627,071.60
01	101000 2081001004	MASTER-SEABOARD 138KV	356	$119,764.44	$186,118.64
01	101000 2081001012	RAILWAY-HIALEAH (OLD)	356	$18,432.02	$94,740.58
01	101000 2081001015	AIRPORT-RIVERSIDE (AIRPORT-FRONTON SECTION)	356	$85,064.14	$332,349.31
01	101000 2081001016	AIRPORT-DADE (AIRPORT-HIALEAH SECTION)	356	$59,381.63	$199,195.72
01	101000 2081001018	HIALEAH SUB-GLADEVIEW TAP-DADE LITTLE RIVER	356	$249,763.71	$913,718.50
01	101000 2081001021	LITTLE RIVER-21A23 (S/O LITTLE RIVER)	356	$226,761.55	$352,754.82
01	101000 2081001023	LAUDERDALE SES-HIALEAH (OLD)	356	$120,350.32	$618,596.75
01	101000 2081001024	BISCAYNE-MIAMI SHORES	356	$140,231.65	$518,431.01
01	101000 2081001034	MARKET-BUENA VISTA-21A23 (S/O LITTLE RIVER)	356	$309,455.74	$1,051,500.30
01	101000 2081001036	HIALEAH-RIVER (OLD)	356	$64,650.51	$175,892.41
01	101000 2081001039	MERCHANDISE-WESTSIDE	356	$30,337.47	$139,412.82
01	101000 2081001040	FLAGAMI-RIVERSIDE #2	356	$77,582.97	$223,849.78
01	101000 2081001042	DADE-WESTSIDE (OLD)	356	$1,221.93	$6,159.64
01	101000 2081001045	GRAPELAND-RIVERSIDE	356	$198,616.01	$669,740.89
01	101000 2081001047	OPA LOCKA TAP	356	$8,416.97	$19,366.37
01	101000 2081001048	CUTLER-HIALEAH (OLD)	356	$3,512.17	$18,052.55
01	101000 2081001049	49A18 (E/O FIU CAMPUS)-54A14B (E/O DAVIS)	356	$920,001.68	$1,752,820.22
01	101000 2081001054	CORAL REEF-54A15 (E/O DAVIS)	356	$146,233.55	$405,956.73
01	101000 2081001057	FRONTON-57A1 (S/O INDUSTRIAL)	356	$7,130.06	$20,045.20
01	101000 2081001058	AIRPORT-RIVERSIDE (FRONTON-LEJEUNE SECTION)	356	$135,703.63	$154,697.56
01	101000 2081001061	CORAL REEF-PERRINE	356	$88,098.75	$360,626.86
01	101000 2081001062	GOULDS-PERRINE	356	$146,956.39	$435,672.08
01	101000 2081001063	GOULDS-PRINCETON	356	$69,264.55	$101,051.23
01	101000 2081001066	62ND AVE-66A1 (W/O RIVERSIDE)	356	$165,010.11	$680,999.76
01	101000 2081001067	62ND AVE-BIRD-KENDALL-SUNLAND-74A17	356	$694,263.13	$1,610,033.00
01	101000 2081001075	CUTLER-75A5 (W/O CUTLER 3 CKTS)	356	$61,062.75	$156,610.34

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01	101000 2081001076	75A5 (W/O CUTLER)-76A20 (SW 87 AVE &152 ST)	356	$527.61	$2,511.42
01	101000 2081001077	CORAL REEF-76A20 (SW 87 AVE & 152 ST)	356	$300,594.39	$941,809.21
01	101000 2081001078	CUTLER-SOUTH MIAMI-COCONUT GROVE	356	$546,256.25	$1,215,651.80
01	101000 2081001084	SOUTH MIAMI-68A25 (N/O SO. MIAMI)	356	$215,268.02	$323,418.40
01	101000 2081001085	FRONTON-INDUSTRIAL-HIALEAH	356	$117,758.54	$372,899.24
01	101000 2081001088	GLADEVIEW TAPS	356	$26,348.74	$96,598.78
01	101000 2081001091	FLAGAMI-92A5 (E/O FLAGAMI)	356	$55,886.07	$141,794.95
01	101000 2081001094	CORAL REEF (OLD)-HIALEAH	356	$3,725.60	$19,305.48
01	101000 2081001095	DADE-HIALEAH-21A23 (S/O LITTLE RIVER)	356	$78,389.27	$183,832.74
01	101000 2081001097	DADE-LITTLE RIVER	356	$572,357.32	$1,170,503.42
01	101000 2081001107	PRINCETON-109A9 (W/O HOMESTEAD)	356	$41,854.02	$106,746.60
01	101000 2081001109	HOMESTEAD-109A9 (W/O HOMESTEAD)	356	($58,395.16)	($55,501.37)
01	101000 2081001111	FLAGAMI-TROPICAL	356	$26,019.99	$91,291.38
01	101000 2081001115	FLORIDA CITY-KEYS ELEC CO-OP	356	$837,574.39	$1,076,337.69
01	101000 2081001119	VILLAGE GREEN-120A18 (W/O V.G)	356	$12,698.81	$37,541.46
01	101000 2081001120	KROME-120A18 (W/O VILLAGE GREEN)	356	$65,679.15	$72,628.93
01	101000 2081001125	FLORIDA CITY-109A9 (W/O HOMESTEAD)	356	$490,407.84	$550,664.17
01	101000 2081001130	AIRPORT-DADE (DADE-HIALEAH SECTION)	356	$250,454.20	$821,222.64
01	101000 2081001132	OPA LOCKA-GOLDEN GLADES-134A15	356	$88,004.26	$261,603.08
01	101000 2081001135	N W 179ST TIE (E/O GARDEN)	356	$5,197.68	$26,716.08
01	101000 2081001136	137TH AVE TAP	356	$48,439.22	$67,620.26
01	101000 2081001139	GARDEN-134A15 (E/O GARDEN)	356	$16,413.81	$29,966.40
01	101000 2081001141	SEABOARD-140A1 (S/O SEABOARD)	356	$94,467.21	$136,494.42
01	101000 2081001143	LITTLE RIVER-S/O MIAMI SHORES	356	$59,736.66	$243,885.67
01	101000 2081001144	CORAL-REEF-144A24 (S/W 117 AV)	356	$204,390.20	$296,039.64
01	101000 2081001145	144A24-145A25 (S/O DAVIS)	356	$78,176.62	$138,212.22
01	101000 2081001146	HAINLIN-146A4 (S/O DAVIS)	356	$355,882.31	$416,682.62
01	101000 2081001151	FLORIDA CITY-HAINLIN	356	$267,169.53	$480,076.18
01	101000 2081001162	DAVIS-144A24 (W/O CORAL REEF)	356	($4,108.38)	$49,194.92
01	101000 2081001165	AVOCADO-DAVIS (BOYSTOWN E.-BOYSTOWN W. UG)	356	$4,237.76	$4,364.89
01	101000 2081001171	CORAL REEF-75A5 (W/O CUTLER)	356	$254,080.16	$930,323.89
01	101000 2081001177	FLAGAMI-62ND AVE AND RIVERSIDE (SW 4ST BETW	356	$226,362.78	$809,861.19
01	101000 2081001179	FLAGAMI-137TH AVE	356	$472,445.72	$789,171.74
01	101000 2081001183	TROPICAL-49A20 (E/O FIU CAMPUS)	356	$57,080.81	$239,270.06
01	101000 2081001185	DADE-WESTSIDE	356	$328,817.82	$652,228.02
01	101000 2081001188	LAWRENCE-RIVERSIDE	356	$226,485.32	$680,049.50
01	101000 2081001191	AIRPORT-RIVERSIDE (RIVERSIDE-LEJEUNE SECTION)	356	$42,118.43	$171,662.66
01	101000 2081001193	FLAGAMI-RIVERSIDE	356	$529,896.17	$899,110.73
01	101000 2081001198	INDUSTRIAL-SEABOARD TAP	356	$66,586.06	$251,330.74

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01	101000 2081001199	LITTLE RIVER-MIAMI SHORES	356	$36,587.12	$68,512.84
01	101000 2081001200	LITTLE RIVER-SEABOARD	356	$114,149.89	$438,975.15
01	101000 2081001203	DADE-HIALEAH #3	356	$94,399.96	$192,239.50
01	101000 2081001205	CUTLER-74A17 (SW 77 AVE & 140 ST)	356	$30,203.70	$148,300.17
01	101000 2081001206	FLAGAMI-PALMETTO XWAY	356	$25,411.92	$74,156.02
01	101000 2081001208	DAVIS-145A25 (S/O DAVIS)	356	$34,078.26	$90,763.25
01	101000 2081001209	DAVIS-146A4 (S/O DAVIS)	356	$44,168.06	$135,684.79
01	101000 2081001210	MASTER-OPA LOCKA	356	$254,714.10	$976,324.99
01	101000 2081001212	GRATIGNY-MASTER	356	$105,248.66	$250,167.98
01	101000 2081001218	MARKET-MIRAMAR-16TH ST CABLE TERMINAL	356	$91,064.26	$343,147.18
01	101000 2081001233	BISCAYNE-OPA LOCKA TAP	356	$15,090.44	$57,556.52
01	101000 2081001234	BISCAYNE-COUNTY LINE	356	$337,677.93	$885,626.12
01	101000 2081001236	GALLOWAY LOOP	356	$19,570.80	$66,651.85
01	101000 2081001237	FLAGAMI-MERCHANDISE	356	$170,128.01	$485,880.03
01	101000 2081001239	GARDEN-LAUDERDALE (DADE CO.)	356	$245,664.40	$1,116,775.98
01	101000 2081001246	FLAGAMI-8TH ST TERMINAL	356	$260,029.73	$740,987.43
01	101000 2081001249	LITTLE RIVER-LEMON CITY	356	$92,722.32	$322,684.53
01	101000 2081001250	DADELAND TAPS	356	$163,054.89	$488,946.02
01	101000 2081001252	CORAL REEF DR @ SW 89 AV-WHISPERING PINES	356	$273,889.74	$541,815.46
01	101000 2081001255	WHISPERING PINES-PRINCETON	356	$655,672.96	$1,025,202.05
01	101000 2081001264	FLA CITY-KEYS COOP 138KV LINE	356	$802,513.03	$998,801.64
01	101000 2081001278	FLORIDA CITY-TURKEY POINT 240KV LINE	356	$666,153.10	$707,109.23
01	101000 2081001286	DADE-MIAMI SHORES 240KV	356	$1,436,409.32	$1,701,446.66
01	101000 2081002001	MIAMI BEACH-RAILWAY (OLD)	356	$17,896.12	$89,426.37
01	101000 2081002006	MIAMI BEACH-FULFORD (OLD)	356	$22,414.70	$88,258.82
01	101000 2081002017	DEAUVILLE-NORMANDY	356	$102,236.22	$147,126.86
01	101000 2081002022	GREYNOLDS-HAULOVER	356	$489,239.47	$1,070,224.79
01	101000 2081002026	GREYNOLDS-FULFORD	356	$117,094.27	$456,335.58
01	101000 2081002028	FULFORD-COUNTY LINE TAP	356	$474,700.73	$1,188,233.01
01	101000 2081002040	ARCH CREEK-ULETA	356	$73,731.10	$294,302.30
01	101000 2081002051	DUMBFOUNDLING-BROWARD CO. LINE	356	$429,501.10	$667,087.34
01	101000 2081002055	DUMBFOUNDLING-GREYNOLDS	356	$67,811.91	$121,448.21
01	101000 2081002072	COUNTY LINE TAP	356	$32,765.94	$119,386.70
01	101000 2081002074	ARCH CREEK-GREYNOLDS	356	$133,029.83	$552,894.79
01	101000 2081002084	GREYNOLDS-IVES-BROWARD CO. LINE	356	$387,613.04	$947,797.39
01	101000 2081020001	CUTLER-DAVIS LOOPS	356	$236,043.71	$467,365.47
01	101000 2081020005	FLAGAMI-DAVIS LOOPS	356	$592,846.47	$1,835,108.61
01	101000 2081020015	DADE-FLAGAMI (H FRAME SECT)	356	$604,686.09	$1,390,635.64
01	101000 2081020041	DADE-GRATIGNY-LAUDERDALE (DADE CO.)	356	$387,534.77	$873,934.14

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01	101000 2081020067	DADE-PORT EVERGLADES (DADE CO.)	356	$599,658.77	$1,545,770.25
01	101000 2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	356	$1,057,866.46	$2,327,615.06
01	101000 2081020116	DAVIS-TURKEY POINT (7 CIRCUITS)	356	$4,523,416.55	$14,016,183.44
01	101000 2081020133	DAVIS LOOP (FROM CUTLER & FLAGAMI)	356	$547,138.01	$1,593,745.30
01	101000 2081020137	MAULE LOOP	356	$235,804.77	$657,987.25
01	101000 2081020140	DADE-LEVEE #1 & 2	356	$206,399.06	$697,102.33
01	101000 2081020144	DAVIS-144U1	356	$2,393,354.66	$5,296,761.51
01	101000 2081020156	CUTLER-DAVIS #1 & 2	356	$6,763.12	$9,671.26
01	101000 2081020158	FLAGAMI-LEVEE 240KV (LEVEE EXTENSION)	356	$175,338.94	$262,069.72
01	101000 2081020180	AVOCADO-DAVIS (BOYSTOWN EAST-DAVIS SECT)	356	$554,299.56	$570,928.55
01	101000 2081020183	AVOCADO-DAVIS (AVOCADO-BOYSTOWN WEST SECT)	356	$1,555,274.78	$1,601,933.02
01	101000 2081020194	DAVIS-LEVEE #3 (DAVIS-NEWTON SECT) 230KV	356	$2,713,870.75	$2,875,300.41
01	101000 2081020209	DAVIS-LEVEE #3 (LEVEE-NEWTON SECT) 230KV	356	$1,935,017.55	$2,051,118.60
01	101000 2081025001	ANDYTOWN-LEVEE 500KV (DADE CO)	356	$1,577,786.76	$2,767,658.88
01	101000 2081045158	DAVIS_LEVEE #1 & 2 (LEVEE EXTENSION)	356	$317,021.78	$498,455.83
01	101000 2081050001	ANDYTOWN-LEVEE #2 500KV LINE (DADE CO.)	356	$132,803.18	$189,908.55
01	101000 2081070133	DAVIS-SW 117 AVE (BETW CORAL REEF & MARION)	356	$33,479.41	$145,052.79
01	101000 2081070158	DADE-LEVEE #2 (LEVEE EXTENSION)	356	$78,905.05	$104,154.67
01	101000 2081095158	LEVEE-TURKEY PT #1 (LEVEE EXTENSION)	356	$130,695.76	$158,678.86
01	101000 2980000000	SUSPENSE-TRANSM LINES	356	$0.00	($504.63)
01	101000 2991514250	KEENTOWN-WHIDDEN 240KV (HARDEE CO)	356	$210,779.34	$278,228.73
01	101000 2992723162	BREVARD-POINSETT #1 240KV (OBO) (OSCEOLA CO)	356	$150,399.22	$207,550.92
01	101000 2992725003	MARTIN-POINSETT 500KV (OBO) (OSCEOLA CO)	356	$5,760,393.39	$7,949,342.88
01	101000 2992725004	MIDWAY-POINSETT 500KV (OBO) (OSCEOLA CO)	356	$5,198,252.94	$7,173,589.06
01	101000 2992748162	POINSETT-WEST LAKE WALES #2 (OBO) (OSCEOLA C)	356	$17,323.44	$23,906.35
01	101000 2993699500	EMERGENCY 500KV TRANSMISSION STRUCTURES	356	$34,095.59	$45,006.18
01	101000 2993714082	CASTLE-TAMPA ELECT. CO. (HILLSBOROUGH CO.)	356	$13,383.02	$17,665.59
01	101000 2993714280	MANATEE-BIG BEND #2 (TEC) (HILLSBOROUGH CO.)	356	$15,627.92	$20,628.85
01	101000 2993714293	MANATEE BIG BEND #2 240KV (HILLSBOROUGH CO.)	356	$820,416.35	$1,132,174.56
01	101000 2999999911	TRANSMISSION-HOLDING LOCN 11	356	($54,297.22)	($179,156.56)
			356 Total	$419,114,436.74	$716,266,029.22
01	101000 2020405132	BANANA RIVER SUB-SOUTH COCOA BEACH	357	$85,527.99	$421,652.99
01	101000 2020405136	BANANA RIVER SUB-PATRICK	357	$96,985.49	$204,548.94
01	101000 2020406109	SOUTH CAPE-C-5 COMPLEX	357	$163,600.22	$289,281.05
01	101000 2042804069	PLUMOSUS-RIVIERA #1	357	$691,906.55	$733,420.94
01	101000 2050800901	ALICO-COLLIER 138KV	357	$208,469.93	$227,232.22
01	101000 2070500916	PORT EVERGLADES-FT LAUDERDALE 240KV CABLE	357	$2,898,777.04	$6,916,390.94
01	101000 2070500920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (BROWAR	357	$1,966,589.43	$5,202,983.60
01	101000 2081000902	MIAMI-COCONUT GROVE 69KV CABLE	357	$973,885.61	$2,715,949.32

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01	101000 2081000903	MIAMI BEACH-DEAUVILLE 69KV CABLE	357	$1,025,321.96	$5,610,421.01
01	101000 2081000905	INDIAN CREEK-LEMON CITY 138KV CABLE	357	$1,960,119.48	$4,913,787.53
01	101000 2081000906	MIAMI-MIAMI BEACH 69KV CABLE	357	$3,173,823.08	$6,594,178.94
01	101000 2081000907	UG-MIAMI-LAWRENCE 138KV CABLE	357	$305,972.39	$1,692,027.32
01	101000 2081000908	LITTLE RIVER-40TH STREET 138KV CABLE	357	$722,759.02	$3,582,498.25
01	101000 2081000909	MIAMI-KEY BISCAYNE 138KV CABLE	357	$1,153,435.54	$4,149,518.35
01	101000 2081000910	MIAMI-RAILWAY 138KV CABLE	357	$372,897.98	$1,715,382.87
01	101000 2081000911	HAULOVER-NORMANDY 138KV CABLE	357	$575,119.12	$2,656,851.12
01	101000 2081000912	KEY BISCAYNE-MIAMI BEACH 138KV CABLE	357	$4,053,443.33	$7,609,941.89
01	101000 2081000913	RAILWAY-16TH STREET TERMINAL 138KV CABLE	357	$166,060.93	$750,595.40
01	101000 2081000914	MIAMI-8TH STREET TERMINAL 240KV CABLE	357	$2,264,282.20	$7,620,584.61
01	101000 2081000915	GREYNOLDS-DUMBFOUNDLING 138KV CABLE	357	$1,429,119.07	$3,518,815.69
01	101000 2081000917	ARCH CREEK-BOULEVARD 138KV CABLE	357	$708,829.81	$1,708,279.84
01	101000 2081000918	ARCH CREEK-NORMANDY 138KV CABLE	357	$586,754.64	$2,646,842.41
01	101000 2081000919	SNAPPER CREEK LOOP 138KV CABLE	357	$344,601.08	$830,488.60
01	101000 2081000920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (DADE C	357	$2,260,609.25	$4,091,108.28
01	101000 2081000921	MIAMI-8TH ST-FLAGAMI #2 240KV CABLE	357	$1,075,812.92	$2,010,888.73
01	101000 2081000922	TURKEY PT. SW. STA.-UNITS #3 & #4	357	$92,208.10	$116,182.21
01	101000 2081001066	62ND AVE-66A1 (W/O RIVERSIDE)	357	$94.02	$553.78
01	101000 2081001165	AVOCADO-DAVIS (BOYSTOWN E.-BOYSTOWN W. UG)	357	$230,310.27	$251,038.19
01	101000 2081001185	DADE-WESTSIDE	357	$386,168.21	$563,805.59
01	101000 2081002006	MIAMI BEACH-FULFORD (OLD)	357	$4,432.72	$26,108.72
01	101000 2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	357	$797,052.19	$1,004,285.76
			357 Total	$30,774,969.57	$80,375,645.09
01	101000 2020405132	BANANA RIVER SUB-SOUTH COCOA BEACH	358	$32,130.57	$195,996.48
01	101000 2020405136	BANANA RIVER SUB-PATRICK	358	$67,612.15	$155,983.46
01	101000 2020406109	SOUTH CAPE-C-5 COMPLEX	358	$267,147.94	$1,393,184.66
01	101000 2023106045	LAUREL-VOLUSIA CO. LINE	358	$30.78	$218.54
01	101000 2042804069	PLUMOSUS-RIVIERA #1	358	$1,160,319.26	$1,218,335.22
01	101000 2042818058	BELLE GLADE-SO.BAY	358	$16,382.82	$118,283.96
01	101000 2043305001	FT PIERCE-OSLO (ST LUCIE CO.)	358	$30.78	$218.54
01	101000 2050800901	ALICO-COLLIER 138KV	358	$2,011,827.20	$2,192,921.65
01	101000 2053014068	SARASOTA & PAYNE LOOPS	358	$842.47	$5,981.54
01	101000 2070500916	PORT EVERGLADES-FT LAUDERDALE 240KV CABLE	358	$1,606,827.69	$5,195,794.48
01	101000 2070500920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (BROWAR	358	$1,534,379.70	$6,149,141.05
01	101000 2081000902	MIAMI-COCONUT GROVE 69KV CABLE	358	$2,466,346.07	$4,455,468.08
01	101000 2081000903	MIAMI BEACH-DEAUVILLE 69KV CABLE	358	$1,388,360.79	$8,553,546.80
01	101000 2081000905	INDIAN CREEK-LEMON CITY 138KV CABLE	358	$3,141,168.63	$7,263,562.32
01	101000 2081000906	MIAMI-MIAMI BEACH 69KV CABLE	358	$1,620,807.17	$6,810,600.08

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01	101000 2081000907	UG-MIAMI-LAWRENCE 138KV CABLE	358	$466,427.11	$2,907,274.40
01	101000 2081000908	LITTLE RIVER-40TH STREET 138KV CABLE	358	$1,142,031.89	$7,367,874.09
01	101000 2081000909	MIAMI-KEY BISCAYNE 138KV CABLE	358	$1,099,204.09	$5,577,725.99
01	101000 2081000910	MIAMI-RAILWAY 138KV CABLE	358	$951,025.43	$4,315,881.20
01	101000 2081000911	HAULOVER-NORMANDY 138KV CABLE	358	$440,435.73	$2,574,067.53
01	101000 2081000912	KEY BISCAYNE-MIAMI BEACH 138KV CABLE	358	$1,851,995.31	$6,933,982.57
01	101000 2081000913	RAILWAY-16TH STREET TERMINAL 138KV CABLE	358	$190,282.87	$1,177,297.07
01	101000 2081000914	MIAMI-8TH STREET TERMINAL 240KV CABLE	358	$3,221,621.87	$14,229,699.59
01	101000 2081000915	GREYNOLDS-DUMBFOUNDLING 138KV CABLE	358	$1,005,523.19	$4,207,180.65
01	101000 2081000917	ARCH CREEK-BOULEVARD 138KV CABLE	358	$631,466.21	$2,044,325.67
01	101000 2081000918	ARCH CREEK-NORMANDY 138KV CABLE	358	$777,087.63	$4,769,702.41
01	101000 2081000919	SNAPPER CREEK LOOP 138KV CABLE	358	$326,600.72	$1,058,186.33
01	101000 2081000920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (DADE C	358	$1,199,597.74	$4,172,695.87
01	101000 2081000921	MIAMI-8TH ST-FLAGAMI #2 240KV CABLE	358	$3,218,439.23	$9,216,685.48
01	101000 2081000922	TURKEY PT. SW. STA.-UNITS #3 & #4	358	$2,473,782.84	$4,155,955.17
01	101000 2081001018	HIALEAH SUB-GLADEVIEW TAP-DADE LITTLE RIVER	358	$1,896.13	$11,737.04
01	101000 2081001034	MARKET-BUENA VISTA-21A23 (S/O LITTLE RIVER)	358	$1,012.93	$5,419.18
01	101000 2081001165	AVOCADO-DAVIS (BOYSTOWN E.-BOYSTOWN W. UG)	358	$447,546.92	$483,350.67
01	101000 2081001185	DADE-WESTSIDE	358	$605,604.57	$862,463.13
01	101000 2081002006	MIAMI BEACH-FULFORD (OLD)	358	$16,853.76	$119,661.70
01	101000 2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	358	$1,254,701.36	$2,227,178.99
			358 Total	$36,637,351.55	$122,127,581.59
01	101000 2010709185	HUDSON-TITANIUM 240KV (CLAY)	359	$1,636.05	$5,873.42
01	101000 2010710040	TRAIL RIDGE TAP (OLD)	359	$3,642.63	$17,266.07
01	101000 2011308054	FLAGLER BCH - ST JOE	359	$7,672.67	$12,275.79
01	101000 2011310048	BUNNELL-PALATKA #2 115KV (FLAGLER CO.)	359	$45,215.95	$104,955.19
01	101000 2011310097	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	359	$120,582.89	$254,429.90
01	101000 2011325075	DUVAL-POINSETT 500KV (OBO) (FLAGLER CO)	359	$394,004.82	$546,832.43
01	101000 2011335048	PUTNAM-VOLUSIA #1 240KV (FLAGLER CO.)	359	$107.05	$507.42
01	101000 2011335073	PUTNAM-VOLUSIA #1 240KV (FLAGLER COUNTY0)	359	$34,914.38	$139,744.84
01	101000 2011360073	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	359	$23,191.29	$42,189.93
01	101000 2012907055	CRESCENT CITY-VOLUSIA CO.LINE	359	$4,061.58	$5,280.05
01	101000 2012907085	PALATKA SES-PALATKA SUB	359	$460.00	$690.00
01	101000 2012907088	PUTNAM - ST JOHNS CO. LINE	359	$15,933.53	$61,077.61
01	101000 2012907121	PALATKA SES-PUTNAM 240KV YARD	359	$767.90	$1,151.85
01	101000 2012909001	PALATKA-MCMEEKIN TAP	359	$20,646.71	$106,455.47
01	101000 2012909025	MCMEEKIN TAP-CLAY CO.LINE	359	$701.92	$3,621.91
01	101000 2012909129	HUDSON TAP	359	$1,215.63	$6,272.65
01	101000 2012909133	BRADFORD-PUTNAM 240KV YARD (PUTNAM CO.)	359	$95,553.33	$293,685.58

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01	101000 2012909175	HUDSON-TITANIUM 240KV (PUTNAM)	359	$102,051.81	$174,658.58
01	101000 2012909188	BLANK CREEK-PUTNAM #1(OBO)-EXT TO SEMINOLE	359	$99,412.21	$146,135.95
01	101000 2012910044	BUNNELL-PALATKA #2 115KV (PUTNAM CO.)	359	$2,503.19	$12,916.46
01	101000 2012925039	DUVAL-POINSETT 500KV (OBO) (PUTNAM CO)	359	$499,628.05	$694,210.64
01	101000 2012925040	DUVAL-POINSETT 500KV (OBO)-ST.JOHNS RIVER XNG	359	$3,737.38	$5,194.96
01	101000 2012934133	PUTNAM-TITANIUM 240KV	359	$25,190.67	$37,786.01
01	101000 2012934188	BLACK CREEK-PUTNAM #2 (OBO)-EXT TO SEMINOLE	359	$6,037.50	$8,875.13
01	101000 2013207099	ST JOHNS RIVER XING @ ORANGEDALE	359	$12,042.48	$62,139.20
01	101000 2013207102	ORANGEDALE-GREENLAND (JACKSONVILLE ELECT AUTH	359	$97,289.40	$179,659.23
01	101000 2013208075	ST AUGUSTINE-FLAGLER CO. LINE	359	$179,283.48	$236,637.42
01	101000 2013208134	LEWIS LOOP	359	$9,202.14	$22,724.87
01	101000 2013210009	PALATKA-ST AUGUSTINE (ST JOHNS CO.)	359	$17,315.53	$27,329.83
01	101000 2013210027	SAN SEBASTIAN RIVER-27J5 (ST AUGUSTINE)	359	$1,011.08	$5,217.17
01	101000 2013210121	ST. JOHN'S-TOCOI 240KV	359	$496,548.52	$729,133.84
01	101000 2013600009	T" EDGEWATER-SMYRNA 115KV "	359	$172,343.26	$177,513.56
01	101000 2013607001	SANFORD SES-DELAND	359	$1,364.91	$1,719.79
01	101000 2013607020	DELAND-PUTNAM CO.LINE (S/O CRESCENT CITY)	359	$18,822.77	$26,648.62
01	101000 2013608001	DELAND-SMYRNA	359	$29,625.99	$62,807.10
01	101000 2013608035	DAYTONA-ORMOND-FLAGLER CO.LINE	359	$6,039.79	$14,800.53
01	101000 2013608109	GENERAL ELECTRIC-VOLUSIA	359	$24.22	$124.98
01	101000 2013608117	EDGEWATER TAP	359	$5,908.27	$8,502.42
01	101000 2013608123	BULOW LOOP	359	$89.70	$351.62
01	101000 2013608128	HOLLY HILL-FLEMING-ORMOND	359	$1,267.61	$1,663.10
01	101000 2013623053	SANFORD-SR 40 (E/O DELAND)	359	$15,300.16	$46,048.77
01	101000 2013623070	VOLUSIA-SR 40(E/O DELAND)	359	$722.47	$2,145.30
01	101000 2013623119	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	359	$107,747.73	$213,912.84
01	101000 2013623143	VOLUSIA - 148X2	359	$3,634.77	$7,669.36
01	101000 2013623148	SUGAR MILL-148X3	359	$66,838.40	$134,848.27
01	101000 2013623152	SUGAR MILL-PORT ORANGE	359	$1,186.22	$2,502.92
01	101000 2013623171	VOLUSIA-SMYRNA #2 115KV	359	$212,344.43	$265,430.54
01	101000 2013625109	DUVAL-POINSETT 500KV (OBO) (VOLUSIA)	359	$547,359.76	$760,587.03
01	101000 2013635088	PUTNAM-VOLUSIA #1 240KV (VOLUSIA CO.)	359	$16,431.32	$59,410.27
01	101000 2013648053	SANFORD-VOLUSIA #2	359	$74,423.52	$221,408.44
01	101000 2013660088	PUTNAM-VOLUSIA #2 240KV (VOLUSIA COUNTY)	359	$2,100.27	$2,520.32
01	101000 2020405035	WABASSO SUB-MICCO SUB (BREVARD CO.)	359	$70,534.72	$143,890.83
01	101000 2020405038	MICCO SUB-51E2A (PALM BAY)	359	$5,701.35	$7,712.37
01	101000 2020405051	MELBOURNE-MALABAR LOOP (N/O PALM BAY)	359	$13,176.94	$67,993.01
01	101000 2020405109	MALABAR-PALM BAY (SO.H-FRAME)	359	$38,881.98	$49,888.02
01	101000 2020405158	BREVARD-EAU GALLIE EXT TO SUNTREE	359	$6,340.92	$7,926.15

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01	101000 2020406012	CAPE CANAVERAL SES-INDIAN RIVER SUB	359	$229.01	$1,085.51
01	101000 2020406025	MIMS-TITUSVILLE	359	$9.29	$45.52
01	101000 2020406077	BREVARD-COCOA	359	$6,279.90	$32,026.16
01	101000 2020406082	BREVARD-CITY POINT TAP	359	$1,323.40	$6,828.74
01	101000 2020406084	BREVARD-COCOA	359	$1,462.71	$7,547.58
01	101000 2020406086	CITY POINT-SOUTH CAPE	359	$62,371.44	$192,326.60
01	101000 2020406093	CAPE CANAVERAL SES-GRISSOM TAP	359	$17,642.39	$65,555.26
01	101000 2020406099	GRISSOM TAP-ORSINO-C-5 COMPLEX	359	$6,035.17	$31,141.48
01	101000 2020406109	SOUTH CAPE-C-5 COMPLEX	359	$1,067.00	$1,280.40
01	101000 2020406134	GRISSOM LOOP	359	$75,368.37	$94,964.15
01	101000 2020406142	EDGEWATER-NORRIS 15KV (BREVARD CO.)	359	$125,427.41	$150,512.89
01	101000 2020422086	BREVARD-RANCH (BREVARD CO.)	359	$141,211.49	$623,032.72
01	101000 2020423001	BREVARD-SANFORD (BREVARD CO.)	359	$32,557.37	$72,804.38
01	101000 2020423080	BREVARD-CAPE CANAVERAL (3 CKTS)	359	$15,504.84	$60,667.12
01	101000 2020423088	CAPE CANAVERAL-INDIAN RIVER (ORLANDO U.C.)	359	$1,259.57	$6,499.38
01	101000 2020423091	CAPE CANAVERAL-VOLUSIA (BREVARD CO)	359	$53,209.74	$159,710.76
01	101000 2020430109	MALABAR-PALM BAY (NO. H-FRAME)	359	$2,425.84	$2,741.20
01	101000 2020447086	BREVARD-RANCH 2ND CKT (BREVARD CO.)	359	$5,774.75	$27,372.32
01	101000 2020448001	BREVARD-WEST LAKE WALES (FLA.POWER CORP)	359	$1,327.86	$2,424.01
01	101000 2020455109	MALABAR-PALM BAY-INDIAN RIVER CROSSING	359	$1,080.98	$1,545.80
01	101000 2022623006	BREVARD-SANFORD (ORANGE CO.)	359	$82,717.88	$202,990.77
01	101000 2022623160	BREVARD-POINSETT #1 240 KV (OBO) (ORANGE CO)	359	$69,624.37	$96,777.87
01	101000 2022623168	BREVARD-W LAKE WALES 230KV (OBO) PURCH FM FPC	359	$19,225.72	$24,995.35
01	101000 2022623270	POINSETT-SANFORD EXT TO CHULUOTA (ORANGE CO)	359	$65,039.04	$78,046.85
01	101000 2022625001	MARTIN-POINSETT 500KV (OBO) (ORANGE CO)	359	$65,189.69	$90,613.67
01	101000 2022625160	DUVAL-POINSETT 500KV (OBO) (ORANGE CO)	359	$463,962.54	$643,961.21
01	101000 2023106045	LAUREL-VOLUSIA CO. LINE	359	$9,775.83	$12,591.95
01	101000 2023106070	ST JOHNS RIVER XING AT SANFORD SES	359	$18,012.74	$23,956.94
01	101000 2023107123	SANFORD-NORTH LONGWOOD (FPC)(SEMINOLE CO)	359	$14,592.78	$25,487.58
01	101000 2023123030	BREVARD-SANFORD (SEMINOLE CO)	359	$75,189.87	$297,208.18
01	101000 2023125144	DUVAL-POINSETT 500KV (OBO) (SEMINOLE CO)	359	$392,129.05	$545,059.38
01	101000 2023125145	POINSETT-RICE 500KV (OBO) (SEMINOLE CO)	359	$7,007.87	$8,691.99
01	101000 2023606036	CELERY-MIMS (VOLUSIA CO.)	359	$3,501.82	$4,377.28
01	101000 2023607123	SANFORD-NORTH LONGWOOD (FPC)(VOLOSIA CO)	359	$319.02	$937.92
01	101000 2023623052	BREVARD-SANFORD (VOLUSIA CO.)	359	$902.00	$4,654.32
01	101000 2023623116	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	359	$6,065.96	$30,208.48
01	101000 2030209124	BALDWIN-MACCLENNY (BAKER CO.)	359	$14,764.89	$76,186.83
01	101000 2030217066	COLUMBIA-MACCLENNY (BAKER CO.)	359	$40,795.41	$184,032.82
01	101000 2030217099	WIREMILL SUB TAP LINE	359	$18,571.48	$38,939.12

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01	101000	2030309051	BALDWIN - STARKE (BRADFORD)	359	$1,691.96	$2,119.55
01	101000	2030309190	BRADFORD-DUVAL 240KV LN (BRADFORD CO)	359	$94,606.76	$218,553.50
01	101000	2030309234	NEW RIVER TAP #2	359	$68,385.56	$128,107.61
01	101000	2030309348	BRADFORD-DEERHAVEN (GRU) (FPL OWNERSHIP)	359	$441,084.45	$611,436.68
01	101000	2030310043	LAWTEY TAP	359	$157.65	$813.47
01	101000	2030709216	BRADFORD-DUVAL 240KV LN (CLAY CO.)	359	$2,948.61	$3,907.77
01	101000	2030709242	BLACK CREEK-TITANIUM 240KV	359	$319,066.62	$478,599.93
01	101000	2030709260	BLACK CREEK-DUVAL 240KV (CLAY COUNTY)	359	$120,884.21	$181,326.32
01	101000	2030725007	DUVAL-POINSETT 500KV (OBO) (CLAY CO)	359	$244,595.11	$339,670.49
01	101000	2030725008	DUVAL-RICE 500KV (OBO) (CLAY CO)	359	$205,169.97	$285,098.21
01	101000	2030917027	COLUMBIA-LAKE BUTLER (COLUMBIA CO.)	359	$4,423.06	$5,971.13
01	101000	2030917040	COLUMBIA-LIVE OAK TAP SECTION	359	$76,910.14	$88,513.76
01	101000	2030917052	LIVE OAK TAP STA-EAST OAK (COLUMBIA CO.)	359	$15,255.05	$18,306.06
01	101000	2030917084	COLUMBIA-MACCLENNY (COLUMBIA CO.)	359	$20,212.91	$96,239.43
01	101000	2031209067	BALDWIN (OLD)-BRADFORD CO. LINE	359	$3,326.11	$7,215.04
01	101000	2031209078	BALDWIN (OLD)-NORMANDY (JACKSONVILLE ELECT AU	359	$4,704.49	$20,809.00
01	101000	2031209100	CALLAHAN TAP (DUVAL CO)	359	$13,634.55	$60,399.72
01	101000	2031209120	BALDWIN-MACCLENNY (DUVAL CO)	359	$21,803.88	$87,188.43
01	101000	2031209224	BRADFORD-DUVAL 240 KV LN (DUVAL CO)	359	$1,647.00	$3,491.64
01	101000	2031209231	STEELBALD SUB TAP LINE	359	$4,567.81	$9,683.76
01	101000	2031209232	BALDWIN-DUVAL 240KV LINE	359	$27,473.45	$58,243.71
01	101000	2031209233	DUVAL-NORMANDY (JEA)	359	$2,327.02	$4,933.28
01	101000	2031209268	BLACK CREEK-DUVAL 240KV (DUVAL COUNTY)	359	$64,674.97	$97,012.46
01	101000	2031209276	DUVAL-CALLAHAN 240KV (DUVAL CO)	359	$94,782.28	$157,352.63
01	101000	2031225001	DUVAL-HATCH (GP) #1 500KV (OBO) (DUVAL CO)	359	$2,753.18	$4,001.55
01	101000	2031225002	DUVAL-POINSETT 500KV (OBO) (DUVAL CO)	359	$105,678.20	$146,691.10
01	101000	2031250001	DUVAL-HATCH (GP) #2 500KV (OBO) (DUVAL CO)	359	($215.64)	($286.80)
01	101000	2032409107	CALLAHAN TAP (NASSAU CO)	359	$18,899.57	$87,820.33
01	101000	2032409178	CALLAHAN SUB-YULEE SUB 240KV (NASSAU CO)	359	$95,188.03	$179,880.01
01	101000	2032409287	DUVAL-CALLAHAN 240KV (NASSAU CO)	359	$74,302.55	$119,091.54
01	101000	2032409314	YULEE-KINGSLAND 240KV (GPC)	359	$173,110.33	$294,143.96
01	101000	2032425008	DUVAL-HATCH (GP) #1 500KV (OBO) (NASSAU CO)	359	$5,437.23	$7,992.73
01	101000	2032450008	DUVAL-HATCH (GP) #2 500KV (OBO) (NASSAU CO)	359.	($2,309.88)	($3,021.25)
01	101000	2033417055	LIVE OAK TAP STA-EAST OAK (SUWANNEE CO.)	359	$15,654.29	$18,840.85
01	101000	2033417102	LIVE OAK-SUWANNEE PLT (FPC) 115KV	359	$128,568.38	$160,710.48
01	101000	2033517019	COLUMBIA-LAKE BUTLER (UNION CO.)	359	$4,771.16	$7,425.88
01	101000	2041621044	FT. MYERS-RANCH 138KV (HENDRY CO.)	359	$7,804.82	$38,826.10
01	101000	2041646044	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	359	$2,341.46	$12,081.93
01	101000	2041712012	CHILDS-OKEECHOBEE (HIGHLANDS CO.)	359	$35,558.94	$50,848.01

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01	101000 2041805011	FT. PIERCE-OSLO (INDIAN RIVER CO.)	359	$822.82	$1,678.55
01	101000 2041805013	OSLO-WEST SUB (VERO BEACH)	359	$4,114.09	$8,392.74
01	101000 2041805019	WEST SUB (VERO BEACH)-WABASSO SUB	359	$613.16	$1,250.85
01	101000 2041805027	WABASSO-MICCO (INDIAN RIVER CO.)	359	$220,582.14	$449,761.19
01	101000 2041822067	BREVARD-RANCH (INDIAN RIVER CO.)	359	$168,885.94	$469,239.56
01	101000 2041825043	MARTIN-POINSETT 500KV (OBO) (INDIAN RIVER CO)	359	$700,989.14	$974,103.10
01	101000 2041825044	MIDWAY-POINSETT 500KV (OBO) (INDIAN RIVER CO)	359	$2,955.25	$3,723.62
01	101000 2041847067	BREVARD-RANCH 2ND CKT (INDIAN RIVER CO.)	359	$30,372.56	$68,440.29
01	101000 2042204028	PORT SEWALL-PALM BCH.CO.LINE	359	$2,744.14	$6,959.27
01	101000 2042204118	SANDPIPER-TURNPIKE 240 KV (MARTIN CO.)	359	$105,756.38	$140,655.99
01	101000 2042204138	TURNPIKE-CRANE 230KV (MARTIN CO)	359	$67,367.23	$80,840.68
01	101000 2042204164	CRANE-BRIDGE	359	$191,481.11	$229,777.33
01	101000 2042204174	BRIDGE-ALEXANDER (MARTIN CO.)	359	$104,512.11	$125,414.53
01	101000 2042204203	HOBE-COVE 138KV RADIAL LINE	359	$258,008.24	$291,549.31
01	101000 2042204210	HOBE-HILLS 138KV RADIAL LINE	359	$173,460.40	$196,010.25
01	101000 2042215009	SHERMAN SW STA-MARTIN PLANT (MARTIN CO.)	359	$70,599.17	$113,901.41
01	101000 2042222024	BREVARD-RANCH (MARTIN CO.)	359	$60,561.38	$203,897.76
01	101000 2042222155	FLA STEEL-MARTIN PLT 240KV LINE	359	$14,080.67	$29,095.60
01	101000 2042222160	HOBE-INDIANTOWN 240KV	359	$473,368.51	$674,813.90
01	101000 2042222179	INDIANTOWN-MARTIN #1-INDIANTOWN-FLA. STEEL	359	$125,921.29	$142,291.06
01	101000 2042222186	INDIANTOWN-MARTIN #1-FLA.STEEL-MARTIN SECT	359	$65,531.50	$74,050.60
01	101000 2042225001	MARTIN-MIDWAY 500KV (MARTIN CO)	359	$606,116.74	$906,059.51
01	101000 2042225024	CORBETT-MIDWAY 500KV (MARTIN CO)	359	$743,255.67	$839,895.42
01	101000 2042225077	CORBETT-MARTIN 500KV (MARTIN CO.)	359	$393,112.27	$444,216.87
01	101000 2042225079	ANDYTOWN-MARTIN 500KV #1 (MARTIN CO.)	359	$281,236.42	$421,854.63
01	101000 2042225100	MARTIN-POINSETT 500KV (OBO) (MARTIN CO)	359	$282,396.10	$392,530.58
01	101000 2042247024	BREVARD-RANCH 2ND CKT (MARTIN CO.)	359	$3,943.19	$18,690.72
01	101000 2042247186	INDIANTOWN-MARTIN #2-WARFIELD-MARTIN SECT	359	$10,182.61	$11,506.35
01	101000 2042250079	ANDYTOWN-MARTIN 500KV #2 (MARTIN CO)	359	$263,563.95	$395,345.93
01	101000 2042511035	OKEECHOBEE-34K14	359	$69,514.78	$87,097.22
01	101000 2042511059	MIDWAY SHERMAN(OKEECHOBEE CO.)	359	$82,302.94	$134,111.82
01	101000 2042511066	OKEECHOBEE-SHERMAN #2	359	$185,971.31	$232,464.14
01	101000 2042515001	OKEECHOBEE (34K14)-SHERMAN SW STA)	359	$74,026.91	$92,533.64
01	101000 2042515002	SHERMAN SW STA-MARTIN PLANT (OKEECHOBEE CO.)	359	$76,859.38	$128,134.95
01	101000 2042803088	LINTON-YAMATO	359	$6,232.39	$32,159.13
01	101000 2042803093	IBM-YAMATO	359	$2,201.44	$11,359.43
01	101000 2042803095	IBM-BOCA RATON TAP (OLD)	359	$20,044.76	$36,505.27
01	101000 2042803100	BOCA RATON-BROWARD CO. LINE	359	$278.87	$1,464.07
01	101000 2042803113	BOYNTON-LANTANA	359	$11,892.79	$14,984.92

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01	101000	2042803116	LANTANA-RANCH	359	$5,991.84	$7,789.39
01	101000	2042803151	MILITARY TRAIL-RANCH	359	$3,516.55	$4,219.86
01	101000	2042803166	NORTON TAP	359	$1,343.31	$4,822.48
01	101000	2042803168	BROWARD-YAMATO 240KV (PALM BCH CO.)	359	$284.07	$1,465.80
01	101000	2042803195	CEDAR-DELTRAIL 240KV	359	$215,720.79	$299,851.90
01	101000	2042804069	PLUMOSUS-RIVIERA #1	359	$1,117.71	$2,272.67
01	101000	2042804088	RIVIERA-WEST PALM BEACH	359	$7,652.86	$33,583.64
01	101000	2042804144	RANCH-RIVIERA #2 EXTEND TO TERMINAL SUB	359	$30,338.74	$36,406.49
01	101000	2042804179	BRIDGE-ALEXANDER (PALM BEACH CO.)	359	$44,915.32	$53,898.38
01	101000	2042804182	ALEXANDER-PLUMOSUS	359	$903,283.21	$1,083,939.85
01	101000	2042815023	OKEECHOBEE (34K14)-PAHOKEE (PALM BEACH CO.)	359	$98,283.37	$122,648.15
01	101000	2042815056	QUAKER OATS TAP (DOUBLE CKT)	359	$4.98	$24.40
01	101000	2042819030	LAUDERDALE-RANCH (PALM BEACH CO.)	359	$6,700.01	$17,224.42
01	101000	2042819056	RANCH-RIVIERA (3 CKTS)	359	$15,844.01	$79,700.30
01	101000	2042819100	RANCH-BROWARD #2 240KV (PALM BEACH CO.)	359	$152,413.62	$489,952.69
01	101000	2042819183	RANCH-RIVIERA #3 RECWAY TAP	359	$6,882.21	$8,602.76
01	101000	2042821062	FT.MYERS-RANCH 138KV (PALM BEACH CO.)	359	$12,274.55	$54,699.02
01	101000	2042821109	BROWARD-RANCH #2 CORBETT EXTENSION	359	$346,001.28	$428,986.43
01	101000	2042821121	ORANGE RIVER-RANCH CORBETT EXTENSION	359	$37,548.86	$46,936.08
01	101000	2042822001	BREVARD-RANCH (PALM BEACH CO.)	359	$65,456.27	$186,569.94
01	101000	2042825001	CORBETT-MIDWAY 500KV (PALM BCH.CO)	359	$175,686.43	$219,608.04
01	101000	2042825002	CORBETT-MARTIN 500KV (PALM BCH CO.)	359	$2,080,824.32	$2,351,331.48
01	101000	2042825016	CONSERVATION-CORBETT 500KV (PALM BEACH CO.)	359	$9,125,470.99	$9,672,999.25
01	101000	2042825023	ANDYTOWN-MARTIN 500KV #1 (PALM BCH CO.)	359	$1,997,915.77	$2,996,873.66
01	101000	2042825036	ANDYTOWN-ORANGE RIVER 500KV LN (PALM BCH CO)	359	$460,921.32	$1,085,556.17
01	101000	2042844030	CEDAR-LAUDERDALE (PALM BEACH CO.)	359	$5,750.36	$19,593.70
01	101000	2042844046	CEDAR-RANCH (PALM BEACH CO.)	359	$209,153.98	$299,090.19
01	101000	2042846062	ORANGE RIVER-RANCH 240KV (PALM BEACH CO.)	359	$213.63	$1,102.33
01	101000	2042846109	CORBETT-RANCH #1 & CORBETT-CEDAR 240KV	359	$1,073.01	$1,287.61
01	101000	2042847001	BREVARD-RANCH 2ND CKT (PALM BEACH CO.)	359	$1,416.41	$6,835.04
01	101000	2042850023	ANDYTOWN-MARTIN 500KV #2 (PALM BCH CO)	359	$1,867,074.62	$2,800,611.93
01	101000	2042853131	RANCH-WPB #1 138KV RANCH-JOG SECTION	359	$135,477.75	$162,573.30
01	101000	2043304098	MIDWAY-WHITE CITY	359	$3,186.48	$3,935.27
01	101000	2043304108	ST LUCIE PLANT-MIDWAY #1 240KV	359	$154,931.54	$365,638.43
01	101000	2043304119	SANDPIPER-TURNPIKE 240KV (ST. LUCIE CO.)	359	$105,851.10	$140,781.96
01	101000	2043304125	MIDWAY-TURNPIKE 240KV (ST. LUCIE CO.)	359	$105,756.38	$140,655.99
01	101000	2043304134	TURNPIKE-CRANE 230KV (ST LUCIE CO)	359	$263,717.26	$316,460.71
01	101000	2043305001	FT PIERCE-OSLO (ST LUCIE CO.)	359	$43,490.04	$88,719.68
01	101000	2043311001	FT. PIERCE-MIDWAY	359	$4,083.02	$8,615.17

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01	101000	2043311039	MIDWAY-SHERMAN (ST. LUCIE CO.)	359	$245,228.33	$410,318.15
01	101000	2043322042	BREVARD-RANCH (ST LUCIE C.)	359	$175,117.60	$442,330.03
01	101000	2043322176	EMERSON-MIDWAY TAP STR 64W5	359	$70,233.16	$97,624.09
01	101000	2043325013	MARTIN-MIDWAY 500KV (ST.LUCIE CO)	359	$1,082,937.10	$1,297,632.63
01	101000	2043325022	CORBETT-MIDWAY 500KV (ST. LUCIE CO.)	359	$577,720.45	$652,824.11
01	101000	2043325071	MARTIN-POINSETT 500KV (OBO) (ST. LUCIE CO)	359	$695,691.28	$965,118.11
01	101000	2043325072	MIDWAY-POINSETT 500KV (OBO) (ST.LUCIE CO)	359	$868,011.77	$1,171,815.89
01	101000	2043329108	ST LUCIE PLANT-MIDWAY #2	359	$152,014.04	$358,753.13
01	101000	2043347042	BREVARD-RANCH 2ND CKT (ST LUCIE CO.)	359	$5,580.20	$26,450.15
01	101000	2050612265	MYAKKA-ROTUNDA 138KV (CHARLOTTE CO.)	359	$343,097.37	$453,640.20
01	101000	2050613017	CHARLOTTE-NOCATEE (CHARLOTTE CO.)	359	$1,210.76	$2,527.76
01	101000	2050613022	CHARLOTTE-PUNTA GORDA (NO. CKT)	359	$27,104.00	$34,119.36
01	101000	2050613030	LEE-PUNTA GORDA (E. CKT-CHARLOTTE CO.)	359	$2,396.20	$12,364.39
01	101000	2050613057	LEE-PUNTA GORDA (W.CKT-CHARLOTTE CO.)	359	$173.48	$895.16
01	101000	2050613235	DORRFIELD TAP-CHARLOTTE (CHARLOTTE CO.)	359	$13,818.40	$26,037.86
01	101000	2050614001	PUNTA GORDA-MURDOCK-SARASOTA CO. LINE	359	$207.63	$1,071.37
01	101000	2050624054	CHARLOTTE-RINGLING 138KV (CHARLOTTE CO.)	359	$41,018.83	$190,619.84
01	101000	2050624063	CHARLOTTE-CALUSA-FT. MYERS (CHARLOTTE CO.)	359	$14,930.69	$39,078.60
01	101000	2050624151	CHARLOTTE-LAURELWOOD 240KV (CHARLOTTE C.)	359	$35,127.65	$102,695.58
01	101000	2050624160	FT. MYERS-CHARLOTTE (CHARLOTTE CO.)	359	$10,699.35	$12,397.96
01	101000	2050649054	FT. MYERS-RINGLING #1 240KV (CHARLOTTE CO.)	359	$5,941.00	$20,180.34
01	101000	2050813083	NAPLES-SOLANA-LEE CO. LINE	359	$13,881.55	$21,123.33
01	101000	2050813137	FT. MYERS-COLLIER (COLLIER CO.)	359	$64,892.03	$175,799.43
01	101000	2050813145	COLLIE-NAPLES	359	$35,734.87	$155,505.12
01	101000	2050813153	ALLIGATOR-COLLIER	359	$52,502.25	$179,750.27
01	101000	2050813156	ALLIGATOR-BELLE MEADE	359	$115,485.25	$434,995.01
01	101000	2050813258	ALICO-COLLIER (COLLIER CO.)	359	$54,313.96	$115,145.60
01	101000	2050813280	CAPRI-GOLDEN GATE-COLLIER 138KV	359	$1,393,772.40	$2,048,438.09
01	101000	2050813299	ALICO-NAPLES/ALICO-COLLIER TIE LINE	359	$115,287.29	$138,344.75
01	101000	2050825068	ANDYTOWN-ORANGE RIVER 500KV LN (COLLIER CO)	359	$201,194.13	$407,309.10
01	101000	2051112066	WHIDDEN TAP 69KV	359	$662.08	$701.80
01	101000	2051113001	ARCADIA-NOCATEE 69KV	359	$61,620.02	$100,807.93
01	101000	2051113009	CHARLOTTE-NOCATEE (DE SOTO CO.)	359	$45,671.91	$117,360.31
01	101000	2051113218	DORRFIELD TAP-CHARLOTTE (DE SOTO CO.)	359	$297,706.17	$533,766.64
01	101000	2051114231	KEENTOWN-WHIDDEN 240KV (DE SOTO CO.)	359	$877,936.21	$1,289,419.88
01	101000	2051124052	CHARLOTTE-RINGLING 138KV (DE SOTO CO.)	359	$913.81	$4,699.96
01	101000	2051149052	FT. MYERS-RINGLING #1 240KV (DE SOTO CO.)	359	$116.80	$602.69
01	101000	2051621015	FT. MYERS-RANCH 138KV (HENDRY CO.)	359	$208,114.89	$308,247.40
01	101000	2051625043	ANDYTOWN-ORANGE RIVER 500KV LN (HENDRY CO)	359	$343,574.83	$632,460.09

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01	101000	2051646015	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	359	$6,504.55	$10,091.61
01	101000	2051913046	FT MYERS TAP CROSSOVER-LEE	359	$2,042.40	$10,538.78
01	101000	2051913050	FT MYERS TAP	359	$1,633.34	$5,781.60
01	101000	2051913052	FT MYERS-BUCKINGHAM AIR FIELD	359	$1.34	$6.91
01	101000	2051913068	CALOOSAHATCHEE RIVER XING #2 LINE	359	$3,826.96	$11,251.26
01	101000	2051913075	ALICO-COLONIAL TAP	359	$1,318.70	$2,387.10
01	101000	2051913078	ALICO-BONITA SPRINGS-COLLIER LINE VIA ESTERO	359	$68,780.35	$94,376.21
01	101000	2051913091	FT.MYERS SES-FT MYERS (SINGLE POLE SECT)	359	$109.90	$567.08
01	101000	2051913092	FT.MYERS SES-FT MYERS (DOUBLE CKT SECT)	359	$8,034.28	$23,128.28
01	101000	2051913096	BUCKINGHAM 69KV TAP	359	$507.11	$2,616.69
01	101000	2051913098	IONA TAP	359	$22,084.91	$97,666.72
01	101000	2051913105	FT MYERS SES-BUCKINGHAM	359	$1,033.95	$1,156.49
01	101000	2051913110	COLONIAL TAP	359	$6,031.92	$14,235.33
01	101000	2051913113	FT MYERS-COLLIER (LEE CO.)	359	$24,497.28	$44,305.58
01	101000	2051913164	COLONIAL-IONA	359	$13,161.44	$62,385.23
01	101000	2051913178	BUCKINGHAM-COLONIAL TAP	359	$18,334.86	$61,153.94
01	101000	2051913183	FT MYERS SUB-NAPLES TAP (OLD)	359	$307.71	$1,587.78
01	101000	2051913208	ALICO-SR 45	359	$317.09	$748.33
01	101000	2051913241	ALICO-245M7	359	$53,494.94	$113,409.27
01	101000	2051913245	COLLIER-ORANGE RIVER (LEE CO.)	359	$1,332,558.02	$1,965,158.82
01	101000	2051921001	FT. MYERS-RANCH 138KV (LEE CO.)	359	$9,182.01	$36,810.58
01	101000	2051924080	CHARLOTTE-CALUSA-FT. MYERS (LEE CO.)	359	$9,272.04	$41,168.52
01	101000	2051924176	FT MYERS-CHARLOTTE 240KV (LEE CO.)	359	$6,160.41	$8,038.33
01	101000	2051925087	ANDYTOWN-ORANGE RIVER 500KV LN (LEE CO)	359	$165,597.46	$367,454.41
01	101000	2051938212	FT MYERS PLT-ORANGE RIVER #2 240KV	359	$8,561.03	$17,464.50
01	101000	2051938241	ALICO-COLLIER 138KV	359	$144,938.31	$182,546.59
01	101000	2051946001	ORANGE RIVER-RANCH 240KV (LEE CO.)	359	$63,135.59	$80,341.53
01	101000	2051949080	FT MYERS-RINGLING #1 240KV (LEE CO.)	359	$1,456.03	$7,513.11
01	101000	2052014056	CORTEZ TAP-WHITFIELD-SARASOTA CO. LINE	359	$59,462.86	$95,308.98
01	101000	2052014071	BRADENTON-CASTLE	359	$312.59	$343.85
01	101000	2052014076	CASTLE-RUBONIA	359	$80,077.46	$160,216.66
01	101000	2052014078	RUBONIA-TAMPA ELECTRIC(BIG BEND)	359	$402,917.10	$571,816.78
01	101000	2052014083	CORTEZ TAP	359	$230.00	$1,173.35
01	101000	2052014088	CASTLE-RINGLING (W CKT, MANATEE CO.)	359	$19,560.13	$61,640.61
01	101000	2052014111	CORTEZ-PALMA SOLA-BRADENTON	359	$1,243.81	$6,298.69
01	101000	2052014121	BORDEN TAP #1 (NORTH)	359	$5,109.68	$18,515.56
01	101000	2052014125	FRUIT INDUSTRIES TAP	359	$632.31	$3,177.45
01	101000	2052014135	RINGLING-MANATEE #1 240KV (MANATEE CO.)	359	$316,134.73	$586,951.21
01	101000	2052014150	MANATEE-TAMPA #1 240KV (MANATEE CO.)	359	$112,405.60	$179,395.86

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01	101000 2052014171	CORTEZ-JOHNSON 138KV	359	$93,588.58	$140,382.87
01	101000 2052014187	KEENTOWN-MANATEE 240KV	359	$652,158.97	$958,406.11
01	101000 2052014229	BEKER-KEENTOWN TAP 69KV	359	$177.70	$261.22
01	101000 2052014253	KEENTOWN-WHIDDEN 240KV (MANATEE CO.)	359	$569,339.09	$836,725.27
01	101000 2052014270	MANATEE-BIG BEND #2 240KV (TECO)	359	$223,228.86	$325,723.08
01	101000 2052024001	CASTLE-RINGLING (MANATEE CO.)	359	$13,666.16	$60,445.87
01	101000 2052024033	CHARLOTTE-RINGLING 138KV (MANATEE CO.)	359	$3,594.95	$17,160.67
01	101000 2052039121	BORDEN TAP #2 (SOUTH)	359	$18,553.58	$37,259.86
01	101000 2052039135	RINGLING-MANATEE #2 240KV (MANATEE CO.)	359	$206,912.39	$398,776.69
01	101000 2052049033	FT MYERS-RINGLING #1 240KV (MANATEE CO.)	359	$1,073.37	$2,737.12
01	101000 2052064135	RINGLING-MANATEE #3 240KV (MANATEE CO.)	359	$17,996.21	$33,133.95
01	101000 2053012263	MYAKKA-ROTUNDA 138KV (SARASOTA CO.)	359	$193,708.34	$261,506.26
01	101000 2053014012	VENICE-ENGLEWOOD-CHARLOTTE CO.LINE	359	$19,213.53	$33,342.29
01	101000 2053014034	CLARK-VENICE	359	$1,599.43	$4,196.09
01	101000 2053014047	CLARK-HYDE PARK-RINGLING	359	$2,656.92	$13,709.71
01	101000 2053014053	MANATEE CO. LINE-53N11 (E/O SARASOTA)	359	$40,078.00	$73,536.63
01	101000 2053014068	SARASOTA & PAYNE LOOPS	359	$5,879.41	$30,337.76
01	101000 2053014096	CASTLE-RINGLING (W CKT. SARASOTA CO.)	359	$7,225.39	$32,272.76
01	101000 2053014102	RINGLING-TUTTLE AVE. (DOUBLE CKT)	359	$1,683.58	$8,687.27
01	101000 2053014131	RINGLING-MANATEE #1 240KV (SARASOTA CO.)	359	$11,328.17	$28,841.20
01	101000 2053014166	LAURELWOOD TAP 138KV	359	$121,211.52	$225,243.25
01	101000 2053014180	PHILLIPPI LOOP EXTENSION (NORTH)	359	$43,809.07	$62,646.97
01	101000 2053014206	LAURELWOOD-MYAKKA 240KV	359	$745,162.34	$1,065,751.20
01	101000 2053024009	CASTLE-RINGLING (SARASOTA CO.)	359	$4,947.78	$23,066.84
01	101000 2053024013	CHARLOTTE-RINGLING 138KV (SARASOTA CO.)	359	$340,880.91	$550,061.47
01	101000 2053024087	RINGLING-VENICE #2	359	$150,623.25	$258,271.76
01	101000 2053024107	LAURELWOOD-RINGLING #1	359	$169,372.51	$383,437.88
01	101000 2053024128	CHARLOTTE-LAURELWOOD (SARASOTA CO.)	359	$243,856.27	$536,244.15
01	101000 2053024182	LAURELWOOD-RINGLILNG #2 240KV	359	$433,979.59	$637,950.00
01	101000 2053039131	RINGLING-MANATEE #2 240KV (SARASOTA CO.)	359	$19,330.41	$40,980.47
01	101000 2053049013	FT MYERS-RINGLING #1 240KV (SARASOTA CO.)	359	$14,699.52	$28,507.42
01	101000 2053064131	RINGLING-MANATEE #3 240KV (SARASOTA CO.)	359	$2,709.16	$5,093.22
01	101000 2070502033	LAUDERDALE-32B8 (TO FULFORD)	359	$1,399.45	$6,857.31
01	101000 2070502034	LAUDERDALE-HOLLYWOOD	359	$148,977.90	$149,196.67
01	101000 2070502043	GRANT STREET TIE LINE	359	$8.41	$43.40
01	101000 2070502044	HALLANDALE-HOLLYWOOD	359	$206.92	$1,067.71
01	101000 2070502058	LAUDERDALE-HOLLYWOOD (STIRLING RD SECT)	359	$44.17	$227.92
01	101000 2070502059	HOLLYWOOD-STIRLING	359	$1,074.00	$5,289.95
01	101000 2070502066	PORT SUB-RAVENSWOOD (OLD DANIA TAP)	359	$97,514.48	$183,327.22

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01	101000 2070502079	STIRLING RD (W/O STIRLING)-PEMBROKE-DADE CO L	359	$3,767.74	$18,461.93
01	101000 2070502092	MELALEUCA-TRACE 24OKV LINE	359	$65,702.76	$88,698.73
01	101000 2070502096	ANDYTOWN-TRACE 240KV	359	$521,268.18	$651,585.23
01	101000 2070503001	LAUDERDALE-PINEHURST-POMPANO-PALM BCH CO.	359	$122,430.86	$153,167.97
01	101000 2070503024	BROWARD-YAMATO (BROWARD CO.)	359	$621.01	$3,204.41
01	101000 2070503097	SAMPLE-DEERFIELD-PALM BCH CO.LINE	359	$6,775.06	$15,142.64
01	101000 2070503135	BROWARD-LYONS-HOLY CROSS-OAKLAND PARK	359	$668.44	$3,449.15
01	101000 2070503170	LAUDERDALE-PORT EVERGLADES #1-4 240KV LINES	359	$157,777.76	$814,133.24
01	101000 2070503187	BROWARD-YAMATO #| 240KV	359	$30,450.13	$62,118.27
01	101000 2070518062	LAUDERDALE-DAVIE	359	$75,359.33	$161,401.18
01	101000 2070518067	DAVIE-JACARANDA-MOTOROLA	359	$24,030.46	$54,740.30
01	101000 2070518072	MOTOROLA-SPRINGTREE-77S3	359	$18,837.56	$25,053.95
01	101000 2070518078	HIATUS-SPRING TREE TAP 230KV LINE BRD CO	359	$1,254.92	$1,669.04
01	101000 2070518081	HIATUS-MELALEUCA	359	$263,407.94	$329,259.93
01	101000 2070519009	LAUDERDALE-RANCH (BROWARD CO.)	359	$13,586.32	$61,060.80
01	101000 2070519073	BROWARD LOOP	359	$16,391.55	$66,820.30
01	101000 2070519083	BROWARD-FT.LAUDERDALE	359	$1,315.09	$3,945.27
01	101000 2070519118	RANCH-BROWARD #2 240KV (BROWARD CO.)	359	$48,075.67	$124,928.36
01	101000 2070519130	BROWARD-LAUDERDALE #2 240KV	359	$276,733.52	$648,397.58
01	101000 2070519154	ANDYTOWN-LAUDERDALE #2 & #3 240KV	359	$59,807.59	$199,821.87
01	101000 2070519171	ANDYTOWN-LAUDERDALE #1 240KV	359	$430,227.95	$902,112.55
01	101000 2070520051	DADE-GRATIGNY-LAUDERDALE (BROWARD CO.)	359	$4,362.86	$18,233.86
01	101000 2070520084	DADE-PORT EVERGLADES (BROWARD CO.)	359	$6,682.60	$13,632.50
01	101000 2070520103	DADE-LAUDERDALE #3 & #4 (BROWARD CO.)	359	$12,134.50	$19,185.76
01	101000 2070520161	DADE-LAUDERDALE (ANDYTOWN EXTENSION)	359	$14,320.13	$19,332.18
01	101000 2070520166	FLAGAMI LAUDERDALE (ANDYTOWN EXTENSION)	359	$814,754.01	$1,098,983.56
01	101000 2070520219	ANDYTOWN-BASSCREEK-ANDYTOWN 230KV	359	$227,886.15	$273,463.38
01	101000 2070525001	ANDYTOWN-ORANGE RIVER 500KV LN (BROWARD CO)	359	$1,570,155.50	$3,703,348.84
01	101000 2070525002	ANDYTOWN-MARTIN 500KV #1 (BROWARD CO.)	359	$744,150.64	$1,116,225.96
01	101000 2070525012	ANDYTOWN-LEVEE 500KV (BROWARD CO)	359	$651,478.28	$1,107,513.08
01	101000 2070525016	CONSERVATION-CORBETT 500KV (BROWARD CO.)	359	$10,054,615.34	$10,657,892.26
01	101000 2070544009	CEDAR-LAUDERDALE (BROWARD CO.)	359	$3,836.02	$6,750.16
01	101000 2070550001	ANDYTOWN-MARTIN 500KV #2 (BROWARD CO)	359	$693,816.74	$1,040,725.11
01	101000 2081000011	T" AVOCADO-FLA CITY 138KV "	359	$210,570.59	$214,782.00
01	101000 2081001036	HIALEAH-RIVER (OLD)	359	$1.03	$5.31
01	101000 2081001042	DADE-WESTSIDE (OLD)	359	$1,889.87	$8,542.21
01	101000 2081001058	AIRPORT-RIVERSIDE (FRONTON-LEJEUNE SECTION)	359	$182.21	$940.20
01	101000 2081001066	62ND AVE-66A1 (W/O RIVERSIDE)	359	$7,511.70	$9,389.63
01	101000 2081001111	FLAGAMI-TROPICAL	359	$46.16	$238.19

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01	101000	2081001115	FLORIDA CITY-KEYS ELEC CO-OP	359	$32,979.79	$39,761.73
01	101000	2081001120	KROME-120A18 (W/O VILLAGE GREEN)	359	$1,969.44	$2,363.33
01	101000	2081001125	FLORIDA CITY-109A9 (W/O HOMESTEAD)	359	$3,722.54	$5,472.13
01	101000	2081001146	HAINLIN-146A4 (S/O DAVIS)	359	$620.10	$911.55
01	101000	2081001183	TROPICAL-49A20 (E/O FIU CAMPUS)	359	$1,051.30	$1,187.97
01	101000	2081001209	DAVIS-146A4 (S/O DAVIS)	359	$3,288.19	$3,945.83
01	101000	2081001239	GARDEN-LAUDERDALE (DADE CO.)	359	$5.07	$24.03
01	101000	2081001252	CORAL REEF DR @ SW 89 AV-WHISPERING PINES	359	$2,543.08	$3,178.85
01	101000	2081001255	WHISPERING PINES-PRINCETON	359	$1,614.07	$2,308.12
01	101000	2081001264	FLA CITY-KEYS COOP 138KV LINE	359	$308,647.42	$566,091.89
01	101000	2081001278	FLORIDA CITY-TURKEY POINT 240KV LINE	359	$495,245.57	$686,920.29
01	101000	2081002051	DUMBFOUNDLING-BROWARD CO. LINE	359	$602.55	$885.75
01	101000	2081002084	GREYNOLDS-IVES-BROWARD CO. LINE	359	$4,628.95	$22,681.86
01	101000	2081020001	CUTLER-DAVIS LOOPS	359	$3,950.10	$12,796.87
01	101000	2081020005	FLAGAMI-DAVIS LOOPS	359	$18,159.01	$30,830.15
01	101000	2081020015	DADE-FLAGAMI (H FRAME SECT)	359	$238.01	$1,228.09
01	101000	2081020041	DADE-GRATIGNY-LAUDERDALE (DADE CO.)	359	$2,198.98	$11,346.74
01	101000	2081020067	DADE-PORT EVERGLADES (DADE CO.)	359	$25,115.26	$36,919.43
01	101000	2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	359	$61,871.32	$223,430.23
01	101000	2081020116	DAVIS-TURKEY POINT (7 CIRCUITS)	359	$424,068.91	$1,818,114.68
01	101000	2081020133	DAVIS LOOP (FROM CUTLER & FLAGAMI)	359	$92,364.35	$387,528.95
01	101000	2081020137	MAULE LOOP	359	$68,854.31	$275,222.80
01	101000	2081020140	DADE-LEVEE #1 & 2	359	$309,640.79	$909,141.78
01	101000	2081020144	DAVIS-144U1	359	$18,687.38	$22,184.75
01	101000	2081020156	CUTLER-DAVIS #1 & 2	359	$3,709.65	$4,514.12
01	101000	2081020158	FLAGAMI-LEVEE 240KV (LEVEE EXTENSION)	359	$2,883.06	$4,901.20
01	101000	2081020194	DAVIS-LEVEE #3 (DAVIS-NEWTON SECT) 230KV	359	$895,432.09	$1,074,518.51
01	101000	2081020209	DAVIS-LEVEE #3 (LEVEE-NEWTON SECT) 230KV	359	$596,929.20	$716,315.04
01	101000	2081025001	ANDYTOWN-LEVEE 500KV (DADE CO)	359	$1,316,459.31	$2,237,464.45
01	101000	2991514250	KEENTOWN-WHIDDEN 240KV (HARDEE CO)	359	$145,867.23	$214,424.83
01	101000	2992725003	MARTIN-POINSETT 500KV (OBO) (OSCEOLA CO)	359	$916,722.98	$1,273,276.66
01	101000	2999999911	TRANSMISSION-HOLDING LOCN 11	359	($14,670.52)	($74,102.55)
				359 Total	$71,582,397.59	$105,992,008.93

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Gen. Ldgr.	Cpr. Location	Description	Plant Acc.	Original Cost	Replacement Cost
105000	1050612690	COAST	352	$433,152.29	$459,141.43
105000	1081001500	ARCH CREEK	352	$8,349.28	$10,019.14
105000	1081044850	LEVEE SUBSTATION	352	$694,639.26	$891,152.71
			352 Total	$1,136,140.83	$1,360,313.28
105000	1023664140	OSTEEN	353	$32,015.89	$37,138.43
105000	1050612690	COAST	353	$25,623.39	$27,160.79
105000	1081044850	LEVEE SUBSTATION	353	$94,390.42	$126,264.37
			353 Total	$152,029.70	$190,563.59
105000	2081000923	COCONUT GROVE-OLYMPIA HTS 230KV CABLE	357	$1,046,430.41	$1,140,609.15
			357 Total	*$1,046,430.41*	*$1,140,609.15*

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	Gen. Ldgr.	Cpr. Loc.	Description	Plant Acct.	Original Cost	Replacement Cost
01	106100	1012973600	PUTNAM PLANT 230KV SWITCHYARD	352	$3,215.16	$3,311.61
01	106100	1013283850	ST. JOHN'S SWITCHING STATION	352	$2,251.87	$2,251.87
01	106100	1013619750	DELAND	352	$1,998.03	$1,998.03
01	106100	1020410250	C-5 COMPLEX	352	$68,095.86	$68,095.86
01	106100	1020489600	DELTA	352	$260,527.43	$260,527.43
01	106100	1023678500	SANFORD PLANT SWITCH YARD	352	$3,884.32	$3,962.01
01	106100	1031221080	DUVAL	352	$383,434.35	$383,434.35
01	106100	1042208230	BRIDGE	352	$4,775.14	$4,775.14
01	106100	1042235140	HOBE SUBSTATION	352	$4,247.42	$4,247.42
01	106100	1042249290	MARTIN PLANT SWITCHYARD	352	$443.41	$452.28
01	106100	1042249310	MARTIN (OBO)-ADD BAY #4-RELOC TRAPS BAYS #1&3	352	$21,094.94	$21,095.14
01	106100	1042277890	SANDPIPER	352	$5,706.90	$5,706.90
01	106100	1042561000	OKEECHOBEE	352	$7,671.42	$7,824.85
01	106100	1042810990	CEDAR	352	$4,854.27	$4,854.27
01	106100	1042814550	CORBETT SWITCHING STATION	352	$8,264.40	$8,264.40
01	106100	1042863640	OSCEOLA (OKEELANTA COOP)	352	($28.71)	($31.58)
01	106100	1042863660	OKEELANTA (OKEELANTA COOP)	352	$4,779.85	$4,779.85
01	106100	1042874650	RECWAY	352	$104.31	$130.39
01	106100	1042882250	SOUTH BAY	352	$7,895.41	$7,895.41
01	106100	1043337050	ST LUCIE PLANT SWITCHYARD	352	$942.31	$3,010.91
01	106100	1043389060	TURNPIKE #2 (SITE)	352	$2,651.90	$2,651.90
01	106100	1050813600	COLLIER	352	$17,620.35	$17,620.35
01	106100	1051909880	CALUSA	352	$67,433.95	$67,433.95
01	106100	1051962450	ORANGE RIVER	352	$5,134.11	$5,134.11
01	106100	1052039800	JOHNSON	352	$21,571.12	$21,571.12
01	106100	1053036870	HOWARD	352	$22,092.76	$22,092.76
01	106100	1053043770	LAURELWOOD	352	$9,543.34	$9,547.10
01	106100	1070508500	BROWARD	352	$13,057.63	$13,057.63
01	106100	1070526000	SISTRUNK SUB (FORMERLY FT. LAUDERDALE SUB)	352	$8,465.36	$8,465.36
01	106100	1070543500	LAUDERDALE PLANT SWITCH YARD	352	$12,717.65	$12,717.65
01	106100	1081016250	CUTLER PLANT SWITCH YARD	352	$4,164.49	$4,414.36
01	106100	1081020660	DORAL (RESOURCE RECOVERY - DADE COUNTY)	352	$2,421.76	$2,421.76
01	106100	1081024500	FLAGAMI	352	$4,139.24	$4,222.02
01	106100	1081027750	40TH STREET - MIAMI BEACH	352	$4,560.92	$4,697.75
01	106100	1081053250	MIAMI SUB (FORMERLY MIAMI PLANT SWITCH YARD)	352	$210.39	$223.01
01	106100	1081054250	MIAMI SHORES	352	$4,691.27	$4,691.27
01	106100	1081067080	PENNSUCO	352	$351,988.34	$351,988.34
01	106100	1081074000	RAILWAY	352	$85,094.61	$87,551.96

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01	106100	1081076650	RONEY	352	$1,450.58	$1,450.58
01	106100	1980000000	SUSPENSE-SUBSTATIONS	352	($125,628.64)	($125,693.77)
				352 Total	$1,307,539.22	$1,312,845.75
01	106100	1011309000	BUNNELL	353	$48,788.48	$48,788.48
01	106100	1012965000	PUTNAM PLANT 115KV SWITCH YARD	353	$56.78	$56.78
01	106100	1012973600	PUTNAM PLANT 230KV SWITCHYARD	353	$124,642.02	$124,642.02
01	106100	1012974960	RICE (NON-OBO)	353	$30,210.90	$30,338.34
01	106100	1013255400	MILLCREEK	353	$338,168.77	$338,168.77
01	106100	1013283850	ST. JOHN'S SWITCHING STATION	353	$4,017.51	$4,017.51
01	106100	1013287520	TOCOI	353	$298.51	$310.45
01	106100	1013618500	DAYTONA BEACH	353	$16,195.32	$16,195.32
01	106100	1013619750	DELAND	353	$30,117.78	$30,117.78
01	106100	1013663000	ORMOND	353	$14,596.84	$14,596.84
01	106100	1020402880	BARNA TRANSMISSION SUBSTATION	353	$1,640.03	$1,640.03
01	106100	1020407750	BREVARD	353	$73,129.95	$73,129.95
01	106100	1020410250	C-5 COMPLEX	353	$120,326.29	$120,326.29
01	106100	1020410750	CAPE CANAVERAL PLANT SWITCH YARD	353	$70,676.72	$70,676.72
01	106100	1020421750	EAU GALLIE	353	$7,654.10	$7,654.10
01	106100	1020463250	ORSINO	353	$3,635.48	$3,635.48
01	106100	1020482500	SOUTH CAPE	353	$61,772.40	$61,772.40
01	106100	1020482650	CAPE CANAVERAL - USAF ROCC	353	$55,264.95	$55,264.95
01	106100	1020489600	DELTA	353	$795,116.23	$795,116.23
01	106100	1022669590	POINSETT (NON-OBO)	353	$19,632.37	$19,632.37
01	106100	1023620320	DELTONA	353	$4,828.80	$4,828.80
01	106100	1023678500	SANFORD PLANT SWITCH YARD	353	$884,755.51	$892,289.75
01	106100	1030090000	RESERVE - NORTHERN DIVISION-LAKE CITY AREA	353	$320,021.71	$320,021.71
01	106100	1031202500	BALDWIN SWITCHING STATION	353	$14,374.84	$14,401.30
01	106100	1031221080	DUVAL	353	$1,907,563.39	$1,907,674.68
01	106100	1031221160	EASTPORT (JEA)	353	$84.39	$92.83
01	106100	1040090000	RESERVE - EASTERN DIVISION	353	$406,939.21	$406,939.21
01	106100	1041634100	HENDRY (CITY OF CLEWISTON)	353	$1,291.52	$1,291.52
01	106100	1042238600	INDIANTOWN SUBSTATION	353	($282,383.31)	($313,176.35)
01	106100	1042249290	MARTIN PLANT SWITCHYARD	353	$168,703.22	$168,973.71
01	106100	1042249310	MARTIN (OBO)-ADD BAY #4-RELOC TRAPS BAYS #1&3	353	$63,169.74	$63,173.79
01	106100	1042293500	PORTABLE TRAILER SUBSTATION EQUIPMENT	353	$24,382.33	$24,626.15
01	106100	1042808640	BRYANT (USSC)	353	$734.76	$742.11
01	106100	1042837320	HYPOLUXO ROAD (LAKE WORTH UTILITY)	353	$1,313.60	$1,326.74
01	106100	1042863640	OSCEOLA (OKEELANTA COOP)	353	$28.71	$30.43
01	106100	1042872000	PRATT & WHITNEY	353	$1,343.35	$1,397.08

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01	106100	1042874650	RECWAY	353	$6,330.10	$8,735.54
01	106100	1042882250	SOUTH BAY	353	$812,638.45	$812,638.45
01	106100	1042893250	WEST PALM BEACH	353	$20,180.63	$20,180.63
01	106100	1043323150	EMERSON	353	$166.78	$173.45
01	106100	1043337050	ST LUCIE PLANT SWITCHYARD	353	$53,210.13	$53,217.43
01	106100	1043354970	MIDWAY SUBSTATION (FORMERLY ST. LUCIE SUB)	353	$128,777.40	$128,777.40
01	106100	1050611250	CHARLOTTE	353	$4,890.95	$4,890.95
01	106100	1050813600	COLLIER	353	$1,238,940.94	$1,238,940.94
01	106100	1051711400	CHILDS (GLADES CO-OP)	353	$10,060.55	$10,060.55
01	106100	1051900280	ALICO SWITCHING STATION	353	$9,560.43	$9,600.82
01	106100	1051908700	BUCKINGHAM SW STA	353	$51,848.30	$52,366.78
01	106100	1051909880	CALUSA	353	$1,336,938.60	$1,336,940.58
01	106100	1051926500	FORT MYERS PLANT SWITCH YARD	353	$166,729.58	$166,908.61
01	106100	1051927000	FT MYERS SUBSTATION	353	$80,578.27	$80,578.27
01	106100	1051962450	ORANGE RIVER	353	$1,517,042.38	$1,517,042.38
01	106100	1052014750	CORTEZ	353	$3,334.97	$3,334.97
01	106100	1052028500	FRUIT INDUSTRIES	353	$2,547.12	$2,572.59
01	106100	1052047800	MANATEE PLANT SWITCH YARD	353	$39,259.76	$41,857.31
01	106100	1053036870	HOWARD	353	$7,202.95	$7,202.95
01	106100	1053043770	LAURELWOOD	353	$7,609.68	$7,923.73
01	106100	1053057350	MYAKKA SWITCHING STATION	353	$6,992.18	$7,062.10
01	106100	1053075000	RINGLING	353	$23,538.61	$24,308.65
01	106100	1053091000	VENICE	353	$4,591.97	$4,649.05
01	106100	1070500500	ANDYTOWN TRANSMISSION SUB	353	$201,413.62	$201,413.62
01	106100	1070508500	BROWARD	353	$12,110.62	$12,278.84
01	106100	1070543500	LAUDERDALE PLANT SWITCH YARD	353	$597,054.40	$597,054.40
01	106100	1070570750	PORT EVERGLADES PLANT SWITCH YARD	353	$103,999.77	$103,999.77
01	106100	1081013500	COCONUT GROVE	353	$3,528.63	$3,528.63
01	106100	1081016250	CUTLER PLANT SWITCH YARD	353	$35,374.57	$35,483.19
01	106100	1081017250	DADE	353	$42,759.59	$42,717.69
01	106100	1081018250	DAVIS	353	$6,704.88	$6,704.88
01	106100	1081020660	DORAL (RESOURCE RECOVERY - DADE COUNTY)	353	$81,062.56	$81,062.56
01	106100	1081024500	FLAGAMI	353	$28,879.12	$29,201.95
01	106100	1081027750	40TH STREET - MIAMI BEACH	353	$170,087.94	$170,087.94
01	106100	1081032500	GREYNOLDS	353	$11,197.47	$11,309.44
01	106100	1081044850	LEVEE SUBSTATION	353	$49,844.04	$51,269.83
01	106100	1081045500	LITTLE RIVER	353	$27,800.99	$27,800.99
01	106100	1081054250	MIAMI SHORES	353	$7,031.35	$7,031.35
01	106100	1081059000	NORMANDY BEACH	353	$143,199.60	$143,199.60

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01	106100 1081067080	PENNSUCO	353	$1,689,229.87	$1,689,229.87
01	106100 1081074000	RAILWAY	353	$68,394.12	$68,585.50
01	106100 1081075250	RIVERSIDE	353	$20,828.99	$20,828.99
01	106100 1081083250	SOUTH MIAMI	353	$16,362.62	$16,362.62
01	106100 1081089000	TURKEY POINT PLANT SWITCH YARD	353	$331,216.25	$333,117.16
01	106100 1980000000	SUSPENSE-SUBSTATIONS	353	($2,970.38)	($3,145.27)
			353 Total	$14,511,174.55	$14,499,801.95
01	106100 2042225079	ANDYTOWN-MARTIN 500KV #1 (MARTIN CO.)	354	$260.35	$260.35
01	106100 2052064135	RINGLING-MANATEE #3 240KV (MANATEE CO.)	354	$100,420.73	$100,420.73
			354 Total	$100,681.08	$100,681.08
01	106100 2010709155	BRADFORD-PUTNAM 240KV YARD (CLAY CO.)	355	$22,555.26	$22,555.26
01	106100 2011335073	PUTNAM-VOLUSIA #1 240KV (FLAGLER COUNTY0)	355	$73,052.27	$71,591.22
01	106100 2011360073	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	355	$37,633.07	$36,880.41
01	106100 2012907070	PALATKA SES-POMONA PARK LOOP	355	$71,484.45	$71,484.45
01	106100 2012907088	PUTNAM - ST JOHNS CO. LINE	355	$38,972.38	$38,972.38
01	106100 2012909001	PALATKA-MCMEEKIN TAP	355	$427,176.98	$427,176.98
01	106100 2012910001	PALATKA-ST AUGUSTINE (PUTNAM CO.)	355	$145,001.86	$145,001.86
01	106100 2013207099	ST JOHNS RIVER XING @ ORANGEDALE	355	$2,102.08	$2,102.08
01	106100 2013207102	ORANGEDALE-GREENLAND (JACKSONVILLE ELECT AUTH	355	$18,925.72	$18,925.72
01	106100 2013208150	MILLCREEK-TOLOMATO 115KV	355	$779,050.75	$779,050.75
01	106100 2013210009	PALATKA-ST AUGUSTINE (ST JOHNS CO.)	355	$148.62	$148.62
01	106100 2013608030	MISSION CITY 66KV TAP (OLD)	355	$280.00	$280.00
01	106100 2013608108	VOLUSIA TIE LINES	355	$13,875.91	$13,875.91
01	106100 2013608111	DAYTONA-VOLUSIA	355	$5,130.92	$5,130.92
01	106100 2013608124	PORT ORANGE-SOUTH DAYTONA	355	$3,071.39	$3,071.39
01	106100 2013623053	SANFORD-SR 40 (E/O DELAND)	355	$94,283.24	$94,283.24
01	106100 2013623070	VOLUSIA-SR 40(E/O DELAND)	355	$164,812.81	$164,812.81
01	106100 2013623119	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	355	$130,152.49	$130,152.49
01	106100 2013635088	PUTNAM-VOLUSIA #1 240KV (VOLUSIA CO.)	355	$2,435.64	$2,435.64
01	106100 2020400003	T" BREV-MALABAR 1&2 - WICKHAM LOOP "	355	$146,349.75	$146,349.75
01	106100 2020400004	T" EAU GALLIE-AURORA - WICKHAM LOOP "	355	$204,525.31	$204,525.31
01	106100 2020405063	EAU GALLIE-ROCKLEDGE	355	$38,461.75	$38,080.89
01	106100 2020405079	BREVARD-ROCKLEDGE	355	$1,973.41	$1,973.41
01	106100 2020405083	COCOA-SYKES CREEK LOOP	355	$1,656.75	$1,822.43
01	106100 2020405086	SYKES CREEK LOOP	355	$941.13	$1,035.24
01	106100 2020405087	COCOA BEACH-SYKES CREEK LOOP	355	$5,808.43	$6,389.27
01	106100 2020405089	BANANA RIVER CROSSING @ COCOA BEACH	355	$472.37	$519.61
01	106100 2020405103	INDIAN HARBOR-PATRICK	355	$16,595.17	$16,594.08
01	106100 2020405109	MALABAR-PALM BAY (SO.H-FRAME)	355	$5,075.69	$5,075.69

