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January 27, 2006

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VIA HAND DELIVERY

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

Re: Docket No. 020233-EI

Dear Ms. Bayó:

Enclosed for filing on behalf of GridFlorida Companies are the original and fifteen copies of the GridFlorida Companies' Motion to Withdraw Compliance Filing and Petition and Close Docket.

Please acknowledge receipt of these documents by stamping the extra copy of this letter "filed" and returning the copy to me. Please contact me if you have questions regarding this filing.

Thank you for your assistance with this filing.

Sincerely,

Kenneth A. Hoffman

KAH/rl
Enclosures
FPL\bayoltr.jan27

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of GridFlorida Regional Transmission Organization (RTO) Proposal	))))	Docket No. 020233-EI Filed: January 27, 2006

GRIDFLORIDA COMPANIES' MOTION TO WITHDRAW COMPLIANCE FILING AND PETITION AND CLOSE DOCKET

Florida Power & Light Company ("FPL"), Progress Energy Florida ("PEF") and Tampa Electric Company ("TECO") (hereinafter referred to collectively as the "GridFlorida Companies"), by and through undersigned counsel, hereby move to withdraw the Compliance Filing filed on March 20-21, 2002 and the September 19, 2002 Petition of the GridFlorida Companies regarding Prudence of GridFlorida Market Design Principles, and request that the Florida Public Service Commission ("Commission" or "FPSC") close the above-styled docket. In support of this Motion, the GridFlorida Companies state as follows:

1. On October 16, 2000, pursuant to Federal Energy Regulatory Commission ("FERC") Order No. 2000, FPL, PEF's predecessor, Florida Power Corporation ("FPC") and TECO filed a Joint Compliance Filing with FERC concerning the establishment of the GridFlorida Regional Transmission Organization ("RTO"). The October 16, 2000 filing requested an expedited ruling on the governance and independence aspects of the GridFlorida RTO proposal.

2. On December 15, 2000, the GridFlorida Companies submitted a Supplemental Filing with FERC incorporating the pricing, market design, operations and planning protocols, and market monitor company incorporation documents and tariff.

3. On January 10, 2001, FERC issued a limited ruling addressing the governance and independence aspects of the GridFlorida RTO proposal. On March 28, 2001, FERC granted provisional approval of GridFlorida requiring GridFlorida to make a compliance filing within sixty days, including a revised market design and progress reports on negotiations with public entities for their participation in GridFlorida. See GridFlorida, LLC, 94 FERC ¶ 61,020 (2001) ("GridFlorida I"); GridFlorida, LLC, 94 FERC ¶ 61,363 ("GridFlorida II"), order on reh'g, 95 FERC ¶ 61,473 (2001).

4. On May 29, 2001, in Docket Nos. 000824-EI, 001148-EI and 010577-EI, the FPSC voted to require each GridFlorida Company to file a petition to determine the prudence of their formation and participation in GridFlorida.

5. On that same day, May 29, 2001, the GridFlorida Companies submitted a compliance filing with FERC pursuant to FERC's March 28, 2001 Order. The GridFlorida Companies notified FERC of the status of various aspects of GridFlorida, including the formal prudence investigation initiated by the FPSC regarding participation in GridFlorida.

6. On June 12, 2001, each GridFlorida Company filed a Petition to Determine the Prudence of Formation of and Participation in GridFlorida, LLC.

7. On December 20, 2001, the Commission issued Order No. PSC-01-2489-FOF-EI ("Order No. 01-2489") finding the proactive formation of GridFlorida prudent and requiring the filing of a modified GridFlorida proposal. Order No. 01-2489 held, in pertinent part, that: (a) the GridFlorida Companies were prudent in proactively forming GridFlorida (see Order at 4); (b)

GridFlorida initially should be structured as an independent system operator ("ISO") rather than a transmission-owning company (see id. at 12); and (c) GridFlorida must use the "get what you bid" market approach as part of the market design for GridFlorida (see id. at 20-23).

8. On March 13, 2002, the above-captioned docket was opened and, thereafter, on March 20-21, 2002, the GridFlorida Companies filed a Modified GridFlorida Proposal pursuant to and in compliance with Order No. 01-2489 (the "Compliance Filing"). The Compliance Filing amended the original GridFlorida proposal in four basic ways. First, GridFlorida was changed from a for-profit transco to a non-profit ISO. Second, subject to one exception, at a transmission customer's option, that customer's bundled retail load would be exempt from zonal transmission charges under the GridFlorida transmission tariff for a five year transition period.[1] Third, the Compliance Filing incorporated a "get what you bid" approach for balancing energy and redispatch. Fourth, the GridFlorida planning process was revised to make it more compatible with the ISO structure ordered by the Commission.

9. On May 29, 2002, the Commission held a workshop to address various issues regarding the GridFlorida Companies' Compliance Filing. As a result of that workshop, analysis of stakeholder comments at the workshop, and additional deliberations, the GridFlorida Companies proposed to amend the market design filed as part of their Compliance Filing.

10. On July 2, 2002, the GridFlorida Companies proposed to amend certain aspects of the market design filed with the Commission as part of the Compliance Filing by proposing the use of: (a) a locational marginal pricing model, i.e., a financial transmission rights ("FTRs") model with locational or nodal pricing, rather than a physical transmission rights model, for

[1]The GridFlorida Companies indicated in the Compliance Filing that they would choose to exempt bundled retail load.

congestion management and energy markets; (b) a two-tier settlement system consisting of a voluntary day-ahead market and a real-time market; and (c) payments of market clearing prices calculated on a nodal basis rather than the "get what you bid" approach included in the Compliance Filing.

11. On September 3, 2002, the Commission issued Order No. PSC-02-1199-PAA-EI ("Order No. 02-1199") which ruled in part on the GridFlorida Companies' compliance with Order No. 01-2489, requiring an evidentiary hearing to address the merits of the revised GridFlorida market design proposal, and set forth proposed agency action determinations regarding specific changes to the GridFlorida Compliance Filing.

12. On September 19, 2002, the GridFlorida Companies filed their Petition and supporting testimony addressing their proposed changes for the GridFlorida market design. The September 19, 2002 Petition requested the Commission to determine that it was prudent for the GridFlorida Companies to develop detailed market design rules and a transmission tariff that would implement: (a) FTRs and locational marginal pricing for congestion management and energy markets; (b) a voluntary day-ahead market and a real-time market; (c) payments of market clearing prices calculated on a "nodal" basis; (d) mechanisms to ensure resource adequacy; (e) allocation of FTRs; (f) market power mitigation measures; and (g) a hierarchical control system.[2]

13. Protests to various proposed agency action determinations and motions for reconsideration of various final agency action determinations of the Commission were filed following the issuance of Order No. 02-1199. In addition, the Office of Public Counsel ("OPC") filed an appeal of Order No. 02-1199 triggering an automatic stay.

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[2]On October 7, 2002, the GridFlorida Companies filed a Motion for Leave to File Amended Petition and Proposed Amended Petition to Remove Hierarchical Control Areas as a Component of the New Market Design as such had already been approved by the Commission.

14. On July 8, 2003, the Supreme Court of Florida issued an Order dismissing OPC's appeal without prejudice to any party to bring a challenge to Order No. 02-1199 after all portions are final. See Citizens v. Jaber, 847 So.2d 975 (Fla. 2003).

15. On September 8, 2003, the Commission issued Order No. PSC-03-1006-FOF-EI resolving the outstanding motions for reconsideration of Order No. 02-1199.

16. In November 2003, the GridFlorida Companies announced that they had retained ICF Consulting Resources, LLC ("ICF") to conduct a cost/benefit analysis of the revised market design and GridFlorida RTO structure to determine the level of costs and benefits that could be expected from its formation.

17. On December 15, 2003, Order No. PSC-03-1414-PCO-EI was issued scheduling new workshops and the submissions of comments and positions to address pending issues in the areas of pricing and market design, along with a wrap-up workshop. On January 15, 2004, Staff submitted a list of issues to be addressed at the pricing workshop including the "[c]ontinued review of RTO costs and benefits."

18. Following the two scheduled pricing and market design workshops, a third workshop was held on June 30, 2004 before the full Commission for the purpose of gathering input from interested persons regarding the cost-benefit analysis of GridFlorida being conducted by ICF and to discuss the project's proposed assumptions.

19. On December 12, 2005, ICF issued its final report entitled "Cost-Benefit Study of the Proposed GridFlorida RTO," a copy of which is attached hereto as Exhibit A. The ICF Study clearly demonstrates that the GridFlorida RTO, whether modeled as a Day 1 or Delayed Day 2 proposal, is not cost beneficial for the retail customers of the GridFlorida Companies. As stated in the "Summary of Conclusions" section on page 149 of the Report:

> ICF's analysis shows that the quantitative benefits of a Delayed Day-2 RTO operation are significant, and range from \$810 million to \$968 million in the scenarios in this study. However, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at \$1.25 billion. The prospects of a Day-1 RTO are bleak, especially if designed along a "greenfield" RTO with wholly new systems, personnel and physical facilities, because the benefits of a Day-1 RTO operation are not nearly as large as a Delayed Day-2 RTO operation, while the fixed costs are high.

20. In light of the findings and conclusions of the final ICF Study, the GridFlorida Companies submit that it is no longer prudent to pursue implementation of the GridFlorida RTO. Accordingly, the GridFlorida Companies maintain that it is in the best interests of their retail customers that the Commission approve the withdrawal of the GridFlorida Companies' Compliance Filing and September 19, 2002 Petition and that this docket be closed.

WHEREFORE, for the foregoing reasons, the GridFlorida Companies respectfully request that the Commission enter a Final Order approving:

A. The Withdrawal of the GridFlorida Companies' Compliance Filing filed on March 20-21, 2002;

B. The withdrawal of the GridFlorida Companies' Petition regarding Prudence of GridFlorida market design principles filed on September 19, 2002; and

C. The closure of the above-referenced docket.

Respectfully submitted,

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By: Kenneth A. Hoffman
Kenneth A. Hoffman, Esq.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the GridFlorida Companies' Motion to Withdraw Compliance Filing/Petition and Close Docket has been furnished by Electronic Mail, this 27th day of January, 2006, to the following:

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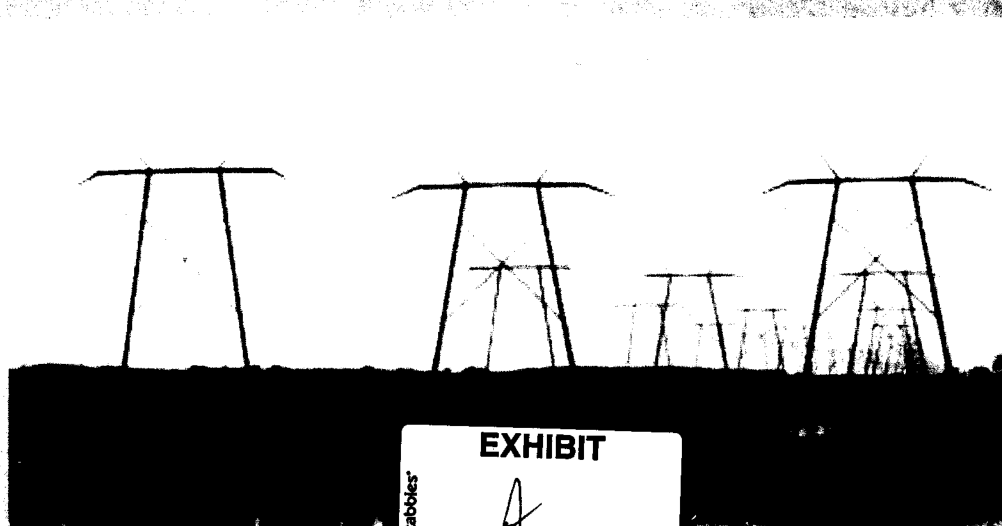
Cost-Benefit Study of the Proposed GridFlorida RTO

ICF CONSULTING

GRIDFLORIDA



EXHIBIT

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EXECUTIVE SUMMARY

Introduction

This study examined the costs and benefits to Peninsular Florida consumers of transforming the current decentralized market to a centrally organized market under two modes of operation – a Day-1 only RTO and a Delayed Day-2 RTO. A Day-1 Only RTO configuration reflects 13 years of decentralized company operation, but with a single transmission provider under a single GridFlorida-wide transmission tariff. Thus, under a Day-1 RTO configuration, currently "pancaked" transmission charges are eliminated. A Delayed Day-2 RTO configuration comprises three initial years of Day-1 operation, followed by 10 years of Day-2 operation. Under Day-2 operation, unit commitment and dispatch for the entire Peninsular Florida region is centralized under the GridFlorida RTO, with all market participants taking transmission service from the RTO under a single tariff. Each of these two RTO modes of operation is compared to a Base Case that reflects the current decentralized market, with individual company and control area operation, multiple transmission providers and "pancaked" transmission rates.

Cases Examined

As part of this assessment, ICF reviewed and analyzed a Reference Set of Cases (Base Case, Day-1 Case and Delayed Day-2 Case) and two sensitivity analysis cases – JEA and TALL as non participants of Grid Florida, and a Market Imperfection Case which addresses real world imperfections with unit commitment compared to the model outcome. Each case spans a 13-year forecast period, representing the period from 2004 through 2016. Exhibit ES-1 provides a summary of all the cases modeled.

Exhibit ES-1
Summary of Cases Analyzed

	Base Case	Day-1 Case	Delayed Day-2 Case	Total Number of Cases
Reference Cases	Yes	Yes	Yes	**3**
Sensitivity Analysis – JEA and TALL Out Case	Unchanged from Reference Case	Not in Scope of Study	Yes	**1**
Sensitivity Analysis – Market Imperfection Case	Unchanged from Reference Case	Not in Scope of Study	Yes	**1**
Total Number of Cases	**1**	**1**	**3**	**5**

Summary of Quantitative RTO Costs and Benefits

Exhibit ES-2 summarizes the quantitative RTO costs and benefits across all the cases examined.

Exhibit ES-2
Summary of Quantitative RTO Costs and Benefits (Million 2004$)
NPV (Years 1-13)[1]

Case	RTO Operation	RTO Benefits[1]	RTO Costs[2]	Net Quantitative Benefit/Costs[3]
Reference Cases	Day-1 Only	71	775	-704
	Delayed Day-2	968	1,253	-285
JEA and TALL Out Case	Delayed Day-2	891		-362
Market Imperfection Case	Delayed Day-2	810		-443

[1,2]All costs and benefits are discounted using a 3.15% real discount rate over the 13-year forecast period.
[3]The RTO Costs presented are estimates associated only with the new RTO. None of the potential changes in existing utility operational costs has been considered in this estimate.

A comparison of the quantitative RTO costs and benefits in net present value terms over the 13-year forecast period indicates a loss in all the cases examined, before considering qualitative costs/benefits and other utility operational cost changes. Whereas the quantifiable benefits under Delayed Day-2 RTO operation were

[1] All costs and benefits were discounted using a 3.15 percent real discount rate

substantial, and ranged from approximately $810 million in the Market Imperfection Case to almost $968 million in the Reference Case, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at $1.25 billion. The quantitative benefits to Peninsular Florida consumers of Day-1 Only RTO operation is $71 million over this period, while the quantitative start-up and operating costs of a "greenfield" Day-1 RTO is $775 million. Thus, the Day-1 RTO configuration reflects an estimated net loss of $704 million.

The quantitative analysis of the Day-1 RTO and Delayed Day-2 RTO indicate that the majority of the benefits to Peninsular Florida consumers come from centralized market operation, especially from centralized unit commitment[2]. The model calibration exercise revealed through the realized hurdle rates that the inefficiencies associated with unit commitment are by far larger than those associated with dispatch. This outcome is not surprising because in Peninsular Florida, more than ten entities separately commit units to meet load for a system with a total peak load of approximately 43 GW[3]. In systems such as PJM (116 GW); NYISO (31 GW) and ISO-NE (25 GW), a single entity performs unit commitment. Secondary benefits arise from centralized dispatch, which is related to real time operation of the generating units, but the inefficiencies associated with dispatch are not nearly as large as those associated with unit commitment, as there is already a high level of connectivity between control areas in Florida and most transactions occur between adjacent systems. For these reasons, maintaining a

[2] Centralized commitment is the day-ahead determination of which generating units will be used to meet load the following day.

[3] The three jurisdictional utilities comprise almost 77% of the load and the incremental benefit of centralized unit commitment may not be as large as the incremental benefit of unit commitment for the eight non-jurisdictional utilities that perform centralized unit commitment.

decentralized unit commitment and dispatch operation under a Day-1 RTO configuration, similar to the existing market, is expected to yield only moderate benefits.

Qualitative Factors: There are also various qualitative factors that should be considered along with the quantitative costs and benefits estimated for the Day-1 and Delayed Day-2 RTO operations. These qualitative costs and benefits are summarized in Exhibit ES-3.

Exhibit ES-3
Potential Impact of Qualitative Factors in Day-1 and Day-2 RTOs

Qualitative Factor	Potential Day-1 Impact		Potential Day-2 Impact	
	Costs	Benefits	Costs	Benefits
Investment Efficiency				
Transmission		√		√
Generation		√		√
Bilateral Long-Term Contracting		√		√
Elimination of Contract Path Scheduling		√		√
Transition Risks	√		√	
Market Transparency		√		√
Scope, Organizational and Regulatory Issues	√		√	
Other factors				
ROE		-		-
Inter-Regional Tariffs		√		√
Efficiency and Standards		√		√
Merchant Power Plants		√		√

Jurisdictional and Non-Jurisdiction RTO Costs/Benefits and Transmission Owner Cost Shifts

The quantitative RTO costs and benefits in the Reference Case were disaggregated between jurisdictional utility consumers and those that are non-jurisdictional to the FPSC. The benefits to each of these two groups were estimated from the change in their local generation and bilateral transactions (between the two groups) and external imports in response to the change in market structure in Day-1 and Day-2. The quantitative RTO costs were also disaggregated between the two groups based on load ratio share i.e., 77% for the jurisdictional consumers and 23% for the non-jurisdictional consumers.

These jurisdictional and non-jurisdictional costs and benefits were combined with Transmission Owner cost shifts. Under the GridFlorida tariff, there are three factors which lead to cost shifts between transmission owners: (1) the costs of transmission dependent utilities (TDU) transmission facilities being included in transmission rates for all transmission customers, not just TDU customers; (2) the transmission facilities of all Peninsular Florida utilities being blended together in a single region-wide rate; and (3) multiple access charges being eliminated for service within GridFlorida ("de-pancaking"). The net impact of the cost shifts is that the jurisdictional transmission owners' cost to serve retail customers increases, thus increasing their retail rates, and the non-jurisdictional transmission owners' cost and retail rates decreases.

Exhibit ES-4 shows the combined effect of the transmission owner cost shifts and jurisdictional and non-jurisdictional costs and benefits.

Exhibit ES-4
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Transmission Owner Costs[4] (Cost Shifts)	525	-525	-	525	-525	-
Net Benefits	-1,135	431	-704	-1,083	798	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

[4] The Transmission Owner costs shifts have been estimated based on the GridFlorida tariff filed with the FPSC by the GridFlorida Applicants. However the quantitative RTO benefits have been estimated using a simplified form of the tariff structure because the tariff as filed did not lend itself to analytic modeling. Thus, the net benefits shown in Exhibit ES-4 should be interpreted as indicative rather than definitive.

Overall, under Day-1 RTO Operation, jurisdictional consumers incur a loss of approximately $1.1 billion and non-jurisdictional consumers earn a benefit of approximately $431 million. Under Delayed Day-2 RTO operation, jurisdictional consumers incur a loss of approximately $1.1 billion and non-jurisdictional consumers earn a benefit of approximately $798 million.

Conclusions

The overall outcome of net benefits or costs to Peninsular Florida consumers depends on both quantitative and qualitative aspects of the RTO. ICF's analysis shows that the prospects of a Day-1 RTO are bleak, especially if designed along a "greenfield" RTO with wholly new systems, personnel and physical facilities because while the fixed costs are high, the benefits of a Day-1 RTO operation are not as large as a Delayed Day-2 RTO operation. The quantitative Delayed Day-2 RTO benefits to Peninsular Florida consumers come largely from centralized market operation, especially from unit commitment. Secondary benefits come from centralized dispatch, but the inefficiencies associated with dispatch are not nearly as large as those associated with unit commitment, as there is already a high level of connectivity between control areas in Florida and most transactions occur between adjacent systems. The GridFlorida Delayed Day-2 RTO could breakeven under the scenarios examined in this study if the net benefits from the qualitative factors and the change in utility operational costs should be within the range of $285 million and $443 million over the 13-year forecast period. This study also indicates that the non-jurisdictional consumers would receive net positive benefits of $798 million from the implementation of a GridFlorida Delayed Day-2 RTO while jurisdictional consumers would receive a net loss of $1.1 billion.

While the overall GridFlorida consumer cost/benefit remains unchanged, the RTO costs allocation and the transmission owner cost shifts exacerbates the quantitative loss to jurisdictional consumers and improves the benefits to non-jurisdictional consumers.

CHAPTER ONE
PROJECT BACKGROUND

1.1 Background on the FPSC Order

In September 2003, the Federal Energy Regulatory Commission (FERC) met with the Florida Public Services Commission (FPSC) and discussed the principles surrounding the creation of a regional transmission organization (RTO) in Florida. As a follow up to this meeting, on December 15, 2003, the FPSC issued Order PSC-03-1414-PCO-EI establishing revised dates for Stakeholder workshops on the potential structure and impacts of creating an RTO in Peninsular Florida (GridFlorida).

The FPSC's issues list for the Pricing and the Market Design Workshops included an issue for the continued review of RTO costs and benefits. The applicants engaged ICF to evaluate the costs and benefits of GridFlorida. ICF worked with the stakeholders to model GridFlorida consistent with the Applicant's September 19, 2002 filing "Petition of the GridFlorida Companies Regarding Prudence of GridFlorida Market Design". In addition, to the extent that an RTO structure based on the principles stated in the filing differed from an RTO structure based on FERC's guidelines per the Standard Market Design (SMD) and subsequent White Paper dated April 2003, these differences were analyzed.

1.2 Study Overview and Objectives

To comply with the requested review of RTO costs and benefits, ICF Resources LLC ("ICF") was engaged by GridFlorida LLC ("GridFlorida") to independently assess the costs and benefits to Peninsular Florida consumers of restructuring the Peninsular Florida power market from the existing decentralized utility control area operation, and bilateral market to a centrally organized one, i.e., the GridFlorida RTO. This document presents the results of ICF's assessment.

In both Peninsular Florida and in general, the primary costs and benefits from centrally coordinated and dispatched markets through an RTO derive from four principal sources, which include:

- Operational efficiency;
- Investment efficiency;
- Market participant net costs or benefits from working with the new RTO; and
- Cost of forming and maintaining a new RTO.

Of the various costs and benefits associated with market restructuring, some can be readily quantified, while others are best left to qualitative assessment. The costs and benefits that are quantifiable lend themselves to commercially available analytic modeling tools based on approaches widely accepted by the industry. ICF deployed a range of analytical tools, as described in Chapter 3, to develop these quantitative assessments. ICF also identified and discussed a number of qualitative factors and the potential for each of these factors to provide benefits or costs. These are described in Chapter 5.

In this study, most of the operational efficiencies were quantified using industry accepted analytical techniques, while the investment efficiency and selected aspects of operational efficiencies have been qualitatively assessed. Arguably, some of the qualitative costs and benefits may be quantifiable, and several approaches have been suggested for doing so. However, we note that the industry as a whole has not accepted any one approach so in this study, we believe these factors are best left as qualitative features of the report. In addition, analyzing individual market participants' costs or benefits from working with the RTO were not part of the scope of this study. All quantified costs and benefits have been compared to a continuation of the status quo (i.e. a "Base Case" reflective of today's decentralized wholesale power market) over a thirteen year forecast period.

A key component of the ICF study involved the identification of the significant structural and functional differences between the Peninsular Florida market today and a future centrally organized market. These differences enable us to anticipate the quantifiable costs and benefits that would be derived from the implementation of a GridFlorida RTO. For example, the elimination of "pancaked"[5] transmission rates between existing control areas should improve the efficiency in generation dispatched to serve load and meet reserve requirements. Thus, to the extent there are no internal transmission constraints, the least cost generation facilities serving the Peninsular Florida market as a whole will be dispatched, which should result in overall benefits to consumers. Depending on their magnitude, pancaked transmission tariffs can act like trade obstacles that effectively segment a market into sub-markets. Similarly, decentralized unit commitment and dispatch operations act like trade obstacles. When such barriers

[5] "Pancaking" is a term commonly used to explain the practice of incurring multiple wheeling charges when moving power from one area to another across multiple utility territories, each with its own transmission system costs and associated wheeling charge.

exist, each sub-market realizes a local optimum instead of a Peninsular Florida-wide optimum, as would be the case in a centrally organized RTO market[6].

As part of the overall cost-benefit assessment, it is also critical to assess the costs of forming and maintaining a new organization in the form of the GridFlorida RTO that would provide various functions necessary for the centralized market operation. This evaluation involved a detailed bottom-up assessment of the costs likely to be associated with each key function and department of the RTO, an assessment which benefited from extensive research on the experience of other RTOs.

In this study, ICF evaluated two specific RTO configuration alternatives, namely a "Day-1" only operation and a "Delayed Day-2" operation. These alternative configurations differ in their structural and operational functions. A Day-1 only RTO maintains the existing decentralized company operation but transmission service is provided by the GridFlorida RTO and under a single GridFlorida-wide transmission tariff[7]. Thus in Day-1 we eliminate currently "pancaked" transmission charges and all transmission customers take transmission service from the RTO. A Delayed Day-2 operation reflects three initial years of Day-1 operation followed by ten years of Day-2 operation. Under Day-2 operation, the entire market is centralized under the GridFlorida RTO. Unit commitment and dispatch is centralized to meet the GridFlorida-wide load and reserve requirements.

1.3 Stakeholder Participation

This study was driven by a multi-faceted and interactive Stakeholder process designed to ensure the accurate representation of the Peninsular Florida system and to benefit

[6] Theoretically, a centralized market should provide a Peninsular Florida-wide optimum.

[7] Although the GridFlorida Applicants filed a GridFlorida tariff that phases out "pancaking" of transmission rates over time, in this study a single rate has been used as a simplification.

from the feedback of all Stakeholders. The scope of the study was developed and approved by the GridFlorida Applicants in consultation with the FPSC and other Stakeholders, including municipal utilities, cooperative utilities, and independent power producers active in the Peninsular Florida market. A Project Steering Committee comprising the GridFlorida Applicants provided guidance and administration in gathering Stakeholder and relevant market data, and in providing ICF with the year-by-year representation of the transmission system over the 13 year forecast period. For example, all generation resource thermal and cost data used for modeling was provided confidentially by the individual Stakeholders in the best position to supply that data. In addition to regular conference calls with various participants during the course of the study, ICF conducted six Cost-Benefit Working Group (CBWG) meetings with the entire Stakeholder Group to:

- Discuss the study approach and assumptions;
- Review interim modeling results;
- Solicit Stakeholder comments; and
- Present results incorporating Stakeholder feedback.

Additionally, ICF established three time periods to afford Stakeholders with an opportunity to provide written comments on the Study Approach, the preliminary RTO cost estimates and the preliminary RTO benefit estimates. Relevant feedback from Stakeholders was incorporated into the study.

Thus, in sum, this study, performed with significant Stakeholder participation, provides a comprehensive evaluation of the costs and benefits of forming a GridFlorida RTO, many of which were quantifiable, and some of which were not.

The remainder of this report is organized into six Chapters and Appendices. Chapter 2 discusses the Peninsular Florida power market and the proposed GridFlorida market structure. Chapter 3 discusses the analytic approach to quantifying costs and benefits. Chapter 4 presents the quantitative results, and Chapter 5 discusses qualitative factors. The quantitative RTO costs and benefits are disaggregated between jurisdictional and non-jurisdictional consumers in Chapter 6 including discussion of transmission owner costs shifts that result from blending all transmission facilities under a single GridFlorida tariff. We finally present our conclusions in Chapter 7, followed by relevant Appendices.

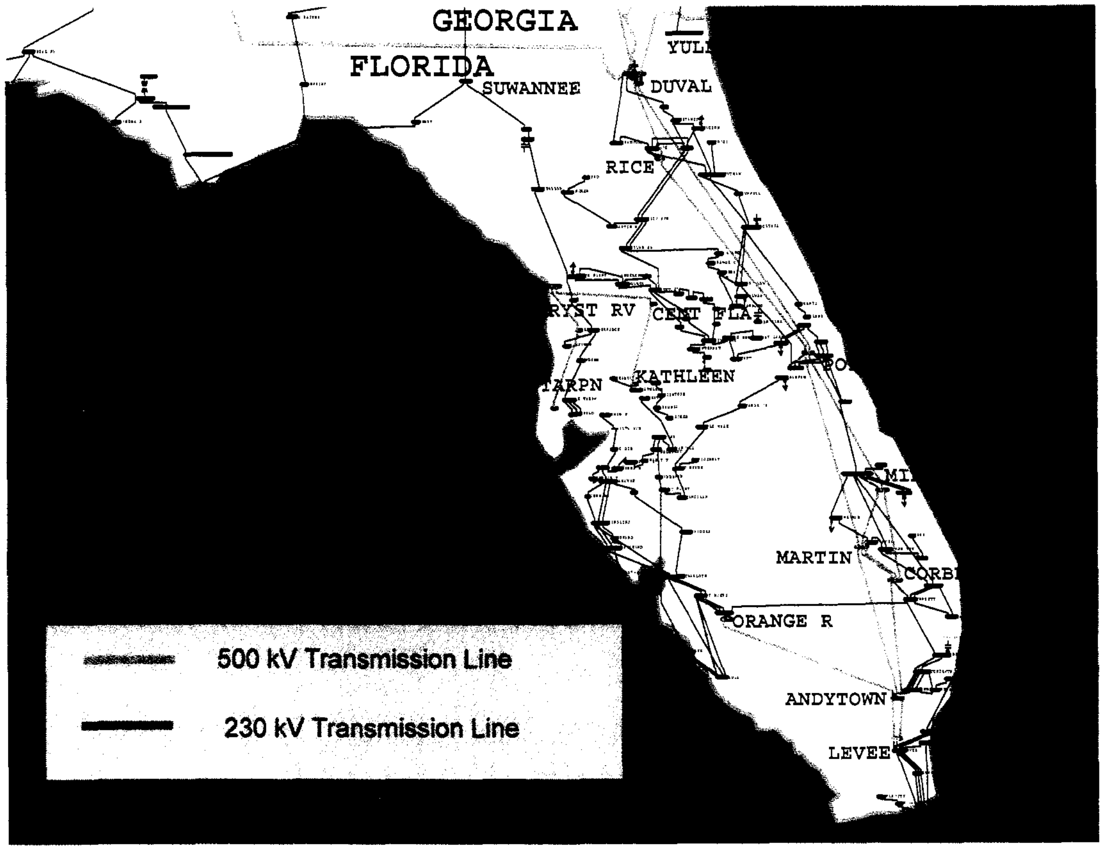
CHAPTER TWO
THE PENINSULAR FLORIDA POWER MARKET AND THE PROPOSED GRIDFLORIDA MARKET STRUCTURE

This chapter provides background on the Florida power market, including an introduction to the Florida Reliability Coordinating Council (FRCC) and the geographic extent of its market coverage, an overview of the physical transmission condition (external and internal), and the supply/demand fundamentals prevailing in the market. This chapter also provides an overview of the current market structure and participants and concludes with a discussion of the proposed market structure.

2.1 Background on the FRCC

Peninsular Florida was formerly a sub-region of the Southeastern Electric Reliability Council (SERC). However, in 1996, the FRCC was established after the Florida Electric Power Coordinating Group (FCG) decided to establish its own reliability council to ensure and enhance the future reliability and adequacy of bulk electricity supply in Florida, in recognition of Florida's unique reliability needs. The FRCC includes all utility systems within the state's border, with the exception of the northwestern Panhandle, which is partially operated by Gulf Power Company and remains part of SERC.

Exhibit 2-1
Peninsular Florida Transmission System



In December 2001, the FRCC amended its Bylaws to provide for a balanced sector board and representation on its standing committees. The FRCC's activities are directed by its Board of Directors, which is comprised of top-level executives from members of FRCC. Technical activities are carried out by the Engineering and Operating Committees. The Market Interface Committee addresses the effects of new and evolving market practices on electric system reliability, and ensures that the impacts of the electric industry's reliability standards are addressed from the market perspective. Thus, there already exists in Florida an organization designed to coordinate reliability[8] that the proposed GridFlorida RTO would interact with.

2.2 Florida's Interconnectivity with the Rest of the Grid

Peninsular Florida operated its electric system in virtual isolation from the rest of the Southeast until the summer of 1982, when two 500 kV interconnections with Georgia Power were established. Even now, it is relatively isolated in terms of its electric power interconnections. Its only link with another system is with SERC at the Florida/Georgia border and in the Florida Panhandle. This makes FRCC among the regions in the US with the lowest potential to import or export power. Based on North-America Electric Reliability Council (NERC) and FRCC forecasts of import capability and demand, only about 9 percent of FRCC's net internal peak demand can currently be met through imports. Only the ERCOT region in Texas is more electrically isolated among the regions typically analyzed in the continental United States (US).

The interconnections between Florida and the Southern region within SERC consist of:

- 500 kV transmission lines from Duval to Hatch and from Duval to Thalman;
- 230 kV transmission lines from Port St. Joe to Callaway, from Sub 20 to S. Bainbridge, from Suwannee to Sterling, and from Yulee to Kingsland;
- 115 kV transmission lines from Jasper to Tarver, from Jasper to Wrights Chapel, from Suwannee to Twin Lakes and from Woodruff to Scholz.

[8] The FRCC has contracted with FPL to provide Security Coordination services for the Peninsular Florida power system.

As mentioned earlier, the state's unique geographic location and relatively modest inter-regional transfer capability were the main forces behind the establishment of the FCG in 1972, and the subsequent Florida Reliability Coordinating Council in 1996.

2.3 Transmission Within Florida

In contrast to external interconnectivity, there is significant and substantial interconnectivity within Florida. The utilities within Peninsular Florida are interconnected via a high-voltage system made up of 500 kV and 230 kV lines. Double circuit 500 kV lines run the length of the State's eastern seaboard and enable significant power flows from the north to load centers in the southeast and around Miami. Florida's transmission system is considered by NERC to be adequate for power transactions within the region, with no problems that would significantly affect reliability. Indeed, only one transmission loading relief (TLR) event which was due to a hurricane has occurred in the FRCC since 2000.

2.4 Supply and Demand Conditions

FRCC is an average sized market compared to other power markets in the U.S. Net internal peak demand is approximately 43 GW[9], and Florida has a bimodal winter and summer peaking profile. Whether looking at 10 year rolling averages or more recent averages, peak demand and energy growth rates in Florida has been very strong (energy demand has been in excess of 3.0 percent on average), making Florida one of the fastest growing markets in the US. This is in comparison to the US average growth rate of closer to 2.5 percent.

[9] 2004 actual peak demand was approximately 43 GW

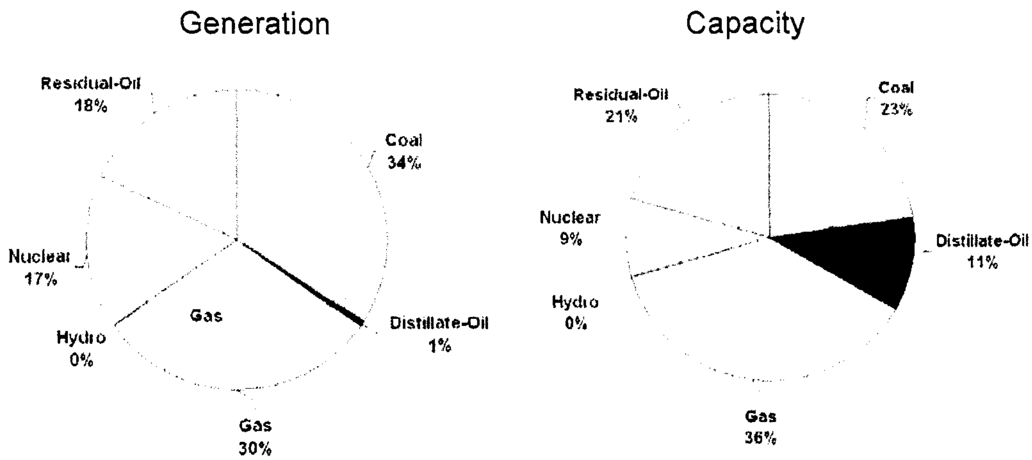
Exhibit 2-2
Historical Peak Demand and Energy Growth Rates – FRCC

Year	Peak Demand (MW)	Energy (GWh)
2003	40,475	219,021
2002	40,696	211,116
2001	39,062	200,134
2000	37,194	196,561
1999	37,493	188,598
1998	38,730	188,384
1997	35,375	175,557
1996	35,444	173,377
1995	34,524	169,021
1994	32,904	159,861
1993	32,823	153,468
1992	30,601	147,464
1991	28,818	146,906
1990	27,266	142,502
1989	27,972	142,959
Historical Annual Average Growth Rates (%)		
10 Year Rolling Averages		
1993-2003	2.12%	3.62%
1992-2002	2.89%	3.65%
1991-2001	3.09%	3.14%
1990-2000	3.15%	3.27%
1989-1999	2.97%	2.81%
Average of 10 Year Rolling Averages (1989-2003)	**2.84%**	**3.30%**

Source: NERC ES&D 2004

The Florida capacity mix is diverse (see Exhibit 2-3). More oil is used in generating power in Florida than in any other state, with oil/gas steam units accounting for almost 20 percent of FRCC's capacity. Due to natural gas pipeline constraints, a relatively large portion of Florida's combustion turbines can also be oil fired, specifically distillate-fired. Florida made efforts after the oil crises of the 1970s to increase its use of fuels other than oil, resulting in significant coal use even though there is no coal mined in the state and it is relatively costly to transport coal to Florida. Nuclear and combined cycle units make up the remainder of Florida's capacity mix.

Exhibit 2-3
Capacity and Generation Mix in FRCC – 2003



Source: GridFlorida Applicants and Stakeholder
The total reported capacity and generation is the sum of the 2003 unit capacity and dispatch reported by Florida Power & Light, Progress Energy Florida, Tampa Electric Company, Seminole Electric Cooperative and member systems, Gainesville Regional Utilities, Jacksonville Electric Authority, Florida Municipal Power Agency (FMPA) member systems, Orlando Utilities Commission, Lakeland Electric, City of Tallahassee Electric Department. Excludes resources of New Smyrna Beach, Reedy Creek Improvement District and City of Homestead.