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01	106100	2020405132	BANANA RIVER SUB-SOUTH COCOA BEACH	355	$326,066.79	$326,066.79
01	106100	2020405136	BANANA RIVER SUB-PATRICK	355	$6,044.77	$6,044.77
01	106100	2020405158	BREVARD-EAU GALLIE EXT TO SUNTREE	355	$16,867.59	$16,867.59
01	106100	2020406020	INDIAN RIVER-TITUSVILLE	355	$37,268.20	$37,268.20
01	106100	2020406025	MIMS-TITUSVILLE	355	$74,953.91	$74,953.91
01	106100	2020406031	MIMS-VOLUSIA CO LINE	355	$113,457.98	$113,457.98
01	106100	2020406086	CITY POINT-SOUTH CAPE	355	$29,457.47	$28,868.32
01	106100	2020406131	LINDE-MIMS	355	$4,500.80	$4,500.80
01	106100	2020423001	BREVARD-SANFORD (BREVARD CO.)	355	$38,461.43	$38,461.43
01	106100	2020423088	CAPE CANAVERAL-INDIAN RIVER (ORLANDO U.C.)	355	$315,002.56	$315,002.56
01	106100	2020423091	CAPE CANAVERAL-VOLUSIA (BREVARD CO)	355	$71,901.02	$71,901.02
01	106100	2020448001	BREVARD-WEST LAKE WALES (FLA.POWER CORP)	355	$23,364.24	$23,364.24
01	106100	2022623006	BREVARD-SANFORD (ORANGE CO.)	355	$5,736.97	$5,736.97
01	106100	2023106045	LAUREL-VOLUSIA CO. LINE	355	$26,690.86	$26,690.86
01	106100	2023623116	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	355	$105,779.93	$105,779.93
01	106100	2030309161	BRADFORD-PUTNAM 240KV YARD (BRADFORD CO.)	355	$4,512.16	$4,512.16
01	106100	2030309167	BRADFORD-STARKE	355	$2,543.94	$2,543.94
01	106100	2030917027	COLUMBIA-LAKE BUTLER (COLUMBIA CO.)	355	$11,429.22	$11,200.64
01	106100	2032409314	YULEE-KINGSLAND 240KV (GPC)	355	$31,636.93	$31,636.93
01	106100	2033517019	COLUMBIA-LAKE BUTLER (UNION CO.)	355	$0.02	$0.02
01	106100	2041621044	FT. MYERS-RANCH 138KV (HENDRY CO.)	355	$47,540.25	$47,540.25
01	106100	2041646044	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	355	$6,256.64	$6,256.64
01	106100	2041805013	OSLO-WEST SUB (VERO BEACH)	355	$64,980.32	$64,980.32
01	106100	2041847067	BREVARD-RANCH 2ND CKT (INDIAN RIVER CO.)	355	$120,457.28	$120,457.28
01	106100	2042204028	PORT SEWALL-PALM BCH.CO.LINE	355	$451,240.52	$451,240.52
01	106100	2042204044	PORT SEWALL-ST. LUCIE CO. LINE	355	$2,959.68	$2,959.68
01	106100	2042204118	SANDPIPER-TURNPIKE 240 KV (MARTIN CO.)	355	$7,254.20	$7,254.20
01	106100	2042204138	TURNPIKE-CRANE 230KV (MARTIN CO)	355	$25,459.83	$25,459.83
01	106100	2042204174	BRIDGE-ALEXANDER (MARTIN CO.)	355	$884.81	$1,026.38
01	106100	2042222024	BREVARD-RANCH (MARTIN CO.)	355	$118,197.91	$118,197.91
01	106100	2042800022	T" HOBE-PLUMOSUS #2 (PALM BCH CO) "	355	$661,187.50	$655,896.08
01	106100	2042803116	LANTANA-RANCH	355	$9,943.89	$9,943.89
01	106100	2042803150	ATLANTIC LOOP	355	$37,308.99	$37,308.99
01	106100	2042803151	MILITARY TRAIL-RANCH	355	$7,738.65	$7,738.65
01	106100	2042803195	CEDAR-DELTRAIL 240KV	355	$26,480.55	$26,312.37
01	106100	2042804008	PLUMOSUS-RIVIERA #2	355	$194,871.16	$191,625.30
01	106100	2042804022	PLUMOSUS-MARTIN CO. LINE	355	$42,936.58	$42,945.81
01	106100	2042804088	RIVIERA-WEST PALM BEACH	355	$217,283.51	$217,283.51
01	106100	2042804179	BRIDGE-ALEXANDER (PALM BEACH CO.)	355	$528.39	$612.93

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01	106100 2042804182	ALEXANDER-PLUMOSUS	355	$4,097.06	$4,752.59
01	106100 2042815023	OKEECHOBEE (34K14)-PAHOKEE (PALM BEACH CO.)	355	$10,580.70	$10,580.70
01	106100 2042815056	QUAKER OATS TAP (DOUBLE CKT)	355	$354.63	$354.63
01	106100 2042819030	LAUDERDALE-RANCH (PALM BEACH CO.)	355	$89,584.21	$89,584.21
01	106100 2042819056	RANCH-RIVIERA (3 CKTS)	355	$63,544.50	$63,544.50
01	106100 2042819099	RIVIERA (STEEL TOWERS)	355	$44,357.89	$43,470.73
01	106100 2042819100	RANCH-BROWARD #2 240KV (PALM BEACH CO.)	355	$0.03	$0.03
01	106100 2042819183	RANCH-RIVIERA #3 RECWAY TAP	355	($0.03)	($0.04)
01	106100 2042819186	RANCH-WEST PALM BEACH #3	355	$218,941.34	$218,941.34
01	106100 2042821109	BROWARD-RANCH #2 CORBETT EXTENSION	355	$27,222.37	$27,222.37
01	106100 2042822001	BREVARD-RANCH (PALM BEACH CO.)	355	$10,618.77	$10,618.77
01	106100 2042825016	CONSERVATION-CORBETT 500KV (PALM BEACH CO.)	355	$58,393.97	$58,393.97
01	106100 2042829022	HOBE-PLUMOSUS #2 230KV	355	$28.87	$33.49
01	106100 2042846062	ORANGE RIVER-RANCH 240KV (PALM BEACH CO.)	355	$22,791.25	$22,791.25
01	106100 2042847001	BREVARD-RANCH 2ND CKT (PALM BEACH CO.)	355	$98,165.29	$98,165.29
01	106100 2043347042	BREVARD-RANCH 2ND CKT (ST LUCIE CO.)	355	$52,757.57	$52,757.57
01	106100 2050612265	MYAKKA-ROTUNDA 138KV (CHARLOTTE CO.)	355	$145,499.57	$145,499.57
01	106100 2050613199	CHARLOTTE-PUNTA GORDA (SO.CKT)	355	$933.51	$933.51
01	106100 2050624160	FT. MYERS-CHARLOTTE (CHARLOTTE CO.)	355	$28,944.26	$28,944.26
01	106100 2050649054	FT. MYERS-RINGLING #1 240KV (CHARLOTTE CO.)	355	$20,367.01	$19,959.67
01	106100 2050813137	FT. MYERS-COLLIER (COLLIER CO.)	355	$218,397.04	$218,397.04
01	106100 2050813145	COLLIE-NAPLES	355	$5,784.76	$5,784.76
01	106100 2050813258	ALICO-COLLIER (COLLIER CO.)	355	$343,883.47	$343,883.47
01	106100 2051646015	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	355	$14,952.39	$14,952.39
01	106100 2051913052	FT MYERS-BUCKINGHAM AIR FIELD	355	$187,341.45	$187,341.45
01	106100 2051913078	ALICO-BONITA SPRINGS-COLLIER LINE VIA ESTERO	355	$32,934.06	$32,934.06
01	106100 2051913113	FT MYERS-COLLIER (LEE CO.)	355	$34,530.74	$34,530.74
01	106100 2051913215	FT MYERS PLT STRING BUS	355	$344,747.04	$344,747.04
01	106100 2051924176	FT MYERS-CHARLOTTE 240KV (LEE CO.)	355	$4,164.79	$4,081.49
01	106100 2051946001	ORANGE RIVER-RANCH 240KV (LEE CO.)	355	$8,917.95	$8,917.95
01	106100 2051949080	FT MYERS-RINGLING #1 240KV (LEE CO.)	355	$0.02	$0.02
01	106100 2052014083	CORTEZ TAP	355	$216,370.00	$216,291.36
01	106100 2052014088	CASTLE-RINGLING (W CKT, MANATEE CO.)	355	$18,456.15	$18,456.15
01	106100 2052014125	FRUIT INDUSTRIES TAP	355	$8,670.33	$8,670.33
01	106100 2052024001	CASTLE-RINGLING (MANATEE CO.)	355	$3,523.17	$3,523.17
01	106100 2053014012	VENICE-ENGLEWOOD-CHARLOTTE CO.LINE	355	$5,236.36	$5,206.49
01	106100 2053014034	CLARK-VENICE	355	$26,741.34	$26,741.34
01	106100 2053014047	CLARK-HYDE PARK-RINGLING	355	$14,048.44	$14,048.44
01	106100 2053014068	SARASOTA & PAYNE LOOPS	355	$4,571.79	$4,571.79

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01	106100 2053014102	RINGLING-TUTTLE AVE. (DOUBLE CKT)	355	$53,538.37	$53,538.37
01	106100 2053014108	RINGLING-54N2	355	$166,362.77	$166,362.77
01	106100 2053024087	RINGLING-VENICE #2	355	$3,548.55	$3,548.55
01	106100 2053024107	LAURELWOOD-RINGLING #1	355	$21,720.68	$21,720.68
01	106100 2053024128	CHARLOTTE-LAURELWOOD (SARASOTA CO.)	355	$8,890.24	$8,890.24
01	106100 2070501028	LAUDERDALE SES-COUNTY LINE	355	$11,354.08	$11,321.26
01	106100 2070502034	LAUDERDALE-HOLLYWOOD	355	$1,048,022.55	$1,048,022.55
01	106100 2070502037	HOLLYWOOD 138KV TAP	355	$2,021.83	$1,981.39
01	106100 2070502044	HALLANDALE-HOLLYWOOD	355	$2,373.05	$2,325.59
01	106100 2070502059	HOLLYWOOD-STIRLING	355	$10,635.28	$10,635.28
01	106100 2070502079	STIRLING RD (W/O STIRLING)-PEMBROKE-DADE CO L	355	$2,863.49	$2,863.49
01	106100 2070503001	LAUDERDALE-PINEHURST-POMPANO-PALM BCH CO.	355	$135,593.22	$135,593.22
01	106100 2070503097	SAMPLE-DEERFIELD-PALM BCH CO.LINE	355	$13,183.74	$13,183.74
01	106100 2070503135	BROWARD-LYONS-HOLY CROSS-OAKLAND PARK	355	($5.16)	($5.11)
01	106100 2070518078	HIATUS-SPRING TREE TAP 230KV LINE BRD CO	355	$7,731.31	$7,654.00
01	106100 2070519083	BROWARD-FT.LAUDERDALE	355	$15,237.31	$15,117.60
01	106100 2070519118	RANCH-BROWARD #2 240KV (BROWARD CO.)	355	$12,304.93	$12,304.93
01	106100 2070520051	DADE-GRATIGNY-LAUDERDALE (BROWARD CO.)	355	$169,627.70	$169,627.70
01	106100 2070520084	DADE-PORT EVERGLADES (BROWARD CO.)	355	$1,801.81	$1,801.81
01	106100 2070520103	DADE-LAUDERDALE #3 & #4 (BROWARD CO.)	355	$23,899.08	$23,899.08
01	106100 2070520161	DADE-LAUDERDALE (ANDYTOWN EXTENSION)	355	$43,058.76	$43,058.76
01	106100 2070525016	CONSERVATION-CORBETT 500KV (BROWARD CO.)	355	$47,796.26	$47,796.26
01	106100 2070570111	GRATIGNY-LAUDERDALE #2 138KV	355	$54,270.02	$54,270.02
01	106100 2081001012	RAILWAY-HIALEAH (OLD)	355	$6,014.34	$6,014.34
01	106100 2081001045	GRAPELAND-RIVERSIDE	355	$178,795.34	$178,795.34
01	106100 2081001063	GOULDS-PRINCETON	355	$32,177.54	$32,177.54
01	106100 2081001066	62ND AVE-66A1 (W/O RIVERSIDE)	355	$2,398.55	$2,350.58
01	106100 2081001097	DADE-LITTLE RIVER	355	$43,641.49	$42,878.03
01	106100 2081001120	KROME-120A18 (W/O VILLAGE GREEN)	355	$1,160.65	$1,973.11
01	106100 2081001171	CORAL REEF-75A5 (W/O CUTLER)	355	$3,030.41	$5,151.70
01	106100 2081001185	DADE-WESTSIDE	355	$1,384.34	$2,477.97
01	106100 2081001205	CUTLER-74A17 (SW 77 AVE & 140 ST)	355	$5,771.29	$5,771.29
01	106100 2081001210	MASTER-OPA LOCKA	355	$2,400.63	$2,352.62
01	106100 2081001252	CORAL REEF DR @ SW 89 AV-WHISPERING PINES	355	$21,448.87	$22,703.40
01	106100 2081001286	DADE-MIAMI SHORES 240KV	355	$45,063.39	$44,162.12
01	106100 2081002026	GREYNOLDS-FULFORD	355	$4,745.40	$4,745.40
01	106100 2081002055	DUMBFOUNDLING-GREYNOLDS	355	$11,108.92	$11,108.92
01	106100 2081020001	CUTLER-DAVIS LOOPS	355	$74,020.55	$74,020.55
01	106100 2081020005	FLAGAMI-DAVIS LOOPS	355	$68,197.95	$68,197.95

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01	106100 2081020015	DADE-FLAGAMI (H FRAME SECT)	355	$17,467.55	$17,467.55
01	106100 2081020041	DADE-GRATIGNY-LAUDERDALE (DADE CO.)	355	$83,058.25	$82,447.94
01	106100 2081020067	DADE-PORT EVERGLADES (DADE CO.)	355	$31,626.39	$31,219.97
01	106100 2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	355	$101,090.62	$99,497.60
01	106100 2081020194	DAVIS-LEVEE #3 (DAVIS-NEWTON SECT) 230KV	355	$37,797.33	$37,797.33
01	106100 2081999999	SOUTH AREA POLE PULLING BLANKET	355	$2,300.14	$2,300.14
01	106100 2980000000	SUSPENSE-TRANSM LINES	355	($298,895.58)	($298,258.56)
			355 Total	**$10,463,281.34**	**$10,452,690.31**
01	106100 2010709155	BRADFORD-PUTNAM 240KV YARD (CLAY CO.)	356	$36,582.17	$36,582.17
01	106100 2011335073	PUTNAM-VOLUSIA #1 240KV (FLAGLER COUNTY0)	356	$48,701.56	$43,831.40
01	106100 2011360073	PUTNAM-VOLUSIA #2 240KV (FLAGLER CO.)	356	$25,088.71	$22,579.84
01	106100 2012907088	PUTNAM - ST JOHNS CO. LINE	356	$27,391.00	$27,391.00
01	106100 2012909001	PALATKA-MCMEEKIN TAP	356	$262,521.78	$262,521.78
01	106100 2012909023	MCMEEKIN TAP	356	$3,370.22	$3,370.22
01	106100 2012909325	PACIFIC SUB TAP (GP)	356	$3,370.24	$3,370.24
01	106100 2012910001	PALATKA-ST AUGUSTINE (PUTNAM CO.)	356	$95,772.40	$95,772.40
01	106100 2013207102	ORANGEDALE-GREENLAND (JACKSONVILLE ELECT AUTH	356	$19,672.78	$19,672.78
01	106100 2013208150	MILLCREEK-TOLOMATO 115KV	356	$605,133.11	$605,133.11
01	106100 2013210009	PALATKA-ST AUGUSTINE (ST JOHNS CO.)	356	$99.15	$99.15
01	106100 2013608030	MISSION CITY 66KV TAP (OLD)	356	$99.96	$99.96
01	106100 2013608108	VOLUSIA TIE LINES	356	$2,676.97	$2,676.97
01	106100 2013608124	PORT ORANGE-SOUTH DAYTONA	356	$2,047.59	$2,047.59
01	106100 2013623053	SANFORD-SR 40 (E/O DELAND)	356	$25,454.55	$25,454.55
01	106100 2013623070	VOLUSIA-SR 40(E/O DELAND)	356	$36,770.88	$36,770.88
01	106100 2013623119	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	356	$51,984.18	$51,984.18
01	106100 2013623143	VOLUSIA - 148X2	356	$813.99	$732.59
01	106100 2013635088	PUTNAM-VOLUSIA #1 240KV (VOLUSIA CO.)	356	$0.03	$0.03
01	106100 2020400003	T" BREV-MALABAR 1&2 - WICKHAM LOOP "	356	$167,126.19	$167,126.19
01	106100 2020400004	T" EAU GALLIE-AURORA - WICKHAM LOOP "	356	$150,182.12	$150,182.12
01	106100 2020405056	EAU GALLIE-MELBOURNE	356	$8,261.96	$8,261.96
01	106100 2020405063	EAU GALLIE-ROCKLEDGE	356	$20,249.43	$18,979.88
01	106100 2020405079	BREVARD-ROCKLEDGE	356	$3,797.22	$3,797.22
01	106100 2020405083	COCOA-SYKES CREEK LOOP	356	$97.65	$100.58
01	106100 2020405086	SYKES CREEK LOOP	356	$2,178.82	$2,244.18
01	106100 2020405087	COCOA BEACH-SYKES CREEK LOOP	356	$6,179.57	$6,364.96
01	106100 2020405089	BANANA RIVER CROSSING @ COCOA BEACH	356	$422.68	$435.36
01	106100 2020405103	INDIAN HARBOR-PATRICK	356	$3,355.21	$3,355.21
01	106100 2020405109	MALABAR-PALM BAY (SO.H-FRAME)	356	$2,041.41	$2,041.41
01	106100 2020405132	BANANA RIVER SUB-SOUTH COCOA BEACH	356	$70,268.22	$70,268.22

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01	106100	2020405136	BANANA RIVER SUB-PATRICK	356	$22,136.36	$22,136.36
01	106100	2020405158	BREVARD-EAU GALLIE EXT TO SUNTREE	356	$15,689.01	$15,689.01
01	106100	2020406001	CLEARLAKE-COCOA	356	$7,173.39	$7,173.39
01	106100	2020406012	CAPE CANAVERAL SES-INDIAN RIVER SUB	356	$21,599.89	$21,599.89
01	106100	2020406031	MIMS-VOLUSIA CO LINE	356	$83,183.45	$83,183.45
01	106100	2020406086	CITY POINT-SOUTH CAPE	356	$27,299.25	$24,569.33
01	106100	2020406109	SOUTH CAPE-C-5 COMPLEX	356	$17,908.99	$18,446.26
01	106100	2020423001	BREVARD-SANFORD (BREVARD CO.)	356	$56,484.83	$56,484.83
01	106100	2020423088	CAPE CANAVERAL-INDIAN RIVER (ORLANDO U.C.)	356	$247,225.73	$247,225.73
01	106100	2020423091	CAPE CANAVERAL-VOLUSIA (BREVARD CO)	356	$62,257.94	$62,257.94
01	106100	2020448001	BREVARD-WEST LAKE WALES (FLA.POWER CORP)	356	$7,474.84	$7,474.84
01	106100	2022623006	BREVARD-SANFORD (ORANGE CO.)	356	$25,187.90	$25,187.90
01	106100	2023106045	LAUREL-VOLUSIA CO. LINE	356	$13,613.26	$13,613.26
01	106100	2023623116	CAPE CANAVERAL-VOLUSIA (VOLUSIA CO.)	356	$73,940.21	$73,940.21
01	106100	2030309161	BRADFORD-PUTNAM 240KV YARD (BRADFORD CO.)	356	$7,318.28	$7,318.28
01	106100	2030309234	NEW RIVER TAP #2	356	$73,719.30	$66,347.37
01	106100	2032409314	YULEE-KINGSLAND 240KV (GPC)	356	$11,950.61	$11,950.61
01	106100	2032450008	DUVAL-HATCH (GP) #2 500KV (OBO) (NASSAU CO)	356	$101,448.11	$91,303.30
01	106100	2041621044	FT. MYERS-RANCH 138KV (HENDRY CO.)	356	$3,397.97	$3,397.97
01	106100	2041805013	OSLO-WEST SUB (VERO BEACH)	356	$5,357.93	$5,357.93
01	106100	2041822067	BREVARD-RANCH (INDIAN RIVER CO.)	356	$0.01	$0.01
01	106100	2041847067	BREVARD-RANCH 2ND CKT (INDIAN RIVER CO.)	356	$88,739.46	$88,739.46
01	106100	2042204028	PORT SEWALL-PALM BCH.CO.LINE	356	$248,264.75	$248,264.75
01	106100	2042204118	SANDPIPER-TURNPIKE 240 KV (MARTIN CO.)	356	$2,413.81	$2,413.81
01	106100	2042222024	BREVARD-RANCH (MARTIN CO.)	356	$32,438.40	$32,438.40
01	106100	2042225077	CORBETT-MARTIN 500KV (MARTIN CO.)	356	$278,302.67	$250,472.40
01	106100	2042800022	T" HOBE-PLUMOSUS #2 (PALM BCH CO) "	356	$328,676.30	$314,456.28
01	106100	2042803088	LINTON-YAMATO	356	$4,942.75	$4,942.75
01	106100	2042803093	IBM-YAMATO	356	$1,710.79	$1,710.79
01	106100	2042803095	IBM-BOCA RATON TAP (OLD)	356	$6,856.94	$6,856.94
01	106100	2042803100	BOCA RATON-BROWARD CO. LINE	356	$17,424.72	$17,424.72
01	106100	2042803116	LANTANA-RANCH	356	$3,756.69	$3,756.69
01	106100	2042803150	ATLANTIC LOOP	356	$24,199.20	$24,199.20
01	106100	2042803151	MILITARY TRAIL-RANCH	356	$4,152.28	$4,152.28
01	106100	2042803168	BROWARD-YAMATO 240KV (PALM BCH CO.)	356	$2,887.46	$2,887.46
01	106100	2042803195	CEDAR-DELTRAIL 240KV	356	$9,116.04	$8,700.51
01	106100	2042803227	CEDAR-JOG (CEDAR-FOUNTAIN SECTION)	356	$52,783.73	$52,783.73
01	106100	2042803233	CEDAR-JOG (FOUNTAIN-STR B131C17 SECTION)	356	$36,619.27	$36,619.27
01	106100	2042804008	PLUMOSUS-RIVIERA #2	356	$141,202.19	$129,473.26

Florida Power Light Co.
Insurable value analysis as of 12/31/99
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01	106100	2042804022	PLUMOSUS-MARTIN CO. LINE	356	$16,257.93	$16,257.93
01	106100	2042804088	RIVIERA-WEST PALM BEACH	356	$80,110.03	$80,110.03
01	106100	2042815023	OKEECHOBEE (34K14)-PAHOKEE (PALM BEACH CO.)	356	$3,307.04	$3,307.04
01	106100	2042818058	BELLE GLADE-SO.BAY	356	$2,701.88	$2,701.88
01	106100	2042819030	LAUDERDALE-RANCH (PALM BEACH CO.)	356	$203,648.73	$203,648.73
01	106100	2042819056	RANCH-RIVIERA (3 CKTS)	356	$310,811.18	$310,811.18
01	106100	2042819099	RIVIERA (STEEL TOWERS)	356	$39,354.84	$35,419.36
01	106100	2042819183	RANCH-RIVIERA #3 RECWAY TAP	356	($0.02)	($0.02)
01	106100	2042819186	RANCH-WEST PALM BEACH #3	356	$79,374.99	$79,374.99
01	106100	2042822001	BREVARD-RANCH (PALM BEACH CO.)	356	$1,376.20	$1,376.20
01	106100	2042825016	CONSERVATION-CORBETT 500KV (PALM BEACH CO.)	356	$672,134.42	$672,134.42
01	106100	2042844030	CEDAR-LAUDERDALE (PALM BEACH CO.)	356	$119,891.13	$119,891.13
01	106100	2042846062	ORANGE RIVER-RANCH 240KV (PALM BEACH CO.)	356	$6,586.66	$6,586.66
01	106100	2042846109	CORBETT-RANCH #1 & CORBETT-CEDAR 240KV	356	$15,409.50	$15,409.50
01	106100	2042847001	BREVARD-RANCH 2ND CKT (PALM BEACH CO.)	356	$34,185.98	$34,185.98
01	106100	2042853131	RANCH-WPB #1 138KV RANCH-JOG SECTION	356	$22,616.82	$22,616.82
01	106100	2043304125	MIDWAY-TURNPIKE 240KV (ST. LUCIE CO.)	356	$17,530.76	$17,530.76
01	106100	2043347042	BREVARD-RANCH 2ND CKT (ST LUCIE CO.)	356	$37,138.86	$37,138.86
01	106100	2050612265	MYAKKA-ROTUNDA 138KV (CHARLOTTE CO.)	356	$157,979.57	$157,979.57
01	106100	2050624151	CHARLOTTE-LAURELWOOD 240KV (CHARLOTTE C.)	356	$0.03	$0.03
01	106100	2050624155	PEACE RIVER XING @ CHARLOTTE SUB	356	$1,031.36	$1,031.36
01	106100	2050624160	FT. MYERS-CHARLOTTE (CHARLOTTE CO.)	356	$34,658.65	$34,658.65
01	106100	2050649054	FT. MYERS-RINGLING #1 240KV (CHARLOTTE CO.)	356	$9,700.89	$8,730.80
01	106100	2050813137	FT. MYERS-COLLIER (COLLIER CO.)	356	$168,235.01	$168,235.01
01	106100	2050813145	COLLIE-NAPLES	356	$1,762.02	$1,762.02
01	106100	2050813258	ALICO-COLLIER (COLLIER CO.)	356	$124,577.48	$124,577.48
01	106100	2051113009	CHARLOTTE-NOCATEE (DE SOTO CO.)	356	$35,083.78	$35,083.78
01	106100	2051646015	ORANGE RIVER-RANCH 240KV (HENDRY CO.)	356	$12,336.81	$12,336.81
01	106100	2051913052	FT MYERS-BUCKINGHAM AIR FIELD	356	$47,621.42	$47,621.42
01	106100	2051913078	ALICO-BONITA SPRINGS-COLLIER LINE VIA ESTERO	356	$32,467.30	$32,467.30
01	106100	2051913113	FT MYERS-COLLIER (LEE CO.)	356	$45,071.49	$45,071.49
01	106100	2051913164	COLONIAL-IONA	356	$530.17	$530.17
01	106100	2051913178	BUCKINGHAM-COLONIAL TAP	356	$1,206.88	$1,206.88
01	106100	2051913215	FT MYERS PLT STRING BUS	356	$229,831.35	$229,831.35
01	106100	2051924176	FT MYERS-CHARLOTTE 240KV (LEE CO.)	356	$2,776.54	$2,498.89
01	106100	2051949080	FT MYERS-RINGLING #1 240KV (LEE CO.)	356	$267.05	$240.35
01	106100	2052014083	CORTEZ TAP	356	$25,217.53	$25,056.12
01	106100	2052014088	CASTLE-RINGLING (W CKT, MANATEE CO.)	356	$11,843.95	$11,843.95
01	106100	2052014125	FRUIT INDUSTRIES TAP	356	$1,858.44	$1,858.44

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Florida Power Light Co.
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01	106100 2053014012	VENICE-ENGLEWOOD-CHARLOTTE CO.LINE	356	$547.95	$547.95
01	106100 2053014034	CLARK-VENICE	356	$17,489.32	$17,489.32
01	106100 2053014047	CLARK-HYDE PARK-RINGLING	356	$3,485.77	$3,485.77
01	106100 2053014068	SARASOTA & PAYNE LOOPS	356	$1,283.01	$1,283.01
01	106100 2053014102	RINGLING-TUTTLE AVE. (DOUBLE CKT)	356	$34,598.62	$34,598.62
01	106100 2053014108	RINGLING-54N2	356	$55,461.49	$55,461.49
01	106100 2053024087	RINGLING-VENICE #2	356	$13,944.56	$13,944.56
01	106100 2053024107	LAURELWOOD-RINGLING #1	356	$7,543.33	$7,543.33
01	106100 2053024128	CHARLOTTE-LAURELWOOD (SARASOTA CO.)	356	$31,263.13	$28,909.58
01	106100 2053049013	FT MYERS-RINGLING #1 240KV (SARASOTA CO.)	356	$5,182.86	$5,182.86
01	106100 2070501028	LAUDERDALE SES-COUNTY LINE	356	$3,244.74	$3,135.36
01	106100 2070502034	LAUDERDALE-HOLLYWOOD	356	$614,180.00	$614,180.00
01	106100 2070502037	HOLLYWOOD 138KV TAP	356	$1,830.83	$1,647.75
01	106100 2070502044	HALLANDALE-HOLLYWOOD	356	$1,582.03	$1,423.83
01	106100 2070502059	HOLLYWOOD-STIRLING	356	$2,505.94	$2,505.94
01	106100 2070502079	STIRLING RD (W/O STIRLING)-PEMBROKE-DADE CO L	356	$6,190.44	$6,190.44
01	106100 2070503001	LAUDERDALE-PINEHURST-POMPANO-PALM BCH CO.	356	$117,410.63	$117,410.63
01	106100 2070503097	SAMPLE-DEERFIELD-PALM BCH CO.LINE	356	$31,337.93	$31,337.93
01	106100 2070503135	BROWARD-LYONS-HOLY CROSS-OAKLAND PARK	356	$9,209.52	$9,209.21
01	106100 2070518067	DAVIE-JACARANDA-MOTOROLA	356	$11,801.33	$11,801.33
01	106100 2070518072	MOTOROLA-SPRINGTREE-77S3	356	$4,383.25	$3,944.93
01	106100 2070518078	HIATUS-SPRING TREE TAP 230KV LINE BRD CO	356	$307.17	$282.60
01	106100 2070519073	BROWARD LOOP	356	$12,374.74	$12,374.74
01	106100 2070519083	BROWARD-FT.LAUDERDALE	356	$6,879.54	$6,480.50
01	106100 2070520051	DADE-GRATIGNY-LAUDERDALE (BROWARD CO.)	356	$57,719.04	$57,719.04
01	106100 2070520084	DADE-PORT EVERGLADES (BROWARD CO.)	356	$1,829.96	$1,829.96
01	106100 2070520103	DADE-LAUDERDALE #3 & #4 (BROWARD CO.)	356	$9,669.93	$9,669.93
01	106100 2070520161	DADE-LAUDERDALE (ANDYTOWN EXTENSION)	356	$45,692.46	$45,692.46
01	106100 2070525016	CONSERVATION-CORBETT 500KV (BROWARD CO.)	356	$288,743.97	$288,743.97
01	106100 2070544009	CEDAR-LAUDERDALE (BROWARD CO.)	356	$43,965.29	$43,965.29
01	106100 2081001012	RAILWAY-HIALEAH (OLD)	356	$10,364.65	$10,364.65
01	106100 2081001018	HIALEAH SUB-GLADEVIEW TAP-DADE LITTLE RIVER	356	$2,114.68	$2,114.68
01	106100 2081001045	GRAPELAND-RIVERSIDE	356	$102,356.13	$102,356.13
01	106100 2081001054	CORAL REEF-54A15 (E/O DAVIS)	356	$31,158.75	$31,158.75
01	106100 2081001063	GOULDS-PRINCETON	356	$6,930.71	$6,930.71
01	106100 2081001097	DADE-LITTLE RIVER	356	$36,655.62	$33,354.62
01	106100 2081001120	KROME-120A18 (W/O VILLAGE GREEN)	356	($1,160.65)	($1,636.52)
01	106100 2081001171	CORAL REEF-75A5 (W/O CUTLER)	356	$80,369.33	$79,454.39
01	106100 2081001185	DADE-WESTSIDE	356	$2,277.74	$1,668.63

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Florida Power Light Co.
Insurable value analysis as of 12/31/99
Total Property Cost

01	106100 2081001188	LAWRENCE-RIVERSIDE	356	$2,221.79	$1,999.61
01	106100 2081001205	CUTLER-74A17 (SW 77 AVE & 140 ST)	356	$1,072.70	$1,072.70
01	106100 2081001210	MASTER-OPA LOCKA	356	$1,600.41	$1,440.37
01	106100 2081001252	CORAL REEF DR @ SW 89 AV-WHISPERING PINES	356	($767.06)	($1,812.69)
01	106100 2081001278	FLORIDA CITY-TURKEY POINT 240KV LINE	356	$38,678.27	$38,678.27
01	106100 2081001286	DADE-MIAMI SHORES 240KV	356	$8,234.22	$7,410.80
01	106100 2081002026	GREYNOLDS-FULFORD	356	$1,416.08	$1,416.08
01	106100 2081002055	DUMBFOUNDLING-GREYNOLDS	356	$9,643.47	$9,643.47
01	106100 2081020001	CUTLER-DAVIS LOOPS	356	$14,518.99	$14,518.99
01	106100 2081020005	FLAGAMI-DAVIS LOOPS	356	$38,027.94	$37,756.01
01	106100 2081020015	DADE-FLAGAMI (H FRAME SECT)	356	$9,769.92	$9,769.92
01	106100 2081020041	DADE-GRATIGNY-LAUDERDALE (DADE CO.)	356	$33,926.67	$32,055.29
01	106100 2081020067	DADE-PORT EVERGLADES (DADE CO.)	356	$14,910.42	$13,609.92
01	106100 2081020093	DADE-LAUDERDALE #3 & #4 (DADE CO.)	356	$35,976.32	$32,657.54
01	106100 2081020194	DAVIS-LEVEE #3 (DAVIS-NEWTON SECT) 230KV	356	$37,647.11	$37,647.11
01	106100 2081020209	DAVIS-LEVEE #3 (LEVEE-NEWTON SECT) 230KV	356	$17,216.07	$17,216.07
01	106100 2081999999	SOUTH AREA POLE PULLING BLANKET	356	$1,533.43	$1,533.43
01	106100 2980000000	SUSPENSE-TRANSM LINES	356	($33,503.52)	($30,153.17)
			356 Total	$8,401,910.08	$8,299,540.11
01	106100 2042800022	T" HOBE-PLUMOSUS #2 (PALM BCH CO) "	357	$1,117,348.06	$1,117,348.06
01	106100 2081000915	GREYNOLDS-DUMBFOUNDLING 138KV CABLE	357	$541.92	$569.02
01	106100 2081000920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (DADE C	357	$1,274.20	$1,337.91
01	106100 2081000922	TURKEY PT. SW. STA.-UNITS #3 & #4	357	$248,699.49	$248,699.49
01	106100 2081002051	DUMBFOUNDLING-BROWARD CO. LINE	357	$516,400.05	$516,400.05
			357 Total	$1,884,263.72	$1,884,354.53
01	106100 2042800022	T" HOBE-PLUMOSUS #2 (PALM BCH CO) "	358	$208,996.68	$208,996.68
01	106100 2070500916	PORT EVERGLADES-FT LAUDERDALE 240KV CABLE	358	$19,181.41	$19,181.41
01	106100 2070500920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (BROWAR	358	$19,175.93	$19,175.93
01	106100 2081000908	LITTLE RIVER-40TH STREET 138KV CABLE	358	$16,368.51	$16,368.51
01	106100 2081000911	HAULOVER-NORMANDY 138KV CABLE	358	$4.24	$4.24
01	106100 2081000913	RAILWAY-16TH STREET TERMINAL 138KV CABLE	358	$27,348.19	$27,348.19
01	106100 2081000915	GREYNOLDS-DUMBFOUNDLING 138KV CABLE	358	$226.92	$236.00
01	106100 2081000920	PORT EVERGLADES-GREYNOLDS 240KV CABLE (DADE C	358	$226.93	$236.01
01	106100 2081000921	MIAMI-8TH ST-FLAGAMI #2 240KV CABLE	358	$4.19	$4.19
01	106100 2081000922	TURKEY PT. SW. STA.-UNITS #3 & #4	358	$37,438.03	$37,438.03
01	106100 2081002051	DUMBFOUNDLING-BROWARD CO. LINE	358	$143,775.78	$143,775.78
			358 Total	$472,746.81	$472,764.97
01	106100 2050649054	FT. MYERS-RINGLING #1 240KV (CHARLOTTE CO.)	359	$10,023.41	$10,023.41
01	106100 2051113218	DORRFIELD TAP-CHARLOTTE (DE SOTO CO.)	359	$13,262.44	$13,262.44

Florida Power Light Co.
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01	106100	2051913113 FT MYERS-COLLIER (LEE CO.)	359	$2,573.75	$2,573.75
01	106100	2051913164 COLONIAL-IONA	359	$2,432.75	$2,432.75
01	106100	2052014253 KEENTOWN-WHIDDEN 240KV (MANATEE CO.)	359	$2,791.17	$2,791.17
01	106100	2053024107 LAURELWOOD-RINGLING #1	359	$22,053.88	$22,053.88
01	106100	2070502034 LAUDERDALE-HOLLYWOOD	359	$795,407.05	$795,407.05
			359 Total	**$848,544.45**	**$848,544.45**

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ACG(RA)-TD (NETBKSM_S6) Net Book Summary Report 04/28/00 10.55.19

Net Book Cost For GSU's And GSU Cooling Banks

Work Order Number :

Plant Account	PA/PU Account	Vintage Year	Original Cost (a)	Accumulated Depreciation (b)	Net Book Value (c)=(a)-(b)	Calculation Through	Note
353	353.009	1969	291,163.00	229,691.04	61,471.96	12/1999	
	353.115	1969	33,431.34	26,373.14	7,058.20	12/1999	
	353.009	1996	2,137,338.45	153,353.18	1,983,985.27	12/1999	
	353.115	1996	132,278.51	9,490.93	122,787.58	12/1999	
	353.016	1996	136,425.86	9,788.50	126,637.36	12/1999	
	353.009	1991	890,839.29	148,621.54	742,217.75	12/1999	
	353.115	1994	146,487.24	15,783.95	130,703.29	12/1999	
	353.009	1992	1,121,389.55	164,657.15	956,732.40	12/1999	
	353.115	1993	33,167.04	4,206.69	28,960.35	12/1999	
	353.009	1974	237,001.75	148,896.26	88,105.49	12/1999	
	353.115	1974	6,490.31	4,077.58	2,412.73	12/1999	
	353.009	1974	237,001.75	148,896.26	88,105.49	12/1999	
	353.115	1974	6,490.31	4,077.58	2,412.73	12/1999	
	353.009	1974	237,001.75	148,896.26	88,105.49	12/1999	
	353.115	1974	6,490.31	4,077.58	2,412.73	12/1999	
	353.009	1974	237,001.75	148,896.26	88,105.49	12/1999	
	353.115	1974	6,490.31	4,077.58	2,412.73	12/1999	
	353.009	1974	237,363.24	149,123.36	88,239.88	12/1999	
	353.115	1974	6,490.31	4,077.58	2,412.73	12/1999	
	353.009	1974	237,001.75	148,896.26	88,105.49	12/1999	
	353.115	1974	6,490.31	4,077.58	2,412.73	12/1999	
	353.009	1958	338,143.57	338,143.57	.00	12/1999	
	353.115	1958	18,346.21	18,346.21	.00	12/1999	
	353.009	1992	2,863,051.92	420,390.91	2,442,661.01	12/1999	
	353.115	1993	30,487.46	3,866.80	26,620.66	12/1999	
	353.009	1999	431,783.24	5,145.32	426,637.92	12/1999	
	353.115	1999	75,827.39	903.60	74,923.79	12/1999	
	353.009	1970	137,264.94	103,755.11	33,509.83	12/1999	
	353.115	1970	4,278.81	3,234.26	1,044.55	12/1999	
	353.009	1970	135,511.71	102,429.86	33,081.85	12/1999	
	353.115	1970	4,278.82	3,234.26	1,044.56	12/1999	
	353.009	1970	135,562.63	102,468.31	33,094.32	12/1999	
	353.115	1970	4,278.82	3,234.26	1,044.56	12/1999	
	353.009	1986	520,214.97	149,388.09	370,826.88	12/1999	
	353.115	1986	41,621.64	11,952.32	29,669.32	12/1999	
	353.009	1972	232,968.47	160,719.02	72,249.45	12/1999	
	353.115	1972	4,530.77	3,125.65	1,405.12	12/1999	
	353.009	1972	232,968.18	160,718.88	72,249.30	12/1999	
	353.115	1972	4,530.76	3,125.64	1,405.12	12/1999	
	353.009	1991	1,928,786.84	321,785.57	1,607,001.27	12/1999	
	353.115	1993	71,715.47	9,095.90	62,619.57	12/1999	

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ACG(RA)-TD (NETBKSM_S6) Net Book Summary Report 04/28/00 10.55.19

Net Book Cost For GSU's And GSU Cooling Banks

Work Order Number :

Plant Account	PA/PU Account	Vintage Year	Original Cost (a)	Accumulated Depreciation (b)	Net Book Value (c)=(a)-(b)	Calculation Through	Note
353	353.009	1991	1,924,070.14	320,998.66	1,603,071.48	12/1999	
	353.115	1993	71,715.47	9,095.90	62,619.57	12/1999	
	353.009	1992	1,785,525.24	262,174.28	1,523,350.96	12/1999	
	353.115	1992	39,492.62	5,798.83	33,693.79	12/1999	
	353.009	1992	1,785,525.07	262,174.27	1,523,350.80	12/1999	
	353.115	1992	39,492.62	5,798.83	33,693.79	12/1999	
	353.009	1992	1,934,214.10	284,006.74	1,650,207.36	12/1999	
	353.115	1992	39,492.62	5,798.83	33,693.79	12/1999	
	353.009	1992	1,934,214.10	284,006.74	1,650,207.36	12/1999	
	353.115	1992	39,492.62	5,798.83	33,693.79	12/1999	
	353.009	1998	540,433.43	18,329.37	522,104.06	12/1999	
	353.115	1999	36,265.05	631.60	35,633.45	12/1999	
	353.009	1999	876,858.10	15,271.67	861,586.43	12/1999	
	353.115	1999	75,827.39	1,320.64	74,506.75	12/1999	
	353.009	1975	468,570.44	280,322.06	188,248.38	12/1999	
	353.115	1976	10,930.85	6,211.43	4,719.42	12/1999	
	353.009	1975	471,450.02	282,044.77	189,405.25	12/1999	
	353.115	1976	10,930.85	6,211.43	4,719.42	12/1999	
	353.009	1975	478,759.92	286,417.98	192,341.94	12/1999	
	353.115	1976	10,930.85	6,211.43	4,719.42	12/1999	
	353.009	1981	1,574,406.95	672,533.20	901,873.75	12/1999	
	353.115	1982	140,704.00	56,164.26	84,539.74	12/1999	
	353.009	1980	2,763,226.57	1,257,726.91	1,505,499.66	12/1999	
	353.115	1980	41,210.62	18,757.70	22,452.92	12/1999	
	353.016	1994	140,897.85	15,181.68	125,716.17	12/1999	
	353.009	1980	2,763,226.57	1,257,726.91	1,505,499.66	12/1999	
	353.115	1980	41,210.62	18,757.70	22,452.92	12/1999	
	353.016	1994	139,105.77	14,988.58	124,117.19	12/1999	
	353.009	1981	2,410,474.25	1,029,672.79	1,380,801.46	12/1999	
	353.115	1981	41,210.62	17,603.80	23,606.82	12/1999	
	353.016	1994	167,349.52	18,031.84	149,317.68	12/1999	
	353.009	1995	3,239,671.84	290,759.24	2,948,912.60	12/1999	
	353.115	1996	170,968.63	12,266.94	158,701.69	12/1999	
	353.016	1994	167,349.52	18,031.84	149,317.68	12/1999	
	353.009	1992	1,985,605.96	291,552.79	1,694,053.17	12/1999	
	353.115	1993	131,728.37	16,707.52	115,020.85	12/1999	
	353.016	1992	126,307.64	18,546.16	107,761.48	12/1999	
	353.009	1992	1,978,257.03	290,473.72	1,687,783.31	12/1999	
	353.115	1993	131,728.37	16,707.52	115,020.85	12/1999	
	353.016	1992	126,271.73	18,540.87	107,730.86	12/1999	
	353.009	1993	2,029,332.48	257,386.60	1,771,945.88	12/1999	

ACG(RA)-TD (NETBKSM_86) Net Book Summary Report 04/28/00 10.55.19

Net Book Cost For GSU's And GSU Cooling Banks

Work Order Number :

Plant Account	PA/PU Account	Vintage Year	Original Cost (a)	Accumulated Depreciation (b)	Net Book Value (c)=(a)-(b)	Calculation Through	Note
353	353.115	1993	131,728.37	16,707.52	115,020.85	12/1999	
	353.016	1993	129,531.86	16,428.92	113,102.94	12/1999	
	353.009	1993	1,987,136.54	252,034.79	1,735,101.75	12/1999	
	353.115	1993	131,728.37	16,707.52	115,020.85	12/1999	
	353.016	1993	126,838.50	16,087.32	110,751.18	12/1999	
	353.009	1993	1,988,470.87	252,204.04	1,736,266.83	12/1999	
	353.115	1993	131,728.37	16,707.52	115,020.85	12/1999	
	353.016	1993	126,923.68	16,098.14	110,825.54	12/1999	
	353.009	1993	1,987,161.26	252,037.91	1,735,123.35	12/1999	
	353.115	1993	131,728.37	16,707.52	115,020.85	12/1999	
	353.016	1993	126,840.09	16,087.52	110,752.57	12/1999	
	353.009	1960	348,662.73	348,662.73	.00	12/1999	
	353.115	1960	2,781.12	2,781.12	.00	12/1999	
	353.016	1992	403,915.84	59,308.26	344,607.58	12/1999	
	353.009	1961	380,152.94	380,152.94	.00	12/1999	
	353.115	1961	2,495.88	2,495.88	.00	12/1999	
	353.016	1961	24,265.08	24,265.08	.00	12/1999	
	353.009	1971	312,743.70	226,074.44	86,669.26	12/1999	
	353.115	1971	2,310.56	1,670.28	640.28	12/1999	
	353.016	1971	19,962.36	14,430.33	5,532.03	12/1999	
	353.009	1971	312,216.26	225,693.27	86,522.99	12/1999	
	353.115	1971	2,310.56	1,670.28	640.28	12/1999	
	353.016	1971	19,928.70	14,405.91	5,522.79	12/1999	
	353.009	1971	316,441.34	228,747.41	87,693.93	12/1999	
	353.115	1971	2,310.56	1,670.28	640.28	12/1999	
	353.016	1971	20,198.38	14,600.84	5,597.54	12/1999	
	353.009	1991	3,274,010.06	546,213.41	2,727,796.65	12/1999	
	353.115	1998	375,379.59	12,731.39	362,648.20	12/1999	
	353.009	1996	2,138,391.41	153,428.73	1,984,962.68	12/1999	
	353.115	1996	78,984.70	5,667.11	73,317.59	12/1999	
	353.016	1996	136,493.07	9,793.33	126,699.74	12/1999	
	353.009	1975	303,970.35	181,850.18	122,120.17	12/1999	
	353.016	1975	19,402.36	11,607.50	7,794.86	12/1999	
	353.009	1975	287,925.86	172,251.52	115,674.34	12/1999	
	353.016	1975	60,702.24	36,315.04	24,387.20	12/1999	
	353.009	1975	323,304.69	193,416.84	129,887.85	12/1999	
	353.016	1975	20,636.47	12,345.78	8,290.69	12/1999	
	353.009	1975	323,304.69	193,416.84	129,887.85	12/1999	
	353.016	1975	20,636.47	12,345.78	8,290.69	12/1999	
	353.009	1962	321,903.82	321,903.82	.00	12/1999	
	353.115	1962	5,699.34	5,699.34	.00	12/1999	

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ACG(RA)-TD (NETBKSM_S6) Net Book Summary Report 04/28/00 10.55.19

Net Book Cost For GSU's And GSU Cooling Banks

Work Order Number :

Plant Account	PA/PU Account	Vintage Year	Original Cost (a)	Accumulated Depreciation (b)	Net Book Value (c)=(a)-(b)	Calculation Through	Note
353	353.016	1962	20,570.61	20,570.61	.00	12/1999	
	353.009	1994	2,065,124.92	222,516.38	1,842,608.54	12/1999	
	353.115	1994	129,468.17	13,950.15	115,518.02	12/1999	
	353.009	1958	316,827.77	316,827.77	.00	12/1999	
	353.115	1958	18,322.77	18,322.77	.00	12/1999	
	353.016	1958	20,223.05	20,223.05	.00	12/1999	
	353.009	1972	337,633.90	232,925.07	104,708.83	12/1999	
	353.115	1972	6,585.72	4,543.30	2,042.42	12/1999	
	353.016	1972	21,551.10	14,867.54	6,683.56	12/1999	
	353.009	1972	337,633.90	232,925.07	104,708.83	12/1999	
	353.115	1972	6,585.72	4,543.30	2,042.42	12/1999	
	353.016	1972	21,551.10	14,867.54	6,683.56	12/1999	
	353.009	1983	2,136,776.84	793,099.00	1,343,677.84	12/1999	
	353.115	1983	636,030.41	236,072.90	399,957.51	12/1999	
	353.016	1996	196,263.11	14,081.81	182,181.30	12/1999	
	353.009	1983	2,136,776.84	793,099.00	1,343,677.84	12/1999	
	353.115	1983	636,030.42	236,072.90	399,957.52	12/1999	
	353.016	1997	515,636.85	27,715.27	487,921.58	12/1999	
	353.009	1988	2,323,776.74	550,734.14	1,773,042.60	12/1999	
	353.115	1995	595,164.69	53,415.78	541,748.91	12/1999	
	353.016	1996	507,124.05	36,385.95	470,738.10	12/1999	
	353.009	1997	2,758,814.29	148,285.16	2,610,529.13	12/1999	
	353.115	1998	652,465.99	22,129.07	630,336.92	12/1999	
	353.016	1997	176,094.53	9,465.01	166,629.52	12/1999	
	353.009	1988	706,968.77	167,551.34	539,417.43	12/1999	
	353.115	1988	852.82	202.12	650.70	12/1999	
	353.009	1991	644,821.96	107,577.70	537,244.26	12/1999	
	353.115	1991	42,474.95	7,086.24	35,388.71	12/1999	
	353.009	1987	771,583.18	201,382.91	570,200.27	12/1999	
	353.115	1987	929.15	242.48	686.67	12/1999	
	353.009	1987	771,583.17	201,382.91	570,200.26	12/1999	
	353.115	1987	929.14	242.48	686.66	12/1999	
	353.009	1972	731,974.79	504,970.77	227,004.02	12/1999	
	353.115	1972	98,433.35	67,906.63	30,526.72	12/1999	
	353.016	1997	537,428.89	28,886.59	508,542.30	12/1999	
	353.016	1998	114,922.61	3,897.72	111,024.89	12/1999	
	353.009	1973	731,974.80	481,822.11	250,152.69	12/1999	
	353.115	1973	48,270.15	31,773.71	16,496.44	12/1999	
	353.016	1996	439,905.53	31,563.05	408,342.48	12/1999	
	353.009	1990	2,913,400.15	550,631.44	2,362,768.71	12/1999	
	353.115	1990	141,551.73	26,753.20	114,798.53	12/1999	

ACG(RA)-TD (NETBKSM_S6) Net Book Summary Report 04/28/00 10.55.19

Net Book Cost For GSU's And GSU Cooling Banks

Work Order Number :

Plant Account	PA/PU Account	Vintage Year	Original Cost (a)	Accumulated Depreciation (b)	Net Book Value (c)=(a)-(b)	Calculation Through	Note
353	353.009	1996	2,134,560.54	153,153.86	1,981,406.68	12/1999	
	353.115	1997	506,879.56	27,244.58	479,634.98	12/1999	
	353.016	1996	136,248.54	9,775.78	126,472.76	12/1999	
	353.009	1996	3,012,440.43	216,141.39	2,796,299.04	12/1999	
	353.009	1999	1,915,420.69	36,871.18	1,878,549.51	12/1999	
	353.016	1992	391,863.50	57,538.54	334,324.96	12/1999	
	353.009	1976	754,224.86	428,588.05	325,636.81	12/1999	
	353.009	1970	135,562.63	102,468.31	33,094.32	12/1999	
	353.009	1970	137,763.53	104,131.95	33,631.58	12/1999	
PA TOTAL 353			97,741,683.48	23,452,692.62	74,288,990.86		
* WO TOTAL :			97,741,683.48	23,452,692.62	74,288,990.86		

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ACG(RA)-TD (NETBKSM_S6) Net Book Summary Report 04/28/00 10.55.19

Work Order Number :

Plant Account	PA/PU Account	Vintage Year	Original Cost (a)	Accumulated Depreciation (b)	Net Book Value (c)=(a)-(b)	Calculation Through	Note
TOTAL			97,741,683.48	23,452,692.62	74,288,990.86		

Bulletin No. 152

1912 to July 1, 2000

The Handy-Whitman Index® of Public Utility Construction Costs™

Trends of Construction Costs

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Baltimore, Maryland 21218

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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS 1912	1913	1914	1915	1916	1917	1918	1919	1920	1921	1922	1923	1924	1925
1	Total Plant-All Steam Generation		10	10	9	10	12	14	16	18	20	18	17	18	18	18
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		-	-	-	10	12	5	18	19	21	19	18	18	18	18
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		8	9	9	9	11	15	18	18	20	19	17	18	18	18
7	Structures & Improvements-Indoor	311	-	-	-	9	11	15	16	17	19	17	16	17	17	17
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Boiler Plant Equipment-Coal Fired	312	8	8	8	9	10	16	19	17	18	16	14	16	17	16
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		10	10	10	9	11	18	20	21	19	18	17	18	19	19
12	Turbogenerator Units	314	9	9	9	9	13	14	17	19	22	23	20	19	19	19
13	Accessory Electrical Equipment	315	13	13	13	13	14	16	19	23	26	26	24	24	25	25
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		-	-	-	8	10	13	14	15	16	15	14	15	15	15
23	Structures & Improvements	331	-	-	-	9	11	15	16	17	19	17	16	17	17	17
24	Reservoirs, Dams & Waterways	332	-	-	-	8	9	12	15	16	17	15	15	15	16	16
25	Water Wheels, Turbines & Generators	333	-	-	-	7	9	11	12	13	14	13	12	12	12	12
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		11	11	10	11	13	16	18	20	22	19	18	19	19	19
34	Station Equipment	353	15	15	15	15	16	20	24	27	30	30	27	28	29	29
	Towers & Fixtures	354	7	8	8	8	11	14	15	15	15	14	13	13	15	15
	Poles & Fixtures	355	6	6	6	6	7	9	10	12	13	12	12	12	12	13
	Overhead Conductors & Devices	356	14	14	13	14	20	23	25	27	29	22	20	21	21	22
	Underground Conduit	357	6	6	6	6	6	9	11	12	13	14	13	12	13	13
39	Underground Conductors & Devices	358	12	11	10	11	15	17	19	21	22	18	18	21	20	20
40																
41	**Distribution Plant**															
42	Total Distribution Plant		11	12	11	12	13	15	19	21	22	21	19	19	20	20
43	Station Equipment	362	16	16	16	16	17	20	24	27	30	30	29	29	30	30
44	Poles, Towers & Fixtures	364	6	6	6	6	7	8	10	12	13	12	12	12	12	13
45	Overhead Conductors & Devices	365	11	11	10	11	15	18	20	21	23	17	16	17	17	17
46	Underground Conduit	366	7	8	8	8	8	11	15	16	17	18	17	16	17	17
47	Underground Conductors & Devices	367	12	12	11	11	16	18	20	23	23	19	19	22	21	21
48	Line Transformers	368	42	42	42	42	42	45	62	64	68	70	62	60	62	61
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Services-Overhead	369	11	11	10	10	15	17	18	20	21	15	14	15	15	16
51	Services-Underground	369	9	10	10	11	13	15	17	20	20	17	15	16	15	16
52	Meters Installed	370	31	31	31	31	31	35	39	44	46	49	46	44	43	42
53	Street Lighting-Overhead	373	-	-	-	-	-	-	-	-	-	-	-	-	21	21
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	-	-	-	-	-	-	-	-	-	-	-	-	22	22
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1926	1927	1928	1929	1930	1931	1932	1933	1934	1935	1936	1937	1938	1939
1	Total Plant-All Steam Generation		18	18	18	19	18	18	16	17	18	19	19	21	21	21
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		18	18	18	19	18	17	16	17	18	18	19	20	20	21
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		18	18	18	19	19	18	16	17	19	20	20	22	22	22
7	Structures & Improvements-Indoor	311	17	17	16	16	15	14	13	13	15	15	15	16	16	16
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Boiler Plant Equipment-Coal Fired	312	16	16	16	16	16	16	14	14	16	16	17	19	19	20
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		19	20	20	20	20	20	18	16	16	17	17	19	19	19
12	Turbogenerator Units	314	19	19	19	22	23	22	21	22	25	26	26	29	30	30
13	Accessory Electrical Equipment	315	26	26	26	28	27	26	24	26	27	27	28	30	30	30
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		15	15	15	15	15	14	13	13	14	15	14	15	16	16
23	Structures & Improvements	331	17	17	16	16	15	14	13	13	15	15	15	16	16	16
24	Reservoirs, Dams & Waterways	332	16	15	15	15	15	14	13	13	15	15	14	15	15	16
25	Water Wheels, Turbines & Generators	333	12	12	13	14	14	14	13	13	14	16	16	17	18	19
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		19	19	19	21	19	18	17	17	19	19	20	21	21	21
34	Station Equipment	353	30	29	28	31	30	29	27	29	32	32	32	34	35	35
35	Towers & Fixtures	354	15	14	14	14	14	13	12	12	13	13	13	15	15	15
36	Poles & Fixtures	355	13	12	12	12	12	12	11	11	12	12	12	13	13	14
37	Overhead Conductors & Devices	356	22	22	23	26	23	19	17	18	20	21	22	23	21	22
38	Underground Conduit	357	13	12	12	12	12	12	11	11	12	12	12	12	14	14
39	Underground Conductors & Devices	358	20	19	21	23	19	18	17	18	20	20	21	23	21	21
40																
41	**Distribution Plant**															
42	Total Distribution Plant		19	19	19	20	19	18	17	17	19	19	19	21	21	21
43	Station Equipment	362	29	29	29	30	30	29	28	28	30	31	32	33	34	34
44	Poles, Towers & Fixtures	364	13	11	11	12	11	11	11	10	12	12	11	13	13	13
45	Overhead Conductors & Devices	365	17	17	18	20	18	15	14	14	16	16	17	18	17	17
46	Underground Conduit	366	17	16	16	16	16	16	15	14	16	16	16	16	18	18
47	Underground Conductors & Devices	367	21	20	22	24	20	19	18	19	21	21	23	24	22	23
48	Line Transformers	368	57	53	52	56	55	53	51	52	55	55	55	59	61	61
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Services-Overhead	369	16	16	17	19	16	14	13	14	15	15	16	17	16	16
51	Services-Underground	369	17	17	16	17	17	15	13	14	15	15	16	18	16	16
52	Meters Installed	370	42	42	42	43	43	42	42	43	47	48	48	48	48	48
53	Street Lighting-Overhead	373	20	20	21	22	22	21	20	20	22	22	23	23	23	23
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	22	21	22	23	24	23	23	23	24	24	24	25	24	25
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1940	1941	1942	1943	1944	1945	1946	1947	1948	1949	1950	1951	1952	1953
1	Total Plant-All Steam Generation		21	23	24	24	24	24	28	33	36	38	40	44	45	48
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		21	22	24	24	24	25	28	33	36	38	39	43	44	47
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		23	24	25	25	24	25	29	33	37	39	40	44	45	47
7	Structures & Improvements-Indoor	311	16	18	20	20	20	21	24	28	32	33	34	37	37	39
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	37	37	37	38	41
9	Boiler Plant Equipment-Coal Fired	312	20	21	22	22	22	22	24	28	33	36	38	42	42	44
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		20	21	21	22	22	21	24	27	30	30	33	36	38	39
12	Turbogenerator Units	314	30	30	30	30	30	31	34	41	45	47	47	52	52	55
13	Accessory Electrical Equipment	315	30	32	33	33	31	31	35	40	43	45	48	54	55	58
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	38	39	41	43	45
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		17	18	20	20	21	21	24	29	32	33	34	36	38	40
23	Structures & Improvements	331	16	18	20	20	20	21	24	28	32	33	34	37	37	39
24	Reservoirs, Dams & Waterways	332	16	17	19	19	20	21	24	28	31	32	33	35	37	39
25	Water Wheels, Turbines & Generators	333	20	21	22	23	23	23	26	31	34	35	37	41	43	46
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		22	23	25	25	25	25	28	33	37	38	40	44	46	48
34	Station Equipment	353	35	36	37	37	35	35	40	47	50	53	56	64	65	69
35	Towers & Fixtures	354	15	17	19	19	19	20	24	27	30	31	32	35	37	39
36	Poles & Fixtures	355	14	16	18	19	20	22	24	29	32	32	33	35	37	39
37	Overhead Conductors & Devices	356	23	24	26	27	27	27	31	36	40	40	42	46	48	52
38	Underground Conduit	357	14	15	17	17	17	19	21	24	27	28	29	30	32	34
39	Underground Conductors & Devices	358	22	25	27	26	25	26	30	35	42	47	50	61	62	62
40																
41	**Distribution Plant**															
42	Total Distribution Plant		21	23	24	25	26	26	29	34	38	39	40	44	45	48
43	Station Equipment	362	35	36	37	37	36	36	40	45	48	51	54	58	59	63
44	Poles, Towers & Fixtures	364	14	16	18	18	20	22	23	28	31	31	32	34	36	38
45	Overhead Conductors & Devices	365	18	19	21	21	21	21	24	28	31	32	33	36	38	40
46	Underground Conduit	366	18	20	21	22	22	22	25	29	32	33	34	36	37	39
47	Underground Conductors & Devices	367	23	26	28	27	26	27	31	37	45	49	52	64	66	65
48	Line Transformers	368	61	63	62	58	58	58	65	82	83	87	91	103	103	110
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	102	102	102	102	102
50	Services-Overhead	369	17	18	20	20	20	20	23	27	30	30	32	34	36	38
51	Services-Underground	369	18	21	23	23	23	23	26	29	34	36	37	41	42	42
52	Meters Installed	370	48	48	49	49	49	49	54	61	65	71	71	71	70	73
53	Street Lighting-Overhead	373	23	25	26	26	26	26	29	35	38	42	43	48	49	50
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	26	26	27	28	29	29	30	36	41	42	42	45	45	46
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS 1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967
1	Total Plant-All Steam Generation		49	51	55	59	60	62	61	60	60	61	62	64	66	68
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	64	66	68
3	Total Plant-All Steam & Hydro Gen.		48	50	54	57	58	59	60	59	60	60	62	63	65	68
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		49	51	57	63	65	67	65	63	63	63	65	66	68	70
7	Structures & Improvements-Indoor	311	41	42	46	48	50	51	52	53	54	55	56	57	59	60
8	Structures & Improvements-Semi-Outdoor	311	42	44	50	54	55	57	57	56	57	57	58	59	60	62
9	Boiler Plant Equipment-Coal Fired	312	46	48	54	61	62	65	66	65	65	66	67	68	70	72
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		42	44	49	54	55	58	61	61	62	63	63	64	66	69
12	Turbogenerator Units	314	57	58	68	75	80	79	75	70	68	67	68	69	71	72
13	Accessory Electrical Equipment	315	60	61	65	69	71	71	66	59	59	57	60	64	65	69
14	Misc. Power Plant Equipment	316	46	48	51	54	56	58	59	59	60	61	62	63	65	68
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	66	67	70
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	62	64	65
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	67	69	71
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		42	43	48	51	53	55	56	56	57	59	60	61	63	65
23	Structures & Improvements	331	41	42	46	48	50	51	52	53	54	55	56	57	59	60
24	Reservoirs, Dams & Waterways	332	40	42	45	48	49	52	53	54	56	58	59	60	63	65
25	Water Wheels, Turbines & Generators	333	47	49	56	62	65	66	66	65	64	65	66	67	69	71
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	70	71	74	80
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	62	63	64	67
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	74	74	77	85
31																
32	**Transmission Plant**															
33	Total Transmission Plant		50	52	56	57	59	59	59	57	58	58	60	63	65	68
34	Station Equipment	353	70	72	78	82	85	84	78	70	68	64	68	72	74	78
35	Towers & Fixtures	354	41	42	45	47	49	51	53	54	56	57	59	61	64	67
36	Poles & Fixtures	355	40	41	45	47	48	49	51	52	54	55	56	58	60	62
37	Overhead Conductors & Devices	356	53	56	62	65	64	62	63	63	64	60	63	66	68	70
38	Underground Conduit	357	35	36	39	41	43	44	46	48	49	51	52	53	55	57
39	Underground Conductors & Devices	358	64	57	66	58	57	60	61	60	60	61	65	70	71	73
40																
41	**Distribution Plant**															
42	Total Distribution Plant		49	51	54	55	56	57	58	58	58	59	60	62	64	67
43	Station Equipment	362	65	67	73	77	80	80	78	73	73	71	73	75	76	80
44	Poles, Towers & Fixtures	364	39	40	44	46	47	48	50	51	53	54	55	57	59	61
45	Overhead Conductors & Devices	365	42	45	49	49	48	50	51	52	52	53	55	58	60	64
46	Underground Conduit	366	41	43	45	47	49	51	52	54	56	57	58	59	60	61
47	Underground Conductors & Devices	367	67	71	69	61	60	63	64	63	63	64	68	74	75	76
48	Line Transformers	368	111	111	115	122	118	114	112	109	99	93	93	95	96	99
49	Pad Mounted Transformers	368	102	102	102	102	102	102	100	95	95	95	91	91	93	96
50	Services-Overhead	369	39	43	45	44	43	46	47	48	48	50	51	54	56	60
51	Services-Underground	369	42	42	44	44	42	43	41	42	44	45	47	50	54	57
52	Meters Installed	370	75	72	75	79	81	83	84	83	83	83	83	83	83	84
53	Street Lighting-Overhead	373	53	54	56	61	64	64	64	63	63	64	66	66	68	71
54	Mast Arms & Luminaires Installed	373	-	58	65	71	71	66	67	66	65	66	67	68	72	71
55	Street Lighting-Underground	373	51	53	54	58	60	61	61	60	60	60	61	61	66	73
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS 1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
1	Total Plant-All Steam Generation		71	76	81	88	94	100	120	139	148	157	166	182	199	217
2	Total Plant-All Steam & Nuclear Gen.		71	76	81	88	94	100	119	139	148	157	166	182	199	217
3	Total Plant-All Steam & Hydro Gen.		71	76	82	88	94	100	119	139	147	156	166	181	198	216
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		72	75	80	87	95	100	118	137	147	157	170	187	205	223
7	Structures & Improvements-Indoor	311	65	70	73	82	93	100	115	127	131	139	152	164	179	191
8	Structures & Improvements-Semi-Outdoor	311	65	70	75	82	91	100	125	139	139	144	156	173	196	205
9	Boiler Plant Equipment-Coal Fired	312	74	77	82	89	94	100	120	142	153	163	177	195	213	232
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		71	74	81	89	96	100	113	127	138	149	165	183	198	215
12	Turbogenerator Units	314	72	75	80	88	96	100	110	129	142	155	166	183	200	222
13	Accessory Electrical Equipment	315	73	77	83	88	95	100	116	135	145	158	164	178	193	214
14	Misc. Power Plant Equipment	316	71	76	82	88	94	100	115	129	137	149	161	177	194	217
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		71	75	81	88	95	100	114	129	139	151	162	177	195	212
18	Structures & Improvements	321	68	72	77	85	92	100	114	126	134	149	161	178	196	210
19	Reactor Plant Equipment	322	73	77	83	89	95	100	114	129	140	149	159	173	191	208
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		69	73	77	84	92	100	115	129	134	145	157	172	188	205
23	Structures & Improvements	331	65	70	73	82	93	100	115	127	131	139	152	164	179	191
24	Reservoirs, Dams & Waterways	332	68	72	76	83	91	100	116	129	132	141	152	167	182	198
25	Water Wheels, Turbines & Generators	333	73	78	83	88	95	100	114	130	143	157	171	189	208	233
26																
27	**Other Production Plant**															
28	Total Other Production Plant		84	88	92	96	98	100	109	133	145	159	166	180	193	212
29	Fuel Holders, Producers & Accessories	342	69	74	80	88	95	100	115	130	142	152	166	183	201	218
30	Gas Turbogenerators	344	89	92	95	98	100	100	107	133	147	162	168	181	194	213
31																
32	**Transmission Plant**															
33	Total Transmission Plant		71	77	82	89	93	100	123	145	154	163	167	180	200	216
34	Station Equipment	353	81	84	88	90	93	100	125	149	155	165	176	189	206	223
35	Towers & Fixtures	354	70	74	78	84	92	100	124	142	143	148	161	178	201	213
36	Poles & Fixtures	355	65	71	76	79	86	100	127	145	146	150	159	176	193	212
37	Overhead Conductors & Devices	356	71	78	88	97	99	100	117	147	169	181	171	184	207	224
38	Underground Conduit	357	60	66	72	83	95	100	112	125	135	145	157	170	185	202
39	Underground Conductors & Devices	358	70	77	81	81	91	100	134	136	140	151	151	179	214	234
40																
41	**Distribution Plant**															
42	Total Distribution Plant		70	76	82	87	93	100	119	139	147	155	163	177	192	210
43	Station Equipment	362	83	87	90	91	93	100	124	145	149	160	170	182	198	213
44	Poles, Towers & Fixtures	364	64	70	75	80	87	100	126	146	146	152	163	184	202	220
45	Overhead Conductors & Devices	365	67	75	85	93	98	100	115	143	162	173	168	181	201	218
46	Underground Conduit	366	64	70	76	84	94	100	111	123	129	138	149	162	175	191
47	Underground Conductors & Devices	367	74	81	85	86	98	100	124	129	134	143	151	184	209	212
48	Line Transformers	368	103	100	100	101	99	100	109	130	134	145	155	163	165	192
49	Pad Mounted Transformers	368	98	95	95	97	100	100	104	106	108	119	132	139	160	187
50	Services-Overhead	369	63	71	81	89	96	100	108	121	131	141	152	165	185	196
51	Services-Underground	369	61	67	72	76	86	100	115	107	112	118	125	136	163	180
52	Meters Installed	370	87	90	95	98	100	100	108	124	134	140	144	149	147	164
53	Street Lighting-Overhead	373	73	79	86	91	96	100	121	148	158	169	184	204	223	244
54	Mast Arms & Luminaires Installed	373	71	76	89	94	97	100	118	138	153	168	182	199	222	248
55	Street Lighting-Underground	373	70	75	86	92	98	100	120	148	159	171	187	208	225	245
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1982	1983	1984	1985	1986	1987	1988 Jan. 1	1988 Jul. 1	1989 Jan. 1	1989 Jul. 1	1990 Jan. 1	1990 Jul. 1	1991 Jan. 1	1991 Jul. 1
1	Total Plant-All Steam Generation		227	232	237	241	242	246	253	263	268	275	279	282	282	285
2	Total Plant-All Steam & Nuclear Gen.		228	233	237	241	242	246	253	263	268	275	279	282	282	284
3	Total Plant-All Steam & Hydro Gen.		226	231	236	239	241	245	251	262	267	273	277	280	280	282
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		233	239	248	253	255	261	270	279	280	288	293	294	297	296
7	Structures & Improvements-Indoor	311	195	201	208	214	217	219	221	227	227	237	237	235	232	232
8	Structures & Improvements-Semi-Outdoor	311	200	201	212	219	222	226	229	237	238	246	250	245	240	233
9	Boiler Plant Equipment-Coal Fired	312	242	248	257	264	268	277	289	296	292	305	310	314	318	319
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		230	227	227	230	231	240	256	264	267	270	271	270	267	273
12	Turbogenerator Units	314	234	246	254	257	254	259	270	277	282	284	290	289	295	294
13	Accessory Electrical Equipment	315	237	244	239	239	241	242	246	275	282	287	290	294	294	296
14	Misc. Power Plant Equipment	316	235	246	254	263	268	274	281	286	293	299	304	307	310	314
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		226	232	236	240	242	247	254	261	267	272	275	277	278	279
18	Structures & Improvements	321	218	220	225	229	231	232	236	242	245	250	250	252	250	252
19	Reactor Plant Equipment	322	223	230	234	239	242	251	262	264	270	278	282	283	285	286
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		213	218	224	231	232	234	238	248	246	251	255	253	256	250
23	Structures & Improvements	331	195	201	208	214	217	219	221	227	227	237	237	235	232	232
24	Reservoirs, Dams & Waterways	332	205	208	213	220	222	222	225	235	236	234	234	238	237	227
25	Water Wheels, Turbines & Generators	333	247	256	265	270	271	276	285	296	299	303	323	303	325	326
26																
27	**Other Production Plant**															
28	Total Other Production Plant		228	233	235	238	241	258	266	309	311	324	328	329	327	334
29	Fuel Holders, Producers & Accessories	342	230	228	231	236	241	246	253	262	266	273	281	279	283	285
30	Gas Turbogenerators	344	230	236	239	241	245	266	275	326	328	342	346	347	345	355
31																
32	**Transmission Plant**															
33	Total Transmission Plant		224	228	229	231	233	234	239	262	268	273	275	284	280	289
34	Station Equipment	353	235	236	238	241	242	248	253	257	266	273	278	291	293	289
35	Towers & Fixtures	354	210	211	222	228	232	237	241	249	250	257	257	257	251	245
36	Poles & Fixtures	355	222	225	229	230	233	235	238	255	269	277	281	282	297	305
37	Overhead Conductors & Devices	356	229	245	235	234	236	226	250	309	308	304	297	316	291	337
38	Underground Conduit	357	213	214	215	214	215	219	225	231	241	249	245	243	242	241
39	Underground Conductors & Devices	358	247	249	244	236	258	261	259	282	272	296	320	345	369	391
40																
41	**Distribution Plant**															
42	Total Distribution Plant		221	225	227	228	229	231	235	241	252	255	259	263	262	267
43	Station Equipment	362	224	222	225	229	232	241	249	257	271	283	285	308	310	305
44	Poles, Towers & Fixtures	364	229	229	230	231	234	235	235	242	246	252	259	259	264	270
45	Overhead Conductors & Devices	365	227	238	238	237	238	236	250	283	287	289	284	292	281	305
46	Underground Conduit	366	196	204	208	207	207	211	216	221	238	250	246	241	237	233
47	Underground Conductors & Devices	367	210	210	209	213	222	227	232	224	239	244	256	253	256	261
48	Line Transformers	368	206	209	210	211	212	211	213	208	221	219	226	223	223	222
49	Pad Mounted Transformers	368	185	186	202	204	210	233	246	256	261	273	273	273	280	285
50	Services-Overhead	369	204	206	218	214	213	218	223	235	249	253	249	250	249	251
51	Services-Underground	369	179	197	199	181	174	186	205	181	227	214	210	225	212	204
52	Meters Installed	370	189	202	202	203	208	207	197	195	186	182	186	181	185	203
53	Street Lighting-Overhead	373	258	258	268	276	275	262	261	263	269	275	278	282	284	290
54	Mast Arms & Luminaires Installed	373	260	265	281	291	283	272	269	272	281	289	293	296	300	307
55	Street Lighting-Underground	373	262	261	269	277	276	262	261	263	267	273	278	280	282	287
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	1992 Jan. 1	1992 Jul. 1	1993 Jan. 1	1993 Jul. 1	1994 Jan. 1	1994 Jul. 1	1995 Jan. 1	1995 Jul. 1	1996 Jan. 1	1996 Jul. 1	1997 Jan. 1	1997 Jul. 1	1998 Jan. 1	1998 Jul. 1
1	Total Plant-All Steam Generation		282	287	293	294	301	306	315	316	321	320	326	327	335	335
2	Total Plant-All Steam & Nuclear Gen.		281	286	293	294	301	306	314	316	321	320	325	326	334	334
3	Total Plant-All Steam & Hydro Gen.		279	284	291	292	299	303	312	314	318	318	323	324	332	332
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		298	301	308	312	321	324	332	334	339	340	350	350	357	356
7	Structures & Improvements-Indoor	311	230	236	243	246	253	258	264	264	268	269	275	276	280	279
8	Structures & Improvements-Semi-Outdoor	311	227	233	241	244	249	261	266	266	274	278	283	284	286	288
9	Boiler Plant Equipment-Coal Fired	312	321	325	332	337	344	346	352	354	360	361	370	370	377	376
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		273	273	274	279	283	284	287	292	295	294	304	298	305	302
12	Turbogenerator Units	314	297	298	305	307	323	322	335	337	338	339	353	351	361	359
13	Accessory Electrical Equipment	315	300	305	314	319	320	323	333	343	349	349	354	358	366	367
14	Misc. Power Plant Equipment	316	316	320	327	332	340	350	356	357	359	361	366	373	378	379
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		280	283	289	293	302	302	311	314	317	318	326	327	332	332
18	Structures & Improvements	321	250	256	261	267	275	277	285	282	288	292	299	301	304	303
19	Reactor Plant Equipment	322	288	290	294	296	305	304	311	317	318	317	325	324	330	330
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		248	253	259	262	268	272	280	281	282	288	295	295	300	299
23	Structures & Improvements	331	230	236	243	246	253	258	264	264	268	269	275	276	280	279
24	Reservoirs, Dams & Waterways	332	225	232	236	240	245	250	258	258	259	268	273	274	276	276
25	Water Wheels, Turbines & Generators	333	325	323	330	331	342	339	348	354	352	356	367	366	378	376
26																
27	**Other Production Plant**															
28	Total Other Production Plant		334	338	348	345	340	337	336	343	347	356	356	356	367	367
29	Fuel Holders, Producers & Accessories	342	283	287	289	294	296	298	302	304	311	313	318	320	327	328
30	Gas Turbogenerators	344	354	358	369	364	357	352	349	357	360	371	370	370	382	382
31																
32	**Transmission Plant**															
33	Total Transmission Plant		276	285	295	293	300	308	322	323	329	328	333	333	344	345
34	Station Equipment	353	286	297	308	306	312	324	334	336	339	335	338	339	351	352
35	Towers & Fixtures	354	243	246	255	258	264	275	280	281	290	294	300	300	304	306
36	Poles & Fixtures	355	309	324	317	324	335	343	356	354	358	371	376	380	389	389
37	Overhead Conductors & Devices	356	287	291	312	300	307	310	337	342	349	344	350	345	363	363
38	Underground Conduit	357	236	239	242	243	247	248	252	252	255	254	259	256	266	265
39	Underground Conductors & Devices	358	391	393	395	397	398	399	402	411	413	412	415	416	420	420
40																
41	**Distribution Plant**															
42	Total Distribution Plant		261	267	272	270	274	280	286	288	293	288	287	290	298	298
43	Station Equipment	362	296	318	317	316	311	326	338	343	340	332	334	333	354	356
44	Poles, Towers & Fixtures	364	271	284	285	287	298	308	312	317	327	321	331	331	338	337
45	Overhead Conductors & Devices	365	278	280	297	290	298	302	320	327	332	328	334	333	347	348
46	Underground Conduit	366	230	231	233	236	241	243	251	247	251	251	256	255	264	263
47	Underground Conductors & Devices	367	259	261	265	264	264	265	270	279	281	282	282	282	287	289
48	Line Transformers	368	223	228	229	226	229	233	232	225	231	225	210	214	216	217
49	Pad Mounted Transformers	368	280	281	282	290	291	291	282	293	294	304	305	306	308	308
50	Services-Overhead	369	244	242	253	248	253	259	269	273	279	271	267	274	281	281
51	Services-Underground	369	211	200	204	202	205	212	215	219	219	215	214	220	219	213
52	Meters Installed	370	197	193	201	200	192	185	187	181	188	187	188	204	206	206
53	Street Lighting-Overhead	373	295	297	306	310	318	327	331	341	350	357	366	365	369	367
54	Mast Arms & Luminaires Installed	373	317	318	323	326	336	349	354	358	367	383	393	389	392	387
55	Street Lighting-Underground	373	292	293	303	307	314	320	324	335	343	350	358	357	362	361
56																

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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

SOUTH ATLANTIC REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS 1999 Jan. 1	1999 Jul. 1	2000 Jan. 1	2000 Jul. 1	2001 Jan. 1	2001 Jul. 1	2002 Jan. 1	2002 Jul. 1	2003 Jan. 1	2003 Jul. 1	2004 Jan. 1	2004 Jul. 1	2005 Jan. 1	2005 Jul. 1
1	Total Plant-All Steam Generation		337	337	342	354										
2	Total Plant-All Steam & Nuclear Gen.		336	336	341	353										
3	Total Plant-All Steam & Hydro Gen.		334	334	339	350										
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		361	364	372	386										
7	Structures & Improvements-Indoor	311	288	287	293	308										
8	Structures & Improvements-Semi-Outdoor	311	290	294	305	308										
9	Boiler Plant Equipment-Coal Fired	312	384	385	391	409										
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-										
11	Boiler Plant Piping Installed		316	311	312	322										
12	Turbogenerator Units	314	360	364	375	386										
13	Accessory Electrical Equipment	315	368	376	383	404										
14	Misc. Power Plant Equipment	316	388	392	401	415										
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		335	339	345	355										
18	Structures & Improvements	321	307	313	316	326										
19	Reactor Plant Equipment	322	334	334	339	348										
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		301	303	311	315										
23	Structures & Improvements	331	288	287	293	308										
24	Reservoirs, Dams & Waterways	332	278	280	288	289										
25	Water Wheels, Turbines & Generators	333	372	377	386	386										
26																
27	**Other Production Plant**															
28	Total Other Production Plant		380	383	390	416										
29	Fuel Holders, Producers & Accessories	342	339	336	338	347										
30	Gas Turbogenerators	344	396	399	407	437										
31																
32	**Transmission Plant**															
33	Total Transmission Plant		343	338	341	360										
34	Station Equipment	353	353	356	360	381										
35	Towers & Fixtures	354	311	314	322	324										
36	Poles & Fixtures	355	375	378	372	376										
37	Overhead Conductors & Devices	356	359	324	326	366										
38	Underground Conduit	357	280	271	275	277										
39	Underground Conductors & Devices	358	421	433	423	425										
40																
41	**Distribution Plant**															
42	Total Distribution Plant		300	297	299	304										
43	Station Equipment	362	356	358	359	360										
44	Poles, Towers & Fixtures	364	336	339	339	342										
45	Overhead Conductors & Devices	365	346	332	336	361										
46	Underground Conduit	366	266	271	278	278										
47	Underground Conductors & Devices	367	291	296	295	300										
48	Line Transformers	368	222	217	218	218										
49	Pad Mounted Transformers	368	309	310	311	311										
50	Services-Overhead	369	279	279	284	287										
51	Services-Underground	369	210	209	216	223										
52	Meters Installed	370	210	196	192	193										
53	Street Lighting-Overhead	373	371	374	376	378										
54	Mast Arms & Luminaires Installed	373	387	388	388	392										
55	Street Lighting-Underground	373	365	368	372	374										
56																

Q.

Provide all work papers and any other supporting documentation used to prepare Witness Holcombe's Exhibit BLH-3.

A.

Please refer to Witness Holcombe's Exhibit BLH-1, Business Blueprint Documents, Section 5, Cost Estimates, including pages 36 - 28.

Exhibit BLH-3, Page 1 of 3, Line 4, Columns (7) and (10) the sum of $10,985 (000) is supported by attached worksheet showing amount of $10,984,642.

6. Provide all work papers and any other supporting documentation used to prepare Witness Holcombe's Exhibit BLH-3.

SYSTEM SOFTWARE COST SUMMARY

		% of Total Cost
Distribution Total	$3,701,329	26%
Generation Software Total	$1,005,998	10%
Generation License Total	$280,988	
Transmission Total	$2,369,349	18%
Total of System to be allocated	$6,112,479	46%
Additional ESCA Licenses	$248,620	
System Software Total	$13,470,142	100%

LABOR EXPENSES

	FPL Payroll	Consultant	ESCA	Training	Totals
Distribution Total	$1,550,601	$467,699	$4,227,451	$137,181	$6,382,932
Generation Software Total	$305,189	$51,507	$832,057	$99,000	$1,287,753
Transmission Total	$1,196,105	$213,589	$3,261,064	$105,819	$4,776,576
FPL System Totals	$3,051,895	$732,794	$8,320,572	$342,000	$12,447,261

GRID FLORIDA SYSTEM COSTS- NO HARDWARE

Allocation Percentage based on Transmission Points 46.07%

	First Release	End State	System Total	GridFlorida costs from: FPL	Others
Allocated System Cost	$2,816,096.81			$2,816,097	
Transmission Only Software	$2,369,349			$2,369,349	
Generation Software(50% Allocation)		$502,999		$502,999	
Generation Software License - Non transferable(see Note)		$280,988			$280,988
Non sharable ESCA licenses (see Note)		$248,620			$248,620
System Software Total	$5,185,446	$1,032,607	$6,218,053		
Labor Costs (End state allocated at 50% for Gen)	First Release	End State	Totals		
FPL	$1,196,105	$152,595	$1,348,699	$1,348,699	
Consultant	$213,589	$25,753	$239,342	$239,342	
ESCA	$3,261,064	$416,029	$3,677,093	$3,677,093	
Training (20% of total for start up)	$21,163.79	$9,900	$31,064	$31,063.79	
Totals	$4,691,921	$604,277	$5,296,198		
TOTAL SYSTEM COSTS TO GRID FLORIDA	$9,877,367	$1,636,883	$11,514,250	$10,984,642	$529,608
					$11,514,250

Note--Costs for Generation and "Non sharable" licenses may be obtained as an incremental costs from ESCA at some reduced cost.

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Q.

Provide the land use agreement that will allow GridFlorida access to access FPL's land and land rights.

A.

No such agreements yet have been entered into. In as much as FPL plans to retain ownership of its land and land rights, but make access available to GridFlorida for operations, FPL expects to enter into such an agreement sometime prior to the commencement of commercial operations.

Q.

Provide all documents referred to or relied upon in assuming a 30% contingency for Release 1 start up costs.

A.

No specific documents are available. The contingency reflects Accenture's experience in working on projects of this nature where there are estimating uncertainties resulting from the fact that the project is early in the development cycle and GridFlorida requirements are not yet complete. The use of the 30% contingency is a standard component in Accenture's estimating models for projects of this nature at this stage in development.

Q.

Provide all documents referred to or relied upon in determining that divested transmission assets should be transferred to GridFlorida at net book value.

A.

There is no such supporting documentation

Q.

Provide copies of all documents used by the company in developing the replacement value updated as of December 31, 2000.

A.