Florida's capacity mix has been changing over the last several years with over 15 GW of newly operational capacity having come on-line between 2001 and 2005 (see Exhibits 2-4 and 2-5). Capacity additions in Florida in the 1999 to 2001 timeframe lagged those of the neighboring markets of Southern Company and Entergy. However, there was significant capacity expansion activity in Florida thereafter. The majority of builds consisted of efficient combined cycle units due to the arbitrage opportunities against higher heat rate oil/gas steam units.

Exhibit 2-4
FRCC Summary of Recent and Under Construction Capacity

	2001	2002	2003	2004	2005	2006
Combined Cycle	141	3,362	2,960	1,642	2,628	0
Combustion Turbine	1,391	2,622	0	0	99	537
Total	**1,532**	**5,984**	**2,960**	**642**	**2,727**	**537**

Source: GridFlorida Applicant and Stakeholder Data

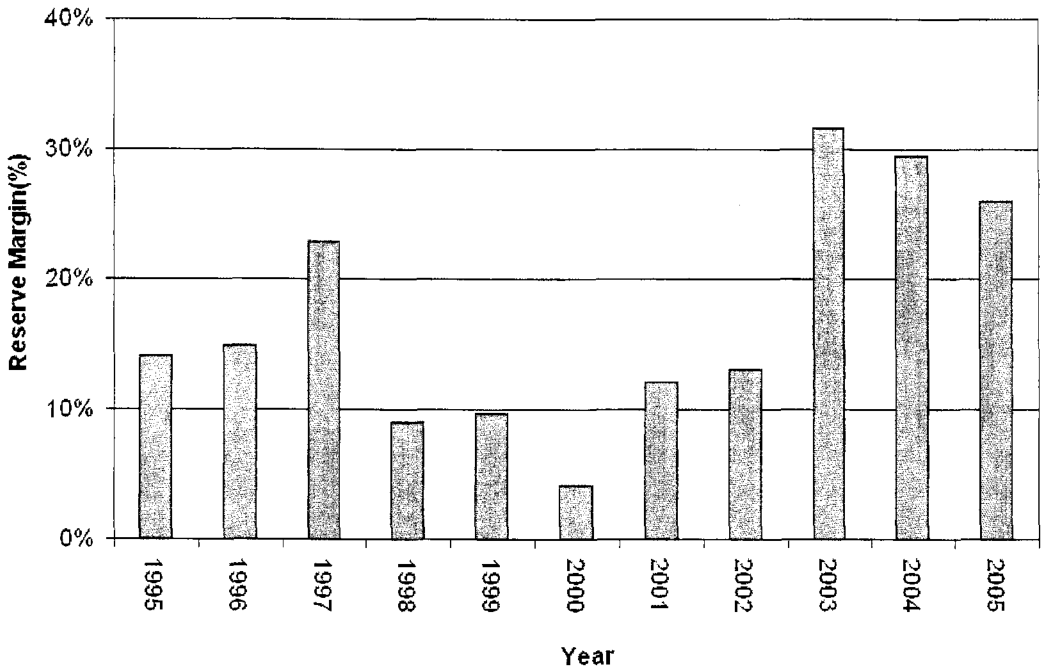
Exhibit 2-5
FRCC Capacity Mix 2001 to 2005

Year	2001	2002	2003	2004	2005
Combined Cycle	4,165	7,527	10,487	12,129	14,757
Cogens	821	821	821	821	821
Combustion Turbine	8,420	10,867	10,867	10,867	10,966
Hydro	47	47	47	47	47
Nuclear	3,928	3,928	3,928	3,928	3,928
Steam	10,578	10,753	10,753	10,753	10,753
Coal	9,470	9,470	9,470	9,470	9,470
Other	399	399	399	399	399
Grand Total	**37,829**	**43,813**	**46,773**	**48,415**	**51,142**

Source: GridFlorida Applicant and Stakeholder Data

Increases in demand and limited plant construction contributed to lower reserve margins in the late nineties. Since that time, a development boom has pushed reserve margins above their equilibrium levels (see Exhibit 2-6). The reserve margin in FRCC in 2005 under normal conditions is estimated at approximately 21%. FRCC has typically maintained a 15% planning reserve margin in the region. This target reserve margin level is within the typical range of US reserve margin levels (15-18 percent). However, the jurisdictional utilities have an arrangement with the FPSC to maintain a 20% reserve margin level. At this target level, with additional builds forthcoming and a rapid demand growth rate, Florida is expected to maintain equilibrium supply/demand balance conditions well ahead of most other parts of the Eastern Interconnect.

Exhibit 2-6
Reserve Margins in FRCC: 1995 – 2005



Source: FRCC State Resource Plan 2005
Note: Reserve Margin calculated as Total Installed Capacity/Actual Peak Demand and does not include Exports and Imports. FRCC total installed capacity includes non-utility capacity and merchant capacity

2.5 Current Florida Market Structure

The major investor-owned utilities (IOUs) in Florida include Florida Power & Light (FPL), Tampa Electric Company (TECO) and Progress Energy Florida (PEF). These three IOUs together comprise over 70 percent of all electric power sales in the FRCC. In fact, FPL alone accounted for nearly half of all generation and sales in the region in 2003 (see Exhibit 2-7). In addition to the IOUs, Florida also has a strong public power sector. The larger municipal and cooperative systems include Jacksonville Electric Authority, Florida Municipal Power Agency (FMPA) member systems, Seminole Electric Cooperative (SECI) member systems, Kissimmee Utility Authority, Lakeland Dept. of Electric & Water Utilities, Orlando Utilities Commission (OUC), Gainesville Regional Utilities, City of Homestead, Reedy Creek Improvement District and City of Tallahassee Electric Department (TALL). Of these entities, four have direct ties with Southern Company (SOCO), namely the City of Tallahassee Electric Department, Jacksonville Electric Authority, Florida Power & Light and Progress Energy Florida.

Exhibit 2-7
FRCC 2003 Market Sales By Utility

Utility	Sale to End Users (MWh)	Share
Florida Power & Light	99,635,281	45.3%
Progress Energy Florida	37,956,700	17.3%
Tampa Electric Company	18,242,316	8.3%
Jacksonville	12,582,876	5.7%
Gulf Power Company	11,248,860	5.1%
Orlando Utilities	7,567,400	3.4%
Withlacoochee	3,210,356	1.5%
Lee County	3,116,182	1.4%
Clay	2,873,635	1.3%
Lakeland	2,736,686	1.2%
Tallahassee	2,601,510	1.2%
Sumter	2,099,972	1.0%
Gainesville	1,785,967	0.8%
Ocala	1,275,044	1%
Kissimmee	1,218,620	1%
Reedy Creek	1,124,269	1%
Others[10]	10,503,065	5%
TOTAL	219,778,737	100%

Source: Statistics of the Florida Electric Utility Industry 2003, FPSC

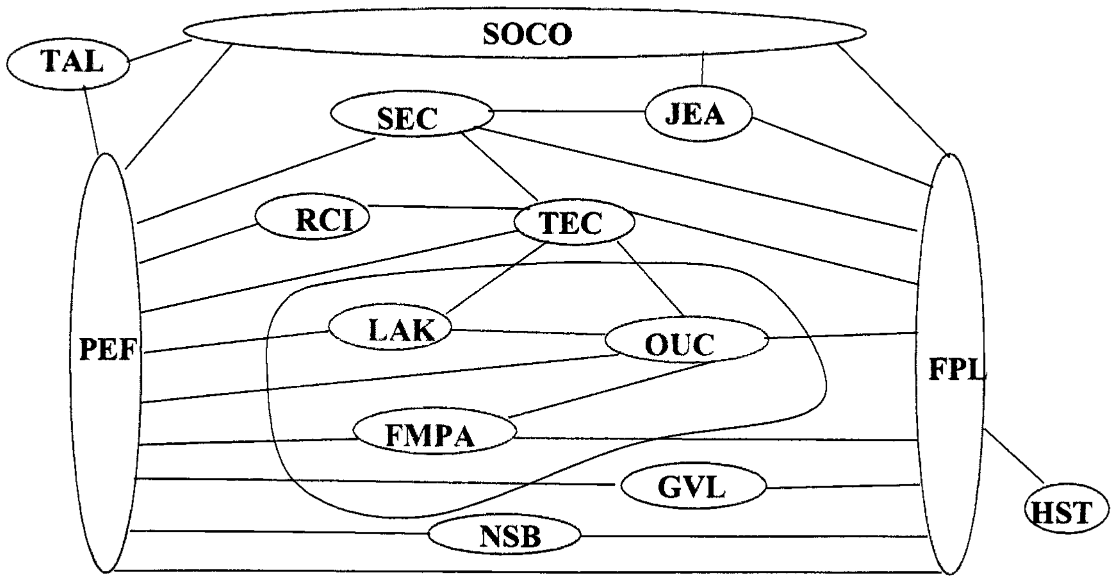
The Peninsular Florida power market functions through decentralized, utility control area operation. Exhibit 2-8 shows a schematic of the interconnected control areas. There are currently eleven entities responsible for transmission operations in Peninsular Florida. Each of these entities is responsible for scheduling and dispatching their

[10] Includes Choctawhatchee, Central Florida, Florida Keys, Jacksonville Beach, Key West, Leesburg, New Smyrna Beach, Talquin, Fort Pierce, Bartow, Vero Beach, Florida Public Utilities, and Peace River etc. Maximum and average sales to end users in this group are approximately .93 TWh and 0.32 TWh respectively.

generation resources to serve their load and reserve requirements. Simultaneously, these eleven transmission providers coordinate with each other during real time operations to balance generation against load and thereby maintain system frequency. FPL provides security coordination services for the entire FRCC region.

While Florida has never had a tightly operated pool, in 1976, Florida utilities began active power trading using a centralized power exchange called the Energy Broker Network (EBN). The EBN was a cost-based voluntary mechanism for marketing non-firm next hour electric energy among electric utilities that had sufficient generating capacity to meet their loads. While in operation, the EBN facilitated power marketing amongst the utilities by increasing transaction volumes and providing fuel cost savings to Florida consumers annually. The EBN was discontinued on September 1, 2000 because of rapid changes in the industry, such as the emergence of power marketing entities that sought alternative ways to market energy. Since then, utilities and marketers have engaged in bilateral trading, both within Florida and externally, capturing some cost savings. Trades are predominantly short-term, on a non-firm basis and recallable which introduces some amount of uncertainty in unit commitment decisions and may result in some market inefficiency. Some of the utilities have long-term, firm bilateral trade agreements.

Exhibit 2-8
Schematic Diagram of Interconnected Control Areas



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

There are several other key features of the FRCC market structure and operation that this study took into consideration. For example:

- Some of the Florida utilities have resources external to FRCC which they regularly dispatch as network resources to serve their load in Florida. FPL and JEA for example jointly own the Scherer Unit 4 coal facility in Georgia and dynamically schedule this resource across their ownership share of the Southern Company/Florida transmission interface to serve their load. FPL, JEA and PEF also have Unit Power Sales (UPS) contracts which they treat similar to the Scherer unit.

- Utilities such as Seminole and FMPA have load embedded in other control areas and depend on transmission services of other entities to serve their load.
- Although Lakeland Dept. of Electric & Water Utilities (LAK), Orlando Utilities Commission (OUC), Florida Municipal Power Agency member systems (FMPA) are control areas, operationally they dispatch their facilities in a pool to meet their joint load and reserve requirements.

These and other features of the FRCC market, such as those described in the earlier section on supply/demand fundamentals, were captured in our assessment and modeling efforts.

2.6 Transmission Operations

Transaction scheduling in Peninsular Florida is performed by multiple transmission providers. Each transmission provider administers its own portion of Florida's Open Access Same-time Information System (OASIS) where Available Transfer Capability (ATC) and transmission rates for transmission services are posted. Each transmission provider, in coordination with the FRCC, calculates ATC on specific transmission corridors (Contract Paths) within its territory to reflect the throughput capacity of the network and sells ATC across these corridors to transmission customers. Transmission customers request transmission service from transmission providers along the path of the proposed transaction and the transmission providers approve and schedule the transaction, provided there is no reliability concern. However, the use of Contract Paths is not necessarily reflective of how power flows in a transmission network. Rather, it is an approach accepted within the industry to represent the commercial throughput capacity of the transmission network and to provide excess transmission capacity to prospective transmission customers. It is noteworthy that the use of Contract Paths for transaction scheduling is significantly different from how power is scheduled in Day-2 RTOs. Day-2 RTOs provide transmission access to those who value it the most. In the case without congestion, and ignoring losses, the least bid generation resource gets transmission access. When congestion occurs, a market based congestion management system provides the necessary re-dispatch, out of merit order, to give generation transmission access. Market participants that value transmission access can use Financial Transmission Rights (FTRs) to hedge against the congestion charges that result from re-dispatch. By contrast, under Contract Path, the transmission customer must prearrange transmission access across designated transmission corridors on a first-come, first-served basis. Each control area commits its resources to meet its next day load forecast, reserve requirements and sales commitments.

2.7 Proposed GridFlorida Market Structure

The proposed GridFlorida market structure is a Location-based Marginal Pricing (LMP), Financial Transmission Right (FTR), multi-settlement market model. LMP is a pricing scheme that is used for transactions in wholesale power markets. Under an LMP scheme, power prices vary by location due to transmission congestion and losses. Transmission congestion imposes costs on power consumers, as consumers at the receiving-end of a congested transmission line incur the cost of that congestion implicitly in their LMP. The cost associated with congestion can be hedged using FTRs, which are financial instruments that the holder may use to recover their congestion payments. The total number of available FTRs reflects the operating capacity of the grid - they are initially made available to market participants with entitlements to use the transmission system and they are subsequently traded in secondary markets.

The proposed GridFlorida RTO is designed to have two market settlements – a Day-Ahead market settlement and a Real-Time market settlement. The Day-Ahead market would provide participants with the opportunity to enter financially binding contracts to provide or consume power and also to allow them to avoid the potential volatility of the Real-Time markets. Day-Ahead market transactions are settled at Day-Ahead prices and Real-Time market transactions are settled at Real-Time prices.

The structure of the proposed GridFlorida RTO consists of one main control area (the RTO) and a number of Control Zones comprised of the existing Utility Control Areas. The functional responsibilities of the Control Zones are expected to change gradually as the RTO and the Peninsular Florida market evolves from inception through Day-1 and subsequently, Day-2 operation. Throughout the RTO developmental process, the Control Zones would work in tandem with the RTO, but would not be part of the RTO organization. The Control Zones would continue to be part of their parent utility organizations, a structure similar to the current MISO[11] framework and consistent with the September 2002 FPSC filing of the GridFlorida Applicants. In this filing, the GridFlorida Applicants proposed a hierarchical control area structure which retains the existing Utility Control Areas operating under a main GridFlorida RTO.

[11] Midwest Independent System Operator

The table below summarizes the functions of the proposed GridFlorida RTO under Day-1 and Day-2 operation. The roles and responsibilities of the Control Zones and the main RTO in this study were designed to ensure compliance with FERC Order 2000. For example, the responsibilities for the GridFlorida RTO under Day-1 operation would include OASIS administration, ATC and Total Transfer Capability (TTC) determination, Open Access Transmission Tariff (OATT) Administration, Security Coordination, Transmission Planning, System Operations and Market Monitoring. The Control Zones would balance generation with load in their respective geographic regions, and each Control Zone would be responsible for unit commitment and economic dispatch of generation to serve their load. The proposed GridFlorida RTO would use non-market mechanisms such as Transmission Loading Relief (TLR) calls and generation re-dispatch to manage transmission congestion in Day-1. The Control Zones would self-provide their ancillary services needs and administer operating reserves according to the existing FRCC Reserve Sharing Agreement. The Control Zones would maintain primary responsibility for ensuring Resource Adequacy. Day-1 market monitoring functions are designed to be minimal and for the purposes of this work, would be outsourced. The RTO would perform minimal commercial functions in Day-1, including credit checks for transmission customers and billing and settlement functions for transmission access.

Exhibit 2-9
GridFlorida Responsibilities Under Day-1 and Day-2 operation

GridFlorida Responsibilities	Day-1	Day-2
OASIS Administration	YES	YES
Tariff Administration	YES	YES
Security Coordination	YES	YES
Transmission Planning	YES	YES
System Operations	YES	YES
Congestion Management	Redispatch	LMP
Resource Adequacy	N/A	YES
FTR Market Management	N/A	YES
Day Ahead and Real-time Market Administration	N/A	YES
Market Monitor	Minimum	YES

Under Day-2 operation, the proposed GridFlorida RTO would expand its Day-1 responsibilities to include operation of Day-Ahead and Real-Time markets, and market-based congestion management using transmission rights. The RTO would ensure resource adequacy and would be responsible for billing and settlement of all non-bilateral RTO transactions. Because of the introduction of a Day-Ahead market, a Real-Time market and an FTR market, the market monitoring responsibilities for Day-2 would increase significantly.

The GridFlorida RTO would manage the single GridFlorida-wide transmission tariff under both Day-1 and Day-2 operations. The applicable transmission rate was filed by the GridFlorida Applicants at the FPSC Pricing Issues workshop on March 17-18, 2004. In their filing the GridFlorida Applicants stated that:

"GridFlorida's rates must be designed to recover the transmission revenue requirements of all Transmission Owners (TOs) and the revenue requirements associated with GridFlorida's grid management charge. The grid management charge for GridFlorida shall include the annual operating costs for GridFlorida and a five-year amortization of the recovery of the start-up costs of GridFlorida. Consistent with GridFlorida's current pricing protocol, GridFlorida's rate design shall consist of (a) zonal rates, (b) system-wide rates and (c) a phase out of zonal rates in the sixth through tenth year. The FPSC shall have the opportunity to review and provide a final approval of the phase out of zonal rates prior to the end of the 5th year of commercial operations of GridFlorida."

Under both Day-1 and Day-2 operation, all market participants will take transmission service from the GridFlorida RTO under its tariff[12].

As described in this chapter, while the physical fundamentals may remain largely unchanged in the near-term, the existing Peninsular Florida market and the proposed GridFlorida RTO have significant structural and operational differences, especially in key operational areas such as unit commitment and dispatch, transmission scheduling, and applicable transmission rates. When the impact of these differences is appropriately modeled for a future time period, they provide results that can be used to support policy decisions on the formation of an RTO in Peninsular Florida.

[12] This study did not model the full detail of the proposed GridFlorida tariff filed by the GridFlorida Applicants. The exact tariff structure did not lend itself to analytic modeling. Therefore, a simplified form of the tariff was modeled under Day-1 and Day-2 RTO operation.

CHAPTER THREE
ANALYTIC APPROACH AND CASES EXAMINED

3.1 Introduction

As mentioned earlier, of the various costs and benefits associated with market restructuring, some can be readily quantified, while others are best left to qualitative assessment. This chapter describes the approach used to quantify the proposed GridFlorida RTO costs and benefits. RTO benefits are derived from the difference in total system production costs between the existing and proposed markets as a result of the structural and operational changes described in the previous chapter. We note that our reference to the change in total system production costs between the two cases as RTO benefits does not necessarily mean any market restructuring effort will yield benefits. Other structural and operational changes could cause increased production costs. In this study, however, the proposed restructuring of the existing market to a Day-1 RTO or to the Delayed Day-2 RTO resulted in lower total system production costs, hence our reference to the savings as RTO benefits. The other quantifiable aspect of the cost-benefit assessment involves assessment of the change in fixed and operational costs associated with formation of the RTO. A complete analysis of this should examine both the startup and operational cost of forming the RTO and the change in the costs of the existing utility operations as a result of the formation of the new RTO entity. We note, however, that the RTO costing effort in this study examined only the first component, i.e., only the fixed and operational costs associated with forming and maintaining the new entity, and did not examine the second component, i.e., it did not simultaneously examine the change in existing utility fixed and operational costs as a result of the formation of the new entity. Therefore the RTO costs presented in this report do not include any changes in costs associated with existing utility operations or the associated costs of market participants in working with the new GridFlorida RTO and should be interpreted as such.