Please see attached excel workpapers. Detail entries are too voluminous. A summary of accounts is attached.

CO	G/L	CPR	CPR DESCRIPTION	PLT	BALANCE A/O 12/31/2000	REPLACEMENT COST	
				301	$125,000.00	$125,000.00	
				302	$77,627.33	$77,627.33	
				303	$193,799,935.16	$193,799,935.16	
				310	$29,867,551.90	$29,867,551.90	
				311	$608,664,736.90	$1,090,177,801.16	
				312	$1,434,139,211.42	$2,757,166,100.62	
				314	$638,207,729.93	$1,428,663,843.76	
				315	$182,925,905.62	$381,761,548.54	
				316	$46,340,423.12	$91,721,138.68	
				320	$12,590,563.42	$12,590,563.42	
				321	$1,008,101,802.66	$1,691,162,115.82	
				322	$1,407,265,629.23	$2,233,866,733.86	
				323	$444,684,766.33	$804,825,483.99	
				324	$535,994,344.96	$875,143,799.12	
				325	$112,767,277.58	$172,289,245.35	
				340	$3,365,293.31	$3,365,293.31	
				341	$147,857,964.33	$206,423,734.91	
				342	$46,925,711.17	$76,557,625.86	
				343	$843,626,022.10	$1,278,910,542.17	
				344	$146,831,953.44	$313,536,529.47	
				345	$138,960,961.15	$207,246,997.60	
				346	$17,453,918.11	$23,164,263.29	
				350	$177,935,984.21	$177,935,984.21	
				352	$45,657,319.72	$74,205,531.23	$74,205,531.23
				353	$803,746,360.85	$1,347,402,689.09	$1,347,402,689.09
				354	$272,439,861.35	$422,101,912.67	$422,101,912.67
				355	$375,454,993.94	$836,999,706.58	$836,999,706.58
				356	$422,766,563.03	$719,040,985.44	$719,040,985.44
				357	$35,340,875.87	$85,682,075.16	$85,682,075.16
				358	$39,947,834.94	$122,591,438.84	$122,591,438.84
				359	$72,433,645.89	$110,810,048.89	
				360	$35,157,707.33	$35,157,707.33	
				361	$70,973,823.61	$116,707,542.38	
				362	$803,934,534.04	$1,362,030,943.21	
				364	$533,324,643.60	$905,322,229.29	
				365	$787,945,856.83	$1,250,913,640.31	
				366	$622,176,338.54	$903,818,312.09	
				367	$1,083,181,263.94	$1,491,142,819.53	
				368	$1,225,118,999.42	$1,526,138,227.53	
				369	$511,292,106.78	$686,584,034.23	
				370	$339,378,036.44	$398,754,917.28	
				371	$100,967,762.89	$116,986,890.10	
				373	$247,020,216.58	$376,276,411.80	
				389	$31,541,030.84	$31,541,030.84	
				390	$326,251,274.54	$502,281,956.73	
				391	$86,470,831.32	$90,807,004.15	
				392	$225,946,925.33	$270,798,548.96	

	393	$16,912,230.22	$17,727,574.74		
	394	$26,203,687.16	$27,512,089.84		
	395	$34,651,740.33	$36,603,143.35		
	396	$5,681,591.85	$8,894,239.48		
	397	$96,647,736.96	$101,367,464.40		
	398	$5,542,608.67	$5,917,622.91		
101000 Total		$17,462,618,716.19	$28,032,498,197.91		
	310	$34,762.25	$34,762.25		
	311	$468,233.10	$1,598,875.70		
	314	$2,656,441.23	$14,238,361.26		
	315	$1,017,931.81	$6,195,958.44		
	316	$61,920.30	$94,118.86		
	320	$21,420,638.44	$21,420,638.44		
	350	$17,565,855.10	$17,565,855.10		
	352	$1,136,140.83	$1,413,948.85		
	353	$152,029.70	$192,313.63		
	357	$1,046,430.41	$1,161,537.76		
	360	$8,663,319.13	$8,663,319.13		
	361	$1,275,453.45	$1,606,265.12		
	362	$162,871.38	$185,845.30		
	389	$5,649,812.34	$5,649,812.34		
	390	$26,379.82	$37,923.30		
105000 Total		$61,338,219.29	$80,059,535.48		
	303	$63,159,937.60	$63,159,937.60		
	310	$61,294.48	$61,294.48		
	311	$939,591.99	$939,591.99		
	312	$14,195,015.42	$14,200,337.97		
	314	$5,166,477.96	$5,166,477.96		
	315	$1,985,189.33	$2,023,456.61		
	316	$1,653,263.69	$1,653,326.33		
	320	($10,972.77)	($10,972.77)		
	321	($152,692.27)	($158,183.49)		
	322	($6,283,954.12)	($6,496,556.23)		
	323	($675,984.01)	($750,850.43)		
	324	($31,333.75)	($78,472.32)		
	325	$312,383.55	($143,041.87)		
	341	$27,815,016.35	$27,815,016.35		
	342	$2,824,399.47	$2,824,399.47		
	343	$107,102,554.27	$107,125,850.34		
	344	$659,444.62	$659,444.62		
	345	$9,334,477.84	$9,334,477.84		
	346	$1,134,779.15	$1,134,779.15		
	350	$523,184.79	$523,184.79		
	352	$294,750.41	$298,907.21	$298,907.21	$74,504,438.44
	353	$6,797,982.81	$6,772,437.10	$6,772,437.10	$1,354,175,126.19
	354	$70,793.74	$70,793.74	$70,793.74	$422,172,706.41
	355	$12,782,036.93	$12,774,925.97	$12,774,925.97	$849,774,632.55
	356	$9,867,121.79	$9,839,140.63	$9,839,140.63	$728,880,126.07

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	357	$281,389.25	$281,498.22	$281,498.22	$85,963,573.38
	358	$362,155.09	$362,159.63	$362,159.63	$122,953,598.47
	359	$260,009.41	$260,009.41		
	360	$1,545,179.59	$1,545,179.59		
	361	$6,285,242.12	$6,324,327.93		
	362	$28,179,008.83	$28,209,734.80		
	364	$11,360,096.61	$11,368,113.00		
	365	$13,435,424.67	$13,448,438.24		
	366	$18,337,841.89	$18,389,211.94		
	367	$28,668,554.86	$28,671,652.36		
	368	$9,124,755.73	$9,125,143.10		
	369	$9,980,307.58	$10,006,210.65		
	370	$344,272.48	$343,203.64		
	371	$624,105.80	$623,675.67		
	373	$4,558,184.37	$4,546,597.80		
	389	$0.00	$0.00		
	390	$9,337,359.42	$9,305,428.70		
	391	$29,662,268.41	$29,872,275.62		
	392	$3,056,935.17	$3,085,845.57		
	393	$1,316,354.20	$1,319,564.18		
	394	$911,775.05	$911,679.53		
	395	$820,432.11	$820,090.96		
	397	$1,880,641.70	$1,890,612.81		
	398	$185,899.39	$192,679.01		
106100 Total		$440,042,953.00	$439,643,035.40		
	350	($15,642.00)	($15,642.00)		
	360	($19,604.66)	($19,604.66)		
106200 Total		($35,246.66)	($35,246.66)		
	360	$1,330,979.95	$1,330,979.95		
106500 Total		$1,330,979.95	$1,330,979.95		
	310	$38,364.43	$38,364.43		
	340	$691,914.36	$691,914.36		
	350	$2,818,287.63	$2,818,287.63		
	360	$1,026,802.39	$1,026,802.39		
	361	$17,225.66	$62,204.20		
	389	$1,008,834.94	$1,008,834.94		
121100 Total		$5,601,429.41	$5,646,407.95		
01 Total		$17,970,897,051.18	$28,559,142,910.03		
	Grar	$17,970,897,051.18	$28,559,142,910.03		
Grand Total		$17,970,897,051.18	$28,559,142,910.03		
Grand Total		$17,970,897,051.18	$28,559,142,910.03		

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Florida Power Light
Docket No. 001148-EI
Staff's Fourth Request For the Production of Documents
Request #12

Reconciliation of Transmission Plant 2000

G/L	Plt. Acct.	Original Cost	Replacement Cost	Account 101 and 106 Replacement Cost	Account 105 Replacement Cost	Factor for GSU's =F10/C12	GSU Replacement Cost
101	352	$45,657,319.72	$74,205,531.23				
106	352	$294,750.41	$298,907.21	**$74,504,438.44**			
105	352		$1,413,948.85		**$1,413,948.85**		
Total		**$45,952,070.13**	**$75,918,387.29**				
101	353	$803,746,360.85	$1,347,402,689.09				
106	353	$6,797,982.81	$6,772,437.10	**$1,354,175,126.19**		**167%**	**$ 187,331,248.55**
105	353		$192,313.63		**$192,313.63**		
Total		**$810,544,343.66**	**$1,354,367,439.82**				
101	354	$272,439,861.35	$422,101,912.67				
106	354	$70,793.74	$70,793.74	**$422,172,706.41**			
Total		**$272,510,655.09**	**$422,172,706.41**				
101	355	$375,454,993.94	$836,999,706.58				
106	355	$12,782,036.93	$12,774,925.97	**$849,774,632.55**			
Total		**$388,237,030.87**	**$849,774,632.55**				
101	356	$422,766,563.03	$719,040,985.44				
106	356	$9,867,121.79	$9,839,140.63				
Total		**$432,633,684.82**	**$728,880,126.07**	**$728,880,126.07**			
101	357	$35,340,875.87	$85,682,075.16				
106	357	$281,389.25	$281,498.22	**$85,963,573.38**			
105	357		$1,161,537.76		**$1,161,537.76**		
Total		**$35,622,265.12**	**$87,125,111.14**				
101	358	$39,947,834.94	$122,591,438.84				
106	358	$362,155.09	$362,159.63				
Total		**$40,309,990.03**	**$122,953,598.47**	**$122,953,598.47**			
101	359	$72,433,645.89	$110,810,048.89				
106	359	$260,009.41	$260,009.41				
Total		**$72,693,655.30**	**$111,070,058.30**	**$3,638,424,201.51**	**$2,767,800.24**		**$187,331,248.55**

105	352	$1,136,140.83
	353	$152,029.70
	354	$0.00
	355	$0.00
	356	$0.00
	357	$1,046,430.41
	358	$0.00
	359	$0.00
Total		**$2,334,600.94**

GSU Investment as of December 2000	Factor	Replacement Cost
$ 112,127,509.19	167%	$ 187,331,248.55

Q.

Provide all supporting documents used or relied upon in the development of the reproduction cost or the market value of FPL's transmission assets to be transferred to GridFlorida.

A.

FPL did not establish the reproduction cost or the market value of FPL's assets being transferred to GridFlorida, and therefore there are no responsive documents to this request.

Q. Please provide all documentation of any accounting procedures suggested or provided by FERC related to transferring assets from the participating companies to GridFlorida.

A. Excerpts from the Uniform System of Accounts 18CFR Ch.1 Pt.101

Electric Plant Instructions

2. Electric Plant To Be Recorded at Cost.

A. All amounts included in the accounts for electric plant acquired as an operating unit or system, except as otherwise provided in the texts of the intangible plant accounts, shall be stated at the cost incurred by the person who first devoted the property to utility service. All other electric plant shall be included in the accounts at the cost incurred by the utility, except for property acquired by lease which qualifies as capital lease property under General Instruction 19.

5. Electric Plant Purchased or Sold.

A. When electric plant constituting an operating unit or system is acquired by purchase, merger, consolidation, liquidation, or otherwise, after the effective date of this system of accounts, the costs of acquisition, including expenses incidental thereto properly includible in electric plant, shall be charged to account 102, Electric Plant Purchased or Sold.

B. The accounting for the acquisition shall then be completed as follows:

(1) The original cost of plant, estimated if not known, shall be credited to account 102, Electric Plant Purchased or Sold, and concurrently charged to the appropriate electric plant in service accounts and to account 104, Electric Plant Leased to Others, account 105, Electric Plant Held for Future Use, and account 107, Construction Work in Progress--Electric, as appropriate.

(2) The depreciation and amortization applicable to the original cost of the properties purchased shall be charged to account 102, Electric Plant Purchased or Sold, and concurrently credited to the appropriate account for accumulated provision for depreciation or amortization.

(3) The cost to the utility of any property includible in account 121, Nonutility Property, shall be transferred thereto.

(4) The amount remaining in account 102, Electric Plant Purchased or Sold, shall then be closed to account 114, Electric Plant Acquisition Adjustments.

C. If property acquired in the purchase of an operating unit or system is in such physical condition when acquired that it is necessary substantially to rehabilitate it in order to bring the property up to the standards of the utility, the cost of such work, except replacements, shall be accounted for as a part of the purchase price of the property.

D. When any property acquired as an operating unit or system includes duplicate or other plant which will be retired by the accounting utility in the reconstruction of the acquired property or its consolidation with previously owned property, the proposed accounting for such property shall be presented to the Commission.

E. In connection with the acquisition of electric plant constituting an operating unit or system, the utility shall procure, if possible, all existing records relating to the property acquired, or certified copies thereof, and shall preserve such records in conformity with regulations or practices governing the preservation of records of its own construction.

F. When electric plant constituting an operating unit or system is sold, conveyed, or transferred to another by sale, merger, consolidation, or otherwise, the book cost of the property sold or transferred to another shall be credited to the appropriate utility plant accounts, including amounts carried in account 114, Electric Plant Acquisition Adjustments. The amounts (estimated if not known) carried with respect thereto in the accounts for accumulated provision for depreciation and amortization and in account 252, Customer Advances for Construction, shall be charged to such accounts and contra entries made to account 102, Electric Plant Purchased or Sold. Unless otherwise ordered by the Commission, the difference, if any, between (1) the net amount of debits and credits and (2) the consideration received for the property (less commissions and other expenses of making the sale) shall be included in account 421.1. Gain on Disposition of Property, or account 421.2, Loss on Disposition of Property. (See account 102, Electric Plant Purchased or Sold.)

Note: In cases where existing utilities merge or consolidate because of financial or operating reasons or statutory requirements rather than as a means of transferring title of purchased properties to a new owner, the accounts of the constituent utilities, with the approval of the Commission, may be combined. In the event original cost has not been determined, the resulting utility shall proceed to determine such cost as outlined herein.

102. Electric plant purchased or sold.

A. This account shall be charged with the cost of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and shall be credited with the selling price of like property transferred to others pending the distribution to appropriate accounts in accordance with electric plant instruction 5.

B. Within six months from the date of acquisition or sale of property recorded herein, the utility shall file with the Commission the proposed journal entries to clear from this account the amounts recorded herein.

114. Electric plant acquisition adjustments.

A. This account shall include the difference between (1) the cost to the accounting utility of electric plant acquired as an operating unit or system by purchase, merger, consolidation, liquidation, or otherwise, and (2) the original cost, estimated, if not known, of such property, less the amount or amounts credited by the accounting utility at the time of acquisition to accumulated provisions for depreciation and amortization and contributions in aid of construction with respect to such property...

C. Debit amounts recorded in this account related to plant and land acquisition may be amortized to account 425, Miscellaneous Amortization, over a period not longer than the estimated remaining life of the properties to which such amounts relate.

425. Miscellaneous amortization.

This account shall include amortization charges not includible in other accounts which are properly deductible in determining the income of the utility before interest charges. Charges includible herein, if significant in amount, must be in accordance with an orderly and systematic amortization program.

ITEMS

1. Amortization of utility plant acquisition adjustments, or of intangibles included in utility plant in service when not authorized to be included in utility operating expenses by the Commission.
2. Other miscellaneous amortization charges allowed to be included in this account by the Commission.

Q.

Please provide all documentation showing how FPL developed the dollar amounts associated with systems to be retired as a result of GridFlorida, as referenced in Interrogatory No. 135.

A.

Please see response to Interrogatory Number 135. It is too early in the GridFlorida development process to identify the necessary planned new systems required to comply with FERC Order 2000 or those systems to be retired by FPL as a result of GridFlorida. Therefore no documents exist developing dollar amounts associated with systems to be retired as a result of GridFlorida.

Q.

Please provide all maps or similar documents reflecting the locations/layout of the contiguous transmission facilities referred to in Interrogatory No. 134c.

A.

Please see file named FCG Transmission 2001.dwf in attached diskette.

TR 8

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	Docket No. 000824-EI
In re: Review of Tampa Electric Company and impact of its participation in GridFlorida, a Florida Transmission Company, on TECO's retail ratepayers.	Docket No. 010577-EI
In re: Review of Florida Power & Light Company's proposed merger with Energy Corporation, the formation of a Florida transmission company ("Florida transco"), and their effect on FPL's retail rates.	Docket No. 001148-EI

GRIDFLORIDA RTO FORMATION DOCUMENTS

VOLUME I

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 4- Part 1 of 6
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3 — 5-01

CLK note: See DN 09244-01 for Complete Document.

July 30, 2001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	Docket No. 000824-EI
In re: Review of Tampa Electric Company and impact of its participation in GridFlorida, a Florida Transmission Company, on TECO's retail ratepayers.	Docket No. 010577-EI
In re: Review of Florida Power & Light Company's proposed merger with Energy Corporation, the formation of a Florida transmission company ("Florida transco"), and their effect on FPL's retail rates.	Docket No. 001148-EI

GRIDFLORIDA RTO FORMATION DOCUMENTS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO. 4-Pag 2-86
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3 — 5-01

VOLUME II

CLK note: See DN 09244-01 for complete Document.

July 30, 2001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	Docket No. 000824-EI
In re: Review of Tampa Electric Company and impact of its participation in GridFlorida, a Florida Transmission Company, on TECO's retail ratepayers.	Docket No. 010577-EI
In re: Review of Florida Power & Light Company's proposed merger with Energy Corporation, the formation of a Florida transmission company ("Florida transco"), and their effect on FPL's retail rates.	Docket No. 001148-EI

GRIDFLORIDA RTO FORMATION DOCUMENTS

VOLUME III

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 4-Part 3 & 6
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3 — 5-01

July 30, 2001

CLK note: See DN 09244-01 for complete Document.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	Docket No. 000824-EI
In re: Review of Tampa Electric Company and impact of its participation in GridFlorida, a Florida Transmission Company, on TECO's retail ratepayers.	Docket No. 010577-EI
In re: Review of Florida Power & Light Company's proposed merger with Energy Corporation, the formation of a Florida transmission company ("Florida transco"), and their effect on FPL's retail rates.	Docket No. 001148-EI

GRIDFLORIDA RTO FORMATION DOCUMENTS

VOLUME IV

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 4- Part 4 86
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3-5-01

CLK note: See DN 09244-01 for complete Document.

July 30, 2001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light. — Docket No. 000824-EI

In re: Review of Tampa Electric Company and impact of its participation in GridFlorida, a Florida Transmission Company, on TECO's retail ratepayers. — Docket No. 010577-EI

In re: Review of Florida Power & Light Company's proposed merger with Energy Corporation, the formation of a Florida transmission company ("Florida transco"), and their effect on FPL's retail rates. — Docket No. 001148-EI

GRIDFLORIDA RTO FORMATION DOCUMENTS

VOLUME V

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 4-Part 5 of 6
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3 — 4-01

CLK note: See DN 09244-01 for complete Document.

July 30, 2001

TR 8

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of Florida Power Corporation's earnings, including effects of proposed acquisition of Florida Power Corporation by Carolina Power & Light.	)	Docket No. 000824-EI
In re: Review of Tampa Electric Company and impact of its participation in GridFlorida, a Florida Transmission Company, on TECO's retail ratepayers.	)	Docket No. 010577-EI
In re: Review of Florida Power & Light Company's proposed merger with Energy Corporation, the formation of a Florida transmission company ("Florida transco"), and their effect on FPL's retail rates.	)	Docket No. 001148-EI

GRIDFLORIDA RTO FORMATION DOCUMENTS

VOLUME V

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO. 4-Part 6 of 6
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3-5-01

CLK note: See DN 10013-01 for complete Document

August 15, 2001

DOCUMENT NUMBER-DATE
10013 AUG 15 01
FPSC-COMMISSION CLERK

3393

TO: Bill Massey
Linda Breathitt
Nora Brownell

FROM: Pat Wood, III

RE: September 26, 2001 Open Meeting, Item E-3, Docket No. EX01-3, Discussion of RTO Progress

It has been more than two months since we discussed Regional Transmission Organizations (RTOs). In light of the events that have happened in that time, it is important that we give the effort some additional focus and guidance today to bring the transition period to an end. Federal Reserve Chairman Greenspan noted last Thursday how much more improvement is needed in the nation's energy infrastructure to keep pace with long-term demand.

Our goal is to have a seamless national power marketplace.

I view the RTO effort as two parallel tracks. One should get the RTOs up and working, while the second addresses business and process issues.

On the first track are the Spring 2001 MISO/Alliance settlement and the Northeast and Southeast mediations of the past several weeks. I understand that the MISO/Alliance parties are to issue a status report in early October, and the mediation judges have recently issued their reports for the other two regions. I plan to place these important efforts on an October Open Meeting.

Some guidance from us today on the efforts in the Western USA would be useful. I suggest a two-pronged approach there. Continue with RTO West, and encourage Desert Star to join forces. On a separate track, as Nora has suggested, perform an audit of the substantive operations of the California ISO and make recommendations to us about any changes that are needed. In light of the progress the Western Governors are making toward region-wide transmission and resource planning, it is not as imperative that a single Western Interconnection RTO be pursued at this time.

By early November, we will indicate which RTO organizations are approved, consistent with Order No. 2000 for governance and scope.

The second parallel track is the substantive track -- how should these organizations accomplish the functions and characteristics of Order No. 2000? The Commission, since Order No. 2000, has issued a number of orders on discrete issues raised by the succession

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 5
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3-5-01

of independent RTO filings giving some guidance on key market design issues. I am not comfortable that this effort to date has been as focused as it should be. This was made clear to me during the very helpful June 19 seams conference. To remedy that, I propose we initiate, under Section 206, a rulemaking on market design and market structure, to translate the eight RTO functions in Order No. 2000 into concrete protocols for the RTO organizations. This would begin with a series of Commissioner-led workshops in mid-October with broad participation from the brightest minds available focusing on each of the core subject areas (congestion management, cost recovery, market monitoring, transmission planning, business and reliability standards, nature of transmission rights, etc.). This Section 206 proceeding will yield a new *pro forma* tariff to replace the Order No. 888 OATT, and will be required of all public utilities and of all RTOs. It will lean strongly toward market design standardization and build upon efforts already underway by various industry and commission initiatives.

What to do about the December 15, 2001 date in Order No. 2000? I recommend that this be changed to be the date by which all jurisdictional utilities must either elect to join an approved RTO organization or have all market based rate privileges by any corporate affiliate be prospectively revoked, following a Section 206 investigation. I would also recommend that no mergers be approved relating to entities who do not become part of an operational RTO. And for an public utility that chooses not to be part of an RTO, I believe we would need to take a hard look at the transmission rates they are permitted to charge to ensure that they are just and reasonable and recognize the interdependence of the power grid.

I would also like staff to take a look at the pending rehearings and RTO filings to make a recommendation on their disposition in the near future based on where we are. To the extent parties wish to place into the rulemaking filings from the pending compliance dockets, that would be welcome.

In addition, we should also complete cost/benefit studies to demonstrate to those for whom the balance is not self-evident that RTOs yield significant customer savings. There was a recent study by Mirant for the Northeast RTO that would be useful here, and the Commission did some preliminary work on this in the past. More such work is needed.

Although I received more calls of elation than letters of opposition, we need to heal the rift with some of our state regulatory colleagues caused by the abruptness of our July 11 orders. State regulators must be included in all aspects of our October market design workshops and the NOPR process, particularly on the critical issues relating to cost recovery and on market monitoring.

Handling important market design issues in a rulemaking context rather than the contested case format we have used to date will allow us to have more open communication with states and with all other parties. It will also let us gather broad, insightful input from a variety of stakeholders and make these important decisions in a coordinated and expeditious manner. This is how FERC made successful, smart policy on the gas agenda a decade ago. And it is how I propose we get the RTO ball across the goal line.

EXHIBIT NO. 6

DOCKET NO: 000824-EI, 001148-EI, 010577-EI

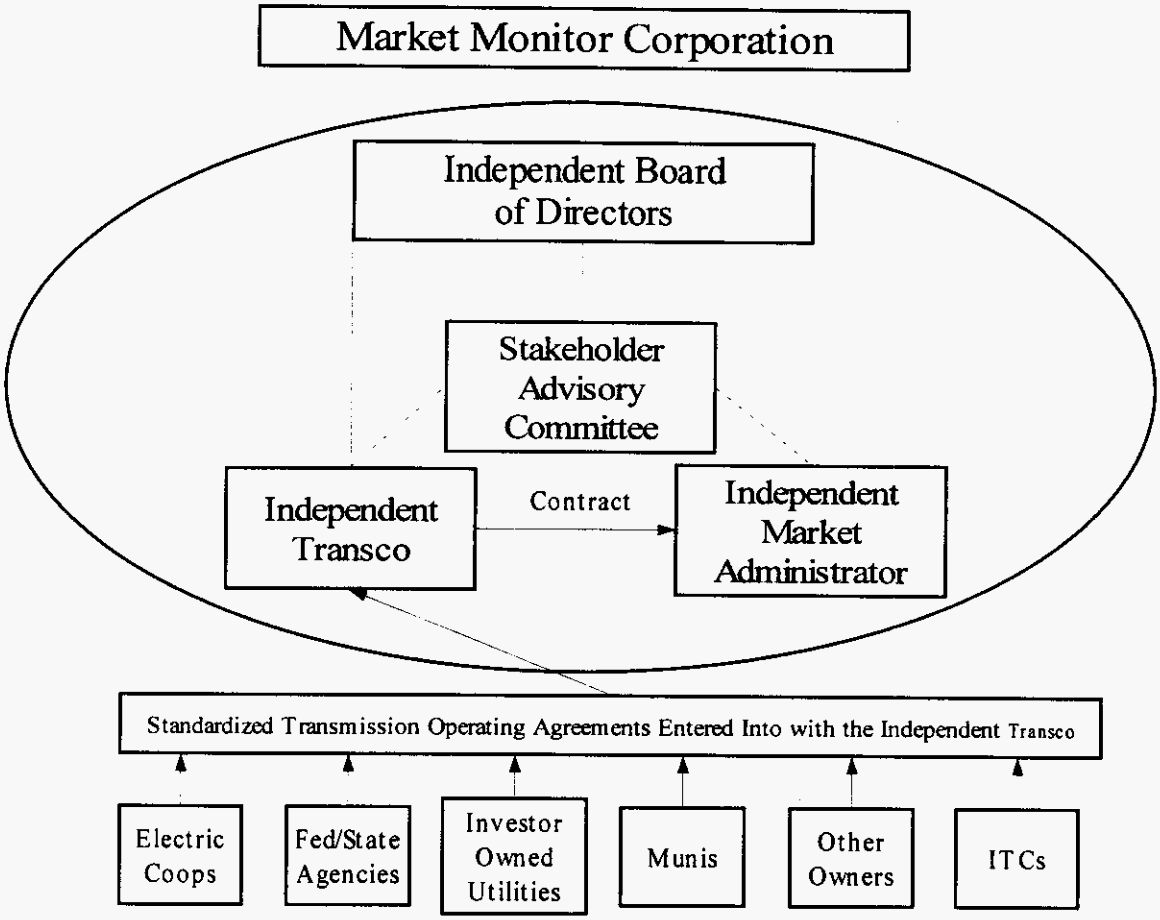
WITNESS: MIKE NAEVE

PARTY: FLORIDA POWER CORPORATION
FLORIDA POWER & LIGHT COMPANY
TAMPA ELECTRIC COMPANY

DESCRIPTION: PROPOSED STRUCTURE OF SOUTHEAST RTO

PROFERRED BY: STAFF

Southeast Power Grid (SPG)



Docket Nos. 000824-EI
001148-EI, 010577-EI
Errata to Joint Panel Testimony
of Mike Naeve, C. Martin Mennes
Henry Southwick, and Greg Ramon

October 2, 2001

Page No.	Line No.	Change
6	5	insert "non-" between "Class B" and "voting".
17	17	insert "three to " in front of "six percent".
19	21- 22	Delete the last sentence on this page that starts "Transmission breakers in a ring bus..."
41	3	Replace "Number of Units" with "Number of Sites"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI EXHIBIT NO. 7
COMPANY/
WITNESS: Florida Power & Light
DATE: 10-3 — 5-01

DOCKET NO. 010577-EI
DOCKET NO. 000824-EI
DOCKET NO. 001148-EI
LATE-FILED EXHIBIT 8
WITNESS: RAMON
TR. 459

CIRCUIT MILES OF TRANSMISSION

	Circuit Miles	% of Total
Florida Power & Light	6,190	43
Florida Power Corporation	4,688	32
Tampa Electric Company	1,277	9
Total GridFlorida Companies	12,155	84
All Others	2,281	16
Total Peninsular Florida	14,436	100

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO. 8
COMPANY/
WITNESS: FPSC Staff
DATE: 10-3-5-01

EXHIBIT NO. 10

DOCKET NO: 001148-EI, 010577-EI, and 000824-EI

WITNESS: NAEVE, MENNES, SOUTHWICK, AND RAMON

PARTY: FLORIDA POWER & LIGHT COMPANY, FLORIDA POWER CORPORATION, AND TAMPA ELECTRIC COMPANY

DESCRIPTION: LATE FILED DEPOSITION EXHIBIT #2, UTILITY OWNED GENERATION INTERCONNECTION QUEUES

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO. 10
COMPANY/
WITNESS: FPSC Staff
DATE: ~~10-3~~ 10-5-01

UTILITY GENERATION IN GRIDFLORIDA COMPANIES INTERCONNECTION QUEUES FOR 2001-05		
In-Service Date	**Number of Sites**	**Total MW**
2001	1	362
2002	3	2,613
2003	5	2,713
2004	8	3,693
2005	4	1,126
Total 2001-05	**21**	10,507

Florida Power & Light Company
Potential Financial Vulnerability Due to FERC Sanctions
Proposed In the Memorandum of September 26, 2001, Exhibit No. 5

Pat Wood's September 26, 2001 memorandum identifies three FERC responses to a utility's failure to join an RTO within the appropriate time period: (1) FERC will revoke the authority of the utility and its corporate affiliates to engage in wholesale sales of electricity at market based rates; (2) FERC will not approve any Section 203 application for merger involving that utility; and (3) FERC will take a "hard look" at the transmission rates that the utility is permitted to charge "to ensure that they are just and reasonable and recognize the interdependence of the power grid." The financial vulnerability associated with each of these courses of action is discussed below:

1. Market-based Sales

The FERC has authorized FPL to engage in wholesale sales of electricity at market based rates outside of Florida. Substantially all of gains from these off-system sales are passed through to customers in the fuel or capacity clauses. Recently, in docket 010001-EI, FPL provided testimony on gains received from off-system sales and establishing a threshold amount to be used in calculating Company incentives for the sharing of revenues from off-system sales. The Company's testimony provides gains on off-system sales of $159 million for the years of 1998 through 2000. Of this amount, approximately $110 million was from sales at market based rates. We cannot evaluate how much lower the gain would have been, but the loss of revenues associated with wholesale market based rates could lead to the retail customers not realizing these savings to this degree.

FPL Energy, a wholly owned subsidiary of FPL Group Capital, aggregates FPL Group's unregulated energy-related operations outside of Florida. The potential impact on its financial operations and growth of FPL Energy due to potential FERC sanctions cannot be measured. FPL Energy had over $600 million in sales in 2000 with assets totaling over $2.6 billion.

While it is difficult to predict with any real certainty what level of cost-based rates would be approved by FERC as a substitute for existing market based rates, based on a preliminary analysis, FPL and its affiliates could expect revenues to be reduced.

2. Merger Approval

FPL has no pending applications for Section 203 approval and cannot quantify the effect, if any, the loss of the ability to seek Section 203 approval of a transaction would mean in the future.

3. Transmission Rates

FPL reads Chairman Wood's memorandum as suggesting that entities not participating in RTOs by the FERC's deadline will face the prospect of having their wholesale transmission rates subjected to scrutiny in a rate case proceeding and may face a reduction in the FERC-approved rate of return for their transmission assets. While impossible to quantify at this point in time, the reduction in the approved rates certainly could have a negative impact on FPL's wholesale revenues, its ability to attract investment and the value of the Company to its shareholders, which could in turn have a detrimental effect on FPL's retail ratepayers.

Pat Wood, September 26, 2001: "...utilities must either elect to join an approved RTO organization or have all market based privileges by any corporate affiliate be prospectively revoked"

Calculation of FPL losing Market Based Rates on off-system sales based on 3-year average

	Gains on Off-System Sales [1]	Estimate of amount of sales made at Market Based Rates	Gains on Sales from Market Based Rates
1998	$ 62,276,203	75%	$ 46,707,152
1999	$ 59,183,161	75%	$ 44,387,371
2000	$ 37,400,076	50%	$ 18,700,038
Total:	$ 158,859,440		$ 109,794,561

[1] Testimony of Korel M. Dubin at 5-6 in Docket No. 010001-EI

Potential Financial Vulnerability Due to FERC Sanctions
Proposed In the Memorandum of September 26, 2001, Exhibit No. 5

FERC Chairman Wood's September 26, 2001 memorandum identifies three FERC responses to a utility's failure to join an RTO within the appropriate time period: (1) FERC will revoke the authority of the utility and its corporate affiliates to engage in wholesale sales of electricity at market based rates; (2) FERC will not approve any Section 203 application for merger involving that utility; and (3) FERC will take a "hard look" at the transmission rates that the utility is permitted to charge "to ensure that they are just and reasonable and recognize the interdependence of the power grid." The financial vulnerability associated with each of these courses of action is discussed below:

1. Market-based Sales

The FERC has authorized FPC to engage in wholesale sales of electricity at market based rates outside of peninsular Florida. FPC's revenues from short-term sales of electricity at wholesale made under its market based rate authority for the three year period from July 1, 1998 to June 30, 2001 as reported to the FERC totaled $53.9 million. In circumstances where FPC resources are utilized, FPC credits a major portion of these revenues to its retail ratepayers. Thus, the loss of revenues associated with wholesale sales could lead to an increase in retail rates.

While it is difficult to predict with any real certainty what level of cost-based rates would be approved by FERC as a substitute for existing market based rates, based on a preliminary analysis, FPC and its affiliates could expect revenues to be reduced.

2. Merger Approval

FPC has no pending applications for Section 203 approval and cannot quantify the effect, if any, the loss of the ability to seek Section 203 approval of a transaction would mean in the future.

3. Transmission Rates

Chairman Wood's memorandum suggests that entities not participating in RTOs by the FERC's deadline will face the prospect of having their wholesale transmission rates subjected to scrutiny in a rate case proceeding and may face a reduction in the FERC-approved rate of return for their transmission assets. While impossible to quantify at this point in time, the reduction in the approved rates certainly could have a negative impact on FPC's wholesale revenues, its ability to attract investment and the value of the Company to its shareholders, which could in turn have a detrimental effect on FPC's retail ratepayers.

Henry I. Southwick
Manager, Regional Transmission Organization Development
Florida Power Corporation
P.O. Box 14042
St. Petersburg, Florida 33733

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Late Filed Exhibit No. 12, filed on behalf of Florida Power Corporation has been furnished by overnight delivery (*) or U. S. Mail on this 11th day of October, 2001 to the following:

Cochran Keating*
Robert V. Elias
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd., Room 370
Tallahassee, FL 32399-0850

J. Roger Howe
Office of Public Counsel
111 West Madison Street, Room 812
Tallahassee, FL 32399-1400

John McWhirter, Jr.
Florida Industrial Power Users Group
McWhirter, Reeves, McGlothlin, Davidson,
Decker, Kaufman, Arnold & Steen, P.A.
400 North Tampa St., Suite 2450 (33602)
Tampa, FL 33601-3350

Joseph McGlothlin
Vicki Gordon Kaufman
McWhirter, Reeves, McGlothlin, Davidson,
Decker, Kaufman, Arnold & Steen, P.A.
117 South Gadsden Street
Tallahassee, FL 32301

Jon C. Moyle, Jr.
Cathy M. Sellers
Dan Doorakian
Moyle, Flanigan, Katz, Raymond
& Sheehan, P.A.
118 North Gadsden Street
Tallahassee, FL 32301

Diane K. Kiesling
Leslie Paugh
Landers & Parsons, P.A.
310 W. College Avenue
Tallahassee, FL 32301

William L. Bryant, Jr.
Natalie B. Futch
Katz, Kutter, Haigler, Alderman,
Bryant & Yon
106 East College Avenue, 12th Floor
Tallahassee, FL 32301

Michael Twomey, Esq.
Post Office Box 5256
Tallahassee, FL 32314-5256

Thomas A. Cloud
Dynegy Midstream Services, L.P.
Gray, Harris & Robinson
301 E. Pines Street, Suite 1400 (32801)
Post Office Box 3068
Orlando, FL 32802-3068

Frederick M. Bryant
Florida Municipal Power Agency
2061-2 Delta Way
Tallahassee, FL 32303

Matthew M. Childs, P.A.
Steel Hector & Davis
215 South Monroe, Suite 601
Tallahassee, FL 32301-1804

James A. McGee
Senior Counsel
Florida Power Corporation
One Progress Plaza – Suite 1500 (33701)
Post Office Box 14042
St. Petersburg, FL 33733

Mark F. Sundback
Kenneth L. Wiseman
Andrews & Kurth L.L.P.
1701 Pennsylvania Avenue, N.W.
Suite 300
Washington, D.C. 20006

Harry W. Long, Jr.
Tampa Electric Company
Post Office Box 111
Tampa, FL 33601

Robert C. Williams, P.E.
Director of Engineering
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, FL 32819-9002

Paul Lewis, Jr.
Florida Power Corporation
106 East College Avenue, Suite 800
Tallahassee, FL 32301

Lee L. Willis
James D. Beasley
Ausley Law Firm
Post Office Box 391
Tallahassee, FL 32302

N. Wes Strickland
Foley & Lardner
Seminole Electric Cooperative, Inc.
106 East College Avenue, Suite 900
Tallahassee, FL 32301-1514

Peter Antonacci
Gray, Harris & Robinson, P.A.
225 South Adams Street
Tallahassee, FL 32301

Seann Frazier
Greenberg Traurig
101 E. College Avenue
Tallahassee, FL 32301

Daniel Frank
Sutherland, Asbill & Brennan
1275 Pennsylvania Avenue NW
Washington, DC 20004-2415

Attorney

TAMPA ELECTRIC COMPANY
DOCKET NO. 010577-EI
LATE-FILED EXHIBIT NO. 13
FILED: OCTOBER 12, 2001

Potential Financial Vulnerability Due to FERC Sanctions Proposed in the Memorandum of September 26, 2001

FERC Chairman Pat Wood's September 26, 2001 memorandum identifies three FERC responses to a utility's failure to join an RTO within the appropriate time period: 1) FERC will revoke the authority of the utility and its corporate affiliates to engage in wholesale sales of electricity at market based rates; 2) FERC will not approve any Section 203 application for merger involving that utility; and 3) FERC will take a "hard look" at the transmission rates that the utility is permitted to charge "to ensure that they are just and reasonable and recognize the interdependence of the power grid." The financial vulnerability associated with each of these courses of action is discussed below:

1. Market-based Sales

The FERC has authorized Tampa Electric to engage in wholesale sales of electricity at market-based rates inside and outside of Florida. Tampa Electric's revenues from sales of electricity at wholesale made under its market based rate authority for the period July 1, 1998 through June 30, 2001 as reported to FERC totaled $12,613,898. Substantially all of the gains from these off-system sales are passed through to customers in the fuel and/or capacity cost recovery clauses. Thus, the loss of revenues associated with wholesale sales could lead to an increase in retail rates.

While it is difficult to predict with any real certainty what level of cost-based rates would be approved by FERC as a substitute for existing market based rates, based on a preliminary analysis Tampa Electric and its affiliates could expect revenues to be reduced.

2. Merger Approval

Tampa Electric has no pending applications for Section 203 approval and cannot quantify the effect, if any, the loss of the ability to seek Section 203 approval of a transaction would mean in the future.

3. Transmission Rates

Tampa Electric interprets Chairman Wood's memorandum as suggesting that entities not participating in RTOs by the FERC's deadline will face the prospect of having their wholesale transmission rates subjected to scrutiny in a rate case proceeding and may face a reduction in the FERC-approved rate of return for their transmission assets. While impossible to quantify at this time, the reduction in the approved rates certainly could have a negative impact on Tampa Electric's wholesale revenues, its ability to attract investment and the value of the company to its shareholders, which could in turn have a detrimental effect on Tampa Electric's retail ratepayers.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI etc. EXHIBIT NO. 13
COMPANY/
WITNESS: FPSC Staff
DATE: 10-3-[illegible]

EXHIBIT NO. 14
DOCKET NOS. 000824-EI,
001148-EI, 010577-EI
FLORIDA POWER CORPORATION
FLORIDA POWER & LIGHT
TAMPA ELECTRIC COMPANY
(WRA-2)
DOCUMENT NO. 1
FILED: AUGUST 15, 2001

EXHIBITS TO THE JOINT TESTIMONY OF

WILLIAM R. ASHBURN

DOCUMENT NO. 1

DEVELOPMENT OF START-UP COST

REVENUE REQUIREMENT

NET COST RESPONSIBILITY

ON GRIDFLORIDA USER - TOTAL RETAIL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 14
COMPANY/
WITNESS. Ashburn
DATE: 10-3—5-01

GridFlorida

Development of Start-up Cost Revenue Requirement
Net Cost Responsibility on GridFlorida User - Total Retail

Line			*Revenue Requirement Developed For Illustrative Purposes:* Year 1	2	3	4	5
1			1	2	3	4	5
2	**Revenue Requirement Summary (000)**						
3	Annual Amortization		$24,007	$24,007	$24,007	$24,007	$24,007
4	Return on Rate Base		10,533	8,192	5,852	3,511	1,170
5	Income Taxes		4,478	3,483	2,488	1,493	498
6	**Total Revenue Requirement**		$39,018	$35,682	$32,346	$29,011	$25,675
7							
8							
9	**Return on Rate Base (000):**	(L20 * L27)	$10,533	$8,192	$5,852	$3,511	$1,170
10							
11	**Rate Base ($000s)**						
12	Plant in Service		120,035	120,035	120,035	120,035	120,035
13	Accumulated Amortization		24,007	48,014	72,021	96,028	120,035
14	Net Plant in Service		96,028	72,021	48,014	24,007	-
15	Average Net Plant		108,032	84,025	60,018	36,011	12,004
16							
17	Deductions to Rate Base:						
18	Accumulated Deferred Income Tax		0	0	0	0	0
19							
20	Total Rate Base	(L15 - L18)	108,032	84,025	60,018	36,011	12,004
21							
22	**Rate of Return Equals**						
23	*Illustrative overall weighted cost assumptions:*				Ratio	Costs	ROR
24	Long Term Debt				45%	7%	3.15%
25	Preferred Stock				0%	0%	0.00%
26	Common Stock				55%	12%	6.60%
27							9.75%
28							
29	**Income Tax Equals (000)**						
30	*The total Federal and State Income Taxes determined by the following formula:*						
31	Income Taxes = Total Rate Base x (Preferred Stock ROR + Common Stock ROR) x Composite Tax Rate						
32							
33	Total Rate Base	(L20)	108,032	84,025	60,018	36,011	12,004
34	Pref Stk ROR + Common Stk ROR	(L25 + L26)	6.6%	6.6%	6.6%	6.6%	6.6%
35	After-tax return	(L33 x L34)	7,130	5,546	3,961	2,377	792
36	Composite Tax Rate	L44+(1-L44)xL45	38.575%	38.575%	38.575%	38.575%	38.575%
37	Pre-tax return	L35 / (1 - L36)	11,608	9,028	6,449	3,869	1,290
38	Income Tax Equals (000)	L37 - L35	4,478	3,483	2,488	1,493	498
39							
40	Assumptions:						
41	Start-up Costs based on Table 1, Witness Holcombe Exhibit (BLH 3)		$120,035				
42	Recovery period (subject to FERC approval)		5 years				
43	Tax Life (years)		5 straight line				
44	State Tax Rate		5.5%				
45	Federal Tax Rate		35.0%				

Docket No. 001148-EI
Docket No. 000824-EI
Docket No. 010577-EI
GridFlorida Companies Witness Holcombe
Exhibit No. _____ (BLH-1)
Business Blueprint Documents

GridFlorida

Establishing the Grid Florida RTO
BluePrint Project
June 2001

BUSINESS BLUEPRINT

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 15
COMPANY/
WITNESS. Holcombe
DATE: 10-3-5-01

GridFlorida

Establishing the GridFlorida RTO
BluePrint Project
May 2001

Docket No. 000824-EI
Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. ______ (BLH-1)
Business Blueprint Documents

End State Operating Model- v5

07/24/2001

Topics

Market Assumptions

Operating Model

Questions

Appendix

Market Entity Descriptions

GridFlorida

Market Assumptions

The GridFlorida Operating Model is driven by the following market assumptions (currently):

- GridFlorida will own and have operational control of transmission assets of 69 KV and above for FPL and TECO, and will have operational control of FPC transmission assets via a Participating Owner Agreement (PO). Other entities may decide to join later; otherwise, they will be termed 'non-participating owners'.
- There will be multiple control areas both within GridFlorida and between GridFlorida and non-participating entities within peninsular Florida (will not be combined into one control area). Therefore, GridFlorida will operate an overlay control area.
- GridFlorida will need to develop procedures and rules for managing interactions with other RTOs and non-participating control areas.
- There will be no dis-aggregation of vertically integrated utilities (except for Divesting Owners who are partially dis-aggregated, having contributed their transmission) based on the reliability needs of the grid.
- GridFlorida may initially rely on existing control area operators to implement its Direct control and/or instructions.
- GridFlorida will be the Transmission provider, administering its OATT, with sole responsibility for transmission reservations service & transmission scheduling.
- GridFlorida will have authority to approve when generation and transmission facilities will be placed in and out of service (outages/maintenance).
- GridFlorida will receive, confirm and implement all interchange schedules for other RTOs, participating control areas, and non-participating control areas (from a Scheduling Coordinator).

GridFlorida

Market Assumptions

The GridFlorida Operating Model is driven by the following market assumptions (currently):

- GridFlorida will be the provider of last resort for ancillary services to support transmission services. Participants may self provide or contract to supply Regulation and Frequency Response Service and Operating Reserves, but must buy (and can offer to sell) Balancing Energy, Scheduling, System Control and Dispatch Service, and System Blackstart Service. Generators must provide Reactive Supply and Voltage Control (sometimes there may be a charge).
- GridFlorida currently does not plan to operate a forward energy market.
- A Day Ahead congestion management regime will be based on a physical rights model. Each PTR will be defined as the right to schedule the delivery of one MW of energy, capacity, or ancillary service in a specific direction across a specified flowgate for one hour. Details are still being determined (e.g. define flowgates, PTR rules, etc).
- Scheduling coordinators will submit to GridFlorida a set of hourly balanced schedules for the following day (capacity to balancing energy, self supply plans and offer to supply ancillary services to others, PTRs, etc). Interim Scheme for Release 1.
- GridFlorida will perform a settlement function for balancing energy, ancillary service markets, access charges, grid management charges, transmission service charges (some zonal and some system-wide), and the collection and allocation of transmission congestion costs once real time operations commences.
- Pending FRCC approval and execution of a contract, GridFlorida will become the agent for Security Coordination for all entities in the FRCC. The FRCC has additional roles.
- There are no current plans for retail competition in Florida.

GridFlorida

Market Assumptions

Certain elements of the Market Design are still in progress and impact market assumptions:

- Congestion Management Details
- ICE – Installed Capacity and Energy Obligation
- Losses
- Energy Balancing Market Details
- Control Area Hierarchy and Relationships

GridFlorida Operating Model- Participants View

Other RTOs

GridFlorida RTO
Security Coordinator
Transmission Owner/Operator

Participating Transmission Owner

Scheduling Coordinators

Generators (within GridFlorida Control Area)

Load Serving Entities (Including TDUs)

Non-Participating Transmission Owner

Generators (within Participating Control Areas)

Power Marketers

Generators (within Non-participating Control Areas)

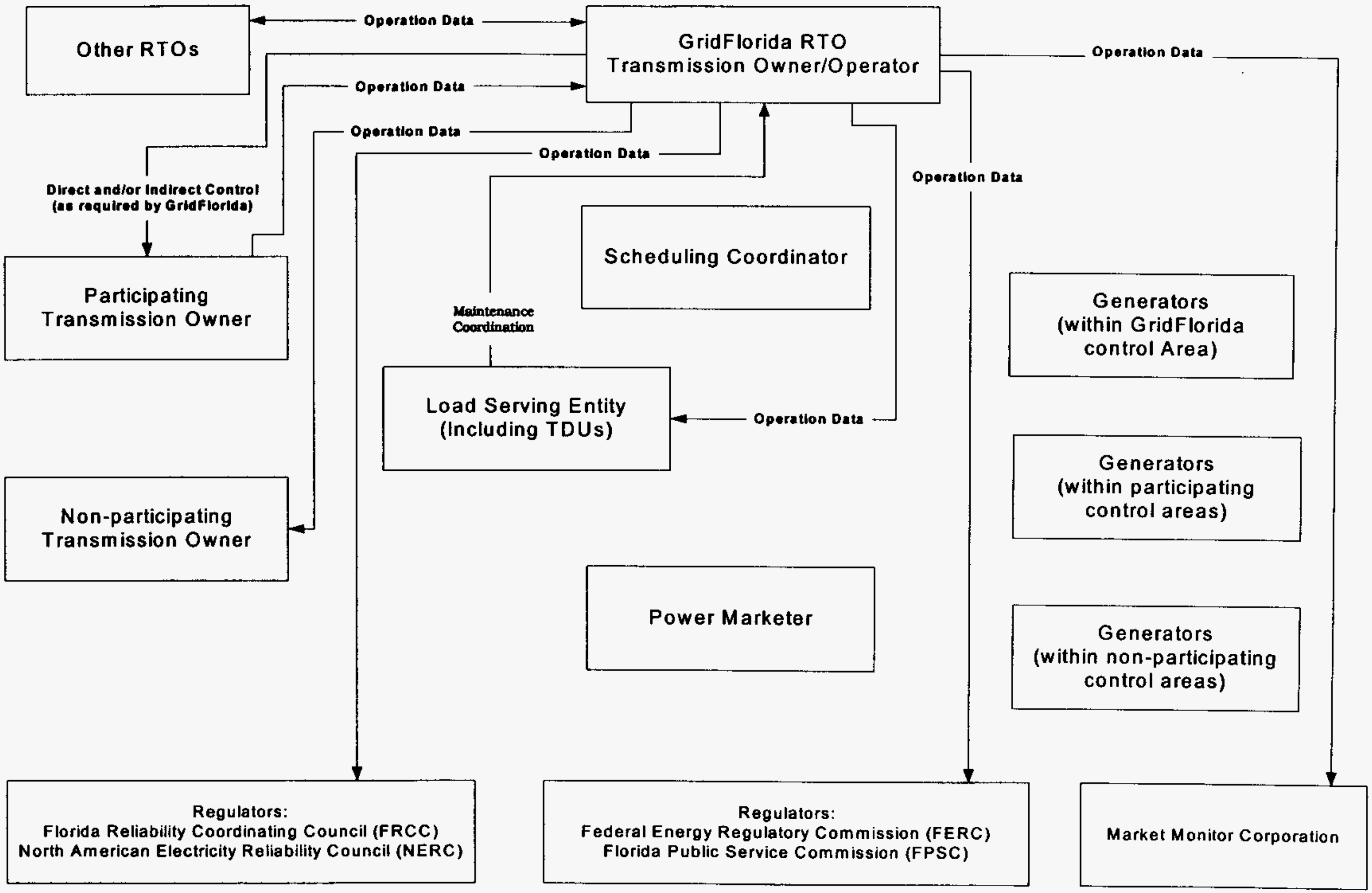
Regulators: Florida Reliability Coordinating Council (FRCC), North American Electric Reliability Council (NERC)

Regulators: Federal Energy Regulatory Commission (FERC), Florida Public Service Commission (FPSC)

Market Monitor Corporation

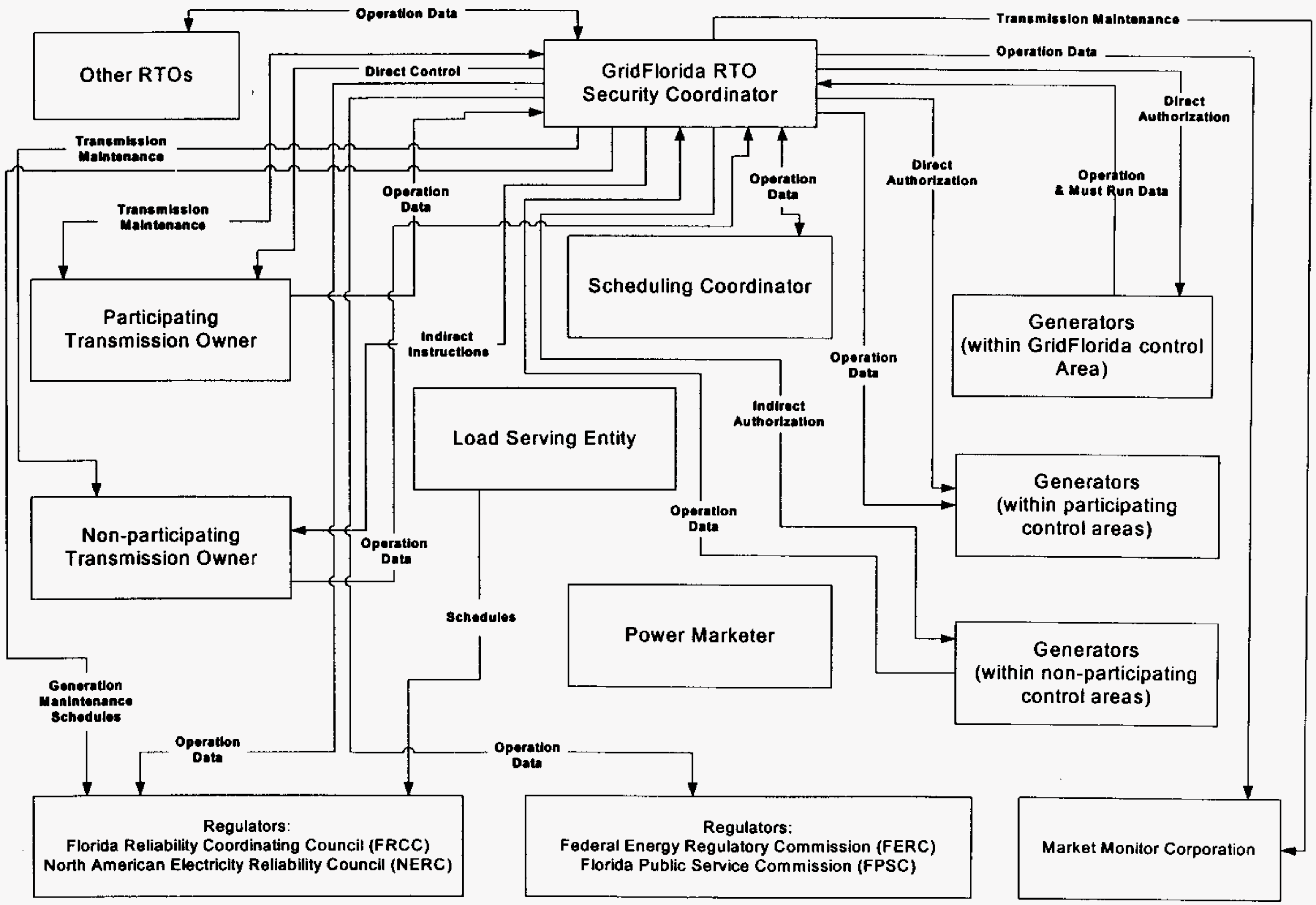
Note: Florida is not a dis-aggregated market. However, for the purposes of depicting the overall operations of the market, the entities are broken down.

GridFlorida Operating Model- Transmission Operations View



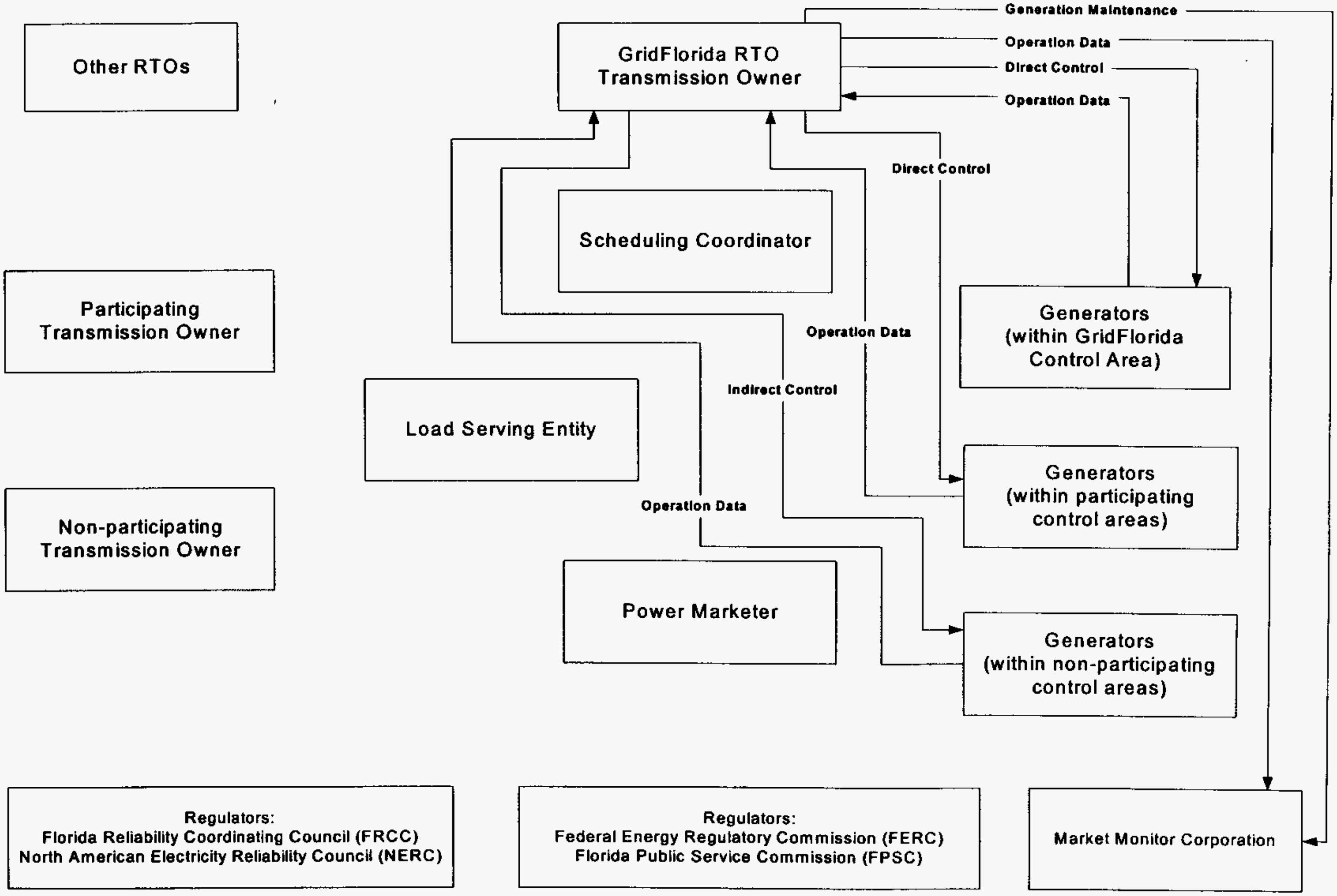
GridFlorida

Operating Model- Security Coordinator View



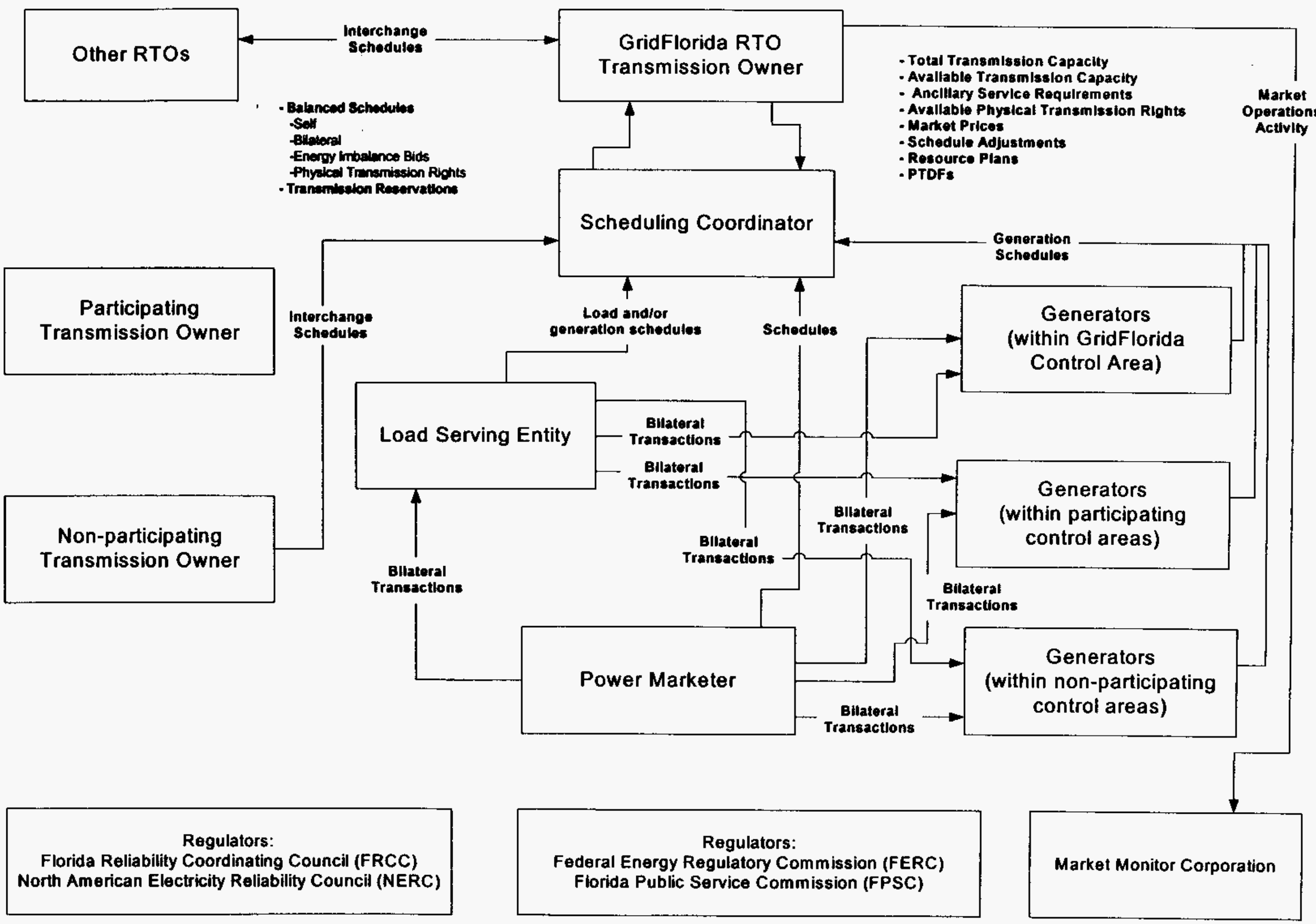
GridFlorida

Operating Model- Generation Control View

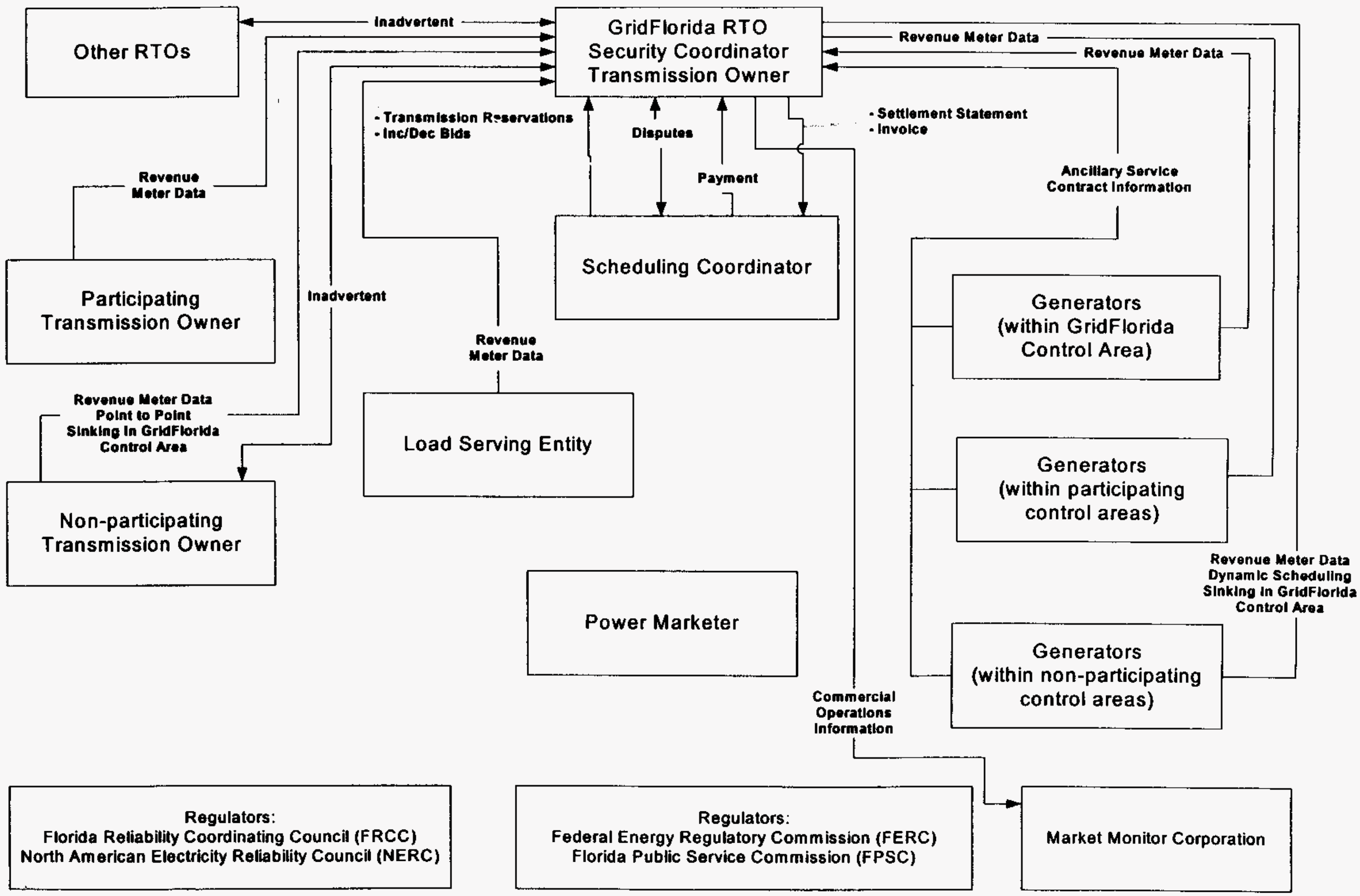


GridFlorida

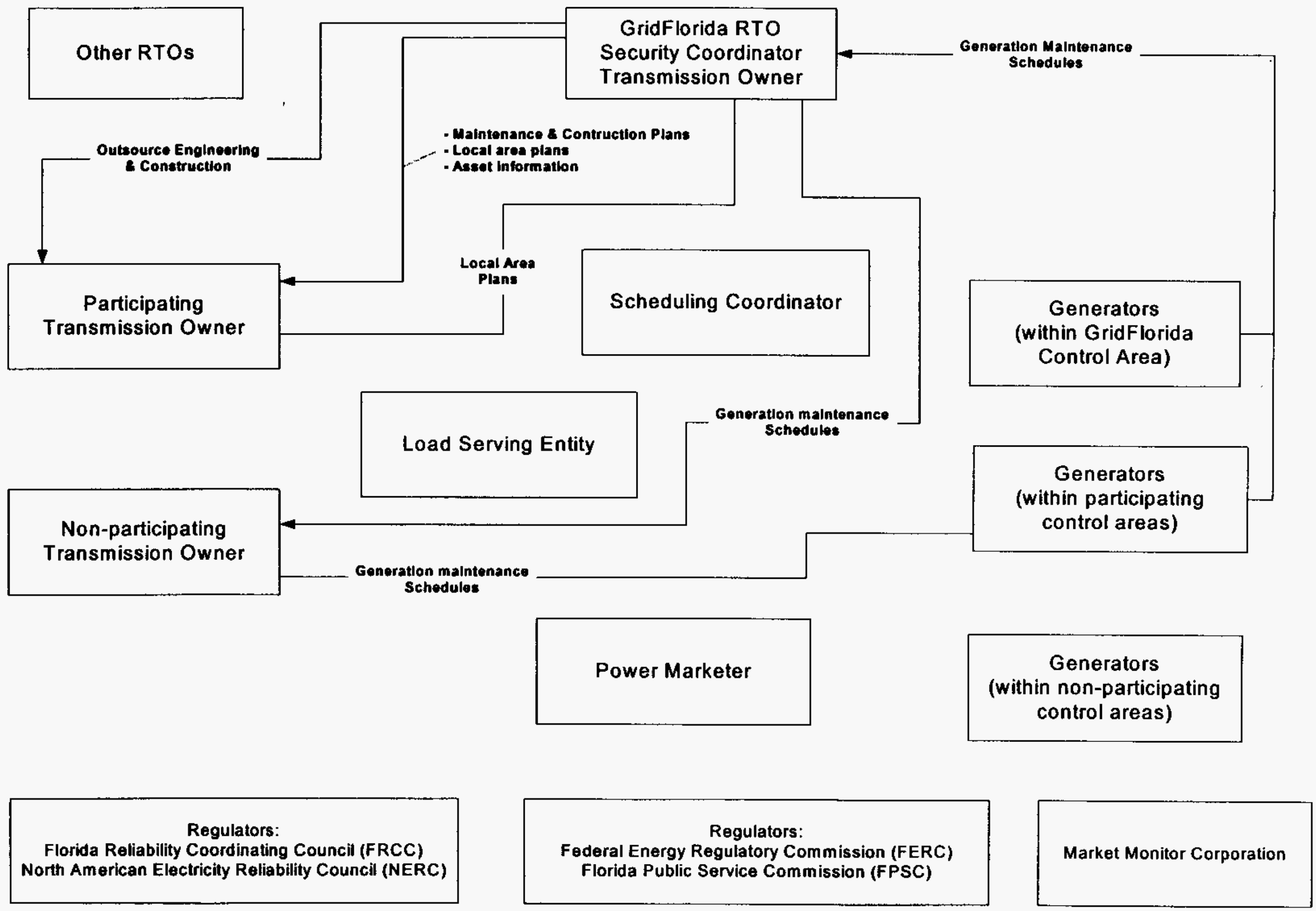
Operating Model- Market Operations View



GridFlorida Operating Model- Financial Commercial Operations View



GridFlorida Operating Model- Asset Optimization View



07/24/2001

Appendix

Market Entity Descriptions

GridFlorida

Market Entity Descriptions

GridFlorida RTO	GridFlorida has received provisional status as a Regional Transmission Organization under FERC Order 2000. GridFlorida will be responsible for security coordination, planning, and will offer ancillary services for purchase. GridFlorida is an Independent Transmission Company (ITC), which means it owns some assets and is for profit. Therefore, it is a ITC acting as an RTO.
Scheduling Coordinator	A Scheduling Coordinator (SC) could be an: 1)existing utility, 2) a private power exchange, or 3) an entity which exists only to sell scheduling coordinator services. Any market participant that meets the necessary qualifications can be a Scheduling Coordinator. Those qualifications include maintaining a 24-hour a day (24 x 7) scheduling center and necessary communications and IT equipment, and meeting financial qualifications. The SC submits to the transmission provider requests for reservations and balanced schedules for energy and ancillary services.
Control Area Operator	Any party who maintains its own control area with all of its attendant NERC-defined control area rights and obligations and purchases or sells inadvertent energy, as applicable, from the real-time energy imbalance market.
Transmission Owner	An entity which owns transmission facilities.

GridFlorida

Market Entity Descriptions

Load Serving Entity	An entity that purchases and or generates electricity that it sells to retail customers. A joint action agency or other agent for a group of LSEs, and which is the Transmission Customer for such LSEs, shall have the right to act as the agent for the LSEs with respect to all aspects of the GridFlorida Tariff.
Generators	Owner or controller of a generator used for generating electricity and electrically connected to a transmission or distribution system. Generators may be part of a vertically integrated power utility that includes the transmission or distribution system.
Power Marketer	An entity who (a) becomes an owner of electric energy for the purpose of selling the electric energy at wholesale; (b) does not own generation, transmission or distribution facilities; (c) does not have a certified service area; and (d) has been granted authority by the FERC to sell electricity at market-based rates or is registered as a power marketer.
Regulatory Bodies	These include: Florida Reliability Coordinating Council (FRCC), North American Electric Reliability Council (NERC), Federal Energy Regulatory Commission (FERC), and Florida Public Service Commission (FPSC).

GridFlorida

Market Entity Descriptions

Market Monitor Corporation	This entity will examine: 1- the structure and operation of the markets GridFlorida operates and administers, 2- compliance with market rules by market participant and GridFlorida, 3- competitive prices, and 4- market power and market power abuses. Can file a complaint with the Commission if it observes specific violations of market rules or otherwise anticompetitive behavior.

GridFlorida

Establishing the GridFlorida RTO
BluePrint Project
May 2001

Docket No. 000824-EI
Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. ______ (BLH-1)
Business Blueprint Documents

End State Capability Model- v5

GridFlorida

Capability Model

System Operations

Management and control of the grid assets to maintain system reliability, stability, efficiency. For the Transmission Operator and Security Coordinator roles.

Market Operations

Management and control of the market functions in order to provide open access to transmission resources enabling a competitive wholesale electricity market.

Commercial Operations

Financial and other commercial operations related to market participant and market participant contracts and transactions.

Customer Interface

Mechanisms for Customer information collection, operations and market interactions and publishing.

Asset Optimization

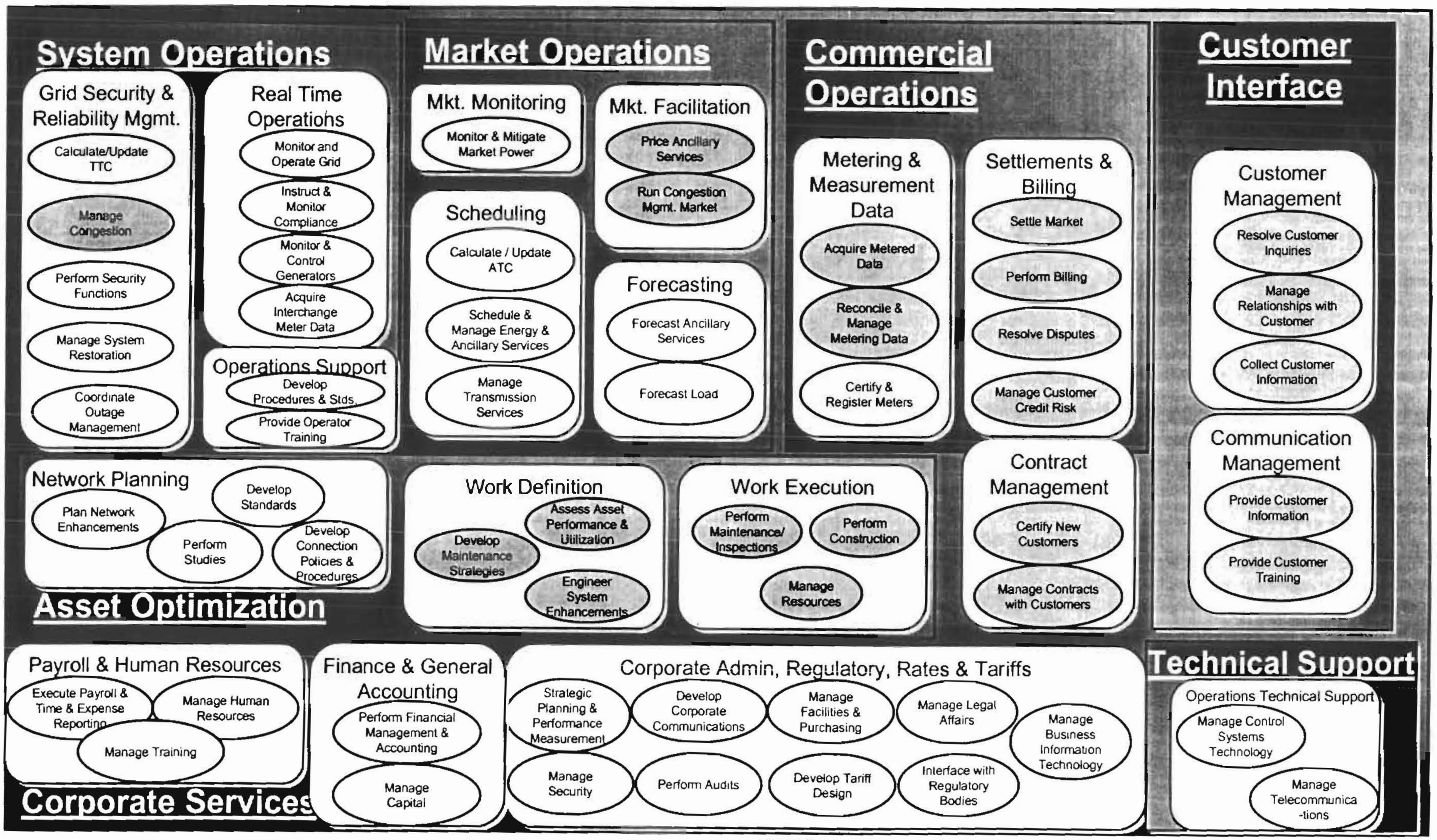
System planning, maintenance policy development, project design, and oversight of work to improve physical and financial performance of assets.

Corporate Services

Governance, administration, and support services to operate the organization, manage the people and technology, and measure/meet the performance objectives of the RTO.

GridFlorida

Capability Model



Out-of-Scope Capability | New Capability | Modified Capability

07/24/2001

GridFlorida

System Operations

Capability: Grid Security & Reliability Management

Sub-Capability: Calculate/Update TTC

Sub-Capability Description

GridFlorida has sole authority to determine, update and post the TTC for its transmission facilities based on system design, scheduling, outage and operations data.

Requirements

- TTC will be determined by line ratings, design criteria and other relevant data provided by TOs and subject to GridFlorida's independent verification and confirmation
- Calculations will be in accordance with the FRCC ATC Coordination Procedures and NERC standards
- Posting will be made daily
- Value will be based on calculations for each defined flowgate

Key Assumptions

- Capability will be required for Release 1 (possible use of FPC tool)and End State
- Current TTC calculation methods and posting practices are in place in the FRCC and will form the basis of the new capability

Solution Strategy

Technology

- TTC Calculator
- Contingency Analysis (Steady-state, dynamic)
- Integrated Model Management tool
- Load Forecaster
- Load Flow

People:

- Operations Prep

Facilities:

- Control center (back offices)

GridFlorida

System Operations

Capability: Grid Security & Reliability Management

Sub-Capability: Manage Congestion

Sub-Capability Description

GridFlorida will manage congestion to maintain firm transmission service and transmission system security using mechanisms that provide all transmission customers with efficient price signals regarding the consequences of their transmission use decisions.

Requirements

- Coordinate a short and long-term scheduling and congestion management process
- Manage congestion through a flowgate approach with PTRs and a balancing market to clear congestion in real time
- Balanced schedules and PTRs to minimize need for redispatch to resolve congestion during real time operations
- Require inc and dec bids with resource schedules to facilitate least-cost redispatch
- Only GridFlorida will be authorized to redispatch generation or call for TLRs
- Firm PTR allocations for existing uses; non-scheduled PTRs will be auctioned as recallable PTRs (use-it-or-lose-it)
- Maintain and post a PTR holder list on a web page
- Real time congestion resolution by a least-cost redispatch of generation based on inc and dec bid prices
- Facilitate bilateral redispatch contracts to enable schedules by avoiding flowgate impacts
- Flowgate impact analysis performed on all submitted schedules to ensure operational feasibility

Key Assumptions

- Full flowgate-based regional pricing (PTR) will follow as part of a final approved regime
- Current NERC TLR solution and interim CM (MRD/SRD) will be implemented for the Release 1 and be part of the End State

Solution Strategy

Technology:

- Redispatch bid collection application/bulletin board with user-interface for entry and non-firm bilateral redispatch solution information
- Congestion Management software: Impact analysis using current state as input, running various scenarios to determine solutions
- Mechanism to capture redispatch decisions, incremental increase/decrease in output
- Price Based Security Dispatch

People:

- 7 x 24 coverage by Security Coordinator
- Settlements Analysts

Facilities:

•Control center

GridFlorida

System Operations

Capability: Grid Security & Reliability Management

Sub-Capability: Perform Security Functions

Sub-Capability Description

GridFlorida will monitor and asses the transmission system with an emphasis on contingency analysis and security coordination. It may implement an on-line dynamic assessment capabilities in order to more quickly and accurately analyze and predict stability problems and potentials, determine realistic operating limits in order to update TTC and ATC values in order to pursue more aggressive system operations.

Requirements

- Ability to monitor and assess state (security, stability, contingencies) of transmission system.
- Ability to communicate preventative and corrective actions to Control Areas when needed.
- Use of static security study and assessment tools
- Implementer of NERC Policy 9 (Security Coordination Sub-Capability)
- Network model and analysis data from the real-time database and sequence applications in the EMS
- Ability to perform on-line transient and voltage assessment analysis using real-time data
- Visualization of identified contingencies

Key Assumptions

- Static assessment capability will be required for the End State; FRCC Security Coordinator capabilities through FPL required for the Release 1
- Value in accurately determining TTC/ATC and realistic operating limits in real-time
- Additional requirements may be implemented beyond the End State to maintain & enhance system stability while operating closer to constraints

Solution Strategy

Technology:

- Same tools as in Monitor Transmission System
- Access to Internet: ISN, IDC, SCIS
- Network Model interface
- Contingency analysis (Steady state, dynamic, voltage)
- Security Constrained OPF
- Dynamic mapboard
- FTMS message exchange

People:

- NERC-certified 24 x 7 Security Coordinator

Facilities:

•Control Center

GridFlorida

System Operations

Capability: Grid Security & Reliability Management

Sub-Capability: Manage System Restoration

Sub-Capability Description

GridFlorida will plan, coordinate and have operation control of system restoration for the GridFlorida area, as well as coordinate restoration for the FRCC region.

Requirements

- GridFlorida will develop an RTO-wide plan to conduct system restoration based on plans currently in place at individual Control Areas
- GridFlorida will determine the black start capability it requires and its locations
- System restoration has real time transmission monitoring implications (getting the system back up) as well as planning/contingency implications (developing system restoration contingency plans)
- GridFlorida will review after-the-fact restoration information & file appropriate reports
- Black start service will be obtained through bilateral arrangements and collect costs as authorized in the tariff
- GridFlorida will manage and deploy system black start capability

Key Assumptions

- GridFlorida will take planning lead and coordination role in system restoration
- Capability required for End State; capability through the current FPL coordinated FRCC plan will be implemented for the Release 1

Solution Strategy

Technology:

- Real-time: same applications as Monitor Transmission System
- Planning: Offline Power Flow, office software, and DTS

People:

- Real-time: Security Coordinator
- Planning: Security Coordinator, Operations Prep

Facilities:

- Real-time: Control Center
- Planning: Office

GridFlorida

System Operations

Capability: Grid Security & Reliability Management

Sub-Capability: Coordinate Outage Management

Sub-Capability Description

GridFlorida will accept, approve, and change or deny transmission maintenance outage requests based on system reliability coordination criteria. GridFlorida will take into account the generator outage schedules and will change these only for security provision purposes.

Requirements

- Ability to accept, validate and evaluate the annual, monthly and day-ahead outage request combinations
- Ability to modify, if needed, the timing of outages within predetermined tolerances

Key Assumptions

- GridFlorida will have RTO and Security Coordinator authority over coordination of transmission & generation maintenance outage for security purposes
- Capability required for the End State; existing FPL Security Coordinator functions will provide capability for the Release 1

Solution Strategy

Technology:

- Outage Scheduler
- Message Exchange
- Same applications as Calculate/Update TTC

People:

- EMS NERC-certified control center operators
- Operations planning engineers- Operations Prep

Facilities:

- Control Center
- Office

)))

GridFlorida

Capability: Real Time Operations

Sub-Capability: Monitor and Operate Grid

Sub-Capability Description

GridFlorida will monitor the transmission system state in real time for events that affect system security and transfer capacity.

Requirements

- Ability to monitor & assess state of transmission system
- Ability to control and/or communicate corrective instructions to Control Area Operators when needed
- Ability to monitor and audit compliance

Key Assumptions

- GridFlorida to have Security Coordinator level authority over all Control Areas and either direct or indirect operational control of Control Area facilities.
- Capability will be required for the End State; capability provided through existing Control Area Centers for the Release 1

Solution Strategy

Technology:

- SCADA (control, including alarming, logging, equipment tagging)
- State Estimator
- Load Flow (input from State Estimator)
- Contingency Analysis
- LSE Interfaces
- Dynamic Overview/Mapboard
- Weather forecast/radar
- FTMS Messaging

People:

- EMS NERC-certified Control Center Operators 7x24

Facilities:

- Control room with Internet access and high speed data links to Control Areas and other Security Coordinators, dual redundant CPUS, etc.
- UPS
- Backup Control Center facility with minimal Sub-Capabilities

GridFlorida

System Operations

Capability: Real Time Operations

Sub-Capability: Monitor & Control Generation

Sub-Capability Description

GridFlorida will monitor the generation units in real time in accordance with the GridFlorida OATT and FRCC Security Coordinator responsibilities.

Requirements

- Ability to monitor & assess state of generators
- Ability to control and/or communicate corrective instructions to the generator units directly or indirectly through the Control Area facilities or through the Scheduling Coordinators
- Ability to monitor and audit compliance

Key Assumptions

- GridFlorida will have RTO authority to redispatch for congestion management and balancing energy purposes
- GridFlorida will have Security Coordinator authority over all Control Areas
- Security Coordination capability will be required for the End State; capability provided through existing Control Area Centers for the Release 1

Solution Strategy

Technology:

- SCADA (control, including alarming, logging, equipment tagging)
- Load Forecast
- Operating Plan (Control Area schedules)
- Load & Frequency Control (LFC) (Regulation market)
- LSE interfaces
- Reserve Monitoring
- LFC Performance Monitoring
- Dynamic Overview/Mapboard

People:

- EMS NERC-certified Control Center Operators, 7x24

Facilities:

- Control room with Internet access and high speed data links to Control Areas and other Security Coordinators, dual redundant CPUS, etc.
- UPS
- Backup Control Center facility with minimal Sub-Capabilities

Capability: Real Time Operations

Sub-Capability: Instruct & Monitor Compliance

Sub-Capability Description

GridFlorida will issue instructions to Control Areas, monitor the compliance of Control Areas, and verify they followed the issued instructions for congestion management, Energy Imbalance, etc. This function also includes monitoring GridFlorida compliance with NERC Compliance Programs.