3.2 Cases Examined

As part of this assessment, ICF reviewed and analyzed a number of varying market structure cases. We believe that our model-based assessment of these market structure scenarios as will be described later in this chapter and in Chapter 4 captures the key physical characteristics of grid operation, the salient demand/supply fundamentals, and the market structure and operational parameters. However, we acknowledge that any model has limitations in terms of perfect simulation of the system and participant behavior, and some parameters are best treated through simplified assumptions which can be further tested or examined through sensitivity cases. As such, ICF was requested by the Project Steering Committee in consultation with the larger Stakeholder group and the FPSC to examine a Reference set of cases and additionally, two sensitivity cases. In total, these cases highlight key parameters and select uncertainties that are relevant in developing the cost benefit assessment.

The Reference Cases consist of three market structure cases:

- A Base Case that reflects the decentralized market as-is with individual company and control area operation, multiple transmission providers and "pancaked" transmission rates for the entire 13 year study period.

- A Day-1 Only Case that reflects decentralized company operation but with a single transmission provider and a single GridFlorida-wide transmission tariff for the 13 year study period.
- A Delayed Day-2 Case that comprises three initial years of Day-1 operation, followed by 10 years of Day-2 operation. Under Day-2 operation, unit commitment and dispatch for the entire Peninsular Florida region is centralized under the GridFlorida RTO and all market participants take transmission service from the RTO under a single tariff.

All three cases (Base Case, Day-1 Case and Delayed Day-2 Case) are collectively described in this report as the Reference Cases. Each case spans a 13-year forecast period, representing the period from 2004 through 2016 in calendar year terms. However, this forecast period is more appropriately referred to as Year 1 through Year 13.

In addition to the Reference Cases, two sensitivity analyses were performed as described below. Because of the relatively low RTO Benefits realized in the Reference Case Day-1 RTO Case, the other two sensitivity analyses described below were conducted for only the Delayed Day-2 case[13,14]. Exhibit 3-1 provides a summary of all the cases modeled.

[13] Note that the Base Case remains unchanged under these two sensitivity analyses.

[14] The final set of sensitivity analysis cases were decided by the Applicants in consultation with Stakeholders after Stakeholder review of the results from the Reference Cases.

Exhibit 3-1
Summary of Cases Analyzed

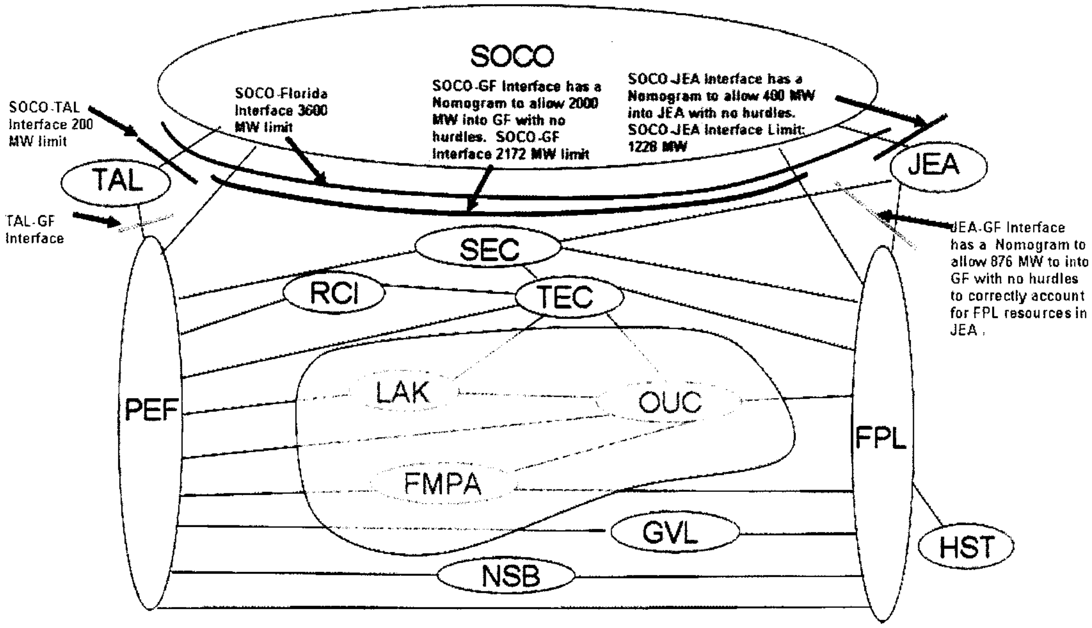
	Base Case	Day-1 Case	Delayed Day-2 Case	Total Number of Cases
Reference Cases	Yes	Yes	Yes	3
Sensitivity Analysis – JEA and TALL Out Case*	Unchanged from Reference Case	Not in Scope of Study	Yes	1
Sensitivity Analysis – Market Imperfection Case*	Unchanged from Reference Case	Not in Scope of Study	Yes	1
Total Number of Cases	1	1	3	5

*Note that the Base Case remains unchanged under these two sensitivity analyses.

JEA and TALL Out Case: The first sensitivity analysis case is associated with the possibility that some utilities may choose not to participate in a GridFlorida RTO. Jacksonville Electric (JEA) and Tallahassee Electric Department (TALL) were chosen for this sensitivity case because of their proximity to Georgia and their previous consideration of joining the now suspended SeTrans RTO. Therefore this case looked at a smaller GridFlorida RTO with JEA and TALL as non-participants. This sensitivity analysis case is subsequently referred to in this study as the JEA and TALL Out Case.

In the JEA and TALL Out Case, the key parameter changes occur in Day-2 with the formation of the proposed GridFlorida RTO and the definition of the new transmission interface between the RTO and the three key adjacent entities – Southern Company, TALL and JEA. Thus, the JEA and TALL out sensitivity analysis was modeled off the Delayed Day-2 Case only. As mentioned earlier, given the low level of benefits projected for Day-1 in the Reference Case, the Day-1 case was not considered in this sensitivity analysis. The Base Case modeling treatment also remained unchanged as part of this sensitivity analysis. Exhibit 3-2 shows a schematic diagram of the reconfigured RTO in Day-2 and the modeled transmission interfaces.

Exhibit 3-2
Schematic Diagram of the Proposed GridFlorida RTO with JEA and TALL as Non Participants



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

As a result of the new configuration under the GridFlorida RTO, in the Reference Case, power transfers from Georgia incur a single transmission charge to access the wholesale power market in Peninsular Florida. However, in this sensitivity case, in the event the power from Georgia to the GridFlorida RTO flows through either JEA or TALL an additional "pancaked" transmission charge is incurred. We note that the quantitative costs of forming the new RTO as presented in this study (and discussed in the last part of this chapter) remained unchanged under this sensitivity case. However if this total quantitative cost is adjusted for the cost changes associated with changes in existing utility operation, the overall cost of the RTO with JEA and TALL as non participants would change accordingly.

Market Imperfection Case: The second sensitivity analysis addresses load uncertainty and transaction costs. As was discussed earlier, the Base Case incorporated commitment hurdles and dispatch hurdles that were derived through calibrating to actual market outcomes. Thus, certain elements of actual market operation such as load uncertainty and minimum transaction volumes were implicitly taken into consideration. In contrast, however, the Delayed Day-2 Case did not assume any commitment or dispatch hurdles nor incorporate explicit treatment of load uncertainty, unlike real-time operations where load uncertainty necessitates additional generation resource commitment. Since load is known with certainty in these models, unit commitment tends to be more efficient than would be achievable in actual practice. The Delayed Day-2 Reference case also did not consider any minimum transaction volumes or margin between any two transacting entities to buy or sell power. With no established minimum transaction sizes and margin, the volume of trade between counterparties also tends to be more than would be achievable in actual practice. Thus, this sensitivity analysis sought to retain select aspects of actual market operation such as demand uncertainty and minimum transaction blocks. Specifically, demand uncertainty was simulated through committing more megawatts which in turn was simulated through a simplifying assumption of retaining a $5/MWh commitment hurdle in the Delayed Day-2 Case[15]. Capturing minimum transaction blocks was simulated by retaining a greater dispatch hurdle for power transfer, i.e., 25% of the Base Case

[15] Typically, the inclusion of commitment hurdles results in a greater level of commitment simply because the model is constrained from optimizing across a broader set of units. With a more limited set of units, the actual megawatts committed are likely to be higher as units cannot be partially commitment.

dispatch hurdles up to a $0.5/MWh cap. This sensitivity analysis is subsequently referred to in this report as the Market Imperfection Case.

As mentioned earlier, additional scenarios are certainly possible as there is a range of uncertainty around a number of other market constructs, supply/demand fundamentals, market behavior, etc. However, capturing the full range of uncertainty is somewhat impractical and was outside the scope of the ICF study. Additionally, a number of scenarios would have a low probability of occurring and thus have less relevance. For example, an alternate scenario that was raised in discussion with the Stakeholder Group was one in which there are no commitment and dispatch hurdles between Peninsular Florida and the Southern Company region. Such an alternative would mean all generation resources in Southern's territory are considered network resources in Peninsular Florida; and all of Southern's generation resources combined with Peninsular Florida generation resources are equally eligible to be committed to serve load in Peninsular Florida. Such a scenario did not appear likely mainly because it would not only mean the integration of GridFlorida RTO and Southern Company as a single market but with the suspension of the SeTrans RTO efforts in 2003, it was considered unlikely that that an RTO effort would be started anytime soon. Therefore in consultation with the Project Steering Committee, this alternative scenario was not considered. Thus, all cases modeled in this study retained commitment hurdles between Peninsular Florida and Southern Company (with the exception of the FRCC resources located external to GridFlorida).

3.3 Approach to Estimating RTO Benefits

ICF used GE Energy's Multi Area Production Simulation (MAPS) software model for estimating the benefits associated with transforming the Peninsular Florida market. MAPS is a highly detailed model that chronologically calculates hour-by-hour production costs while recognizing the constraints on the dispatch of generation imposed by the transmission system. MAPS uses a detailed electrical model of the entire transmission network, along with generation shift factors from a solved power flow case to determine how power from generating plants will flow over the AC[16] transmission network[17]. This feature enables MAPS to capture the economic penalties of re-dispatching generation to satisfy transmission facility limits and security constraints. ICF used MAPS to perform a security constrained unit commitment and economic dispatch of generating resources to meet load and reserve requirements. ICF modeled a 13-year forecast period with 10 explicit model run years. Specifically, ICF modeled Years 1-7, 9, 11, and 13. In calendar years, this is equivalent to 2004-2010, 2012, 2014 and 2016. The outputs of the modeling exercise include power plant dispatch, hourly nodal and zonal prices, fuel use, emissions and power flows on monitored transmission lines and transmission interfaces. These outputs were generated for all the cases referenced in the previous section and will be discussed in greater detail in Chapter 4.

3.4 Model Calibration

A key element of the approach to estimating RTO benefits involves the use of "hurdle rates" to capture potential inefficiencies associated with decentralized markets. Two key inefficiencies associated with the existing Peninsular Florida's decentralized market

[16] Alternating Current

[17] MAPS uses a linearized Direct Current (DC) Network approximation.

are: (i) individual and independent company operation; and (ii) multiple transmission providers, each with its OATT, scheduling and dispatching practices. As described earlier, hurdle rates are a modeling construct that allows us to simulate these aspects of decentralized model operation by imposing an additional cost component, in most cases a significant additional cost component, on resources outside the company control. This naturally provides the economic incentive, within the modeling context, for local company resources to be utilized first ahead of external resources, thereby simulating the current framework for unit commitment and dispatch.

The determination of the appropriate level of hurdle rates is achieved through a detailed model calibration exercise where hurdle rates are introduced in the model to calibrate historical market outcomes with the model simulated outcome. The historical market outcomes used to calibrate the models include a number of parameters such as internal Peninsular Florida generation, net interchange (net power imports/exports), generation by unit type, power prices and power flows across key transmission interfaces over a historical period. Since production cost models are not designed to solve for these hurdle rates, calibration exercises tend to be iterative processes whereby an initial assumption of these hurdle rates is used and refined with each successive iteration until the model outcome is reasonably close to the historical actual market outcome.

In calibrating the model, ICF used commitment hurdles to capture company operation (decentralized operation) and dispatch hurdles to capture the combined effect of "pancaked" transmission rates and additional inefficiencies associated with scheduling and dispatching practices of multiple transmission providers. Without the use of commitment hurdle rates, most production cost models would assume a single region-wide market where all units are equally eligible to commit to serve the region-wide load based on economics. For example a unit in Georgia could be committed to serve load in Peninsular Florida and vice versa to the extent it is economic to do so. The use of commitment hurdles provides the MAPS model with the sophistication to recognize market and operational boundaries such as between Peninsular Florida and Southern Company as well as practices across companies such as FPL, TECO, and PEF, operating separately within Peninsular Florida. During the commitment process, these commitment hurdles ensure that only company resources are committed to meet company load first before becoming available to meet the needs of companies which have resource deficiencies to meet their own load.

The Project Steering Committee in consultation with Stakeholders selected 2003 as a reasonable market year to use to calibrate the model for this study. Therefore, ICF used the 2003 market data provided by Stakeholders for this calibration exercise. Exhibit 3-3 provides a high level overview of the data used for the calibration and the associated sources.

Exhibit 3-3
Summary of Calibration Data

Parameter	Source
2003 Hourly Demand	Applicants and Stakeholders
Existing Generator Cost and Performance	Applicants and Stakeholders
Existing Generator Interconnection Nodes	Applicants and Stakeholders
Operating Reserve Requirements	Applicants and Stakeholders
Existing Transmission Network	Applicants and Stakeholders
Transmission Access Rates	Applicants and Stakeholder OASIS
"Must-Take" Contracts	Applicants and Stakeholders
Voltage Support Facilities	Applicants and Stakeholders
Coal Prices (2003)	Applicants and Stakeholders
Natural Gas Prices (2003)	Applicants and Stakeholders
Oil Prices (2003)	Applicants and Stakeholders
Environmental Policies and Allowance Prices	ICF
2003 Actual Unit Dispatch	Applicants and Stakeholders
2003 Hourly Tieline Flows	Applicants and Stakeholders

Both the commitment and dispatch hurdle rates were determined simultaneously during the calibration exercise. Each iteration of the model provided sufficient information to guide which of the commitment or dispatch hurdles or both needed upward or downward adjustment. Specifically, for each unit within Peninsular Florida, the model determines hourly whether the unit should be committed and dispatched. This is done through a multi-pass commitment process that performs hourly commitment of resources to serve load while simultaneously looking one week ahead[18]. Thus the total number of hours the unit is committed and dispatched (and associated generation) can be imputed for the year. Note that in the model, a unit that is not committed will not dispatch; consequently, the level of commitment (in hours) will always be greater than or equal to the level of dispatch. Through the iterative calibration process, the model's projections for unit commitment and dispatch were compared to actual historical operation especially for units that showed large deviations to determine the appropriate hurdle rate adjustments. For example, if a unit that historically dispatched in 2003 did not dispatch as much in the 2003 calibration model and did not commit as much as would be required to permit the level of historical dispatch, then the commitment hurdle was adjusted. In contrast, if the unit was committed as expected but did not dispatch as much as it actually did historically, then the dispatch hurdles were adjusted.

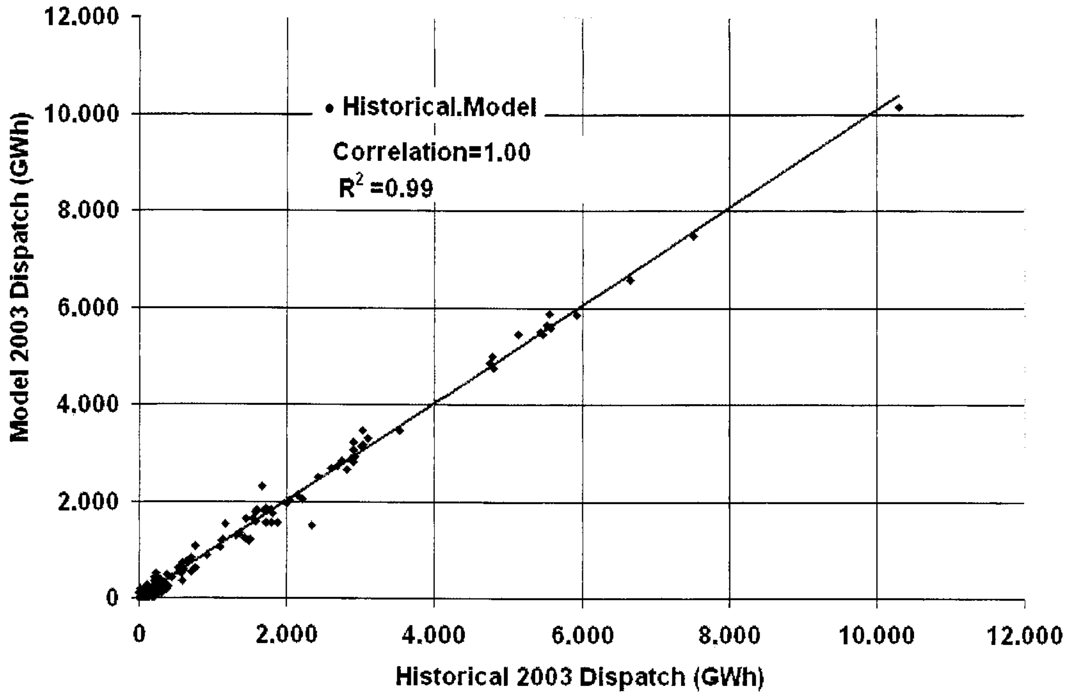
Through this calibration exercise, ICF determined a single commitment hurdle rate across all companies, but a different dispatch hurdle rate for each company-to-company tie-line. These hurdle rates are discussed in Chapter 4. It is theoretically possible for each company to have a different commitment hurdle to ensure its resources are

[18] The forward looking view ensures that each unit's operating characteristics such minimum uptime and downtimes are not violated.

appropriately committed to meet its load but ICF chose to apply a uniform commitment hurdle rate for several reasons. First, the range of rates is not significant and thus a single average number was a reasonable approximation while maintaining simplicity. Second, unlike dispatch hurdles that directly affect dispatch and marginal energy clearing prices, commitment hurdles affect dispatch only indirectly. Specifically, commitment hurdle rates are used as a basis to determine the supply of available resources for dispatch but not as a basis for the production costs for (and thus dispatch of) the units within this supply stack. Production costs are instead a function of variable costs and the dispatch hurdle rate. Finally, we note that ICF is not unique in this aspect of the approach and other cost-benefit studies have applied this similar simplified assumption. Thus ICF concluded that the use of a uniform commitment hurdle for each company was reasonable and validated this assumption by ensuring that the right units were committed for each company, i.e., by ensuring that units belonging to that company/control area were those that were first committed to the appropriate company/control area load.

As discussed earlier, ICF calibrated all generation units in Peninsular Florida and imports across the Peninsula Florida/Southern interface to their 2003 market outcomes. Exhibit 3-4 shows a correlation of 2003 aggregate generation by unit between the model and the actual market. Additional model calibration results are provided in the Appendix B.

Exhibit 3-4
Correlation Between 2003 Actual Generation and the Model Calibration Outcome



3.5 Modeling of the Reference Cases

In modeling the reference cases, there were a large number of parameters that were modeled consistently across all three Reference Cases. These included basic supply/demand fundamentals such as demand levels, physical supply characteristics, fuel prices, environmental allowance prices, etc. See Appendix A. Additionally, the approach to capacity expansion was modeled consistently across all cases, as was the treatment of must-run / must-take contracts. These are described below.

3.5.1 Capacity Expansion

Stakeholders provided their generation and transmission capacity expansion plans for the thirteen-year forecast period for this study through the Project Steering Committee.

This plan was incorporated into each of the annual model runs. Exhibit 3-5 shows the aggregate annual generation expansion plans provided to ICF.

Exhibit 3-5
Stakeholder Generation Expansion Plans Modeled (MW)

Year	Combined Cycle	Cogeneration	Gas Turbine	Coal	Total
2004	1,642	0	0	0	1,642
2005	2,628	0	99	0	2,727
2006	0	210	327	0	537
2007	1,540	0	100	0	1,640
2008	602	0	1,031	0	1,633
2009	1,729	0	180	0	1,909
2010	706	0	725	0	1,431
2011	0	0	1,179	0	1,179
2012	2,582	0	568	150	3,300
2013	1,012	0	871	300	2,183
2014	2,095	0	277	0	2,372
2015	672	0	247	0	919
2016	1,023	0	188	0	1,211
Total	**16,231**	**210**	**5,792**	**450**	**22,683**

Source: GridFlorida Applicants and Stakeholders

3.5.2 Modeling of Contracts

Within Peninsular Florida, ICF did not model any existing economic contracts as the model implicitly optimizes economy energy flows between control areas. Only contracts with must-run or must-take characteristics were explicitly modeled. These contracts were confidentially provided to ICF by Stakeholders. Must-run resources required for voltage support were modeled to have their minimum operating capacity as must run but only for the periods when they are needed for voltage support service. For example if a 250 MW unit with a minimum operating capacity of 125 MW was required to provide voltage support during the peak hours of the summer season, that unit was modeled to provide a fixed minimum of 125 MW in all peak hours of the summer season. The remaining capacity of the unit was available for dispatch based on market economics during that same period. The full capacity of the unit was made available to the generation pool of the associated company for unit commitment and dispatch on an economic basis in all other seasons. Exhibit 3-6 summarizes the aggregate must-run capacity modeled.

Exhibit 3-6
Aggregate Must Run Capacity Modeled

Owner	Unit Name	RMR Capacity (MW)	Summer Capacity (MW)	Seasonality (If Applicable)	RMR Type / Condition
PEF	Anclote 1	90	498	Annual	Voltage
PEF	Anclote 2	90	495	Seasonal	Voltage
PEF	Bartow 1	45	121	Seasonal	Voltage
PEF	Bartow 2	45	119	Seasonal	Voltage
PEF	Bartow 3	90	204	Annual	Voltage
PEF	University of Florida	41	41	Annual	Contract
Calpine	Auburndale 1	132	152	Annual	Contract
FPL	Fort Myers CT 1 & 2	240	298	Annual*	Voltage*
FPL	Lauderdale CC	150	422	Annual*	Voltage*
FPL	Putnam	90	239	Annual*	Voltage*
TOTAL		1,013	2,589		

* These units are Must Run only under specified load conditions.

These must-run assumptions were modeled in all three Reference Cases. Arguably, the need and the amount of must-run capacity could change significantly with the expected change in dispatch from a decentralized operation with "pancaked" transmission charges to a centralized dispatch system. ICF in consultation with the Project Steering Committee and Stakeholders chose to retain the same Base Case must-run assumptions for the Day-1 and Day-2 RTO scenarios because not only did the scope of work not permit a separate AC power flow modeling to estimate the must-run needs of Day-1 and Day-2 operation but such an effort would have greatly expanded the scope of the work.

3.6 Differential Modeling Treatment Across the Reference Cases

There were, however, key structural and operational parameters and constructs that were modeled differentially across the three Reference Cases to capture the alternative market structures. Exhibit 3-7 summarizes the treatment of key parameters in the modeling of the Reference Cases and the major differences across the Reference Cases from a modeling perspective. These major areas of differences are captured through the treatment of:

- Unit commitment and dispatch;
- Transmission rates;
- Operating reserves;
- Losses.

Exhibit 3-7
Summary of Key Differences Across Reference Cases

Parameters	Base Case	Day-1 Case	Day-2 Case
Security Constrained Unit Commitment (SCUC)	Commit to meet control area load plus reserve;		GridFlorida-wide centralized commitment
Security Constrained Economic Dispatch (SCED)	To meet Control Area load plus economy interchange;		GridFlorida-wide centralized dispatch
Transmission Rates	Pancaked transmission rates based on existing control areas	GridFlorida transmission rate based on Day 1 pricing proposal	GridFlorida transmission rate based on Day 2 pricing proposal
Hurdle Rates	H1 – Hurdle designed in model to force unit commitment by Control Area – Applicable only to unit commitment (SCUC) – does not directly affect SCED		None
	H2 – Realized hurdles from model calibration exercise to capture non-tariff related market inefficiencies	None	
Transmission Losses	Based on average losses		Losses priced on the Margin (Marginal Losses)
Operating Reserves	Based on existing FRCC Reserve Sharing Agreement. Each control area provides operating reserves based on their allocation under the Reserve Sharing Agreement		Based on centralized GridFlorida-wide operating reserve market

3.6.1 Unit Commitment and Dispatch

The Base Case model was configured to permit each company to serve its own load. This was achieved by constraining each company's generation resources to serving its load first. Although many of the companies had all their load and resources confined within their control area, some companies either had distributed generation resources serving load that was confined within their control area or had distributed load that was served by generation within their control area. By using the commitment hurdles and operating nomograms, ICF ensured that each company committed its fleet of generation resources to serve its load first regardless of whether that generation or load was located within the geographic boundary of that control area.

3.6.2 Application of the Commitment Hurdles

The application of the commitment hurdles was performed with extreme caution to ensure that the desired effect was achieved i.e., for each company or control area, that least cost units are committed before the more expensive units. In many of the models used for cost benefit analyses such as MAPS, the commitment decision for a generation unit is based on its priority cost. The lowest priority cost generation resource within a control area or within a company's fleet of resources gets committed first to serve its load. In turn, each unit's priority cost is determined by two key components:

- its variable costs[19], and
- its natural location factor[20] with respect to transmission constraints and losses.

[19] The variable cost components of each unit's priority costs include fuel, variable operation and maintenance cost, start-up costs and emissions cost.

When commitment hurdles are introduced in the model as a means to simulate a decentralized market, a third component is introduced to the priority cost equation. This third component, if not properly applied, can introduce distortions to the resultant unit commitment stack. Since the commitment hurdle is designed to constrain a group of generation resources available within a control area or belonging to a company to serve its load, appropriate care should be taken to ensure that the impact of the commitment hurdle is uniform across that target group of resources. These commitment hurdles, if applied across control area tie-lines, can introduce locational biases to the target resources and the effect would be a non-uniform impact of the commitment hurdle across the target resources. For example, assume a particular control area has a single tie with its external electrical world. If a $20/MWh commitment hurdle is placed at this tie, then the impact of the commitment hurdle on each of the units within that particular control area will depend on each unit's shift factor across that tie. Thus, if two units in that control area have different shift factors across this tie, the impact of the commitment hurdle will not be uniform and may distort the priority costs of both units. Thus, an improper application of the commitment hurdle may have the unintended consequence of committing the more expensive generation resource before the cheaper generation resource.

[20] The natural location factor of a generation unit is a measure of its locational advantage or disadvantage with respect to constraints within the transmission system. It is represented by a matrix of the unit's shift factor on all transmission system elements with respect to a designated Reference location on the grid. Thus, all units have their matrix of shift factors. These shift factors change with a change in the Reference Location and/or a change in the grid topology.

Due to this problem, ICF did not apply the commitment hurdles at the control area ties. Instead, ICF used special operating nomograms to uniformly apply the commitment hurdle to each company's units to achieve the dual objective of:

- Constraining units within the company/control area to commit to the control area/company load first before committing to some other load;
- Ensuring that units within each control area/company maintain their true commitment priority derived from their variable costs and their natural location factors.

3.6.3 Application of the Dispatch Hurdles

Dispatch hurdles derived from the calibration exercise were applied between control area ties. These dispatch hurdles are assumed to be primarily associated with scheduling and dispatching operations of multiple transmission providers. In the Base Case, these dispatch hurdles included the transmission rates of each control area as well. For example, if the transmission rate for directional power transfers from TECO to FPL is $2/MWh and the market inefficiency hurdle between the two entities is $3/MWh, then the total dispatch hurdle that was applied in the Base Case for direction power transfers from TECO to FPL is $5/MWh. Note that the $2MWh transmission rate is the power export rate paid to TECO for power transfers from TECO to FPL. The additional charge paid to FPL i.e., the FPL zonal charge was not explicitly modeled. Since the focus is on wholesale generation production costs, the cost to wheel power within each market zone was not explicitly modeled. In the Base Case, the relevant market zone is each control area. In the Day-1 and Day-2 RTO cases, the relevant market zone is Peninsular Florida. Therefore consistent with the treatment of zonal charges in the base case, the single GridFlorida-wide transmission zonal charge paid in both the Day-1 and Day-2 markets was not explicitly modeled. Thus, the dispatch hurdle between Peninsular Florida control areas was eliminated entirely in both Day-1 and in Day-2 due to the elimination of "pancaked rates" and the elimination of scheduling and dispatching operations of multiple transmission providers. Under both Day-1 and Day-2 operation a single entity is responsible for transmission operations (the RTO) and all market participants take service under a single GridFlorida transmission tariff.

3.6.4 Transmission Rates

Not all transmission providers in Peninsular Florida have published transmission rates. Therefore ICF worked with the Project Steering Committee to determine the transmission rates for use in modeling of the Reference Cases. A uniform transmission rate was assumed for all transmission providers and this rate was derived from the projected revenue requirements of all transmission owning entities in Peninsular Florida. The total revenue requirement was divided by the total projected load of Peninsular Florida to arrive at the transmission rate. The total revenue requirements are slightly different between the Base Case (market as-is) and the RTO Cases (Day-1 and the Delayed Day-2 cases) because of differing treatment of transmission facilities owned by the transmission dependent utilities such as Seminole and FMPA which is explained in detail in Chapter 4. For the most part, however, the transmission rates are similar in both the Base Case and the RTO Cases as shown in Exhibit 3-8.

Exhibit 3-8
Base Transmission Rates

Year	Annual Revenue Requirement (2004 $000s)		Net Energy for Load (GWh)	Base Case Rate (2004 $/MWh)	RTO Case Rate (2004 $/MWh)
	Base Case	RTO Case			
2004	647,687	647,687	226,267	2.86	2.86
2005	683,739	683,739	231,969	2.94	2.94
2006	722,366	722,366	238,870	3.03	3.03
2007	759,047	759,047	244,567	3.11	3.11
2008	793,187	793,187	249,924	3.17	3.17
2009	829,581	830,756	255,534	3.25	3.25
2010	863,368	864,567	261,819	3.30	3.30
2011	900,690	902,487	267,854	3.36	3.37
2012	934,851	937,249	273,993	3.42	3.43
2013	967,066	969,744	280,273	3.45	3.46
2014	999,103	1,001,750	286,622	3.49	3.50
2015	1,036,058	1,037,990	292,968	3.54	3.55
2016	1,066,367	1,068,299	299,555	3.56	3.57

Source: Pricing Team with input from Applicants and Stakeholders.

In the Base Case, the applicable Base transmission rate was used for all transmission entities. In the Day-1 and Day-2 cases, additional transmission charges were added to the Base transmission rate. These additional charges were a Grid Management Charge (GMC) for the new RTO and a levy on all transactions for the first five years to recover the startup cost of forming the new RTO consistent with the amortization plan filed by the GridFlorida Applicants with the FPSC. Ideally, the GMC should be an output of this study but an initial estimate is needed for modeling purposes which could be refined in successive iterations. The scope of the study did not permit this iterative approach therefore the initial estimate was used as a simplification. Thus, the Project Steering Committee estimated the GMC at fixed rate of $0.23/MWh in Day-1 and $0.67/MWh in Day-2. Similarly, the levy on all transactions for the RTO startup cost recovery was $0.08/MWh and $0.18/MWh for Day-1 and Day-2 respectively. Exhibit 3-9 shows the total transmission rate applied in each of the Reference Cases.

Exhibit 3-9
Reference Cases Transmission Rates (2004$/MWh)

Year	Base Case			Day-1 Case				Delayed Day-2 Case			
	Rate	GMC[1]	Total Rate	Rate	GMC[1]	Start Up Cost Amortized Over 5 years	Total Rate	Rate	GMC[1]	Start Up Cost Amortized Over 5 years	Total Rate
2004	2.86	N/A	2.86	2.86	0.24	0.08	3.18	2.86	0.24	0.08	3.18
2005	2.94	N/A	2.94	2.94	0.24	0.08	3.26	2.94	0.24	0.08	3.26
2006	3.03	N/A	3.03	3.03	0.24	0.08	3.34	3.03	0.24	0.08	3.35
2007	3.11	N/A	3.11	3.11	0.24	0.08	3.43	3.11	0.69	0.26	4.06
2008	3.17	N/A	3.17	3.17	0.24	0.08	3.49	3.17	0.69	0.26	4.12
2009	3.25	N/A	3.25	3.25	0.24		3.49	3.25	0.69	0.18	4.12
2010	3.30	N/A	3.30	3.30	0.24		3.54	3.30	0.69	0.18	4.17
2011	3.36	N/A	3.36	3.37	0.24		3.61	3.37	0.69	0.18	4.24
2012	3.42	N/A	3.42	3.43	0.24		3.66	3.43	0.69		4.12
2013	3.45	N/A	3.45	3.46	0.24		3.69	3.46	0.69		4.15
2014	3.49	N/A	3.49	3.50	0.24		3.73	3.50	0.69		4.19
2015	3.54	N/A	3.54	3.55	0.24		3.78	3.55	0.69		4.24
2016	3.56	N/A	3.56	3.57	0.24		3.80	3.57	0.69		4.26

Source: Pricing Team with input from Applicants and Stakeholders.
[1] Grid Management Charge

3.6.5 Operating Reserve Treatment

In the Base Case, ICF modeled operating reserves based on the existing reserve sharing agreement of the Peninsular Florida companies. This reserve sharing agreement mandates a total of 910 MW of operating reserves for the FRCC region. This requirement is derived from the most critical single contingency which is the unplanned outage of the St Lucie nuclear generating unit[21]. This operating reserve requirement is met by all FRCC control areas and allocated based on each control area's peak hour net energy for load in the year 2000, as shown in Exhibit 3-10.

[21] The St. Lucie nuclear unit is a jointly owned unit. Therefore Exhibit 3-10 does not show a 910 MW unit in the "*Capability Largest Unit Gross MW*" column.

Exhibit 3-10
FRCC Operating Reserve Allocation Share

Control Area	2000 Peak Hour NEL MW	Capability Largest Unit Gross MW	Operating Reserve Allocation Percentage	Total Operating Reserve MW	Required Minimum Non-spinning Reserve MW	Minimum Spinning Reserve MW
FMPP	2,950	600	10.40%	98.9	74.2	24.7
FPL	17,808	846	32.01%	291.3	218.5	72.8
GVL	425	235	3.14%	28.6	21.5	7.2
HST	67	9	0.18%	1.7	1.3	0.4
JEA	2,614	518	9.06%	82.5	61.9	20.6
LWU	85	33	0.47%	0.0	0.0	0.0
NSB	88	4	0.16%	1.4	1.1	0.4
PEF	8,694	804	19.96%	181.7	136.2	45.4
RC	68	38	0.51%	4.6	3.5	1.2
SEC	2,553	694	10.94%	99.5	74.6	24.9
TAL	550	250	3.47%	31.6	23.7	7.9
TEC	3,435	480	9.69%	88.1	66.1	22.0
TOTAL	39,337	4,511	100.00%	910	683	228

Source: FRCC

Similar to the Base Case, in the Day-1 Case, the reserve markets will still be under the control of the existing transmission providers and therefore the same spinning reserve criteria modeled in the base case was modeled in the Day-1 scenario as well. However, in the Day-2 Case, the spinning reserve markets are centralized and although the single largest contingency remains unchanged, all spinning reserve-qualified units are eligible to supply spinning reserves based on economics. So in Day-2, the spinning reserve allocation modeled in the Base Case is eliminated while the total requirement remains unchanged. Thus in Day-2, all operating reserve capable resources in Peninsular Florida are committed for operating reserves based on economics.

3.6.6 Treatment of Losses

Another key modeling element that differed among the Reference Cases was in the treatment of losses. Many of the transmission providers in Peninsular Florida have varying treatment of transmission losses. For example some transmission providers have loss charges that vary with the level of transmission facility utilization such as different rates for peak and off-peak transfers while other transmission providers apply uniform loss charges across all transfers. In both the Base Case and the Day-1 case, average losses were modeled since the existing control areas will be responsible for scheduling and dispatching operations, however in Day-2, marginal transmission losses were modeled with dispatching and transmission operations under the RTO.

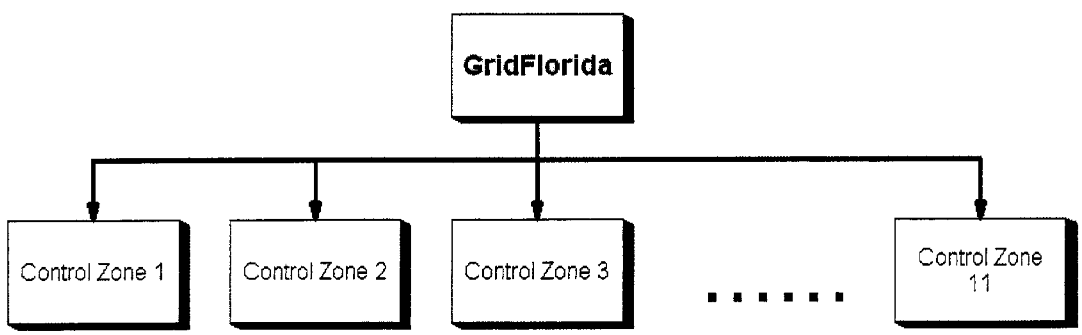
3.7 Approach to Estimating RTO Costs

This section first presents a more detailed overview of the structure of the proposed GridFlorida RTO including a description of the functions and responsibilities assumed under Day-1 and Day-2 operation. Next, these functions are mapped to explicit requirements for the RTO, in the areas of systems, facilities, and personnel. Finally, this section concludes with a discussion of the RTO cost model and the derivation of the underlying cost estimates.

It is important to note that the RTO modeled in this study is a "greenfield" organization with wholly new personnel, physical facilities and systems. That is, none of the existing control area systems, personnel and physical facilities was assumed available to the new RTO. Additionally, the RTO startup and operating costs provided comprises costs associated with the main "greenfield" GridFlorida RTO only. None of the costs of existing Control Zones or potential change in existing utility operational cost from the creation of the new RTO is included in the RTO estimates provided. However all the necessary communication links between the main RTO and the Control Zones are included in the overall RTO cost estimates.

The proposed GridFlorida RTO modeled maintains the essential elements of the hierarchical control area structure proposed in the September 19, 2002 GridFlorida Applicants filing with the FPSC. Under the hierarchical control area structure, the existing control areas are designed as Control Zones operating under a "greenfield" GridFlorida RTO which becomes the substantive control area for the entire Peninsular Florida region. The functional roles and responsibilities between the proposed GridFlorida RTO and the Control Zones were defined for each major activity under both Day-1 operation and Day-2 RTO operation.