Requirements

- Mechanism for logging instructions and a feedback loop for determining if instructions were implemented
- Mechanism for logging NERC compliance templates
- Verify and track ancillary services usage

Key Assumptions

- Determination if instructions to Scheduling Coordinators & Market Participants were followed in a timely manner is required
- Failure to follow GridFlorida instructions or meet NERC compliance templates has implications
- SCADA will be used for monitoring where appropriate
- Capability will be required for the End State; capability for reduced functions and operations through existing Control Areas for the Release 1

Solution Strategy

Technology:

- Electronic logging application and messaging system with a Database for storing/retrieving all GridFlorida instructions
- Telephone for giving instructions to Control Areas and Voice recorder
- Other Control Center applications as needed

People:

- 7x24 Operators at Security and Generation consoles are responsible for logging instructions when issued
- Backroom personnel recording/monitoring compliance (after the fact)- Post Operations

Facilities:

- Control Center
- Office

GridFlorida

System Operations

Capability: Real Time Operations

Sub-Capability: Acquire Interchange Meter Data

Sub-Capability Description

Interchange meter data will be collected on an hourly basis to coordinate with operations data and will be used in the inadvertent process. GridFlorida will serve as a collection point for this data.

Requirements

- Control Areas will be the primary collectors for interchange meter data, which will be passed to GridFlorida
- Data should be verified each hour
- Data should be matched with schedules
- Process should support the Settlements and Billing capability

Key Assumptions

- Asset owners are responsible for validity and timely delivery of metered data
- GridFlorida operators are responsible for ensuring data is received
- Capability will be required for the End State; existing metering through control centers & new scheduling service will be used for the Release 1

Solution Strategy

Technology:

- ICCP
- ISN Portal
- FTMS
- Scheduling Service with inadvertent calculation

People:

- Operators, 7X24
- Settlements Analysts

Facilities:

- Control Center
- Office

Capability: Operations Support

Sub-Capability: Provide Operator Training

Sub-Capability Description

GridFlorida will provide comprehensive training for its operators and support staff. This training will included classes, OJT, field work and simulator training.

Requirements

- Training needs of Operations personnel must be defined
- GridFlorida should develop training with the Dispatcher Training Simulator to simulate the GridFlorida environment as closely as possible
- Field work (i.e. travel to member utilities, customer sites, etc.) should be included
- NERC certification
- Regulatory and code of conduct training
- Other potential, non-EMS training

Key Assumptions

- Capability with full applications will be required for the End State
- Leverage existing FPL DTS system for training of personnel for the Release 1

Solution Strategy

Technology:

- DTS (EMS, CM & market applications)
- Other Control Center applications as needed

People:

- Operators
- Dedicated training staff, including experienced NERC-certified Operators for training new and less-experienced operators
- Regulatory and NERC experts

Facilities:

- Control Center

Capability: Operations Support

Sub-Capability: Develop & Maintain Operating Procedures & Standards

Sub-Capability Description

GridFlorida will develop and maintain the processes, procedures and standards necessary to securely and efficiently operate the power system and coordinate operations.

Requirements

- Develop and maintain rules for implementation of market
- Develop and maintain the power system operations procedures and standards
- Determine the training protocols for Operations personnel

Key Assumptions

- Capability will be required for the End State; initial procedures & standards capability required for the Release 1

Solution Strategy

Technology:

- DTS (EMS, CM & market applications)
- Other Control Center applications as needed

People:

- Operators
- Operations Management staff

Facilities:

- Control Center

GridFlorida

Market Operations

Capability: Scheduling

Sub-Capability: Calculate/Update ATC

Sub-Capability Description

Calculate Available Transmission Capability (ATC) based on OASIS reservations, energy schedules and transmission system conditions.

Requirements

- Knowledge of scheduled transmission outages, generation outages, and any other transmission-related equipment
- Need to know how transactions are dispersed across control areas to compute accurate ATCs
- Daily & hourly ATC calculations & posting to OASIS
- Calculate ATC's for Control Area to Control Area, Congestion Zone to Congestion Zone (flowgate and non-flowgate)
- Calculate ATC's for interfaces to contiguous non-GridFlorida Control Areas

Key Assumptions

- OASIS will be implemented per FERC requirements
- GridFlorida will adopt the existing FRCC calculation methodology
- Capability will be required for the End State; use existing tool (possible FPC) extended for GridFlorida data for the Release 1

Solution Strategy

Technology:

- OASIS software
- ATC Calculator
- Integrated Model Management tool
- Interface to TTC data
- Interchange Scheduling software
- Transmission Scheduling software
- IDC
- FTMS

People:

- 7x24 coverage at a ATC Console
- Planning personnel (power system engineers)

Facilities:

•Control Center

)))

Capability: Scheduling

Sub-Capability: Schedule & Manage Energy & Ancillary Services

Sub-Capability Description

GridFlorida will receive day ahead, balanced energy and self-provided ancillary services schedules, transmission reservations and adjusted energy schedules from Scheduling Coordinators and determine their validity and operational feasibility.

Requirements

- Receive generator and forecasted energy load schedules (intra-Control Area)
- Receive energy schedules for transmission reservations (tagging for inter-Control Area)
- Determine net interchange schedules
- Disseminate all interchange schedules to Control Area Operators
- Validate interchange schedules with adjacent Control Areas and perform hourly checks and adjustments electronically

Key Assumptions

- All Ancillary Services will be dispatched in real-time by GridFlorida
- After-the-fact schedules are needed for settlement process
- Capability will be required for the End State; capability provided through existing Control Areas for the Release 1

Solution Strategy

Technology:

- Energy Scheduling service to parse schedules and determine interchange schedules for control areas.
- Provide schedules to Control Areas via a common format
- Mechanism to receive feedback on how schedules were implemented (synching logic)
- Congestion Management Software
- Tagging Service (NERC & GridFlorida)
- FTMS
- Transmission Scheduling Service
- Interface with overlay Control Area application

People:

- Transaction Scheduling Console position, 24 x 7

Facilities:

•Control Center

Capability: Scheduling

Sub-Capability: Manage Transmission Services

Sub-Capability Description

Market Participant requests for transmission service will be submitted via OASIS. GridFlorida will be responsible for receiving the reservation requests, validating them, and approving or denying the transmission service requests.

Requirements

- Distribute transactions across control areas to compute accurate ATCs
- Receive, validate, accept/reject, and tag incoming transmission requests for GridFlorida Transmission service
- Perform curtailments & schedule adjustments as required
- Track disposition of all requests under OATT

Key Assumptions

- OASIS will be implemented to meet FERC requirements
- GridFlorida will be single point of contact for OASIS reservations for transmission beginning, ending or passing through the GridFlorida region
- Capability may need to be transitioned prior to the Release 1; capability (possible OASIS Phase 2) will be required for the End State

Solution Strategy

Technology:

- Reservation Priority Tracking Software
- ATC Calculator interface
- OASIS/Transmission Scheduling Service
- IDC
- Integrated Model Management tool
- Provide data to Settlements and Interchange Scheduling

People:

- 7x24 coverage at a Transmission Reservation console by a NERC-certified operator
- Operational Planning staff

Facilities:

•Control Center

GridFlorida

Market Operations

Capability: Forecasting

Sub-Capability: Forecast Ancillary Services

Sub-Capability Description

GridFlorida will forecast short-term ancillary services needs within its control area, and it will procure ancillary services when necessary in its role as the provider of last resort for its region.

Requirements

- Verify that proposed transactions can be supported by the required ancillary services
- Determine the ancillary service requirements (e.g. voltage support), based on forecasted load
- Coordinate ancillary service requirements for imbalance, reserves, voltage support, etc., with self-suppliers or contract suppliers

Key Assumptions

- GridFlorida will be the provider of last resort for day-ahead & 1-hour ahead ancillary services within its region
- Provision of ancillary services will be from GridFlorida (procured through market and non-market mechanisms), or through self-supply or contracts with generators under the auspices of the OATT
- Capability will be required for the End State; capability will be provided by Control Areas for the Release 1

Solution Strategy

Technology:

- Scheduling Tools for documenting transactions supported by required ancillary services.

People:

- Scheduling personnel 24 x 7
- Operations planning personnel

Facilities:

- Control Center

Capability: Forecasting

Sub-Capability: Forecast Load

Sub-Capability Description

GridFlorida will develop short, mid and long-term load forecasts for its security coordination area and for planning the expansion and enhancement of the transmission system with information from SC's LSE's and Generators.

Requirements

- Track area forecasts for accuracy and develop historical data for analysis on a system-wide, control area, congestion zone and bus load basis
- Gather information from LSEs, Generators, and adjacent Control Areas to develop forecasts
- Develop an independent forecast to minimize underscheduling

Key Assumptions

- Short-term load forecast horizon will cover hourly load over 7 days, comprising 168 hourly values; mid-term will cover up to 1 year; long term will be 1 year and longer
- Data will be used to look at day-ahead and review of morning forecasts
- Capability will be required for the End State; capability will be provided by Control Areas for the Release 1

Solution Strategy

Technology:

- Method or application for creating and aggregating load forecasts
- Mechanism to receive load forecast data in a common format
- Mechanism for inserting aggregated data into network applications
- Tool to track accuracy of forecasts
- Weather forecast information
- FTMS message exchange

People:

- Security Operator, 24 x 7

Facilities:

- Control Center

GridFlorida

Market Operations

Capability: Market Facilitation	**Sub-Capability:** Operate a Market for Ancillary Services & ICE

Sub-Capability Description

GridFlorida will operate markets to obtain ancillary services for Regulation, Balancing and Operating Reserves. It will also operate a market for LSEs to meet Installed Capacity and Energy (ICE) requirements.

Requirements

- Support for overlay Control Area
- Produce a MCP using inc/dec bids from SCs for balancing market and congestion management redispatch
- Produce a MCP using capacity and energy bids from SCs for regulation and operational reserve
- Amounts of services determined by requirement forecast less self-supply or third party contracts by SCs
- Conduct a monthly deficiency auction to purchase sufficient installed capacity for LSEs to meet FPSC and FRCC reserve requirements

Key Assumptions

- Capability for Ancillary Services will be required for the End State; capability will not be required for the Release 1
- Assume overlay Control Area in place for the Release 1
- ICE market requirements have not been defined and are an uncertain requirement for the End State

Solution Strategy

Technology:

- Bidding and market clearing pricing mechanism
- Market Participant interfaces to support bidding
- Overlay Control Area application

People:

- Market desk staffing, 24 X 7

Facilities:

- Control Center or Office

GridFlorida

Market Operations

Capability: Market Facilitation	Sub-Capability: Run Congestion Management PTR Market

Sub-Capability Description

GridFlorida will operate a bulletin board system where offers to buy and sell PTRs can be posted.

Requirements

- Track use of PTRs and post as recallable (RTRs) if not scheduled in day-ahead process
- Identify additional capacity PTRs, based on ATC calculations, for auction
- Auction available PTRs and RTRs, clear prices and settle

Key Assumptions

- NERC TLR and interim CM (MRD+SRD solutions) will be used for the Release 1
- Full CM market solution will be required within 1-year from the Release 1 & will likely be included in the End State

Solution Strategy

Technology:

- Bulletin board and bidding/pricing mechanism
- Congestion management clearing engine
- Calculate PTDFs (from Network Sensitivity Analysis)

People:

- Market desk staffing, 24 x 7

Facilities:

- Control Center or Office

GridFlorida

Commercial Operations

Capability: Metering & Measurement Data

Sub-Capability: Acquire Metered Data

Sub-Capability Description

Revenue-quality metering data must be collected by GridFlorida in order to support the Settlements and Billing capability. GridFlorida will serve as a collection point for metering data from the individual Control Areas.

Requirements

- Control Areas will be the primary collectors for metering data. The data will be passed from the Control Areas to GridFlorida through a pre-described interface in a defined format.
- Provide metering database with data analysis capability, and ability to store large volumes of meter data.
- Maintain flexibility to meet future demands once improved and additional metering data is available (beyond the end state).
- Archive Meter & Meter Read Data

Key Assumptions

- Revenue quality metering will not be available in many cases. Specifically metered load data is available at the ties/interchange points, but not at most load points of delivery. Generation metered data is mostly available, but may not all be revenue quality or may be in the wrong location in some cases. The lack of meter data will impact Settlements calculations for EI, Congestion Management, etc (see other sub-capabilities).
- Minimal new metering beyond what is currently available is assumed for the end state. There might be selective replacement of some metering.
- Where possible, revenue quality meter data will be provided to GridFlorida according to the settlement interval (assumed to be 10 seconds)
- All metered data is received from the Control Areas; GridFlorida does not poll any meters, for example, to retrieve data
- Asset owners are responsible for validity and timely delivery of metered data and GridFlorida is responsible for ensuring data is received
- It is not yet determined who will own the meters in all cases (some GF, some the Transmission companies)

Solution Strategy

Technology:

- Portal (EDI transaction) to receive metered data from Control Areas
- ICCP protocol for transfer of generation meter data
- ISN Portal

People:

- Meter Data Analysts

Facilities:

- Receive data through GridFlorida Control Center
- Office

Capability: Metering & Measurement Data

Sub-Capability: Reconcile & Manage Metering Data

Sub-Capability Description

The primary purpose of this function is to reconcile and validate the meter data acquired for Settlements and Billing. Where necessary, this sub-capability will also have the responsibility to convert the meter data into the correct format and Settlements interval.

Requirements

- Reconcile and manage metering data
- Perform load allocation/load profiling methodologies to disaggregate or allocate total load actuals down to the level required (e.g. to each load asset) on the network, in order to calculate charges. This will be a complex, but necessary part of the Commercial Operations capability, given an absence of revenue quality metering data, particularly at load points.
- Interface with the Settlement & Billing sub-capabilities
- Identify and implement corrective action for apparent metering data errors and lack of metering data

Key Assumptions

- This is a required capability for the end state. A potential Release 1 of GridFlorida would not have this capability in place, and may need to rely on current methods (of utilities) for calculating Energy Imbalance, and other, in the absence of a metering data sub-capability.
- For the end state, GridFlorida expects to have to make use of the current metering system if possible. There may be some replacement of selective meters, and in the case of new customers, correct metering should be installed wherever possible.
- The primary purpose of this function is to prepare the meter data for Settlements and Billing
- GridFlorida will receive revenue quality meter readings from the different Control Areas

Solution Strategy

Technology:

- Meter data database (significant size and storage capabilities)
- Load allocation/profiling tool(s)

People:

- Meter Data Analysts, who support the Settlements sub-capability by performing the day-to-day operations of reconciling & managing meter data

Facilities:

- Office

Capability: Metering & Measurement Data

Sub-Capability: Certify and Register Meters

Sub-Capability Description

The primary purpose of this function is to ensure that meters connected to the Grid Florida system and/or providing meter data to GridFlorida for Settlements & Billing are certified and registered, in order to ensure the accuracy of the Settlements & Billing calculations.

Requirements

- Have ability to certify and register meters being used by the GridFlorida system
- Requires specialized skills/training to do the certification and registration
- Document results of the certification and registration in the meter data system, such that meter data received can be recognized as from a certified and registered meter

Key Assumptions

- This is a required capability for the end state. A potential Release 1 of GridFlorida would assume that this sub-capability is in place through the Transmission companies.
- The question of meter ownership will need to be resolved. The initial assumption is that TECO is keeping its meters, and FP&L is planning to contribute its meters to GridFlorida. This discrepancy will need to be resolved.
- Irregardless of meter ownership, GridFlorida have the ability to certify and register meters in order to ensure the Settlements & Billing results.

Solution Strategy

Technology:

- Meter database in which to store certification and registration of each meter – assumed to be either in the main meter database or in the Settlements system

People:

- Meter Technicians – with qualifications to certify and register various meters – at Generation and Load points

Facilities:

- Office, and work will be done in the Field

GridFlorida

Commercial Operations

Capability: Settlements & Billing

Sub-Capability: Settle Market

Sub-Capability Description

Responsible for performing settlements steps and functions in order to reconcile scheduled data with actual usage information for the calculation of charges/credits for services provided by GridFlorida. (e.g. transmission service (point to point vs network), ancillary services, and other RTO services). Both the tariff and specific market rules will drive the settlements calculations.

Requirements

- Calculate and allocate the charges & credits for GridFlorida services to each customer. The tariff and specific market rules will drive calculations.
- Perform settlement function for transmission services, ancillary services, energy imbalance, congestion management, grid management, & losses
- Transmission is settled for network load and point to point. Network load is settled by a percent of system peak monthly (including losses). For the first 1-5 years, it is settled by zonal transmission rates at zonal peak. For 6+ years (and 1-5 years for new facilities), transmission is settled using a system wide average charge. Point to point is settled on reservation with a potential penalty for exceeding (or not meeting) reservation.
- Ancillary services scheduling is linked to transmission for point to point and network. Customers can self supply Regulation and Frequency Response Service (RFR) and Operating Reserves. There will not be markets for these two in the end state.
- Customers must purchase Balancing Energy Service from GridFlorida and may offer/bid to sell Balancing Energy to GridFlorida.
- Charges for Scheduling, System Control and Dispatch Service, Grid Management and Black Start services will be applied to customers.
- Reactive Supply and Voltage Control (RSVC) will not result in charges/credit, except in security constrained situations – there may be a charge.
- Settlements functions will be performed on a periodic (i.e. daily, monthly) basis and will occur in 10 minute intervals.
- Details for how to settle for Congestion management are not yet fully defined. There may be an interim plan which changes in the long term.
- Includes initial settlements (some may be on estimates) followed by resettlements. Requirement to validate, balance & audit Settlements data.

Key Assumptions

- This is a new capability for GridFlorida and is a required capability in the end state. An initial Settlements capability will be required in a potential Release 1 scenario. This initial capability will not settle for any market services, and may be done by GridFlorida or may have to be done through the Transmission companies. Capability depends on details of OATT and on completion of specific market rules design.

Solution Strategy

Technology:

- Settlements system and interfaces to Energy Schedules (etags), Generation Schedules, OASIS(Transmission reservations), Meter Data, Prices, and Market Operations results. Ability to store large volumes of data over time, in order to recreate historical charges.

- *People & Facilities:*
- Settlements Manager, Settlements Analysts, Office and powerful PCs

Capability: Settlements & Billing

Sub-Capability: Perform Billing

Sub-Capability Description

Based on the settlements data calculated a periodic (i.e, weekly, monthly) invoice must be constructed and sent to the customer and with charges/credits captured as Accounts Receivable/Account Payables. The invoice must be prepared/calculated covering all charges and credits. The invoice will be electronically prepared and sent to the customers (potentially through the customer interface portal).

Requirements

- Develop a billing engine which uses the settlements results and billing determinants to calculate the charges and credits
- Customer account information, previous payments processed, resolution of previous customer disputes/inquiries, taxes, outstanding receivables carried from prior periods, penalty charges, and adjustments are consolidated with the current charge and credit information into bill line items
- Tariff requires monthly billing for transmission service; imbalances may need to be more often.
- Typically in active, competitive wholesale markets, with market services, settlements statements are generated on a daily basis and sent to the customer, with bills/invoices generated approximately weekly or potentially monthly.
- At the creation of a bill, amounts are recorded in the Accounts Receivable/Accounts Payable systems and handed off to Corp. Finance & Acctg.

Key Assumptions

- This is a new capability for GridFlorida, with little/no reuse from member utilities and is a required capability on Release 1.
- An invoice is the compilation of multiple settlement statements. A settlement statement is for one settlement day. An invoice is for a set amount of previous settlement days combined.
- Settlement statements and bills will be posted via the portal to Scheduling Coordinators (who then settle with customers).

Solution Strategy

Technology:

- Portal for distribution of Settlements statements and potentially bills
- Settlements and Billing system. Bill print software.
- Financial Management system – specifically Accounts Receivable and Accounts Payable.

People:

- Settlements Manager, who is responsible for overall Settlements and Billing functions. Oversees the calculation of settlements and services charges for each customer, ensures that settlement statements and bills are accurate and created on a timely basis.
- Settlements Analysts, who support the Settlements Manager by performing the day-to-day operations of settlements and billing

Facilities:

- Office

GridFlorida

Commercial Operations

Capability: Settlements & Billing

Sub-Capability: Resolve Disputes

Sub-Capability Description

All customer inquiries are captured in the Resolve Customer Inquiries and Disputes function (in the Customer Interface capability). Inquiries specifically related to Settlements and Billing disputes are then routed to Settlements personnel for resolution. Dispute Resolution process will follow rules and process outlined in the tariff.

Requirements

- Strong communication and interface between customer service account reps. roles and Settlements roles to ensure solid dispute resolution from a customer service point of view
- Ability to answer customer questions in areas such as billing adjustments, missing meter data notification, customer information requests, and technical assistance
- Ability to follow steps to investigate/resolve inquiries, and determine when an official dispute must be logged.
- Details of disputes must be tracked and used to ensure that procedures and specific dispute resolution rules are being followed
- Research or re-routing of disputes to appropriate personnel where necessary

Key Assumptions

- This sub-capability will increase in scope for GridFlorida (compared to current), with little/no reuse from member utilities and is a required capability in both the end state and potential Release 1 timeframes.

Solution Strategy

Technology:

- Portal for distribution of results and information to customers
- Settlements and Billing system to review and recreate (where necessary) historical charges and credits
- System in which to record disputes – steps and resolution
- Access to operational data necessary to resolving disputes (e.g. reviewing dispatcher logs and taped conversations)

People:

- Settlements Manager, who is responsible for overall Settlements and Billing functions. Oversees the calculation of settlements and services charges for each customer, ensures that settlement statements and bills are accurate and created on a timely basis.
- Settlements Analysts, who support the Settlements Manager by performing the day-to-day operations of settlements and billing

Facilities:

- Office

GridFlorida

Commercial Operations

Capability: Settlements & Billing

Sub-Capability: Manage Customer Credit Risk

Sub-Capability Description

This sub-capability is responsible for assessing and managing any potential ongoing credit risks, specific to Transmission customers of GridFlorida.

Requirements

- Evaluate potential credit risks on an ongoing basis. Develop specific credit management policies.
- Required to evaluate a combination of factors to assess customer specific risks. Factors include: established credit limit, outstanding amounts owing, collections history, and amount of new business booked/reserved (e.g. Transmission reservations made, not billed/paid).
- Ensure that customers do not purchase over their credit limits. Alert Market Operations/Scheduling to "close to credit" situations.
- Does not include more general credit management sub-capability (e.g. for establishing/assessing credit limits of parties other than Transmission customers).

Key Assumptions

- This is a required sub-capability in the end state.
- In a potential Release 1 scenario, GridFlorida may need an initial, simplified version of this sub-capability.
- This sub-capability requires coordination and information from a number of sub-capabilities: Scheduling, Collections, Certify New Customer.

Solution Strategy

Technology:

- Access to information in Scheduling, OASIS, Settlements & Billing, Accounts Receivable, and Customer System/Portal
- Potential for regularly produced report that would "flag" close to credit customers, from data in multiple systems

People:

- Credit Risk Analyst/Manager (might be part of Settlements Manager role)
- Settlements Analysts, who support the Settlements Manager by performing the day-to-day operations of settlements and billing

Facilities:

- Office

GridFlorida

Commercial Operations

Capability: Settlements & Billing

Sub-Capability: Collect Payments & Make Disbursements

Sub-Capability Description
GridFlorida must coordinate collections and disbursements of cash, track and monitor outstanding amounts, and enforce collections procedures when necessary.

Requirements
- Payments from customers are received (electronic funds transfers between banks and potentially by checks) and distributed to the appropriate outstanding accounts
- Customer accounts are updated in accordance with their received payment
- Customers with outstanding accounts are given notification and collection action is taken if required
- Late charges are assessed immediately after due date
- Disbursements are made to service providers
- In participating owners agreement, GridFlorida pays the Transmission Owner for use of the transmission system as the Transmission Customer pays GridFlorida (pass through to meet revenue requirements)

Key Assumptions
- This is a new capability for GridFlorida, with little/no reuse from member utilities and is required in both the end state, and in a potential Release 1 scenario
- All financial transactions go through the Scheduling Coordinators

Solution Strategy
Technology:
- Financial Management System (Accounts Receivable and Accounts Payable), Electronic Funds Transfer capability between banks

People:
- Settlements Manager, who is responsible for overall Settlements and Billing functions. Oversees the calculation of settlements and services charges for each customer, ensures that settlement statements and bills are accurate and created on a timely basis.
- Settlements Analysts, who support the Settlements Manager by performing the day-to-day operations of settlements and billing
- CFO

Facilities:
- Office

GridFlorida

Commercial Operations

Capability: Contract Management

Sub-Capability: Certify New Customers

Sub-Capability Description

Contract Management is the management of the contractual agreements between GridFlorida and its customers. Everyone who will be providing or procuring OATT/transmission services to/from GridFlorida (e.g., ancillary services) will need to be certified customers. This process will gather customer details (business, credit, and operational related) in order to certify the customer to do business with GridFlorida.

Requirements

- Develop standard procedures, policies and requirements for certification of new customers of GridFlorida
- Develop customer information package detailing business, credit and operational related data. Portions of this is gathered by the new customer.
- Interface with customer for certification inquiries. Customer must meet requirements related to information technology, transmission service, and establishing training
- Perform evaluation of legal and technical requirements (e.g equipment and characteristics) and financial requirements (e.g. credit check). Review and approve (may require multiple levels of review across capability areas (e.g. System & Market Operations, and Corporate Services)
- Set-Up & Notify customers, including the training on the use and setup of systems, and the notification of user names and passwords, etc.

Key Assumptions

- Services will only be procured from or sold to customers who have been certified through the Certify New customers function
- This is a new capability for GridFlorida, with some reuse from member utilities and is required in the end state. In a potential Release 1 scenario, this could be based on current certification procedures implemented by current Transmission companies.

Solution Strategy

Technology:

- Set up of new customers in Contract Management software, Customer Information system and Settlements & Billing system

People:

- The Contract Administrator is responsible for monitoring and coordinating the negotiation of contracts for GridFlorida. This manager will provide contracting support to all areas of the organization and will receive support from the appropriate legal counsel whenever required.
- Account Managers, who are a key point of contact for customers. They will manage and maintain the registration and certification of the entire Contract Management process.

Facilities:

- Office

GridFlorida

Commercial Operations

Capability: Contract Management

Sub-Capability: Manage Contracts with Customers

Sub-Capability Description

This process establishes and maintains the contractual arrangements between GridFlorida and its Transmission customers (e.g. contracts for Transmission services). GridFlorida will verify that the terms and conditions of contracts are met, and manage any Settlements & Billing impacts.

Requirements

- Process must support the verification and certification of existing contract arrangements (grandfathered contracts)
- GridFlorida will only administer contracts in its tariff. However, GridFlorida can file with FERC to modify contracts if they are not in line with GridFlorida's operating guidelines.
- There will be a few existing contracts with not be able to be amended. However, the TO takes on that responsibility and risk (i.e. the TO will buy from GridFlorida and then take have to settle/bill with their own customer according to the contract terms).
- Contract and legal documentation development
- Standard contract management capability to monitor the contracts with each customer
- Process supports contract compliance monitoring and enforcement if necessary

Key Assumptions

- This is a new capability for GridFlorida, with some reuse from member utilities and is required in the end state. Additional analysis is required to determine status impact of contracts in a potential Release 1 scenario.
- GridFlorida needs to determine how previously agreed upon contracts will be incorporated into the new market
- Current Transmission owners have significant work to do to get current contracts converted to fit with new rules

Solution Strategy

Technology:

- Contract Management software

People:

- The Contract Administrator is responsible for monitoring and coordinating the negotiation of contracts for GridFlorida. This manager will provide contracting support to all areas of the organization and will receive support from the appropriate legal counsel whenever required.
- Account Managers, who are a key point of contact for customers. They will manage and maintain the registration and certification of the entire Contract Management process.
- Settlements Analysts to analyze and manage the Settlements & Billing implications of contract terms

Facilities:

- Office

Capability: Customer Management	**Sub-Capability:** Resolve Customer Inquiries

Sub-Capability Description

Once the customers are certified and registered with GridFlorida, this process becomes their main interface with GridFlorida for resolving inquiries and obtaining information for existing and new relationships

Requirements

- Development of customer service activities such as the establishment of a key account manager function for inquiries to serve as one point of contact
- Maintain and store customer information
- Handle customer registration and route questions. Will need to coordinate with the rest of the organization.
- Answer customer questions in areas such as the planning process, meter data, project construction, training, study requests- longer term, disputes, credit and billing, tariff questions, maintenance schedules, customer feedback (market rules, etc), certify/register new customer profile (load, contacts, future connects, etc), load forecasts from customers (annually), and technical problems
- Research or re-routing of inquiries to appropriate personnel
- Account managers must understand the tariff

Key Assumptions

- This is a new capability for GridFlorida, with no reuse from member utilities and is a required capability prior to Release 1
- Skilled, capable personnel with technical and functional skills will perform the customer service responsibilities
- Initial contact person will have access to all necessary data and appropriate skills/training to handle most calls
- Customer info will be captured on a common data base used by other processes
- Need consistent communication of tariff information to all customers

Solution Strategy

Technology:

- A customer service application would assist in the resolution/routing/monitoring of customer inquiries and the management of customer relationships and data
- Web interface which is accessible from OASIS
- Phone calls

People:

- Account Managers, who are a key point of contact for customers. AMs should be able to resolve questions or problems posed by their customers. They should be functional experts as well as customer service experts.

Facilities:

- Corporate Headquarters

Capability: Customer Management | **Sub-Capability:** Manage Relationships with Customers

Sub-Capability Description
This process supports proactive customer service by gathering input from customers and supporting the development of new services, and communication and training to meet customer needs

Requirements
- Information collection from customers (and advisory committee) through customer focus groups, surveys and other RTO processes
- Analysis of input, and identification of alternatives to meet those needs
- Coordination with the appropriate parts of the RTO organization to develop effective communications and training
- Facilitate the delivery of adequate training and communication to facilitate participation (systems and OATT)
- Coordinate with additional appropriate GridFlorida capabilities to create customer development and marketing plans and strategies

Key Assumptions
- This is a new capability for GridFlorida, with no reuse from member utilities and is a required capability prior to Release 1
- Personnel with technical, functional, and interpersonal customer service skills will perform the customer service responsibilities

Solution Strategy

Technology:
- A customer service application would assist in the resolution/routing/monitoring of customer inquiries and the management of customer relationships and data
- Web interface which is accessible from OASIS

People:
- Account Managers, who are a key point of contact for customers. Account Managers should be able to resolve questions or problems posed by their customers. They should be functional experts as well as customer service experts.

Facilities:
- Corporate Headquarters

GridFlorida

Customer Interface

Capability: Customer Management

Sub-Capability: Collect Customer Information

Sub-Capability Description

GridFlorida must maintain information about each customer. This function is the key step to gathering the appropriate information, verifying, and maintaining it in a common format and facility

Requirements

- Information is collected through a well-defined registration process
- Verify that customers have completed proper contract documentation for services being requested
- Data should be captured and stored in a single location
- Data should be accessible by internal GridFlorida users
- Appropriate levels of security over data should be maintained
- Coordinate with the rest of the organization to maintain information about customers

Key Assumptions

- Customers will convert at some date determined by GridFlorida
- This is a new capability for GridFlorida, with no reuse from member utilities and is a required capability prior for Release 1

Solution Strategy

Technology:

- Customer Service Application
- Web interface which is accessible from OASIS

People:

- Account Managers, who are a key point of contact for customers. They collect customer data and enter it into the appropriate system. They also maintain the integrity of the customer information database.

Facilities:

- Corporate Headquarters

Customer Interface

Capability: Communication Management

Sub-Capability: Provide Customer Information

Sub-Capability Description

Customer Management & Communication is the capability which allows the RTO to provide customers with operational information while managing relationships with these customers. GridFlorida will provide information to customers and the public about the transmission system, settlements and invoicing, OATT, and other relevant information

Requirements

- This process serves as a primary interface between GridFlorida and its customers
- Market information should be provided by GridFlorida to customers, regulators, and internal users
- Information should be posted to an area, such as a portal or electronic bulletin board, that allows *for fair and equal access to all customers*
- Appropriate levels of security must be determined and maintained for sensitive data (i.e. there will be a public "site" and a "private site")

Key Assumptions

- This is a new capability for GridFlorida, with no reuse from member utilities and is a required capability for Release 1

Solution Strategy

Technology:

- Web interface which is accessible from OASIS (public and private interface)
- Web interface would interface with Data Warehouse

People:

- Communications Analysts /Webmasters are responsible for maintaining the information portal, bulletin or adding information to OASIS- these people could be outsourced

Facilities:

- *Corporate Headquarters*

GridFlorida

Customer Interface

Capability: Communication Management

Sub-Capability: Provide Customer Training

Sub-Capability Description

This process meets the training needs of GridFlorida external customers and users (including regulators)

Requirements

- Training needs of customers must be defined
- GridFlorida must design, develop, and deliver customer training (and certify customers)
- Perform training needs analysis for ongoing customers as changes to the tariff, procedures, and computer systems impact the way they operate or deal with GridFlorida
- Regulatory and code of conduct training

Key Assumptions

- This is a new capability for GridFlorida, with no reuse from member utilities
- This is a required capability prior to Release 1
- Some training may be conducted by third-party vendors as needed (outsourced)

Solution Strategy

Technology:

- Low tech paper based training (Release 1)
- Registration system on web interface for training (end state)
- Web based training (end state)

People:

- Communications and Training Analysts (CTA), who are responsible for supporting Account Managers and other areas of the organization to provide customers with the comprehensive training and communications necessary to be effective. On an on-going basis, the CTA will monitor customer needs and will provide regular communication, education, or training as appropriate
- Coordinate with internal training department
- Some or all of training staff could be outsourced

Facilities:

- Corporate Headquarters- training staff
- Training can be conducted in off site meeting locations or at customer's location

GridFlorida

Asset Optimization

Capability: Network Planning

Sub-Capability: Plan Network Enhancements

Sub-Capability Description

The planning process to be used by GridFlorida is intended to satisfy FERC's directive that a single entity must coordinate both transmission planning and expansion within its region to ensure a least-cost outcome that maintains or improves existing reliability levels and accommodates growth.

Requirements

- Regional planning analyses and basis for decisions must be available for review by interested parties; through annual planning process and is intended to ensure fair, unbiased and efficient enhancement of the transmission system to support *robust wholesale competition*
- GridFlorida shall have the obligation & sole responsibility for planning and directing the expansion of Controlled Facilities
- GridFlorida will have review and approval authority over transmission facilities connecting either load serving delivery points or a specific *generating unit, and will coordinate* the review of the impact of new additions on the Transmission System with the Transmission Owner, Generation Owner, and Local Distribution Utility planning the addition, as appropriate.
- GridFlorida will perform analyses to ensure compliance with NERC Planning Standards

Key Assumptions

- GridFlorida holds final responsibility for the regional transmission plan and requires the capability to do bulk transmission and interconnection planning (including planning around seams issues); includes managing potential congestion
- There is a *transition provision for Local Area Planning – for the first three years* GridFlorida will contract back the Local Area planning to be done by FP&L, TECO and FPC, with final review/approval by GridFlorida. GridFlorida will develop capability to do Local Area Planning over time (beyond both Release 1 and end state).
- In the event a Participating Owner doesn't want to construct/modify/expand facilities, GridFlorida may do so themselves
- If a non-participating owner requests a new interconnection, GridFlorida will have to review/approve request
- GridFlorida will adopt 5-10 year expansion plans of Pos/Dos, at commencement of operations, as baseline plan (will change as required)

Solution Strategy

Technology:

- Network planning suite (e.g. PSSE) and extracts of real time data, transfer analysis software (e.g. MUST), ATC calculations, and OASIS access
- Real time data archive - PI/EMS type of data, and e-tag access

People:

- Network Planning Group (Engineers and others) will be required in both end state and a potential Release 1 scenario

Facilities:

- Office, including PC's with sufficient speed & memory to simultaneously run PSSE, MUST & Office software

GridFlorida

Asset Optimization

Capability: Network Planning	**Sub-Capability:** Perform Studies

Sub-Capability Description

System studies will be conducted by various committees, workgroups, and GridFlorida personnel in order to promote grid reliability, system efficiency, and coordinated planning efforts.

Requirements

- GridFlorida will have primary responsibility for the coordinated performance of all system studies and will define coordinated planning studies to be conducted under its direction and develop work assignments and schedules for conducting such studies
- GridFlorida will have the obligation and sole authority to receive and process requests from generation owners to interconnect
- Transmission studies associated with new load connections will be conducted, where grid reliability is affected, transmission congestion increased, or ATC reduced, and other studies associated with transmission service requests, including System Impact Studies
- Generator studies including the determination of System Upgrades & Direct Assignment Facilities and associated costs
- GridFlorida may also perform its own alternative system expansion studies, commission studies to be performed by a third party, and consider the input of studies from other interested parties in choosing a preferred plan

Key Assumptions

- Existing processes at member utilities will be leveraged to Perform Studies. GridFlorida will have the overall responsibility for doing studies, and will outsource back to engineering in the three Transmission Cos. to get the study and estimates done (end state & potential Release 1 scenario)
- Example: Generator requires an impact study. GridFlorida has the responsibility, contracts with FP&L, TECO or FPC to get the work done. GF charges and collects from the Generator, while the Utility charges and collects from GF.
- As Utilities will still be doing studies to meet their needs (e.g. voltage/VAR related studies), and GF will have an interest in studies as well, there is potential for duplication (e.g. GF does study from security point of view & LSE does from a network development view)

Solution Strategy

Technology:

- Network planning suite (e.g. PSSE), transfer analysis software (MUST)
- Real time operations data (PI/MMW/EMS)

People:

- Network Planning Engineers and Analysts

Facilities:

- Office

GridFlorida

Asset Optimization

Capability: Network Planning

Sub-Capability: Develop Standards

Sub-Capability Description

Develop GridFlorida standards for Planning, Design, Construction and Maintenance. Develop and then maintain/update standards on an ongoing basis. Will require a central repository for standards, equipment manuals, procedures, etc.

Requirements

- GridFlorida needs to develop standards for all planning, design and work done to the transmission facilities.
- GridFlorida will be starting with the standards of three current Transmission groups, but will need to develop their own standards for Design and Construction, integrating and changing the current standards, as well as developing new to meet the needs of the new RTO
- The standards will include such items as: materials standards, estimated labor standards, and procedures/standards and expectations around how work will be done
- Once standards are developed, they must be updated on a regular basis, in part based on measuring/comparing estimates to actuals in Design and/or Construction. Include feedback loop based on actuals to update design standards

Key Assumptions

- This capability will develop over time, and could take approximately a year for initial development, followed by full development of standards. Therefore this is primarily beyond end state capability, and in a potential Release 1 scenario, GridFlorida would need to rely on current standards. GridFlorida will be starting with the standards developed in each of the Utilities
- GridFlorida expects it could take 3-5 years to fully develop a new set of standards, however at a minimum GridFlorida will need to understand current standards from three Utilities in order to work with them in the Work Definition sub-capabilities

Solution Strategy

Technology:

- Tool in which to develop, record and modify standards (common repository and/or might be part of a Work/Maintenance Management system)
- Access to information on current standards and actuals from the Work/Maintenance Management, Financial and other systems

People:

- People (Engineers, Planners, Designers) from current organizations familiar with Design and Construction standards

Facilities:

- Office

GridFlorida

Asset Optimization

Capability: Network Planning

Sub-Capability: Develop Connection Policies and Procedures

Sub-Capability Description

Develop interconnection agreements between GridFlorida and generation owners & transmission customers and LSEs.

Requirements

- GridFlorida will develop requirements for connection to GridFlorida Controlled Facilities
- GridFlorida will perform the planning required for generation interconnections through GIS Feasibility and Facility studies
- The intent of the requirements is to ensure reliable transmission system operations and adequate response for the purposes of maintaining system control security, and to comply with NERC and other applicable industry standards and guidelines
- GridFlorida will coordinate transmission planning process associated with interconnecting generators that wish to provide Installed Capability

Key Assumptions

- Existing policies and procedures at member utilities can be leveraged
- GridFlorida will develop interconnection and queuing procedures
- GridFlorida will enter into operating agreements, Point-to-Point Transmission Service agreements or Network Integration Transmission Service agreements, as appropriate, with all Transmission Customers (including Transmission Owners) or other interconnected entities for the purpose of ensuring reliable operations of the Transmission System
- Currently working on Generation Interconnection studies in preparation for RTO in a potential Release 1 scenario. Interconnection Agreements (TECO and FP&L) have to be in place).

Solution Strategy

Technology:

- Business Software
- Access to previous connection policies and procedures

People:

- Network Planning personnel
- Access to Legal and Contract staff
- Some overlap with Plan Network Enhancements

Facilities:

- Office

GridFlorida

Asset Optimization

Capability: Work Definition

Sub-Capability: Develop Maintenance Strategies

Sub-Capability Description

Develop strategy for performing routine and non-routine maintenance work on transmission assets. Strategy to balance cost and benefit for scope and frequency of maintenance. Goal is to maintain/increase profitability of assets.

Requirements

- Goal is to maximize the use of assets to generate optimum sustainable financial returns
- Determine required maintenance strategies based on a number of criteria: network age and condition, historical data available, reliability results, utilization rate
- Determine elements of maintenance strategies for transmission assets; fix vs: replace, frequency, methods depending on component
- Link maintenance strategies to revenue opportunities (not just reliability & safety)
- Measure results of maintenance strategies and modify accordingly

Key Assumptions

- GridFlorida has the obligation to provide reliable service through solid maintenance planning and execution and will do maintenance planning in the long-term, but in the end-state and in the Release 1 scenario will contract back to the Transmission owners for this service
- First GridFlorida will take as-is maintenance plans and use these. Reliability criteria will drive spending. Within first year of operation GridFlorida will need to measure results/costs and revise budgets. Later there may be performance incentives to increase efficiency.
- GridFlorida will determine and own the budget for maintenance
- Question re: materials. FPL – once materials are in-service, sell to GF. TECO plans to sell all their materials to GF.
- Ability to develop/maintain their own records on the network assets and their condition/performance. (Initial for Release 1, with additional later).

Solution Strategy

Technology:

- Access to information/reporting from three Transmission companies re: maintenance strategies & plans. For Release 1 – initial Asset Management system (e.g. with high priority assets).
- End state - Maintenance Management System may be the same/part of the Work Management System
- Access to information from other systems (reliability results, historical maintenance done, costs to do maintenance work, etc.)

People:

- Maintenance Supervisors and Maintenance Planners
- Contract Managers – to manage the process and outsourcing relationships and results

Facilities: - No special facilities required

GridFlorida

Asset Optimization

Capability: Work Definition

Sub-Capability: Assess Asset Performance & Utilization

Sub-Capability Description

Assess the performance and utilization of transmission assets, through physical and financial modeling, with the goal to maximize profitable, sustainable use of the assets.

Requirements

- Measure results and assess performance of transmission assets based on a number of criteria; profitability, compliance/reliability, sustainability, and transmission customer satisfaction
- Measure and assess asset utilization or the extent to which existing assets are used for given demands (e.g. asset turnover)
- Requires ability to model and proactively manage current and future demand and compare to current and future utilization rates.
- Link results into maintenance strategies

Key Assumptions

- Assessing asset performance and utilization becomes more important in a competitive, for-profit environment
- Optimum asset utilization ensures effective use of invested capital
- This is not a required capability in a potential Release 1 scenario. In the end state, there will be focus on costs/results of work done to assets. Full analysis of asset performance will come later in the evolution of GridFlorida.

Solution Strategy

Technology:

- For Release 1 – initial Asset Management system (e.g. with high priority assets).
- Information on reliability incidents, information from Scheduling/Market Operations re: Transmission system usage
- Information from costing system(s)
- Long-term - Maintenance and/or Work Management systems and may require financial modeling (in case that profitability analysis beyond standards for rate-making change).

People:

- Combination of people & skills from: Network Planning, Develop Maintenance Strategies, Finance and Accounting and Scheduling Capabilities. Shared responsibility between Corporate Services and Asset Optimization.

Facilities: - PCs

GridFlorida

Asset Optimization

Capability: Work Definition

Sub-Capability: Engineer System Enhancements

Sub-Capability Description

Create standard, cost-effective plans, designs and work estimates for approved system enhancements. Approve/review others' plans and designs.

Requirements

- Engineer system enhancements for transmission assets owned by GridFlorida. Covers more detailed planning stemming from the overall network plan.
- Coordinate with Transmission owners (for assets not owned by GridFlorida) on their plans and designs for system enhancements

Key Assumptions

- GridFlorida will have the obligation to engineer plans for system enhancements, however will outsource the development of detailed plans and cost-effective work estimates for transmission system enhancements. Will be outsourced in both the end state, and a potential Release 1 scenario
- Review detailed plans produced by others to enhance the system
- Identify and manage dependencies that impact design (e.g. permits, critical path)
- Manage other approval processes required

Solution Strategy

Technology:

- Access to information/reporting from three Transmission companies re: details of System Enhancement Plans
- Long-term - Work Management System and/or estimating tool with Compatible Units (or similar)
- Network model, routine office software

People:

- Engineer (one in lead role), plus support staff (Asset Planners/Designers, Contract Managers)
- Maybe some remote work (e.g. on-site)

Facilities:

- Laptop PCs (potentially)

GridFlorida

Asset Optimization

Capability: Work Execution

Sub-Capability: Perform Maintenance/Inspections

Sub-Capability Description

Perform routine and non-routine maintenance work on transmission assets. Focus on operational efficiency in completing the work, and optimize the lifecycle and performance of assets through appropriate application of maintenance strategies. Ensure qualified maintenance crews.

Requirements

- Initiate or receive maintenance work orders (may be unplanned, emergency or routine/planned work). Review details of work required, adjust if necessary
- Ensure work site is ready for maintenance (materials available, resources, schedules, permits/other procured).
- Coordinate with control area operators to schedule and start work, execute work in the field, supervise resources, capture information required to track progress and gather as-built information
- Complete the work and timely capture of all as-built information. Will be a more streamlined version of work completion.
- Close out the work and feed details back into Asset Performance/Maintenance Management system.

Key Assumptions

- GridFlorida will outsource the Perform Maintenance/Inspections capability back to Transmission Owners and will have a large role around managing this outsourced work (in other sub-capabilities as well) both in the end state and in a potential Release 1 scenario
- GridFlorida will need to coordinate and provide oversight of contract work forces doing maintenance/inspections and evaluate results which will then feed back into the changing maintenance strategies, budgets or practices. Must be able to get detailed information from the TOs.

Solution Strategy

Technology:

- For Release 1 – initial Asset Management system (e.g. with high priority assets).
- Access to information from Transmission systems (financial/cost systems, reliability results, historical maintenance, costs to do maintenance)
- Longer-term - Maintenance Management System may be the same/part of the Work Management System

People:

- Maintenance Supervisors/Managers, Contract Managers
- Field crews – will be an outsourced/contracted workforce – initially coming from the three Transmission companies. Crews may overlap maintenance and construction work.

Facilities: - No special facilities required

GridFlorida

Asset Optimization

Capability: Work Execution	**Sub-Capability:** Perform Construction

Sub-Capability Description

Perform construction of system additions/modifications. Focus on maximizing the productivity, and managing the work effectively throughout the lifecycle of the project(s). This sub-capability focuses more on the complex, longer cycle work. Ensure qualified construction crews.

Requirements

- Review and ensure work or ready for construction (design approved, materials will be available, resources, schedules, permits/other procured). Review details of project plan, adjust if necessary, and ensure project approved.
- Coordinate with control area operators to schedule and start work, execute work in the field, supervise resources, capture information required to track progress and gather as-built information
- Complete the work and timely capture of all as-built information. Close out the work and conduct detailed review of costs and results. Feed information back into the Design capability for improvements.

Key Assumptions

- GridFlorida will outsource the Perform Construction capability back to Transmission Owners and will have a large role around managing this outsourced work (in other sub-capabilities as well) both in the end state and in a potential Release 1 scenario
- GridFlorida will need to coordinate and provide oversight of contract work forces doing construction and evaluate results which will then feed back into the changing system enhancement plans. Must be able to get detailed information from the TOs.
- Requires linkage to System Operations for scheduling outages to perform work.
- There is also a key role to coordinate construction work with network requirements, ensuring the security and reliability of the grid
- Need ability to capture as-built information and update asset records.

Solution Strategy

Technology:

- Access to information from Transmission systems (financial/cost systems, detailed construction project plans, etc.), Project Management tool, and potentially a Contract Management tool.
- Longer-term - Work Management System

People:

- Project/Construction Managers, Contract Managers
- Field crews – will be an outsourced/contracted workforce – initially coming from the three Transmission companies. Crews may overlap maintenance and construction work.

Facilities:

- Potentially – laptop PCs or mobile computing devices

GridFlorida

Asset Optimization

Capability: Work Execution	**Sub-Capability:** Manage Resources

Sub-Capability Description

Ensure that resources are matched and available to meet workload requirements. Manage resources across multiple priorities, maximize number of productive hours, and meet service level agreements internally and externally.

Requirements

- Forecast, plan and schedule work over the short and medium term (e.g. 3-18 months). Jointly forecast work, coordinating between Transmission and Distribution where necessary
- Schedule resources using a detailed resource plan; include multiple resources – labour, materials, equipment
- Require contractors to plan, schedule and manage their work in a detailed manner
- Coordinate contractors and any internal workforces to understand their schedules and assignments to maximize ability to meet commitments
- Increased reliance on external service providers and potential for separation of T workforce from D workforce
- Inventory management and Purchasing of Transmission materials sold into GridFlorida will be outsourced back to utilities, and GridFlorida will need visibility into what utilities are holding, as they will be paying for it.

Key Assumptions

- GridFlorida will outsource resource requirements (labor, and equipment) for work execution back to utility companies.
- GridFlorida will require visibility into the materials that the utilities are holding
- GridFlorida will require its own Resource and Contract Management capabilities to coordinate agreements with the Transmission companies. This will be a significant challenge in both the Release 1 and longer-term situations.
- Will require access to benchmarking information to monitor costs and make sure that they are paying a fair amount to service providers.
- Will require visibility into the work that service providers have planned, but don't need detailed ability to do detailed scheduling (approx. 5 yrs)

Solution Strategy

Technology:

- Project Management tool and access to information out of Work Management and/or Scheduling systems that schedule, assign and manage work flows in the Transmission companies
- Longer term - Forecasting tool to forecast work vs: resource requirements over time, Work and/or Maintenance Management systems

People:

- Resource Manager/Contract Manager and Resource Schedulers, with input from Finance and Accounting

Facilities:

- Laptop PCs

GridFlorida

Corporate Services

Capability: Payroll & Human Resources

Sub-Capability: Execute Payroll & Time & Expense Reporting

Sub-Capability Description

This capability calculates the compensation and benefits for GridFlorida employees and provides tax reporting. It also allows GridFlorida personnel to appropriately submit time and expense reports on a regular basis. GridFlorida will be able to track and monitor time, expense and payroll activity as needed.

Requirements

- The calculation of payroll will be done on a periodic basis (bi-weekly, monthly, etc.)
- The payroll systems should be flexible and scalable to handle changes in compensation, benefits plans, and volumes of employees
- Perform general tax reporting functions for Payroll taxes and Income taxes (including state, federal, local, social security, etc.)
- Proper levels of security should be maintained for sensitive data
- This process will coordinate closely with the Manage HR sub-capability in order to ensure that corporate policies and procedures are being implemented properly
- GridFlorida personnel should log their time and expense items in a common format on a timely basis for processing
- Support the Cost Accounting process which feeds into other processes (e.g. Tariff Design, Product & Service Development)
- Prepare reports to periodically track and manage time and expenses
- Develop policies, procedures, and guidelines for time and expense reporting

Key Assumptions

- This capability is required prior to Release 1(GridFlorida startup personnel requirements)
- Elements of the payroll/time & expenses requirement can potentially be outsourced (payroll, Benefits, Time, Expenses)

Solution Strategy

Technology:

•Payroll and benefits application -

•Time and Expense Tracking System

•Reporting capabilities

People:

•A Payroll Clerk

•Manager – Outsource relationship

Facilities:

•Office

Outsource :

•Payroll

•Benefits administration

GridFlorida

Corporate Services

Capability: Payroll & Human Resources

Sub-Capability: Manage Human Resources

Sub-Capability Description

The Manage Human Resources sub-capability will support managers across the organization to attract, hire, compensate, develop, and keep the best professionals that appropriately fit with the GridFlorida organization. Strategies, policies, and programs for developing and training GridFlorida employees will also be the responsibility of the Human Resource area.

Requirements

- Develop & enforce HR Policies and procedures
- Manage corporate procedures and information
- Monitor process effectiveness
- Implement change
- Design and manage organization structure
- Recruit employees
- Design and manage employee and organizational development, such as managing performance, career, and compensation and producing performance evaluations
- Manage employee benefits
- Provide reports to EEOC on issues such as discrimination and affirmative action
- Develop and maintain employee information system
- Administer executive compensation
- Define and administer employee insurance/compensation
- Manage health and safety requirements

Key Assumptions

- This is a new capability for GridFlorida, with potentially significant reuse from member utilities through leveraging existing HR processes and skills
- Elements of the Human Resources requirements can potentially be outsourced (HR representative, policies and procedures, Systems)
- This capability is required prior to Release 1

Solution Strategy

Technology:

•HR System

•Reporting capabilities

People:

•HR Manager

•Recruiter

Facilities:

•Office

Outsource:

•None

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GridFlorida

Corporate Services

Capability: Payroll & Human Resources

Sub-Capability: Mange Training

Sub-Capability Description

This process meets the training needs of GridFlorida personnel and business users

Requirements

- Define and plan customer and employee training needs
- Identify and manage legally required training (for example labor law)
- Deliver and manage training plan
- Perform periodic training needs analysis for employees and customers to reflect changes to procedures and related systems
- Support multiple methods of training -- computer based (CBTs), workshops, external training seminars, etc.
- Coordinate with the Customer Training group as necessary in the development and delivery of training

Key Assumptions

- Customer and employee training requirements for GridFlorida will be a centralized function
- This is a new capability for GridFlorida, with some reuse from member utilities through leveraging existing training documentation and materials
- This is a required capability prior to Release 1 and there will be significant training around the time of start-up (new systems, processes, and relationships between entities)
- GridFlorida personnel will be cross-trained in technical and functional areas wherever possible
- Some training may be conducted by third-party vendors as needed

Solution Strategy

Technology:

•Computer-Based Training

•Distance Learning

People:

•Training Analysts

Facilities:

•Office

Outsource:

•Generic training requirements

(note RTO specific training will be developed and managed internally by GridFlorida HR)

GridFlorida

Corporate Services

Capability: Finance & General Accounting

Sub-Capability: Perform Financial Management & Accounting

Sub-Capability Description

Financial Management & Accounting is the core financial and accounting process for general ledger, budgeting, fixed assets, accounts payable, accounts receivable and other associated capabilities.

Requirements

- Manage financial accounting including General Ledger, Accounts Receivable, Accounts Payable, Fixed Assets Invoicing, Miscellaneous billing
- Define chart of accounts per FERC uniform system of accounts
- Develop and manage budgets and Monitor costs
- Manage cash flow/treasury and financing
- Manage financial market relationships (Bank, debt & equity markets)
- Perform regulatory accounting functions
- Manage property accounting
- Develop and manage job costing function
- Generate and distribute internal and external financial and management reports
- Manage taxation including depreciation and deferred tax implications of acquiring transmission assets at book value
- Credit control and revenue collection
- Financial Risk Management (including insurance, self insurance)

Key Assumptions

- Cut off between settlements and financials is clearly defined
- Miscellaneous billing items exist outside of the settlement system system (Surveys, settlement agreements… etc)
- The monitoring function to determine whether costs and revenues are in balance will be performed by the Financial Management and Accounting process
- This sub-capability has key interfaces with Settlements & Billing and the Customer interface system
- Elements of the financial and manage accounting requirement can potentially be outsourced (System, Treasury, Taxation, Reporting)
- Elements of the insurance requirement can potentially be outsourced (Insurance assessment/acquisition, Claim management)

Solution Strategy

Technology:

•Financial Accounting system

•Tax accounting system

•Job Costing System

•Reporting capabilities management and regulatory reporting

People:

•Finance and Accounting Analysts

Facilities:

•Office

Outsource:

•None

GridFlorida

Corporate Services

Capability: Finance & General Accounting

Sub-Capability: Manage Capital

Sub-Capability Description

This process involves the management of GridFlorida's investments and capital decisions. The process includes evaluating opportunities, reporting recommendations to management, coordinating the acquisition of investments, and the ongoing management and maintenance of the investments.

Requirements

- Define capital management processes and procedures
- Identify costs and related revenues of providing new services or products and capital investment.divestment opportunities
- Develop capital budgets
- Interface with marketing participations on capital budgeting and prioritizing capital projects
- Validate key assumptions relating projected costs, revenues and market conditions
- Provide efficient capital management with a goal of full revenue recovery, plus making a reasonable rate of return on assets
- Develop and manage performance tracking and reporting
- Provide management reports
- Manage capital structure and policies (i.e, desired debt/equity ratios, bond ratings, etc.)
- Define approval and funding process for capital projects including new [products and services
- Determine the costing targets and return on investments that is needed for the business
- Compare actual costs to forecasted costs. Analyze the difference and allocate appropriately
- Coordinate with other GridFlorida capabilities (such as Develop Products & Services and Manage Facilities & Purchasing) as necessary

Key Assumptions

- This is a new capability for GridFlorida and is required for Release 1; elements are required pre- Release 1 for investment decisions for start-up of GridFlorida
- In the interim expenditures for acquisition of software, etc. must be reviewed by Advisory Committee, potentially prior to the Board being in place

Solution Strategy

Technology:

•Investment analysis tools

•Reporting tool

People:

•Finance and Accounting Analysts

Facilities:

•Office

Outsource:

•None

GridFlorida

Corporate Services

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Strategic Planning & Performance Measurement

Sub-Capability Description

This process is responsible for the long term vision and strategy for GridFlorida.This process includes defining the GridFlorida mission, core values and culture. The high level tactical plans to implement the GridFlorida strategy are included as part of this capability

Requirements

- Develop long term strategy for GridFlorida growth and development
- Communicate strategy to personnel at all levels of the organization
- Support Mergers & Acquisitions and asset acquisition
- Support development of new markets
- Involve internal and external groups for thoughts and approval on long term vision
- Develop and manage continuous improvement function
- Perform high level business planning
- Perform environmental and scans and benchmarking exercises (market information/analysis, strategic decision information)
- Identify and manage risk within GridFlorida business

Key Assumptions

- Growth is the key strategic goal of GridFlorida
- Strategic direction is a key requirement for effective business operation within GridFlorida
- Strategy is a priority item for the GridFlorida Board of Directors and CEO in the short term

Solution Strategy

Technology:

•Planning tool

•Risk management tool

•Performance assessment tool (Balanced Score Card, Business Metric)

•Reporting tool

People:

•Strategic Planning Manager

•Strategy Analyst

Facilities:

•Office

Outsource:

•None

GridFlorida

Corporate Services

Capability: Finance & General Accounting

Sub-Capability: Manage Security

Sub-Capability Description

This processes involves the the management of security at GridFlorida facilities to ensure proper access, control and safe use of GridFlorida plant and assets

Requirements

- Define, implement and manage security access controls to all GridFlorida facilities including offices, sites, control room…etc)
- Define, implement and manage, asset management to to control ownership, use and location of GridFlorida Assets
- Manage physical security of facilities, including security risk assessment on new facilities
- Define and administer security policies and procedures

Key Assumptions

- This is a new capability for GridFlorida
- Growth through new products and services is consistent with GridFlorida Strategic plan

Solution Strategy

Technology:

•Security systems

•Asset management system

•Key facility access tracking system

•Reporting tool

People:

•Faciltiies Team Member

Facilities:

•Office

Outsource:

•Physical security tasks can be outsourced to security service providers

GridFlorida

Corporate Services

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Develop Corporate Communications

Sub-Capability Description

This process is responsible for communication GridFlorida activities both internally and externally

Requirements

- Manage external communications with City, State and Federal authorities, Environmental Groups, Financial institutions and the media
- Manage internal communications including change issues, employee information and corporate performance
- Report to the GridFlorida Board on status of FERC proceedings and filings
- Coordinate stakeholder meetings and gather their comments on issues
- Manage interface with Board of Directors
- Serve as primary contact for external inquiries related to GridFlorida activities
- Develop press releases and promotional literature

Key Assumptions

- This is a new capability for GridFlorida
- This is a required capability prior to Release 1
- Elements of the communications requirements can potentially be outsourced (Public relations)

Solution Strategy

Technology:

•Reporting tool

•Portal

People:

•Communications Manager (Will manage outsource relationships)

Facilities:

•Office

Outsource:

•Transactional Public Relations Activities

- •Promotional literature
- •Marketing Information
- •Employee Newsletter
- •Media Campaigns… etc.

GridFlorida

Corporate Services

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Perform Audits

Sub-Capability Description

This process involves the internal auditing of all GridFlorida systems, applications, processes, and procedures. The requirement for external financial audits is also included within this process

Requirements

- Develop a prioritized audit schedule for all areas within GridFlorida
- Perform detailed audits and analyses of GridFlorida policies and procedures
- Validate that all GridFlorida applications and systems meet internal and external requirements
- Report audit findings to the Grid Florida Board of Directors
- Follow industry standard auditing practices

Key Assumptions

- Internal Audit is independent and reports directly to the GridFlorida Board of Directors
- All processes, systems and divisions are subject to audit
- Internal audit is deemed a key governance tool by the Board of GridFlorida
- Substantial audits are required at start-up to ensure processes and systems are operating correctly
- This is a new capability for GridFlorida and is required for Release 1, but with a phased approach
- Elements of the internal audit requirement can potentially be outsourced (Audit execution, Audit schedule)

Solution Strategy

Technology:

•Confidential reporting tool

People:

•Finance and Accounting Manager

Facilities:

•Office

Outsource:

•Audit execution

GridFlorida

Corporate Services

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Manage Facilities & Purchasing

Sub-Capability Description
This process is responsible for the management and maintenance of GridFlorida facilities and purchasing decisions.

Requirements
- Develop and manage plans for GridFlorida facilities needs including
- Coordinate building leases, maintenance contracts, etc. with external personnel
- Define procurement process and controls (routine business assets and transmission assets)
- Manage procurement of goods and services including request for tenders and vendor selection for transmission and business support assets
- Manage vendor contracts for operations and corporate materials and services
- Coordinate activities with the Manage Capital capability to ensure consistent approach
- Manage inventory control for business support assets

Key Assumptions
- All purchasing requirements for GridFlorida are centralized and managed through Financial services
- Inventory control is required for maintenance and new works capability
- Operations such as network maintenance and new works are outsourced and no inventory management capability is required
- This is a new capability for GridFlorida
- This is a required capability prior to Release 1

Solution Strategy

Technology:
•Procurement System
•Inventory Control System
•Reporting Tool

People:
•Facilities Manager

Facilities:
•Office

Outsource:
•Facilities management

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Manage Legal Affairs

Sub-Capability Description

This process includes the coordination of all GridFlorida legal requirements and the management of external legal relationships.

Requirements

- Set up and file the GridFlorida Inc.
- Support GridFlorida internal functions on legal matters including, labor issues, facilities leasing, Market participant disputes, vendor contracts, vendor disputes
- Define and manage GridFlorida code of conduct and work ethic
- Represent GridFlorida legal perspective prior to enactment of deregulation legislation
- Manage insurance issues and claims, corporate legal decisions, and financial legal decisions
- Coordinate with GridFlorida's Regulatory team to manage legal interfaces with regulatory bodies
- Manage Routine Legal Affairs
- Support Contract Negotiations with Ancillary Services Providers
- Manage Contracted Legal Services

Key Assumptions

- This is a new capability for GridFlorida and is a requirement for GridFlorida prior to Release 1
- Elements of the legal affaires requirements can be outsourced, however there is a critical need to have legal support internally

Solution Strategy

Technology:

•Legal research tool

•Reporting Tool

People:

•Lawyer

Facilities:

•Office

Outsource:

•Additional legal services will be outsourced as required)

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Develop Tariff Design

Sub-Capability Description

Manages the entire process from the development of regulatory policy to the actual creation, filing, and obtaining approval for the tariffs. Also includes the translation of tariff information into contractual terms and conditions and operating procedures for GridFlorida.

Requirements

- Identify and manage the development of new or revised rates and tariffs for the purposes of recovering the costs associated with system operations
- Monitor market trends to check on the market value of the various services offered by GridFlorida
- Define the products and services that will be offered by GridFlorida and develop a rate strategy for them
- Design rates
- Define specification for enhancing related systems and procedures to settle new tariff
- Prepare, file, and manage the FERC proceedings for amendments to the OATT and protocols
- Coordinate with other GridFlorida departments to negotiate contracts with customers and file those new or revised contracts with FERC
- Communicate new tariff rates to Market Participants

Key Assumptions

- The FERC approved OATT will be subject to change on a periodic basis
- Account managers are involved in the contract negotiations
- This is a required capability for Release 1

Solution Strategy

Technology:

•Revenue requirement modeling tool

•Cost of service modeling tool

•Reporting tool

People:

•Tariff Manager

•Rate design

Facilities:

•Office

Outsource:

•None

GridFlorida

Corporate Services

Capability: Corporate Admin, Regulatory, Rates & Tariffs

Sub-Capability: Interface with Regulatory Bodies

Sub-Capability Description

This process is responsible for keeping regulatory bodies updated on the activities of GridFlorida, for participating in the development of new or modified rates and monitoring regulatory developments

Requirements

- Define and understand regulatory reporting requirements
- Manage FERC proceedings and filings
- Coordinate changes with external governing and regulatory bodies
- Assess the impact of proposed changes in regulatory reporting requirements and provide constructive feedback
- Manage Regulatory & Governmental Relationships
- Manage interface with Board of Directors, advisory committee, FERC Monitor Co
- Coordinate with GridFlorida's Legal team to manage legal obligations and relationships
- GridFlorida will monitor the activities of regulatory bodies
- Manage regulatory filings and coordination of FERC Audits

Key Assumptions

- Interface with regulatory bodies is viewed as a key public relations issue for GridFlorida
- This is a new capability for GridFlorida
- This is a required capability prior to Release 1

Solution Strategy

Technology:

•Reporting Tool

People:

•Lawyer

Facilities:

•Office

Outsource:

•Additional legal services will be outsourced as required)

GridFlorida

Corporate Services

Capability: Corporate Administration

Sub-Capability: Manage Business Information Technology

Sub-Capability Description

Provides information technology strategy to support the non-control systems aspects of the organization (e.g., Payroll, HR, Finance). Its main development and maintenance responsibilities are related to corporate business systems. This includes supporting non-control center infrastructure (e.g., email, office desktops, document management, bill imaging, etc.). This group is also responsible for ensuring that Business IT standards are met and corporate systems are integrated with Operations Systems where appropriate.

Requirements

- Develop/integrate new business software
- Maintain business systems and databases
- Manage corporate technical infrastructure (e.g., office desktops, LANs, backups, file servers, etc.)
- Develop Business IT policies and procedures
- Manage Suppliers & Vendors
- Assist internal business users with inquiries and problems (Help Desk)
- Coordinate with Operations Systems Technical Specialists
- Ensure protection against viruses (Business Systems)
- Coordinate site security with Corporate Security
- Corporate Portal Management

Key Assumptions

- This is a new capability for GridFlorida. Outsourcers will bring in own standards, etc.
- This is a required capability prior to Release 1. Scale will increase over time.
- Some aspects of Corporate Technical Support can be outsourced (e.g., Appl. Dev. & Maint. for Business Systems, Help Desk, technical infrastructure support, etc.)

Solution Strategy

Technology:

- Interface Development
- Enterprise Application Integration Tool
- Desktop Supplier (e.g., ENTEX) with Productivity Tools and Workstation
- Tier 1 Help Desk and Tools for Desktop and Business Applications

People:

- IT Specialists (Corporate desktop expertise)

Facilities:

- Corporate Headquarters
- Control Center if needed

GridFlorida

Technical Support

Capability: Operations Technical Support

Sub-Capability: Manage Control System Technology

Sub-Capability Description

This process will be focused on providing operations staff with high quality and reliable technology to support the System, Market, and Commercial operations of the Transmission System, as well as Asset Optimization and the Customer Interface. This function involves interfacing with Corporate Technical Support to ensure that operations system technology standards are met and systems are integrated where appropriate.

Requirements

- Develop policies and procedures
- Maintain systems and databases
- 7x24 callout capabilities
- Develop/integrate new software
- Manage operations system technical infrastructure (e.g., HVAC, UPS, Generators)
- Coordinate with Corporate Telecommunications Specialists
- Assist Operations users with inquiries and problems
- Provide integration with GridFlorida business systems, where appropriate
- Ensure protection from outside intrusion (Data Security)
- GridFlorida Back-up Site Configuration & Support
- Coordinate Site Security with Corporate Security (i.e., physical)
- Website Management
- Technical Disaster Recovery Site & Plan (e.g., data backups, etc.)

Key Assumptions

- This is a new capability for GridFlorida. Due to continued Control Area Operations, little reuse from member utilities can be leveraged (i.e., existing IT procedures & skills)
- This is a required capability for pre-End State. It is recommended that a core group is brought in early to be part of the development team for the end-state systems.
- A data warehouse is required for End State. Some portion of the data warehouse may be required for Release 1.
- This capability will be insourced.

Solution Strategy

Technology:

- Software Configuration Management Software
- Compilers
- Source Code Control
- Project Management Software
- Operating Systems, Servers
- Database Management
- Name Services
- Firewalls

People:

- Technology Professionals specializing in Power Systems Marketing & Operations Applications & Development
- Experience in Real-Time Computer Programming
- Power System Engineer
- 7x24 support

Facilities:

- Control Center and/or Corporate Headquarters (i.e., closest to the user)

GridFlorida

Technical Support

Capability: Operations Technical Support

Sub-Capability: Manage Telecommunications

Sub-Capability Description

This process will provide telecommunications strategy to support the all aspects of the organization. Its main development and maintenance responsibilities are related to both the corporate and control systems telecommunications network and systems. This process will ensure that control system standards are met and that systems are integrated where appropriate.

Requirements

- Maintain all systems and databases (e.g., control center & office PBX, IP)
- Manage telecommunications infrastructure which is dispersed all over the state (@200 or so RTU's around the state)
- Manage business telecommunications infrastructure
- Develop Telecommunications policies and procedures
- Assist control system users with inquiries and problems
- 7x24 callout capability
- Coordinate with all providers of Telecommunications services
- Manage telecomm bill processing for all data circuits
- Oversight group to manage vendor relationships

Key Assumptions

- Contracts that each utility currently has with telephone companies for communications to the transmission substation RTUs may need to be renegotiated before Release 1 to show change of ownership of the circuits to GridFlorida.
- May also need agreements with LSEs for circuits which go over LSE-owned fibre and microwave facilities.
- This is a new capability for GridFlorida, with some reuse from member utilities by leveraging existing procedures and skills
- Some form of corporate telecommunications management will be required before Release 1 and it would be contracted out (i.e., the facilities [office PBX, etc.) & office infrastructure [desktops, email] functions would be outsourced).
- Will coordinate problems with LSEs and others around telecommunications
- The control system telecommunications capability will be insourced
- RTU and Telecommunications maintenance will be leased back to the LSEs.
- Maintenance of IP Network backbone will be insourced (e.g., WANs)

Solution Strategy

Technology:
- Network Monitoring Tools
- Problem Tracking Tool
- Basic Toolkit

People:
- Telecommunications Specialist
- 7x24 support
- Contract Oversight
- Engineering or strong technical background
- Network Specialist
- Microwave Radio experience

Facilities:
- Office & Control Center

GridFlorida

Establishing the GridFlorida RTO
BluePrint Project
June 2001

Docket No. 000824-EI
Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. ______ (BLH-1)
Business Blueprint Documents

End State Organization Model and Sizing- v6

GridFlorida

Contents

- Benchmark and Research
- Organization Model for End State with Sum Totals
- Organization Model for End State with Sum Totals and Breakdowns

GridFlorida

Benchmark and Research

- Benchmarked estimates and model against other RTOs and ISOs
- Received and reviewed as is data from TECO, FP&L, and FPC
- Interviewed transmission owner SMEs from TECO, FP&L and FPC regarding estimates, roles, and outsourcing
- Interviewed Accenture SMEs regarding estimates, roles, and outsourcing
- Received input regarding organizational structure and key executives from the Hay Group

GridFlorida

Organization Model for End State Sum Totals and Breakdowns

Headcount Range: 190-233 ***
Contractor Range: 9-13
Headcount Range w/ Contractors: 199-246

- Office of the President — President and CEO
  - GridFlorida Board of Directors — **Total = 8 Board Members**
  - Market Monitor — **Total = 9 ****; Board Members = 3; Employees = 6**
  - Audit — **Auditor = 1**

Total Officers plus Clerical Support for Officers- 12

Chief Operating Officer
- Market Operations
- System Operations
- Asset Optimization

Total = 81-94 (plus * and **)

Market Operations = 16-20

System Operations = 43-49

Asset Optimization = 22-25

Legal VP and General Counsel
- Legal Affairs

Total = 3-4 (plus C = 3-4)

Legal Affairs = 3-4 (plus C = 3-4)

Corporate Development/Finance Division CFO
- Payroll and HR
- Financial Mngt and Accounting
- Internal Training
- Corporate Communications
- Facilities and Planning
- Strategic Planning
- Rates and Regulatory Design

Total = 22-26 (plus *)

Payroll and Human Resources = 3

Financial Mngt & Accounting = 6-7

Internal Training = 1

Corporate Communications = 2

Admin- 3

Facilities and Purchasing = 1-2 *

Strategic Planning = 2

Rates and Regulatory Design = 4-6

Market Services Division VP
- Billing
- Transmission Services

Total = 21-29

Billing = 15-20

Transmission Services = 6-9

Information Services Division CIO
- Operations Tech Support
  - Corporate Tech Support

Total = 50-67 (plus C = 6-9 and *)

Operations Tech Support = 40-52 (plus C=4-6)

Corporate Technical Support = 10-13 (plus C = 2-3)

Note:
C = Contractors
* Outsource Service
** Under Asset Opt, Work Defn and Work Exec outsource #s are not included since these groups outsource large #s of people for engineering, construction, and maintenance.
*** This total does not include the GridFlorida Board of Directors or the Market Monitor Board of Directors or employees.
**** Market Monitor Organization model and sizing was not analyzed as a part of the Blueprint.

GridFlorida

Organization Model for End State Sum Totals and Breakdowns

Headcount Range: 190-233 ***
Contractor Range: 9-13
Headcount Range w/ Contractors: 199-246

- Office of the President – President and CEO
  - GridFlorida Board of Directors — **Total = 8 Board Members**
  - Market Monitor — **Total = 9 **** Board Members = 3 Employees = 6**
  - Audit — **Auditor = 1**
  - **Total Officers plus Clerical Support for Officers- 12**

Chief Operating Officer
- Market Operations
- System Operations
- Asset Optimization

Total = 81-94 plus * and **)

Market Operations = 16-20
Director- 1
Admin- 1
Scheduling- 5-6
Tagging- *
Forecasting- 1-2
Market Facilitation- 8-10

System Operations = 43-49
Director- 1
Admin- 1
Real-time Operations- 25-30
Grid Security and Reliability Mngt- 6
Operations Engineering- 8
Operations Support (training & procedures)- 2-3

Asset Optimization = 22-25
Director- 1
Admin- 1
Network Planning- 14-15
Work Definition- 3-4 (**)
Work Execution- 3-4 (**)

Legal VP and General Counsel
- Legal Affairs

Total = 3-4 (plus C = 3-4)

Legal Affairs = 3-4 (plus C = 3-4)
General Counsel- 2-3 (plus C- 3-4)
Admin- 1

Corporate Development/Finance Division CFO
- Payroll and HR
- Financial Mngt and Accounting
- Internal Training
- Corporate Communications
- Facilities and Planning
- Strategic Planning
- Rates and Regulatory Design

Total = 22-26 (plus *)

Payroll and Human Resources = 3
Manager- 1
Payroll- 1 *
Human Resources- 1

Financial Mngt & Accounting = 6-7
Finance-6-7 *

Internal Training = 1
Training Coordinator- 1

Corporate Communications = 2
Communications Coordinator- 1
Communications- 1

Admin- 3

Facilities and Purchasing = 1-2 *
Facilities and Supply Chain- 1-2

Strategic Planning = 2
Manager- 1
Planning- 1

Rates and Regulatory Design = 4-6
Manager- 1
Tariff and Rate Design- 2-3
Regulatory Affairs- 1-2

Market Services Division VP
- Billing
- Transmission Services

Total = 21-29

Billing = 15-20
Director- 1
Admin- 1
Metering & Measurement Data- 5-7
Settlements & Billing- 6-8
Contract Mngt- 2-3

Transmission Services = 6-9
Director- 1
Admin- 1
Account Mngt- 2-3
Communication Mngt- 1-2
Customer Training- 1-2

Information Services Division CIO
- Operations Tech Support
  - Corporate Tech Support

Total = 50-67 (plus C = 6-9 and *)

Operations Tech Support = 40-52 (plus C=4-6)
Director- 1
Admin- 1
Application Dev & Main-18-24 *
Networks & Ops Sys- 10-14
Database Support- 4-6
Telecomm- 6-8 (C= 4-6)

Corporate Technical Support = 10-13 (plus C = 2-3)
Manager- 1
Admin- 1
Application Mngt- 4-5 *
Workstation Support- 2-3 (plus C=2-3)
Help Desk- 2-3

Note:
C = Contractors
* Outsource Service
** Under Asset Opt, Work Defn and Work Exec outsource #s are not included since these groups outsource large #s of people for engineering, construction, and maintenance.
*** This total does not include the GridFlorida Board of Directors or the Market Monitor Board of Directors or employees.
**** Market Monitor Organization model and sizing was not analyzed as a part of the Blueprint.

GridFlorida

Establishing the GridFlorida RTO
BluePrint Project
May 2001

Docket No. 000824-EI
Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. ______ (BLH-1)
Business Blueprint Documents

End State Application Architecture- v8

GridFlorida

Outline

- Assumptions
- Architecture
- Blueprint
- Details

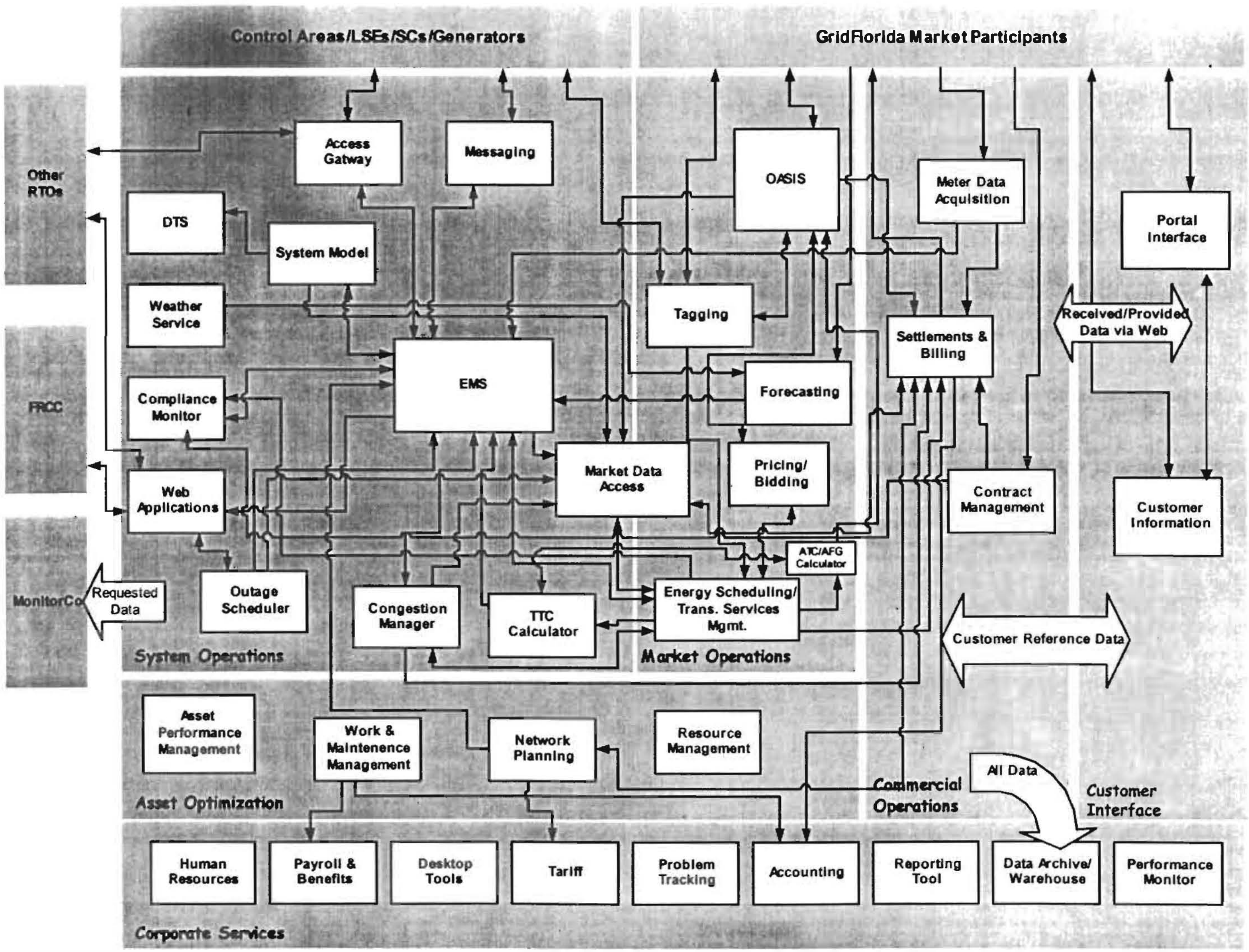
GridFlorida

Assumptions

- Reuse/relicensing of applications from TO's existing systems will be considered where possible, while ensuring independence.
- Consider alternative sourcing (outsourcing or short-term leasing) where capabilities are not core to RTO or development time is short.
- Some functionality required pre- End State release that may be served through current TO systems. This will be considered further at a later point.

GridFlorida

Application Architecture



GridFlorida

Applications in each Capability

System Operations

EMS
- SCADA
- State Estimator
- Study Power Flow
- Contingency Analysis
- OPF
- Reserve Monitor
- AGC
- Volt/Var Dispatch
- Dynamic Mapboard
- DSA
- Full Graphics Display

Web Applications
- IDC
- SDX
- SCIS

Messaging
- FTMS Msg Exchange
- Logging

TTC Calculator
- TTC Calc.

Weather Service
- WX Forecasts

Compliance Monitor
- R-T Compliance Monitor

Access Gateway
- Control Center Data Exchange

DTS
- Dispatch Training Simulator
- Non-EMS Apps

Congestion Manager
- Congestion Mgmt
- P/SCD

System Model
- Model Builder

Outage Scheduler
- Facilities Outage Management & DB

Market Operations

OASIS
- OASIS
- Automation Interface

Forecasting
- Short/Mid-Term Load Forecaster
- Ancillary Services Forecaster

Energy Scheduling & Transmission Service Mgmt.
- Electronic Scheduler
- ATC Adjustment & Posting
- Accounting Data
- Interchange Checkout
- OASIS/Tag Access
- FGR Track/Allocations

Tagging
- Tagging Service

Pricing/ Bidding
- Trading/Bulletin Board
- Pricing/Clearing

ATC/AFG Calculator
- ATC Calc.

Market Data Access
- Messaging
- Database

Commercial Operations

Settlements & Billing
- Settlements / Transmission Services Billing
- Collections / Disbursements
- Financials Interface
- EFT

Meter Data Acquisition
- Meter Data Acquisition
- Meter Data Verification & Aggregation
- Meter Data Error Reporting

Contract Manager
- Contract Management

Customer Interface

Customer Information
- Customer Relationship Management
- Dispute Resolution / Workflow Management
- Registration

Portal Interface
- Web-based Information System
- Customer Portal Services
- Bid Collection

Asset Optimization

Asset Perf. Manager
- Fixed Asset DB

Work Management
- Outage Mgmt.
- Project Management
- Maintenance Mgmt.

Resource Management
- Inventory Mgmt.
- Resource Scheduler

Network Planning
- Long Term Forecaster
- Network Planning Appl. (PSSE)
- Short Circuit Analysis
- Facilities Planning
- Long Term Studies
- Voltage Scheduler

Corporate Services

Payroll & Benefits
- Payroll System
- Benefits System

Human Resources
- HR Management System

Accounting
- General Ledger
- Cost Accounting
- Accounts Rec. / Pay.
- Property/Asset Acctg.
- Purchasing
- Treasury Management
- Prudential Monitoring
- Capital Investment Analysis /Budgeting
- Time & Expense Reporting

Desktop Tools
- Workgroup / Business Software

Reporting Tools
- Reports

Problem Tracking
- Problem Capture/Tracking

Data Warehouse
- DB & Mining

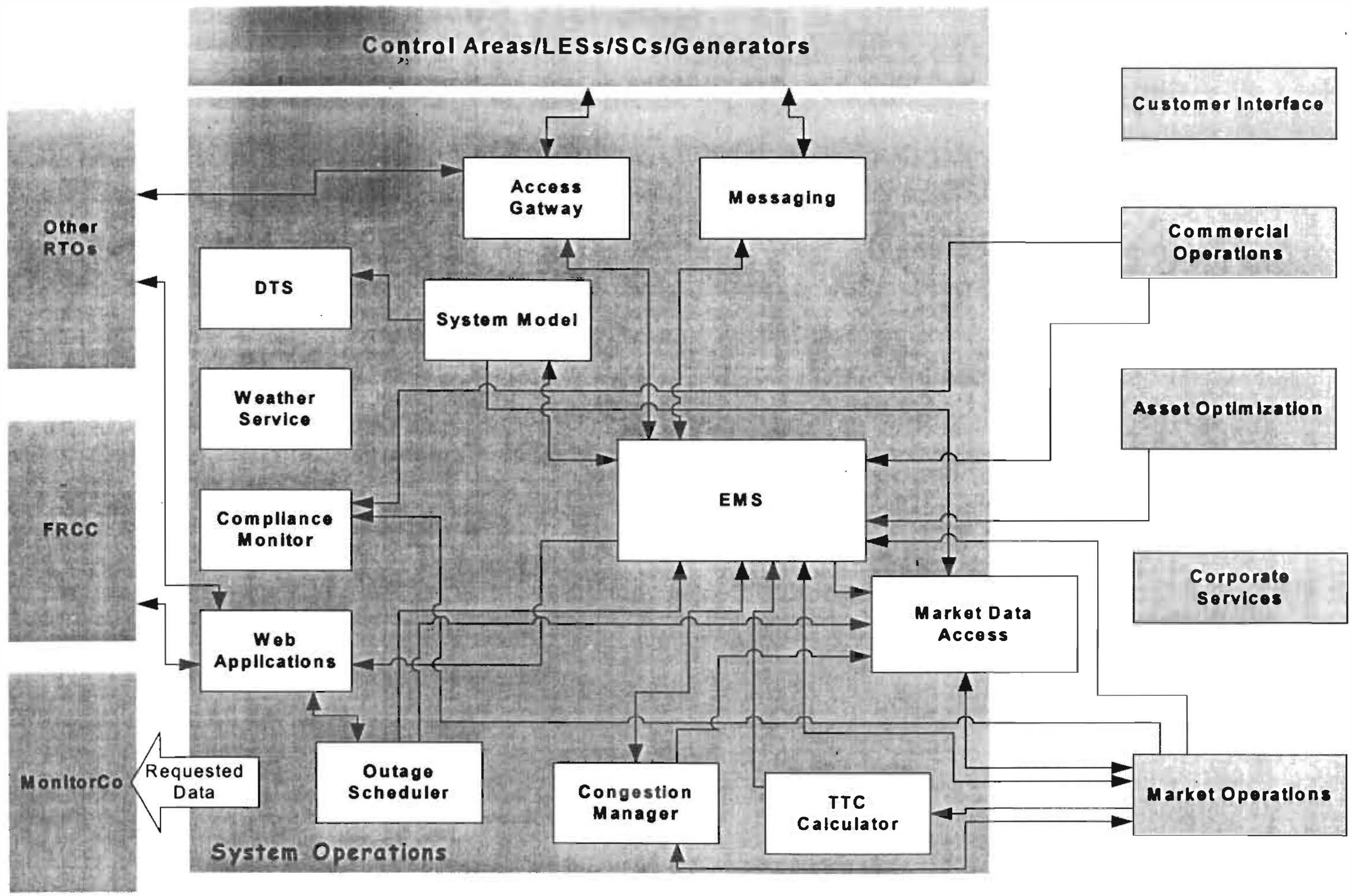
Tariff
- Tariff Modeling

Data Archive
- Data Archive

Performance Monitor
- Application / Network Performance Monitoring

GridFlorida

System Operations



GridFlorida

System Operations

Applications	Existing Capability		End State Release Sourcing (Options)			
	Source	Scope	Buy/Build	Reuse/Upgrade	Lease	Outsource
EMS						
•SCADA	FPL	Full		FPL	FPL	
•State Estimator	FPL	Full		FPL	FPL	
•Study Power Flow	FPL	Full		FPL	FPL	
•Contingency Analysis	FPL	Full		FPL	FPL	
•OPF	FPL	Full		FPL	FPL	
•AGC	FPL	Part.		FPL/Vendor		
•VoltVar Monitor	FPL	Full		FPL	FPL	
•Reserve Monitor	FPL	Full		FPL	FPL	
•Dynamic Mapboard	FPL	Partial		FPL/Vendor	FPL	
•DSA	---	---	Vendor Pkg.			
•Full Graphics Display	FPL	Full		FPL	FPL	
TTC Calculator	FPC	Partial		FPC		
Outage Scheduler						
•Outage DB	FPL	Partial		FPL	FPL	
•Facilities Outage Manager						

GridFlorida

System Operations

Applications	Existing Capability		End State Release Sourcing (Options)			
	Source	Scope	Buy/Build	Reuse/Upgrade	Lease	Outsource
Compliance Monitor						
•Performance Monitor	FPL	Partial		FPL/Vendor	FPL	
Dispatcher Training						
•DTS	FPL	Full		FPL	FPL	
•Non-EMS Applications	FPL	Partial		FPL/Vendor		
Web Applications						
•IDC	FPL	Full		FPL	FPL	Vendor
•SDX	FPL	Full		FPL		Vendor
•SCIS	FPL	Full		FPL		Vendor
Congestion Manager						
•Price/Security Constrained Dispatch	FPL	Partial		FPL/Vendor		
•Congestion Management Application	---	---	Vendor Pkg.			Vendor
Market Data Access						
•Market Database	---	---	Vendor Pkg.			
•Market Messaging	---	---	Vendor Pkg.			

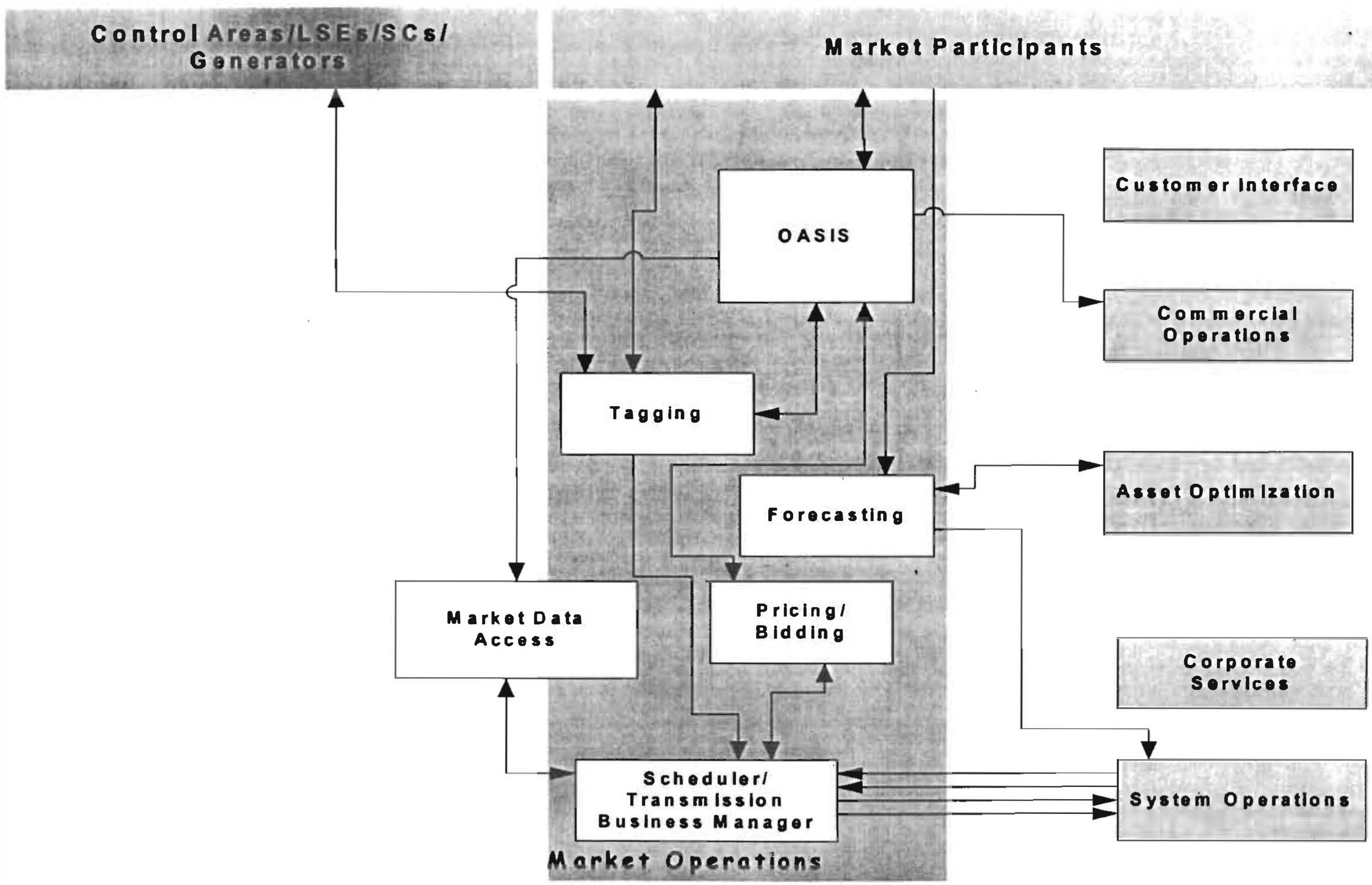
GridFlorida

System Operations

Applications	Existing Capability		End State Release Sourcing (Options)			
	Source	Scope	Buy/Build	Reuse/Upgrade	Lease	Outsource
Weather Service	Service	Full				Vendor
Messaging						
•FTMS Message Exchange	FPL	Partial		FPL/Vendor		Vendor
•Message Logging	FPL	Partial		FPL/Vendor		Vendor
System Model						
•Model Builder	FPL	Full		FPL	FPL	
•Integrated Model Mgmt.	FPL	Full		FPL	FPL	
Access Gateway						
•Control Center Data Exchange (ICCP/ISN)	FPL	Partial		FPL/Vendor		

GridFlorida

Market Operations



GridFlorida

Market Operations

Applications	Existing Capability		End State Release Sourcing (Options)			
	Source	Scope	Buy/Build	Reuse/Upgrade	Lease	Outsource
OASIS						
•OASIS	FOA	Partial		Vendor		Vendor
•Automation Interface	FPL	Partial		FPL/Vendor		Vendor
Energy Scheduling &Trans. Services Mgmt.						
•Electronic Scheduler	FPL	Partial		FPL/Vendor		Vendor
•ATC Adjustment & Posting	FPC	Partial		FPC/Vendor		Vendor
•Accounting Data	FPL	Partial		FPL/Vendor		Vendor
•Interchange Checkout	FPL	Full		FPL	FPL	Vendor
•OASIS/Tag Access	FPL	Full		FPL	FPL	Vendor
•FGR Track & Allocation	---	---	Vendor			
Forecasting						
•Short & Mid-Term Load Forecaster	FPL	Full		FPL	FPL	
•Ancillary Services Forecaster	---	---	Vendor			

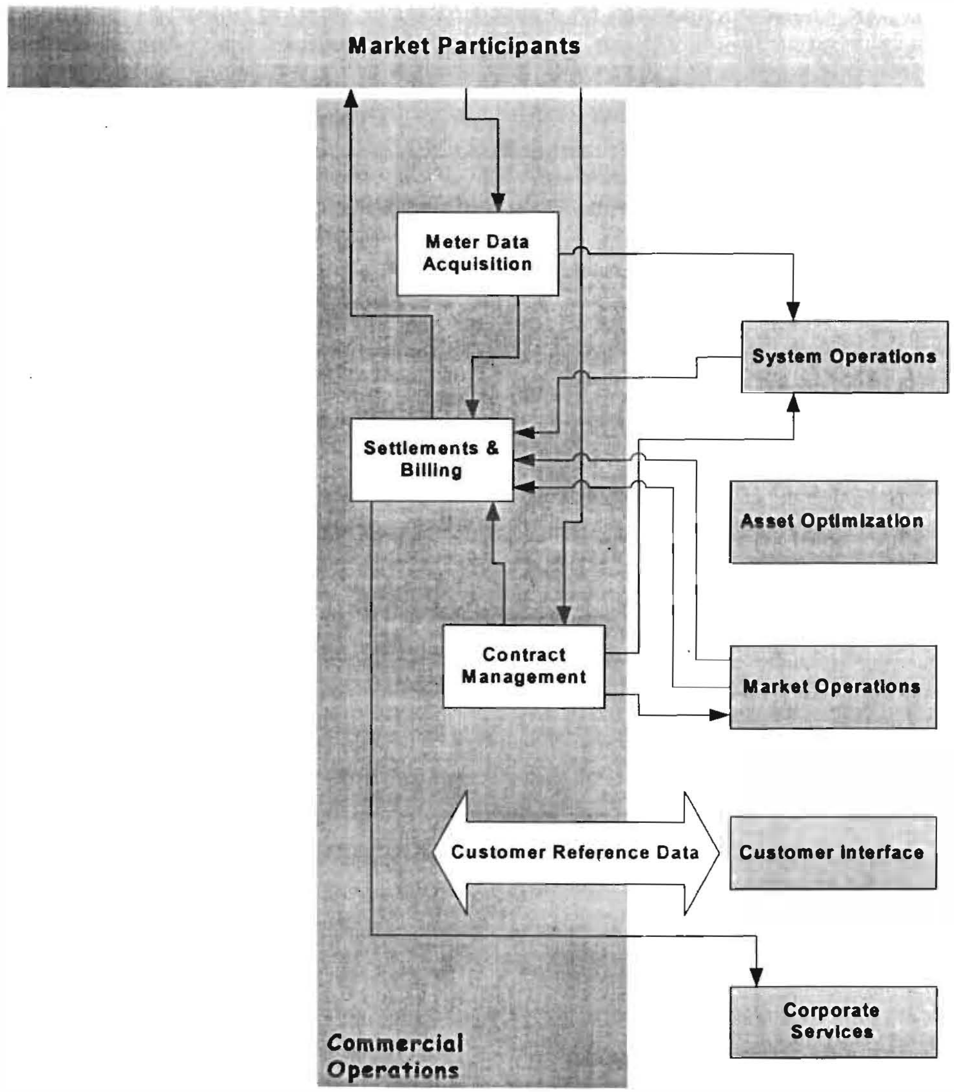
GridFlorida

Market Operations

Applications	Existing Capability		End State Release Sourcing (Options)			
	Source	Scope	Buy/Build	Reuse/Upgrade	Lease	Outsource
Tagging •Tagging Service	Service	Full				Vendor
Pricing/Bidding •Trading/Bulletin Board •Pricing/Clearing	--- ---	--- ---	Vendor Vendor			Vendor Vendor
ATC/AFG Calculator	FPC	Partial		Vendor		

GridFlorida

Commercial Operations



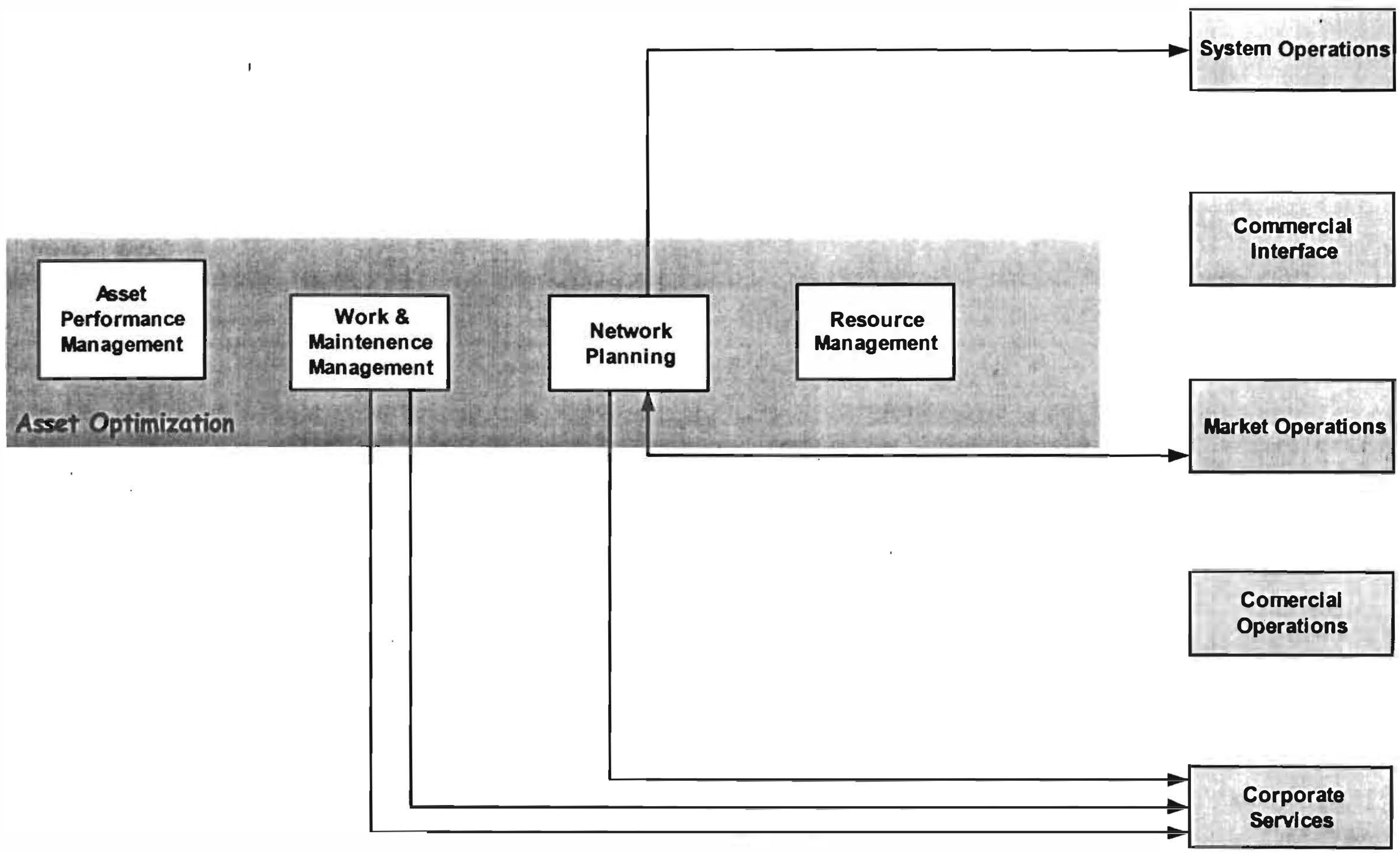
GridFlorida

Commercial Operations

Applications	Business Requirements		Potential Sources		
	Release 1	End State	Buy/Build	Reuse	Outsource
Settlements & Billing •Settlements/Transmission Services Billing •Collections/Disbursements •Financials Interface •EFT	• Need to settle for Transmission services • AS & CM may be as-is today • Need to Bill & interface to Financials	•Full Settlements & Billing of AS, Market based services (EI, AS and CM) •Additional interfaces and data	• Typically a bought package, with significant configuration required	•Potentially in an release 1, however not likely a solution that will meet full requirements	• Potentially, however would require build first to specific GF requirements
Meter Data Acquisition •Meter Data Acquisition •Meter Data Verification & Aggregation •Meter Data Error Reporting	• Application to store interchange and generation meter data • Might be part of Settlements system • Large volume of data & interfaces	• Application must be scaleable to accommodate different types & additional volume of data in the future - as metering is replaced/added	•Typically a bought solution, with large database & key interface with Settlements	•May be specific interfaces today that would not hold up in future with additional data	•Potentially in future, more typical in retail space today, not in wholesale
Contract Manager •Contract Manager	• May be limited contracts on Release 1 if managed by Utilities	•Need place to store contract terms (e.g. new contracts) that are used in Settlements	•Typically may be part of Settlements/ Customer solutions	•May be handled today manually	•Usually specific & not outsourced alone

GridFlorida

Asset Optimization



GridFlorida

Asset Optimization

Applications	Business Requirements		Potential Sources		
	Release 1	End State	Buy/Build	Reuse	Outsource
Asset Performance Management • Fixed Asset Database(Release 1) • Asset Assessment Tool(End State)	• Manage high priority assets • Measure results of maintenance strategies	• Manage current & future utilization and performance of assets • More asset data converted • Link results to revenue opportunities(i.e. which asset segments are profitable)	• Typically a package, with significant configuration & data conversion required	• Can't likely reuse as utilities will need to keep own systems for all assets	• No, GF will need to manage the assets they own
Work Definition & Execution • Work and/or Maintenance Management(simple tracking Release 1 • Outage Management • Project Management Tool	• Coordinate outages and recovery procedures • Track work performed by Utilities • Evaluate maintenance & construction, & outage management strategies & plans	• Increased tracking capability to track work done(may not be a full work/or maintenance management system)	• Typically packages, with configuration required	• Can't likely reuse as utilities will need to keep own systems for all assets	• Yes at first, but, GF will need to define information requirements of Utilities.
Network Planning • Network Planning Appl. Suite • Long Term Studies Tool/Tracking mechanism	• Will need to be able to perform long term studies & bulk transmission planning • Will have to review & approve planned maintenance and expansion	• Will be the same as Release 1 • On a longer term time frame (e.g.. Past three years will do local area planning)	• Typically packages with configuration required	• Can't likely reuse as utilities will need own systems	• Can not be outsourced, because it is one of the key necessities of being an RTO
Resource Management • Inventory Management • Resource Scheduler(only if & when GF brings work in house	• Visibility into resources held by TOs – Release 1 will be done through reports/info from utilities	• Same as Release 1 • Inventory Mgmt and resource scheduling would be much later	• Typically a package	• No, most likely bought new	• Will be outsourced back to utilities initially

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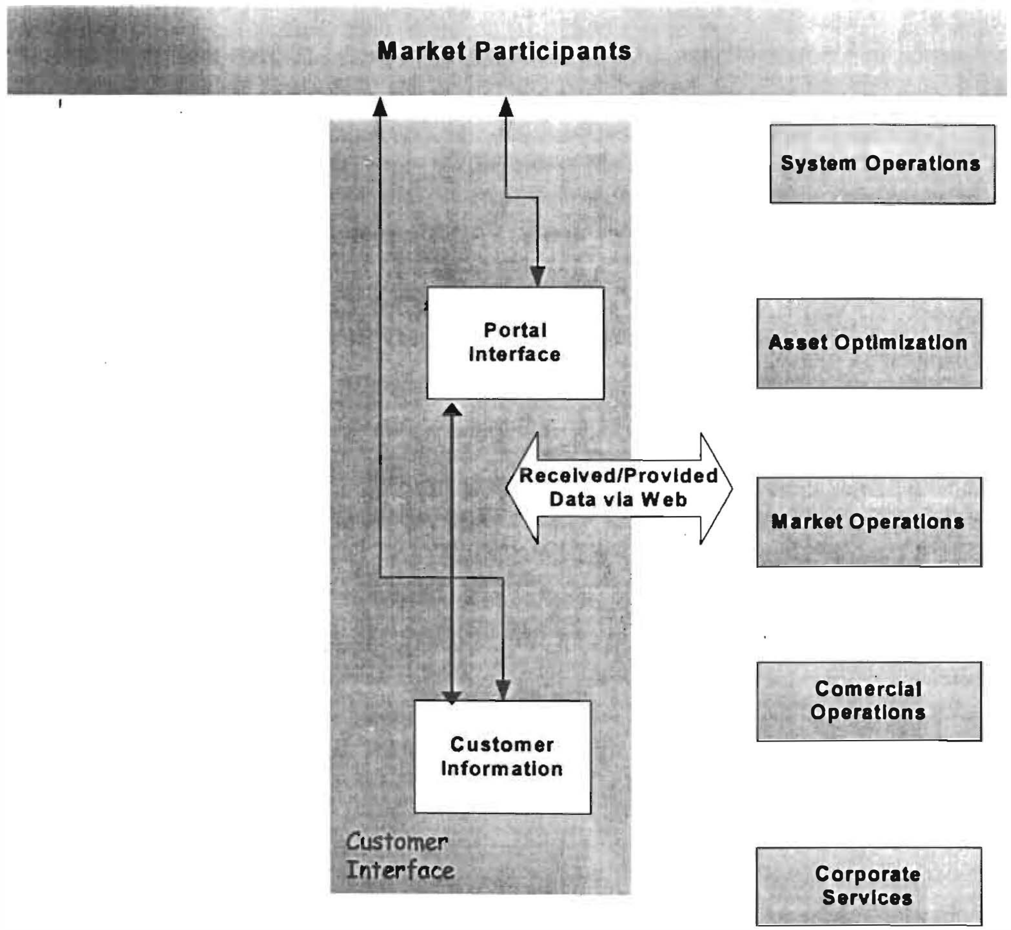
Customer Interface



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Customer Interface

Applications	Business Requirements		Potential Sources		
	Release 1	End State	Buy/Build	Reuse	Outsource
Customer Information •Customer Relationship Management •Dispute Resolution/Workflow Management •Registration	All functionality required Release 1 - robustness depends on functionality decided on in other capabilities	Enhancements and maintenance	Buy application and configure		
Portal Interface •Web-based Information System •Customer Portal Services	All functionality required Release 1 - robustness depends on functionality decided on in other capabilities	Enhancements and maintenance	Buy application and configure		

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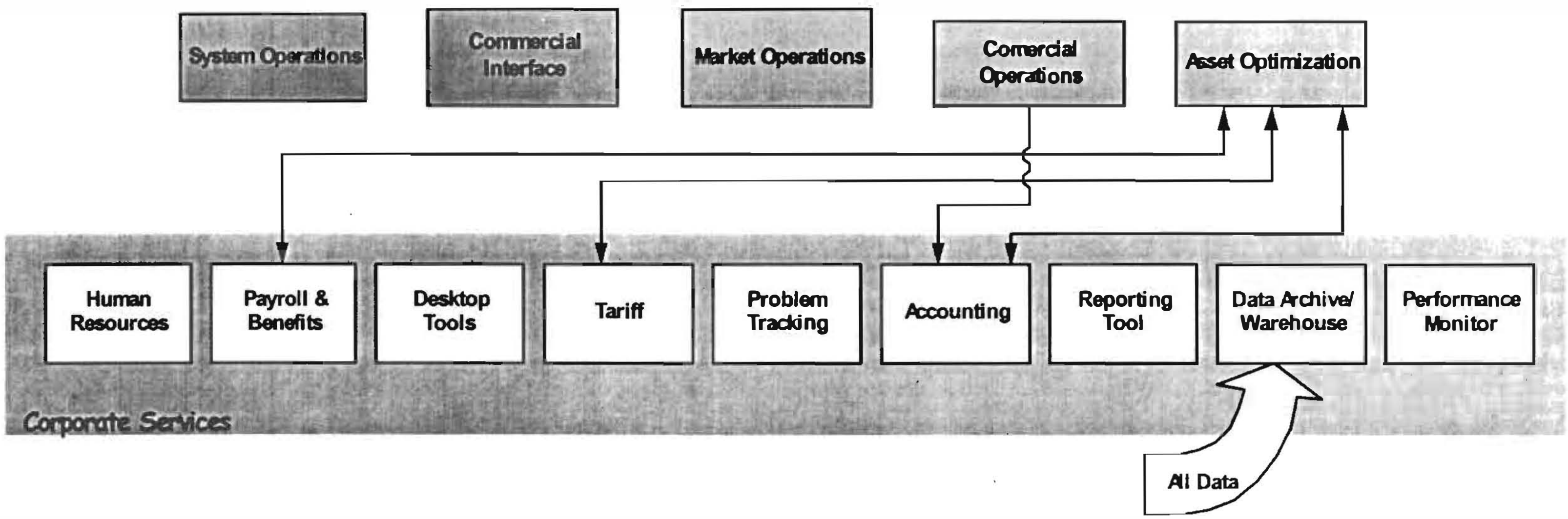
Corporate Services



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Corporate Services

Applications	Business Requirements		Potential Sources		
	Release 1	End State	Buy/Build	Reuse	Outsource
Payroll & Benefits •Payroll System •Benefits System	Need to run payroll and manage benefits and prior to start up				Outsource to service provider
Human Resources •HR Management System	Required prior to start up. Can be minimal automation	Develop robust personnel system	Buy and configure		
Accounting •General Ledger •Cost Accounting •Accounts Receivables/Payables •Purchasing •Treasury Management •Capital Investment Analysis/Budgeting •Property/Asset Accounting •Time & Expense Reporting •Tax Accounting	Require Accounts receivable/payable, General ledger, Purchasing, Capital management, Budgeting at start up	Cost accounting, Treasury Management,time & expense tracking. These systems will become critical soon after Release 1	Buy financial package and configure		Outsource time and expenses
Desktop Tools •Workgroup/Business Software	Required at start up		Buy – standard office software		

GridFlorida

Corporate Services

Applications	Business Requirements		Potential Sources		
	Release 1	End State	Buy/Build	Reuse	Outsource
Reporting Tools •Reports	May be required at start up	Enhance and maintain	Buy		
Problem Tracking •Problem Capture/Tracking	Basic system required at start up	Enhance to cover full IT help desk	Buy		
Data Archive •Data Archive DB & Tool	May not be required at start up Need to archive and version data	Enhance and maintain	Build		
Data Warehouse •Data Warehouse •Warehouse Development Tool •Data Mining Tool	May not be required at start up	Enhance to develop customer and management reports	Build		
Tariff •Tariff Modeling	Work to file tariff for start up	Tariff analysis and design	Buy		
Performance Monitor •IT Applications/Network Performance Monitoring	May be required at start up		Buy		

Docket No. 000824-EI
Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. ___________ (BLH-1)
Business Blueprint Documents

GridFlorida

Establishing the Grid Florida RTO
BluePrint Project
June 2001

COST ESTIMATES

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Start-up Cost Element	Sub-Total	Total	% of Total Program Costs
Application Hardware		$10,373,538	8%
System Operations Project	5,786,038	ok	
Commercial Operations & Customer Interface Project	352,000	ok	
Corporate Services Project	490,000	ok	
Infrastructure Management	1,025,000	ok	
Market Operations	2,612,500	ok	
Asset Optimization	108,000	ok	
Software**		$15,019,433	11%
System Operations Project	8,219,433	ok	
Commercial Operations & Customer Interface Project	2,005,000	ok	
Corporate Services Project	555,000	ok	
Infrastructure Management	690,000	ok	
Market Operations	2,950,000	ok	
Asset Optimization	600,000	ok	
Telecommunications		$500,000	0%
System Operations Telecommunications Infrastructure	500,000	ok	
Network Routers/T1 and CAT 5 Connections	-	ok	
Business Telephone System (existing)	-	ok	
Outsourced Start-up Costs		$24,993,778	19%
Market Monitoring	400,000	ok	
Salary Study	100,000	ok	
Benefits Study	500,000	ok	
Legal Fees	8,000,000	ok	
Financial & Operational Audits	200,000		
Executive Search Firm fees	1,536,000	ok	
Time & Expense Reporting	-	not outsourced	
Payroll Administration	244,560	ok	
Benefits Administration	479,520	ok	
System Operations Vendor Labor	6,696,198	ok	
Datalink Services for Infrastructure	100,000	ok	
Market Operations Vendor Labor	6,737,500	ok	
Start-up Project Labor		$34,391,528	26%
Internal	7,179,040		
External	27,212,488		
Recruiting & Sourcing Costs		$5,181,000	4%
Incentive and Moving expenses -- Senior Management	468,000	ok	
Incentive and Moving expenses -- Skilled Personnel	4,213,000	ok	
Recruiting Expenses	500,000	ok	
Facilities		$5,131,366	4%
Office Furniture	115,000	ok	
Office Infrastructure -- Desktops	60,000	ok	
Upfit Construction of Office and Control Center	303,216	ok	
Permanent HQ Facility	1,913,750	ok	
Interim Office Space	495,000	ok	
Disaster Recovery Facility	2,244,400	ok	
Incentives for Internal Resources(1)		$600,000	0%
Expenses for Internal Resources (2)		$1,534,680	1%
Expenses for External Resources		$4,081,873	3%
Total before Contingency		$101,807,195	
Contingency 20%		$20,361,439	16%
Applicants & GF LLC Total Costs to Date (end of May 2001)		$9,041,418	7%
TOTAL START-UP PROGRAM COSTS		**$131,210,051**	**100%**
Y2001 and 2002 Non-Program Payroll		$12,034,491	
Y2001 and 2002 Board & Executive Management Salary		$3,912,000	
Contingency 20%		$3,189,298	
TOTAL INTERIM OPERATING COSTS		**$19,135,789**	
TOT		**$150,345,840**	

1 Assumes 60 personnel receive bonuses of $10,000 at completion of project.

2 Assumes 50% of average internal resources travel, $4000 in expenses per month for 16 months total.

Internal	14,358
External	15,118
Total	29,476

Start-up Program Average Headcount
86

Quarter	% Build Costs Incurred	Projected Quarterly Costs
Q2 2001	5%	$7,517,292
Q3 2001	10%	$15,034,584
Q4 2001	10%	$15,034,584
Q1 2002	20%	$30,069,168
Q2 2002	20%	$30,069,168
Q3 2002	20%	$30,069,168
Q4 2002	15%	$22,551,876
	100%	**$150,345,840**

Project/Component	Internal %	External %	Estimated Days	Internal Days	External Days	Labor	HW, SW, Facilities & Other**	Comments
Operationalizing the Business Project	80%	20%	1901	1521	380	$ 1,444,760	8,200,000	External Legal fees
Establish Legal Entity & Develop Governance Model			540	432	108			
File with FERC & Manage Filing			492	394	98			
Consummate Agreements			342	274	68			
Develop Brand & Image			220	176	44			
Develop Budgets			80	64	16			
Certify Operations			15	12	3			
Design & Maintain Rules & Procedures			212	170	42			
Organization & People Project	60%	40%	1406	844	562	$ 1,434,120	7,317,000	Exec Search Firm Fees, Incentive Packages, Board & Mgmt
Plan and Select Board & Transition			30	18	12			
Recruit Management & Board			93	56	37			
Design HR Policies/Practices			45	27	18			
Design Organization			91	55	36			
Design Compensation			44	26	18			
Develop Sourcing Strategy			51	31	20			
Recruit Personnel			732	439	293			
Communications			320	192	128			
Facilities Project	85%	15%	416	354	62	$ 289,120	5,131,366	Bldg, Telephone & Network infrastructure, Bldg lease & svc fees
Procure & Manage Project Space			10	9	2			
Confirm Control Center Facility Requirements			30	26	5			
Contract Control Center Site & Vendors			10	9	2			
Design IT / Telecom Infrastructure			20	17	3			
Upgrade Control Center Facility			27	23	4			
Test Site			20	17	3			
Procure & Manage Backup Facility			116	99	17			
Procure & Manage Headquater Facility			183	156	27			
*System Operations**	60%	40%	1949	1169	779	$ 1,967,470	21,201,668	
System Operations			450	270	180			
Grid Security, Reliability Management & Real Time Operations Capabilities			403	242	161			
System Operations Data Setup			450	270	180			
Design Business Policies & Procedures			330	198	132			
Design Jobs & Compensation			66	40	26			
Internal Training Development and Delivery			250	150	100			
*Market Operations**	50%	50%	2244	1122	1122	$ 2,580,600	12,300,000	
Plan & Manage Project			450	225	225			
Market Facilitation			250	125	125			
Scheduling			250	125	125			
Forecasting			20	10	10			
Market Operations Data Setup			245	123	123			
Design Business Policies & Procedures			534	267	267			
Design Jobs & Compensation			90	45	45			
Internal Training Development and Delivery			295	148	148			
Market Operations Product Test			110	55	55			
Commercial Operations	30%	70%	4459	1338	3122	$ 6,287,627	2,357,000	Measurement, Stlmt & Billing, Contract Mgmt
Plan & Manage Project			366	110	256			
Metering & Measurement Data Capability			422	127	295			
Settlement & Billing Capability			1921	576	1345			
Contract Management Capability			98	29	69			
Commercial Operations Data Setup			256	77	179			
Design Business Policies & Procedures			160	48	112			
Design Jobs & Compensation			30	9	21			
Internal Training Development and Delivery			309	93	216			
Commercial Operations Product Test			897	269	628			

Project/Component	Internal %	External %	Estimated Days	Internal Days	External Days	Labor	HW, SW, Facilities & Other**	Comments
Customer Interface	50%	50%	3507	1754	1754	$ 4,033,280		HW, SW & Facilities in Comm Ops for Customer Information, Portal
Plan & Manage Project			290	145	145			
Customer Interface Capability			1578	789	789			
Customer Interface Data Setup			256	128	128			
Design Business Policies & Procedures			144	72	72			
Design Jobs & Compensation			30	15	15			
Internal Training Development and Delivery			269	135	135			
Portal Usability Test			50	25	25			
Customer Training Development and Delivery			263	132	132			
Customer Readiness			48	24	24			
Customer Interface Product Test			579	290	290			
Asset Optimization	60%	40%	1796	1077	718	$ 1,831,531	708,000	Asset Management & Work Tracking
Plan & Manage Project			89	54	36			
Network Planning Data Capability			206	124	82			
Work Definition Capability			123	74	49			
Work Execution Capability			324	194	130			
Asset Optimization Data Setup			340	204	136			
Design Business Policies & Procedures			156	94	62			
Design Jobs & Compensation			30	18	12			
Internal Training Development and Delivery			289	173	116			
Asset Optimization Product Test			239	143	95			
Corporate Services Project	60%	40%	2304	1382	922	$ 2,350,160	1,769,080	Financial software, HRMS, Payroll & Benefits outsourcing
Plan & Manage Project			190	114	76			
Finance & General Accounting Capability			750	450	300			
Payroll & Human Resources			324	194	130			
Corporate Administration			50	30	20			
System Administration and IT Management			118	71	47			
Design Business Policies & Procedures			176	106	70			
Design Jobs & Compensation			79	47	32			
Internal Training Development and Delivery			239	143	96			
Corporate Services Product Test			377	226	151			
Transition & Conversion Project	40%	60%	1110	444	666	$ 1,420,800		
Plan & Execute Cutover			210	84	126			
Operational Preparation			900	360	540			
Technical Architecture Project	40%	60%	3333	1333	2000	$ 4,265,744	1,815,000	Overall technical infrastructure (backbone to rest)
Technical Architecture Integration & Infrastructure Management			3333	1333	2000			
Integration Test & Simulation Project	40%	60%	2618	1047	1571	$ 3,351,040		
Cross-Capability Integration Testing			608	243	365			
Simulation Planning			260	104	156			
Support Simulation			1600	640	960			
Design Integration Architecture			150	60	90			
Program Management & Monitor Co Start-up	40%	60%	2434	974	1460	$ 3,115,275		
Program Management			2434	974	1460			
Monitor Co Startup Costs - Outsourced							400,000	Outsource start-up costs. Ongoing in Operating Budget
Total Days			29476	14358	15118	$34,391,528	$61,199,114	

*Only RTO #1 project team days are included. Vendor days are not included because it is assumed System Ops and Market Ops applications will be delivered turn-key.

Resource Split		Days	Cost/Day	Labor Cost		Other/Totals
Internal		14,358	$ 500	$ 7,179,040		
External		15,118	$ 1,800	$ 27,212,488		
SUBTOTAL		29,476		$ 34,391,528		$61,199,114
INCENTIVES FOR INTERNAL RESOURCES [1]				$ 600,000		
EXPENSES FOR INTERNAL RESOURCES [2]						$1,534,680
EXPENSES FOR EXTERNAL RESOURCES	15%					$4,081,873
TOTAL BEFORE CONTINGENCY				$ 34,991,528		$66,815,667
CONTINGENCY	20%	5,895		$ 6,998,306		$13,363,133
TOTAL AFTER CONTINGENCY		35,371		$ 41,989,833		$80,178,800
APPLICANTS & GF LLC TOTAL COSTS TO DATE (end of May 2001)						$9,041,418
TOTAL PROJECT START-UP COSTS						$131,210,051
Y2001 & 2002 NON-PROJECT PAYROLL					$ 12,034,491	
Y2001 & 2002 BOARD & EXECUTIVE MANAGEMENT SALARY					$ 3,912,000	
CONTINGENCY	20%				$ 3,189,298	
TOTAL INTERIM OPERATING COSTS					$ 19,135,789	
TOTAL START-UP COSTS						$ 150,345,840

1 Assumes 60 personnel receive bonuses of $10,000 at completion of project.

2 Assumes 50% of average internal resources travel, $4000 in expenses per month for 18 months total.

RTO #1

Gantt Chart - End State - 5

	Effort Days	Duration Months	Duration Weeks	Avg FTEs	check	Int/Tot Ratio	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
							MONTHS																	
Operationalizing the Business Project	1901	11	44	8.6	1900	80%	5	5	9	9	9	9	9	10	10	10	10							
Internal FTEs							4	4	7.2	7.2	7.2	7.2	7.2	8	8	8	8							
External FTEs							1	1	1.8	1.8	1.8	1.8	1.8	2	2	2	2							
Organization & People Project	1406	9.0	36.0	7.8	1400	60%	5	5	6	6	6	6	6	6	6	6	6	6						
Internal FTEs							3	3	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6						
External FTEs							2	2	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4						
Facilities Project	416	6	24	3.5	420	85%		2	3					3	3							5	5	
Internal FTEs								1.7	2.55					2.55	2.55							4.25	4.25	
External FTEs								0.3	0.45					0.45	0.45							0.75	0.75	
System Operations Project	1949	15	60	6.5	1950	60%	5	5	5	6.5	6.5	6.5	7	7	7	7	7	7	7	7	7			
Internal FTEs							3	3	3	3.9	3.9	3.9	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2			
External FTEs							2	2	2	2.6	2.6	2.6	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8			
Market Operations	2244	15	60	7.5	2240	50%	5	5	5	7.5	7.5	8	8	9	9	8	8	8	8	8	8			
Internal FTEs							2.5	2.5	2.5	3.75	3.75	4	4	4.5	4.5	4	4	4	4	4	4			
External FTEs							3	3	3	4	4	4	4	5	5	4	4	4	4	4	4			
Commercial Operations	4459	15	60	14.9	4460	30%	6	6	10	10	15	15	15	15	17	19	19	19	19	19	19			
Internal FTEs							1.8	1.8	3	3	4.5	4.5	4.5	4.5	5.1	5.7	5.7	5.7	5.7	5.7	5.7			
External FTEs							4.2	4.2	7	7	10.5	10.5	10.5	10.5	11.9	13.3	13.3	13.3	13.3	13.3	13.3			
Customer Interface & Customer Readiness	3507	15	60	11.7	3500	50%	5	5	7	12	12	12	13	13	13	14	14	14	14	14	13			
Internal FTEs							2.5	2.5	3.5	6	6	6	6.5	6.5	6.5	7	7	7	7	7	6.5			
External FTEs							2.5	2.5	3.5	6	6	6	6.5	6.5	6.5	7	7	7	7	7	6.5			
Asset Optimization	1796	15	60	6.0	1800	60%	3	3	3	6	6	6	7	7	7	7	7	7	7	7	7			
Internal FTEs							1.8	1.8	1.8	3.6	3.6	3.6	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2			
External FTEs							1.2	1.2	1.2	2.4	2.4	2.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8			
Corporate Services Project	2304	15	60	7.7	2300	60%	5	5	5	8	8	8	8	9	9	9	9	8	8	8	8			
Internal FTEs							3	3	3	4.8	4.8	4.8	4.8	5.4	5.4	5.4	5.4	4.8	4.8	4.8	4.8			
External FTEs							2	2	2	3.2	3.2	3.2	3.2	3.6	3.6	3.6	3.6	3.2	3.2	3.2	3.2			
Transition & Conversion Project	1110	6	24	9.3	1110	40%												7.5	8	8	8	8	8	8
Internal FTEs																		3	3.2	3.2	3.2	3.2	3.2	3.2
External FTEs																		4.5	4.8	4.8	4.8	4.8	4.8	4.8
Technical Architecture Project	3333	18	72	9.3	3300	40%	5	5	5	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Internal FTEs							2	2	2	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
External FTEs							3	3	3	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Integration Test & Simulation Project	2618	5	20	26.2	2620	40%														15	20	32	32	32
Internal FTEs																				6	8	12.8	12.8	12.8
External FTEs																				9	12	19.2	19.2	19.2
Program Management	2434	18	72	6.8	2430	40%	4	4	4	7	7	7	7	7	7	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Internal FTEs							1.6	1.6	1.6	2.8	2.8	2.8	2.8	2.8	2.8	3	3	3	3	3	3	3	3	3
External FTEs							2.4	2.4	2.4	4.2	4.2	4.2	4.2	4.2	4.2	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5

Projected Start-up Project Headcount

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	Avg FTE
Total Projected FTEs	48	50	62	82	87	88	90	96	98	98	98	94	89	104	108	63	63	58	86
Projected Internal FTEs	25	27	34	43	44	44	46	50	51	49	49	44	40	46	48	27	27	23	43
Projected External FTEs	23	23	28	39	43	43	44	46	47	48	48	51	48	57	60	35	35	35	43

Budget Area	Qty	Unit	Amount	Total	Comments
CAPITAL EXPENDITURES					
Construction Costs	1	178,000,000	$ 178,000,000	$ 178,000,000	Includes Land & Land Rights, Renew & Replacement, Expansion, & Generation Integration Costs. FPL = $154M; TECO = $24M
TOTAL CAPITAL EXPENSE				$ 178,000,000	
OPERATING EXPENSE					
O&M Related costs	1	47,813,337	$ 47,813,337	$ 74,413,337	Assumes $34,113,337M for FPL Assets & $13.2M for TECO assets, annually. In addition .5 M for TECO for transmission switching operations & telecom & computer costs.
Property Taxes	1	23,500,000	$ 23,500,000		Assumes $20M annually for FPL and $3.5M for TECO
Offices, Service Centers and Storerooms	1	2,000,000	$ 2,000,000		Cost-based lease rates on service centers
Use Fee for Shared Station Equipment	1	1,100,000	$ 1,100,000		GF will pay DOs for use of shared station equipment (such as RTUs, battery banks, etc.), also DOs will pay a use fee to GF for use of the same equipment at its stations. Estimated to be $1 M for FPL. Agreed to use an estiamte 10% of FPL number for TECO = $100k (June 18). Non-applicable for FPC.
Salaries & Benefits (190 Emps)				$ 25,374,600	
Executive	6	405,000	$ 2,430,000		300,000 with 35% loading
Skilled Personnel	164	101,250	$ 16,605,000		75,000 with 35% loading
Assistants	20	47,250	$ 945,000		35,000 with 35% loading
Annual Incentives	19,980,000	20%	$ 3,996,000		Incentives for all personnel
Payroll Taxes	19,980,000	7%	$ 1,398,600		
Contractors				$ 806,400	
Information Services	6	134,400	$ 806,400		Assume 4 telecomm contractors and 2 workstation support contractors.
Lease Back Arrangements				$ 23,100,000	
Information Services	0	-	$ -		This is a placeholder for costs associated with Utility Lease Back Arrangements.
Access Arrangements	1	23,100,000	$ 23,100,000		This is the cost that GF must pay to the Utilities for their cost of ownership of the land. This covers the lease of the land to access GridFlorida's facilities (e.g. GF owns the facilities, FPL owns the land). Estimated at $21M for FPL. Agreed to use an estimate of 10% of FPL number for TECO =
Legal & Consulting Services				$ 4,000,000	TECO Estimate
Legal	1	4,000,000	$ 4,000,000		Based on balance of estimate from original estimate of $12M. $8M in release 1. $4M remaining.
Control Center Facilities and Building Services				$ 1,796,067	Assumes lease-back arrangement to FPL for control center facilities in Miami.
Annual Lease Cost	1,760,850	2%	$ 1,796,067		Assumes annual lease agreement for 7-10 years for 45,000 square feet @ $39.13.Existing control room and computer room are 16,500 sq ft each. Assumes a 2% increase of lease cost each year.
Headquarters Facilities and Building Services				$ 637,500	Assumes that location is somewhere other than Miami, however, Miami was used to estimate this as it is most expensive city.
Annual Lease Cost	625,000	2%	$ 637,500		Assumes annual lease agreement for 7-10 years for 25,000 square feet at $25/sq. ft. Assumes a 2% increase of lease cost each year.
Disaster Recovery Facility				$ 297,048	
Annual Lease Cost	32,400	2%	$ 33,048		
Computer Services Maintenance	1,320,000	20%	$ 264,000		20% of HW acquisition cost. 20% of hardware acquisition costs for Disaster Recovery only. Number comes from HW,SW, Facil sheet, purchase for HW for backup.
Telecommunications	1	-	$ -		FPL stated that this number is included in the overall Telecomm # of $750,000.
Computer Services/Project Dev. Costs	10,325,538	20%	$ 2,065,108	$ 2,065,108	20% of HW Acquisition cost for everything but Disaster Recovery. Number comes from total Application Hardware number in Start-up Cost Breakout worksheet.
Insurance	1	2,000,000	$ 2,000,000	$ 10,470,000	Assumes insurance for Property, Surety Bond, Brokerage Fees, Automobile, Liability, Directors & Officers, Workers Comp
Storm Fund Insurance	1	8,470,000	$ 8,470,000		Based on an estimate of $7.7M from FPL to cover assets from FPL. Agreed to use an estimate of 10% of FPL number for TECO = 770k (June 18). FPC will continue to have its own assets and own storm fund.
Telecommunications	1	774,000	$ 798,000	$ 798,000	Based on FPL's prorated costs of $750k currently. In addition estimated ISP costs for internet connectivity at $2000/month ($24k).
Board Of Directors	8	60,000	$ 480,000	$ 480,000	8 members, $60,000 annual comp.; includes incentives and expense reimbursement
Mtgs., Travel, Seminars	1	500,000	$ 500,000	$ 500,000	
Market Monitoring Fees	1	1,691,945	$ 1,691,945	$ 1,691,945	From MonitorCo Operating Budget Worksheet
Payroll Administration	$ 24,456,000	1%	$ 244,560	$ 244,560	From ADP PEO. 1% of gross annual salary. (Includes board of directors)
Benefits Administration	$ 23,976,000	2%	$ 479,520	$ 479,520	From ADP PEO. 2% of gross annual salary. (Includes board of directors)
Financial & Operational Auditing	1	1,800,000	$ 1,800,000	$ 1,800,000	Assumes Annual Audit = $1.5M; Add'l audits = $300k.
Employee Training Budget (external)	90	3,000	$ 270,000	$ 270,000	90 employees, $3000 per employee. Assumes limited training in first year.
Miscellaneous Fees	1	25,000	$ 25,000	$ 25,000	Assumes annual FRCC membership fee of $25k; FPUC will assess a 1/8 of 1% of annual revenues which are unknown at this time.
FERC Fees	1	1,000,000	$ 1,000,000	$ 1,000,000	As a benchmark, PJM Operating Budget line item for FERC Fees were $2M in 1999.
Communications/Community & Customer Relations	1	500,000	$ 500,000	$ 500,000	Charitable contributions assumes 1% of Labor Costs; the Balance was added for Communications & Customer Relations
Miscellaneous	1	500,000	$ 500,000	$ 500,000	Includes office expenses for postage, supplies, etc. Added money for annual report production, etc.
Total Before Contingency				$ 151,249,085	
Contingency	20%			$ 30,249,817	
Total After Contingency				$ 181,498,902	

Budget Area		Qty	Unit	Amount	Total	Comments
Salaries & Benefits (6 Emps)					$ 1,114,425	
	Executive	1	303,750	$ 303,750		225,000 with 35% loading
	Skilled Personnel (Market Analyst, Economic Modeling Skills)	2	162,000	$ 324,000		120,000 with 35% loading
	Skilled Personnel (IT & Other Support)	2	101,250	$ 202,500		75,000 with 35% loading
	Assistants	1	47,250	$ 47,250		35,000 with 35% loading
	Annual Incentives	877,500	20%	$ 175,500		Incentives for all personnel
	Payroll Taxes	877,500	7%	$ 61,425		
Legal & Consulting Services		1	545,000	$ 545,000	$ 545,000	LEGAL: 1 FTE external lawyer, (450/hr x 6mo x 18d x 8h = 388,800) + expenses (20% of total fees = $78k) = $545k
MonitorCo Facilities & Building Services					$ -	Assumes that space is shared with GridFlorida.
	Annual Lease Cost	-	2%	$ -		
	Utilities	-	3	$ -		
Board Of Directors		3	40,00	$ 120,000	$ 120,000	3 members, $40,000 annual comp.; includes incentives and expense reimbursement
Time & Expense Reporting Administration		0	-	$ -	$ -	Use GridFlorida's application as shared service.
Payroll Administration		$1,053,000	1%	$ 10,530	$ 10,530	Use GridFlorida outsourced solution as shared service
Benefits Administration		$1,053,000	2%	$ 21,060	$ 21,060	Use GridFlorida outsourced solution as shared service
Total w/o Contingency					$ 1,811,015	

Note: Outsourcing benchmark is @ $500k annually based on quote from Charles River to GridSouth. GridSouth will outsource this function and their independent BOD

Note: Total in here goes as a line item in the 2003 Operating Budget

Quarter/Resource Level	Total Headcount per Level	% of Total Hired, non project	Qtrly Hires	Annual Salary	Qtrly Salary	Quarterly Amount	Total	Comments
Salaries & Benefits (190 Emps and 8 Board Members)								
Q3 2001 (Jul - Sep)		5%					$ 219,375	
Executive	0		0	405,000	101,250	$ -		Executives captured in start-up cost (and below)
Skilled Personnel	164		8	101,250	25,313	$ 207,563		75,000 with 35% loading
Assistants	20		1	47,250	11,813	$ 11,813		35,000 with 35% loading
Cumulative Non-Project Employees			9					
Q4 2001 (Oct - Dec)		15%					$ 658,125	
Executive	0		0	405,000	101,250	$ -		
Skilled Personnel	164		25	101,250	25,313	$ 622,688		
Assistants	20		3	47,250	11,813	$ 35,438		
Cumulative Employees			28					
Q1 2002 (Jan - Mar)		35%					$ 1,535,625	
Executive	0		0	405,000	101,250	$ -		
Skilled Personnel	164		57	101,250	25,313	$ 1,452,938		
Assistants	20		7	47,250	11,813	$ 82,688		
Cumulative Employees			64					
Q2 2002 (Apr - Jun)		50%					$ 2,193,750	
Executive	0		0	405,000	101,250	$ -		
Skilled Personnel	164		82	101,250	25,313	$ 2,075,625		
Assistants	20		10	47,250	11,813	$ 118,125		
Cumulative Employees			92					
Q3 2002 (Jul - Sep)		75%					$ 3,290,625	
Executive	0		0	405,000	101,250	$ -		
Skilled Personnel	164		123	101,250	25,313	$ 3,113,438		
Assistants	20		15	47,250	11,813	$ 177,188		
Cumulative Employees			138					
Q4 2002 (Oct - Dec)		100%					$ 3,349,688	
Executive	0		0	405,000	101,250	$ -		
Skilled Personnel	123		123	101,250	25,313	$ 3,113,438		Roughly 41 of the 164 (25%) total skilled personnel will still be working on the project in the final quarter. Therefore, 123 Skilled Personnel are assumed on the non-project payroll in Q4 of 2002.
Assistants	20		20	47,250	11,813	$ 236,250		
Cumulative Employees			143					
INTERIM PAYROLL SUB-TOTAL							$ [illegible]	
Salary for Board							720,000	Assumes 8 members for 18 months of work (July 2001- December 2002); includes incentives
Salary for Management							3,192,000	Assumes 6 team members for 16 months of work, average salary of $300K (July 2001- December 2002); includes incentives ** It is 16 months to account for all executives not starting right on July 1, 2001
Payroll Taxes			7%				787,303	
PROJECTED INTERIM PAYROLL BEFORE CONTINGENCY							$ 15,946,491	
CONTINGENCY			20%				3,189,298	
PROJECTED INTERIM PAYROLL AFTER CONTINGENCY							$ 19,135,789	

No.	End State Start-Up Assumptions
1	Some estimates are case-based, using Accenture experience and knowledge capital
2	Standard estimating factors are used throughout the estimate.
3	The capability map created in the blueprint phase is the basis for the different "projects" represented in this estimate. For example, System Operations, Market Operations, Asset Optimization, Commercial Operations, Customer Interface, etc.
4	GridFlorida will be funded from the 3 utilities: TECO, FP&L, and FPC.
5	This estimate includes four facilities: Control Center facility, Headquarter facility, Disaster Recovery facility, and a Project facility.
6	The following start up costs are assumed to be outsourced (partial or whole): market monitoring, salary study, benefits study, facilities design and project management, legal fees, executive search firm fees,payroll administration, benefits administration, and system operations and market operations vendor labor.
7	The effort to conduct a salary study for GridFlorida management and board positions will be outsourced.
8	An Executive Search Firm will be retained to seek candidates for the Management positions.
9	Estimate does not include any third-party vendor costs for advertising or marketing assistance. It is assumed that all Brand & Image activities will be in-house.
10	Subject Matter Experts will be available on an as-needed basis by the project team.
11	Project Start-up costs assume build out of applications except where noted as outsourced.
12	In Portal development, only the licensing fees for the tool itself are included. Additional content from other websites - news, stocks, radio, tv feeds would require additional fees.
13	Updating or reconfiguring the GridFlorida web site is not included in this estimate.
14	Financing costs are to be included in the estimate - to be confirmed.
16	The organization size is assumed to be 190, with 6 executives, 163 skilled personnel, and 20 assistants.
17	Anticipated payroll and benefits for non-project GridFlorida personnel in 2001 and 2002 is captured on the "2001 & 2002 Payroll" tab. It is assumed that most of the non-project personnel will be hired in Q3 and Q4 and will spend much of their time training for their operational roles and participating in simulated operations.
18	The internal daily rate of $500 was determined through estimates submitted by the utilities.
19	Internal expenses were estimated by assuming 50% of the average number of internal resources will travel to the project site. Of those that travel a monthly expense rate of $4000 was used ($1000/wk x 4 wks a month, 16 months in the program).
20	Internal training is broken down into each capability area.
21	All customer training is accounted for in the Customer Interface capability.
22	Commercial Operations Capability has 2 applications: a Settlements & Billing application and a meter data acquisition application. Contracts will be managed by the customer information application which is accounted for in the Customer Interface project with an interface with Settlements & Billing.
23	Customer Interface Capability has 2 applications: Customer Information (for storing info about customers) and Portal Interface (for collecting and disseminating information to GridFlorida customers).
24	Corporate Services Capability has 5 primary applications: Human Resources, Finance & Accounting, Time & Expense Reporting, Payroll & Benefits, and Facilities & Purchasing.
25	Asset Management Capability has 2 primary applications: an asset management application and a work tracking application.
26	One cutover equals 10 people for 2 days to execute and analyze mock cutovers.
27	Each cutover would be monitored for one week with 6 people.
28	Each cutover would require follow-up for one week with 6 people.
29	The costs for split of SCADA on the new EMS are yet to be determined and included.
30	GridFlorida's unique characteristics include: ownership of transmission assets, Datawarehouse capability, Market Operations capability, to management participant offering/trading, etc.
31	GF employees estimated at 190
32	3 Market participants, FPL, Progress, Teco linked in a dedicated wan links
33	Internet connectivity via dual isp
34	2 Hour outage on a hardware failure ok for Corporate Services, Asset Optimization, Commercial Ops, and Non-portal customer interface
35	Equipment will be acquired via capital purchase and not via leasing
36	All components will be hosted internally by GridFlorida Except for portions of Market Ops
37	DR must be in place for all application and office components
38	All systems disk will be centrally managed via the SAN
39	Great Plains or similar suite of products will be used for back office corporate services function

RTO #1

HW, SW, Facil. - 10

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
Operationalizing the Business Project	$ -	$ -	$ 8,200,000	$ 8,200,000	
Financial & Operational Audits			$ 200,000		Two audits included in start up costs. Initial audit of divesting owner's agreements = 100k. Audit of initial investment = 100k.
Start-up Legal Fees			8,000,000		Assumes that this will be outsourced until GridFlorida hires some permanent legal staff. Estimate is based on a burn rate of $2M/quarter. Estimate is based upon four quarters.
Organization & People Project	$ -	$ -	$ 7,317,000	$ 7,317,000	
Search Firm Fees			1,536,000		For Board & Management & some skilled personnel positions; Equivalent to 40% of the 1st year's cash compensation. Assume 8 Board Members ($30K each), 1 CEO ($300K), 5 Senior Management personnel ($300K each), and 24 (15% of 164) skilled personnel ($75K each).
Incentive/Bonus Package -- Senior Management			180,000		Assumes average senior management incentive/bonus package for 6 FTEs is $30K
Moving Expenses -- Senior Management			288,000		Assumes relocation as a homeowner is $48000 for 6 senior management.
Incentive/Bonus Package -- Skilled Personnel			1,630,000		Assumes non-management personnel receive average signing bonuses/incentives of $10K for 164 FTEs
Moving Expenses -- Skilled Personnel			2,583,000		Assumed relocation as a homeowner is $48,000, and relocation cost for a renter is approximately $15,000. Of the 163 skilled personnel, assume half are relocating. Of the half, half are homeowners and half are renters.
Recruiting Expenses (airfare, hotel, etc.)			500,000		Assumes travel expenses for recruiting management and personnel
Salary Study - Outsource			100,000		Case-based estimate (ISO-NE)
Benefits Study - Outsource			500,000		Includes retirement plans, medical insurance, etc.
Facilities Project - End State	$ -	$ -	$ 5,131,366	$ 5,131,366	
Control Center Facility - End State			478,216		Assume some space in LFO leased for last 90 days before go live - will be 11,000 sq. ft @ $39.13 per sq. ft. After 90 days, lease goes into operating budget. The rest of the Control Center space to a total of 44,000 sq. ft will be occupied by GF at go live (switch over), so not including a lease cost for this. Assume space (in total) for approx. 50 people in R1. Existing control room and computer room are 16,500 sq ft each, plus there are multiple offices and conf. rooms
Office infrastructure (desktop, network routers, cables, wiring, etc.)			60,000		Assumes $3000/workstation for 20 workstations; Assumes $2000 is for desktops, $1000 is for the rest of the infrastructure
Office furniture (cubicles, desks, chairs)			115,000		Assumes $5000/workstation for 15 open office workstations, $8000/office for 5 closed office spaces
Building Lease fees			107,607		See assumption three lines above. 90 days only for part of the space. Rest of lease cost goes into annual lease.
Tenant Improvement Allowance			0		Assumes no allowance
Upfit Construction of Office and Control Center			150,000		Assumes no upfit required for the LFO except upgrade of mapboard. B. Smith called Mauell - upgrade of mapboard estimated at 140k-150k. Assumed this will be done in end state.

RTO #1
HW, SW, Facil. - 11

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
Back-Up Generator			0		Existing

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
UPS/Batteries			0		Existing
Network/Phones			0		Includes CAT 5 and TI connections . Existing telecamm operating expense is $500,000 prorated to Ops. This number is included in the Operating Budget - so is zero here.
Business Telephone/PBX system			0		Existing
Separate Electric Service			0		Separate service for Control Center and 24x7 operations-existing
Facilities Design & Project Management -- Outsource			20,609		Assumes 8% of lease and upfit cost (industry average planning factor)
Training site with dedicated user desktops			0		Assumes existing training room with no upfit per FPL
Moving Expenses to Permanent Facility			25,000		Includes hiring moving company to pack, transfer, and unpack assets to new facility; Assumes $500/person for 50 personnel
Permanent HQ Facility - End State	0	0	1,913,750		Various scenarios exist initial. (1) Sublet/try to get smaller space from one developer and then get more. (2) Move into industrial building (only $6/sq ft & then outfit it ($30/sq ft) more flexible, but may be more costly. (3) Work with Divesting owners on using some vacant space they may have - would be at an embedded cost rate of $15/sq ft. Conclusion: Assumes 25,000 square feet, for 100 people in the end state (250 sq ft/person) at $25/sq ft. Other scenarios might be ways to reduce number later.
Office infrastructure (desktop, network routers, cables, wiring, etc.)			300,000		Assumes $3000/workstation for 100 workstations; Assumes $2000 is for desktops, $1000 is for the rest of the infrastructure.
Office furniture (cubicles, desks, chairs)			545,000		Assumes $5000/workstation for 85 open office workstations, $8000/office for 15 closed office spaces
Building Lease fees			156,250		See assumption three lines above. 90 days only. Rest of lease cost goes into annual lease. Assumes 25,000 square feet, for 100 people (250 sq ft/person) at $25/sq ft.
Tenant Improvement Allowance			0		Assumes no allowance
Upfit Construction of Office and Control Center			0		Includes 25,000 sq ft of Office space @ $75/sq ft; Upfit includes construction, electricity, HVAC, plumbing, and fire protection. We are assuming zero additional dollars for upfit of HQ.
Back-Up Generator			0		None
UPS/Batteries			250,000		To be used for critical business areas
Network/Phones			250,000		Includes CAT 5 and TI connections (estimate)
Business Telephone/PBX system			275,000		Estimate is installed business phone system with voicemail and battery backup to support 150 employees
Separate Electric Service			50,000		Separate service for 24x7 operations
Facilities Design & Project Management -- Outsource			12,500		Assumes 8% of lease and upfit cost (industry average planning factor)
Moving Expenses to Permanent Facility			75,000		Includes hiring moving company to pack, transfer, and unpack assets to new facility; Assumes $500/person for 150 personnel
Project Facility - End State	0	0	495,000		
Project Space -- Lease			490,000		Assumes 50 project personnel, with an average of 250 sq ft/person located at the LFO at $39.13/sq ft. Assumes all space will be office space, with no additional requirements for Control Center space. Assumes lease will be for twelve months
Project Space -- Office Furniture			0		Assumes no upfit cost at LFO

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
Project Space -- Office Infrastructure			5,000		Assumes $100/workstation to lease for 50 project personnel; Includes desktops, telephones, cables, wiring, etc.
Disaster Recovery Facility - John/Bill Smith - End State	0	0	2,244,400		Assume existing back-up site at the customer service center East in West Palm Beach
Building Lease Fees			32,400		Assumes 1,200 sq ft facility for FPL Customer Service Center East and office space; Assumes $27/sq ft;
Tenant Improvement Allowance			0		Assumes no allowance
Office Furniture			21,000		Assumes $3000/workstation for low-end open office space; Assumes 7 workstations
Office Infrastructure			21,000		Assumes $3000/workstation for 7 workstations
Upfit Construction of Office and Control Center			0		Assumes no upfit required
System Operations HW & SW			0		Backup Sys. Ops. HW & SW covered in original FPL EMS project. See SO-HW spreadsheet for details. Allocated 50% of the backup to Grid Florida - this number is included in System Operations on this spreadsheet.
Market Operations HW & SW			450,000		Assumes minimal software licensing fees, only purchase for HW, Backup for market ops
Commercial Operations HW & SW			410,000		Assumes minimal software licensing fees, only purchase for HW Backup of S& B system
Corporate Services HW & SW			350,000		Assumes minimal software licensing fees, only purchase for HW Backup of corp services
Asset Optimization HW & SW			110,000		Assumes minimal software licensing fees, only purchase for HW Backup of Asset opt applications
Infrastructure HW & SW			600,000		Includes scaled down Disk storage, tape backup/recovery unit, network equipment, and minimal SW
Telecommunications Infrastructure			250,000		Assumes some level of reconfiguration will be required
Telecommunications Operating Expense			0		Operating Expense covered under 2003 Operating Budget
System Operations Project	$ 6,286,038	$ 8,219,433	$ 6,696,198	$ 21,201,668	
System Operations					
Allocated EMS costs (from FPL new EMS)	0	5,185,446	4,691,921		Allocation of costs for FPL EMS system to GF. See Cost Summary - FPL and System Operations Cost Summary spreadsheets for detailed assumptions. Based on costs that are sharable between GF and FPL.
Incremental EMS costs to prepare for GridFlorida	5,706,038	1,500,000	1,250,000		Based on estimate of incremental costs to prepare for GF. See SO-HW spreadsheet for Hardware costs. SW and Other from mid-point of vendor estimate.
Plus allocated costs from FPL EMS for functions that will be put in place in the end state (e.g. some Generation related functionality)		783,987	604,277		See System Operations Cost Summary and Cost Summary - FPL spreadsheets for these costs. They are for allocated software and other (labour) costs allocated from FPL to GF - but not until the end state.
Database Management SW		700,000			Oracle DB requires its own license as FPL has own corporate deal.
Telecommunications Infrastructure	500,000	0			Routers and switch equipment
Voice Recorder	80,000		0		Addition to Main Control Center
Outage Scheduler		50,000	150,000		Very approximate estimate for Outage Scheduling (coordinate longer term - in advance of 1 week)
Mapboard			0		June 8 - Zero out mapboard here - covered under Control Center. Rework of existing Mauell mapboard(add 40 feet to existing). (Resurfacing would be $450,000).

RTO #1

HW, SW, Facil. - 14

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
Commercial Operations & Customer Interface Project	$ 352,000	$ 2,005,000	$ -	$ 2,357,000	
Production	220,000	1,390,000	0		
Settlements & Billing Database Serve	30000	80000	0		1 NT, Oracle Maintenance software, scheduling software, SQL Analysis Software
Settlements & Billing NT App Server	30000	630000	0		1 NT, Batch Scheduling software, Settlements and Billing Application Software
Customer Interface Database Server	30000	80000	0		1 NT, Oracle Maintenance software, scheduling software, SQL Analysis Software
Customer Interface NT App and Wor	30000	310000	0		1 NT, Batch Scheduling software, Customer Information application software
Web Servers	50000	50000	0		2 NT, Security Software, Portal Application software
Portal Application Server	25000	50000	0		1 NT, Scheduling Software, Portal Application Software
Portal Database Server	25000	50000	0		1 NT and SQL Server
Database Management SW	0	140000	0		Oracle DB Case-based estimate
Test and Training	66,000	245,000			
Test and Training Web Server	12,000	100,000	0		1 NT, SQL Server, Scheduling software, Portal Development Tools
Test and Training DB Server	30,000	80,000	0		1 NT, Oracle Maintenance software, scheduling software, SQL Analysis Software
Test and Training Settlements and Billing App Server	12,000	10,000	0		1 NT, Batch Scheduling software, Settlements and Billing Application Software assumed included in production license
Web Based Training and Registration Application		45,000	0		Assumes 30 customers using with 10 users per customer at a rate of 100 per user plus a fee for maintenance and support.
Test and Training Customer Interface App Server	12,000	10,000	0		1 NT, Batch Scheduling software, Settlements and Billing Application Software assumed included in production license
Development	66,000	370,000	0		
Development Web Server	12,000	100,000	0		1 NT, SQL Server, Scheduling software, Portal Development Tools
Development DB Server	30,000	80,000	0		1 NT, Oracle Maintenance software, scheduling software, SQL Analysis Software
Develoment Settlements and Billing A	12,000	10,000	0		1 NT, Batch Scheduling software, Settlements and Billing Application Software assumed included
Develoment Customer Interface App	12,000	10,000	0		1 NT, Batch Scheduling software, Settlements and Billing Application Software assumed included
Develoment Test Software	0	120,000	0		Mercury Interactive assumed
Source Code Management Tools	0	40,000	0		$1000/user; Assumes 40 users
Compiler	0	10,000	0		$250/user; Assumes 40 users
Market Operations	$ 2,612,500	$ 2,950,000	$ 6,737,500	$ 12,300,000	
Production, Test, Development, Training	2,612,500	2,950,000	6,737,500		
Package Software and System for Market Operations Capability	2,612,500	2,650,000	6,737,500		Assumes vendor build, test and delivery of all applications; includes all labor, services & training for systems. Assumes a mid-point of two vendors' range of estimates
Database Management SW		300,000	0		Oracle DB Software
Asset Optimization	$ 108,000	$ 600,000	$ -	$ 708,000	
Production	60,000	160,000	0		
Asset Optimization Database Server	30,000	80,000			1 NT, Oracle Maintenance software, SQL Analysis Software
Asset Optimization NT App Server	30,000	10,000			1 NT, Batch Scheduling software
Database Management SW	0	70,000			Oracle DB
Test and Training	24,000	95,000	0		
Asset Optimization Database Server	12,000	50,000	0		1 NT, Oracle Maintenance software, SQL Analysis Software
Asset Optimization NT App Server	12,000	10,000	0		1 NT, Batch Scheduling software
Database Management SW	0	35,000	0		Oracle DB
Development	24,000	345,000	0		

RTO #1
HW, SW, Facil. - 15

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
Asset Optimization Database Server	$ 12,000	$ 50,000	$ -		1 NT, Oracle Maintenance software, SQL Analysis Software
Asset Optimization NT App Server	$ 12,000	$ 10,000	$ -		1 NT, Batch Scheduling software
Database Management SW	$ -	$ 35,000	$ -		Oracle DB
PSSE Application Suite	$ -	$ 250,000	$ -		Estimated cost - Verified with FPL.
	0				
Corporate Services Project	$ 490,000	$ 555,000	$ 724,080	$ 1,769,080	
Production	490,000	555,000	724,080		
File/Print Server Cluster Servers	20,000	30,000	0		2 NT, Antivirus
Active Directory Domain Servers	30,000		0		3 NT
Intranet Web Server Cluster	20,000		0		2 NT
Exchange email Cluster	20,000	15,000	0		2 NT, Exchange 2000
Office SQL Server Cluster	20,000	20,000	0		2 NT, SQL Server
Office Network Infrastructure	200,000		0		Switches, Hubs, Routers
Corporate Services Application Serve	60,000	100,000	0		2 NT and Great Plains e-enterprise or similar Corporate Services Software, Crystal Reports
Corporate Services Database Server	30,000	30,000	0		1 NT and SQL Server
Data Warehouse Database Server	30,000	80,000	0		1 NT, Oracle Maintenance software, scheduling software, SQL Analysis Software
Data Warehouse Query Server	30,000	210,000	0		1 NT, Batch Scheduling, Cognos Query License
Data Warehouse Enterprise Server	30,000	0	0		1 NT, Batch Scheduling, Cognos Enterprise License
Database Management SW	0	70,000	0		Oracle DB
Time & Expense Reporting		0	0		Assuming will be in-house
Payroll Administration -- Outsource			244,560		Assumes administration will be equal to 1% of annual salary expenses (employees & board). Case based
Benefits Administration --			479,520		Assumes administration will be equal to 2% of annual salary expenses. (employees) Case based
Infrastructure Management	$ 1,025,000	$ 690,000	$ 100,000	$ 1,815,000	
Infrastructure	1,025,000	690,000	100,000		
Spare Server in event of DB or App Server failure	50000	0	0		2 NT, 1 Production and 1 Dev/Test/Train
Primary Screening Routers	30000	0	0		4 Routers for Dual Network
Primary Firewall	30000	30000	0		1 NT and Checkpoint Software
Primary Central Switch	60000	0	0		4 Switches for Dual Network
Primary Web Load Balancer	20000	0	0		Cisco Directors
LDAP/PKI/Citrix Server	30000	50000	0		1 NT, Verisign, RSA SecureID, Citrix
Centralized Disk Storage	300000	300000	0		EMC Symetrics and EMC Software (Timefinder, Powerpath, Optimizer, Volumelogics)
Centralized Tape Library	250000	100000	100000		StorageTek M700 and Veritas Netbackup, and Datalink services for SAN installation
Master Backup Server	30000	10000	0		1 NT and Veritas Master Server License
Primary Fibre Channel Switches	150000	0	0		Brocade
Job Scheduling Software / Systems Management	30000	200000	0		1 NT, BMC Patrol, Tivoli Scheduling Console, HP Network Node Manager, Veritas SAN Management
Network Printers (1 per 10 employees)	45000	0	0		Assumes 15 network printers @$3000/ea
Market Monitor Co Start-up	$ -	$ -	$ 400,000	$ 400,000	
Monitor Co Startup	0	0	400,000		

Project/Capability	HW	SW	Other	Total	Comments
TOTAL	########	########	#######	$ 61,199,114	
Monitor Co Startup Costs	0	0	400,000		Cost estimate case-based from another project. Ongoing costs are est. in Operating Budget sheet. It has not yet been determined how GF will start-up Monitor Co - e.g. outsource or

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
1.0	Operationalizing the Business Project						-Project Total:	1901.0	
	Establish the Legal Entity & Develop Governance Model						540.0		
	Establish the LLC Trust Account	Fixed Effort	1	108.0	108.0				Assumes 1 FTE for 6 months
	Manage regulatory legal issues	Fixed Effort	1	324.0	324.0				Assumes 1 FTE for 18 months
	Manage business/operational legal issues	Fixed Effort	1	108.0	108.0				Assumes 1 FTE for 6 months
	File with FERC & Manage Filing						492.0		
	File with FERC	Fixed Effort	6	10.0	60.0				Assumes 6 FTEs for 10d
	Revise FERC filings	Fixed Effort	4	108.0	432.0				Assumes 4 FTEs for about 6 months
	Consummate Agreements						342.0		
	Renegotiate Telecomm agreements	Fixed Effort	1	54.0	54.0				Assumes 1 FTE for 3 months of design
	Develop & negotiate agreements w/ LSEs	Fixed Effort	1	36.0	36.0				Assumes 1 FTE for 2 months
	Develop & negotiate agreements w/ Generators for AS	Fixed Effort	2	108.0	216.0				Assumes 2 FTEs for 6 months
	Develop & negotiate agreements w/ other Transmission Owners	Fixed Effort	1	36.0	36.0				Assumes 1 FTE for 2 months
	Develop Brand & Image						220.0		
	Determine Marketing Strategy for RTO #1	Fixed Effort	1	60.0	60.0				Assumes 1 FTE for 12 months for all Brand & Image activities
	Execute the Marketing Strategy	Fixed Effort	1	80.0	80.0				
	Provide Public Relations support	Fixed Effort	1	80.0	80.0				
	Develop Budgets						80.0		
	Develop annual operating and capital budgets for 2002	Fixed Effort	1	80.0	80.0				Responsibility of RTO Budget Analyst
	Certify Operations						15.0		
	Support RTO Certification by Transmission Owners	Fixed Effort	1	15.0	15.0				Assumes 5 days of effort for each of the 3 TO's
	Design & Maintain Rules and Procedures						212.0		
	Develop the GridFlorida tariff	Fixed Effort	5	10.0	50.0				Assumes 5 FTEs for 10 days
	Manage the GridFlorida tariff	Fixed Effort	3	54.0	162.0				Assumes 3 FTEs for 3 months

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	2.0 Organization and People Project						Project Total:	1406	
	Plan Stakeholder Process						30.0		
	Develop process to establish Stakeholder Committees	Fixed Effort	1	30.0	30.0				Assumes 3 FTEs for 10 days; Responsibility of Governance team
	Recruit Management & Board						93.0		
	Conduct Salary Study for Management Positions	Fixed Effort	1	18.0	18.0				Assumes 1 FTE for 1 month to coordinate with outsource group
	Determine incentive and bonus packages for Management	Fixed Effort	1	15.0	15.0				Includes coordination and review time with Executive Search Firm
	Identify Management candidates	Fixed Effort	1	60.0	60.0				Includes coordination and review time with Executive Search Firm
	Design HR Policies/Practices						45.0		Particularly policies/procedures for employees
	Create Process Maps	Processes	15	2.0	30.0				Responsibility of HR Team
	Implement HR Policies	Processes	15	1.0	15.0				
	Design Organization						91.0		
	Confirm Organization Structure					10.0			
	Confirm Organization Structure	Case-based estimate	1	10.0	10.0				Assumes use of organization structure defined in Planning Phase
	Define Organization Infrastructure					26.0			
	Determine Management Structure, Performance Measurement, Reporting Relationships	Case-based estimate	4	2.5	10.0				Assume 4 internal work groups
	Identify Work Group Support & Measurement Tools	Case-based estimate	4	2.0	8.0				Assume 4 internal work groups
	Confirm Facilities & Logistics Plan	Case-based estimate	1	3.0	3.0				Fixed effort
	Identify Integrating Mechanisms	Case-based estimate	1	5.0	5.0				Fixed effort
	Design Teams					23.0			
	Evaluate processes	Case-based estimate	1	3.0	3.0				
	Design Teams	Case-based estimate	4	5.0	20.0				Assume 4 internal work groups
	Develop Support for New Structure					32.0			
	Develop Support Tools	Case-based estimate	4	2.0	8.0				Assume 4 internal work groups
	Develop Post-Independence Day Support Strategy	Case-based estimate	1	5.0	5.0				Fixed effort
	Modify Performance Support Needs Analysis/Training: Job Changes	Case-based estimate	4	2.0	8.0				Assume 4 internal work groups
	Develop Contingency Plan	Case-based estimate	1	5.0	5.0				Fixed effort
	Develop and Handoff Knowledge Transfer Plan	Case-based estimate	1	6.0	6.0				Fixed effort
	Design Compensation						44.0		
	Conduct Salary Study for Staff Positions	Fixed Effort	1	10.0	10.0				Assumes 1 FTE for 2 weeks to coordinate with outsource group
	Conduct Benefits Study for All Positions	Fixed Effort	1	24.0	24.0				Assumes 1 FTE for 6 weeks to coordinate with outsource group
	Determine incentive and bonus packages for staff	Fixed Effort	1	10.0	10.0				
	Design Sourcing Strategy						51.0		
	Design Sourcing Strategy	Fixed Effort	2	18.0	36.0				Assumes 2 FTEs for 1 month for all Sourcing activities
	Identify & Develop Sourcing Opportunities	Fixed Effort	1	15.0	15.0				
	Recruit Personnel						732.0		
	Design staff recruiting process	Fixed effort	1	30.0	30.0				
	Post Job Listings	# of New Job Roles	[illegible]	5.0	220.0				Includes advertising and marketing of positions
	Review Resumes	Fixed Effort	2	108.0	216.0				Assumes 2 FTEs for 6 months
	Conduct Interviews	Fixed Effort	2	108.0	216.0				Assumes 2 FTEs for 6 months
	Manage Sourcing Relationships	Fixed Effort	1	50.0	50.0				Assumes 1 FTE for 5 days a month, for 10 months
	Communications						320.0		Assume 1 FTE for 16 months
	Plan, Develop, and Manage Internal Communications					160.0			
	Determine message, timing, channel, sender/receiver	Case-based estimate	1	40.0	40.0				
	Develop communication messages -- internal	Case-based estimate	1	90.0	90.0				
	Schedule/Coordinate Internal Delivery	Case-based estimate	1	30.0	30.0				
	Plan, Develop, and Manage External Communications					160.0			
	Determine message, timing, channel, sender/receiver	Case-based estimate	1	35.0	35.0				
	Develop communication messages -- external	Case-based estimate	1	95.0	95.0				
	Schedule/Coordinate External Delivery	Case-based estimate	1	30.0	30.0				

No.			Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
4.0	**Facilities Project**					Project Total:		416	
	Procure & Manage Project Space						10.0		
	Conduct Project Space Requirements Analysis	Fixed Effort	1	5.0	5.0				Assumes 1 FTEs, 1 week
	Select Project Space	Fixed Effort	1	0.0	0.0				Assumes LFO will be used
	Manage preparation of site with office infrastructure	Fixed Effort	1	5.0	5.0				Assume 1 FTEs, 1 week
	Confirm Control Center Facility Requirements						30.0		
	Conduct Facility Requirements Analysis	Fixed Effort	2	10.0	20.0				Assume 2 FTE, 2 week
	Prepare cost estimates and analyses for leases	Fixed Effort	2	5.0	10.0				Assume 2 FTE, 1 week
	Contract Control Center Site & Vendors						10.0		
	Negotiate building leases and maintenance contracts	Fixed Effort	1	10.0	10.0				Assume 1 FTE, 2 week
	Prepare cost estimates and analyses for lease improvements	Fixed Effort	1	0.0	0.0				Assumes no upfit required
	Design IT / Telecom Infrastructure						20.0		
	Conduct IT and Telecom Requirements Analysis	Fixed Effort	1	5.0	5.0				Assumes 1 FTE, 1 week
	Design IT and Telecom Infrastructure	Fixed Effort	1	5.0	5.0				Assumes minimal changes required
	Design & Develop IT policies and procedures	Fixed Effort	2	5.0	10.0				Assume 2 FTE, 1 week
	Upgrade Control Center Facility						27.0		
	Manage procurement of goods and services	Fixed Effort	0.5	54.0	27.0				Assumes .5 FTE for 3 months. Includes office supplies, furniture, and other expenditures
	Manage preparation of site with office infrastructure	Fixed Effort	1	0.0	0.0				Assumes minimum upfit required
	Coordinate with contractors for site upfit	Fixed Effort	1	0.0	0.0				Assumes minimum upfit required
	Test Site						20.0		
	Plan & Conduct Site Operational Readiness Test	Fixed Effort	2	10.0	20.0				Assume 2 FTE, 2 week
	Procure & Manage Backup Facility						116.0		
	Conduct Backup Facility Requirements Analysis	Fixed Effort	2	5.0	10.0				Assumes 2 FTEs, 1 weeks
	Negotiate building leases and maintenance contracts	Fixed Effort	1	0.0	0.0				Assumes site is identified
	Conduct IT and Telecom Requirements Analysis	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks
	Design IT and Telecom Infrastructure	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks
	Manage procurement of goods and services	Fixed Effort	0.5	54.0	27.0				Assumes .5 FTE for 3 months. Includes office supplies, furniture, and other expenditures
	Manage preparation of site with office infrastructure	Fixed Effort	1	10.0	10.0				Assumes 1 FTE for 2 weeks
	Coordinate with contractors to build out site	Fixed Effort	0.[illegible]	18.0	9.0				Assumes .5 FTE for 1 months
	Plan & Conduct Site Operational Readiness Test	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks
	Procure & Manage Headquarter Facility						183.0		
	Conduct Headquarter Facility Requirements Analysis	Fixed Effort	2	10.0	20.0				Assumes 2 FTEs, 2 weeks
	Select Facility Site	Fixed Effort	2	10.0	20.0				Assumes 2 FTEs, 2 weeks
	Negotiate building leases and maintenance contracts	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks
	Conduct IT and Telecom Requirements Analysis	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks
	Design IT and Telecom Infrastructure	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks
	Manage procurement of goods and services	Fixed Effort	0.5	54.0	27.0				Assumes .5 FTE for 3 months. Includes office supplies, furniture, and other expenditures
	Manage preparation of site with office infrastructure	Fixed Effort	1	18.0	18.0				Assumes 1 FTE for 1 month
	Coordinate with contractors t i build out site	Fixed Effort	0.5	36.0	18.0				Assumes .5 FTE for 2 months
	Plan & Conduct Site Operational Readiness Test	Fixed Effort	2	10.0	20.0				Assume 2 FTEs, 2 weeks

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
4.0	**System Operations**						Project Total:	1949	
	System Operations						450		Assumes that 7 FTEs will be needed by 6F team across entire project for involvement in delivering System Ops capabilities. Includes design, test, model building. Vendor delivery days are not represented.
	Manage System Operations					450			
	Manage System Operations Project	Case-based estimate	1.5	300.0	450.0				Assumes 1.5 FTEs for 15 Months
	Grid Security, Reliability Management, Real Time Operations Capabilities						403		Assume package application
	Requirements Analysis	Estimating Factor	4.5	35.0	158				
	Select Vendor	Fixed Effort	2	10.0	20				Assume 2 people, 2 weeks
	Functional Design	Estimating Factor	4.5	50.0	225				
	Development (code, configure, unit test)	Case-based estimate	0	0.0	0				See HW, SW & Other - to be done by Vendor
	Assembly Test								See HW, SW & Other - to be done by Vendor
	Plan Assembly Test	Estimating Factor	0	0.0	0				
	Execute Assembly Test	Estimating Factor	0	0.0	0				
	Learn Product Customization and Test	Estimating Factor	0	0.0	0				
	System Operations Data Setup						450.0		5 FTE for 5 Months
	Plan RTO EMS Data Model & Displays					50.0			
	Develop Overall Data Model & Display Approach	Case-based estimate	5	10.0	50.0				
	Build RTO EMS Data Model & Displays					400.0			
	Design and Build Data Model & Displays	Case-based estimate	5	80.0	400.0				
	Design Business Policies & Procedures						330.0		
	Design Workflows for Processes, Activities and Tasks					180.0			
	Create Process Maps	Processes	9	10.0	90.0				Assume 9 processes per capability
	Identify Skill Requirements	Processes	9	5.0	45.0				Assume 9 processes per capability
	Identify Process Performance Metrics and Initial Targets	Processes	9	5.0	45.0				Assume 9 processes per capability
	Maintain Processes, Policies, and Rules					150.0			
	Track and Manage Changes to Processes, Policies & Rules	Months	15	4.0	60.0				Assumed 15 months
	Manage On-going Integration of Solution	Months	15	6.0	90.0				
	Design Jobs & Compensation						66.0		
	Identify and Document New Roles	Case-based estimate	8	2.0	16.0				Based on number of new job roles. Assume 8 new job roles.
	Map Roles to Responsibilities	Case-based estimate	8	3.0	24.0				Based on number of new job roles. Assume 8 new job roles.
	Determine K, S, As (knowledge, skills & abilities) for each new role	Case-based estimate	8	3.0	24.0				Based on number of new job roles. Assume 8 new job roles.
	Determine Profile Format/Interface with HR	Case-based estimate	1	2.0	2.0				
	Internal Training Development and Delivery						250.0		
						160.0			
	Develop DTS Training Scenarios	# of Scenarios	20	8.0	160.0				
	System Ops. Training Delivery					90.0			
	Coordination Support	Case-based estimate	1	20.0	20.0				Includes time to work with other vendors to coordinate training (e.g., ESCA)
	Logistics Preparation and Support	Case-based estimate	1	10.0	10.0				
	Conduct functional testing of database/economics/training material	Case-based estimate	1	20.0	20.0				
	Dispatcher Training Delivery – Trainers	Case-based estimate	1	40.0	40.0				Assumes training 20 users. 2 conducts, 10 people per class, 10 days of training, 2 FTEs to deliver