Exhibit 3-11
Schematic of the proposed GridFlorida RTO and the Control Zones



ICF worked with the GridFlorida Applicants and Stakeholders to define the functional responsibilities for the RTO and the Control Zones under Day-1 and Day-2 operations. To comply with FERC Orders and to avoid undue discrimination with transmission access under a Day-1 RTO operation, the RTO maintains exclusive responsibility over OATT administration, OASIS, market monitoring, ATC and TTC calculations. The RTO also maintains primary responsibility for both short-term and long-term reliability and security coordination. Under Day-1 operation, there are no GridFlorida-wide markets. Unit commitment and dispatch is decentralized and performed by the Control Zones, i.e., each control zone has primary responsibility for committing and dispatching generation to serve its load while the RTO provides back-up responsibilities. The RTO is also responsible for billing and settlement; however, compared to Day-2, Day-1 billing and settlement needs are minimal and basically related to transmission access.

Under Day-2 operation, the GridFlorida RTO has either primary or exclusive responsibility for all market and control area activities. The Control Zones have secondary responsibilities, but only for selected reliability functions. Exhibit 3-12 provides a detailed listing of functional roles and responsibilities assumed for the RTO and the Control Zones.

Exhibit 3-12
GridFlorida Roles and Responsibilities Summary

X – Full and exclusive responsibility *A – Primary responsibility* *B - Support sole*	Day-1		Day-2	
	GridFlorida RTO	Control Zones	GridFlorida RTO	Control Zones
Grid Operations				
Energy Management System	A	B	X	
ICCP Data Communication System	A	B	X	
Resource Adequacy	A	B	A	B
Planning and Engineering				
Long-Term Reliability	A	B	A	B
Engineering and Facility Studies	A	B	A	B
Interconnection Requests	A	B	A	B
Long Term Activities				
Planning and Expansion	A	B	A	B
Tariff Administration and OATT	X		X	
OASIS	X		X	
Market Monitoring	X		X	
Inter RTO Coordination	A	B	X	
Short Term Reliability	A	B	X	
ATC and TTC Calculation	X		X	
Seasonal Activities				
Congestion Right Allocation and Auctions			X	
RMR Designations	A	B	A	B
Weekly Activities				
Load Forecasting	A	B	A	B
Outage Scheduling	A	B	A	B
Day Ahead Activities				
Day Ahead Market Operations			X	
Day Ahead Reliability Review	A	B	A	B
Day Ahead Ancillary Services Markets			X	
SCUC	B	A	X	
Real-time Activities				
Scheduling and Dispatching Operations (SCED)	B	A	X	
Ancillary Services - Operating Reserves and AGC	B	A	A	B
Security Coordination	A	B	X	
Balancing Function	A	B	X	
Billing and Settlement				
Billing	A	B	X	
Settlement	A	B	X	
Archiving				
Data Storage and Archiving	A	B	X	
Administration				
Customer Interface and Administrative Services	X		X	
Publications and Documentation	X		X	
Operations Support and Training	X		X	
Enforcement	X		X	
Corporate Services and Human Resources	X		X	
Performance Monitoring and Compliance	X		X	
Regulatory Affairs	X		X	
Board of Directors (BOD), Committees and Working Groups	X		X	

3.7.1 Cost Model Architecture (Organizational Design of the GridFlorida RTO)

ICF designed the architecture of the cost model to clearly delineate the Day-1 functions and the incremental functions required for Day-2 operation. This was done to identify the RTO functions that are exclusively Day-1 only, those that are Day-2 only, and those Day-1 functions that require significant incremental investment for Day-2 operation. By identifying each of the functions required for Day-1 and Day-2 operation, ICF was able to design the specific systems and subsystems needed for each mode of RTO operation. ICF identified nine major categories under which functions for Day-1 and incremental functions for Day-2 were grouped.

These categories are as follows:

- Control Center Operations: The Control Center is responsible for real-time balancing of generation and load to maintain system frequency. This functional unit has responsibility for all control center functions such as security coordination, systems operations; energy management, SCADA[22] systems management, interchange coordination with external systems, near-term demand forecasting, OASIS administration and outage scheduling. Control Center operations are required under both Day-1 and Day-2 operations.
- Market Operations: This is the commercial arm of the RTO with responsibility for all commercial transactions. Market operations are largely a Day-2 function with responsibility for all the major markets,

[22] Supervisory Control And Data Acquisition

namely the Day-Ahead and Real-Time markets including ancillary services, and Financial Transmission Rights (FTR) markets. This functional unit is also responsible for billing and settlements. The Market Operations function under Day-1 is minimal and limited to OATT administration, TTC and ATC oversight and some minimal billing and settlement functions primarily for transmission owners.

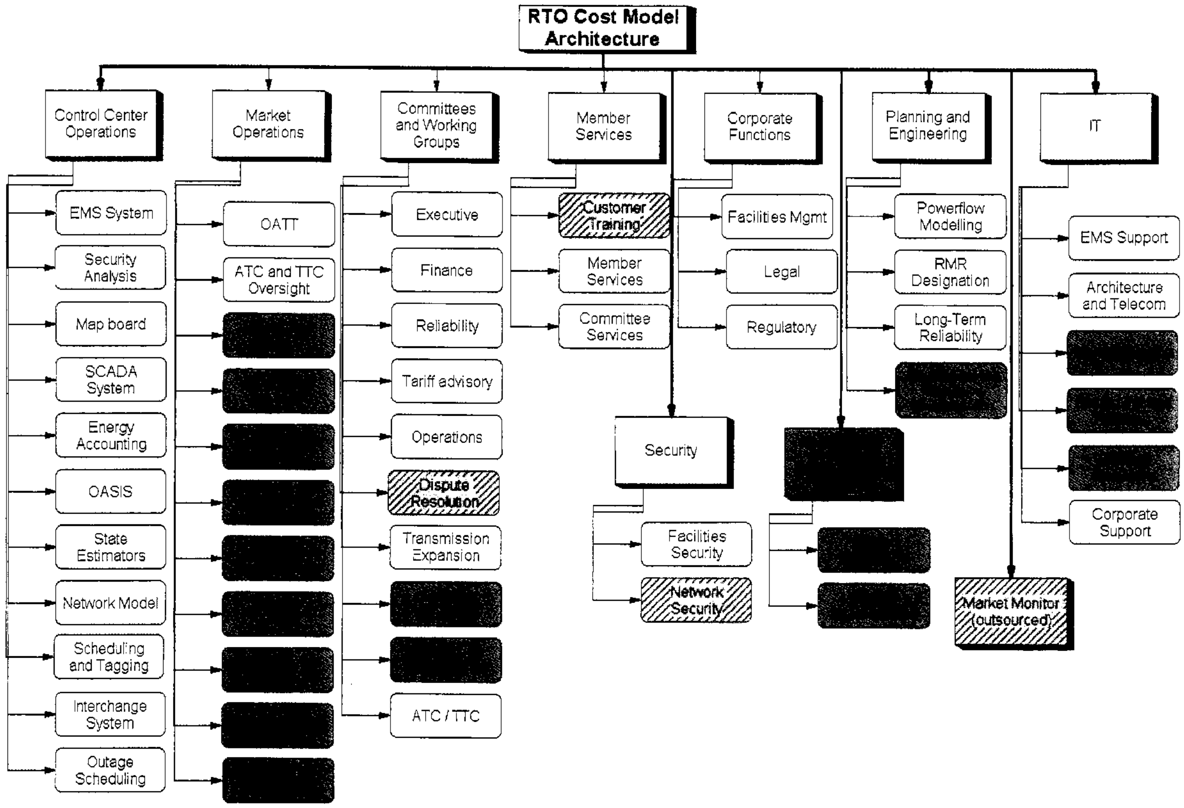
- Committee, Working Groups and Member Services: This functional unit is responsible for providing support for the various RTO working groups. The responsibility of this functional unit increases in Day-2 with the introduction of markets. For example, the number of working groups increases in Day-2 to include congestion management and energy markets.
- Security: This functional unit is responsible for both physical facilities and information security. Responsibilities for this unit include monitoring appropriate access to the GridFlorida facility and confidential data. Information security needs increase significantly under Day-2 operation with the introduction of Day-Ahead and Real-Time markets.
- Corporate Services: This functional unit provides a variety of services for the GridFlorida organization. Responsibilities for this unit include human resources oversight, ongoing recruiting, facilities management, and corporate accounting. Corporate service functions increase with increased Day-2 RTO personnel and functions.
- Planning and Engineering: This functional unit performs all the long term reliability studies and assessment for the RTO. Specifically, the unit is

responsible for power flow modeling, Reliability-Must-Run designation, interconnection studies (transmission and generation), long-term reliability planning, and resource adequacy. This function is needed in both Day 1 and Day 2 RTO operation.

- Information Technology (IT): The IT unit is responsible for providing general corporate IT support as well as the Control Center IT support and EMS system maintenance. In Day-2, this unit's responsibilities increase to include, all market systems and subsystems such as the day-ahead and real-time market systems and the billing and settlement systems.
- Mature Market Functions: This is a Day-2 function and it is designed to explore needs to improve quality assurance and market development for a functional, mature market. Responsibilities include coordination with and study of similar market systems, performance benchmarking, and the evaluation of service or product development opportunities.
- Market Monitoring: Market monitoring needs under Day-1 operation are mainly geared towards ATC and TTC oversight and TLR review. Market monitoring requirements increase in Day-2 with the commencement of day-ahead and real-time markets. Note that for the purposes of this costing exercise, this division is assumed to be fully outsourced and reports directly to the Board of Directors (BOD) in order to maintain objectivity.

Exhibit 3-13 below graphically summarizes the combined Day-1 and Day-2 RTO cost model architecture with a detailed view of exclusive Day-1 and Day-2 functions and those functions with significant incremental investment in Day-2.

Exhibit 3-13
Combined Day-1 and Day-2 RTO Cost Model Architecture



Shaded boxes indicate cost items associated primarily with Day 2 operation

Hatched boxes indicate areas which will incur significant incremental investment to support Day 2

3.7.2 Systems and Physical Facility Requirements

Upon outlining the Cost Model architecture, ICF subsequently derived the system and subsystem requirements and the physical facility requirements for Day-1 and the incremental requirements for Day-2. Exhibit 3-14 summarizes the systems and subsystem requirements for each of the proposed RTO operational modes.

Exhibit 3-14
Systems and Physical Facility Requirements for Day-1 and Day-2 RTO Operational Modes

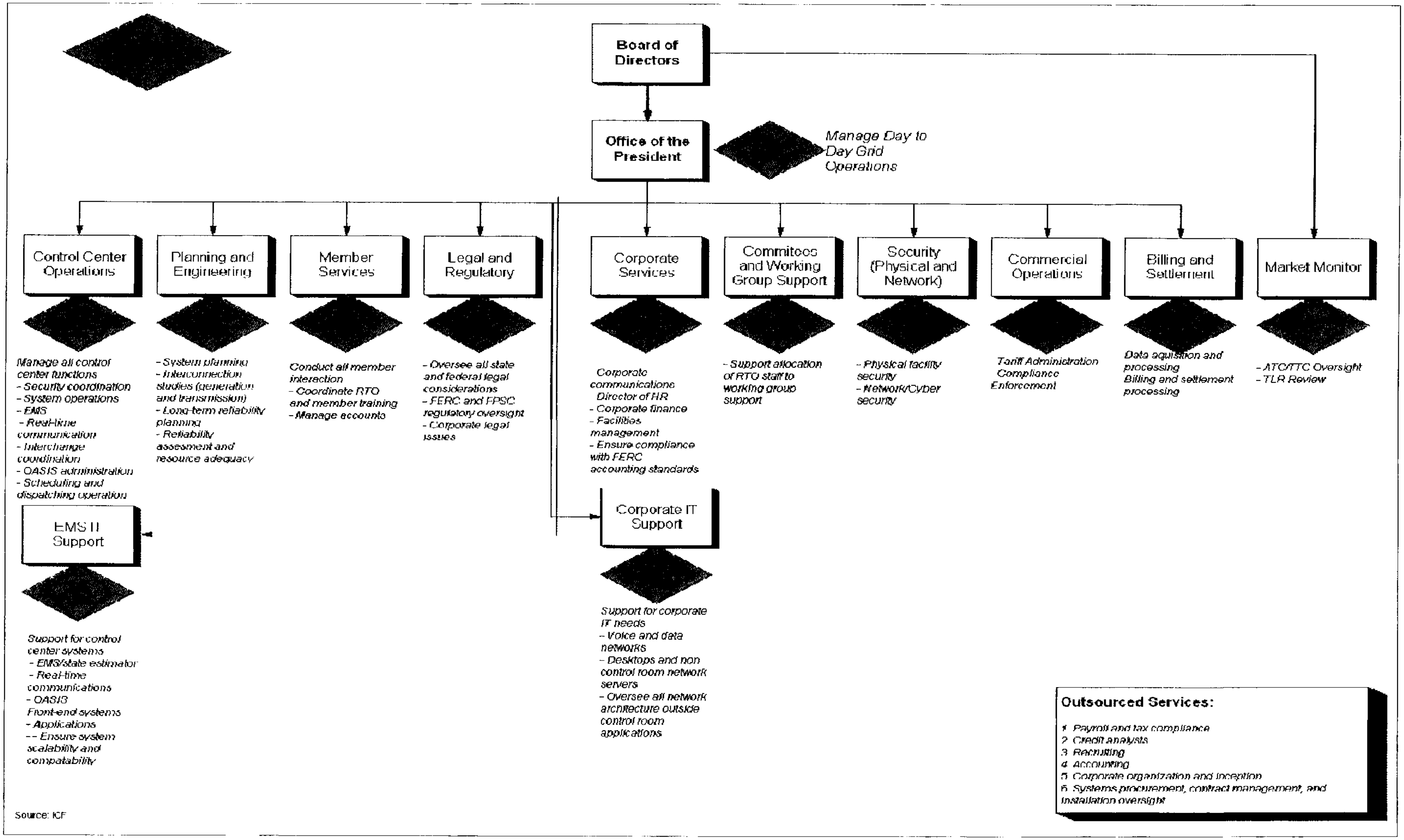
		Day-1	Day-2
Proposed Systems and Subsystems Requirements	EMS System and Applications	√	√
	– State estimator	√	√
	– Network/Power flow model	√	√
	– Security analysis model	√	√
	– SCADA application	√	√
	– Simulation and Training Systems	√	√
	– Hardware support	√	√
	– Annual maintenance		
	Map Board		
	– EMS link	√	√
	– Annual maintenance	√	√
	Communication (ICCP Pathways and Frame Relay) and backup systems	√	√
	Scheduling and Tagging System	√	√
	OASIS (hosted by 3rd party)	√	√
	Compliance with current requirements and OASIS 2A	√	√
	Various transmission models (Load Flow, Production Cost, etc...)	√	√
	Minimal Commercial Operations/Billing and Settlement Software	√	
	Real-Time Market Engine (includes Operating Reserves and AGC markets)		√
	– Bidding and publishing system		√
	– Market clearing engine (MCE)		√
	– EMS Interface		√
	– Settlement interface		√
	– Market database		√
	– Annual maintenance		
	Day Ahead Market Engine		
	– Bidding and publishing system		√
	– Market clearing engine MCE)		√
	– EMS Interface		√
	– Settlement interface		√
	– Market database		√
	– Annual maintenance		√
	– Real-time market interface		√
	– Reliability assessment		√
	FTR Market Engine (multi-period)		
	– Market database		√
	– Contingency analysis		√
	– Bid/post interface		√
	– Interface to outage schedule and network model		√
	Enhanced Commercial Operations / Billing and Settlement Systems		√
	Simulation and Training Systems – Market system		√
	Backup Control Center (BCC) Systems Market Monitor (outsourced)		√
Physical Facility Requirements	Main Control Center (MCC),	97,000 sq. ft.	139,000 sq. ft.
	– Hardened	√	√
	– Redundant backup generators	√	√
	– Full telecom redundancy	√	√
	– UPS system	√	√
	Back up control center (w/EMS)		
	– 25,000 sq. ft.	√	√
	– Hardened	√	√
	– Redundant Backup generators	√	√
	– Full telecom redundancy	√	√
	– UPS System	√	√

3.7.3 Personnel Requirements

ICF estimated personnel requirements for each activity to be performed by the RTO in both Day-1 and Day-2 and upward aggregated these estimates into Full-Time Equivalents (FTEs). An 18-month ramp-up period was assumed for the necessary preparations from Day-0 to Day-1 operation. The major activities assumed to be performed during this period are recruiting, system procurement and installation, and employee training.

In total, ICF estimated a need for 194 FTEs for a fully functional Day-1 RTO. These FTE's are summarized by division for Day-1 RTO operation in Exhibit 3-15.

Exhibit 3-15
GridFlorida Day-1 RTO Organizational Chart and FTE Count



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The major FTE allocations for Day-1 operation are as follows:

- 51 FTEs are planned for Control Center Operations and will be responsible for services such as security coordination, dispatching system operations, interchange scheduling, outage coordination, OASIS administration and all scheduling and system operation requirements,
- 27 FTEs are planned for IT Services. Since the EMS system is the central system for transmission and dispatching operations and it is also the real time data repository, 14 FTEs out of the 27 FTEs are earmarked to focus on EMS IT support only. The remainder provides Corporate IT support (i.e., general voice and data networks, desktop and laptop coordination, etc.) Note that the EMS system budget does include significant budget for real-time 24-hour vendor support on an ongoing basis (for example, a number of IT services are outsourced).
- 26 FTEs are planned for Corporate Services and these involve activities such as corporate communications, human resources, corporate finance and accounting, facilities management, and general administration.
- 25 FTEs are planned for Planning and Engineering Services. They are responsible for system planning, generation and transmission interconnection studies, long-term reliability planning, and resource adequacy.
- 14 FTEs are planned for Member Services. The Member Services unit is responsible for all member training and account management. Member Services responsibilities increase significantly under Day-2 operation as member interaction ramps-up with market inception.

- 11 FTEs are planned for Legal and Regulatory Services which will include Federal and State legal compliance, FERC and FPSC regulatory compliance and corporate legal issues. The legal staff is responsible for assisting external legal staff in drafting market rules and protocols during inception.
- 9 FTEs are planned for the Day-1 Billing and Settlement division. Under Day-1 operation, billing and settlement activity is limited to processing of transmission related bills.