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	5.0 Market Operations						Project Total:	2244	
	Plan & Manage Project						450		Assumes that 8 FTEs will be needed by GF team across entire project for involvement in delivering Market Ops capabilities. Includes design, test, model building. Vendor delivery days are not represented.
	Plan & Manage Project	Estimating Factor	1.5	300.0	450				Assume 1.5 FTEs over 15 months
	Market Facilitation						250		Assume package application
	Requirements Analysis	Estimating Factor	2	40.0	80				
	Select Vendor	Fixed Effort	2	10.0	20				Assume 2 persons, 1 week
	Functional Design	Estimating Factor	2.5	60.0	150				
	Development (code, configure, unit test)	Case-based estimate			0				
	Assembly Test								
	Plan Assembly Test	Estimating Factor			0				
	Execute Assembly Test	Estimating Factor			0				
	Learn Product Customization and Test	Estimating Factor			0				
	Scheduling						250		Assume package application
	Requirements Analysis	Estimating Factor	2	40.0	80				
	Select Vendor	Fixed Effort	2	10.0	20				Assume 2 persons, 2 weeks
	Functional Design	Estimating Factor	2.5	60.0	150				
	Development (code, configure, unit test)	Case-based estimate			0				
	Assembly Test								
	Plan Assembly Test	Estimating Factor			0				
	Execute Assembly Test	Estimating Factor			0				
	Learn Product Customization and Test	Estimating Factor			0				
	Forecasting						20		Assume part of application provided under System Operations Project
	Requirements Analysis	Estimating Factor	1	5.0	5				
	Select Vendor	Fixed Effort	1	5.0	5				Assume 1 person, 5 days
	Functional Design	Estimating Factor	1	10.0	10				
	Development (code, configure, unit test)	Case-based estimate			0				
	Assembly Test								
	Plan Assembly Test	Estimating Factor			0				
	Execute Assembly Test	Estimating Factor			0				
	Learn Product Customization and Test	Estimating Factor			0				
	Market Operations Data Setup						245.0		
	Prepare Conversion Coordination Approach					45.0			
	Develop Overall Conversion Approach	Case-based estimate	1.5	10.0	15.0				
	Develop Detailed Conversion Coordination Plan	Case-based estimate	1.5	20.0	30.0				
	Coordinate & Validate Converted Data					200.0			
	Identify & Capture Required Business Data	Fixed Effort	4	20.0	80.0				
	Execute Conversion and Validate Results	Case-based estimate	4	30.0	120.0				
	Design Business Policies & Procedures						534.0		
	Design Workflows for Processes, Activities and Tasks					406.0			
	Create Process Maps	Processes	14	15.0	210.0				Assume 14 processes
	Identify Skill Requirements	Processes	14	10.0	140.0				Assume 14 processes
	Identify Process Performance Metrics and Initial Targets	Processes	14	4.0	56.0				Assume 14 processes
	Maintain Processes, Policies, and Rules					128.0			
	Track and Manage Changes to Processes, Policies & Rules	Months	16	4.0	64.0				Assumed 16 months
	Manage On-going Integration of Solution	Months	16	4.0	64.0				
	Design Jobs & Compensation						90.0		
	Identify and Document New Roles	Case-based estimate	8	3.0	24.0				Based on number of new job roles. Assume 8 new job roles.
	Map Roles to Responsibilities	Case-based estimate	8	4.0	32.0				Based on number of new job roles. Assume 8 new job roles.
	Detemine K, S, As (knowledge, skills & abilities) for each new ro	Case-based estimate	8	4.0	32.0				Based on number of new job roles. Assume 8 new job roles.
	Determine Profile Format/Interface with HR	Case-based estimate	1	2.0	2.0				
	Internal Training Development and Delivery						295.0		
	Market Ops. Training and Performance Support Design					50.0			
	Conduct Needs Analysis	Case-based estimate	2	10.0	20.0				Determine audience, content, delivery, etc.
	Create Standards	Case-based estimate	2	5.0	10.0				Development standards for program
	Design Training and Performance Support	Case-based estimate	2	10.0	20.0				Includes work schedule, training & performance support plan, design reviews and sign-off
	Market Ops. Training and Performance Support Development					160.0			
	Market Facilitation Capability	Case-based estimate	1	65.0	65.0				
	Scheduling Capability	Case-based estimate	1	65.0	65.0				
	Forecasting Capability	Case-based estimate	1	30.0	30.0				
	Market Ops. Training Delivery					85.0			
	Coordination Support	Case-based estimate	1	20.0	20.0				Includes time to work with other vendors to coordinate training
	Logistics Preparation and Support	Case-based estimate	1	10.0	10.0				
	Conduct functional testing of database/scenarios/training mate	Case-based estimate	1	15.0	15.0				Assumes build time is included in Tech Arch estimates, assumes data needed for Training db is provided and supported by Testing Team.
	Internal Users Training Delivery -- Trainers	Fixed Effort	1	40.0	40.0				Assumes training 20 users, 2 conducts, 10 people per class, 10 days of training, 2 FTEs to deliver
	Market Operations Product Test						110		Assumes need for testing of interfaces MO to others
	Product Test/Fix-It					110			
	Plan Product Test	Case-based estimate	1	30.0	30				
	Execute Product Test	Case-based estimate	1	40.0	40				
	Fix Defects	Case-based estimate	1	40.0	40				

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	6.0 Commercial Operations						**Project Total:**	**4459**	
	Plan & Manage Project						**366**		
	Plan & Manage Project	Estimating Factor			366				
	Metering & Measurement Data Capability						**422**		**Assume package application**
	Requirements Analysis	Estimating Factor			22				
	Select Vendor	Fixed Effort	1	30.0	30				
	Functional Design	Estimating Factor			60				
	Development (code, configure, unit test)	Case-based estimate	1	200.0	200				Revenue quality meter data not available in many cases. Quality of meter data to be verified (Database, Analysis, Validation & Exception reporting). Required to allocate and/or roll-up available data to standard intervals and zones.
	Assembly Test								
	Plan Assembly Test	Estimating Factor			41				
	Execute Assembly Test	Estimating Factor			55				
	Learn Product Customization and Test	Estimating Factor			14				
	Settlement & Billing Capability						**1921**		**Assume package application**
	Requirements Analysis	Estimating Factor			104				
	Select Vendor	Fixed Effort	1	60.0	60				
	Functional Design	Estimating Factor			285				
	Development (code, configure, unit test)	Case-based estimate	1	950.0	950				Estimated complexity is high due to: - Market settlements for congestion & balancing energy - Inadvertent calculations - Ancillary services provider of last resort - Grand-fathered contracts
	Assembly Test								
	Plan Assembly Test	Estimating Factor			195				
	Execute Assembly Test	Estimating Factor			260				
	Learn Product Customization and Test	Estimating Factor			67				
	Contract Management Capability					-	**98**		**Assume part of the Customer Interface - Integration required**
	Requirements Analysis	Estimating Factor			5				
	Select Vendor	Fixed Effort	0	0.0	0				
	Functional Design	Estimating Factor			15				
	Development (code, configure, unit test)	Case-based estimate	1	50.0	50				Configuration and integration with Customer Interface required to obtain settlement data for Contracts between - GridFlorida and Ancillary Service providers - Grand-fathered contracts
	Assembly Test								
	Plan Assembly Test	Estimating Factor			10				
	Execute Assembly Test	Estimating Factor			14				
	Learn Product Customization and Test	Estimating Factor			4				
	Commercial Operations Data Setup						**256.0**		
	Prepare Conversion Coordination Approach					40.0			
	Develop Overall Conversion Approach	Case-based estimate	1	20.0	20.0				
	Develop Detailed Conversion Coordination Plan	Case-based estimate	1	20.0	20.0				Assume Fixed Effort
	Coordinate & Validate Converted Data					216.0			
	Identify & Capture Required Business Data	Fixed Effort	1	96.0	96.0				Data from three utilities
	Execute Conversion and Validate Results	Case-based estimate	1	120.0	120.0				
	Design Business Policies & Procedures						**160.0**		
	Design Workflows for Processes, Activities and Tasks					96.0			
	Create Process Maps	Processes	12	5.0	60.0				Assume 12 processes
	Identify Skill Requirements	Processes	12	1.0	12.0				Assume 12 processes
	Identify Process Performance Metrics and Initial Targets	Processes	12	2.0	24.0				Assume 12 processes
	Maintain Processes, Policies, and Rules					64.0			
	Track and Manage Changes to Processes, Policies & Rules	Months	16	2.0	32.0				Assumed 16 months
	Manage On-going Integration of Solution	Months	16	2.0	32.0				
	Design Jobs & Compensation						**30.0**		
	Identify and Document New Roles	Case-based estimate	4	2.0	8.0				Based on number of new job roles. Assume 4 new job roles.
	Map Roles to Responsibilities	Case-based estimate	4	2.0	8.0				Based on number of new job roles. Assume 4 new job roles.
	Determine K, S, As (knowledge, skills & abilities) for each new re	Case-based estimate	4	3.0	12.0				Based on number of new job roles. Assume 4 new job roles
	Determine Profile Format/Interface with HR	Case-based estimate	1	2.0	2.0				
	Internal Training Development and Delivery						**309.0**		
	Commercial Ops. Training and Performance Support Design					21.0			
	Conduct Needs Analysis	Case-based estimate	1	8.0	8.0				Determine audience, content, delivery, etc.
	Create Standards	Case-based estimate	1	3.0	3.0				Development standards for program
	Design Training and Performance Support	Case-based estimate	1	10.0	10.0				Includes work schedule, training & performance support plan, design reviews and sign-off
	Commercial Ops. Training and Performance Support Development					220.0			
	Metering & Measurement Data Capability	Case-based estimate	1	40.0	40.0				
	Settlement & Billing Capability	Case-based estimate	1	180.0	180.0				
	Commercial Ops. Training Delivery					68.0			
	Coordination Support	Case-based estimate	1	25.0	25.0				Includes time to work with other vendors to
	Logistics Preparation and Support	Case-based estimate	1	5.0	5.0				
	Conduct functional testing of database/scenarios/training mate	Case-based estimate	1	18.0	18.0				Assumes build time is included in Tech Arch estimates, assumes data needed for Training db is provided and supported by Testing Team.
	Internal Users Training Delivery – Trainers	Case-based estimate	1	20.0	20.0				Assumes training 20 users, 2 conducts, 10 people per class, 10 days of training, 2 FTEs to deliver
	Commercial Operations Product Test						**897.0**		
	Product Test/Fix-It					**897**			
	Plan Product Test	Estimating Factor			117				
	Execute Product Test	Estimating Factor			390				
	Fix Defects	Estimating Factor			390				

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	7.0 Customer Interface Project						Project Total:	3507	
	Plan & Manage Project						290		
	Plan & Manage Project	Estimating Factor			290				
	Customer Interface Capability						1678		
	Customer Management/Customer Information Application					1069			Assume package application
	Requirements Analysis				58				
	Select Vendor		3	10.0	30				
	[illegible]				158				
	[illegible] (code, configure, unit test)	Case-based estimate	1	525.0	525				Based on input from RTO#1
	Assembly Test								
	Plan Assembly Test	Estimating Factor			108				
	Execute Assembly Test	Estimating Factor			144				
	Learn Product Customization and Test	Estimating Factor			37				
	Communication Management/Portal Interface					520			Assume package application
	Requirements Analysis	Estimating Factor			27				
	Select Vendor	Fixed Effort	3	10.0	30				Assume 3 people, 2 weeks
	Functional Design	Estimating Factor			75				
	Development (code, configure, unit test)	Case-based estimate	1	250.0	250				Based on input from RTO#2
	Assembly Test								
	Plan Assembly Test	Estimating Factor			51				
	Execute Assembly Test	Estimating Factor			69				
	Learn Product Customization and Test	Estimating Factor			18				
	Customer Interface Data Setup						256.0		
	Prepare Conversion Coordination Approach					40.0			
	Develop Overall Conversion Approach	Case-based estimate	1	25.0	25.0				
	Develop Detailed Conversion Coordination Plan	Case-based estimate	1	15.0	15.0				Assume Fixed Effort
	Coordinate & Validate Converted Data					216.0			Assumes 2 FTEs for 6 months
		Fixed Effort	1	96.0	96.0				
		Case-based estimate	1	120.0	120.0				
							144.0		
						80.0			
		Processes	10	5.0	50.0				Assume 5 processes for portal and 5 processes for customer interface for a total of 10
	Identify Skill Requirements	Processes	10	1.0	10.0				Assume 5 processes for portal and 5 processes for customer interface for a total of 10
	Identify Process Performance Metrics and Inith	Processes	10	2.0	20.0				Assume 5 processes for portal and 5 processes for customer interface for a total of 10
	Maintain Processes, Policies, and Rules					64.0			
	Track and Manage Changes to Processes, Policies	Months	16	2.0	32.0				Assumed 16 months
	Manage On-going Integration of Solution	Months	16	2.0	32.0				
	Design Jobs & Competencies						30.0		
	Identify and Document New Roles	Case-based estimate	4	2.0	8.0				Based on number of new job roles, Assume 4 new job roles.
	Map Roles to Responsibilities	Case-based estimate	4	2.0	8.0				Based on number of new job roles. Assume 4 new job roles.
	skills & abilities	Case-based estimate	4	3.0	12.0				Based on number of new job roles. Assume 4 new job roles
	Determine Profile Format/Interface with HR	Case-based estimate	1	2.0	2.0				
	[illegible]						269.0		
	Customer Interface Training and Performance Support Design					21.0			
	Conduct Needs Analysis	Case-based estimate	1	8.0	8.0				Determine audience, content, delivery, etc.
	Create Standards	Case-based estimate	1	3.0	3.0				Development standards for program
	Design Training and Performance Support	Case-based estimate	1	10.0	10.0				Includes work schedule, training & performance support plan, design reviews and sign-off
	Customer Interface Training and Performance Support Development					180.0			
	Customer Interface Capability	Case-based estimate	1	180.0	180.0				Excluding contract management in customer application
	Customer Interface Training Delivery					68.0			
	Coordination Support	Case-based estimate	1	25.0	25.0				Includes time to work with other vendors to coordinate training
	Logistics Preparation and Support	Case-based estimate	1	5.0	5.0				
	Conduct functional testing of database/scenario	Case-based estimate	1	18.0	18.0				Assumes build time is included in Tech Arch estimates, assumes data needed for Training db is provided and supported by Testing Team.
	Internal Users Training Delivery – Trainers	Case-based estimate	1	20.0	20.0				Assumes training 20 users 2 conducts, 10 people per class, 10 days of training, 2 FTEs to deliver
	Portal Usability Test						50.0		
	Portal Usability Test					50.0			
	Conduct Usability Test of Portal	Case-based estimate	1	50.0	50.0				Assuming portal will be the front end for accessing the systems that comprise the overall business solution. Assuming users include individuals transacting Com Ops and Customer Interface processes as well as Customers viewing appropriate information.
	Customer Training Development and Delivery						263.0		
	Customer Training and Performance Support Development					163.0			
	[illegible]	Case-based estimate	1	10.0	10.0				
	Conduct Customer Role and Task Analysis	Case-based estimate	1		18.0				
	Create standards for Customer training documentation		1		5.0				
	Develop Customer training documentation	Case-based estimate	1	150.0	150.0				Assumes overview of Customer Registration application, settlements training, asset management training, system ops and market ops training, process documentation reflecting Customer roles, instruction on using/navigating the portal, viewing appropriate information and reports. Assumes 10 days of informational/training sessions. Assumes 20 hours development time per hour of delivery. 10days x 6hours per day = 60 hours delivery x 20 hours development = 1200 devel hours/8 = 150 days
	Customer Training Delivery					80.0			
	Train the Trainer delivery	Case-based estimate	2	15.0	30.0				Assumes 15 days of delivery (10 days to review content and 5 days to review training techniques and practice/feedback), 2 FTEs to deliver
	Internal Users Training Delivery – Trainers	Case-based estimate	2	25.0	50.0				Assumes 5 conducts, 5 days of training for each conduct, 2 FTEs to deliver
	Customer Readiness						48.0		
	Customer Readiness					48.0			
	Customer Readiness Activities	Case-based estimate	1	48.0	48.0				Assumes 1 FTE at 2 days per week for 6 months, working on communications, presentations to market participants, coordinating with the organization, market monitor, regulators to get them ready for the "go live"
	Customer Information System Product Test						579		
	Product Test/Pre-it					579			
	Plan Product Test	Estimating Factor			76				
	Execute Product Test	Estimating Factor			252				
	Fix Defects	Estimating Factor			252				

No.	Project/Work Package/Task/Sub-Tas	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
8.0	**Asset Optimization Project**						Project Total:	1796	
	Plan & Manage Project						89		
	Plan & Manage Project	Estimating Factor			89				
	Network Planning Data Capability						206		Assume package application
	Requirements Analysis	Estimating Factor	1		11				Similar scope to RTO#1
	Select Vendor	Fixed Effort	1	10.0	10				Assume 1 person, 2 weeks
	Functional Design	Estimating Factor			30				Similar scope to RTO#1
	Development (code, configure, unit test)	Case-based estimate	1	100.0	100				Similar scope to RTO#1/RTO#2
	Assembly Test								
	Plan Assembly Test	Estimating Factor			21				
	Execute Assembly Test	Estimating Factor			27				
	Learn Product Customization and Test	Estimating Factor			7				
	Work Definition Capability						123		There will be no Asset Management System. GF expects to do this manually without a system.
	Requirements Analysis	Estimating Factor			33				
	Select Vendor	Fixed Effort	1	0.0	0				
	Functional Design	Estimating Factor							
	Development (code, configure, unit test)	Case-based estimate	1	0.0	0				
	Assembly Test								
	Plan Assembly Test	Estimating Factor			0				
	Execute Assembly Test	Estimating Factor			0				
	Learn Product Customization and Test	Estimating Factor			0				
	Work Execution Capability						324		Assume custom development of Access DB application
	Requirements Analysis	Estimating Factor			16				
	Select Vendor	Fixed Effort	3	10.0	30				Assume 3 people, 2 weeks
	Functional Design	Estimating Factor			45				
	Development (code, configure, unit test)	Case-based estimate	1	150.0	150				Based on implementing a work tracking application (not full Work or Maintenance Management)
	Assembly Test								
	Plan Assembly Test	Estimating Factor			31				
	Execute Assembly Test	Estimating Factor			41				
	Learn Product Customization and Test	Estimating Factor			11				
	Asset Optimization Data Setup						340.0		
	Prepare Conversion Coordination Approach					40.0			
	Develop Overall Conversion Approach	Case-based estimate	1	25.0	25.0				
	Develop Detailed Conversion Coordination Plan	Case-based estimate	1	15.0	15.0				Assume Fixed Effort
	Coordinate & Validate Converted Data					300.0			
	Identify & Capture Required Business Data	Fixed Effort	3	40.0	120.0				Assume asset data gathered from 3 companies
	Execute Conversion and Validate Results	Case-based estimate	3	60.0	180.0				
	Design Business Policies & Procedures						156.0		
	Design Workflows for Processes, Activities and Tasks					96.0			
	Create Process Maps	Processes	12	5.0	60.0				Assume 12 processes (4 per area)
	Identify Skill Requirements	Processes	12	1.0	12.0				Assume 12 processes (4 per area)
	Identify Process Performance Metrics and Initial Targets	Processes	12	2.0	24.0				Assume 12 processes (4 per area)
	Maintain Processes, Policies, and Rules					60.0			
	Understand & manage Utilities Work Policies and Rules	Fixed Effort	3	20.0	60.0				Assume 3 people for 4 weeks
	Design Jobs & Competencies						30.0		
	Identify and Document New Roles	Case-based estimate	4	2.0	8.0				Based on number of new job roles. Assume 4 new job roles
	Map Roles to Responsibilities	Case-based estimate	4	2.0	8.0				Based on number of new job roles. Assume 4 new job roles.
	Detemine K, S, As (knowledge, skills & abilities) for each new role	Case-based estimate	4	3.0	12.0				Based on number of new job roles. Assume 4 new job roles.
	Determine Profile Format/Interface with HR	Case-based estimate	1	2.0	2.0				
	Internal Training Development and Delivery						289.0		
	Asset Optimization Training and Performance Support Design					21.0			
	Conduct Needs Analysis	Case-based estimate	1	8.0	8.0				Determine audience, content, delivery, etc.
	Create Standards	Case-based estimate	1	3.0	3.0				Development standards for program
	Design Training and Performance Support	Case-based estimate	1	10.0	10.0				Includes work schedule, training & performance support plan, design reviews and sign-off
	Asset Optimization Training and Performance Support Development					200.0			
	Network Planning	Case-based estimate	1	30.0	30.0				
	Work Definition	Case-based estimate	1	85.0	85.0				
	Work planning	Case-based estimate	1	85.0	85.0				
	Asset Optimization Training Delivery					68.0			
	Coordination Support	Case-based estimate	1	25.0	25.0				Includes time to work with other vendors to coordinate training
	Logistics Preparation and Support	Case-based estimate	1	5.0	5.0				
	Conduct functional testing of database/scenarios/training materi	Case-based estimate	1	18.0	18.0				Assumes build time is included in Tech Arch estimates, assumes data needed for Training db is provided and supported by Testing Team.
	Internal Users Training Delivery -- Trainers	Case-based estimate	1	20.0	20.0				Assumes training 20 users, 2 conducts, 10 people per class, 10 days of training, 2 FTEs to deliver
	Asset Optimization Product Test						239		
	Product Test/Fix-It					239			
	Plan Product Test	Estimating Factor			31				
	Execute Product Test	Estimating Factor			104				
	Fix Defects	Estimating Factor			104				

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
9.0	**Corporate Services Project**						Project Total:	2304	
	Project Management						190		
	Plan & Manage Project	Estimating Factor			190				
	Finance & General Accounting Capability						750		
	Financial System Application					618			Assume package application install
	Requirements Analysis	Estimating Factor			33				
	Select Vendor	Fixed Effort	1	30	30				
	Functional Design	Estimating Factor			90				
	Development (code, configure, unit test)	Case-based estimate	1	300	300				Based on starting point from RTO#1. Increased complexity includes: - Property/Fixed Asset Accounting - Misc. Invoicing - Credit Control/Assessment - Job Casting - Budgeting System Note - includes A/P, A/R, and G/L
	Assembly Test								
	Plan Assembly Test	Estimating Factor			62				
	Execute Assembly Test	Estimating Factor			82				
	Learn Product Customization and Test	Estimating Factor			21				
	Manage Facilities and Purchasing Application					133			
	Requirements Analysis	Estimating Factor			7				Assume application purchase and configuration
	Select Vendor	Fixed Effort	1	15	15				Application - Time & Expenses
	Functional Design	Estimating Factor			18				
	Development (code, configure, unit test)	Case-based estimate	1	60	60				Configuration of Time & Expenses
	Assembly Test								
	Plan Assembly Test	Estimating Factor			12				
	Execute Assembly Test	Estimating Factor			16				
	Learn Product Customization and Test	Estimating Factor			4				
	Payroll & Human Resources						324		Assume payroll and benefits is outsourced
	Human Resources Management Application					93			
	Requirements Analysis	Estimating Factor			4				
	Select Vendor	Fixed Effort	1	15	15				
	Functional Design	Estimating Factor			12				
	Development (code, configure, unit test)	Case-based estimate	1	40	40				Develop simple custom Personnel database - Complexity estimated at low
	Assembly Test								
	Plan Assembly Test	Estimating Factor			8				
	Execute Assembly Test	Estimating Factor			11				
	Learn Product Customization and Test	Estimating Factor			3				
	Time and Expense Reporting Application					148			
	Requirements Analysis	Estimating Factor			7				Assume application purchase and configuration
	Select Vendor	Fixed Effort	1	30	30				Application - Time and Expenses
	Functional Design	Estimating Factor			18				
	Development (code, configure, unit test)	Case-based estimate	1	60	60				Configuration of Time and Expenses
	Assembly Test								
	Plan Assembly Test	Estimating Factor			12				
	Execute Assembly Test	Estimating Factor			16				
	Learn Product Customization and Test	Estimating Factor			4				
	Payroll & Benefits Application					83			Assume payroll and benefits is outsourced
	Design Payroll and Benefits Process	Fixed Effort	1	20.0	20.0				Assume low level of complexity
	Design Executive Payroll and Benefits Process	Fixed Effort	1	15.0	15.0				
	Select Vendor to perform Payroll and Benefits functions	Fixed Effort	1	20.0	20.0				
	Implement the Payroll and Benefit process	Fixed Effort	1	28.0	28.0				
	Corporate Administration						50.0		
	Manage Internal Audits					50			
	Design internal audit requirements and schedule	Fixed Effort	1	20.0	20.0				
	Select Vendor to perform internal audits	Fixed Effort	1	10.0	10.0				
	Develop a post-Independence Day audit schedule	Fixed Effort	1	20.0	20.0				
	[illegible]						118		
	Problem Tracking Application					118			Assume package software used to track both internal and external problem tickets
	Requirements Analysis	Estimating Factor			5				
	Select Vendor	Fixed Effort	1	30	30				
	Functional Design	Estimating Factor			14				
	Development (code, configure, unit test)	Case-based estimate	1	45	45				Based on RTO experience
	Assembly Test								
	Plan Assembly Test	Estimating Factor			9				
	Execute Assembly Test	Estimating Factor			12				
	Learn Product Customization and Test	Estimating Factor			3				

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumption	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	Design Business Policies & Procedures						176.0		
	Design Workflows for Processes, Activities and Tasks					112.0			
	Create Process Maps	Processes	14	5.0	70.0				Assume 14 processes across Corp Services
	Identify Skill Requirements	Processes	14	1.0	14.0				Assume 14 processes across Corp Services
	Identify Process Performance Metrics and Initial Targets	Processes	14	2.0	28.0				Assume 14 processes across Corp Services
	Maintain Processes, Policies, and Rules					64.0			
	Track and Manage Changes to Processes, Policies & Rules	Months	16	2.0	32.0				Assumed 16 months
	Manage On-going Integration of Solution	Months	16	2.0	32.0				
	Design Jobs & Compensation						79.0		
	Identify and Document New Roles	Case-based estimate	11	2.0	22.0				Based on number of new job roles. Assume 7 new job roles.
	Map Roles to Responsibilities	Case-based estimate	11	2.0	22.0				Based on number of new job roles. Assume 7 new job roles.
	Determine K, S, As (knowledge, skills & abilities) for each new rol	Case-based estimate	11	3.0	33.0				Based on number of new job roles. Assume 7 new job roles
	Determine Profile Format/Interface with HR	Case-based estimate	1	2.0	2.0				
	Internal Training Development and Delivery						239.0		
	Corporate Services Training and Performance Support Design					21.0			
	Conduct Needs Analysis	Case-based estimate	1	8.0	8.0				
	Create Standards	Case-based estimate	1	3.0	3.0				
	Design Training and Performance Support	Case-based estimate	1	10.0	10.0				
	Corporate Services Training and Performance Support Development					150.0			
	Financial System Application	Case-based estimate	1	20.0	20.0				Estimate assumes that training documentation will be included in package software. Assume some time to customize documentation
	New Employee Orientation Job Aids	# of Job Aids	6	5.0	30.0				Includes New Hire orientation, email and other office equipment, voice/phone systems, etc.
	Human Resources Management Application	Case-based estimate	1	20.0	20.0				Estimate assumes that training documentation will be included in package software. Assume some time to customize documentation.
	Time and Expense Reporting Application	Case-based estimate	1	20.0	20.0				Estimate assumes that training documentation will be included in package software. Assume minimal time to customize documentation.
	Purchasing & Facilities Application	Case-based estimate	1	20.0	20.0				Estimate assumes that training documentation will be included in package software. Assume minimal time to customize documentation.
	Reporting Tools	Case-based estimate	1	20.0	20.0				Estimate assumes that training documentation will be included in package software. Assume some time to customize documentation for RTO #1 use.
	Performance Monitoring/Budgeting/Other	Case-based estimate	1	20.0	20.0				Estimate assumes that training documentation will be included in package software. Assume some time to customize documentation for RTO #1 use.
	Corporate Services Training Delivery					68.0			
	Coordination Support	Case-based estimate	1	25.0	25.0				Includes time to work with other vendors to coordinate training
	Logistics Preparation and Support	Case-based estimate	1	5.0	5.0				
	Conduct functional testing of database/scenarios/training material	Case-based estimate	1	18.0	18.0				
	Internal Users Training Delivery -- Trainers	Case-based estimate	1	20.0	20.0				Assumes training 20 users, 2 conducts, 10 people per class, 10 days of training, 2 FTEs to deliver
	Corporate Services Product						377		
	Product Test/Fix-It					377			
	Plan Product Test	Estimating Factor			49				
	Execute Product Test	Estimating Factor			164				
	Fix Defects	Estimating Factor			164				

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
10.0	**Transition & Conversion Project**						Project Total:	1110.0	
	Plan and Execute Cutover						210.0		
	Plan for Cut-over					50.0			
	Create Cut-over Approach	Case-based estimate	1	10.0	10.0				Fixed effort
	Define Go/No-go Criteria	Case-based estimate	1	10.0	10.0				Fixed effort
	Create and Revise Detailed Cut-over Plan	Case-based estimate	3	10.0	30.0				Assumes 3 revisions, 10d each
	Execute Cut-over					160 0			
	Execute and Analyze Mock Cutovers	Cutovers	2	20.0	40.0				Assumes 2 cutover, 5 days to follow up
	Monitor Cut-over Activities	Cutovers	2	30.0	60.0				Assumes 2 cutovers, 2 weeks to monitor
	Follow-up on Issues After Cut-over	Cutovers	2	30.0	60.0				Assumes 2 cutovers, 2 weeks to follow-up
	Operational Preparation						900.0		
	Provide support of business processes for full operational capabilities after go live	Case-based estimate	1	900.0	900.0				Assumes adding 10 people for 4 months, 5 people for 2 months

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
11.0	**Technical Architecture Project**					**Project Total:**		**3333**	
	Technical Architecture Integration						3333		
	Technical Infrastructure					1234			
	Setup Development Environments - Commercial Ops & Customer Interface	Based upon number of development, test, environments for each application, includes time to config hw & install sw 4 environments (build, test, stage, train) for each package * 3 applications (Settlement & Billing, Portal, Customer Information)	12	12.0	144.0				Includes setup of servers and the environments/software to support the applications. Assumed that Contract Management is done with MS Access and/or is part of Customer System, therefore no special environment setup
	Setup Development Environments - Corporate Services	Based upon number of development, test, environments for each application, includes time to config hw & install sw 4 environments (build, test, stage, train) for each package * 3 applications (HR Mgmt System, Finance & Acctg, Time Reporting)	12	12.0	144.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Development Environments - Asset Optimization	Based upon number of development, test, environments for each application, includes time to config hw & install sw 4 environments (build, test, stage, train) for each package * 2 applications (Asset Management and Work Tracking)	8	14.0	112.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Test Environments - Market Operations	Based upon number of development, test, environments for each application, includes time to config hw & install sw 3 environments (test, stage, train) for each package * 3 applications (OASIS, Scheduling, and Bidding)	9	14.0	126.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Commercial Ops & Customer Interface	1 Production Environment, but much more complex due to volume and additional hardware, 3 applications	3	50.0	150.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Corporate Services	1 Production Environment, 3 Applications	3	40.0	120.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Asset Management	1 Production Environment, 2 Applications	2	40.0	80.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Market Operations	1 Production Environment, 3 applications	3	14.0	42.0				Includes the setup of servers and the environments/software to support the applications
	Setup Infrastructure Environment	Estimate is three weeks for each major component. Components are the backup system, monitoring system, scheduling system, and security system. Installation of the SAN is covered by Datalink services estimated in the HW/SW section and therefore is not included.	4	15.0	60.0				Includes setup of hardware and configuration of the software components.
	Project Web Site	Status Reporting, NetMeeting, etc. on Central Location for Distant Locations	18	9.0	162.0				Hardware and software setup
	RTO #1 Administrative Environment Setup	Create/Install File Servers, Printers, LAN, Configure Security at project location	1	30.0	30.0				Assume that project site will NOT be at RTO #1 headquarters originally.
	Technical Infrastructure SME Time (Procurement)	4 days per month - life of project	16	4.0	64.0				Assume 16 months
	Security Architecture					124.0			

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	Security	Uses setup environment to build comprehensive security plan covering requirements - digital certificates, secure communications, etc.	1	60.0	60.0				Size-based estimate from RTO#3
	Security Architect SME Time	4 days per month - life of project	16	4.0	64.0				Assume 16 months
	Performance					354.0			
	Application Performance Testing	Assume testing/tuning for all packaged applications . # of package apps	10	20.0	200.0				Excludes System Operations and Market Operations.Assumed that they will be performance tested by the vendor off-site
	Integration Performance Testing	Complete Performance Testing of Systems, Interfaces, Etc.	1	90.0	90.0				Includes All appliactions
	Performance SME Time	4 days per month - life of project	16	4.0	64.0				Assume 16 months
	Interface Architecture					129.0			
	Point to Point Interface Architecture	Standardize architecture approach for interfaces between System Ops, Comm Ops, Customer Interface	1	25.0	25.0				
	Portal Integration	Number of Applications = 4	4	10.0	40.0				Portal to integrate with Settlement & Billing, System Operations, Transmission Access Operations, Customer Information (4)
	Interface Architect SME Time	Life of project, 4 days a month	16	4.0	64.0				Assume 16 months
	Operations/Management Architecture					1348.6			
	Technology Management	Case-based estimate % of Total Workdays - Support for test/implementation environments	6%	14310.2	859				Percentage of total Commercial Operations + total Corporate Services days+total Asset Optimization days + total Market Operations days + total Customer Interface days
	DBA Support at RTO #1	Full time DBA for life of project	1	216.0	216.0				Assume 12 months of full time DBA support. DBA support not required for entire life of project.
	Define DR Requirements By Application	Total Number of Applications = 10	10	5.0	50.0				Disaster Recover definition for System and Market Operations to be done by vendor and are not included in this estimate.
	Backup/Recovery Implementation/Testing	Total Number of Applications = 10	10	16.0	160.0				Test the ability to successfully backup and recover systems.
	Operations Architect SME Time	4 days per month - life of project	16	4.0	64.0				Assume 16 months lifecycle of project
	Plan Disaster Recovery Procedures					108.0			
	Design Disaster Recovery Procedures	Case-based estimate	2	54.0	108.0				Assumes 2 FTEs for 3 months
	Develop and Maintain Standards					35.0			
	Develop and Maintain GUI Standards	Fixed Effort - 3 weeks	3	5.0	15.0				Assumes re-use from other RTO implementation
	Develop and Maintain Data Definition Standards	Fixed Effort - 4 weeks	4	5.0	20.0				Assumes re-use from other RTO implementation

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
12.0	**Integration Architecture, Test & Simulation Project**						**Project Total:**	**2618**	
	Cross-Capability Integration Testing						**608.0**		
	Define Cross-Capability Integration Test Approach					23.0			
	Define Cross-Package Test Strategy	Fixed Effort	1	5.0	5.0				
	Define Test Plan	Projects	6	3.0	18.0				Coordinate across 6 core project (System Ops, Market Ops, Commercial Ops, Corp Svcs, Customer & Asset Optimization)
	Define Cross-Capability Integration Test Model					260.0			
	Define Test Cycles	Cycles	5	2.0	10.0				
	Create Conditions and Test Scripts	Scripts	25	5.0	125.0				
	Define Test Data and Expected Results	Scripts	25	5.0	125.0				
	Execute Cross-Capability Integration Test					325.0			
	Execute Test Scripts	Scripts	25	5.0	125.0				
	Identify & Fix SIRs	SIRs (5/script)	125	1.0	125.0				Assume approx. 5 SIRs per script
	Follow-up on SIR Completion / Regression Test	Scripts	25	3.0	75.0				
	Simulation Planning						**260.0**		
	Define Simulation Approach	Fixed Effort	1	15.0	15.0				1 FTE for 3 weeks
	Develop Detailed Simulation Plan	Fixed Effort	3	15.0	45.0				3 FTE for 3 weeks
	Prepare Supporting Materials	Fixed Effort	5	40.0	200.0				5 FTE for 8 Weeks
	Support Simulation						**1600.0**		
	Support Simulation	Fixed Effort	40	40.0	1600.0				Assume 40 FTEs for 8 weeks
	Design Integration Architecture						**150.0**		
	Define Integration/Interfaces					120.0			
	Define Integration/Architecture	Fixed Effort	1	120.0	120.0				Assume 1 FTE for 24 weeks
	Confirm Supporting Architectures for Capabilities					30.0			
	Confirm Application & Interface Architecture	Application Areas	6	5.0	30.0				Six high-level app arch areas: System Operations, Commercial Operations, Corporate Services, Market Operations, Customer Interface, Asset Optimization

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
13.0	**Program Management**					Project Total:		2434	
	Program Management						2434		
	Manage Program	Estimating Factor	1	27042	2434				9% of total days.

Project/Capability	HW	SW	Other	Total	Comments

The following changes were made to the end state estimate post June 7th meeting.

The end state was not essentially changed, except where there were errors. The end state has not been adjusted for R1.

Facilities changes - Reduced from $10,932,360 to $5,131,366

(1) $500,000 was removed from the Control Center facility. It was for telecomm operating expenses and belongs in the Operating Budget

(2) Decreased lease costs for Control Center and Headquarters based on three months lease only. See Facilities for additional detail.

(3) $140,000 was removed from System Operations for Mapboard upgrade, as it was/is already covered under Facilities - Control Center upfit.

(4) Removed upfit charge estimated on Headquarters. Assuming included in lease cost per: FPL.

System Operations

Recorder from $32,000 to $80,000 (more accurate estimate)

(2) Increased Telecommunications Infrastructure from 100,000 to 500,000 (more accurate estimate)

(3) Added $200,00 for Outage Scheduling (long-run in advance) based on 50,00 for software and 150,000 for integration

(4) June 15th - minor decrease in First Release numbers. Increase in end state due to allocation of some EMS SW and Labour to end state for functions not in Release 1 (see System Operations Cost Summary &

Cost Summary - FPL.

Asset Optimization

(1) Increased estimate for PSSE software to 250,000 (instead of 200,000), based on estimate from FPL. Hardware already in estimate.

Operating Budget

(1) Updated 3 sections in 2003 Operating Budget: changed legal fees to account for $8M being spent in R1, changed market monitor outsourcing fees to reflect 3 board and $500K estimate, and updated facilities fees to reflect new assumptions (change in square footage for Control Center from 38,000 to 45,000, change in in square footage for Headquarters from 37,500 to 25,000)

(2) Added a placeholder in 2003 Operating Budget to capture Lease Back Arrangement Fees. This field is blank until these numbers are known.

Organization

(1) Total organization size went up from 189 to 190.

Costs to Date

(1) Updated the money spent to date (to end of May) based on new information from applicants. See spreadsheet that documents this information.

Estimating Factors * Note: These are approximate. Some are used in the estimate directly & some are general guidance.		
The following percentages are based on Functional Design thru Development for Software Configuration		
Program Management	9%	
Project Management	9%	
Requirements Analysis	8%	
Plan Application Assemby Test	15%	Assembly Test
Prepare and Execute Application Assembly Test	20%	Assembly Test
Functional Design	30%	
Learning Product Customization and Test	7%	
Product Test Fix	0%	
Plan Capability Product Test	7.5%	Product Test
Prepare and Execute Capability Product Test	25%	
Perform Capability Product Test Fixes	25%	
Workdays per Month		
Workdays per month	18	
Functional Architechture QA/Integration Testing/Fixit	40%	

Costs incurred by Applicants and GF LLC to end of May, 2001

(Information from FPC (Bill Slusser), FPL (Bob Croes), and Teco (Tom Salisbury) - for applicants
Information for GF LLC from Board of Managers - June 13th

FPL			
	To end of May, 2001	3,915,591	
	May, 2001		
	FPL Total	3,915,591	
Teco	Year 2000	1,356,000	
	Year 2001 to end of May	1,061,000	
	Teco Total	2,417,000	
FPC	Costs through end of May	1,708,827	
	FPC Total	1,708,827	
GF LLC	Costs through end of May	1,000,000	Board Selection, Consultant & Insurance Costs
		1,000,000	
	TOTAL FOR 3 APPLICANTS	9,041,418	

**** Note: Other companies may join GridFlorida. If they do, GF must reimburse their costs to join. This is an unknown amount at this point, partly as it is unknown how many/who may join.**

GridFlorida System Operations Estimates -- Hardware Costs

Component	FPL SCC Project	GF Requirement	Comment
	SCC/Backup Systems Hardware		
Phase 1 System	2,319,811	2,319,811	Full requirement
DMS Servers (Compaq)		-260,967	Distribution servers & OS
Emergency Backup System	886,441	443,221	50% allocated from FP&L backup
Additional Compaq Allowance	-65,000	-50,724	Compaq allowance in original procurement
Subtotal System Hardware (UNIX)	3,141,252	2,451,340	
Compaq List Price Adder		2,262,776	48% Compaq discount in original procurement
Total System Hardware (UNIX	3,141,252	4,714,116	
NT Servers	224,821	224,821	Dell procurement; full requirement
Dispatcher's PCs	150,000	150,000	Dell procurement;full requirement
Adder from Base Bid	267,101	267,101	Unknown adder origin; full requirement
Total Dell HW	641,922	641,922	
Total HW	3,783,174	5,356,038	
	Other EMS Hardware		
New GF System Operations		350,000	Vendor estimate
Total Incremental EMS Hardware Costs		5,706,038	
	Other Hardware		
Mapboard		140,000	Mauell upgrade
Voice Recorder		32,000	Addition to Main Control Center
Telecommunications Infrastructure		100,000	Routers and switch equipment
Total Other Hardware		272,000	
Grand Total Hardware		5,978,038	

Florida Power & Light System Control Center
(Information from Ray Falcon)

Assumptions:
1) Assume warranty period of 5 yrs (5 day X 9 hour X next day response)

	COST
Phase 1 System	$2,319,811
Emergency Backup System	$886,441
Additional Compaq Allowance	($65,000)
Total System Hardware (UNIX)	$3,141,251
NT Servers	$224,821
Dispatcher's PC's	$150,000
Adder from Base Bid	**$267,101**
Total	**$3,783,173**

Summary of System Operations Costs - first release and second release

(Based on decisions made at the June 6th and 7th meeting)

		FIRST RELEASE	SECOND RELEASE	ASSUMPTIONS
Allocated Costs			(**Note: end state numbers include all numbers)	
	Hardware	0		
	Software	5,185,446		From Cost Summary - FPL
	Other - Labour	4,691,921		From Cost Summary - FPL
Incremental Costs to prepare EMS for GF plus some Allocated Costs				
	Incremental Hardware		5,706,038	New HW for GF - see SO-HW sheet for details
	Incremental Software		1,500,000	Mid-point of ESCA estimate & includes 248,620 nonsharable licenses from Cost Summary - FPL
	Allocated Generation Software (50% Alloc)		502,999	From Cost Summary - FPL
	Generation SW License - non-Transferable		280,988	From Cost Summary - FPL
	Other (Vendor time & expenses)		1,250,000	Mid-point of ESCA estimate
	Allocated Labour		604,277	From Cost Summary - FPL
Sys Ops Other Costs				
	Database Management SW (Oracle)		700,000	
	Telecommunications Infrastructure		500,000	
	Voice Recorder	80,000		
	Mapboard Upgrade (Mauell) (included in Control Center Facility costs)	0	0	
Sys Ops - Outage Scheduler				
	Hardware & Software	50,000		
	Estimated Labour (approx.) (for interfaces, integration, set-up)	150,000		
	TOTALS	10,157,367	11,044,302	

** Note: *Plus estimated 974 workdays to implement Sys Ops (project management,* requirements analysis, process & procedures design, data conversion, training, etc.)
** Database Management SW (Oracle) is not required until GF has its own hardware (per Ray Falcon)
** No maintenance fee in the first 2 years due to a 2 year warranty

RTO #1

COST SUMMARY - FPL - 38

SYSTEM SOFTWARE COST SUMMARY

		% of Total Cost
Distribution Total	$3,701,329	26%
Generation Software Total	$1,005,998	10%
Generation License Total	$280,988	
Transmission Total	$2,369,349	18%
Total of System to be allocated	$6,112,479	46%
Additional ESCA Licenses	$248,620	
System Software Total	$13,470,142	100%

LABOR EXPENSES

	FPL Payroll	Consultant	ESCA	Training	Totals
Distribution Total	$1,550,601	$467,699	$4,227,451	$137,181	$6,382,932
Generation Software Total	$305,189	$51,507	$832,057	$99,000	$1,287,753
Transmission Total	$1,196,105	$213,589	$3,261,064	$105,819	$4,776,576
FPL System Totals	$3,051,895	$732,794	$8,320,572	$342,000	$12,447,261

GRID FLORIDA SYSTEM COSTS- NO HARDWARE

Allocation Percentage based on Transmission Points 46.07%

	First Release	End State	System Total
Allocated System Cost	$2,816,096.81		
Transmission Only Software	$2,369,349		
Generation Software(50% Allocation)		$502,999	
Generation Software License - Non transferable(see Note)		$280,988	
Non sharable ESCA licenses (see Note)		$248,620	
System Software Total	$5,185,446	$1,032,607	$6,218,053

Note--Costs for Generation and "Non sharable" *licenses may be obtained as an incremental* costs from ESCA at some reduced cost.

Labor Costs (End state allocated at 50% for Gen)	First Release	End State	Totals
FPL	$1,196,105	$152,595	$1,348,699
Consultant	$213,589	$25,753	$239,342
ESCA	$3,261,064	$416,029	$3,677,093
Training(20% of total for start up)	$21,163.79	$9,900	$31,064
Totals	$4,691,921	$604,277	$5,296,198
TOTAL SYSTEM COSTS TO GRID FLORIDA	$9,877,367	$1,636,883	$11,514,250

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	First Release							
Project/Component	**Internal %**	**External %**	**Estimated Days**	**Internal Days**	**External Days**	**Labor**	**HW, SW, Facilities & Other****	**Comments**
Operationalizing the Business Project	80%	20%	1331	1065	264	$ 1,011,332	6,150,000	Approx 70% of Operationalize the Business Project Required
Establish Legal Entity & Develop Governance Model			0	0	0			Assume 75% of original HW, SW, Other costs for audits and start up legal fees
File with FERC & Manage Filing			0	0	0			
Consummate Agreements			0	0	0			
Develop Brand & Image			0	0	0			
Develop Budgets			0	0	0			
Certify Operations			0	0	0			
Design & Maintain Rules & Procedures			0	0	0			
Organization & People Project	60%	40%	1125	675	450	$ 1,147,296	5,853,600	Approximately 80% of the Organization and People required; Assume 80% of original for Other (primarily outsourced items
Plan and Select Board & Transition			0	0	0			e.g. recruiting, searches, and moving/relocation costs)
Recruit Management & Board			0	0	0			
Design HR Policies/Practices			0	0	0			
Design Organization			0	0	0			
Design Compensation			0	0	0			
Develop Sourcing Strategy			0	0	0			
Recruit Personnel			0	0	0			
Communications			0	0	0			
Facilities Project	85%	15%	250	212	37	$ 173,472	3,505,066	Reduction for R1 varies depending on facility (e.g. headquarters or
Procure & Manage Project Space			0	0	0			control center, etc.) See R1 Facilities & Systems spreadsheet
Confirm Control Center Facility Requirements			0	0	0			for assumptions behind the reductions.
Contract Control Center Site & Vendors			0	0	0			Reduce project labour by 40%, due to less complexity re: facilities.
Design IT / Telecom Infrastructure			0	0	0			
Upgrade Control Center Facility			0	0	0			
Test Site			0	0	0			
Procure & Manage Backup Facility			0	0	0			
Procure & Manage Headquater Facility			0	0	0			
System Operations*	60%	40%	974	585	390	$ 993,735	10,157,367	Reduced project labor by 50% based on reduced scope in Sys. Ops
System Operations			0	0	0			For SW & Other (time & expenses) see System Operations
Grid Security, Reliability Management & Real Time Operations Capabilities			0	0	0			HW is in end state. Assumed to use FPL HW in first release.
System Operations Data Setup			0	0	0			
Design Business Policies & Procedures			0	0	0			
Design Jobs & Compensation			0	0	0			
Internal Training Development and Delivery			0	0	0			
Market Operations*	50%	50%	1122	561	561	$ 1,290,300	1,000,000	Reduced by 50% from end state due to no market facilitation
Plan & Manage Project			0	0	0			Vendor estimate, based on services model, is approx. $650,000/yr
Market Facilitation			0	0	0			Discussion (June 7th) & decision to stay with service based estimate
Scheduling			0	0	0			as GF not planning to buy the applications in here
Forecasting			0	0	0			
Market Operations Data Setup			0	0	0			
Design Business Policies & Procedures			0	0	0			
Design Jobs & Compensation			0	0	0			
Internal Training Development and Delivery			0	0	0			
Market Operations Product Test			0	0	0			
Commercial Operations	100%	0%	134	134	0	$ 66,890	37,241	Assume labor is 3% of original estimate and HW, SW, Other is 1.6% of original estimate
Plan & Manage Project			0	0	0			
Metering & Measurement Data Capability			0	0	0			
Settlement & Billing Capability			0	0	0			
Contract Management Capability			0	0	0			
Commercial Operations Data Setup			0	0	0			
Design Business Policies & Procedures			0	0	0			
Design Jobs & Compensation			0	0	0			
Internal Training Development and Delivery			0	0	0			
Commercial Operations Product Test			0	0	0			

Project/Component	Internal %	External %	Estimated Days	Internal Days	External Days	Labor	HW, SW, Facilities & Other**	Comments
Customer Interface	50%	50%	701	351	351	$ 806,686	250,000	HW, SW & Facilities in Comm Ops for Customer Information, Portal
Plan & Manage Project			0	0	0			
Customer Interface Capability			0	0	0			
Customer Interface Data Setup			0	0	0			
Design Business Policies & Procedures			0	0	0			
Design Jobs & Compensation			0	0	0			
Internal Training Development and Delivery			0	0	0			
Portal Usability Test			0	0	0			
Customer Training Development and Delivery			0	0	0			
Customer Readiness			0	0	0			
Customer Interface Product Test			0	0	0			
Asset Optimization	60%	40%	1347	808	539	$ 1,373,648	708,000	Reduce Asset Optimization further by 25%, based on making work tracking more manual, and assuming less of related tasks (data conversion, training, etc.) Do not reduce HW & SW in first release. Continue to assume PSSE planning suite still required
Plan & Manage Project			0	0	0			
Network Planning Data Capability			0	0	0			
Work Definition Capability			0	0	0			
Work Execution Capability			0	0	0			
Asset Optimization Data Setup			0	0	0			
Design Business Policies & Procedures			0	0	0			
Design Jobs & Compensation			0	0	0			
Internal Training Development and Delivery			0	0	0			
Asset Optimization Product Test			0	0	0			
Corporate Services Project	60%	40%	2304	1382	922	$ 2,380,160	1,769,080	Financial software, HRMS, Payroll & Benefits outsourcing Assume 100% of original estimate
Plan & Manage Project			0	0	0			
Finance & General Accounting Capability			0	0	0			
Payroll & Human Resources			0	0	0			
Corporate Administration			0	0	0			
System Administration and IT Management			0	0	0			
Design Business Policies & Procedures			0	0	0			
Design Jobs & Compensation			0	0	0			
Internal Training Development and Delivery			0	0	0			
Corporate Services Product Test			0	0	0			
Transition & Conversion Project	40%	60%	610.8	244	366.3	$ 781,440		This is about 4.7% of total. Based on experience & similar to original and state numbers.
Plan & Execute Cutover			0	0	0			
Operational Preparation			0	0	0			
Technical Architecture Project	40%	60%	2166	866	1300	$ 2,772,734	1,361,250	Reduce labour days by 35% due to fewer applications, environments and shorter project and technical support. See R1 Tech Arch. Reduce HW, SW by 25% - most will still be required but will be some reduced complexity.
Technical Architecture Integration & Infrastructure Management			0	0	0			
Integration Test & Simulation Project	40%	60%	1440	576	864	$ 1,843,072		
Cross-Capability Integration Testing			0	0	0			
Simulation Planning			0	0	0			
Support Simulation			0	0	0			
Design Integration Architecture			0	0	0			
Program Management & Monitor Co Start-up	40%	60%	1339	536	803	$ 1,713,401		
Program Management			0	0	0			
Monitor Co Startup Costs - Outsourced							200,000	MonitorCo will be outsourced for First Release (Assumed 50% of original cost to outsource it)
Total Days			14843	7994	6848	$16,324,136	$30,991,603	

Resource Split		Days	Cost/Day	Labor Cost		Other/Totals
Internal		7,994	$ 500	$ 3,997,101		
External		6,848	$ 1,800	$ 12,327,035		
SUBTOTAL		14,843		$ 16,324,136		$30,991,603
INCENTIVES FOR INTERNAL RESOURCES [1]				$ 300,000		
EXPENSES FOR INTERNAL RESOURCES [2]						$790,450
EXPENSES FOR EXTERNAL RESOURCES	15%					$1,849,085
TOTAL BEFORE CONTINGENCY				$ 16,624,136		$33,631,108
CONTINGENCY	30%	4,453		$ 4,987,241		$10,089,333
TOTAL AFTER CONTINGENCY		19,298		$ 21,611,376		$43,720,441
APPLICANTS & 6F LLC TOTAL COSTS TO DATE (end of May 2001)						$9,041,418
TOTAL PROJECT START-UP COSTS						$74,373,235
Y2001 & 2002 NON-PROJECT PAYROLL					$ 2,943,169	
Y2001 & 2002 BOARD & EXECUTIVE MANAGEMENT SALARY					$ 960,000	
CONTINGENCY	30%				$ 1,170,951	
TOTAL INTERIM OPERATING COSTS					$ 5,074,119	
TOTAL START-UP COSTS						$ 79,447,355

1 Assumes 30 personnel receive bonuses of $10,000 at completion of project.
2 Assumes 50% of average internal resources travel, $4000 in expenses per month for 9 months total.

RTO #1
R1 - Gantt Chart - 42

	Effort Days	Duration Months	Duration Weeks	Avg FTEs	check	Int/Tot Ratio	MONTHS 1	2	3	4	5	6	7	8	9
Operationalizing the Business Project	1331	9	36	7.4	1330		5	5	8	8	8	8	8		8
Internal FTEs						80%	4	4	6.4	6.4	6.4	6.4	6.4	6.8	6.4
External FTEs							1	1	1.6	1.6	1.6	1.6	1.6	1.7	1.6
Organization & People Project	1125	9	36.0	6.2	1120		4	4	4	7	7	7.5	7.5	7.5	7.5
Internal FTEs						60%	2.4	2.4	2.4	4.2	4.2	4.5	4.5	4.5	4.5
External FTEs							1.6	1.6	1.6	2.8	2.8	3	3	3	3
Facilities Project	250	4	16	3.1	250			2	3					[illegible]	4
Internal FTEs						85%		1.7	2.55					3	3
External FTEs														1	1
System Operations Project	974	7	28	7.0	970		4	4	8	8	8	8	8.5		
Internal FTEs						60%	2.4	2.4	4.8	4.8	4.8	4.8	5.1		
External FTEs							1.6	1.6	3.2	3.2	3.2	3.2	3.4		
Market Operations	1122	7	28	8.0	1120		8	8	9	9		9.5	9		
Internal FTEs						50%					3	4.75	[illegible]		
External FTEs								3		5	5	5	5		
Commercial Operations	134	7	28	1.0	140		1	1	1	1	1	1	1		
Internal FTEs						100%	1	1	1	1	1	1	1		
External FTEs							0	0	0	0	0	0	0		
Customer Interface & Customer Readiness	701	7	28	5.0	700		3	3	6	6	6	6	5		
Internal FTEs						50%			3	3	3	3	2.5		
External FTEs									3	3	3	3	2.5		
Asset Optimization	1347	7	28	9.6	1340		6	6	11	11		11	11		
Internal FTEs						60%	3.6	3.6	6.6	6.6	6.6	6.6	6.6		
External FTEs							2.4	2.4	4.4	4.4	4.4	4.4	4.4		
Corporate Services Project	2304	7	28	16.5	2200		10	10	18	18	18	18	18		
Internal FTEs						60%	6	6	10.8	10.8	10.8	10.8	10.8		
External FTEs							4	4	7.2	7.2	7.2	7.2	7.2		
Transition & Conversion Project	611	5	20	6.1	620						5	5	5	8	8
Internal FTEs						40%					2	2	2	3.2	3.2
External FTEs											3	3	3	4.8	4.8
Technical Architecture Project	2166	9	36	12.0	2100		7	7	13	13	13	13	13	13	13
Internal FTEs						40%	2.8	2.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2
External FTEs							4.2	4.2	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Integration Test & Simulation Project	1440	4	16	18.0	1440							8	8	28	28
Internal FTEs						40%						3.2	3.2	11.2	11.2
External FTEs												4.8	4.8	16.8	16.8
Program Management	1339	9	36	7.4	1340		4	4	8	8	8	8	9	9	9
Internal FTEs						40%	1.6	1.6	3.2	3.2	3.2	3.2	3.6	3.6	3.6
External FTEs							2.4	2.4	4.8	4.8	4.8	4.8	5.4	5.4	5.4

Projected Start-up Project Headcount

	1	2	3	4	5	6	7	8	9	Avg FTE
Total Projected FTEs	49	51	89	89	95	103	103	78	78	82
Projected Internal FTEs	28	30	50	50	52	55	55	37	38	44
Projected External FTEs	21	22	39	39	43	48	48	40	40	38

Quarter/Resource Level	Total Headcount per Level	% of Total Hired: non-project	Qtrly Hires	Annual Salary	Qtrly Salary	Quarterly Amount	Total	Comments
Salaries & Benefits (87 Emps and 8 Board Members)								
Q1		20%					$ 371,250	
Executive	0		0	405,000	101,250	$ -		Executives captured in start-up cost (and below)
Skilled Personnel	64		1	101,250	25,313	$ 324,000		75,000 with 35% loading
Assistants	20		4	47,250	11,813	$ 47,250		35,000 with 35% loading
Cumulative Non-Project Employees			17					
Q2		50%					$ 928,125	
Executive	0		0	405,000	101,250	$		
Skilled Personnel	64		32	101,250	25,313	$ 810,000		
Assistants	20		10	47,250	11,813	$ 118,125		
Cumulative Employees			42					
Q3		100%					$ 1,451,250	
Executive	0		0	405,000	101,250	$ -		
Skilled Personnel	48		48	101,250	25,313	$ 1,215,000		Roughly 16 of the 64 (25%) total skilled personnel will still be working on the project in the final quarter. Therefore, 48 Skilled Personnel are assumed on the non-project payroll in the last quarter.
Assistants	20		20	47,250	11,813	$ 236,250		
Cumulative Employees			68					
INTERIM PAYROLL SUB-TOTAL							$,750,625	
Salary for Board							360,000	Assumes 8 members for 9 months of work (3 quarters); includes incentives
Salary for Management							450,000	Assumes 3 team members for 6 months of work (assuming not all hired first month), average salary of $300K (prorated for 6 months each); includes incentives
Payroll Taxes			7%				192,544	
PROJECTED INTERIM PAYROLL BEFORE CONTINGENCY							$ 3,753,169	
CONTINGENCY			20%				750,634	
PROJECTED INTERIM PAYROLL AFTER CONTINGENCY							$	

Project/Capability	HW	SW	Other	Total	Comments
Facilities Project - First Release	$ -	$ -	$ 3,505,066	$ 3,508,066	
Control Center Facility - First Release			316,216		Assume some space in LFO leased for last 90 days before go live - will be 11,000 sq. ft @ $39.13 per sq. ft. After 90 days, lease goes into operating budget. The rest of the Control Center space to a totall of 44,000 sq. ft will be occupied by GF at go live (switch over), so not including a lease cost for this. Assume space (in total) for approx. 50 people in R1. Existing control room and computer room are 16,500 sq ft each, plus there are multiple offices and conf. rooms
Office infrastructure (desktop, network routers, cables, wiring, etc.)			60,000		Assumes $3000/workstation for 20 workstations; Assumes $2000 is for desktops, $1000 is for the rest of the infrastructure
Office furniture (cubicles, desks, chairs)			115,000		Assumes $5000/workstation for 15 open office workstations, $8000/office for 5 closed office spaces
Building Lease fees			107,607		See assumption three lines above. 90 days only for part of the space. Rest of lease cost goes into annual lease.
Tenant Improvement Allowance			0		Assumes no allowance
Upfit Construction of Office and Control Center			0		Assumes no upfit required for the LFO except upgrade of mapboard. B. Smith called Mauell - upgrade of mapboard estimated at 140k-150k- decision that this will be done in the end state per Ray Falcon
Back-Up Generator			0		Existing

Project/Capability	HW	SW	Other	Total	Comments
UPS/Batteries				0	Existing
Network/Phones				0	Includes CAT 5 and T1 connections. Existing telecomm operating expense is $500,000 prorated to Ops. This number is included in the Operating Budget - so is zero here.
Business Telephone/PBX system				0	Existing
Separate Electric Service				0	Separate service for Control Center and 24x7 operations-existing
Facilities Design & Project Management -- Outsource				8,609	Assumes 8% of lease and upfit cost (industry average planning factor) Some work will need to be done to organize for GridFlorida.
Training site with dedicated user desktops				0	Assumes existing training room with no upfit per FPL
Moving Expenses to Permanent Facility				25,000	Includes hiring moving company to pack, transfer, and unpack assets to new facility; Assumes $500/person for 50 personnel
Permanent HQ Facility - First Release	0	0		1,258,750	Various scenarios exist initial. (1) Sublet/try to get smaller space from one developer and then get more. (2) Move into industrial building (only $6/sq ft & then outfit it ($30/sq ft) more flexible, but may be more costly. (3) Work with Divesting owners on using some vacant space they may have - would be at an embedded cost rate of $15/sq ft. Conclusion: Assumes 25,000 square feet, for 100 people (250 sq ft/person) at $25/sq ft. Other scenarios might be ways to reduce number later.
Office infrastructure (desktop, network routers, cables, wiring, etc.)				150,000	Assumes $3000/workstation for 45 workstations; Assumes $2000 is for desktops, $1000 is for the rest of the infrastructure. Assume only put in infrastructure for initial 50 people in R1.
Office furniture (cubicles, desks, chairs)				265,000	Assumes $5000/workstation for 45 open office workstations, $8000/office for 5 closed office spaces. Assume only put in office furniture for initial 50 people in R1.
Building Lease fees				156,250	See assumption three lines above. 90 days only for part of the space. Rest of lease cost goes into annual lease. Assumes 25,000 square feet, for 100 people (250 sq ft/person) at $25/sq ft.
Tenant Improvement Allowance				0	Assumes no allowance. Assumes moving into a building that is ready, other than office infrastructure above.
Upfit Construction of Office and Control Center				0	Assume not required to upfit/construction of office. Will be zero in R1. Usually - Includes 12,500 sq ft of Office space @ $75/sq ft: Upfit includes construction, electricity, HVAC, plumbing, and fire protection
Back-Up Generator				0	None
UPS/Batteries				250,000	To be used for critical business areas
Network/Phones				250,000	Includes CAT 5 and T1 connections (estimate)
Business Telephone/PBX system				100,000	Estimate is installed business phone system with voicemail and battery backup to support 50 employees
Separate Electric Service				50,000	Separate service for 24x7 operations
Facilities Design & Project Management -- Outsource				12,500	Assumes 8% of lease and upfit cost (industry average planning factor)
Moving Expenses to Permanent Facility				25,000	Includes hiring moving company to pack, transfer, and unpack assets to new facility; Assumes $500/person for 50 personnel
Project Facility - First Release	0	0		495,000	
Project Space -- Lease				490,000	Assumes 50 project personnel, with an average of 250 sq ft/person located at the LFO at $39.13/sq ft. Assumes all space will be office space, with no additional requirements for Control Center space. Assumes lease will be for twelve months
Project Space -- Office Furniture	-			0	Assumes no upfit cost at LFO

Project/Capability	HW	SW	Other	Total	Comments
Project Space – Office Infrastructure			5,000		Assumes $100/workstation to lease for 50 project personnel; Includes desktops, telephones, cables, wiring, etc.
Disaster Recovery Facility - First Release	0	0	1,435,100		Assume existing back-up site at the customer service center East in West Palm Beach
Building Lease Fees			8,100		Assumes 1,200 sq ft facility for FPL Customer Service Center East and office space; Assumes $27/sq ft;
Tenant Improvement Allowance			0		Assumes no allowance
Office Furniture			21,000		Assumes $3000/workstation for low-end open office space; Assumes 7 workstations
Office Infrastructure			21,000		Assumes $3000/workstation for 7 workstations
Upfit Construction of Office and Control Center			0		Assumes no upfit required
System Operations HW & SW			0		Backup Sys. Ops. HW & SW covered in original FPL EMS project. See SO-HW spreadsheet for details. Allocated 50% of the backup to Grid Florida - this number is included in System Operations on this spreadsheet.
Market Operations HW & SW			0		Assumes no Market Ops. Backup software and hardware in Release 1
Commercial Operations HW & SW			75,000		Assumes no Comm. Ops Backup software - as using FPL home grown solution. Assumes minimal HW for backup of Comm Ops in R1
Corporate Services HW & SW			350,000		Assumes arrangement could be worked out with outsource provider for hot site backup.
Asset Optimization HW & SW			110,000		Assumes arrangement could be worked out with outsource provider for hot site backup.
Infrastructure HW & SW			600,000		Includes scaled down Disk storage, tape backup/recovery unit, network equipment, and minimal SW
Telecommunications Infrastructure			250,000		Assumes some level of reconfiguration will be required
Telecommunications Operating Expense			0		Operating Expense covered under 2003 Operating Budget

No.	Project/Work Package/Task/Sub-Task	Unit/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
11.0	**Technical Architecture Project**						Project Total:	2172	
	Technical Architecture Integration						2172		
	Technical Infrastructure					884			
	Setup Development Environments - *Commercial Ops & Customer Interface*	Based upon number of development, test, environments for each application, includes time to config hw & install sw 4 environments (build, test, stage, train) for each package * 2 applications (Settlement & Billing, Customer Information)	8	12.0	96.0				Includes setup of servers and the environments/software to support the applications. Assumed that *Contract Management* is done with MS Access and/or is part of Customer System, therefore no special environment setup.
	Setup Development Environments - *Corporate Services*	Based upon number of development, test, environments for each application, includes time to config hw & install sw 4 environments (build, test, stage, train) for each package * 3 applications (HR Mgmt System, Finance & Acctg, Time Reporting)	12	12.0	144.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Development Environments - Asset Optimization	Based upon number of development, test, environments for each application, includes time to config hw & install sw 4 environments (build, test, stage, train) for each package * 1 applications (Work Tracking)	4	14.0	56.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Test Environments - Market Operations	Based upon number of development, test, environments for each application, includes time to config hw & install sw 3 environments (test, stage, train) for each package * 2 applications (OASIS, Scheduling)	6	14.0	84.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Commercial Ops & Customer Interface	1 Production Environment, but much more complex due to volume and additional hardware, 2 applications	2	50.0	100.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Corporate Services	1 Production Environment, 3 Applications	3	40.0	120.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Asset Management	1 Production Environment, 1 Applications	1	40.0	40.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Production Environments - Market Operations	1 Production Environment, 2 applications	2	14.0	28.0				Includes the setup of servers and the environments/software to support the applications.
	Setup Infrastructure Environment	Estimate is three weeks for each major component. Components are the backup system, monitoring system, scheduling system, and security system. Installation of the SAN is covered by Datalink services estimated in the HW/SW section and therefore is not incl	4	15.0	60.0				Includes setup of hardware and configuration of the software components.
	Project Web Site	Status Reporting, NetMeeting, etc. on Central Location for Distant Locations	10	9.0	90.0				Hardware and software setup
	RTO #1 Administrative Environment Setup	Create/Install File Servers, Printers, LAN, Configure Security at project location	1	30.0	30.0				Assume that project site will NOT be at RTO #1 headquarters originally.
	Technical Infrastructure SME Time (Procurement)	4 days per month - life of project	9	4.0	36.0				Assume 9 months
	Security Architecture					96.0			
	Security	Uses setup environment to build comprehensive security plan covering requirements - digital certificates, secure communications, etc.	1	60.0	60.0				Case-based estimate from RTO#3
	Security Architect SME Time	4 days per month - life of project	9	4.0	36.0				Assume 9 months

No.	Project/Work Package/Task/Sub-Task	Units/ Assumptions	Total Units	Days/Unit Assumption	Task Workdays	W.P. Workdays	Total Workdays	Project Workdays	Comments/Assumptions
	Performance					286.0			
	Application Performance Testing	Assume testing/tuning for all packaged applications . # of package apps	8	20.0	160.0				Excludes System Operations and Market Operations.Assumed that they will be performance tested by the vendor off-site.
	Integration Performance Testing	Complete Performance Testing of Systems, Interfaces, Etc.	1	90.0	90.0				Includes All applications
	Performance SME Time	4 days per month - life of project	9	4.0	36.0				Assume 9 months
	Interface Architecture					61.0			
	Point to Point Interface Architecture	Standardize architecture approach for interfaces between System Ops, Comm Ops, Customer Interface	1	25.0	25.0				
	Portal Integration	Number of Applications = 0	0	10.0	0.0				Portal to integrate with Settlement & Billing, System Operations, Transmission Access Operations, Customer Information (4). June 8 - assume no portal in R1
	Interface Architect SME Time	Life of project, 4 days a month	9	4.0	36.0				Assume 9 months
	Operations/Management Architecture					702.5			
	Technology Management	Case-based estimate % of Total Workdays - Support for test/implementation environments	6%	5608.0	336				Percentage of total Commercial Operations + total Corporate Services days+total Asset Optimization days + total Market Operations days + total Customer Interface days
	DBA Support at RTO #1	Full time DBA for life of project	1	162.0	162.0				Assume 9 months of full time DBA support. DBA support not required for entire life of project.
	Define DR Requirements By Application	Total Number of Applications = 8	8	5.0	40.0				Disaster Recover definition for System and Market Operations to be done by vendor and are not included in this estimate.
	Backup/Recovery Implementation/Testing	Total Number of Applications = 8	8	16.0	128.0				Test the ability to successfully backup and recover systems.
	Operations Architect SME Time	4 days per month - life of project	9	4.0	36.0				Assume 9 months lifecycle of project
	Plan Disaster Recovery Procedures					108.0			
	Design Disaster Recovery Procedures	Case-based estimate	2	54.0	108.0				Assumes 2 FTEs for 3 months
	Develop and Maintain Standards					35.0			
	Develop and Maintain GUI Standards	Fixed Effort - 3 weeks	3	5.0	15.0				Assumes re-use from other RTO implementation
	Develop and Maintain Data Definition Standards	Fixed Effort - 4 weeks	4	5.0	20.0				Assumes re-use from other RTO implementation

	Construction Costs	1	178,000,000	$178,000,000	$178,000,000	Includes Land & Land Rights, Renew & Replacement, Expansion, & Generation Integration Costs. FPL = $154M; TECO = $24M
	TOTAL CAPITAL EXPENSE				$178,000,000	
O&M Related costs		1	48,113,337	$ 48,113,337	$ 74,713,337	Assumes $34,113,337M for FPL Assets & $13.5M for TECO assets, annually. In addition .5 M for TECO for transmission switching operations & telecom & computer costs.
	Property Taxes	1	23,500,000	$ 23,500,000		Assumes $20M annually for FPL and $3.5M for TECO
	Offices, Service Centers and Storerooms	1	2,000,000	$ 2,000,000		Cost-based lease rates on service centers
	Use Fee for Shared Station Equipment	1	1,100,000	$ 1,100,000		GF will pay DOs for use of shared station equipment (such as RTUs, battery banks, etc.), also DOs will pay a use fee to GF for use of the same equipment at its stations. Estimated to be $1 M for FPL. Agreed to use an estiamte 10% of FPL number for TECO = $100k (June 18). Not applicable for FPC.
Salaries & Benefits (87 Emps)					$ 10,972,800	
	Executive	3	405,000	$ 1,215,000		300,000 with 35% loading
	Skilled Personnel	64	101,250	$ 6,480,000		75,000 with 35% loading
	Assistants	20	47,250	$ 945,000		35,000 with 35% loading
	Annual Incentives	8,640,000	20%	$ 1,728,000		Incentives for all personnel
	Payroll Taxes	8,640,000	7%	$ 604,800		
Lease Back Arrangements					$ 23,100,000	
	Information Services	0	-	$ -		This is a placeholder for costs associated with Utility Lease Back Arrangements.
	Access Arrangements	1	23,100,000	$ 23,100,000		This is the cost that GF must pay to the Utilities for their cost of ownership of the land. This covers the lease of the land to access GridFlorida's facilities (e.g. GF owns the facilities, FPL owns the land). Estimated at $21M for FPL. Agreed to use an estimate of 10% of FPL number for TECO = $2.1M (June 18). Not applicable for FPC.
Legal & Consulting Services					$ 8,000,000	TECO Estimate
	Legal	1	8,000,000	$ 8,000,000		This is based on $2M a quarter.
Control Center Facilities and Building Services					$ 1,796,067	Assumes lease-back arrangement to FPL for control center facilities in Miami.
	Annual Lease Cost	1,760,850	2%	$ 1,796,067		Assumes annual lease agreement for 7-10 years for 45,000 square feet @ $39.13,Existing control room and computer room are 16,500 sq ft each. Assumes a 2% increase of lease cost each
Headquarters Facilities and Building Services					$ 637,500	Assumes that location is somewhere other than Miami, however, Miami was used to estimate this as it is most expensive city.
	Annual Lease Cost	625,000	2%	$ 637,500		Assumes annual lease agreement for 7-10 years for 25,000 square feet at $25/sq. ft. Assumes a 2% increase of lease cost each year.
Disaster Recovery Facility					$ 140,048	
	Annual Lease Cost	32,400	2%	$ 33,048		
	Computer Services Maintenance	535,000	20%	$ 107,000		20% of HW acquisition cost.
	Telecommunications	1	-	$ -		FPL stated that this number is included in the overall Telecomm # of $750,000.
Computer Services/Project Dev. Costs		1,813,790	20%	$ 362,758	$ 362,758	20% of HW Acquisition cost for everything but Disaster Recovery. Number comes from total Application Hardware. See R1 Operating Budget- Computer Services spreadsheet for more detail on how this number was calculated
Insurance		1	2,000,000	$ 2,000,000	$ 10,470,000	Assumes insurance for Property, Surety Bond, Brokerage Fees, Automobile, Liability, Directors & Officers, Workers Comp
	Storm Fund Insurance	1	8,470,000	$ 8,470,000		Based on an estimate of $7.7M from FPL to cover assets from FPL. Agreed to use an estimate of 10% of FPL number for TECO = 770k (June 18). FPC will continue to have its own assets and own storm fund.
Telecommunications		1	774,000	$ 798,000	$ 798,000	Based on FPL's prorated costs of $750k currently. In addition estimated ISP costs for internet connectivity at $2000/month ($24k).
Board Of Directors		8	60,000	$ 480,000	$ 480,000	8 members, $60,000 annual comp.; includes incentives and expense reimbursement
Mtgs., Travel, Seminars		1	500,000	$ 500,000	$ 500,000	
Market Monitoring Fees		1	620,000	$ 620,000	$ 620,000	3 board members and $500,000/yr estimate for outsourcing (based on quote from Charles River to GridSouth)
Payroll Administration		$ 10,848,000	1%	$ 108,480	$ 108,480	From ADP PEO. 1% of gross annual salary. (Includes board of directors)
Benefits Administration		$ 10,368,000	2%	$ 207,360	$ 207,360	From ADP PEO. 2% of gross annual salary. (Includes board of directors)
Financial & Operational Auditing		1	1,800,000	$ 1,800,000	$ 1,800,000	Assumes Annual Audit = $1.5M; Add'l audits = $300k.
Employee Training Budget (external)		45	3,000	$ 135,000	$ 135,000	45 employees, $3000 per employee. Assumes limited training in first year.
Miscellaneous Fees		1	25,000	$ 25,000	$ 25,000	Assumes annual FRCC membership fee of $25k; FPUC will assess a 1/8 of 1% of annual revenues which are unknown at this time.
FERC Fees		1	1,000,000	$ 1,000,000	$ 1,000,000	As a benchmark, PJM Operating Budget line item for FERC Fees were $2M in 1999.
Communications/Community & Customer Relations		1	500,000	$ 500,000	$ 500,000	Charitable contributions assumes 1% of Labor Costs; the Balance was added for Communications & Customer Relations
Miscellaneous		1	500,000	$ 500,000	$ 500,000	Includes office expenses for postage, supplies, etc. Added money for annual report production, etc.
Total Before Contingency					$136,866,350	
Contingency		20%			$ 27,373,270	
Total After Contingency					$164,239,620	

Computer Services/Project Development Costs in R1 Operating Budget

Project	Percent of HW, SW, Other Used in R1	Total HW for End State	Total for R1	Assumption
SO	0%	$0.00	$0.00	No HW for R1
CO	2%	$352,000.00	$7,040.00	Based on $100,000 assumption of using FPL's system
Corp Services	100%	$490,000.00	$490,000.00	Based on the need for all Corp Svcs HW in R1
Infrastructure	75%	$1,025,000.00	$768,750.00	Based on the need for 75% of infrastructure due to reduced complexity for R1
MO		$2,612,500.00	$390,000.00	Based on estimate from OATI to outsource HW for R1. End state is based on buying HW for MO.
AO	100%	$108,000.00	$108,000.00	Based on the need for all Corp Svcs HW in R1
Customer	20%	$250,000.00	$50,000.00	Based on reduction of customer interface complexity in R1
Total			**$1,813,790.00**	
Reduced by 20%			**$362,758.00**	

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
1	System Operations – Allocated EMS Costs from FPL new EMS	▪ Estimated following components: o Hardware - Allocated zero$ – see incremental numbers o Software - Allocated 50% of total numbers from FPL Cost Breakdown numbers. Subtracted numbers for Generation o Other – Allocated 50% of total from FPL (other includes vendor and FPL labor)	▪ The first release will include Allocated EMS costs for SW and Other (labor and expenses) ▪ First release will function on FPL HW	▪ N/A	**Remaining:** ▪ No additional allocated costs **Incremental:** ▪ No additional allocated costs. See incremental below.
2	System Operations – Incremental EMS costs to prepare for GridFlorida	▪ Based on estimate from Vendor of incremental costs to change the FPL EMS to a GF RTO EMS. o Hardware – Assumed GF requires its own hardware plus incremental hardware. Numbers based on original FPL hardware (5.356 M), plus incremental hardware (350k)	▪ The first release will NOT include incremental EMS costs for HW, SW, and Other. This will be captured in the End State • Vendor indicates incremental costs include: license fees for point counts associated with GF sizing,	▪ 1 Director ▪ 10-12 Real Time Operations ▪ 6 Grid Security and Reliability Management ▪ 5 Operations Engineers ▪ 1-2 Operations Support (Procedures and Training) ▪ Total= 23-26	**Remaining:** ▪ Requirements analysis, design, and build for changes to EMS to accommodate market based functions (CM, EI) ▪ All incremental HW, SW and Other will need to

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Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. __________ (BLH-1)
Business Blueprint Documents

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		o Software – 1.5 M based on mid-point of vendor estimate o Other – 1.25 M based on mid-point of vendor estimate for labor & expenses	interfacing to Market Operations, project engineering, project management, testing, incremental hardware, installation, and planning associated with changing the FPL EMS to a GF RTO EMS.	Operations Technical Support ▪ 1 Director ▪ 1 Application Development and Maintenance ▪ 0 Network and Ops Support ▪ 1 Database Support ▪ 0 Telecomm ▪ Total= 3 (plus 2 from Commercial Operations) ▪ Chief Operating Officer will reside over Market Operations, System Operations, Asset Optimization, Billing and Transmission Services ▪ 2 admin people will be shared amongst Market Operations, System Operations, Asset Optimization, Billing	be accounted for in End State **Incremental:** ▪ Additional testing to reintegrate EMS with other components

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
				and Transmission Services	
3	System Operations – Other	▪ Database Management SW – assumed that GF requires own license. FPL license cannot be used by two companies. ▪ Telecommunications Infrastructure – assumed minimal additions required ▪ Voice Recorder – assumed GF will require its own voice recorder ▪ Mapboard – enhancements to existing mapboard required to fit for GF. The cost for this is in the Control Center Facility.	▪ The following will be a part of the First Release: Database Management SW and Voice Recorder and Mapboard (mapboard covered in Control Center Facility costs) ▪ Telecommunications Infrastructure will be in the end state, assuming use FPL telecomm. in first release.	▪ N/A	**Remaining:** ▪ Telecommunications Infrastructure ▪ **Incremental:**
4	System Operations – Other Labor	▪ Cost for other labor includes tasks for: requirements analysis and functional design, integrated design and testing with other capabilities, business process design, job design, training design and	▪ Assume reduction to manage capability, based on reduced scope in Release 1 ▪ Continue to require some of each of the tasks listed.	▪ N/A	**Remaining:** ▪ Reqts. analysis, design and overall project management related to changes and additions in functions in

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		development, and data set-up.			second release; e.g. GF takes on more direct control of Tx assets, new congestion management model, etc. **Incremental:** ▪ Some limited rework of Release 1 functions and retest with new functions
5	Market Operations	Based on vendor estimates for the following components: ▪ OASIS ▪ Energy Scheduling & transmission Service Management o Scheduler o ATC posting o Interchange checkout o Settlement information ▪ Forecasting o Load	▪ No market facilitation o Congestion management o Ancillary Services o Energy Imbalance ▪ Customization of OASIS to GridFlorida requirements ▪ NERC tag approval service operational ▪ Simple tool required to integrate Tagging and	▪ 1 Director ▪ 5 Schedulers ▪ 0 Forecasting ▪ 0 Market Facilitation ▪ Outsource Tagging ▪ Total= 6 ▪ Chief Operating Officer will reside over Market Operations, System Operations, Asset Optimization, Billing	**Remaining:** ▪ Market facilitation o Congestion management o Ancillary Services o Energy Imbalance **Incremental:** ▪ Interface with new settlements and

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		o Ancillary services ▪ Tagging Services ▪ Pricing & Bidding ▪ ATC Calculator ▪ Assume GridFlorida requires new Hardware - $2.61M based on vendor estimates. ▪ Software - $2.95M Based on mid-point of vendor estimates ▪ Other – Includes requirements definition, design, development configuration, testing training and data set up - $6.74M	OASIS ▪ MAP tool required to manage redispatch ▪ Utilise FPC ATC/TTC calculator ▪ GridFlorida will contract to procure and settle ancillary services from control areas and IPPS as provider of last resort	and Transmission Services ▪ 2 admin people will be shared amongst Market Operations, System Operations, Asset Optimization, Billing and Transmission Services	billing ▪ Transition from contracted to market based pricing for Congestion management, Energy Imbalance and ancillary services.
6	Commercial Operations	Based on: ▪ Settling for the following tariff based charges: o Transmission Service - Point to Point o Transmission Service – System Wide Charge	GridFlorida will Settling for the following charges: o Transmission Service - Point to Point o Transmission Service – System Wide Charge	▪ 1 Supervisor ▪ 0 Metering and Measurement Data ▪ 3 Settlements and Billing ▪ 0 Contract Management ▪ Total= 4	**Remaining:** ▪ Market for congestion management ▪ Market for ancillary services ▪ Transfer of

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		o Transmission Services – Grid Management o Ancillary Services – Scheduling, System Control and Dispatch o Ancillary Services – Reactive Supply & Voltage Control o Ancillary Services – Energy Imbalance o Ancillary services – Spinning Reserve o Congestion Management o Losses ▪ Ancillary service market – settle on market price by the hour ▪ Balancing energy market – settled on market based price by the hour ▪ Congestion management – o PTR ownership over flow gates o Auction of spare and unused RTRs o Recallable PTRs (2hours	o Transmission Service – Zone transmission charge o Transmission Service – network interchange o Transmission Services – Grid Management o Ancillary Services – Scheduling, System Control and Dispatch o Ancillary services – Spinning and Non-spinning Reserve o Congestion Management o Losses ▪ No settlement for reactive ▪ No market for congestion management – performed using TLR process and re-dispatch costs will be allocated to customers based on load share ratio	Operations Technical Support ▪ 1 Application Development and Maintenance ▪ 0 Network and Ops Support ▪ 1 Database Support ▪ 0 Telecomm ▪ Total= 2 (plus 3 for System Operations) ▪ Chief Operating Officer will reside over Market Operations, System Operations, Asset Optimization, Billing and Transmission Services ▪ 2 admin people will be shared amongst Market Operations, System Operations, Asset Optimization, Billing and Transmission	settlement responsibility to GridFlorida ▪ Revenue quality metering required or method to allocate loads to market services **Incremental:** ▪ Transfer of settlement and resettlement history ▪ Transfer of customer information ▪ Data integrity check ▪ Data format changes (map to second release data specifications) ▪ Settlement consistency (must be able to resettle

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		prior to dispatch) o Congestion on non-flow gates - costs allocated to customers on congested path in load ratio share ▪ Settling & managing inadvertent ▪ Settling for grandfathered contracts from 3 control areas ▪ Revenue Quality Meter Data available ▪ Hardware - $0.352M Based on Vendor estimates ▪ Software - $2.0M Based on Vendor estimates ▪ Other costs include system Requirements, design, development, data set up, policies and procedures, training and test – 4459 Days Settling for grandfathered contracts from 3 control areas ▪ Revenue Quality Meter Data available	▪ No market for energy imbalance ▪ No market for ancillary services ▪ GridFlorida will contract to procure (and will settle) ancillary services from control areas and IPPS as provider of last resort ▪ First release will utilise the current FPL Transmission Billing System. (The System is currently used to settle contracted transmission charges with 2 FPL customers.) The system will be customized to settle for GridFlorida First release OATT (see list above) Estimated time to customize the FPL system for GridFlorida first release is 80-120	Services	in the second release bills generated in first release) Transition from first release system to end-state system

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		▪ Hardware - $0.352M Based on Vendor estimates ▪ Software - $2.0M Based on Vendor estimates ▪ Other costs include system Requirements, design, development, data set up, policies and procedures, training and test – 4459 Days	days Estimated cost to customize the FPL system for GridFlorida first release is $100,000		
7	Asset Optimization	▪ Based on: o Network Planning capability in place o Limited Work Definition – mainly manual o A simple tool (probably access and/or reporting) for Work Execution o Assumption that some Asset data will need to be converted and set-up for GF o Assumes 22-25 personnel	▪ Same Network Planning capability, with fewer people ▪ Same limited Work Definition – mainly manual ▪ Small decrease in the amount of time spent on tracking Work Execution. Assumes implementation of a very simple tool. ▪ High risk: Some external SMEs thought that Asset Optimization was already very small	▪ 1 Director ▪ 10 Network Planning ▪ 2-3 Work Definition ▪ 2-3 Work Execution ▪ Total= 15-17 ▪ Chief Operating Officer will reside over Market Operations, System Operations, Asset Optimization, Billing and Transmission Services ▪ 2 admin people will be shared amongst Market Operations, System	**Remaining:** ▪ Will require additional asset optimization capability based on better defined requirements & information expected by the utilities **Incremental:**

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
			in the end state estimate.	Operations, Asset Optimization, Billing and Transmission Services	
8	Corporate Services	Based on: ▪ Financial Accounting o Accounts Receivable o Accounts Payable o General Ledger o Property/Fixed Asset Accounting o Miscellaneous invoicing o Credit Control/Assessment o Job Costing ▪ Payroll & Human Resources o Outsource Solution - management of outsource vendor required o Vendor application for time and expenses tracking ▪ Corporate Administration o Strategic planning o Corporate governess o Internal audit o Facilities o Tariff design	▪ Same corporate service capability required for first release	▪ 1 Payroll Analyst ▪ 1 HR Analyst ▪ 5 Finance and Accounting ▪ 1 Communications Coordinator (PR) ▪ 2 General Counsel ▪ Outsource 1-2 General Counsel ▪ 1 Tariff and Rate Design ▪ 1-2 Regulatory Affairs ▪ 1 Facilities and Supply Chain Analyst ▪ 1 Auditor ▪ 1 Supervisor of Corporate Technical Support ▪ 2 Application Management ▪ 2 Workstation Support ▪ 1 Help Desk	**Remaining:** ▪ Financial accounting system ▪ Asset logs **Incremental:** ▪ Transition of financial data to new system ▪ Data integrity check ▪ System configuration ▪ Testing ▪ Implementation ▪ Transfer of control from control areas to RTO

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		o Procurement o Legal Affaires o Regulatory affaires ▪ IT management ▪ Data warehouse and reporting ▪ Hardware - $0.5M based on vendor estimates ▪ Software - $0.5M based on vendor estimates ▪ Other includes vendor selection, system configuration (mainly financial) implementation, testing, data set up and training – 2304 Days		▪ 2 admin across all of above ▪ Total= 23-24 (plus outsourcing 1-2) (Ops Tech Support numbers captured in Commercial Operations and System Operations) ▪ CFO will reside over Legal Affairs, Rates and Regulatory Design, Payroll and HR, Corporate Communications, Audit, Facilities and Purchasing, Operations Tech Support, Corporate Tech Support for Release 1	
9	Transmission Services	▪ Covered days for tasks to plan and manage this project, design and build the customer interface capability, complete the data	▪ Rather than a complex customer management system and portal, an access database will be used for the customer	▪ 1 Supervisor ▪ 2 Account Management ▪ 1 Customer Training ▪ Total 4	**Remaining:** ▪ Need to create a portal

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		set-up for the customer management system, design policies and procedures, design jobs and compensation, design, develop and deliver internal training, complete a portal usability test, design, develop, and deliver customer training, complete customer readiness activities, and complete product test for the customer information system. ▪ Includes estimate for the customer management system (hardware and software) and the portal (hardware and software), as well as a training and registration web based system	management system and the GridFlorida public website and OASIS will be utilitized in replace of a robust portal. As well, no web-based training will be used. ▪ Policies, procedures, and training still need to be conducted. It will be to a lesser extent.	▪ Chief Operating Officer will reside over Market Operations, System Operations, Asset Optimization, Billing and Transmission Services ▪ 2 admin people will be shared amongst Market Operations, System Operations, Asset Optimization, Billing and Transmission Services	**Incremental:** ▪ Need to create a more robust customer management system
10	Facilities	▪ Control Center Facility – for approx. 50 people ▪ Permanent Headquarters Facility – for approx. 150	▪ Control Center – for approx. 50 people. Reduced the lease time to 90 days.	▪ N/A	**Remaining:** ▪ Control Center – additional for additional people

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		people ▪ Temporary Project Facility for a team of approx. 50 people ▪ Disaster Recovery Facility – to backup all capabilities ▪ Labor to procure and manage facilities = 416 days	▪ Headquarters – assume reduction of costs. To accommodate 100 people. Reduce lease time to 90 days. ▪ Project Facility – assume continue to require project facility. ▪ Disaster Recovery Facility – reduced number to assume facility only for EMS and core business applications (e.g. Corporate Services & Comm. Ops) ▪ Reduce Labor days to manage facilities project assuming reduced complexity		▪ Perm. HQ – additional space and infrastructure for additional people ▪ Project Facility – will need to continue through to end state ▪ Disaster Recovery – will need to increase capability **Incremental:** ▪ Would be incremental if any part of the facilities starts in one place and then has to move.
11	Operationalize the Business Project	▪ Covered days for tasks to set up the business, manage filings with FERC, develop service agreements, develop company brand and image,	▪ All these items need to get accomplished for the First Release, some to a lesser extent	▪	**Remaining:** ▪ Further develop image and branding, work on any remaining

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		budgets, and design and maintain rules & procedures for overall business ▪ Includes estimate for outsourced legal assistance			FERC filings **Incremental:** ▪ 2 releases requires 2 tariffs, additional changes to rules, procedures, agreements
12	Organization and People Project	▪ Covered days for tasks to plan and select board, recruit management and board, design HR policies and practices, design the organization, design compensation, develop sourcing strategy, recruit personnel, and plan and develop internal and external communications ▪ Includes estimate for search firm fees, incentives/bonus packages for senior management and skilled personnel, moving expenses for skilled personnel, recruiting expenses, and a	▪ All these items need to get accomplished for the First Release, some to a lesser extent (e.g. less jobs)	▪	**Remaining:** ▪ Need to recruit the rest of the organization, Need to make communications more robust for larger organization **Incremental:** ▪ May be small incremental for communications

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		salary and benefits study			
13	Transition and Conversion	▪ Covered days for tasks include planning and executing cut-over before go live, and preparing for full operational capabilities	▪ This is based on a percent of the test of the projects	▪	**Remaining:** **Incremental:** ▪ There will be incremental cost for additional data that needs to be converted. New and changed capabilities will be have to be prepared
14	Integration Test and Simulation Project	▪ Covered days for tasks include defining and executing cross-capability integration test approach, planning and executing a simulation, and defining and confirming integration architecture (application and interface architecture)	▪ This is based on a percent of the rest of the projects	▪	**Remaining:** **Incremental:** ▪ An entire new integration test needs to be conducted.
15	Program	▪ Covered days for tasks	▪ Program management is	▪	**Remaining:**

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
	Management and MonitorCo	include time to manage the entire program, and time to set up the MonitorCo	based on a percent of the rest of the projects ▪ MonitorCo is assumed to be outsourced for a First Release		▪ Need to build the remainder of the MonitorCo **Incremental:** ▪ The entire program across will take longer since it is across 2 releases
16	2001 and 2002 Payroll	▪ Covered payroll for executives, skilled personnel, assistants and the board ▪ Includes incentives for board and executives/management	▪ The reduction for the First Release is based on 2 things: the First Release Organization Chart, and the First Release time span only covers 3 quarters (rather than 7 quarters for the 2nd release)	▪	**Remaining:** ▪ Need to hire the rest of the organization **Incremental:** ▪ Payroll costs will be higher since some people will be on for the length of the First Release and the 2nd Release (may be a longer duration in total)
17	Technical Architecture	▪ This project is to design and support the overall technical	▪ Based on fewer applications and shorter	▪ N/A	**Remaining:** ▪ Require technical

	Project/Component	End State Assumptions	First Release Assumptions	First Release Organization Assumptions	End State- What is remaining and incremental?
		architecture across the projects ▪ Sized to cover all end state projects and applications, over an end state timeframe	timeframe, reduce labor and supporting HW, and SW. Reduced by 20%. Overall technical support and integration will be required.		architecture support for additional applications implemented in the end state. **Incremental:** ▪ There could be some incremental associated with supporting reworked applications (e.g. Billing) & reintegrating.

GridFlorida

Establishing the GridFlorida RTO
BluePrint Project
June 2001

Docket No. 000824-EI
Docket No. 010577-EI
Docket No. 001148-EI
GridFlorida Companies Witness Holcombe
Exhibit No. _______ (BLH-1)
Business Blueprint Documents

Release 1 Organization Model and Sizing v2

GridFlorida

Contents

- Benchmark and Research
- Organization Model for Release 1 with Sum Totals
- Organization Model for Release 1 with Sum Totals and Breakdown

GridFlorida

Benchmark and Research

Release 1

- Scaled down organization from End State based on minimal functions in place for Release 1
- Received sizing input from the Hay Group
- Received sizing input from Accenture SMEs

End State

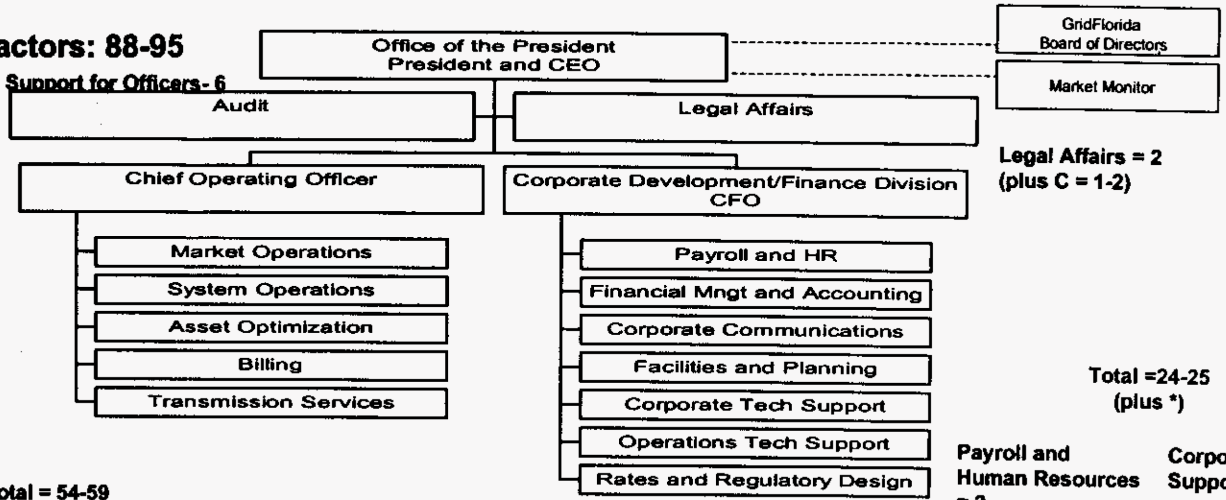
- Benchmarked estimates and model against other RTOs and ISOs
- Received and reviewed as is data from TECO, FP&L, and FPC
- Interviewed transmission owner SMEs from TECO, FP&L and FPC regarding estimates, roles, and outsourcing
- Interviewed Accenture SMEs regarding estimates, roles, and outsourcing
- Received input regarding organizational structure and key executives from the Hay Group

GridFlorida

Organization Model for Release 1 with Sum Totals and Breakdowns

Headcount Range: 87-93 ***
Contractor Range: 1-2
Headcount Range w/ Contractors: 88-95

Total Officers plus Clerical Support for Officers- 6



Total = 8 Board Members

Total = Board Members 3 ****

Audit = 1

Legal Affairs = 2 (plus C = 1-2)

Total = 54-59 (plus * and **)

Market Operations = 6

System Operations = 23-26

Asset Optimization = 15-17

Billing = 4

Transmission Services = 4

Admin- 2

Total =24-25 (plus *)

Payroll and Human Resources = 2

Financial Mngt & Accounting = 5

Corporate Communications = 1

Facilities and Purchasing = 1

Corporate Technical Support = 6

Operations Tech Support = 5*

Rates and Regulatory Design = 2-3

Admin-2

Note:
C = Contractors
* Outsource Service
** Under Asset Opt, Work Defn and Work Exec outsource #s are not included since these groups outsource large #s of people for engineering, construction, and maintenance.
*** This total does not include the GridFlorida Board of Directors or the Market Monitor Board of Directors or employees.
**** Market Monitor Organization model and sizing was not analyzed as a part of the Blueprint.

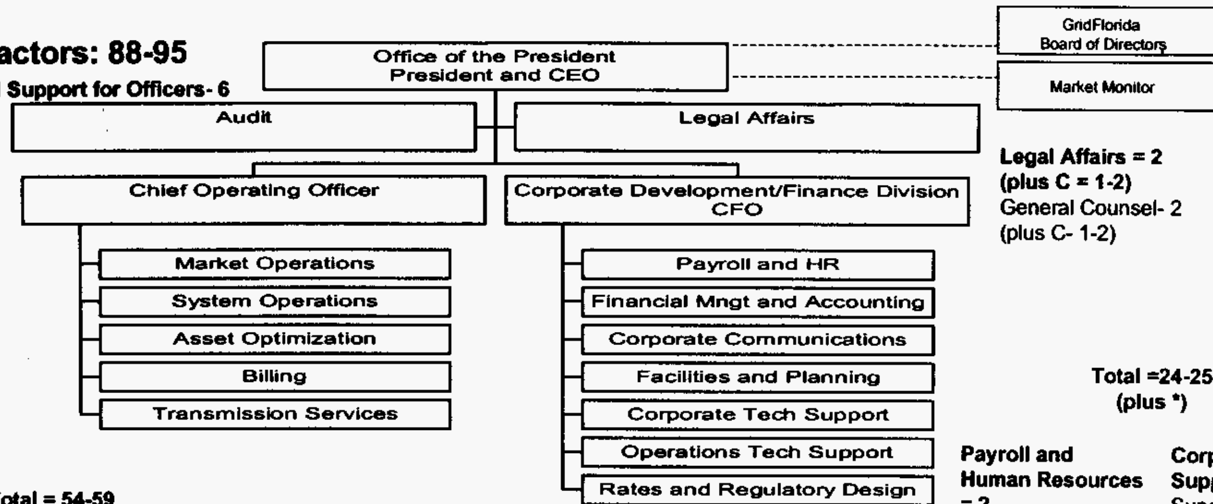
07/24/2001

GridFlorida

Organization Model for Release 1 with Sum Totals and Breakdowns

Headcount Range: 87-93 ***
Contractor Range: 1-2
Headcount Range w/ Contractors: 88-95

Total Officers plus Clerical Support for Officers- 6



Total = 8 Board Members****

Total = Board Members 3

Audit = 1
Auditor = 1

Legal Affairs = 2 (plus C = 1-2)
General Counsel- 2 (plus C- 1-2)

Total = 54-59 (plus * and **)

Market Operations = 6
Director- 1
Scheduling- 5
Tagging- *
Forecasting- 0
Market Facilitation- 0

System Operations = 23-26
Director- 1
Real-time Operations- 10-12
Grid Security and Reliability Mngt- 6
Operations Engineering- 5
Operations Support (training & procedures)- 1-2

Asset Optimization = 15-17
Director- 1
Network Planning- 10
Work Definition- 2-3 **
Work Execution- 2-3 **

Billing = 4
Supervisor- 1
Metering & Measurement Data- 0
Settlements & Billing- 3
Contract Mngt- 0

Transmission Services = 4
Supervisor- 1
Account Mngt- 2
Communication Mngt- 0
Customer Training- 1

Admin- 2

Total =24-25 (plus *)

Payroll and Human Resources = 2
Payroll- 1
Human Resources- 1

Financial Mngt & Accounting = 5
Finance-5

Corporate Communications = 1
Communications Coordinator- 1

Facilities and Purchasing = 1
Facilities and Supply Chain- 1

Corporate Technical Support = 6
Supervisor- 1
Application Mngt- 2
Workstation Support- 2
Help Desk- 1

Operations Tech Support = 5*
Supervisor- 1
Application Dev & Main-2*
Networks & Ops Sys- 0*
Database Support- 2*
Telecomm- 0*

Rates and Regulatory Design = 2-3
Tariff and Rate Design- 1
Regulatory Affairs- 1-2

Admin-2

Note:
C = Contractors
* Outsource Service
** Under Asset Opt, Work Defn and Work Exec outsource #s are not included since these groups outsource large #s of people for engineering, construction, and maintenance.
*** This total does not include the GridFlorida Board of Directors or the Market Monitor Board of Directors or employees.
**** Market Monitor Organization model and sizing was not analyzed as a part of the Blueprint.

07/24/2001

accenture

Accenture Matrix of Experience

	ERCOT	PJM Interconnection LLC	Power Pool of Alberta	British Columbia Hydro (ISO)	ISO New England	Grid South	Southwest Power Pool
RTO Market Design Roles							
Market Design/Rules Filing		A					
Business Capability/Process Design	A	A		A	A	A	A
Infrastructure Requirements	A			A	A	A	A
Organization & Job Design	A	A		A	A	A	A
RTO Implementation Project Roles							
Program Management	A	A		A	A	A	A
Project Management	A	A	A	A	A	A	A
Scope Definition	A	A	A	A	A	A	A
Change Control	A	A	A	A	A		A
Solution Provider Recommendation	A	A	A	A	A	A	
Integration	A	A	A		A	A	A
Testing	A	A	A		A		A
System & Market Operations Applications							
OASIS		A		A			
Scheduling	A	A	A		A		A
Tagging		A					A
Metering, Validating & Profiling	A		A				A
Contract Management	A		A	A	A		
Security Coordination	A						A
ATC		A					A
Congestion Management	A	A					A
Market Participant Interface/Portal	A	A	A	A	A		A
Losses	A	A					A
Settlements and Billing	A	A	A		A		A
Markets (Energy, A/S, Imbalance)	A	A	A	A	A		A

This matrix represents highlights of Accenture's client experience and expertise in RTOs/ ISOs/ TransCos in North America.

Docket No. 001148-EI
Docket No. 000824-EI
Docket No. 010577-EI
GridFlorida Companies Witness Holcombe
Exhibit No. 15 (BLH-2)
Matrix of Accenture's RTO Experience

Table 1

Analysis of Incremental Cost Impact on GridFlorida Users of Accenture's Estimated End State Start-up Costs

Line No.	Project/Component	(1) Start-up Cost $(000)	(2) Alloc Factor (Appendix 1)	(3) GridFlorida User Cost Assessments: FPL Retail	(4) TEC Retail	(5) FPC Retail	(6) Others	(7) Impact of Cost Off-sets: ( ) denotes net reduction: FPL Retail	(8) TEC Retail	(9) FPC Retail	(10) Others	(11) Net Cost Responsibility on GridFlorida Users: FPL (3) + (7)	(12) TEC (4) + (8)	(13) FPC (5) + (9)	(14) Others (6) + (10)
1	Operationalizing the Business Project	9,645	d	5,342	1,085	2,101	1,116	-	-	-	-	5,342	1,085	2,101	1,116
2	Organization & People Project	8,751	d	4,847	984	1,907	1,013	-	-	-	-	4,847	984	1,907	1,013
3	Facilities Project	5,420	d	3,002	610	1,181	627	(588)	-	-	(47)	2,414	610	1,181	580
4	System Operations	23,189	d	12,845	2,608	5,052	2,684	(10,171)	-	-	(814)	2,674	2,608	5,052	1,870
5	Market Operations	14,881	d	8,243	1,674	3,242	1,722	-	-	-	-	8,243	1,674	3,242	1,722
6	Commercial Operations	8,645	d	4,789	972	1,884	1,001	-	-	-	-	4,789	972	1,884	1,001
7	Customer Interface	4,033	d	2,234	454	879	467	-	-	-	-	2,234	454	879	467
8	Asset Optimization	2,540	d	1,407	286	553	294	-	-	-	-	1,407	286	553	294
9	Corporate Services Project	4,119	d	2,282	463	897	477	-	-	-	-	2,282	463	897	477
10	Transition & Conversion Project	1,421	d	787	160	310	164	-	-	-	-	787	160	310	164
11	Technical Architecture Project	6,081	d	3,368	684	1,325	704	-	-	-	-	3,368	684	1,325	704
12	Integration Test & Simulation Project	3,351	d	1,856	377	730	388	-	-	-	-	1,856	377	730	388
13	Program Mgmt. & Monitor Co Start-up	3,515	d	1,947	395	766	407	-	-	-	-	1,947	395	766	407
14	Incentives for Internal Resources	600	d	332	67	131	69	-	-	-	-	332	67	131	69
15	Expenses for Internal Resources	1,535	d	850	173	334	178	-	-	-	-	850	173	334	178
16	Expenses for External Resources	4,082	d	2,261	459	889	472	-	-	-	-	2,261	459	889	472
17	Non-Project Payroll	12,034	d	6,666	1,354	2,622	1,393	-	-	-	-	6,666	1,354	2,622	1,393
18	Board & Executive Management Salary	3,912	d	2,167	440	852	453	-	-	-	-	2,167	440	852	453
19	Subtotal	117,754		65,225	13,244	25,656	13,628	(10,759)	-	-	(861)	54,466	13,244	25,656	12,767
20	Contingency @ 20% on subtotal	23,551		13,045	2,649	5,131	2,726	(2,152)	-	-	(172)	10,893	2,649	5,131	2,553
21	Total Costs Incurred To Date (May 2000)	9,041	d	5,008	1,017	1,970	1,046	-	-	-	-	5,008	1,017	1,970	1,046
22	Total	150,346		83,278	16,910	32,758	17,400	(12,911)	-	-	(1,033)	70,367	16,910	32,758	16,367
23						Total =	150,346			Total =	(13,944)			Total =	136,402

Definitions:

Column (1)	Start-up costs estimated in 2003 dollars. Accenture's start up estimate reflects the total scope of all work to achieve an END STATE, full scope RTO.
Column (2)	Cost Assessment Factor is an allocation basis found in Appendix 1. This allocation is based on the 12-CP load for each utility.
Column (3 - 6)	Estimated Costs are allocated to each group based off the load ratio found in Appendix 1 - GridFlorida Cost Assessment Factor Calculation
Column (6) (10) (14)	The "Others" are non-retail loads or wholesale firm transmission customers.
Column (7 - 10)	Some of Accenture's estimated start-up costs in Column (1) currently are in the rate base of the jurisdictional utilities. These costs are not incremental to customers (ratepayers).
Column (11 - 14)	Net Cost Responsibility is the incremental costs subject to future cost recovery from the customers of GridFlorida

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI EXHIBIT NO. 16
COMPANY/
WITNESS: Holcombe
DATE: 10-3—5-01

7/30/2001

Table 2

Analysis of Incremental Cost Impact on GridFlorida Users of Accenture's Estimated Annual (First Year) GridFlorida Operating Expenses

Line No.	Operating Expense Item	(1) GridFlorida Annual Expense $(000)	(2) Alloc Factor (Appendix 1)	(3) GridFlorida User Cost Assessments FPL Retail	(4) TEC Retail	(5) FPC Retail	(6) Others	(7) Impact of Cost Off-sets: ( ) denotes net reduction FPL Retail	(8) TEC Retail	(9) FPC Retail	(10) Others	(11) Net Cost Responsibility on GridFlorida Users FPL (3) + (7)	(12) TEC (4) + (8)	(13) FPC (5) + (9)	(14) Others (6) + (10)
1	O&M - FPL Divest. Assets	57,113	a	52,882	-	-	4,231	(52,882)	-	-	(4,231)	-	-	-	-
2	- TEC Divest. Assets	17,300	b	-	17,300	-	-	-	(17,300)	-	-	-	-	-	-
3	Salaries & Benefits	25,375	d	14,055	2,854	5,529	2,937	(2,531)	60	(188)	(264)	11,524	2,914	5,340	2,673
4	Contractors	806	d	446	91	176	93	-	-	-	-	446	91	176	93
5	Lease Back Arrangements - FPL	21,000	a	19,444	-	-	1,556	(19,444)	-	-	(1,556)	-	-	-	-
6	- TEC	2,100	b	-	2,100	-	-	-	(2,100)	-	-	-	-	-	-
7	Legal & Consulting Services	4,000	d	2,216	450	872	463	-	-	-	-	2,216	450	872	463
8	Control Cntr Facilities & Bldg Serv.	1,796	d	995	202	391	208	(1,663)	489	-	(133)	(668)	691	391	75
9	HQ Facilities & Building Services	638	d	353	72	139	74	-	-	-	-	353	72	139	74
10	Disaster Recovery Facility	298	d	165	34	65	34	(31)	-	-	(2)	134	34	65	32
11	Computer Services/Project Dev. Cost	2,065	d	1,144	232	450	239	-	-	-	-	1,144	232	450	239
12	Insurance- general	2,000	d	1,108	225	436	231	-	-	-	-	1,108	225	436	231
13	Storm Fund - FPL Divest. Assets	7,700	a	7,130	-	-	570	(4,259)	-	-	(341)	2,870	-	-	230
14	- TEC Divest. Assets	770	b	-	770	-	-	-	-	-	-	-	770	-	-
15	Telecommunications	798	d	442	90	174	92	(694)	-	-	(56)	(252)	90	174	37
16	Board of Directors	480	d	266	54	105	56	-	-	-	-	266	54	105	56
17	Meetings, Travel, Seminars	500	d	277	56	109	58	(66)	-	-	(5)	211	56	109	53
18	Market Monitoring Fees	1,692	d	937	190	369	196	-	-	-	-	937	190	369	196
19	Payroll Administration	245	d	136	28	53	28	-	-	-	-	136	28	53	28
20	Benefits Administration	480	d	266	54	105	56	-	-	-	-	266	54	105	56
21	Financial & Operational Auditing	1,800	d	997	202	392	208	-	-	-	-	997	202	392	208
22	Employee Training Budget	270	d	150	30	59	31	(36)	-	-	(3)	114	30	59	28
23	Misc. Fees	25	d	14	3	5	3	-	-	-	-	14	3	5	3
24	FERC fees	1,000	d	554	112	218	116	(554)	(112)	(218)	(116)	-	-	-	-
25	Communication/Community Relation	500	d	277	56	109	58	-	-	-	-	277	56	109	58
26	Misc. office expenses	500	d	277	56	109	58	-	-	-	-	277	56	109	58
27	Subtotal	151,251		104,531	25,262	9,863	11,596	(82,161)	(18,963)	(406)	(6,706)	22,370	6,298	9,457	4,890
28	Contingency @ 20%	30,250		20,906	5,052	1,973	2,319	(16,432)	(3,793)	(81)	(1,341)	4,474	1,260	1,891	978
29	Total	181,501		125,437	30,314	11,836	13,915	(98,593)	(22,756)	(487)	(8,047)	26,844	7,558	11,348	5,868
30						Total =	181,501			Total =	(129,883)			Total =	51,618

Definitions:

Column (1)	Estimated annual expense for first full year of operations.
Column (2)	Cost Assessment Factor is an allocation basis found in Appendix 1. This allocation is based on the 12-CP load for each utility.
Column (3 - 6)	Estimated operating expenses are allocated to each group based off the load ratio found in Appendix 1 - GridFlorida Cost Assessment Factor Calculation
Column (6) (10) (14)	The "Others" are non-retail loads or wholesale firm transmission customers.
Column (7 - 10)	Some of the estimated operating expenses in Column (1) currently are in the rate base of the jurisdictional utilities. These costs are not incremental to customers (ratepayers).
Column (11 - 14)	Net Cost Responsibility is the incremental costs subject to future cost recovery from the customers of GridFlorida

Appendix 1

Cost Assessment Factor Calculation

Line No.	Allocation Factor:		TRANSMISSION USER FPL RETAIL	TEC RETAIL	FPC RETAIL	OTHERS (*) (Wholesale)	TOTAL
1	a	FPL Pricing Zone					
2		2003 Avg. 12 CP Load, MW	17,000	-	-	1,360	18,360
3		Load Ratio:	93%	-	-	7%	100%
4							
5	b	TEC Pricing Zone					
6		2003 Avg. 12 CP Load, MW	-	3,452	-	-	3,452
7		Load Ratio:	-	100%	-	-	100%
8							
9	c	FPC Pricing Zone					
10		2003 Avg. 12 CP Load, MW	-	-	6,687	2,192	8,879
11		Load Ratio:	-	-	75%	25%	100%
12							
13	d	Grid-wide					
14		2003 Avg. 12 CP Load, MW	17,000	3,452	6,687	3,552	30,691
15		Load Ratio:	55%	11%	22%	12%	100%

(*) Load ratio share responsibility for these transactions is assigned to the utility control area that includes the load (where the transaction sinks, not the source)

Docket No. 001148-EI
Docket No. 000824-EI
Docket No. 010577-EI
GridFlorida Companies Witness Southwick
Exhibit No. __ (HIS-1)
Start Up Costs

Florida Power
A Progress Energy Company

RTO START-UP COSTS

Florida Power Corporation, Tampa Electric Company and Florida Power and Light agree that all incremental[1] costs incurred during the year 2000 through the starting date of the RTO will be deferred for future recovery from the RTO.

The specific categories of costs related to current and future support of the development of the RTO are anticipated to include the following:

- Collaborative process costs, including meetings, facilitators, conference calls and meeting support.
- Computer development costs, including the costs of consultants, hardware and other equipment, license fees, internal costs, training, and travel.
- Project management costs, including salaries for any RTO interim personnel[2], recruiting fees, relocation, interview expenses, and outside auditing.
- Development and regulatory expense costs, including the costs of feasibility studies, developing the RTO structure and tariff and support for the structure in regulatory proceedings, and legal and consulting fees.
- Training costs.

Please sign below to acknowledge your agreement with the above.

Javier Portuondo 1-11-01
Manager, Regulatory Services - Florida
Florida Power Corporation

Phil Barringer
Controller
TECO

Mike Davis
Controller
Florida Power & Light

[1] Incremental is defined as cost, internal or third party, which would not have been incurred if it were not for the RTO project.
[2] The RTO's management costs are to include the costs of the RTO (GridFlorida) and its Managing Member (GF, Inc.).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 17
COMPANY/
WITNESS: Southwick
DATE: 10-3-5-01

GridFlorida LLC
Request for Information Regarding
Program Management Services and Business Systems

Introduction

GridFlorida LLC is seeking proposals from qualified vendors to provide program management services to support the implementation of the GridFlorida regional transmission organization (RTO). GridFlorida plans to commence commercial operation on December 15, 2001 and is currently in the process of selecting a vendor or vendors to meet this implementation schedule. The purpose of this Request for Information (RFI) is to provide vendors with background information regarding the GridFlorida RTO as well as information regarding the scope and nature of program management services sought by GridFlorida.

Background

Pursuant to FERC Order 2000, Florida Power & Light Company, Florida Power Corporation and Tampa Electric Company (the Joint Applicants) filed a joint compliance filing to form GridFlorida, an RTO in Florida on October 16, 2000. This initial filing was followed by a supplemental compliance filing on December 15, 2000 that included additional details regarding the implementation of GridFlorida. In the initial filing, the applicants requested expedited approval of certain governance provisions for GridFlorida in order to allow the applicants to proceed with implementation of GridFlorida to meet a planned operational date of December 15, 2001. On January 10, 2001 FERC issued an order approving these governance provisions, including the process for selecting the board of directors, the qualifications for directors and employees, and restrictions on the financial holdings of directors and employees. In accordance with the RTO formation plan filed with FERC, the applicants and designated stakeholder groups are now proceeding to form a Board Selection Committee and an Advisory Committee along with other activities required to implement the GridFlorida RTO. GridFlorida will be a for-profit transco designed to provide independent oversight of the transmission facilities of its members and the Florida transmission grid. Participants have the option of continuing to own transmission assets or of divesting transmission assets to GridFlorida.

GridFlorida Implementation Requirements

The December 15, 2000 supplemental compliance filing defines the elements and scope of GridFlorida, including governance, transmission service and market design. This filing is available at www.gridflorida.com and is identified at the home page of this site as "12-15 final Volumes I-III.zip". Volume I contains an overview of GridFlorida and the filing. Volume II contains the RTO Formation Plan and related governance documents. Volume III contains the GridFlorida open access transmission tariff (OATT) including supporting schedules and protocols. In particular, Attachment P to the OATT, Congestion Management, Balancing Service, Operating Reserves, and Regulation describes the operation of markets to be included in the GridFlorida business design. The key business functions to be implemented by GridFlorida are as follows:

OASIS and transmission service under the GridFlorida OATT
Single regional queue for transmission service requests
Regional transmission planning per protocol
Day-ahead scheduling and schedule adjustment processes
Regional security coordinator function
Congestion management based on inc/dec bids
Operate control area for GridFlorida transmission system
Energy balancing market
Flowgates and associated physical transmission rights (PTRs)
PTR assignment and auction processes
Installed capacity and energy (ICE) obligation and market
Regulation market
Operating reserve market
Settlement systems for transmission services and markets
Integration of functions with energy management systems

Currently, it is planned that the GridFlorida staff will occupy a building located in Miami that is currently serving as Florida Power & Light Company's energy control center. It is anticipated that this facility will be leased for a period of five or more years as the GridFlorida operating center. A second facility, to be determined, will be leased or contracted to provide back-up operating and security coordinator functions.

Guidelines for Proposals

The following guidelines are provided to assist vendors in developing proposals. Proposals should include a description of recent, relevant experience in projects of similar nature and scope in the electric utility industry with emphasis on experience with domestic independent system operators (ISOs) and RTOs.

Proposals must describe the vendor's program management approach and should identify the individuals proposed by the vendor to perform the work, including the individual that will serve as program manager. Descriptions of the credentials and qualifications of the proposed team, particularly with respect to similar projects, should be included in the proposal. The proposal should provide a description of provisions to ensure "bottom line" program accountability as well as continuity of program management.

The initial task of the program manager will be to develop the start-up plan for GridFlorida, and proposals should focus on the approach to developing this plan. Proposals should address initial steps in detail, including: (1) inventory and assessment of existing resources and infrastructure, (2) determining options regarding reusability and/or integration with existing systems, (3) definition and refinement of project scope, timing and cost, and (4) options for outsourcing functions or of forming beneficial strategic partnerships or alliances.

The start-up plan should address the feasibility of implementing all GridFlorida business and market functions included in the FERC compliance filing by December 15, 2001. The scope of the GridFlorida start-up plan must be comprehensive, and should address the following issues: (1) overall schedule including key milestones, (2) interfaces and coordination with personnel at existing utilities, (3) staffing requirements for the start-up phase as well as the permanent GridFlorida staff, (4) system operations functions, (5) transmission service operations, (6) customer interface and settlement systems, (7) system planning, (8) corporate services and support requirements, (9) facilities and infrastructure requirements, (10) rights to new software developed for GridFlorida and, (11) overall project cost and cash flow requirements, including both start-up costs and the initial annual operating cost of GridFlorida. The start-up plan should address the options and consequences of the partial implementation of business and/or market functions on December 15, 2001. The configuration of functions to be implemented by December 15, 2001 must meet the requirements of FERC's Order 2000, be operationally feasible, and provide an efficient path to fully implement all functions. In the event that any functions are not fully implemented on December 15, 2001, interim procedures may be required to satisfy these criteria.

In addition to the GridFlorida start-up plan, it is also requested that proposals address the vendor's ability to implement the plan, including both ongoing project management and the delivery of the business systems necessary to implement the start-up plan. It is anticipated that implementation will require a multi-disciplinary team, and proposals should explain the vendor's approach to acquiring the necessary resources and skill sets, including an identification of business systems proposed to be developed and delivered by the vendor itself versus sub-contractors with expertise in specific applications.

Schedule and Procedures for Submitting Proposals and Vendor Selection

In evaluating the proposals, the following factors will be considered:

a) Professional expertise and experience of the firm and its proposed staff as it relates to the subject matter of this RFI.

b) Experience and expertise in managing similar large, complex projects and understanding of organizations such as GridFlorida.

c) The bidder's ability to start and complete the project in a timely manner while ensuring stability of assigned staff.

d) Proposed fees and other costs to complete the project.

e) Responsiveness to this RFI, including thoroughness of the proposal.

f) Proposed approach for completing the assignment.

g) Willingness of the vendor to guarantee project completion and the functionality of business systems, including payment of appropriate liquidated damages in the event that these requirements are not met.

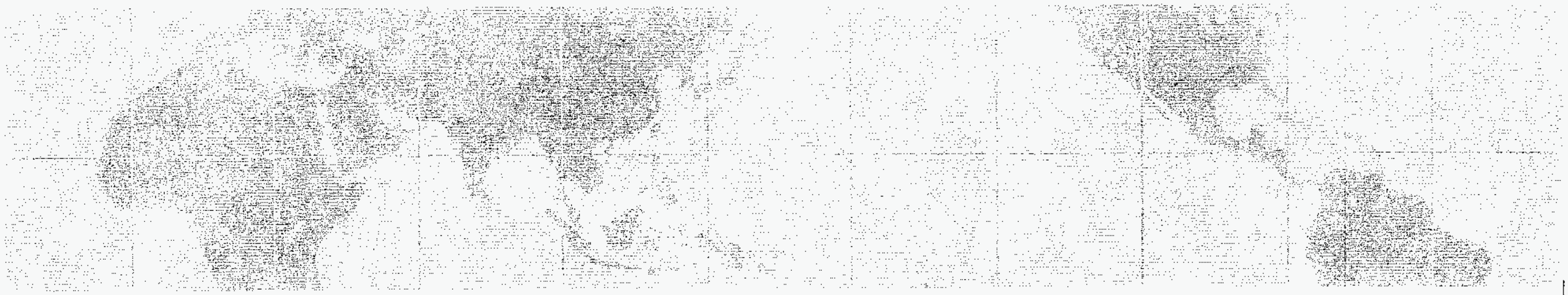
h) Conflicts of interest

i) Other factors to be determined by GridFlorida in its sole discretion

GridFlorida shall select a short list of qualified vendors to meet with the GridFlorida Management Committee to present and discuss proposals. Due to time constraints, GridFlorida plans to complete this vendor selection process within the next four to six weeks. In order to accommodate this schedule, vendors should plan to submit proposals on or before February 15, 2001, and preference will be given to proposals that meet this target submittal date. Nothing in this RFI or any communications between GridFlorida and any vendor submitting a proposal for services or systems pursuant to this RFI creates an obligation for either party to proceed with an engagement absent a written agreement to do so. Proposals (including three complete original sets), and any communication regarding proposals should be directed to:

Mr. Robert Croes
Manager, Transmission Operations
Florida Power & Light Company
P. O. Box 14000
Juno Beach, FL 33408-0420

Phone: (561) 694-4336
Fax: (561) 694-4161
E-mail: bob_croes@fpl.com



Program Manager Proposals to GridFlorida

Summary of Proposals Received

Presented to

GridFlorida Stakeholders

April 2, 2001

Docket No. 001148-EI
Docket No. 000824-EI
Docket No. 010577-EI
GridFlorida Companies Witness Southwick
Exhibit No. __ (HIS-3)
Evaluation of Proposals

Proposals were received from five firms

CAP GEMINI ERNST & YOUNG

R.J. Rudden Associates, Inc.

PRICEWATERHOUSECOOPERS

ARTHUR ANDERSEN

Summary of RFI

- The scope of the RFI focused on program management services and development of the start-up plan:
  - Assess existing resources & infrastructure
  - Analyze reuseability and/or integration with existing systems
  - Refine project scope, schedule and cost
  - Identify options for outsourcing
- Address GridFlorida Business & Market functions including:
  - Key milestones
  - Coordination with applicants and stakeholders
  - Staffing requirements
  - Transmission functions: planning, operations, settlement,
  - Corporate and support services
  - Start-up and operating budgets

RFI Evaluation Criteria

- Professional experience & specific expertise
- Schedule and available resources
- Fees
- Responsiveness and thoroughness of the proposal
- Familiarity of GridFlorida filing
- Management approach

Points of Comparison

- Given limited scope, responses are very similar
  - Implication: Summaries on following pages will seem repetitious
- Main differentiators
  - Experience of personnel is generally what differentiated the firms
  - Knowledge of GridFlorida situation and transco start-up efforts in particular
- The following slides compare the proposals in the following areas:
  - Summary of Approach
  - Project Team
  - Relevant Experience
  - Summary of Evaluation

CAP GEMINI ERNST & YOUNG

Cap Gemini Ernst & Young

Summary of Approach

- Proposed 10 week program to develop start-up plan
- Divided work into 6 Work Streams
  - Operations, Legal & Regulatory, Client Services, Information Technology, HR and Admin., Finance
- Establish Program Management Office on-site (TBD)
  - "PMO in a Box" –CGE&Y project management tools would be used to manage process
  - MarketEdge Accelerated Solutions Environment used to evaluate strengths and weaknesses of proposed solutions
- CGE&Y would potentially be both project manager and vendor of preferred solution identified during start-up phase

Proposed Personnel/Partners

- Project team made up of all CGE&Y staff

GridFlorida
Program Manager

CGEY
Engagement VP
Andy Vesey

CGE&Y
Program Director
Kenneth Pietsch

Executive Planning Council

Bill Hunter
Stephen Behrens
Andy Vesey

GridFlorida Board of Managers- TBD

PMO
Brian Simmons

Operations
- •Grid Operations
- •Grid Reliability
- •Market Operations
- •Operation Engineering
- •Engineering Planning
- •Outage Coordination

Legal and Regulatory
- •Market Analysis

Client Services
- •Settlements
- •Metering

Information Technology
- •Data Quality
- •Project & Application Services
- •Application Development And Support
- •IT Asset, Contract, Change Management
- •IT End User Support Services
- •Telecommunications
- •Information Security

Human Resources And Administration
- •Operations Support And Training (OSAT)
- •Facilities
- •Corporate Services

Finance
- •Accounting
- •Financial Planning & Treasury

Most Relevant Experience

- CAISO – designed and implemented settlement and billing system
- Alliance – retained as system integration vendor
- ISO-NE – retained to create internal program management office for ISO-NE
- NEMMCO (Australia) – Project management, application development and system integration

Summary of Evaluation

- Strong sense of schedule constraints and environment
- Firm has strong experience in large complex projects
- Demonstrated strengths in managing and implementing pieces of similar projects
  - Strong system integration experience
  - Implemented CAISO settlement and billing system
  - Developed and implemented similar applications in other similar organizations
- Weakness seemed to be in lack of experience in overall program management experience

R.J. Rudden
Associates, Inc.

RJ Rudden Associates, Inc.

Summary of Approach

- Proposed multi-disciplinary team approach through creation of partnerships
  - RJ Rudden, Cantor Fitzgerald, PJM Technologies, Darwin Partners
- Two phase approach to be completed in 7 weeks
  - Phase 1: Complete Situational Analysis
  - Phase 2: Develop Start-Up Plan
- Project manager would be on-site for most of time; lead consultants on-site as needed
- Create Advisory Panel to provide policy guidance to teams
  - Each firm had one or more members on advisory panel
  - Not to be confused with stakeholder Advisory Committee

R.J. Rudden Associates, Inc.

Proposed Personnel/Partners

GridFlorida LLC
PROJECT TEAM ORGANIZATION

Rudden Advisory Panel
- Richard J. Rudden
- Richard B. Hieber
- Stephen A. Stolze
- Howard S. Gorman
- William J. Flanagan
- Alan C. Heintz
- Robert L. O'Brien
- Andrew D. de Lannoy

Rudden Responsible Officer
Matthew C. Cordaro

Rudden Project Manager
Kevin M. Harper

Stakeholder Interaction/ Process Oversight Team
- Stephen A. Stolze, Leader
- Richard J. Rudden

Transmission Planning/ Operations Team
- Richard B. Hieber, Leader
- Francis S. Barrett
- Jonathan Z. Ponder
- Robert E. Reed
- Richard P. Felak
- Roger E. Cummins

Organizational Development Team
- Robert L. O'Brien, Leader
- Kevin M. Harper
- James A. Monk

Financial Team
- Howard S. Gorman, Leader
- H. Edwin Overcast
- Alan C. Heintz
- Stephen M. Merchant
- Joseph T. Trainor

Market Design/ Operations Team
- William J. Flanagan, Leader
- Stephen A. Stolze
- B. Jeanine Hull
- David B. Patton
- Philip M. Ginsberg
- Stephen Rodacanachi

Regulatory Team
- Alan C. Heintz, Leader
- H. Edwin Overcast
- Stephen M. Merchant

Back Office Systems Team
- Andrew D. de Lannoy, Leader
- Neal Walsh
- Phil Cheevers
- Diane Marvine
- Terri McGinley

SUBJECT MATTER EXPERTS AND ADVISORS

ANALYTICAL/ADMINISTRATIVE SUPPORT TEAM

Most Relevant Experience

- Midwest ISO
  - Former executive from MISO on team
  - One of the consortium firms advised MISO on organizational issues
- PJM Technologies provides access to PJM's organization and resources familiar with implementing markets

Summary of Evaluation

- Firms have never worked together as a team
  - Not clear who would be in charge as firms worked in separate areas
- Top heavy project organization proposed
- Certain individuals proposed have strong credentials but not clear how much of their time was devoted to effort

Accenture

Summary of Approach

- Two phase approach; Phase 1 completed within 4 weeks
  - Blueprint phase and Initial Design Release
- Organized work into 5 capability areas:
  - System and Market Opers., Asset Management, Corporate Services, Commercial Operations, Customer Interface
- Offered to use existing Accenture facilities in Florida for project management and other development uses as required
- Proposed process for managing implementation and transition
  - Accenture proposed a prime contractor approach to development
  - Accenture would contract with GF as prime contractor and take responsibility for other vendors needed to implement desired systems.

Proposed Personnel/Partners

- Accenture team with Alstom ESCA, Hay Group, OATI and UCI

GridFlorida Management Committee

- Program Management
  - ***Accenture***
  - System Operations & Transmission Services
    - ***Accenture***
    - ***UCI***
    - ***ALSTOM ESCA***
    - ***OATI***
  - Asset Planning & Management
    - ***Accenture***
  - Customer Interface & Settlements
    - ***Accenture***
  - Corporate Services & Support
    - ***Accenture***
  - Organization & HR
    - ***Accenture***
    - ***HayGroup***
  - IT Architecture & Integration
    - ***Accenture***
    - ***ALSTOM ESCA***
  - Facilities
    - ***TBD***

Most Relevant Experience

- GridSouth – retained to develop start-up and implementation plans.
- ERCOT – Retained as prime vendor to deliver major market systems
- ISO-New England – developed and integrated major market systems for ISO-NE.
- PJM Interconnection
- SPP

Summary of Evaluation

- Firm has substantial experience in managing similar RTO projects
  - GridSouth efforts are most relevant to initial start-up plans
  - ERCOT, ISO-NE and SPP demonstrate experience to manage and deliver complex systems in similar RTO-like environment
- Clear understanding of environment and challenges faced by GF
- Proposed project team, including partners, has direct experience with relevant systems (e.g. ESCA, OATI) meaning short learning curve
  - While consortium is proposed, Accenture clearly in charge and accountable for deliverables

PRICEWATERHOUSECOOPERS

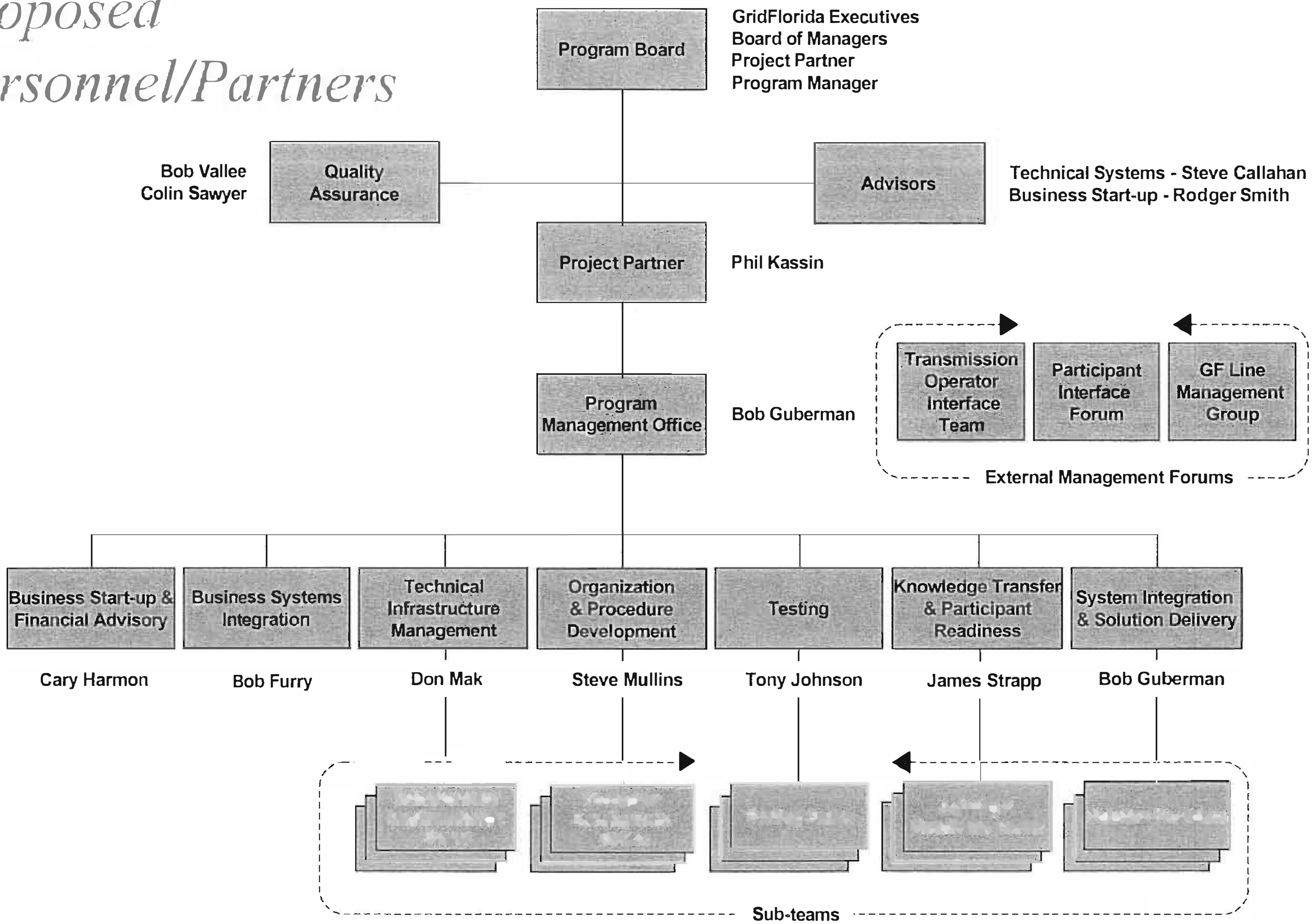
PriceWaterhouseCoopers

Summary of Approach

- Proposed 4-6 week program to develop start-up plan
  - Focus on identifying existing capabilities and desired scope for implementation
  - Identify preferred approach for addressing "gaps" between existing and desired implementation
  - Address business issues related to creating a transco (e.g. asset transfer, financing, etc.)
- Establish Program Management Office on-site
  - Ascendent™ program management methodology used
- Proposed process for managing implementation
  - Proposed to be independent from all vendors
  - Assist in contract negotiations and management with preferred vendors to implement

PRICEWATERHOUSECOOPERS

Proposed Personnel/Partners



Most Relevant Experience

- Ontario IMO – retained as overall program manager for implementation of Ontario's new markets
- CAISO and CalPX – provided overall program management services to Trustee during formation of these two firms
- Asset Transfer projects – have advised several entities considering the transfer of their transmission assets to an RTO organization

PRICEWATERHOUSECOOPERS

Summary of Evaluation

- Demonstrated detailed knowledge of GridFlorida situation and challenges
- Firm has strong experience in managing large complex projects
- Demonstrated strengths in managing projects of similar size and scope
  - Ontario and California projects
- Project team proposed has significant relevant experience
- PwC approach is to stay independent from vendors. Implications include:
  - More time potentially required for vendor selection
  - Requires GridFlorida to manage both project manager and vendors

ARTHUR ANDERSEN

Arthur Andersen

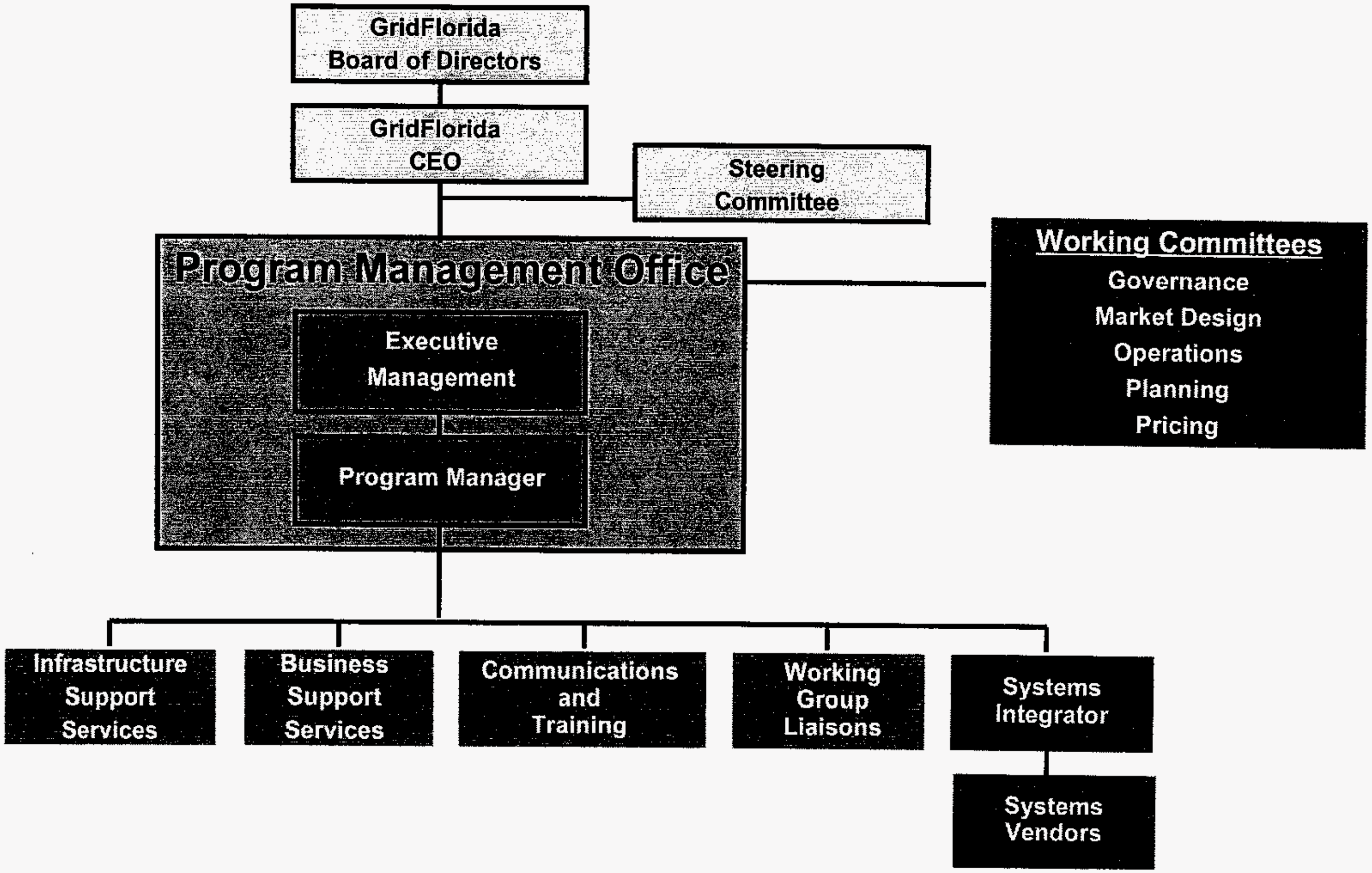
Summary of Approach

- Three phase approach; 6-8 week program to develop start-up plan
- Phase 1 divided into 7 areas:
  - Organization, Operations, Business, IT, Facilities Planning, Market Development, Master Planning
- Establish Program Management Office on-site
- Proposed process for managing implementation and transition
  - Proposal focused on managing transition process; AA could be vendor or program manager only or both

ARTHUR ANDERSEN

Proposed Personnel/Partners

- AA teamed with IBM for this project



Most Relevant Experience

- ERCOT – Program manager responsible for developing start-up plan, initial formation of ERCOT corporate plan, and selection of systems' vendors
- Alliance RTO – recently selected as overall project manager for start-up
- NEMMCO – program management for business systems
- Northwest ITC, American Transmission Co. – advise on tax, governance, accounting and systems

Summary of Evaluation

- Firm has substantial experience in managing similar RTO projects
  - ERCOT
  - Recently selected to manage Alliance
- Clear understanding of environment and challenges faced by GF
- Project team had mix of relevant experience
  - Role of IBM not clear
- Weak presentation of proposal and response to questions

RFI Evaluation Criteria - Summary & Review

- Professional experience & specific expertise
- Schedule and available resources
- Fees
- Responsiveness and thoroughness of the proposal
- Familiarity of GridFlorida filing
- Management approach

RFI Evaluation Criteria - Summary & Review

Professional experience & specific expertise	All firms had good experience; however several lacked the specific expertise Gf is looking for
Schedule and available resources	The various proposed schedules ranged from 4-10 weeks
Responsiveness and thoroughness of the proposal	Little differentiation among the thoroughness of the proposals
Familiarity of GridFlorida filing	Two of the firms seemed to be more familiar with the GF filing
Management approach	Two of the firms proposed the preferred "prime contractor" mgmt approach
Fees	The fees ranged from $400k - $2.3m

Questions ???

CAP GEMINI ERNST & YOUNG

R.J. Rudden Associates, Inc.

PRICEWATERHOUSECOOPERS

ARTHUR ANDERSEN

FOR ILLUSTRATIVE PURPOSES ONLY

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2003 THROUGH DECEMBER 2003

KMD-1
Docket No. 001148-EI
Exhibit _______
Page 1 of 6
August 15, 2001

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2. CAPACITY PAYMENTS TO COGENERATORS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3. CAPACITY PAYMENTS FOR MISSION SETTLEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4. CAPACITY PAYMENTS FOR OKEELANTA/OSCEOLA SETTLEMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5. TRANSMISSION REVENUES FROM CAPACITY SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6. SJRPP SUSPENSION ACCRUAL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7. RETURN REQUIREMENT ON SUSPENSION PAYMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8. SYSTEM TOTAL (Lines 1+2+3+4-5+6-7)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9. JURISDICTIONAL % *													99.03598%
10. JURISDICTIONALIZED CAPACITY PAYMENTS													$0
11. GRIDFLORIDA TRANSMISSION CHARGES (detail on page 2 of 6)													$59,498,841
12. LESS: SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													$0
13. LESS: FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2000 - DECEMBER 2000 $0			EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2001 - DECEMBER 2001 $0										$0
14. TOTAL (Lines 10+11-12-13)													$59,498,841
15. REVENUE TAX MULTIPLIER													1.01597
16. TOTAL RECOVERABLE CAPACITY PAYMENTS													$60,449,038

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN (MW)	%
FPSC	15,948	99.03598%
FERC	155	0.96402%
TOTAL	16,103	100.00000%

* BASED ON 2000 ACTUAL DATA

FOR ILLUSTRATIVE PURPOSES ONLY

FLORIDA POWER & LIGHT COMPANY
PRELIMINARY ESTIMATES OF GRIDFLORIDA COSTS
JANUARY 2003 - DECEMBER 2003

	PRELIMINARY ESTIMATES												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. Zonal Charges	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$24,416,667	$293,000,000
2. System Charges	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$1,916,667	$23,000,000
3. Grid Management Charges	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$4,166,667	$50,000,000
4. Scheduling Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0
5. Total Payment to GridFlorida	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$30,500,000	$366,000,000
6. Transmission Cost in Base Rates Adjusted for Sales (see Note 1)	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$24,708,430	$296,501,159
7. Difference	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$5,791,570	$69,498,841
8. Less: Oil Back-Out flow back to customers	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$833,333	$10,000,000
9. **GridFlorida Transmission Charges**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$4,958,237**	**$59,498,841**

Note 1

	$ Millions	MWH Sales	¢ / KWh
Actual 2000	$265	87,959,341	0.3013
Projected 2003 Sales		98,415,270	
Transmission Costs in Base Rates Adjusted for Sales	$296.5		

Transmission Costs in Base Rates	$296,501,159

FOR ILLUSTRATIVE PURPOSES ONLY

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2003 THROUGH DECEMBER 2003

Rate Class	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1	60.938%	51,792,551,061	9,702,307	1.096656115	1.075433109	55,699,424,211	10,640,094	52.70839%	59.62714%
GS1	71.059%	6,103,694,487	980,550	1.096656115	1.075433109	6,564,115,139	1,075,326	6.21162%	6.02613%
GSD1	78.573%	22,546,325,257	3,275,656	1.096544563	1.075351927	24,245,234,312	3,591,903	22.94327%	20.12904%
OS2	149.531%	22,355,962	1,707	1.080484913	1.063082399	23,766,230	1,844	0.02249%	0.01033%
GSLD1/CS1	81.969%	10,104,646,264	1,407,237	1.094747540	1.074025051	10,852,643,219	1,540,569	10.26986%	8.63336%
GSLD2/CS2	90.955%	1,577,672,977	198,010	1.087891242	1.068548693	1,685,820,398	215,413	1.59529%	1.20718%
GSLD3/CS3	84.688%	533,026,130	71,849	1.026933481	1.022023682	544,765,328	73,784	0.51551%	0.41349%
ISST1D	0.000%	0	0	1.096656115	1.075433109	0	0	0.00000%	0.00000%
SST1T	95.114%	94,440,323	11,335	1.026933481	1.022023682	96,520,247	11,640	0.09134%	0.06523%
SST1D	81.410%	69,037,195	9,681	1.058919085	1.046606781	72,254,796	10,251	0.06837%	0.05745%
CILC D/CILC G	93.492%	3,566,365,476	435,459	1.084866212	1.066720945	3,804,316,751	472,415	3.60003%	2.64742%
CILC T	93.120%	1,271,570,984	155,881	1.026933481	1.022023682	1,299,575,659	160,079	1.22979%	0.89708%
MET	66.484%	91,165,376	15,653	1.058368342	1.046190930	95,376,390	16,567	0.09025%	0.09284%
OL1/SL1/PL1	297.393%	552,410,372	21,204	1.096656115	1.075433109	594,080,404	23,253	0.56218%	0.13031%
SL2	100.229%	90,008,136	10,251	1.096656115	1.075433109	96,797,730	11,242	0.09160%	0.06300%
TOTAL		98,415,270,000	16,296,780			105,674,690,814	17,844,380	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2003 through December 2003.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2000 demand losses.
(5) Based on 2000 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FOR ILLUSTRATIVE PURPOSES ONLY

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2003 THROUGH DECEMBER 2003

Rate Class	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1	52.70839%	59.62714%	$2,450,901	$33,271,416	$35,722,317	51,792,551,061	-	-	-	0.00069
GS1	6.21162%	6.02613%	$288,836	$3,362,528	$3,651,364	6,103,694,487	-	-	-	0.00060
GSD1	22.94327%	20.12904%	$1,066,845	$11,231,827	$12,298,672	22,546,325,257	48.23371%	53,316,880	0.23	-
OS2	0.02249%	0.01033%	$1,046	$5,766	$6,812	22,355,962	-	-	-	0.00030
GSLD1/CS1	10.26986%	8.63336%	$477,541	$4,817,336	$5,294,877	10,104,646,264	61.70922%	22,430,977	0.24	-
GSLD2/CS2	1.59529%	1.20718%	$74,180	$673,593	$747,773	1,577,672,977	67.56448%	3,198,716	0.23	-
GSLD3/CS3	0.51551%	0.41349%	$23,971	$230,721	$254,692	533,026,130	70.23956%	1,039,546	0.25	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
SST1T	0.09134%	0.06523%	$4,247	$36,398	$40,645	94,440,323	10.45089%	1,237,888	**	-
SST1D	0.06837%	0.05745%	$3,179	$32,055	$35,234	69,037,195	62.93622%	150,266	**	-
CILC D/CILC G	3.60003%	2.64742%	$167,399	$1,477,235	$1,644,634	3,566,365,476	73.24678%	6,669,825	0.25	-
CILC T	1.22979%	0.89708%	$57,184	$500,565	$557,749	1,271,570,984	77.61662%	2,244,208	0.25	-
MET	0.09025%	0.09284%	$4,197	$51,805	$56,002	91,165,376	55.94088%	223,243	0.25	-
OL1/SL1/PL1	0.56218%	0.13031%	$26,141	$72,712	$98,853	552,410,372	-	-	-	0.00018
SL2	0.09160%	0.06300%	$4,259	$35,154	$39,413	90,008,136	-	-	-	0.00044
TOTAL			$4,649,926	$55,799,111	$60,449,038	98,415,270,000		90,511,549		

Note: There are currently no customers taking service on Schedule ISST1(T). Should any customer begin taking service on this schedule during the period, they will be billed using the ISST(D) Factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2003 through December 2003
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730) For GSD-1, only 83.265% of KW are billed due to 10 KW exemption
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding.

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Reservation Demand Charge (RDC) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (SDD) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1 (D)	$0.03	$0.01
SST1 (T)	$0.03	$0.01
SST1 (D)	$0.03	$0.01

FOR ILLUSTRATIVE PURPOSES ONLY

Transmission Revenue Requirements

Preliminary Cost of Service Based on 12 Month Ending/13 Month Average
December 2000
In (000)

		2000 Cost of Service (1)
1	**KWH Sales**	87,959,341,413
2		
3	**Transmission -**	
4	Transmission Base Revenues	$277,056
5	Generation Step Up Transformer Adjustment (2)	($14,532)
6	Transmission of Electricity by Others Adjustment (3)	($9,161)
7	Refunctionalization of Distribution Facilities (4)	$12,373
8	Refunctionalization of Transmission Facilities (4)	($359)
9	Transmission Retail Base Revenues (Adjusted)	$265,377

Notes:

(1) Actual 2000 "jurisdictional adjusted" financial data per Surveillance Report was assigned/allocated to operating functions based on traditional FPSC Cost of Service allocation methodologies.
(2) Generation Step Up (GSU) transformers which are traditionally considered Transmission Plant will not be transferred to GridFlorida.
(3) Transmission of electricity by others which is traditionaly funcionalized to the Transmission responsibility center will be excluded from the calculation of GridFlorida revenue requirements.
(4) Estimated adjustment for portion of Transmission/Distribution joint use substations that will be transferred from Distribution to the GridFlorida or from Transmision to Distribution.

FOR ILLUSTRATIVE PURPOSES ONLY

Estimate of FPL Retail Responsibility of Transmission Service from GridFlorida

For Illustrative Purposes:

Line			Year 1 *($Millions)*
1			
2	**FPL Revenue Requirement Summary**		
3	Zonal Charge Estimate	Part 1	$293
4	System Charge Estimate	Part 2	23
4	Grid Management Charge Estimate	GMC	50
5	Scheduling Charge Estimate (included in GMC)	Schedule 1	0
6	**Total Revenue Requirement**		$366
7			
8			
9	**Zonal Charge Revenue Requirement**		
10	Existing Facilities @ 12/31/00	Note 1	$310
11	Phase in TDU Facilities	Note 2	5
12	Total Zonal Revenue Requirement		$315
13	FPL Retail Load Ratio Share of zone		93%
14	Total Zonal Revenue Requirement - FPL Retail		$293
15			
16	**System Charge Revenue Requirement**		
17	FPL Share of Transmission Net Additions (2001 and 2002)	Note 3	$123
18	Annual Carrying Charge Rate	Note 4	18.5%
19	FPL Load Ratio Share of System Charge		$23
20			
21	**Grid Management Charge**		
22	Start-up Costs	Note 5	$23
23	GridFlorida A&G and other expenses	Note 6	27
24	Total Grid Management Charge		$50

Notes:

1 Estimate of Revenue requirement of FPL's transmission facilities as of December 31, 2000

2 Based on estimate of Transmission Dependent Utilities (TDU) revenue requirements in FPL zone as provided during the Collaborative process in 2000 (Exhibit CMN-1, Witness Naeve, page 1265). The revenue requirements of $23 million is phased-in over 5 years

3 This is a proxy of GridFlorida's transmission plant additions during 2001 and 2002 allocated to FPL retail load. This estimate of transmission plant additions is based on FERC Form 1 data of net transmission plant additions for 1999 and 2000. This is only as a proxy of what the System Charge to FPL would be.

4 Annual carrying charge rate estimates revenue requirements to cover expenses as outlined in the Transmission Pricing Plan, and other expenses such as depreciation and return requirements on new facility investments.

5 1st year revenue requirement for GridFlorida's Start-up costs reflect the net cost responsibility to FPL retail customers. Refer to Exhibit WRA 1.

6 1st year revenue requirement for GridFlorida's operating expenses reflect the net cost responsibility to FPL retail customers. Refer to Exhibit BLH 3.

Docket No. 001148-EI
Late Filed Exhibit No. 19
October 12, 2001

FPL Transmission Projects
Volatility of Estimated Generator Integration Costs
MW by In-Service Year

Line		2001	2002	2003	2004	2005	2006	Totals
1	Number Of Requests	2	7	22	14	6	2	53
2	MW In-Service By Year	374	4,218	8,684	6,770	4,055	318	24,419
3	Generation Integration Costs ($millions)		$71	$119	$129	$119	$94	$531
4	Year to Year Change in Rate of Additions for Integration			66%	9%	-8%	-21%	
5	Estimate of Annual Revenue Requirement Inrease*	$ 13	$ 22	$ 24	$ 22	$ 17		
6	$Revenue Requirement/kW Generation Added	$ 3.13	$ 2.52	$ 3.52	$ 5.41	$ 54.69		
7	Impact on Annual System Charge	$ 13	$ 35	$ 59	$ 81	$ 98	$ 286	
8	Annual Increase in Integration Portion of System Charges		166%	68%	37%	21%		

* Estimated using the same 18.5% carrying charge rate used in KMD-1. The actual year portions of these costs would be included in rates is unknown and beyond the control of GridFlorida, because that is dependent on how fast the Generator's contribution to upgrades is credited against transmission service charges, which, in turn, is dependent on the output of each generator.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 19
COMPANY/
WITNESS: FPSC Staff
DATE: 10-3-5-01

EXHIBIT NO. ______
DOCKET NO. 010577-EI
TAMPA ELECTRIC COMPANY
(TLH-1)
DOCUMENT NO. 1

EXHIBITS TO THE TESTIMONY OF
THOMAS L. HERNANDEZ

DOCUMENT NO. 1

TAMPA ELECTRIC COMPANY
RESPONSE TO FLORIDA-SPECIFIC
RTO ISSUE LIST

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 20
COMPANY/
WITNESS: Hernandez
DATE: 10-3 — 5-01

TAMPA ELECTRIC COMPANY RESPONSE TO FLORIDA-SPECIFIC RTO ISSUE LIST

Tampa Electric Company hereby respectfully submits its response to the issue list discussed at the RTO Workshop held at the Florida Public Service Commission on February 4, 1999.

Tampa Electric believes that the workshop process has reached a critical point. With the identification of the issues, the time is now ripe to address next steps and organization of this effort. The goal should be to develop consensus on resolution of the transmission issues described below. The FPSC should lead and chair the study effort. We once again suggest that the use of an expert third party facilitator would help, and not hinder FPSC leadership of the study effort. The issues to be addressed are complex and potentially divisive. An independent, expert facilitator could assist the FPSC by facilitating the process under the FPSC's direction as it relates to discussion, analysis and issue resolution. Facilitation could also include, if desired, administrative support such as scheduling, maintaining meeting records, noticing, establishing agendas, providing meeting materials, etc.

Category I - Planning & Operations Issues

This category of responses addresses the reliability set of issues. Tampa Electric uses the North-American Electric Reliability Council (NERC) definition of reliability, which consists of both adequacy (planning) and security (operations). The Florida Public Service Commission (FPSC) in considering the planning and operations of the Peninsular Florida grid should treat generation and transmission as integrated resources for the region. The Peninsular Florida grid (or bulk electric transmission system) is operated as a single machine moving power in bulk from production to distribution and ultimate consumption. Operation of the entire system involves the real time balancing of generation and demand ensuring interconnection frequency, system stability and safe loading levels on both lines and equipment. Generation reserves enable interconnected operation of the Peninsular Florida grid by providing regulation (AGC), frequency response, and contingency reserves to restore regional generation and demand balance following unit outages within the state. Additionally, generation reactive capability must be available under normal and emergency conditions to maintain adequate voltage levels on the grid. In terms of the operability of this "single machine", generation and transmission cannot be separated as services distinct from each other.

The Federal Energy Regulatory Commission (FERC) recognized the inseparability of generation and transmission by including certain generation services (i.e. ancillary services) as part of the pro-forma transmission tariffs required under FERC Order 888. These services (e.g., operating reserves, regulation, reactive supply and voltage control) are essentially, enabling services without which a power system could not function. FERC recognized that these services are necessary for the provision of basic transmission service, so it required in Order 888 that transmission providers include these services in their tariffs.

(a) What is the proper role of the FPSC in transmission planning?

Existing Situation: Historically the FPSC has had different roles in the planning of generation and transmission capacity. It has played a very significant and important oversight role in the planning of generation capacity as well as in demand side management, including conservation. The FPSC has required utilities to file ten-year generation site plans, reviewed an annual Florida Reliability Coordinating Council (FRCC) process that establishes prospective statewide reserve margins and determined the adequacy of those forecasts. In contrast, the FPSC's role in the assessment and planning of transmission capacity has been more limited. Although the FPSC has exercised its authority under the grid bill in the past to investigate transmission adequacy (e.g. third 500 kV line), it has played less of a role in FRCC's annual transmission planning process.

Complaints: With the advent of increased wholesale competition and "open access" rules by the FERC, the FRCC planning process needs to be re-addressed and the FPSC needs to play a larger role in the determination of statewide transmission adequacy. The revamping of the regional transmission planning process should be done from both a generation and transmission planning perspective. The review should include both, because they can be substitutes for each other to varying degrees in addressing reliability needs.

Solutions: The FPSC should lead the development of a regional planning process that fully:

Integrates Loads
Integrates Generation
Assesses and Ensures Reliability
Facilitates Wholesale Markets
Addresses Transmission Service Requests, and
Addresses compatibility with the generation planning process.

This process should reflect continuing involvement of the FPSC and an important ongoing surveillance review of the adequacy of the then current regional plan.

(b) What is the proper role of the FPSC in transmission siting?

Existing Situation: Under the Transmission Line Siting Act (TLSA), the FPSC holds hearings to certify the need for high voltage transmission lines and responds to complaints regarding the need for lower voltage transmission lines. However, the utilities are on their own to site the needed lines and obtain required permits.

Complaints: The existing siting process is very difficult and expensive. In Florida and nationwide recently there has been limited success in the siting of high voltage transmission lines.

Solutions: The siting difficulties would be significantly mitigated if the FPSC were to play a larger role in regional transmission planning that identifies needed expansion for the Peninsular Florida grid. The FPSC has sufficient legislative mandate (Grid Bill, Power Plant Siting Act [PPSA] and TLSA) to plan, site and order construction of transmission facilities to ensure and maintain a reliable, cost effective and environmentally acceptable Peninsular Florida grid.

(c) What is the proper role of the FPSC in transmission reliability and operations?

Reliability, as defined by NERC, consists of adequacy (planning) and security (operations). The role of the FPSC in transmission adequacy was discussed above. Tampa Electric's following comments focus on the role of the FPSC in transmission security.

Existing Situation: Transmission security of the Peninsular Florida grid is accomplished through the FRCC Operating Committee in compliance with NERC operating policies. The FRCC process to ensure security is well established. A major feature of the FRCC protocols is the "Security Process" published October 30, 1996, by the FRCC. The Peninsular Florida grid security process consists of these major elements:

Security Coordination
Regional Security Plans
Florida Electrical Emergency Contingency Plan
Capacity Emergency Operations
Automatic Load Shedding
Reserve Capability
Transmission - Oscillations
Transmission - Resolving/Reporting Potential Transmission Problems
Florida/Southern Interface

Complaints: There are at least two issue areas regarding the role of the FPSC in transmission operations: (1) independence of system operators, and (2) FPSC involvement in the setting of reliability standards by NERC and FERC.

(1) With the advent of increased wholesale competition and the FERC open access code of conduct rules, concern has been raised by some parties in Florida and elsewhere over potential discrimination by the system operator in making operational decisions that could affect commercial operations.

(2) NERC is undergoing a transition to a self-regulating organization with FERC oversight. Reliability legislation has been developed to make this transition complete. New NERC standards (issued recently and filed with the FERC for approval) will change regional planning and operating practices. Until now, the FPSC has not involved itself in the development of these new NERC standards nor has it evaluated the standards to determine if they meet the needs of the Peninsular Florida grid.

The FRCC Security Process is specific and unique to Peninsular Florida to ensure operational security of the bulk transmission grid and consequently, continuity of service to the citizens and ratepayers of Florida. The Automatic Load Shedding program is a good example of a unique standard to Peninsular Florida that directly impacts retail customers. The utilities in Peninsular

Florida have developed a sophisticated and coordinated load shedding program that is designed to prevent a Peninsular Florida blackout.

Over half of Peninsular Florida's distribution load is placed on the underfrequency load shedding program to protect equipment from generator out of step conditions (instability) and to ensure timely restoration. Recovery from a blackout condition could take days and weeks. The load served from distribution feeders automatically trip, in stages, as frequency dips below 59.82. There are no "boundaries" on who solves this problem; all utilities share equitably in loss of load to enable timely restoration of service to the Peninsular Florida grid.

Solutions:

(1) Tampa Electric does not believe that the current FRCC Security Process results in discriminatory practices, although the potential exists for such discrimination. Tampa Electric does not support a "California" solution where a complete, duplicative infrastructure is being put in place to insure "independence". The California ISO was put in place to enable retail competition. This ISO does not own generation or transmission but is accountable for ensuring reliability. A very complex and costly infrastructure is being put in place to accommodate bidding, scheduling and the procurement of critical generation services for reliability (i.e. ancillary services). Recent estimates are that California has spent in excess of $500 million in creating its ISO and that the ISO's current annual operating expense is $120 million.

At the February 4th FPSC RTO Workshop there was a brief discussion of lower cost solutions. Tampa Electric supports continued discussion through this FPSC study task force to explore within the current FRCC Security Process how to better ensure non-discriminatory actions by system operators and the Security Coordinator. Tampa Electric believes that, when this inquiry is completed and corrective actions are taken, there should be no need to form an ISO in Peninsular Florida

(2) The FPSC should play a role in the development of FRCC reliability standards. FPSC input is necessary during FRCC standards development to ensure a state regulatory perspective prior to approval by the NERC Board and FERC. In addition, the FPSC should be protective of its jurisdiction under the Florida grid law should any federal reliability legislation be proposed.

The FPSC has clear authority over transmission reliability under the grid bill. The regional changes taking place under the new NERC standards are significant. These relate to security coordination, Available Transmission Capability (ATC), tagging, planning standards, Transmission Load Relief Procedures (TLR) and Interconnected Operations Services (i.e. Ancillary Services). The standards involve significant issues. An example is the recent FERC Order on the NERC TLR Policy. The filings required of FERC-jurisdictional Peninsular Florida utilities involve development of a regional congestion management methodology and procedures to ensure comparable curtailment of native retail and wholesale load.

(d) Do / should transmission providers plan their transmission additions based on their

own needs (for generation and load) or do / should they plan their transmission additions based on their own needs and the needs of the transmission dependent utilities?

Existing Situation: Transmission providers do plan their transmission additions based on both their own needs and the needs of Transmission Dependent Utilities (TDU's) but not necessarily in an optimal, regional manner. Currently, each individual transmission provider plans its own optimal local and bulk transmission system taking into account both retail and firm wholesale transactions (native load). These plans are provided individually to the FRCC Engineering Committee, which then aggregates the results and assesses the aggregation under NERC and FRCC planning standards to ensure transmission adequacy. Each provider then builds its own required expansion and deals with cost justification and recovery on its own.

Complaints: The current expansion of the bulk grid may not be optimal nor efficient for Florida as a whole because it results from an aggregated plan rather than a regionally developed plan. Consideration is not given to optimizing the individual plans from a regional perspective. It has been particularly difficult to determine which utility is responsible for expansion needed at utility borders. Providers are reluctant to expand and pay for new facilities unless the costs can be justified based solely on their own needs.

Solutions: The FPSC study task force should explore a regional planning process, which could yield the following; (1) local area planning efforts, led by each transmission provider conducted in an open process with all load-serving entities in each local area, and (2) the regional planning of the bulk transmission grid.

Both local area and bulk transmission planning should be an agreed upon regional process subject to regional organization review by the FPSC. There would need to be some mechanism to determine which provider must build regionally justified transmission as well as to ensure cost recovery. The FPSC should participate in the development and execution of such a regional planning process.

(e) **What information should be shared regarding transmission planning and with whom should this information be shared?**

Existing Situation: In order to plan the Peninsular Florida grid, models of the regional system are required. The FRCC builds such models by aggregating the plans of the individual utilities.

Complaints: In an increasingly competitive wholesale market, some utilities may be concerned about releasing commercially-sensitive information to the public which may, nevertheless, be needed for regional planning, and there is no accountability for changes in plans that may impact regional transmission needs.

Solutions: Ultimately, all Load-Serving Entities (LSE's) within Florida should be required to submit specific load forecasts and resource plans for a defined period of years. Approaches should be explored regarding deviation from submitted LSE forecasts of loads and resources once the bulk grid has been planned based on the information previously provided. While plans do change, LSE's should have an incentive to submit their best estimate of future loads and resources. A regional process should create an incentive for timely declaration of forecasts to ensure transmission capacity.

The regional process should also require all LSE's, to submit wholesale and retail load forecasts, resources and associated requests for transmission service through an OASIS system

(f) What does optimization of transmission planning for Peninsular Florida entail? Is it needed?

See answer to (d) above.

(g) Should there be central dispatch of generation and transmission facilities in Peninsular Florida?

Existing Situation: There is no central dispatch. Each of 12 control areas in Peninsular Florida dispatch generation and control transmission facilities within their respective areas.

Complaints: Tampa Electric has not heard any complaints suggesting the need for a central dispatch or power pool solution for Peninsular Florida.

Solutions: The benefits of central dispatch for the Peninsular Florida grid are unknown, and a cost/benefit study would be necessary to quantify any savings. Years ago a central dispatch study was done by the FCG/FPSC that led to the establishment of the Energy Broker instead of a centrally dispatched system. Central dispatch at that time was not deemed as cost effective as the creation of the Energy Broker.

The Energy Broker and other market-based economy energy interchange transactions have served Peninsular Florida well in increasing the utilization of lower incremental cost generation. However, there may be some functions that could be performed more efficiently with centralization, such as administration of OASIS, ATC calculation and processing of open access requests. The FPSC study task force should address these functions.

(h) What are the appropriate boundaries for regional transmission planning?

Existing Situation: The FRCC creates models of the Peninsular Florida grid that can be used for regional planning. These models include grid facilities as well as facilities in the Southern Company system so as to study import and export capabilities.

Complaints: Tampa Electric agrees with the FPSC's position that the appropriate boundary for regional transmission planning is the Peninsular Florida grid.

Solutions: The Peninsular Florida grid has historically and appropriately been planned as a separate, unique region. It is now a separate reliability region under NERC. The FPSC study task force should develop a planning process that focuses on Peninsular Florida as a separate region.

(i) Please comment on each of the following FERC ISO Principles:

Tampa Electric believes that resolution of each of the issues raised by the FERC ISO Principles set forth below do not require the formation of an ISO and that there are more cost-effective ways to improve the efficiencies and reliability of the Peninsular Florida grid.

Tampa Electric submits, however, that the Florida solution at a minimum must address these ISO Principles in order to meet FERC's threshold for positive consideration of regional transmission organizational (RTO) approaches that address Peninsular Florida's transmission matters. While these legitimate issues raise state and federal jurisdictional questions, it is clear to Tampa Electric that they must be addressed here and now if the FPSC is to have the opportunity to craft a Peninsular Florida solution without total preemption by FERC.

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

Existing Situation: The existing regional organization is the FRCC, a NERC regional reliability council. The governance of the FRCC is weighted by load, transmission facility ownership and generation ownership. This governance has been appropriate for reliability functions to date.

Complaints: The governance of a reliability organization may not be appropriate for matters regarding fair access to the bulk grid. For example, the NERC governance is changing as NERC delves into access and "fairness" matters. There are perceptions that there may be fairness issues relating not only to short and long-term access, but also to security protocols.

Solutions: Any regional transmission organization must be sensitive to fairness issues. Accordingly, a different type of more inclusive governance than the FRCC version may be required.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

Existing Situation: FRCC members each have a financial interest in the economic performance of their own merchant functions. The transmission providers with open access tariffs adhere to strict codes of conduct which separate their grid operations function from their wholesale merchant function.

Complaints: There are no complaints as to the current codes of conduct.

Solutions: The FERC codes of conduct set acceptable standards, but implementation and fairness issues have been raised. See comments elsewhere on access, security and governance issues.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

Existing Situation: Each FERC-jurisdictional transmission provider in Florida has its own open access tariff that provides open access to the grid facilities that it owns and/or operates. There is no Peninsular Florida grid-wide transmission tariff and rates are pancaked.

Complaints: FERC non-jurisdictional utilities are not required to file open access tariffs, and there is a "trust" concern on the part of some parties that the open access provisions of existing tariffs might not be fairly administered. Pancaked rates further contribute to the inefficiency of the Florida Peninsular wholesale market.

Solutions: The FPSC study task force should evaluate the need for a Peninsular Florida grid-wide transmission tariff for wholesale transactions and the desirability of a related centralized administrative function. There should also be addressed the issue of whether a centralized administrative function is an appropriate response to fairness concerns regarding open access. (Also see comments on pancaked rates issue II.c.)

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well defined and comply with applicable standards set by NERC and the regional reliability council.

Existing Situation: Under the FRCC, short-term reliability of the regional grid is the primary responsibility of the Operations Planning Coordinator and Security Coordinator. These roles are currently filled by Florida Power Corporation and Florida Power & Light Company, respectively.

Complaints: No complaints, except that some parties have raised a "trust" issue regarding fair implementation of security protocols.

Solutions: If added assurances are desired, the FPSC could actively participate in monitoring the operation of the Peninsular Florida grid.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

Existing Situation: There are currently 12 separate control areas in Peninsular Florida.

Complaints: No complaints,

Solutions: There is no need to eliminate or duplicate the functions of the existing control areas.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules *should promote efficient trading.*

Existing Situation: NERC and the FRCC are already working to resolve this issue through the recent FERC order on Transmission Loading Relief (TLR) procedures.

Complaints: Because of retail impacts from TLR, the FPSC should be more involved in this issue.

Solutions: The FPSC study task force should address this issue. Regional TLR, redispatch and congestion management procedures that promote efficient trading are necessary for the Peninsular Florida grid. It should be possible to establish and implement such procedures without the necessity of creating an entity with direct operating control.

7. The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open competitive market.

No response is given because there is no need for a separate entity with separate incentives to perform all the functions that could be assigned to an ISO. As identified in other responses, there are more cost-effective ways to assure the efficient, fair and reliable functioning of the Peninsular Florida grid wholesale market.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems and appropriate expansions.

Existing Situation: Each FERC jurisdictional utility offers open access under the FERC pro forma transmission tariff. There is no region-wide transmission pricing or planning, and rates are pancaked.

Complaints: The absence of region-wide pricing and planning and the existence of pancaked rates negatively affects the efficiency of the Peninsular Florida grid and wholesale market.

Solutions: Different transmission pricing approaches to eliminate pancaked rates should be explored. See other comments under pricing issue Category II.c. below. In addition, a regional planning process should be developed and implemented. See comments in Category I.a-h above.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

Existing Situation: Currently, six utilities provide transmission access information on the Florida Open Access Same-Time Information System (FLOASIS). Another utility posts such information on an independent web page. Others post no information.

Complaints: The availability and accuracy of transmission system information is not completely uniform within the Peninsular Florida region.

Solutions: There may be efficiencies to be gained with centralized administration of certain open access functions, such as operation of the FLOASIS, calculation of ATC and processing of requests. All peninsular Florida utilities should participate in any centralized approach.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

Existing Situation: Existing control areas and the FRCC already coordinate" with neighboring control areas and regional reliability councils. More specifically, the transmission interconnections between Peninsular Florida and the Southern Company (the only other neighboring control area with which Peninsular Florida is interconnected) are controlled to ensure reliability in both of the regions and the FRCC coordinates this effort.

Complaints: No complaints.

Solutions: There is no need to make any changes with respect to coordination with neighboring control areas.

Category II - Pricing Issues

(a) Do multiple transmission rates, terms and conditions create problems for transmission dependent utilities?

Existing Situation: Multiple transmission rates impact all wholesale market participants, including transmission dependent utilities, for interchange transactions. When utilities trade power, they use point-to-point transmission services, which often must be scheduled across multiple transmission owners' systems, such that multiple charges for transmission apply. (Also see comments under pancake rates issue c.)

Complaints: Paying multiple transmission rates within the Peninsular Florida grid results in economic inefficiency because economic transactions may not go forward due to multiple transmission charges.

Solutions: This issue creates problems for transmission dependent utilities and other market participants and needs to be addressed. See comments under pancake rates, issue c below.

(b) Is wholesale/retail transmission comparability a desirable goal? If so, how can it be achieved?

Existing Situation: Some retail ratepayers' energy is received as a result of transmission at wholesale across another utility's bulk grid using the FERC transmission tariff rates for ultimate delivery by the retail ratepayer's utility. Other retail ratepayers are served directly by the "other utility" and that energy is considered retail by such utility with the transmission cost bundled within retail rates that are regulated by the FPSC.