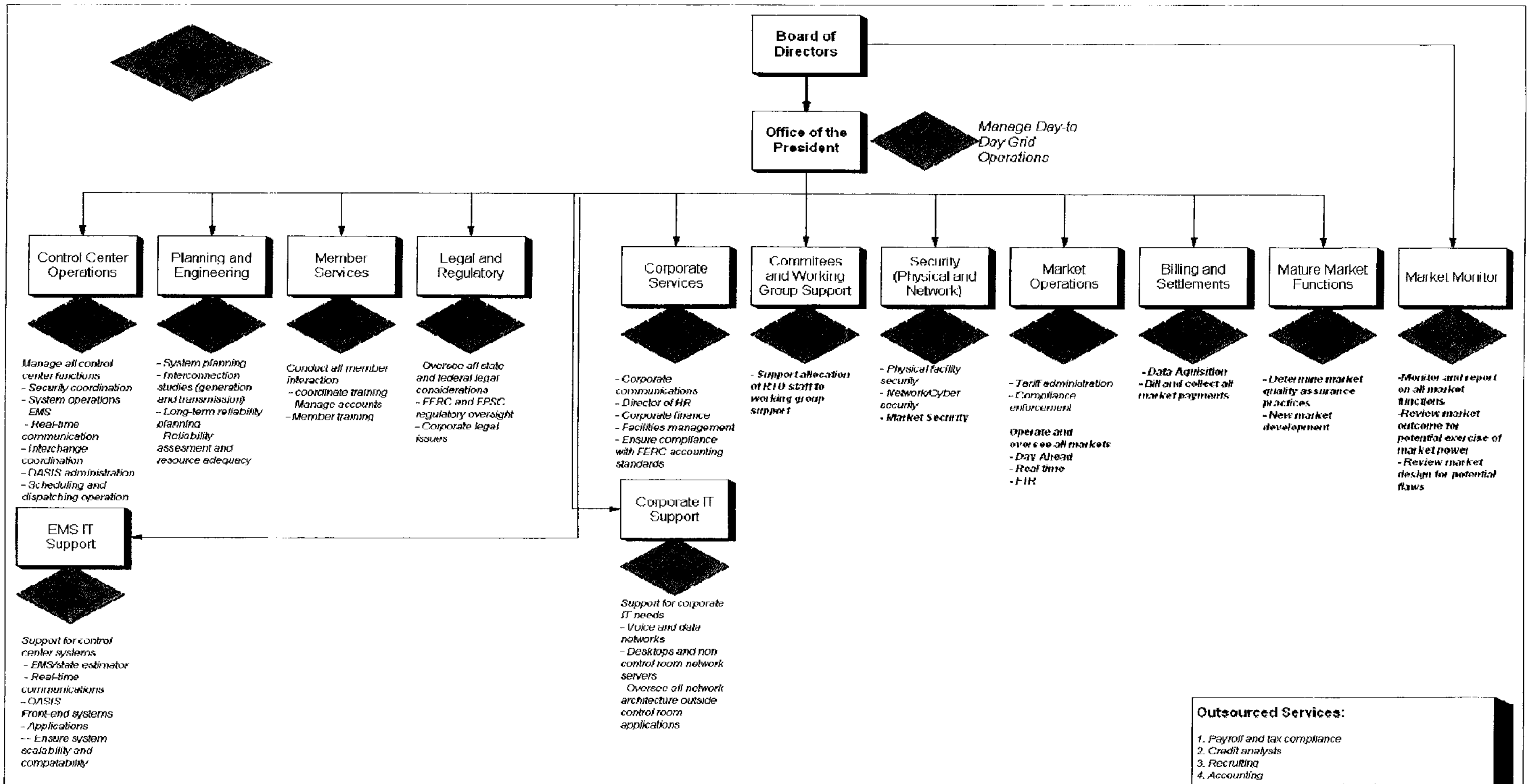
In addition to the 194 Day-1 FTEs many functions are assumed to be outsourced and are therefore estimated in the RTO Cost Model as lump sum expenses. Outsourced functions include market monitoring, payroll and tax compliance, start-up recruiting, accounting, corporate organization and inception, payroll and benefit administration, repro-services, systems procurement contract management and installation oversight, and public relations.

In Day-2, ICF estimates total staffing of 354 FTEs. This represents an incremental 160 FTEs over the Day-1 estimate. In Day-2, the number of FTEs for similar Day-1 functions increases due to increased responsibilities. For example the number of FTEs for Control Center Operations increases from 51 FTEs in Day-1 to 86 FTEs in Day-2 because of increased RTO functions and responsibilities such as coordination requirements with Day-2 markets – energy, regulation, operating reserves and FTR markets. FTE allocations for some of the Day-2 functions are as follows:

- 25 incremental FTEs for Market/Commercial Operations. These FTEs are responsible for the Day-Ahead and Real-Time balancing market operations. Other functions include FTR allocation and auctions and operation of ancillary services markets;

- 12 incremental FTEs for Billing and Settlement. These FTEs are responsible for all commercial billing and settlement activities. Their responsibilities include coordination of payments amongst all participants in the Day-Ahead and Real-Time markets, credit confirmations, and FTR settlement.
- 28 incremental FTEs for IT support. EMS and corporate IT support services increase significantly in Day-2 with the addition of Day-Ahead, Real Time and FTR market systems.

Exhibit 3-16
GridFlorida Day-2 RTO Organizational Chart and FTE Count



Bolded responsibilities are incremental to Day 2 operation.

Source: Industry Survey by ICF. Information provided by MISO and PJM directly; FERC, SETRANS, and GridSouth filings reviewed as well.

3.7.4 RTO Cost Modeling

After defining the systems, facilities, and personnel requirements for Day-1 and Day-2 operation, ICF proceeded to develop the cost model for the GridFlorida RTO operation. The ICF RTO Cost Model serves to aggregate the resource requirements listed above with detailed cost estimates and financial assumptions necessary to derive an all-in cost estimate for the start-up and annual operation of the proposed GridFlorida RTO. The sections below provide the relevant detail regarding the financial assumptions underlying the RTO Cost Model, and the key cost assumptions and approach.

3.7.5 Financial Assumptions

Financial assumptions were developed through close consultation with the GridFlorida Applicants and Stakeholders. These assumptions were benchmarked against existing data and additional confirmation was also sought from contacts in existing RTOs where possible. Exhibit 3-17 summarizes the key financing assumptions used.

Exhibit 3-17
GridFlorida RTO Financing Assumptions

Parameter	Assumption
Debt/Equity Ratio for Start-up Costs	100/0
After Tax Nominal Equity Rate	N/A
Debt Rate for IDC Expenses	4.2 %
Debt Rate for Startup Costs	5.5 %
Assumed Inflation	2.25 %
Real Discount Rate	3.15 %
Startup Cost Amortization Period	5 Years

- Debt/Equity Ratio: In accordance with Applicant and Stakeholder input, ICF assumed that the proposed GridFlorida RTO start-up costs will be fully funded by loans guaranteed through market participants. This is consistent the current funding of the GridFlorida RTO throughout this evaluation period.

- Debt and Equity Rates: Assuming 100 percent debt financing only the debt rate is relevant. We have assumed debt rates of 4.2 percent for IDC[23] and 5.5 percent for capitalized start-up costs. These are consistent with the 2000-2005 average debt rates realized by A-rated utilities in the US for terms of 18 months and 5 years respectively[24].
- Future Inflation: Future inflation is assumed to average 2.25 percent annually. This is consistent with the 1980-2004 average inflation of 2.26 percent reported by the US Bureau of Economic Analysis[25]
- Discount Rate: The assumed discount rate of 3.15 percent is based on the real WACC[26] for the GridFlorida RTO (corresponding to a 5.5 percent nominal rate, adjusted assuming a 2.25 percent inflation rate). This assumption was benchmarked against the average cost of capital reported by existing US ISOs and the large utilities operating in Florida.
- Start-Up Cost Amortization Period – Start-up costs are assumed to be amortized over 5 years in both Day-1 and Day-2. This is consistent with the original GridFlorida proposal submitted in FERC Docket No. RT01-67 filed on October 16, 2000 and supplemented on December 15, 2000. FERC approved the 5 year amortization in its 3/28/01 conditional approval of the GridFlorida RTO.

[23] Interest During Construction

[24] Source: Bloomberg sample data taken as of Jan. 4 each year.

[25] US Gross Domestic Product - Implicit Price Deflator: Bureau of Economic Activity, Department of Commerce http://www.bea.doc.gov/bea/dn/nipaweb/TableViewFixed.asp#Mid

[26] Weighted Average Cost of Capital

3.7.6 Key Cost Assumptions and Approach

While the RTO Cost Model comprises hundreds of assumptions, a relative few of these have a profound impact on the model outcome. We have given special focus to each of these categories of assumptions, working with industry experts from existing RTOs and ISOs, consulting system vendors and market design experts, and touring existing utility facilities within Peninsular Florida. We summarize these key assumptions below with brief discussions of the methodology and benchmarking underlying each.

- Personnel Costs – Personnel costs were derived from multiple public sources. Base salaries for six broad categories (Executive, Legal, Manager, Skilled, Unskilled, and Administrative) were taken from the Bureau of Labor Statistics (BLS) for the US utility sector[27]. We then inflated the base salaries by the BLS Wage/Benefit package ratio, and added federal social security[28] and payroll taxes[29]. These costs were then benchmarked against actual salary and benefit costs at FPL and PEF as well as aggregate salary information available from the NYISO[30], PJM[31], and ISO-NE[32]. These national average numbers were found to be somewhat lower than current experience within Florida and at existing RTOs indicated. As a result, a 10 percent premium on salaries was included in order to bring our estimates per employee up to the appropriate range. Cost of living data for the three target cities in

[27] Source: All data from U.S. Department of Labor, Bureau of Labor Statistics, National Compensation Survey - Compensation Cost Trends, Employer Cost for Employee Compensation (ECEC), Customized Tables, as of March 11, 2003.
[28] Source: http://www.payroll-taxes.com/PayrollTaxes/00000014.htm
[29] Source: http://www.payroll-taxes.com/PayrollTaxes/00000014.htm
[30] New York Independent System Operator
[31] PJM Independent System Operator
[32] New England Independent System Operator

Peninsular Florida that could potentially host the RTO i.e., Miami, Tampa, and Orlando support a minimum 2-3[33] percent premium over the national average salaries. The remaining premium is based upon benchmarking with existing RTOs and Florida utilities.

- Recruiting, Relocation, and Signing Bonuses – These peripheral personnel costs also added significantly to the RTO Costs, especially in the Day-1 start-up phase. For executives within GridFlorida, recruiting and signing bonuses are estimated to be 33 percent and 15 percent of annual salaries respectively. Relocation expenses are expected to average $42,000 for each of the 44 senior employees of GridFlorida. Recruiting and signing expense estimates are based upon industry literature and a survey of energy industry recruiting firms. Relocation expenses were developed through industry consultation, and benchmarked against FPL and PEF current relocation policies and practices.
- Systems and Subsystems – A large portion of both Day-1 and Day-2 startup expenses are allocated to the acquisition and installation of critical systems necessary to perform RTO functions. Considerable time and effort was spent in building these cost estimates from the bottom up.
  - The single largest line item within the Systems category is the Energy Management System (EMS) estimated at a total of $20 million. This estimate was developed through consultations with EMS vendors familiar with RTO roles and responsibilities, and a

[33] The Average cost of living premium in Tampa, Miami, and Orlando is 2.5 percent according to http://houseandhome.msn.com

detailed review of FPL's recent experience with replacement of an existing EMS system. This estimate includes both hardware and software needs for the Main Control Center (MCC) and the Back-up Control Center (BCC), simulation and training systems, and a budget for any system customizations that may be needed[34].

  - Under Day-2 operation significant additional systems expense is incurred to support market operations as well as to support the expanded billing and settlement function. ICF worked closely with representatives from existing RTOs as well as system vendors to accurately estimate hardware, software, and maintenance needs for real-time, day-ahead, and FTR market operations. Billing and Settlement systems were also benchmarked against experiences in PJM, the now defunct GridSouth, the UK, and Ireland as applicable.

- Physical Facilities Costs - The largest physical facility cost component included in the RTO Cost Model is the lease expense for the MCC and the BCC. In determining the amount of office space required, we assumed 250 square feet[35] of office space per GridFlorida employee, with additional square footage allocated for the control room and emergency power facilities. This yields an estimate of 96,500 sq-ft of office space required for the MCC under Day-1 operation, with an incremental 42,000 sq-ft required for Day-2 operation. In addition, we assumed 25,000 sq-ft will be needed for the BCC under both Day-1 and Day-2 operations. All facilities

[34] Specifically, some customizations may be needed within Florida to account for fast moving weather patterns significantly affecting demand as they pass over the peninsula.
[35] Source: ICF industry survey and literature review

were assumed to lease Class A office space at a cost of $22.8 per square foot[36]. This adds up to a total annual cost of $2.2 million for the main control center under Day-1, $0.57 million annually for lease costs for the BCC, and an incremental $0.96 million for expansion of the main control center under Day-2 operation.

- Soft Facility Costs: Significant expense is budgeted for "soft" facility costs such as facility hardening, office furniture, personal computers, facility design, and voice/data network infrastructure. Each of these line items was estimated using industry standards and in some cases, results of an ICF industry survey.
- Market Monitoring: For ease of estimating market monitoring costs, this function was assumed to be outsourced and performed by a fully separate entity reporting directly to the RTO board of directors (BOD) or the office of the President. The cost assumptions for market monitoring were developed through consultation with appropriate vendors and existing system operators.
- Incremental FERC fees: The FERC is currently mandated to recover all annual operating costs through fees assessed to those entities under FERC jurisdiction. A principal source of revenue recovery is a levy on all "firm sales and transmission activities". In 2003, FERC collected $78 million through a $0.04/MWh fee assessed to IOUs and RTOs throughout the US. As the Peninsular Florida marketplace is transformed into Day-1

[36] Source: This estimate is the average Class A lease cost for Orlando, Miami, and Tampa based on ICF's industry survey. Facilities are assumed to be "build to suit" with a premium for secure/hardened facilities included in the Start-up cost estimate.

and Day-2 operations, ICF expects the number of firm transactions subject to FERC fees to rise significantly as unbundled transmission transactions become more widespread. In developing these estimates, ICF examined recent FERC fees assessed to Investor-owned Utilities (IOUs) operating within Peninsular Florida as well as existing representative Day-1 and Day-2 RTOs. The average percentage of load subject to FERC fees was then estimated for each of the three market structures – Base Case; Day-1 and Day-2.

For the purposes of the cost modeling, the formation of the proposed GridFlorida RTO is planned in three stages:

- Day-0 is the period starting from the time the Applicants and Stakeholders began discussing the formation of the RTO through to the time when a decision is reached to move forward with a Day-1 RTO. The Applicants have provided cost estimates for ongoing Day-0 costs. All costs incurred under Day-0 as part of ongoing operational activities are treated as start-up costs.
- Day-1 startup begins immediately following the final decision to move forward with the GridFlorida RTO. We have assumed the ramp-up period to be 18 months prior to commencement of Day-1 operations, i.e., prior to Year 1. The activities to be performed during the 18 month ramp-up period to Day-1 operation will include facility modification/construction, formation of the BOD, recruiting and hiring, installation of the GridFlorida EMS system and all appropriate communications pathways, system testing and member training. We have assumed that the GridFlorida

system will operate under Day-1 roles and responsibilities for a period of 3 years before roll-out of Day-2 operations.

- Day-2 is the 10 year period following a three year Day-1 operation in the Delayed Day-2 Case. Similarly, we have assumed an 18 month ramp-up period preceding Day-2 operation, during which market rules must be developed, facilities must be expanded, market and settlement systems must be installed and tested, and an incremental 160 FTEs are recruited, hired, and trained.

The detailed results of the RTO costs and benefits modeling based on the approach described in this chapter is presented in Chapter 4.

CHAPTER FOUR
QUANTITATIVE RTO COSTS AND BENEFITS

The quantitative GridFlorida RTO costs and benefits derived from the approach described in Chapter 3 are presented in this section. The results reflect the overall quantitative costs and benefits associated with transforming the Peninsular Florida market from a decentralized operation to either a Day-1 only RTO operation or a Delayed Day-2 RTO operation. The results are presented separately i.e., RTO costs and RTO benefits, and then combined into net costs/benefits for each of the two RTO operating modes. As we have stated earlier, we note that the RTO costs, and accordingly the net costs/benefits, do not reflect the changes in existing utility/control area costs that will result as a consequence of the RTO formation. This is followed by the results of the sensitivity analyses, which are presented separately for each case[37]. Further, the RTO benefits from the Reference Cases are disaggregated into FPSC jurisdictional and non-jurisdictional consumer benefits including transmission cost shifts between jurisdictional and non-jurisdictional transmission providers as a result of a single GridFlorida transmission rate. All figures presented are in 2004 constant dollars unless otherwise stated.

4.1 Summary of Quantitative RTO Costs and Benefits

Exhibit 4-1 shows the summary of the RTO costs and benefits across all cases examined.

[37] Note that the alternative treatment of the external resources in Georgia as non-network resources is only presented for the purposes of comparison to the Reference Case.

Exhibit 4-1
Summary of Quantitative RTO Costs and Benefits (Million 2004$)
NPV (Years 1-13)[38]

Case	RTO Operation	RTO Benefits	RTO Costs[1]	Net Benefit/Costs[2]
Reference Cases	Day-1 Only	71	775	-704
	Delayed Day-2	968	1,253	-285
JEA and TALL Out Case	Delayed Day-2	891	1,253	-362
Market Imperfection Case	Delayed Day-2	810	1,253	-443

[1]Discounted using a 3.15 percent real discount rate
[2]The RTO Costs presented are only costs associated with the new RTO entity. None of the change in existing utility operational costs has been considered in this estimate

A comparison of the quantitative RTO costs and benefits in net present value terms over the 13 year forecast period indicate a loss in all the cases examined before considering qualitative benefits and costs and other utility operational costs and benefits. Whereas the benefits under Delayed Day-2 RTO operation were substantial and ranged from approximately $810 million in the Market Imperfection Case to almost $968 million in the Reference Case, the quantitative startup and going forward operating costs of the wholly new "greenfield" RTO entity with all new systems, personnel and physical facilities is $1.25 billion[39]. Again we note that the RTO costs provided does not include any changes associated with any of the existing utility operational costs as a result of the formation of the new RTO entity. The benefits of a Day-1 only operation were 71 million and the cost of a wholly new "greenfield" Day-1 RTO was 775 million[40]. The Day-1 benefits were small compared to Delayed Day-2 benefits reflecting the fact that the bulk of RTO benefits are derived from centralized unit commitment and dispatch. In Day-1, unit commitment and dispatch are still decentralized so the benefits

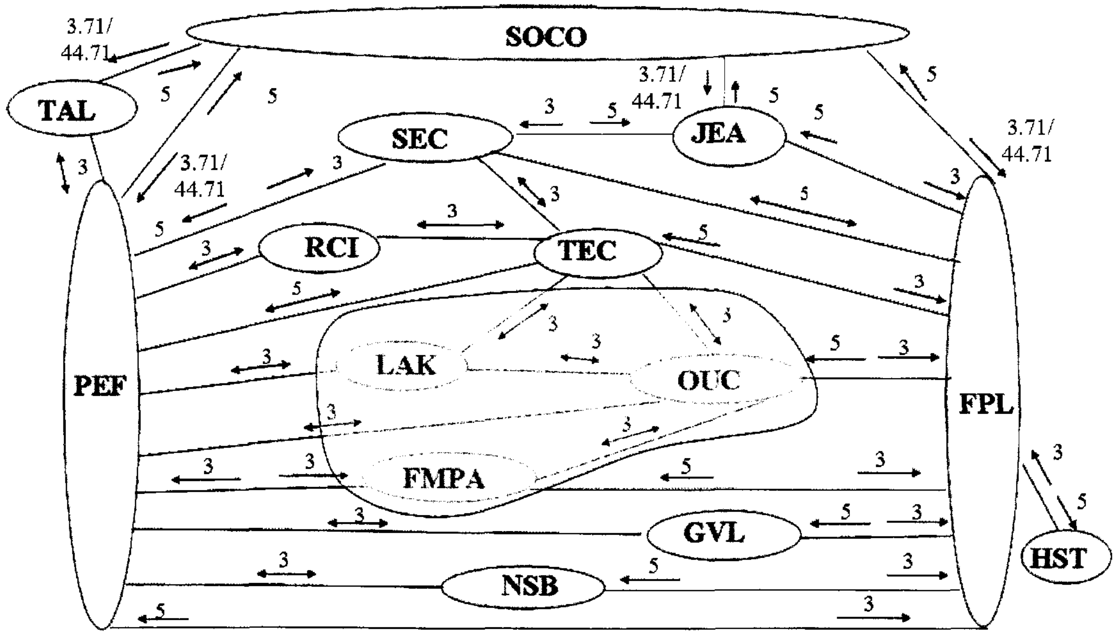
[38] Discounted using a 3.15 percent real discount rate
[39] Includes 33 million of Day-0 costs estimated by the GridFlorida Applicants.
[40] Includes 33 million of estimated Day-0 costs.

are relatively small. The treatment of the UPS contracts as non-network resources reduced the benefits to Peninsular Florida consumers in both the Day-1 Only and the Delayed Day-2 RTO operations. Each of these costs and benefits are discussed in detail below but we begin with a brief discussion of the calibration results used to derive the RTO benefits.