Complaints: While both groups of retail ratepayers make use of the "other utility's" bulk transmission system, access to the grid is different for wholesale and retail purposes. In addition, there is a mix of regulation over transmission; some is subjected to regulation by FERC, some to the FPSC, some to neither.

Solutions: While the FERC has mandated that there should be wholesale/retail transmission comparability, and while this is a desirable goal, there are complex jurisdictional and implementation issues. This matter should be considered in the context of eliminating pancaked rates, which will at least mitigate discrepancies between wholesale and retail transmission service. See comments under pancake rates, issue c below.

(c) **Does pancaking of transmission rates (defined as additive transmission wheeling rates from control area to control area) exist in Florida? Should pancaking be eliminated and, if so, how?**

Existing Situation: Yes, it exists. There are two forms of rate pancaking in Florida. One form is for point-to-point services, where a power sale whose contract path traverses multiple control areas incurs a transmission charge to each owner, regardless of the distance traversed on any particular line, or whether any real power flows on the line at all. Another form of rate pancaking occurs for network service. Some utilities have non-contiguous systems such that their resources are not directly connected to their loads. These utilities have some local transmission systems that they own, but mostly they rely on the owners of the bulk grid to transmit their energy to their isolated, local distribution systems. These utilities pay the cost of their own transmission systems, plus a load ratio share of the cost of whatever bulk grid systems they use on a network basis. In addition, they pay any point-to-point charges incurred to transmit energy across any other utilities' transmission systems.

Complaints: Pancaked rates for point-to-point service are not economically efficient. Nor are additive rates involving combinations of point-to-point and network services. Lastly, rates for network service may not appropriately separate or credit local and bulk grid facilities. Transmission rate proceedings at FERC are very expensive and take many years (e.g. parties are still waiting for a FERC order regarding FPL's 1993 transmission rate filing). Although FERC sets protested rates for hearing "subject to refund," refund protection of a rate that remains in place for many years does not protect market structure or market transactions subject to such rates.

Solutions: Rate pancaking should be eliminated in Peninsular Florida if cost subsidy issues can be resolved. As a general matter, this elimination of pancaked rates should positively affect the efficiency of the wholesale generation market for the benefit of all retail ratepayers. The elimination of pancaked rates does not imply the establishment of a single postage stamp rate for the Peninsular Florida grid. There are other rate models which can be utilized which address both increased efficiency in the wholesale market while providing appropriate price signals for siting new generation. The issues are complex and the study task force, under the leadership of the FPSC, should address potential economic solutions in working toward a comprehensive Peninsular Florida grid solution.

(d) Should a cost-benefit analysis be performed on any proposed changes to the current regime? If so, generally speaking, how would such an analysis be performed?

Existing Situation: Generally, cost-benefit analysis is used in evaluating any changes considered by the FPSC.

Complaints: No cost/benefit analyses have been done at a regional level of any proposed changes. Additionally, not all issues can be resolved through cost-benefit analyses. Some involve issues of discrimination, fairness, law, etc., that require solutions that may not be the most cost effective to companies or ratepayers.

Solutions: A cost-benefit analysis should be performed on any proposed changes, however, it should be recognized that such analyses are only one of the factors to be used to assess any need for change.

(e) Is transmission congestion pricing a problem in Florida? What is the appropriate methodology to be used to determine congestion pricing in Florida?

Existing Situation: Transmission congestion pricing is an issue which is currently being addressed by FERC and NERC. This issue is in the Transmission Loading Relief (TLR) dockets at FERC and in a NERC pilot study to be conducted this summer.

Complaints: No complaints, except that some parties have raised a "trust" issue regarding security protocol procedures.

Solutions: The FPSC study task force should include this issue in its scope of work. Regional TLR, redispatch and congestion management procedures that promote efficient trading are currently the subject of discussion at the FRCC, and the FPSC's active participation would be constructive and important.

Category III - Governance Issues

(a) Comment in general on the proper governance of any RTO or ISO that may be implemented in Florida? What governmental and private agencies should be involved and to what extent?

Existing Situation: The FRCC currently conducts activities relating to regional reliability. The governance of the FRCC is established and has so far served the parties well.

Complaints: The governance of a reliability organization may not be appropriate for matters regarding fair access to the bulk grid. For example, the NERC governance is changing as NERC delves into access and "fairness" matters. There are perceptions on the part of some parties that there may be fairness issues relating not only to short and long-term access, but also to security protocols.

Solutions: Any regional transmission organization must be sensitive to fairness issues. Accordingly, a different type of more inclusive governance than the FRCC version may be required.

(b) What is the FPSC role in transmission dispute resolution?

Existing Situation: Alternative Dispute Resolution (ADR) procedures are included in open access tariffs. NERC and the FRCC also have ADR procedures for operational disputes. Transmission rate disputes are subject to FERC jurisdiction. Although disputes dealing with uneconomic duplication of facilities are decided by the FPSC, there is little attention to unfulfilled expansion needs.

Complaints: The areas where transmission disputes arise are: (1) operational disputes, (2) tariff/rate disputes, and (3) transmission expansion disputes.

(1) Operational: No serious complaints have arisen because the existing procedures have been sufficient in a regime where the rules have not been mandatory. Under this non-mandatory regime, the NERC and FRCC ADR procedures have been little used. In the future world of mandatory rules, the NERC and FRCC operating standards will be backed up with commensurate penalties to ensure compliance. National legislation is being proposed to facilitate this. This future mandatory regime will bring about an increased need for the use of effective ADR processes at the regional level.

(2) Tariffs/Rates: The FERC process for resolving tariff and rate filings is time-consuming and expensive. Pricing issues often are left unresolved after many years. Wholesale transmission rates will continue to be regulated and thus will be subject to rate proceedings.

(3) Transmission Expansion: In the past, the absence of regional planning has resulted in a failure to develop a consensus on what transmission expansion is necessary for wholesale market efficiency purposes, in contrast to reliability purposes.

Solutions: Proper regional planning will result in the identification of needed transmission expansion or other fixes necessary for economic or reliability purposes that will raise cost responsibility issues. FPSC involvement after ADR proceedings could be helpful in resolving these in a timely manner in furtherance of the Grid Law objectives. The FPSC study task force should include transmission expansion, (3) above, in its scope of work. In addition, the FPSC study task force should explore involvement by the FPSC after any unsuccessful ADR proceedings relating to operational matters, (1) above, and tariffs/rates, (2) above. For example, many of the disputes subject to FERC jurisdiction might be avoided or their resolution expedited if there was a "statewide settlement" on the application of transmission rates to all users.

(c) Does undue market power exist in Florida? What problems are caused by the fact that the security coordinator as currently structured is not fully independent from a Florida utility?

Existing Situation: Functional unbundling, properly administered under FERC Order 888 and 889, together with evolving rules under NERC's leadership relating to the security of the transmission system, should effectively mitigate market power concerns as these relate to the Security Coordinator.

Complaints: No complaints, except that some parties have raised a "trust" issue regarding the independence of the Security Coordinator.

Solutions: If added assurances are desired, the FPSC could increase their participation in monitoring the operation of the Peninsular Florida grid.

(d) Is functional unbundling working in Florida? Can it work in Florida?

Functional unbundling can work in Peninsular Florida with the implementation of a regional planning process, resolution of trust issues relating to open access and security, elimination of pancaked rates and increased FPSC participation in monitoring the operation of the Peninsular Florida grid.

EXHIBITS TO THE TESTIMONY OF
THOMAS L. HERNANDEZ

DOCUMENT NO. 2

TAMPA ELECTRIC COMPANY'S
INITIAL COMMENTS ON PROPOSED RULEMAKING
IN FERC DOCKET NO. RM-99-2-000

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of	)	
	)	Docket No. RM99-2-000
Regional Transmission Organizations	)	

INITIAL COMMENTS OF TAMPA ELECTRIC COMPANY ON PROPOSED RULEMAKING

Tampa Electric Company ("Tampa Electric") hereby submits its initial comments on the "Notice of Proposed Rulemaking" that the Federal Energy Regulatory Commission ("Commission") issued in the above-captioned docket on May 13, 1999 ("RTO NOPR"). 1/ In accordance with the procedures prescribed in the RTO NOPR, Tampa Electric is also submitting with the original of these initial comments a diskette that contains the comments in electronic format.

Tampa Electric is a public utility organized under the laws of the State of Florida, with its principal place of business located at 702 North Franklin Street, Tampa, Florida 33602. Tampa Electric sells electric power at retail to approximately 500,000 customers in its service area in and around the City of Tampa. Tampa Electric also sells electric power at wholesale to customers in the region.

1/ IV FERC Stat. & Reg. ¶32,541.

Tampa Electric owns transmission facilities and provides transmission and ancillary services pursuant to an open access transmission tariff that is on file with the Commission. 2/ Tampa Electric is also reliant, directly or indirectly, on the services of other transmission providers within and beyond Peninsular Florida 3/ to effect many of its wholesale transactions. These comments are therefore provided from the perspective of both a provider and a user of transmission and ancillary services.

I

EXECUTIVE SUMMARY

In March, 1995, the Commission issued its "Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking" in the matter of *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services By Public Utilities; Recovery of Stranded Costs By Public Utilities and Transmitting Utilities*, Docket Nos. RM95-8-000 and RM94-7-001

2/ The tariff is designated as Tampa Electric's FERC Electric Tariff, First Revised Volume No. 4.

3/ For the purposes of these initial comments, "Peninsular Florida" means the whole of Florida east of the Gulf Power Company system in the Florida Panhandle, *i.e.*, roughly, east of the Apalachicola River.

("Open Access NOPR"). 4/ That proceeding culminated with issuance of a "Final Rule," Order No. 888, in April, 1996. 5/

One of the Commission's goals in that proceeding was to foster wholesale competition by requiring transmission providers to "functionally unbundle" their services and submit to the same rates and procedures as other users of their transmission systems. To that end, transmission providers were required to file open access transmission tariffs containing separately stated rates for transmission and ancillary services, to obtain such services under their own open access tariffs for all new wholesale transactions, and to rely on the same electronic information system as other customers to access such services. "Comparability" of service would thus be assured.

In its August, 1995 initial comments on the Open Access NOPR, Tampa Electric stated that "[i]mposition of the comparability standard without a precise focus on specific implementation measures for unbundling will not achieve the desired objective." At that time, Tampa Electric believed functional unbundling could work to achieve the Commission's goals, if properly implemented. Now, three years after the implementation of open access transmission and the functional unbundling requirement, the perception of undue discrimination in

4/ FERC Stat. & Reg. (Proposed Regulations, 1988-1998) ¶32,514.

5/ FERC Stat. & Reg. (Reg. Preambles, 1991-1996) ¶31,036 (1996); *on reh'g*, Order No. 888-A, III FERC Stat. & Reg. ¶31,048 (1997); *on reh'g*, Order No. 888-B, 81 FERC ¶61,248 (1997); *on reh'g*, Order No. 888-C, 82 FERC ¶61,046 (1998).

wholesale transmission services remains among some stakeholders in the Peninsular Florida region.

In recognition of this continued perception, interested parties have begun a deliberative process to identify and resolve the issues under the leadership of the Florida Public Service Commission ("FPSC"). The FPSC has held several workshops in 1999 to study Florida-specific issues regarding the advisability of establishing some form of Regional Transmission Organization ("RTO") or Independent System Operator ("ISO") for the region.

The participants in the FPSC workshops have focused on efforts to reach consensus on solutions to the relevant issues that are appropriate to the circumstances of the Peninsular Florida region. There is already a general consensus that the appropriate regional boundaries should be coextensive with the regional reliability boundaries of the Florida Reliability Coordinating Council ("FRCC"). Peninsular Florida is a large and efficient marketplace of sufficient size to allow regional coordination to benefit all users of the grid. In addition, the region has a unique geographical configuration and electrical characteristics and is situated such that the reliability of the system is under the jurisdiction of a single state regulatory authority, the FPSC, which facilitates efficient planning and operation of the system. Other relevant issues under discussion in Florida include governance, pricing, planning, and operations.

Based on its reading of the RTO NOPR, Tampa Electric believes that it is in agreement with the Commission's ultimate goals in this proceeding, namely, to further encourage and promote efficient and competitive wholesale electric markets. However, Tampa Electric believes that the Commission should defer to regional approaches that achieve regional market consensus, are endorsed by local state regulators, and that establish mechanisms to encourage further progress toward the desired goals. Within the Peninsular Florida region, the FPSC's leadership will be an important factor in the success of such efforts, and the Commission should not micro-manage the process even under circumstances where regional approaches do not initially meet its vision of an ideal RTO. The Commission should allow state regulators, such as the FPSC, to lead discussions on these issues in areas where they are willing to do so, and should be available to help such regulators, at their request.

The Commission should encourage regional discussions of transmission issues, including all of the RTO characteristics and functions described in the RTO NOPR. As long as all of the issues are considered, the Commission should defer to regional approaches that are endorsed by affected state regulators if they represent progress toward the Commission's goals. This policy would be consistent with the Commission's proposed "open architecture" approach, which recognizes the need for flexibility and constructive, evolutionary change.

Tampa Electric provides responses herein to many of the questions posed in the Commission's RTO NOPR, with a view, particularly, to defining what is currently needed within Peninsular Florida to resolve issues of trust and to improve the competitive wholesale market.

II

INITIAL COMMENTS

Below, Tampa Electric has set forth each of the Commission's specific requests for comments (with page citations to the mimeo version of the RTO NOPR), followed by Tampa Electric's corresponding comments. While section headings are used to group the requests by subject matter, the requests are numbered seriatim, 1 through 181, for ease of future reference.

A. Issues Concerning Discriminatory Conduct

1. **Public comments are requested on the extent to which there remains undue discrimination in transmission services, and if it remains, in what forms. (pages 83-84)**

Many market participants believe that there continues to be undue discrimination in the provision of wholesale transmission services within Peninsular Florida. Access to transmission services within this region is not as open as it could be to facilitate an efficient, robust wholesale market. Transmission users often must go to several individual transmission providers and Open Access Same-Time Information System ("OASIS") nodes, sign multiple agreements with various providers, and attempt to piece together and navigate through various partial paths to connect a power sale to a buyer. There is no central source of information to help a new market participant figure out how to do wholesale electric trading within the region. Also, many market participants perceive that firm transmission capacity is being unfairly withheld from the market.

2. **Comments are requested regarding what remedies should be imposed in an effort to eliminate any remaining discriminatory conduct. (page 84)**

The appropriate remedy is to encourage regional approaches that resolve the problems present within the regions. For the Peninsular Florida region, discussions on these issues are underway under the auspices of the FPSC.

3. **Should participation in RTOs be mandatory or are there other possible remedies? (page 84)**

While the FPSC should require all transmission owners and providers within Peninsular Florida to participate in regional discussions on transmission issues, other entities using wholesale transmission services within the region should be encouraged to participate as well. Participation by all transmission owners will be essential for a successful regional resolution. In any case, the Commission should give deference to a regional approach that has been endorsed by the FPSC.

4. **Could a performance-based rate system be designed to realign economic interests to remove the motive for discrimination? (page 84)**

It is possible, but there could still be incentives to discriminate under a performance-based rate system.

B. Issues Concerning RTO Benefits

5. The Commission seeks comment on the effect of RTOs on electricity market performance, including any data or other information that shed light on quantifying the extent of those benefits. (page 101)

No comment.

6. The Commission seeks comment on what types of disputes or other matters would be appropriate for the Commission to defer to the decisions of the RTO. (page 102)

Once a regional approach on transmission issues is established, the Commission should defer to decisions on matters that are placed under the management of the region, such as expansion planning and OASIS operations, as well as matters that are deemed to be subject to state jurisdiction, such as siting, permitting, need, etc.

7. In granting deference to decisions that result from an acceptable ADR process, would there be a need to distinguish between RTOs that are ISOs and RTOs that are transcos? (page 102)

No, so long as the ADR processes reflect regional solutions developed by market participants, with the active participation of the affected state regulatory authorities.

8. The Commission could also consider adopting streamlined filing and approval procedures. The Commission could consider different filing requirements for established RTOs. For example, should the threshold be lowered for the types of changes to operations or

practices that would not require a filing with the Commission? (pages 102-03)

Yes, the threshold should be lower for any region that resolves transmission issues with the endorsement of relevant state regulators. Initially, transmission providers were only required to file their pro forma open access tariffs with the Commission. Recently, the Commission has required more specific operating procedures (*e.g.*, curtailment practices) and other implementation practices (*e.g.*, OASIS practices) to be filed. If this trend continues, many detailed operating and planning procedures developed within the North American Electric Reliability Council ("NERC") and regional reliability councils may be required to be filed at the Commission, including updates of those procedures each time they are changed. Once resolution of transmission issues has been reached within a particular region, there should be less need for involvement in such matters by the Commission. For regions that successfully resolve transmission access issues, the Commission should require only that general transmission access procedures and practices be filed with it, and allow the detailed day-to-day procedures to be posted on the OASIS.

Should such a policy be applied equally for non-profit and for-profit RTOs? (page 103)

Yes, so long as the Commission defers, as appropriate, to regional solutions resulting from participation of the market participants and active involvement of state regulatory authorities.

9. **The Commission believes that the widespread formation of RTOs can provide substantial benefits. The Commission invites comment on the benefits of RTOs and the magnitude of these benefits. (page 103)**

In Peninsular Florida, settlement of transmission issues, whether this results in an RTO or some other arrangement, would likely result in increased wholesale trade within the region at lower transmission cost. As long as transmission owners can continue to recover their costs, there should be net benefits realized from such developments within the region. In addition, settlement and consensus on issues would lower litigation costs in Florida. The preparation of a cost-benefit analysis is under discussion within the region under the leadership of the FPSC.

C. <u>Issues Relating to State Commission Concerns</u>

10. **The Commission seeks comments regarding how an RTO would affect power costs. (page 109)**

Continued uncertainty in transmission markets will lead to reluctance on the part of existing market participants to actively engage in the market and can result in new entrants being reluctant to join in the market. Power cost savings within the Peninsular Florida region are likely if transmission issues are resolved. The desirability of doing such analyses is under discussion in the region under the direction of the FPSC.

11. **The Commission requests comments on the appropriate state role in RTO governance. For example, should state government officials participate as voting members of an RTO? (page 113)**

The FPSC could participate as a non-voting member of the governing board of any regional transmission entity that may evolve from discussions on transmission issues within the Peninsular Florida region. Such involvement is important to keep the FPSC fully informed of goals and strategies considered by the board, and of actions taken by the board, yet keep the relationship appropriately distant to allow the FPSC to continue its regulatory role with respect to issues within its jurisdiction.

12. **The Commission invites further comments from the state Commissions on all aspects of the proposed rule. (page 115)**

No comment.

D. Issues Relating to Minimum Characteristics and Functions

1. General

13. **There are four proposed minimum characteristics for an RTO:**

(1) independence from market participants;

(2) appropriate scope and regional configuration;

(3) possession of operational authority for all transmission facilities under the RTO's control; and

(4) exclusive authority to maintain short-term reliability.

In addition, the are seven proposed minimum functions that an RTO must perform. An RTO must:

(1) administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;

(2) create market mechanisms to manage transmission congestion;

(3) develop and implement procedures to address parallel path flow issues;

(4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;

(5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;

(6) monitor markets to identify design flaws and market power; and

(7) plan and coordinate necessary transmission additions and upgrades.

The Commission seeks comment on the following questions:

(1) whether the Commission's enumeration of minimum criteria omits a necessary minimum characteristic or function, or includes an unnecessary minimum characteristic or function;

(2) whether there is a need to distinguish between minimum characteristics and minimum functions (*i.e.*, adopt separate categories for the minimum requirements); and

(3) if so, whether any of the minimum characteristics should be re-characterized as minimum functions, and vice versa.

Comments on these questions should take into account the Commission's objective in this rulemaking of encouraging the formation of RTOs that promote competitive markets and non-discriminatory access to, and reliable operation of, the electric grid. (pages 116-17)

The distinctions drawn seem to be appropriate, but flexibility should be provided consistent with the Commission's "open architecture" policy.

14. **The Commission seeks comments on whether RTO status should be granted to entities that are not able to perform the three functions immediately (*i.e.*, establishing procedures for addressing parallel path flows with neighboring systems, managing congestion, and planning transmission expansion). (page 117)**

The Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities, even if the solutions do not include performance of all of the identified functions initially.

15. **The Commission also seeks comments on whether RTO status should be granted to entities that may not be able to perform on the first day of operation certain other (*i.e.*, any of the remaining four) of the minimum functions. (page 117)**

Yes. *See* comments under number 14 above.

16. **Should the Commission differentiate, for purposes of initial implementation, between any of the seven minimum functions? If**

so, has the Commission appropriately identified those minimum functions that are most likely to require additional time to perform? (page 117)

No. *See* comments under number 17 above.

17. **For five of the functions (tariff administration, congestion management, ancillary services, market monitoring and planning and expansion), the Commission proposes to establish standards for how the function is performed, but an RTO will have the option of demonstrating that an alternative proposal is consistent with or superior to the standards in the proposed rule. The Commission seeks comments on whether this flexibility -- *i.e.,* the option of demonstrating that an alternative proposal is consistent with or superior to the proposed rulemaking standards -- should apply to any or all of the minimum characteristics. (pages 117-18)**

The flexibility should apply to all of the minimum characteristics. The Commission should defer to a regional approach to establishing standards that has been endorsed by the relevant state regulators.

2. Characteristics

In this section, Tampa Electric introduces the specific requests for comments and Tampa Electric's responses thereto by citing the proposed characteristic at issue and its projected section number in the Commission's Regulations.

<u>Characteristic 1: Independence.</u> <u>The RTO must be independent of market participants. (Proposed § 35.34(i)(1))</u>

a. <u>The RTO, its employees and any non-stakeholder directors must not have financial interests in any electricity market participants. (Proposed § 35.34(i)(1)(i))</u>

18. **Does the Commission need to define the financial independence requirement in more specific terms or is it sufficient to enunciate the general principle and then apply it on a case-by-case basis? (page 121)**

The Commission should enunciate the general principle and evaluate individual regional approaches on a case-by-case basis.

19. **Should the definition of stakeholders or market participants be expanded to include entities that operate distribution-only facilities (*i.e.*, entities that perform the "wires" function at lower voltages) and transmission entities in neighboring regions? (page 121)**

This issue should be determined on a regional basis.

20. **Should this definition of stakeholders or market participants be broadened to include sellers and buyers of ancillary services? (page 121)**

This issue should be determined on a regional basis.

21. **Are there any circumstances in which the definition should be expanded to include entities that do not participate in power markets**

in the region but that provide transmission services to the RTO or buy transmission service from the RTO? (page 121)

This issue should be determined on a regional basis.

22. **Is more specificity needed relative to the requirement that RTOs have conflict of interest standards? (page 121)**

No.

23. **Are there lessons to be learned from the experience of ISOs with conflict of interest standards that can now be applied more generally to RTOs? (page 121)**

No comment.

b. An RTO must have a decision-making process that is independent of control by any market participant or class of participants. (Proposed § 35.34(i)(1)(ii))

24. **The Commission seeks comment on whether this kind of RTO (*i.e.*, non-stakeholder governing board and a prohibition on market participants having more than a de minimis -- one percent -- ownership interest in the RTO) should be deemed to satisfy automatically this element of the independence requirement. (page 122)**

Yes, this could satisfy the independence requirement for an RTO, but the standard should be more flexible and not require a non-stakeholder board.

25. **The Commission also requests comments on whether there should be a single standard for independent decision-making for all RTOs**

regardless of whether they are for-profit or non-profit entities. (page 122)

This issue should be determined on a regional basis.

26. **What, if any, additional requirements should apply to a governing board that is not a stakeholder board or to a governing board with both stakeholders and non-stakeholders? (page 123)**

Stakeholders should be grouped and represented as determined in regional approaches endorsed by state regulators.

27. **For either stakeholder or non-stakeholder boards, should an upper limit on the size of the board be imposed? (pages 123-24)**

No. The size of the board should be determined by the regional participants and the relevant state regulatory authorities. In addition, the "open architecture" policy proposed by the Commission will allow needed changes in governance as experience dictates.

28. **How should the Commission consider proposals for state regulatory or other governmental officials to select board members for either stakeholders or non-stakeholder boards? (page 124)**

For the Peninsular Florida regional resolution of transmission issues, the Commission should defer to any FPSC-sanctioned proposal for the involvement of state regulatory or other governmental personnel in the selection of board members for either stakeholder or non-stakeholder boards.

29. **How should the Commission view proposals for state government officials to serve as voting members of RTO boards? (page 124)**

See comments under number 28 above.

30. **The Commission seeks comment on whether one percent is an appropriate de minimis ownership interest and, if not, what would constitute appropriate de minimis ownership for purposes of establishing independence. (page 124)**

This issue should be determined on a regional basis.

31. **Are there conditions under which market participants should be allowed to have more than a de minimis ownership interest in an RTO? (page 124)**

This issue should be determined on a regional basis.

32. **Should the Commission have a different standard for passive interests? (page 124)**

This issue should be determined on a regional basis.

33. **How should the Commission treat preferred equity shares? (page 124)**

This issue should be determined on a regional basis.

34. **Commenters are asked to address whether the Commission's assessments of the effects of allowing market participants to have more than a de minimis ownership interest in RTOs are reasonable. (page 126)**

This issue should be determined on a regional basis.

35. **Is there relevant experience from other regulated industries? (page 126)**

No comment.

36. If the Commission were to allow market participants to have more than a <u>de minimis</u> ownership interest for a transition period, how long should the transition period be? (page 126)

There may be no need for a transition period. A regional solution may devise appropriate standards and safeguards that permit market participants to own transmission facilities.

37. Would any additional safeguards be required during such a transition period? (page 126)

See comments under number 36 above.

38. In general, which type of institution would better serve the goal of independence: a transco with <u>de minimis</u> ownership and a non-stakeholder board or an ISO with a non-stakeholder board? (page 126)

The relative effectiveness in serving the goal would depend on the overall structure of the institution and on the market in which it operates. The Commission's "open architecture" concept will allow entities to evolve as experience dictates.

<u>c.</u> <u>The RTO must have exclusive and independent authority to file changes to its transmission tariff with the Commission under Section 205 of the Federal Power Act. (Proposed § 35.34(i)(1)(iii))</u>

39. Can an RTO be truly independent if it does not have the authority to file changes in its tariff without the approval of other entities such as transmission owners? (pages 127-28)

No comment.

40. Should the ISO's unilateral filing authority be limited to transmission rate design and terms and conditions that directly affect access but not to changes that would affect transmission owners' ability to collect their overall revenue requirements? (page 128)

This possibility should be considered, as long as transmission owners can otherwise seek relief with respect to collecting their revenue requirements.

41. In practice, is this a viable distinction? (page 128)

It may be.

42. If an RTO's filed rate schedule also includes market design rules, should the RTO have Section 205 filing authority to make changes in the rules? (page 128)

The Commission's RTO principles should not be prescriptive on this issue. Regional approaches should include consideration of such matters.

Characteristic 2: Scope and Regional Configuration. The RTO must serve an appropriate region. The region must be of sufficient scope and configuration to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. (Proposed § 35.34 (i) (2))

a. Factors Affecting The Appropriate Scope and Regional Configuration of an Acceptable Region.

i. Regional configuration factors.

ii. Factors for evaluating boundaries.

(a) Facilitate performing essential RTO functions and achieving RTO goals, as discussed elsewhere in this proposed rule.

(b) Recognize trading patterns.

(c) Not facilitate the exercise of market power.

(d) Encompass existing control areas.

(e) Encompass existing regional transmission entities.

(f) Encompass one contiguous geographic area.

(g) Encompass a highly interconnected portion of the grid.

(h) Take into account existing regional boundaries (*e.g.*, NERC regions) to the extent consistent with the Commission's goals for RTOs.

(i) Take into account international boundaries.

43. The Commission solicits comments on the technical limitations or cost limitations on how large an RTO can be if it is to have control area responsibilities. (page 132)

See comments under number 45 below.

44. The Commission solicits comments on how the number of transmission systems to be combined would affect the cost and time required to form an RTO. (page 132)

Discussions are underway in Peninsular Florida. The merits of cost/benefit analyses have been discussed under the leadership of the FPSC, but such analyses have not yet been performed. Time requirements may be more a function of regional experience than of the number of parties at the table.

45. Are there other factors that may limit the geographic scope of an RTO? (page 133)

Regional boundaries should be justified individually, on a case-by-case basis. The primary criteria for the determination of regional boundaries must include reliability considerations. The Commission must give particular weight to boundaries that utilize the existing reliability boundaries of the NERC regions. The electrical topology (*i.e.,* how the region is electrically designed to reflect geography and the historical development of an area) is critical to establishing initial regional boundaries. In the future, experience with new markets may dictate the development of different boundaries for reliability and market purposes. The drawing of new regional boundaries without allowing time for transition from existing boundaries can have serious negative implications for reliability as well as cost.

The following regional reliability considerations and criteria are necessary in determining the boundaries of an RTO. These considerations are essential elements that contribute to the electrical topology of a region.

1. Generation & Transmission (G&T) Adequacy/Reliability -- The ability of a region to plan, site, and install G&T capacity (*i.e.*, siting laws and an effective planning process) is fundamental to ensuring continued reliability. Boundaries 'should not be drawn that are different than present boundaries with the assumption that the necessary state and/or federal planning and siting legislation will later be enacted. Such legislative changes would have to be made before any new boundaries are created.

Reliability of the bulk power transmission system is a G&T issue and not just a transmission issue. The system is planned, designed, and operated as a single machine moving power in bulk from production to consumption. The Commission recognized this by including certain generation services (*i.e.*, ancillary services) as part of the pro forma transmission tariffs required under Commission Order No. 888. These services (*e.g.*, Operating Reserves, Regulation and Frequency Response, Reactive Supply and Voltage Control) are essentially "enabling services" without which a power system could not function. The Commission recognized that denial of these services is, in effect, denial of basic transmission service and, thus, made transmission providers include these services in their tariffs.

Regulatory jurisdiction is an important factor in assuring regional reliability. the FRCC is unique among regional reliability councils because all of the FRCC region is within the geographical purview of only one state regulatory body, the FPSC. There is no need for a joint regional/state regulatory board to address regional adequacy issues. The FPSC has a significant legislative mandate to plan, site, and install G&T to ensure and maintain a reliable, cost-effective, and environmentally acceptable power system.

2. Location of Constraints -- A review of the Peninsular Florida region yields the following points:

- Geographically, it is a peninsula, *i.e.*, surrounded on three sides by water.

- The bulk transmission grid has regional interconnections only to the north, with the Southern subregion of the Southeastern Electric Reliability Council ("SERC"). Consequently, the Peninsular Florida regional grid does not experience any "through" or "parallel" flows from other electrical regions of the country with multiple inter-regional interfaces.

3. Unique Electrical Characteristics -- Peninsular Florida has unique electrical characteristics. One good example is the under-frequency load shedding program which is designed and operated to maintain FRCC regional reliability. Due to the peninsular nature of the electrical system, over half of the Peninsular Florida load is armed on the under-frequency program. In the event of separation of the peninsular system from the SERC region, the generation and load unbalance could be as much as 5000 MW (3600 MW import plus loss of a major plant in Florida). This would cause a very severe frequency decline and would cause a peninsular blackout unless the frequency decline could be arrested. Because of the steep decline in frequency, load has to be shed very quickly to allow generation to remain on line to begin restoration.

4. Size/Markets -- Although it might appear that, for competitive market purposes, the larger the size of the region the better, such is not the case. A viable market can develop only within a region that provides the infrastructure necessary to support reliability. Significantly, the problems faced in operating electric power systems are local and regional, not national; they are related to network security, with generation control being an important but relatively minor burden. Network security in Peninsular Florida and elsewhere requires very large amounts of real-time data on voltages, currents, real and reactive power, and the status of thousands of switches and circuit breakers. Using this data, extensive computations must be performed to verify accuracy and to display the network status to operators in a form that has meaning. With the advent of open access, the information and data requirements are increasing at an exponential rate.

In some respects, there is a parallel here with air traffic control centers. Could these centers be combined into one national center? Probably, but consider the amount of information that would have to be collected at one place, or the effect of communication failures. And even if it worked, the problems would remain local and regional and cannot be managed on a super-regional or national level.

Effective management requires that the appropriate boundaries be coextensive with the regional reliability boundaries, or FRCC's boundaries in Peninsular Florida. Peninsular Florida is a large and efficient marketplace. In terms of electrical demand, as the following table demonstrates, the FRCC ranks in size with ERCOT, PJM, the US portion of NPCC, and the US portion of MAPP.

Region	1997 Peak Demand (MW)
FRCC	37,127
ERCOT	45,636
PJM	45,628
NPCC (US)	48,950
MAPP (US)	29,199

These data suggest that the Peninsular Florida region is of sufficient market size to allow benefits to all users of the grid.

46. What are the relative merits of internalizing constraints within a region versus having constraints act as natural boundaries between regions? (page 136)

Both internal and external constraints will need to be dealt with in regional approaches. The need to address constraints is only one of many issues to be considered in the determination of regional boundaries. The Commission should allow regions to present rationales for boundaries on a case-by-case basis. Generally speaking, of course, constraints may be resolved more effectively within regions where affected parties can agree upon the means of resolution.

47. The Commission seeks comments on the appropriateness of these factors to determine an appropriate configuration for the regions in which RTOs would operate, and also asks if any additional factors may be appropriate. (page 137)

Other factors that may be appropriate include (1) state regulatory relationships and authorities, (2) the "size" of the region, measured by the load served within the region, and (3) technical and operational considerations. *See* also the comments under number 45 above.

<u>b.</u> <u>Potential Geographic Configurations.</u>

48. The Commission seeks comments on how well the regions served by existing institutions would satisfy the factors enunciated above, and specifically how well they would be able to satisfy the minimum RTO characteristics and functions outlined in this section, and the advantages and disadvantages of these three examples. (page 138)

The existing institution for Peninsular Florida, the FRCC, which is one of the ten NERC reliability councils, would meet appropriate geographic configuration criteria for a transmission region. Rationales for regional boundaries will be case-specific.

49. The Commission also welcomes presentation and evaluation of other methods to define appropriate regions. (page 138)

No comment.

c. Control of Facilities within a Region.

50. The Commission solicits comments on how best to balance its goal of having RTOs in place that operate all transmission facilities within an appropriately sized and configured region against the reality that there may be difficulties in obtaining 100 percent participation in all regions in the near term. (page 139)

In Peninsular Florida, the FPSC has sufficient jurisdiction over transmission reliability to ensure the appropriate operation of transmission facilities within the region.

51. Should the Commission deny RTO status for any proposal that does not include all transmission facilities within an appropriate region? (page 139)

The Commission should defer to any regional resolution of transmission issues that is endorsed by the relevant state regulators, to the extent that the resolution makes progress toward the Commission's goals in this matter.

52. If the Commission does not deny RTO status for less than 100 percent participation, is there some guideline that it should use for determining when the proponents represent an appropriate "critical mass" for the region? (pages 139-40)

See comments under number 51 above.

53. Should the Commission require that the RTO at least negotiate certain agreements with any non-participants within its region to ensure maximum coordination? (page 140)

No. Non-participants may not be willing to negotiate agreements with participants, and it would be unfair to require this of participants. However, participants may need to address treatment of non-participants in various regional procedures documents.

54. If so, what should be the terms of such agreements? (page 140)

No agreements should be required.

55. Finally, the Commission seeks comment on the question of how much deference, if any, should be given to the proposed scope and regional configuration of a proposed RTO. (page 140)

The Commission should defer, as appropriate, to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

56. How readily, if at all, after balancing all appropriate factors, should the Commission be willing to substitute its vision of an appropriate RTO configuration for that of its proponents? (page 140)

The Commission should defer, as appropriate, to any regional approach on transmission issues that is endorsed by the relevant state regulators to the extent that the approach moves the region toward achievement of the Commission's goals.

57. To what extent should the Commission take into account the degree of support in assessing a proposed RTO configuration? (page 140)

The degree of support that is necessary to make a regional approach satisfactory should be a matter for the state regulatory authority to determine, in the first instance.

58. Should approval or disapproval by affected state Commissions of the scope or configuration of a proposed RTO affect the level of deference the Commission should afford such a proposal? (page 140)

Yes.

Characteristic 3: Operational Authority. The RTO must have operational responsibility for all transmission facilities under its control. (Proposed § 35.34(I) (3))

a. The Regional Transmission Organization may choose to directly operate facilities (direct control), delegate certain tasks to other entities (functional control) or use a combination of the two approaches. (Proposed § 35.43(i)(3)(i))

59. What has been the experience of existing tight power pools with master-satellite and hierarchical forms of control? (page 143)

No comment.

60. Was there a need to modify these operational arrangements when the pool was replaced by an ISO? (page 143)

No comment.

61. Outside of tight power pools, has the functional unbundling requirement in Order No. 888 led to any divisions of previously integrated internal operational systems? (page 143)

Yes. Various integrated systems, including software, hardware, and organizations, were revamped to accommodate the functional separation of the merchant function from the transmission service function to ensure the blocking of non-public reliability information from those performing the merchant function.

62. If so, have these new divisions of operational responsibilities created any reliability problems? (page 143)

No, although separation has resulted in higher costs and less efficient management and operations within the integrated utility, particularly for power purchases for native load.

b. The RTO must be the security coordinator for the transmission facilities that it controls. (Proposed § 35.34(i)(3)(ii))

No questions pertaining to this subpart.

Characteristic 4: Short-term Reliability. The RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. (Proposed § 35.34 (i)(4))

a. The RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules. (Proposed § 35.34 (i)(4)(i))

63. **In addition to the current code of conduct standards, are there any actions that the Commission should require to reduce the likelihood of this problem (*i.e.*, non-RTO control area operators who are also competitors in power markets may be "able to know their competitors' schedules or transactions" and such knowledge would give the control area operators an unfair competitive advantage) that do not require the consolidation of all existing control areas within the region? (page 147)**

This issue has already been resolved within the FRCC by requiring all entities that operate control areas within the region and that require access to commercially sensitive operating information to sign agreements that separate reliability personnel and the relevant information from wholesale merchant personnel. The Commission's future actions should allow the continued implementation of the FRCC's resolution of this matter.

64. **Is it feasible for a non-RTO control area operator, operating within an RTO region, to perform its functions without having access to commercially sensitive information involving its competitors? For example, could an RTO provide control area operators with information about scheduled net interchange between control areas without disclosing the individual transactions making up the new interchanges? (page 147)**

No. Current transmission scheduling, tagging, and reservation practices reveal transaction information to control area operators. Such information is required to operate the system safely and reliably. It would not be feasible to shield commercially sensitive information from control area operators. Adding transaction information into a "net" number would not sufficiently shield relevant market information and would result in less reliable operation.

b. The RTO must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for reliable operation of these facilities. (Proposed § 35.34 (i)(4)(ii))

No questions pertaining to this subpart.

c. When the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards. (Proposed § 35.34 (i)(4)(iii))

65. Does this requirement cede too much or too little authority to the RTO? (page 150)

Any central operator of transmission facilities with responsibility for safety and reliability of the regional system would need to be the final authority for coordinating facility outages. The requirement should be stated in sufficiently general language to allow for regions to work out specific procedures, while requiring central operators to have the final authority.

66. **If the RTO requires a transmission owner to reschedule its planned maintenance, should the transmission owner be compensated for any costs created by the required rescheduling? (page 150)**

Such details should be worked out regionally.

67. **Would it be feasible to create a market mechanism to induce transmission owners to plan their maintenance so as to minimize reliability effects? (page 150)**

Such details should be worked out regionally.

68. **Should an RTO that is an ISO have any authority to require rescheduling of maintenance if it anticipates that the planned maintenance schedule will adversely affect power markets? (page 150)**

No comment.

69. **If the RTO is a transco, can it manipulate its transmission maintenance schedules in a manner that harms competition? (page 150)**

No comment.

70. **Should the RTO have some authority over generation maintenance schedules? If so, how much authority should it have? (page 150)**

Such details should be worked out regionally.

71. **Is it possible for a non-profit ISO to establish similar incentive schemes for the transmission owners whose facilities it operates? (page 151)**

No comment.

72. Given that an RTO has responsibility for system reliability, what should be the extent of its liability for its actions? (pages 153-54)

Liability for operating other entities' assets would be one of the most difficult aspects of regional operation of multiple owners' transmission facilities. Responsibilities would need to be very clearly defined. Line ratings, for example, are critical safety factors. An overheated transmission line could sag down into trees, streets, or pedestrian areas, resulting in destruction of property or possible loss of life. It is crucial that any entity responsible for operation of the system which also has financial incentives to maximize the use of the system be properly held responsible for unsafe operations. The appropriate allocation of liability should be governed by contractual arrangements among the RTO participants, within the limits of the law.

73. Would this differ depending on whether the RTO owns the facilities? (page 154)

This is largely a question of law, the answer to which could depend on the nature of contractual arrangements among owners and operators.

d. If the RTO operates under reliability standards established by another entity (*e.g.*, a regional reliability council), the RTO must report to the Commission if these standards hinder it from providing reliable, non-discriminatory and efficiently priced transmission service. (Proposed § 35.30 (i)(4)(iv))

No questions pertaining to this subpart.

3. <u>Functions</u>

In this Section, Tampa Electric introduces the specific requests for comments and Tampa Electric's responses thereto by citing the proposed function at issue and its projected section number in the Commission's Regulations.

<u>Function 1: Tariff Administration and Design. The RTO must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities. (Proposed § 35.30(j)(1))</u>

74. The Commission invites commenters to address whether more specific guidance is required. (page 157)

Not at this time.

<u>a. The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The RTO must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The RTO must have the authority to review and approve requests for new interconnections. (Proposed § 35.30(j)(1)(i))</u>

75. The Commission invites comments on how this standard can be made effective for RTOs that are ISOs. (page 159)

No comment.

76. **Are there lessons to be learned from the experience of qualifying facilities (QFS) under PURPA in getting interconnections to the grid that would be applicable to ISOs? (page 159)**

No comment.

77. **Should this standard be expanded to give the RTO the authority to review and approve all new interconnections (*e.g.*, to connect new generators, to improve reliability, to increase trading opportunities with neighboring regions) or all transmission investments above some threshold dollar amount? (pages 159-60)**

No comment.

b. The RTO tariff must not result in transmission customers paying multiple access charges to recover capital costs over facilities that it controls (i.e., no pancaking of transmission access charges). (Proposed § 35.34(j)(1)(ii))

78. **Would the requirement for a tariff with non-pancaked rates make the voluntary formation of RTOs more difficult because it might result in the potential for sudden and unacceptable transmission rate changes? (page 161)**

Changes to rates as well as changes in revenues are probably the most difficult region-specific issues. Regional discussions will have to include resolution of these matters, including a possible transition period. There are two issues of concern: (1) impact on rates and revenue collection resulting from transfer from state to federal jurisdiction for revenue requirement and earnings oversight, and (2) the potential for cost responsibility shifting among native load customers of the affected entities. These impacts result from differences in return-on-equity and revenue requirement calculation methods used by federal versus state regulators, loss of point-to-point revenues, elimination of prior contractual arrangements, etc. These are matters that will require encouragement from state regulators to resolve, along with cooperation from the Commission.

79. Is the severity of any such problem related to the scope and regional configuration of the proposed RTO? (page 161)

Not necessarily, but the number of parties involved and their relationships, and the number of state regulatory jurisdictions involved can complicate the implementation of solutions. In Florida, the successful resolution of these difficult issues will best be realized by keeping the geographical scope within Peninsular Florida, where all of the affected parties have similar reliability interests under the leadership of a single state regulatory authority.

80. Does the use of so-called license plate design allow the RTO to meet this requirement without cost-shifting? (page 161)

Some form of license plate pricing may ease the initial impact of change. License plate pricing would ensure that most costs are paid by the same ratepayers, with the owners receiving approximately the same revenues, particularly where bundled retail rate-making continues, as in Peninsular Florida. Changes in point-to-point rates and revenues could be addressed in a comprehensive solution with some form of transition period.

81. Would the provision for a reasonable transition period help? (page 161)

Yes, and the duration of any such period is a region-specific issue.

82. Even if there is mutual waiving of access charges, are there other pricing impediments to inter-regional trade (*e.g.*, differences in scheduling and curtailment conventions between regions) that are likely to impede trade? (pages 161-62)

The Commission should focus on the initial development of regional transmission approaches at this time. Inter-regional pricing matters and other such issues should be dealt with after the initial round of regional approaches. Many relevant issues are currently evolving within NERC, and the Commission staff should participate in and monitor these developments.

Function 2: Congestion Management. The RTO must ensure the development and operation of market mechanisms to manage transmission congestion. (Proposed § 35.34(j)(2))

a. The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions. The RTO must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant. (Proposed § 35.34(j)(2)(i))

83. **The Commission invites comments on its requirement that RTOs must be responsible for managing congestion with a market mechanism. (page 165)**

Solutions to congestion will be region-specific, except to the extent NERC operating policies evolve to encompass congestion management. The Commission should continue to participate in and monitor discussions of these issues within NERC, and not duplicate or foreclose their development and resolution. An appropriate Peninsular Florida regional solution to congestion could conceivably be quite different from a solution in a region where power can flow in and out from every direction.

84. **Can decentralized markets for congestion management be made to work effectively and quickly? (page 165)**

The Commission should not preclude this option. Regions may find ways to make this work through automation.

85. **Can the RTO's role be limited to that of a facilitator that simply brings together market participants for the purpose of engaging in bilateral transactions to relieve congestion? (pages 165-66)**

The Commission should not preclude this option. Regions may find ways to make this work through automation.

86. **If not, will these markets require centralized operation by the RTO or some other independent entity? (page 166)**

No comment.

87. **How can an RTO ensure that enough generators will participate in the congestion management market to make possible a least-cost dispatch? (page 166)**

A regional solution to congestion will need to be simple and fast to encourage participation.

88. **Are there any special considerations in evaluating market power in a congestion market operated or facilitated by an RTO? (page 166)**

No comment.

89. **The Commission seeks comment on whether such an additional implementation time period is warranted (the Commission proposes to allow up to one year after start-up for this function), and whether one year is an appropriate additional time period. (page 166)**

NERC and various regional entities are working on resolution of congestion management issues. The Commission should encourage such resolution, but be careful not to push for individual regional solutions that may ultimately conflict at the national level and at regional boundaries. However, regional discussions should consider, and potentially commit, as to whether the region intends to ultimately adopt the NERC process or some other congestion management process.

<u>Function 3: Parallel Path Flow.</u> <u>The RTO must develop and implement procedures to address parallel path flow issues within its region and with other regions. The RTO must satisfy this requirement with respect to</u>

<u>coordination with other regions no later than three years after it commences initial operation. (Proposed § 35.34(j) (3))</u>

90. **The Commission seeks comment on whether such an additional implementation time period is warranted, and whether three years is an appropriate additional time period. (page 169)**

The timing of resolution of parallel flow concerns is a region-specific issue. For Peninsular Florida, the focus should be solely upon internal parallel flow issues. Inter-regional parallel flow is not an issue. Therefore, the Commission should allow for regional differences and not set a definitive schedule for resolution of parallel flow issues. In addition, NERC continues to work toward a national resolution of this issue, and regional discussions should include consideration, and potentially commitment, as to whether the region intends to ultimately adopt the NERC process or some other congestion management process.

<u>Function 4: Ancillary Service.</u> <u>An RTO must serve as the supplier of last resort of all ancillary services required by Order No, 888, Commission Stats. & Regs. 31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders. (Proposed § 35.34(j)(4))</u>

<u>a.</u> <u>All market participants must have the option of self-supplying or acquiring ancillary services from third parties subject to any general restrictions imposed by the Commission's ancillary services regulations in Order No. 888, Commission Stats & Regs. ¶ 31,036 (Final Rule on Open Access and</u>

<u>Stranded Costs), and subsequent orders. (Proposed § 35.34(j)(4)(i))</u>

91. **The ancillary service policies in Order Nos. 888 and 889 were developed for transmission providers that were generally vertically integrated utilities. There was an expectation that they would be able to provide many of the generation based ancillary services from their own generating resources. An RTO by definition will not own any generating resources. Does this difference necessitate a different set of ancillary service requirements for RTOs? (page 171)**

The Commission should consider approaches to this matter on a case-by-case basis. The design of ancillary services is still evolving within NERC. Those services that involve energy will likely be further unbundled as these services evolve. For example, energy balancing requires management and scheduling services that only a control area can provide, yet the energy portion of the service could be provided by generators competitively. Until these matters are worked out nationally, they will need to be dealt with initially in regional discussions. Ancillary services that provide control area balancing and reserve services, as well as energy for transmission losses, must be dealt with differently in regions with multiple control areas than in regions with a single control area.

92. **Are there other ancillary services, in addition to scheduling, system control and dispatch, and reactive supply and voltage control from**

generation sources, for which the self-supply option should be eliminated? (page 171)

No comment.

93. **Under what circumstances can the RTO's obligation as the ancillary services supplier of last resort be eliminated? (page 171)**

There must always be a supplier or suppliers of last resort, but an RTO itself need not directly supply such services.

b. **The RTO must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All ancillary service providers must be subject to direct or indirect operational control by the RTO. The RTO must promote the development of competitive markets for ancillary services whenever feasible. (Proposed § 35.34(j)(4)(ii))**

94. **The Commission requests commenters to address whether these are minimum requirements needed to ensure that the RTO can satisfy its obligation to maintain targeted levels of reliability. (page 172)**

The Commission should consider approaches to this matter on a case-by-case basis. The issue of ancillary services is still evolving at NERC and will need to be dealt with in regional discussions. Ancillary services that provide control area balancing and reserve services, as well as energy for transmission losses, must be dealt with differently in regions with multiple control areas than in regions with a single control area.

95. **Would it be feasible for the RTO to maintain reliability with less authority? (page 172)**

The Commission should defer as appropriate to regional solutions that achieve consensus with market participants and the affected state regulatory authorities.

c. The RTO must ensure that its transmission customers have access to a real-time balancing market. The RTO must either develop and operate such markets itself or ensure that this task is performed by another entity that is not affiliated with any market participant. (Proposed § 35.34(j)(4)(iii))

96. **The Commission invites comments on the use of market mechanisms to support overall system balancing and imbalances of individual transmission users. (page 177)**

Balancing functions are control area functions. Regions where a regional transmission provider operates a single control area would offer such services in a different manner than regions where multiple control areas operate. Each control area must be separately "balanced." The Commission should not preclude either option at this time.

97. **Is it feasible to rely on markets to support a function that is so time-sensitive? (page 177)**

Yes. All aspects of electric system operations are time-sensitive. If there can be a market at all, it will need to be able to work instantaneously.

98. **Can such markets be made to function efficiently if the RTO is not a control area operator? (page 177)**

Yes. This option should not be precluded at this time.

99. **For the imbalances of individual transmission customers, should a distinction be made between loads and generators? (page 177)**

Yes. Loads and generators can impact the system differently. Generators must be able to meet their schedules or arrange for back up. Generators can impact a control area's ability to meet its performance criteria imposed by NERC, which ultimately could lead to system failure or financial penalties. Loads should also make arrangements for adequate power supply, but operators can protect the integrity of the system by shedding load at any time supply is interrupted.

100. **Should customers have the option of paying for all imbalances in such a market or only imbalances within a specified band? (pages 177-78)**

Individual transmission customers should not expect access to unlimited amounts of power at all times. Operation of control areas could not be managed reliably with such chaos. For example, if market prices suddenly rise and all generators simultaneously decided to oversell and under generate, the entire system could shut down. Likewise, if load-serving entities do not arrange for sufficient power supply, they must face the consequence (and cost) of curtailment. Inadvertent energy accounting between control areas serves to enhance reliability for all participants transacting within or between control areas and should continue to be allowed within the operating standards of NERC.

Function 5: OASIS and TTC and ATC. The RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC. (Proposed § 35.34(j)(5))

No questions pertaining to this function.

Function 6: Marketing Monitoring. The RTO must monitor markets for transmission services, ancillary services, and bulk power to identify design flaws and market power and propose appropriate remedial actions. (Proposed § 35.34(j)(6))

a. The RTO must monitor markets for transmission service and the behavior of transmission owners, if any, to determine if their actions hinder the RTO in providing reliable, efficient, and nondiscriminatory transmission service (Proposed § 35.34(j)(6)(i))

b. The RTO must monitor markets for ancillary services and bulk power. This obligation is limited to markets that the RTO operates. (Proposed § 35.34(j)(6)(ii))

c. The RTO must periodically assess how behavior in markets operated by others (*e.g.*, bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects RTO operations and conversely how RTO operations

affect the performance of power markets operated by others. (Proposed § 35.34(j)(6)(iii))

101. **The proposed requirements are arguably based on the presumption that an RTO will be a non-profit, system operator that does not own any facilities. The requirements may not be appropriate for a for-profit transco that owns facilities that it operates. Therefore, a threshold question is: what should be the market monitoring role, if any, of an independent, for-profit transco? (page 182)**

No comment.

102. **Is it reasonable to expect that such an RTO could be objective in its assessments? (page 182)**

No comment.

103. **If the RTO is an ISO, do its monitoring activities need to be further insulated to ensure independence and objectivity? (page 182)**

No comment.

104. **For example, should monitoring be performed by one or more individuals or organizations that are funded by the RTO but that have the right to issue reports without the RTO's approval? (pages 182-83)**

No comment.

105. **Some argue that RTOs should not be charged with any monitoring responsibilities particularly with respect to market power abuses. They argue that the antitrust laws and the Commission offer**

sufficient protection against competitive abuses. Others have argued that RTOs are somewhat akin to organized stock exchanges and the Commission should follow the SEC precedent of requiring extensive and sophisticated market monitoring by all of the organized exchanges. Are there features of electricity and transmission markets that argue for imposing similar market monitoring responsibilities on RTOs? (page 185)

No comment.

106. **Should the Commission rely on RTOs as the "first line of defense" for detecting both design flaws and market power abuses? (pages 185-86)**

No comment.

107. **If this were the Commission's approach, what would be an appropriate role for the Commission in market monitoring? (page 186)**

The Commission should carefully monitor the market initially to the extent called for by the level of disputes brought to its attention. The initial monitoring should be done through existing mechanisms, such as OASIS and other information already made available to the Commission. No additional reporting burdens should be imposed on market participants.

108. **If the RTO is operating one or more markets (*e.g.*, ancillary services), is it reasonable to expect that it can perform an objective self-assessment? (page 186)**

No comment.

109. **Is there a difference in the market monitoring that the Commission can expect from RTOs? For example, if the RTO proposes to take a market position in secondary transmission rights, is it plausible to expect that the RTO can perform an objective assessment of this market? (page 186)**

No comment.

110. **Since the success of retail competition will often depend critically on the actions of RTOs, what should be the role of state commissions in market monitoring? (page 186)**

The Commission should defer, as appropriate, to regional solutions that achieve consensus on this issue among market participants and the affected state regulatory authorities.

111. **The Commission welcomes estimates of the amount of money spent by ISOs to monitor markets and their assessments as to whether they will need to spend more or less money in the future. (page 187)**

No comment.

112. **For abuses that arise from market power, should the RTO's role be limited to detecting and describing the abuses? (page 187)**

No comment.

113. **In the case of localized market power (*e.g.*, generating units that must run for reliability reasons), should the RTO have the authority to take corrective actions? (page 187)**

The Commission should defer, as appropriate, to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

114. **If the market power has structural causes, what role should the RTO have in developing structural solutions? (pages 187-88)**

No comment.

115. **Should RTOs that are ISOs be required to make regular assessments as to whether they have sufficient operational authority? (Page 188)**

No comment.

116. **The Commission seeks comment on whether RTOs should be allowed to impose penalties and sanctions. (page 188)**

As the market evolves, and as NERC moves to a system of penalties and sanctions for operators, and as transmission tariffs include pricing that simulates penalties, care must be taken to ensure against overlapping penalties from multiple sources.

117. **Should the penalties be limited to violations of RTO rules and procedures? (page 188)**

This would depend on how those rules correspond to penalties already imposed by NERC or within open access tariffs.

118. **Should the RTO be allowed to impose penalties for the exercise of market power? For example, should the RTO's penalty authority be limited to collecting liquidated damages? (page 188)**

No. Only the Commission should make determinations regarding the abuse of market power. Any market participant, including an RTO, should be able to bring complaints to the Commission for such determination.

d. **The RTO must provide reports on market power abuses and market design flaws to the Commission and affected regulatory authorities. The reports must contain specific recommendations about how observed market power abuses and market flaws can be corrected (Proposed § 35.34(j)(6)(iv))**

119. Should this reporting requirement be limited to producing reports only when a specific problem is encountered? Or should RTO's be required to make periodic reports that assess the state of competition and transmission access even in the absence of specific problems? (page 188)

Reporting requirements should be kept to a minimum. The Commission should consider specific reporting approaches on a case-by-case basis.

Function 7: Planning and Expansion. The RTO must be responsible for planning necessary transmission additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with the appropriate state authorities. (Proposed § 35.34(j)(7))

a. **The RTO planning and expansion process must encourage market-driven operating and investment actions for** preventing and relieving congestion. (Proposed § 35.34(j)(7)(i))

b. The RTO's planning and expansion process must accommodate efforts by state regulatory Commissions to create multi-state agreements to review and approve new transmission facilities. The RTO's planning and expansion process must be coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary. (Proposed § 35.34(j)(7)(ii))

c. **If the Regional Transmission Organization is unable to satisfy this requirement when it commences operation, it must file a plan with the Commission with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. (Proposed § 35.34(j)(7)(iii))**

120. The Commission seeks comment on whether three years is an appropriate amount of time for implementation of this function. (page 193)

Regions should determine planning procedures at the outset, and the planning process should commence immediately. Given this premise, there is no need for a three-year implementation period.

E. Issues Concerning Open Architecture

121. The Commission is interested in receiving comments regarding an open architecture policy to ensure that initial RTOs can develop. What flexibility needs to be built into RTO contracts? (page 195)

Any regional transmission approach should include the ability for the parties, or the governing board of a regional transmission entity, to vote to propose changes at any time, subject to endorsement by relevant state regulators and the Commission's approval, as appropriate.

122. What regulatory flexibility is needed from the Commission as part of an open architecture policy? (page 195)

The Commission should defer to regional transmission approaches that are endorsed by relevant state regulators and that move in the direction desired by the Commission, even if the approach falls short of the Commission's desire for and vision of a "perfect RTO." Any movement should be viewed as positive. Some regions may move slower or to a lesser degree than others, due to the circumstances particular to the regions.

123. In which areas of RTO organization or operations is it especially important for the Commission to expect improvement? (page 195)

It is likely that initial regional transmission approaches will leave room for further improvement in many important areas, including organization and operations, as the industry evolves toward competitive markets. The Commission's proposal for an "open architecture" will facilitate this "growing up" process.

F. Issues Concerning Ratemaking

124. The Commission proposes to continue its flexibility in allowing the recovery of current sunk transmission costs as transition mechanisms to single rates if proposed by RTOs, including the license plate approach as well as others. The Commission requests comment regarding whether the license plate approach to fixed cost recovery is an appropriate long-term measure. (page 197)

The Commission's open architecture approach will allow pricing approaches to evolve such that it is not necessary for the Commission to determine at this time whether the license plate approach is appropriate for the long term.

125. The Commission intends to be flexible in reviewing congestion pricing innovations, and asks for comments as to what specific requirements, if any, may best suit its RTO goals. (page 198)

The flexibility the Commission proposes is appropriate for congestion pricing. Since resolution of this issue is evolving, the opportunity for experimentation should not be foreclosed.

126. The Commission seeks comments on applying PBR (performance-based rate-making) to RTOs. Should PBR be voluntary or applied to all RTOs? (page 199)

The Commission should defer, as appropriate, to regional solutions that achieve consensus among market participants and the affected state regulatory authorities. Performance-based rate-making may make sense, but there needs to be a period of development before performance expectations can be established.

127. **What degree of regulatory scrutiny would a PBR regime require? (page 199)**

A PBR regime would require regulatory scrutiny similar to the current, traditional rate regime, but may require a different reporting and oversight process.

128. **In addition, the Commission seeks comment on the specifics of how PBR would be applied effectively to an RTO. For productivity incentives, what productivity objectives should be adopted and how should productivity be measured? (page 199)**

No comment.

129. **How would a revenue cap or a price cap be set? (page 199)**

No comment.

130. **What intermediate adjustments to the cap should be allowed? (page 199)**

No comment.

131. **How often should base costs be examined? (page 199)**

No comment.

132. **Is it appropriate to allow a higher ROE as a means of sharing the benefits created by RTOs or should higher ROEs be limited only to increases in risk? (page 200)**

No comment.

133. **Is the risk of transmission capital recovery increased or decreased by transferring transmission facilities to an RTO from a vertically integrated firm? (page 200)**

It depends on who has transferred the facilities and the structure of the RTO.

134. **Another incentive that could be considered would be to keep transmission rates at current levels and allow participating RTO transmission owners to keep the benefits from cost savings over time or to lower transmission rates partly while owners keep part of the benefits. Would such treatment encourage better performance? (page 201)**

No comment.

135. **Similarly, the recovery of capital start-up costs of RTO participation could be accelerated as well. Is it appropriate to allow such accelerated recovery as an incentive to transfer transmission facilities to an RTO or should capital recovery periods continue to be based on the useful life of transmission facilities? (page 201)**

No comment.

136. **Is industry restructuring and the potential introduction of distributed generation technology likely to affect the risk associated with transmission investment recovery periods? (page 201)**

No comment.

137. **The Commission seeks comments on whether to entertain case-by-case proposals of rate incentive treatments for RTO participants. Will transmission owners respond to incentives, and will incentives be sufficient to achieve our objective of RTO formation? (page 202)**

The Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

138. **Which incentives are most likely to be successful in so doing? (page 202)**

No comment.

139. **Are there specific forms of incentive pricing that are inappropriate and problematic? (page 202-03)**

No comment.

140. **Are safeguards needed if the Commission decides to allow incentive treatments? (page 203)**

No comment.

141. **In justifying a proposed rate treatment, should an RTO be required to demonstrate that its benefits are likely to outweigh the pecuniary "costs" of the proposal? (page 203)**

The Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

142. Would certain incentive pricing encourage RTOs to favor capital-based resource decisions (at the expense of more efficient alternatives) or to favor transmission solutions over alternative ways of relieving particular transmission constraints? (page 203)

No comment.

143. The Commission also seeks comment on whether and how public power transmission owners that participate in RTOs could benefit from flexible rate making and incentive pricing treatments. (page 203)

No comment.

G. Issues Concerning Public Power Participation

144. The Commission requests comments that identify issues that public power entities and others face regarding RTO participation and that suggest ways the Commission might facilitate their resolution. (page 204)

No comment.

145. The Commission solicits comments on the extent to which IRS Code restrictions may limit the transfer of operational control or other forms of control, or ownership, of public power transmission facilities to a for-profit transco. (page 205)

No comment.

146. What impact would IRS Code restrictions have on public power participation in other forms of an RTO? (page 205)

No comment.

147. While IRS Code restrictions might prevent issue of additional tax-exempt bonds for transmission expansions made in accordance with RTO participation, are non-tax exempt forms of financing a viable option for public power participation in selected transmission additions? (page 205)

No comment.

148. In addition to private use restrictions, are there other restrictions on public power institutions that may limit their participation in RTOs? For example, to what extent would state or local charter limitations, prohibitions on participating in stock-owning entities, or the current policies of various local regulatory entities affect or impede full public power participation in RTOs? (page 205)

No comment.

149. Are there some forms of associate membership or participation in RTOs, or other special accommodations, that the Commission should consider to make it more feasible for public power entities to overcome obstacles to participation in RTOs? (pages 205-06)

No comment.

150. The Commission seeks comment on legal restrictions or other considerations regarding the PMAs that prevent their participation

in RTOs. For example, Bonneville Power Administration and other entities in the Pacific Northwest may face unique circumstances that may affect RTO formation in that area. (page 206)

No comment.

151. **How can the Commission help overcome any such limiting factors to full RTO formation? (page 206)**

No comment.

H. <u>Other Issues</u>

152. **What is the appropriate treatment of existing transmission agreements when an RTO is formed? (page 206)**

The Commission should defer, as appropriate, to regional solutions that achieve consensus among market participants and the affected state regulatory authorities. There may be financial settlements among parties to move all uses of transmission to the purview of the regional approach.

153. **In the ISO filings that the Commission has acted on to date, it has evaluated various "transition plans" regarding existing contracts on a case-by-case basis. At this juncture, the Commission does not intend to resolve this issue generically but instead proposes to confine its policy to addressing this issue on an RTO-by-RTO basis. The Commission solicits comments on this approach. (page 207)**

Case-by-case resolution is appropriate, as long as the issue is dealt with at the outset.

154. **How critical is this concern to transmission owners' and others' decisions on whether to support RTO formation? (page 207)**

The issue of treatment of existing transmission arrangements is critical in Peninsular Florida because there are many long-term contracts in place, many of which contain provisions that are substantially different from open access pricing, terms and conditions under Order No. 888.

155. **Is the financial impact of giving up an advantageous transmission arrangement significant enough to act as a disincentive to RTO membership? (page 207)**

No comment.

156. **The Commission is also concerned about impediments to transactions between existing transmission entities, as well as any future RTOs. It therefore encourages existing transmission entities to consider ways to reduce any impediments to transactions among them and direct them to provide the Commission with a progress report by January 15, 2001. The Commission seeks comment on this issue. (page 209)**

No comment.

157. **The Commission invites the comments of Canadian and Mexican authorities on these and other issues. (page 210)**

No comment.

158. **To what extent should transmission owners who do not participate in their region's RTO share in those benefits? (page 210)**

The Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

159. **Would it be appropriate to allow RTO members to provide transmission service at individual system rates to non-participating transmission owners located in the RTO region, thereby denying non-participants the benefits of non-pancaked transmission rates? (pages 210-11)**

The Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

160. **The Commission seeks comment on the treatment by an RTO of non-participating transmission owners in the RTO region. (page 211)**

The Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

161. **The Commission requests comments on whether it should provide for expedited or streamlined processing procedures for Section 203 transfers of jurisdictional facilities to RTOs that meet the characteristics and functions of the Final Rule, and for the related Section 205 transmission rates, terms, and conditions. (page 211)**

All of the Commission's processing procedures should be as streamlined as possible.

162. The Commission also welcomes specific suggestions regarding how it can further expedite or streamline its procedures. (page 211)

The Commission should make information, clarification, and advice available directly to jurisdictional entities responsible for implementing the Commission's open access rules and policies, without having to engage in formal filings or running the risk of violating ex parte rules. This would likely lead to more uniform implementation of rules and reduced need for time-consuming proceedings. It would also be useful if the Commission would make available an on-line reference service that tracks, by issue, all current Commission guidance on specific implementation issues, and that is updated regularly. The Commission should make its open access regulations more "user friendly" by facilitating access to its interpretive glosses.

163. Given that a power exchange is useful, should it be part of an RTO or otherwise associated with an RTO? (page 214)

On this issue, the Commission should defer to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

164. If an area has more than one PX, should the PXs have equal standing before the RTO? (page 214)

No comment.

165. Is an organized PX necessary for successful retail competition? (page 214)

No comment.

166. If an RTO operates congestion markets and balancing markets, are there efficiencies to be gained by allowing or encouraging the RTO to operate day ahead or hour ahead energy markets? (page 214)

No comment.

167. Is it feasible for an RTO to operate a spot energy market without compromising its ability to provide non-discriminatory transmission service to all market participants? (page 214)

Yes. Such a market can be automated. The Energy Broker Network operating in Florida is an example of such a market. Next-hour bids are matched automatically (highest with lowest). Transmission operators "operate" the system, without involvement in the market itself.

168. If a PX is operated by a non-RTO entity, is there a need to require certain specified forms of coordination between the two organizations? (page 214)

The same coordination would be required between any marketer and the control area operators and transmission providers, regardless of whether these functions are performed within a single room or spread among separate entities. Transmission costs and reservations need to be taken into account in setting up market "deals," whether or not the deals are set up remotely.

I. Implementation

169. Would regional workshops advance RTO formation? (page 216)

Yes. Workshops are already underway in the Peninsular Florida region under the leadership of the FPSC.

170. Under whose auspices should regional workshops be held? (page 216)

For the Peninsular Florida region, ongoing regional workshops are and should be under the auspices of the FPSC. The Commission staff should make itself available to attend and participate if requested by the FPSC.

171. Would it be beneficial to have the Commission's Dispute Resolution Service staff facilitate discussions regarding RTO formation? (page 216)

For the Peninsular Florida region, the Commission should defer to the leadership of the FPSC and make assistance available as requested by the FPSC.

172. Should the Commission staff be made available to attend meeting convened by others? (page 216)

Yes. For the Peninsular Florida region, the Commission staff should be made available to attend such meetings upon the request of the FPSC.

173. If the Commission staff convenes workshops, in how many cities should meetings be convened and how should the cities be chosen? (page 216)

The Commission staff should convene workshops in regions where discussions are not progressing. The Peninsular Florida region discussions are currently progressing.

174. Would the three U.S. interconnections be appropriate starting points? (page 216)

No. *See* comments under number 173 above.

175. Would participation by the Commission staff aid or stifle negotiations on RTO development? (page 216)

The Commission should defer to the recommendations of state regulators on this matter.

176. The Commission seeks comment on whether the filing requirements discussed above are inconsistent with or otherwise would inhibit voluntary participation in RTOs. (page 219-20)

Since the filing requirements constitute "status reports" and do not require participation in an RTO, the requirements will not impact voluntary participation in RTOs.

177. The Commission also seeks comment on whether it needs to generically mandate RTO participation by all public utilities to remedy undue discrimination under sections 205 and 206 of the FPA. (page 220)

The Commission should continue to encourage regional discussions on transmission issues to promote progress toward the Commission's goals, but a federal mandate for such participation at this time would be premature.

178. The Commission also seeks comment on whether a performance-based system could be designed to realign economic interests to remove the motive for discrimination. (page 220)

The Commission should defer on this issue to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

179. **In considering what actions might be appropriate if a utility fails to voluntarily join an RTO, the Commission seeks comment on whether market-based rates for generation services could continue to be justified for a public utility that does not participate in an RTO, whether a merger involving a public utility that is not a member of an RTO would be consistent with the public interest, whether non-participants that own transmission facilities should be allowed to use the non-pancaked transmission rates of the RTO participants in that region, whether transmission services provided by a transmitting utility need to be under RTO control to satisfy the discrimination standards of sections 211 and 212 of the FPA, and whether a public utility's lack of participation would otherwise be in violation of the FPA. (page 220)**

The Commission should defer to regional solutions on these issues that achieve consensus among market participants and the affected state regulatory authorities. The Commission should continue to encourage the development of such solutions, but should not resort to tying this development to favorable or unfavorable determinations in other proceedings.

180. How should the Commission consider the efficiency, reliability, and discrimination implications of RTO non-participation? (page 220)

The Commission should defer on this issue to regional solutions that achieve consensus among market participants and the affected state regulatory authorities.

181. How should the Commission consider non-participation by utilities that constitute "holes" in an RTO region? (pages 220-21)

The Commission should defer to regional solutions that are based on a consensus among market participants and the affected state regulatory authorities.

III

CONCLUSION

Tampa Electric respectfully requests the Commission to consider these initial comments carefully in its deliberation on the proposals set forth in the RTO NOPR.

Respectfully submitted,

TAMPA ELECTRIC COMPANY

By Thomas L. Hernandez

Mr. Thomas L. Hernandez
Vice President, Regulatory Affairs
Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111
Telephone: (813) 228-4495
Facsimile: (813) 228-1770
E-Mail: tlhernandez@tecoenergy.com

Peter C. Lesch, Esq.
Gallagher, Boland and Meiburger
1023 15th Street, N.W.
Suite 900
Washington, D.C. 20005-2602
Telephone: (202) 289-7200
Facsimile: (202) 289-7698
E-Mail: plesch@gbmdc.com

Dated: August 23, 1999

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 23rd day of August, 1999.

Peter C. Lesch
Attorney for Tampa
Electric Company

FLORIDA PUBLIC SERVICE COMMISSION

ERRATA SHEET

IN RE: DOCKET NO. 010577-EI
NAME: WILLIAM R. ASHBURN
DATE: SEPTEMBER 26, 2001

PAGE	LINE	REVISION
8	2	Change “Pricing Plan” to “pricing protocol”
8	16	Change “five years” to “year”
10	1	Change “GridFlorida tariff” to “pricing protocol”
12	1	Change “Pricing Plan” to “pricing protocol”
12	4	Change “plan” to “protocol”
12	18	Change “Pricing Plan's” to “pricing protocol's”
12	21	Change “Pricing Plan” to “pricing protocol”
12	25	Change “Pricing Plan” to “pricing protocol”
13	6	Change “Pricing Plan” to “pricing protocol”
13	16	Change “Pricing Plan” to “pricing protocol”
13	18	Change “Pricing Plan” to “pricing protocol”

Sept 24 2001
Date

William R. Ashburn

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO. 21
COMPANY/
WITNESS. Ashburn
DATE: 10-3 — 5-01

EXHIBIT NO. ______
DOCKET NO. 010577-EI
TAMPA ELECTRIC COMPANY
(WRA-1)
DOCUMENT NO. 1

EXHIBITS TO THE TESTIMONY OF

WILLIAM R. ASHBURN

DOCUMENT NO. 1

STAFF'S FIRST SET OF

INTERROGATORIES NO. 19

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc. EXHIBIT NO. 22
COMPANY/
WITNESS: Ashburn
DATE: 10-3 — 5-01

19. Using a fully allocated cost of service study, please provide the amount of transmission expenses associated with each rate class.

A. Based on a year 2000 fully allocated retail cost of service study that reflects then current functionalization of plant to transmission and subtransmission functions (i.e., does not reflect any reclassification to production or distribution functions as a result of divestiture in a future period), the transmission revenue requirements associated with each rate class are as follows ($000):

RS	GS	GSD	GSLD & SBF	IS & SBI	SL & OL
$26,937	$3,306	$11,725	$4,157	$9,492	$310

EXHIBIT NO. ______
DOCKET NO. 010577-EI
TAMPA ELECTRIC COMPANY
(WRA-1)
DOCUMENT NO. 2

EXHIBITS TO THE TESTIMONY OF

WILLIAM R. ASHBURN

DOCUMENT NO. 2

TAMPA ELECTRIC COMPANY'S

ESTIMATED IMPACT OF INCREASED

TRANSMISSION COSTS ON RETAIL CUSTOMERS

EXHIBIT NO. ________
DOCKET NO. 010577-EI
TAMPA ELECTRIC COMPANY
(WRA-1)
DOCUMENT NO. 2

TAMPA ELECTRIC COMPANY
ESTIMATED IMPACT OF INCREASED TRANSMISSION COSTS ON RETAIL CUSTOMERS
($ millions)

Estimated Incremental Charges from GridFlorida [1]:

Start-up Costs	$ 5.5
On-going Operating Costs	7.6
Total	$ 13.1

Incremental as a Percent of Transmission Revenues:

GridFlorida Incremental Charges	$ 13.1
Estimated Retail Transm Revenues [2]	$ 55.9
Percent Increase	23%

Incremental as a Percent of Total Retail Revenues:

GridFlorida Incremental Charges	$ 13.1
Total Retail Revenues [3]	$1,242.0
Percent Increase	1%

Notes:

(1) Per W. R. Ashburn Exhibit WRA-2
(2) Based on Estimated 2000 Cost of Service Study filed with the response to Staff's 1st Set of Interrogatories, No. 18; included as Document No. 1 of this Exhibit
(3) Per TEC Rate of Return Report for December 2000, Schedule 2, page 2 of 3

EXHIBIT NO. __________

DOCKET NO: 001148-EI

WITNESS: C. MARTIN MENNES

PARTY: FLORIDA POWER & LIGHT COMPANY

DESCRIPTION: RESPONSES TO STAFF DATA REQUESTS

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 000824-EI, etc EXHIBIT NO 24
COMPANY/
WITNESS: FPSC Staff
DATE: 10-3-01

Docket No. 001148-EI
Data Request No. 1
Deposition of C. Martin Mennes
Page 1 of 1
October 2, 2001

Why FPL Has Used the Retrospective Method to Calculate the Depreciation Reserve For Those Assets Being Transferred to GridFlorida

Where assets to be transferred do not alone comprise a complete FERC plant account, the accumulated depreciation expense is calculated based on the depreciation rates approved by the FPSC over the life of the asset. This method is the only way to compute the total depreciation expense recorded on the FPL's books from the in service date of the asset to arrive at its net book value.

Accounting Treatment Regarding Partial Transfer of a FERC Account Balance for Units of Property That are Not Transferred to GridFlorida

Units of property that are in a FERC account that will not in its entirety be transferred to GridFlorida will remain in the current FERC account.

Amount and Disposition of Account 359, Roads and Trails – To be Retained by FPL

Account 359 balance at 12/31/99: (See 1999 FERC Form I, p. 207)	$72,431,000

At one time account 359, Roads and Trails, was included in the list of potential assets to be transferred to GridFlorida. FPL has subsequently decided not to transfer account 359, Roads and Trails, for the same reason all other land and land rights were not transferred as explained in the Joint Panel Testimony of Messrs. Naeve, Mennes, Southwick, and Ramon, p. 23.

Accounting Treatment of Distribution Assets Marked for Transfer to GridFlorida

The GridFlorida collaborative effort established a demarcation systematic to standardize the classification of assets to "distribution use" or "transmission use" among Florida transmission owners. Assets determined as 'transmission use" are marked as assets that would be transferred to GridFlorida. On FPL records, certain assets marked as "transmission use" are properly recorded in distribution accounts. FPL is not aware of any "transmission use" assets recorded in distribution accounts that will be reclassified to Transmission accounts on FPL's books and records. Upon a transfer, GridFlorida will determine how these amounts will be recorded on their books, however, GridFlorida will be required to follow the Uniform System of Accounts as prescribed by this Commission.

The Transmission revenue requirements associated with GridFlorida have been adjusted to reflect "transmission use" assets by including those in distribution accounts, and eliminating certain "non-transmission use" items in the transmission accounts, such as GSUs.

Docket No. 001148-EI
FPSC Staff Data Request No. 5
Deposition of C. Martin Mennes

October 2, 2001

FPL Telecommunication Expense

FPL Telecommunications Expense (2000):	**$ 26,306,922**
Amount Allocable to GridFlorida:	**$ 750,000**
Percent of Total	**2.9%**

GridFlorida's First Year Storm Fund Expense

Components of first year expense:	Amount $millions
1. Estimated transmission portion of FPL's annual accrual based on a preliminary forecast (July, 2000)	$4.6
2. Additional expense assumed for the first five years to build fund balance (i.e., supplemental contributions)	$2.9
3. Storm fund annual accrual	$7.5
4. Line of credit fees	$0.2
5. Total first year GridFlorida storm fund expense	$7.7

Assumptions:

FPL will not transfer any of its existing storm fund balance to GridFlorida.

GridFlorida will establish and maintain its own stand-alone funded reserve to cover transmission and other assets that may be divested to or otherwise acquired by GridFlorida.

FPL developed a target balance of $30 million for the stand alone GridFlorida storm fund to cover transmission assets that FPL may elect to divest to GridFlorida.
FPL will not transfer any of its existing storm fund balance to GridFlorida

FPL assumed that GridFlorida, as a newly created entity, would need to build its funded reserve balance in the early years (i.e. five years) through the combination of an annual accrual and through supplemental contributions.

FPL assumed that GridFlorida would evaluate its annual accrual amount and target fund balance after five years. During that time, GridFlorida would develop its own stand alone storm damage experience with transmission assets and based on that experience will develop its own risk management strategy.

FPL assumed an additional expense of $0.2 million for line of credit fees to secure the ability to borrow additional funds up to $30 million target balance.

Disposition of Pension and Benefit Funds Related to Potential FPL Staff Reductions as a Result of GridFlorida

The anticipated employee reduction associated with GridFlorida would have insignificant actuarial impact on the funding level of the FPL Group Employee Pension Plan. FPL Group will not transfer any excess pension funds for they are assets of the plan and are not tied to individual employees.

Docket No. 001148-EI
Data Request No. 8
Deposition of C. Martin Mennes
Page 1 of 1
October 2, 2001

FPL EMS System Costs

		$Millions
1.	Total estimated New EMS Project Cost Associated with hardware, software, and labor	$30
2.	Estimated cost off-set associated with transmission	$11
3.	Percentage of Total	36.7%

1. Referring to Staff's Third Set of Interrogatories, No. 80, why did FPL decide to use the retrospective method of calculating the depreciation reserve for those assets being transferred to GridFlorida?

Please see response to Staff's Data Request No.1 made during the deposition of C. Martin Mennes.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Reclassification of Assets No. 2
October 1, 2001

In those cases where not all of the assets in a transmission FERC plant account are going to be transferred to GridFlorida, why has FPL decided to reclassify these remaining transmission assets or otherwise change the function from transmission to distribution?

Please see response to Staff's Data Request No.2 made during the deposition of C. Martin Mennes.

If the asset is actually associated with the transmission function, does it necessarily have to be reclassified to another function or FERC plant account?

No.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Reclassification of Assets No. 4
October 1, 2001

Is there any directive or order that requires those transmission assets not being transferred to GridFlorida or any other RTO be reclassified to another function or FERC plant account?

There is no directive or order from any regulatory body that requires transmission assets not being transferred to GridFlorida or any other RTO be reclassified to another function or plant account.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Reclassification of Assets No. 5
October 1, 2001

Has FPL identified those assets that will be reclassified to another FERC plant account?

FPL is not aware of any assets that will be reclassified to another FERC plant account.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Reclassification of Assets No. 6
October 1, 2001

Will this reclassification involve changing the function of the assets? In other words, will they be reclassified from transmission to distribution or production or some other function?

NA

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Development of Original and Replacement Costs for
Transmission Items Being Transferred to GridFlorida No. 1
October 1, 2001

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

In looking at page number 000001, please explain the determination of the replacement value for G/L 106, Plant Account 353, of $190,563.59 when the original cost is shown as $14,511,174.55.

In response to Staff question, the line items represented in the schedule should be as follows:

General Ledger	Plt. Acct.	Original Cost	Replacement Cost
106	353	$14,511,174.55	$14,499,801.95
105	353	$152,029.70	$190,563.59

The replacement cost for 106 property in account 353 is lower than the original cost as a result of a Contribution In Aid Of Construction (CIAC) that was made for an interconnect at Indiantown with an in-service year of 1994.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Development of Original and Replacement Costs for
Transmission Items Being Transferred to GridFlorida No. 2
October 1, 2001

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

What is the source document for pages 000002 through 000075?

The plant in service balances shown on pages 000002 through 000075 was obtained from FPL's mechanized Property Record System. The information used to develop the schedule was obtained at the General Ledger, Plant Account, CPR location, and In-Service Year level. The replacement costs were determined by trending the original costs for each in-service year to year-end 1999 using the Handy-Whitman Index of Public Utility Construction Costs.

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

Please refer to page 000003, cpr location 1042292130, Warfield. What plant in service is represented by the negative dollar amount of $89,193.31? How was the insurable value of this negative number ascertained?

The $89,193.31 negative plant in-service balance shown on page 000003 at Warfield Substation (CPR location 1042292130) consists of the following 1994 in-service year property:

Property Unit	Property Unit Description	Surviving Balance
352.093	Customer Contribution – Cash	$ (393,767.56)
352.140	Rock Surface	16,772.25
352.150	Site Drainage System	19,932.23
352.200	Relay Vault (Building)	218,282.26
352.201	Roof (Relay Vault)	28,439.89
352.410	Fence	18,959.93
352.462	Gate/Entry Manual	2,187.69
		$ (89,193.31)

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Development of Original and Replacement Costs for
Transmission Items Being Transferred to GridFlorida No. 4
October 1, 2001

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

Please refer to page 000031, cpr location 2980000000, Suspense-Transm lines, Account 355. The original cost is zero dollars yet the replacement cost or insurable value is a negative $18.39. Please explain the development of this replacement/insurable value amount.

The negative $18.39 replacement cost was the result of a discrepancy between the in-service year placed on the addition of a $91.93 asset (1992) and its actual in-service year (1997). The negative replacement cost occurs because the addition is at an older in-service year (and thus a greater trending ratio) than the offsetting plant in service correction. This mismatch in in-service years has been corrected.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Development of Original and Replacement Costs for
Transmission Items Being Transferred to GridFlorida No. 5
October 1, 2001

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

Please refer to same page as above, 000031, cpr location 2999999911, Transmission-Holding Locn 11, Account 355. Please explain what plant in service is represented by the negative amount of $120,404.88.

The $120,404.88 negative plant in-service balance shown on page 000031 for CPR location 2999999911, Transmission-Holding Location 11, is the result of Contributions In Aid Of Construction (CIAC).

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

Please refer to page number 000047, cpr location 2081001162, Davis-144A24 (w/o Coral Reef), Account 356. This indicates a negative plant in service amount of $4,108.38. Please explain the positive replacement cost of $49,194.92. In other words, how does a negative investment dollar amount become a positive insurable/replacement amount?

Although the total plant in service balance in Account 356 at CPR location 2081001162, is negative in total, the replacement costs are based on the trending of individual in-service year balances. In the case of this account and CPR location, there are some older positive balances (which have a higher trending factor) and one more recent negative balance (which due to its age, has a lower trending factor). When these balances are trended and summarized, a positive replacement cost results.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Development of Original and Replacement Costs for
Transmission Items Being Transferred to GridFlorida No. 7
October 1, 2001

Please refer to Staff's Second Request for Production of Document, Request No. 1. The request was to provide copies of all documents FPL used in developing the replacement value shown in its response to Staff's First Set of Interrogatories, No. 14E. The documents provided were Bates numbered 000001 through 000081.

Is it FPL's contention that negative investment represents actual plant in service?

Negative investments shown on pages 000001 through 000081 are primarily the result of Contributions In Aid Of Construction (CIAC). These contributions are offsets made to reduce the original cost on the company's books and should be considered when determining the plant in service to be transferred.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Development of Original and Replacement Costs for
Transmission Items Being Transferred to GridFlorida No. 8
October 1, 2001

For those assets being transferred to GridFlorida, will FPL conduct a physical verification or inventory of the assets as shown on the continuing property records? If no, why not? If such verification and reconciliation is not performed, what assurance is there that the dollars transferred to GridFlorida actually represent the physical assets being transferred or vice versa?

A.

A physical inventory would be an expensive and time-consuming effort and, at this time, is unnecessary. There is still some question as to whether FPL will transfer its transmission assets to GridFlorida. Should FPL transfer these assets, GridFlorida may elect to conduct its own physical inventory of these assets. In addition, FPL's property records system and associated databases have been developed over a number of years in accordance with FPSC requirements and accurately reflect the physical attributes, and financial information associated with these assets. The financial information associated with these assets is within the scope of the annual audit conducted by independent accountants.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Other Miscellaneous Questions No. 1
October 1, 2001

Referring to page 10, line 18, of witness Mennes' testimony, what will FPL do with the excess pension funds resulting from the 27 employee reduction?

A.
Please see response to FPSC staff data request No. 7 made during deposition of C. Martin Mennes.

Referring to page 12, line 4-14, of witness Mennes' testimony, who will own the telecommunications equipment on the transmission towers once GridFlorida becomes operational?

A.
Please see response to FPSC staff data request No. 5 made during deposition of C. Martin Mennes.

No telecommunications equipment will be transferred to GridFlorida.

Docket No. 001148-EI
FPSC Staff Information Request Dated 9/27/01
Other Miscellaneous Questions No. 3
October 1, 2001

What percentage of FPL's total telecommunications costs does the $750,000 estimate that is to be assigned to GridFlorida represent? Is this percentage proportional to FPL's total telecommunications ownership in Peninsular Florida?

A.
Please see response to FPSC staff data request No. 5 made during deposition of C. Martin Mennes.

FPL does not know the total amount of Telecom in Peninsular Florida and therefore cannot determine a percentage ownership interest of Telecom assets.