4.2 Model Calibration Results

The commitment hurdle derived from the model calibration exercise was $20/MWh. We believe this relatively high commitment hurdle is reasonable because Peninsular Florida has many control areas and probably the least footprint per control area compared to most other power markets in the continental US. Thus, for modeling, a relatively high commitment hurdle was required to force each control area to commit its units to serve its load first. A set of dispatch hurdles was derived from the calibration effort. These hurdles were applied to the Base Case modeled as part of the Reference Cases. This same set of dispatch hurdles was applied in the JEA and TALL Out and the Market Imperfection sensitivity analyses. Exhibit 4.2 shows the dispatch hurdles used for the various cases. Note that these dispatch hurdles reflect the combined effect of market inefficiencies associated with scheduling and dispatching operations and "pancaked" transmission rates. The relatively high dispatch hurdles in the model associated with the Southern/Florida interface were necessary to constrain imports from the Southern Company region to match the realized 2003 Peninsular Florida import levels and to match the internal Peninsular Florida generation with the 2003 actual generation. The combined dispatch hurdle rate and transmission rate between Peninsular Florida control areas were in the $3/MWh to $5/MWh range. The calibration results indicate a high commitment hurdle and a relatively modest set of dispatch hurdles. This reflects the fact that there are a number of entities within Peninsular Florida performing unit commitment and that some consolidation may provide benefits to consumers. However economic dispatch within Peninsular Florida is relatively efficient, largely because of the high interconnectivity between the control areas and the fact that most transactions are between adjacent systems pay the network transmission rate.

Exhibit 4.2
Dispatch Hurdles for the Base Case Modeled as Part of the Reference Case, and for the JEA and TALL Out Case, and the Market Imperfection Case



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

4.3 Reference Case Results – Quantitative RTO Benefits

Day-1 Only GridFlorida RTO Operation: The RTO benefits from Day-1 only operation over the 13-year forecast period is $71 million (2004$ NPV). These Day-1 benefits reflect traditional company operation with the primary benefits of Day-1 operation, which is de-pancaked transmission charges. The elimination of pancaked transmission charges is expected to enable more transactions between counterparties, both short-term and long-term. However, the analytical modeling framework used in this exercise is only capable of capturing the benefits associated with incremental short-term transactions. Since, all economy transactions in the model are assumed to be short-term. Long term transactions are only captured if and only if they are explicitly modeled, but since they are generally not known *apriori*, they are not captured in this analysis. Nevertheless, the relatively low level of Day-1 RTO benefits compared to Day-2 RTO is considered reasonable for the following reasons:

- The major source of consumer benefits in Peninsular Florida comes from GridFlorida-wide unit commitment and dispatch, which is only realized under Day-2. Thus, maintaining a decentralized unit commitment and dispatch operation under Day-1, similar to the existing market, is expected to yield only modest benefits;
- Additionally, because there is already a high level of connectivity between control areas in Florida, most transactions occur between adjacent systems. The need for transactions wheeled through multiple systems is typically infrequent and such transactions are generally small. Thus, the benefits of eliminating "pancaked" transmission charges are not as significant.

- Finally, most transmission service provided in Florida is Network Service, as opposed to Point-to-Point Service. Utilities pay for transmission based on their respective load ratio share of the embedded cost of the transmission system, giving them Network Customer priority. As such, their transactions are not subject to additional wheeling charges, so the elimination of such charges would make little difference.

Exhibit 4-3 shows the annual and total Day-1 RTO benefits over the 13 year forecast period.

Exhibit 4-3
Annual Day-1 Benefits (Million 2004$)

Year	Day-1 Benefits
2004	17
2005	5
2006	5
2007	8
2008	5
2009	7
2010	4
2011	3*
2012	3
2013	4*
2014	6
2015	7*
2016	8
NPV (Years 1-13)	**71**

Discounted using a 3.15 percent real discount rate. *Interpolated

Delayed Day-2 GridFlorida RTO Operation: The Delayed Day-2 RTO benefit over the 13-year forecast period is $968 million (2004$ NPV), significantly higher than the Day 1 benefits. This delayed Day-2 benefit comprise three initial years of Day-1 benefits, followed by ten years of Day-2 benefits. Exhibit 4-4 shows the annual and total benefits for the Delayed Day-2 RTO operation.

Exhibit 4-4
Annual and Net Delayed Day-2 GridFlorida RTO Benefits (Million 2004$)

Year	Delayed Day-2 Benefits
2004	17*
2005	5*
2006	5*
2007	106
2008	119
2009	98
2010	95
2011	108**
2012	121
2013	130**
2014	139
2015	139**
2016	139
NPV (Years 1-13)	**968**

*Day-1 RTO operation
**Interpolated
Discounted using a 3.15 percent real discount rate

As mentioned above, the Day-2 benefits are largely derived from centralized unit commitment and dispatch of resources to serve load and reserve requirements, which in turn allows for a much greater level of optimization over a considerably larger set of resources. Mathematically this can be described as decentralized operation yielding local optimums in unit commitment and in dispatch, while centralized operation yields global optimums in both.

4.4 Reference Case Results – RTO Costs

The benefits described above must be compared to costs of achieving them. ICF modeled RTO costs were modeled as Start-up and Operating costs for three developmental stages, with Start-up divided into three categories and Operating costs into two categories:

- Day-0 Start-up Costs: All costs incurred prior to the FPSC decision to proceed with the RTO;
- Day-1 Start-up Costs: Incremental costs to transform the existing decentralized operation to a Day-1 RTO;
- Day-2 Start-up Costs: Incremental costs to transform the RTO from a Day-1 operation to a Day-2 operation.
- Day-1 Operating Costs: Annual expenses associated with operating a Day-1 RTO;
- Day-2 Operating Costs: Annual expenses associated with operating a Day-2 RTO;

Exhibit 4-5 shows estimates of start-up and operating costs for Day-0, Day-1 and Day-2.

Exhibit 4-5
GridFlorida Startup Costs for Day-0, Day-1 and Day-2 Operations (Million 2004$)

Parameter	Day-0 Costs	Day-1 Costs	Day-2 Costs
Costs Incurred Through 12/31/2003	19.0	--	--
Estimated Incremental costs to Day-0	14.4	--	--
Facilities	--	12.2	3.2
Corporate Inception	--	16.8	6.7
Systems	--	33.4	38.3
Operating Costs During Inception	--	40.2	27.2
Day-0 Costs IDC[1]	--	2.2	--
Day-1 Startup Cost IDC[1]	--	5.4	4.0
Total	**33.4**	**110.2**	**79.3**

Total costs incurred through December 31, 2003 in support of the GridFlorida RTO formation is approximately $19 million. These expenses were incurred largely through regulatory filings and feasibility studies by or on behalf of the GridFlorida Applicants. It is expected that an additional $14.4 million will be expended between January 1, 2004 and the final "go" decision on GridFlorida, bringing total Day-0 start-up costs to $33.4 million. All Day-0 cost estimates were provided by the Applicants and reviewed by Stakeholders.

Day-1 startup costs are those expenses necessary to bring the GridFlorida RTO organization from the final "go" decision to operation of the Day-1 RTO. These costs are divided into five broad categories covering:

- $12.2 million in facilities costs that encompass headquarters and Backup Control Center buildings, interim office space, furniture, voice and data infrastructure, backup generators, and facility hardening.
- $16.8 million in corporate inception costs that comprise legal fees, recruiting and relocation expenses, and consultant fees.
- $33.4 million in systems expenses that encompass IT network design, EMS system (HQ and backup) installation, Map board installation, billing and settlement setup, and purchase of various transmission models.
- $40.2 million in operating costs during inception that comprise all employee costs during the 18 month Day-1 ramp-up period.
- $7.6 million in interest during construction (IDC) costs needed to capitalize Day-0 and Day-1 startup costs on the date of operation.

These five broad categories bring the total Day-1 startup cost estimate to $110.2 million incrementally, and $143.6 million when costs to Day-0 are included. Additional detail on start-up costs are provided in Appendix D.

Day-2 start-up costs are those costs expected to be incurred during the period from Day-1 operation to a market-based Day-2 operation. These costs are expected to be incurred during the 18-month ramp-up period to Day-2 operation, and are similarly divided into five broad categories for analysis. Note that all Day-2 costs presented are incremental to Day-1 expenses.

- $3.2 million in incremental facilities costs which include expansion of the headquarters facility, infrastructure, and furniture.
- $6.7 million in incremental corporate inception costs which include recruiting and relocation expenses, consultant fees, and other small items.
- $38.3 million in incremental systems costs which include hardware and software needed for operation of the Day-Ahead, Real-Time, and FTR markets, expansion of the market monitoring function, and expansion of billing and settlement systems needed for Day-2 markets.
- $27.2 million in operating costs during inception that include all employee costs during the 18-month Day-2 ramp-up period.
- $4.0 million in interest during construction (IDC) costs needed to capitalize Day-2 startup costs on the date of operation.

These five broad categories bring the total Day-2 startup cost estimate to $79.3 million incrementally and $222.9 million when Day-0 and Day-1 costs are included. Additional detail on startup costs can be found in Appendix D.

Exhibit 4-6 below provides operating costs for the first year of Day-1 and Day-2 operation. Note that these are different years, since the first year of Day-1 operating costs occur in Year 1 and the first year of Day-2 operating costs occur in Year 4. The Day-2 operating costs provided are incremental to the Day-1 operating costs in that year.

Exhibit 4-6
GridFlorida Operating Costs for First Year of Day-1 Operation and Incremental Costs for First Year of Day-2 Operations (Million 2004$)

Parameter	Day-1 Costs (Year 1)	Incremental Day-2 Costs (Year 4)
Facilities	4.5	1.8
Total Salary and Benefit Cost	30.9	24.1
Systems	5.6	3.1
Outsourced Functions	3.0	4.7
Other/Misc.	5.7	6.8
Capital and Interest Expenses	12.3	9.6
Total Operating Costs	**61.9**	**50.0**

Day-1 operating costs for the first year include all annual operating expenses needed for operation of the GridFlorida RTO under Day-1 roles and responsibilities. ICF's analysis included six broad categories:

- $4.5 million in facilities costs which includes lease expenses for the headquarters and BCC facilities as well as utility expenses for both facilities.
- $30.9 million in salary and benefit expense for GridFlorida employees. This category includes salary, benefit expense, payroll taxes, social security taxes, performance bonuses, and Board of Director expenses.
- $5.6 million in systems costs related to maintenance and license agreements for the EMS and billing/settlement systems, management of the OASIS system, and ICCP[41] link expenses.
- $3.0 million in expenses for outsourced functions such as market monitoring, payroll and benefit administration, external audits, and public relations.

[41] Inter-Control Center Communications Protocol

- $5.7 million in miscellaneous costs such as insurance, taxes, incremental FERC fees, ongoing recruiting and relocation expenses, and business travel expenses.
- $12.3 million in capital and interest expenses which covers interest payments on outstanding loans, as well as ongoing capital replacement budgets. Note that this excludes principle repayment on capitalized startup costs.

These six broad categories bring the total annual operating expense for the GridFlorida RTO in the first year of Day-1 operation to $61.9 million in total.

Day-2 operating costs are divided into the same six broad categories. Note that all Day-2 operating costs are presented as incremental to Day-1 operating expenses.

- $1.8 million in facilities costs which cover additional facility lease costs needed to accommodate new employees and systems and increased facility utility costs.
- $24.1 million in incremental salary and benefit costs for new GridFlorida employees.
- $3.1 million in additional system costs which provides budget for increased data storage needs, and license and maintenance fees for new market and billing systems.
- $4.7 million in incremental costs associated with outsourced functions. These costs support the need for increased market monitoring, payroll and benefit administration, and public relations.

- $6.8 million in miscellaneous costs associated largely with increased FERC fees and insurance.
- $9.6 million capital and interest expenses which cover interest payments on outstanding loans, as well as ongoing capital replacement budgets. Note that this excludes principal repayment on capitalized startup costs.

These six broad categories bring the incremental operating expense of the GridFlorida RTO under Day-2 operation to $50.0 million in the first year of operation. When Day-1 operating costs for the same year are considered, the total operating cost is $109.1 million for the first year of Day-2 operation.

Exhibit 4-7 provides the annual operating expenses for each year of the 13 year forecast horizon for the GridFlorida under Day-1 and Day-2 market structures. Note that all operating costs are presented in real dollars (millions 2004$). Changes in operating costs across years is due to changing interest payments on startup and recapitalization projects, and the underlying assumption of 1% real salary escalation going forward.

Exhibit 4-7
GridFlorida Annual Operating Costs for Day-1 and Day-2 Operations
(Millions 2004$)

Year	Day-1 Costs	Incremental Day-2 Costs	Total Delayed Day-2 Costs
1	61.9	--	61.9
2	61.1	--	61.1
3	60.2	--	60.2
4	59.1	50.0	109.1
5	57.9	51.2	109.1
6	56.6	52.3	108.9
7	57.0	51.9	108.9
8	57.4	51.5	108.9
9	57.9	50.9	108.8
10	58.3	51.3	109.6
11	58.7	51.7	110.4
12	59.2	52.1	111.3
13	59.6	52.5	112.1
NPV (Years 1-13)	640.3	409.8	1,050.2

Note: Excludes principal payments on amortized start-up costs. Discounted using a 3.15 percent real discount rate.

Exhibit 4-8 below shows the annual cash expenditures expected at the GridFlorida RTO through the 13 year forecast horizon. Annual cash expenses start with operating costs, to which is added principal and interest repayment on loans of all startup costs.

Exhibit 4-8
GridFlorida Annual Cash Expenses for Day-1 and Day-2 Operations (Million 2004$)

Year	Day-1 Costs	Incremental Day-2 Costs	Total Day-2 Costs
1	87.6	-	87.6
2	88.2	-	88.2
3	88.8	-	88.8
4	89.3	64.2	153.5
5	89.8	66.2	155.9
6	56.6	68.1	124.7
7	57.0	68.6	125.6
8	57.4	69.1	126.5
9	57.9	50.9	108.8
10	58.3	51.3	109.6
11	58.7	51.7	110.4
12	59.2	52.1	111.3
13	59.6	52.5	112.1
NPV Years 1-13	774.9	477.6	1,252.5

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate

4.5 Sensitivity Analysis Results – JEA and TALL Out Case.

Exhibit 4-9 shows the annual and net benefits from a Delayed Day-2 GridFlorida RTO with JEA and TALL as non participants. The total benefit from this reduced GridFlorida RTO over the 13–year forecast period is $891 million (2004$ NPV) and represents 92% of the $968 million total benefit realized from the larger GridFlorida RTO modeled in the Reference Case. With JEA and TALL as non-participants, approximately 7.5% of the total Peninsular Florida load is excluded from the GridFlorida RTO. The reduced load translates into a lower Delayed Day-2 RTO benefit. Additionally, with JEA and TALL out of a GridFlorida RTO, power imports from the SERC region pay additional transmission wheeling charges when these imports are wheeled through the JEA and the TALL systems, further reducing the overall benefits. Thus the net effect of a JEA and TALL Out scenario is an 8% reduction in the RTO benefits estimated in the Reference Case.

Exhibit 4-9
Annual Delayed Day-2 Benefit – JEA and TALL Out Case (Million 2004$)

Year	Delayed Day-2 Benefits
2004	17
2005	5
2006	5
2007	91
2008	101
2009	90
2010	98
2011	105*
2012	111
2013	121*
2014	130
2015	127*
2016	124
NPV (Years 1-13)[42]	**891**

* Interpolated

4.6 Sensitivity Analysis Results – Market Imperfection Case

Exhibit 4-10 shows the annual and net benefits projected for Day-2 under a Market Imperfection Case. This case incorporated commitment hurdles of $5/MWh and 25% higher dispatch hurdles up to a cap of $0.50/MWh to account for the combined effect of demand uncertainty and transaction costs associated with minimum transaction sizes and margins. The total RTO benefit realized from this case is $810 million (2004$ NPV) which represents 84% of the $968 million in benefits realized in the Reference Case. Thus, up to 16% of the benefits reported in the Reference Cases may not be realized due to these market uncertainties.

[42] *Discounted using a 3.15 percent real discount rate*

Exhibit 4-10
Annual and Total RTO Benefit – Market Imperfection Case (Million 2004$)

Year	Delayed Day-2 Benefits
2004	17
2005	5
2006	5
2007	96
2008	99
2009	82
2010	79
2011	90*
2012	101
2013	104*
2014	108
2015	114*
2016	119
NPV (Years 1-13)	**810**

Discounted using a 3.15 percent real discount rate; * Interpolated

Overall, the Reference Cases and the Sensitivity Analyses indicate that the RTO benefits are mostly significant under Day-2 RTO configuration rather than under Day-1 RTO configuration. While the quantitative benefits of a Day-2 RTO configuration are significant and very large, the quantitative costs of forming and maintaining a Day-2 RTO are even larger. In the next chapter we discuss qualitative factors that should be considered side-by-side with the quantitative benefits and costs presented in this chapter.

Sensitivity of RTO Benefits to the Base Case Commitment and Dispatch Hurdles

ICF performed a sensitivity analysis of Day-1 and Day-2 benefits to the Base Case commitment and dispatch hurdles. These sensitivity analyses were performed off the Year 4 (2007) annual model runs. Two cases were simulated to test the sensitivity of the Day-1 benefits:

- A sensitivity analysis case with each of the dispatch hurdles between Peninsular Florida Control Areas increased by $2/MWh. For example if the dispatch hurdle was $5/MWh in the Reference Case, this was elevated to $7/MWh in this sensitivity case.
- A sensitivity analysis case where the commitment hurdle was cut in half i.e., the commitment hurdle of $20/MWh was reduced to $10/MWh.

The results of this sensitivity analysis are presented in Exhibit 4-11 below and they are compared to the Reference Case Day-1 and Delayed Day-2 benefits.

Exhibit 4-11
Sensitivity of Day-1 Benefits to the Base Case Commitment and Dispatch Hurdles

	Day-1 Benefits Sensitivity of Year 4 (2007) Benefits (Millions 2004 $)	Day-2 Benefits Sensitivity of Year 4 (2007) Benefits (Millions 2004 $)
Base Case Commitment and Dispatch Hurdles as Modeled in the Reference Case	6.5	112.3
Base Case Dispatch Hurdles Increased by $2/MWh	13.1	118.8
Base Case Commitment Hurdles reduced from $20/MWh to $10/MWh	6.5	99.2

These sensitivity analyses results indicate that the Day-1 benefits are largely unaffected by the size of the commitment hurdle but very sensitive to the dispatch hurdles. The Day-1 benefits doubled from $6.5 million to $13.1 million in Year 4 (2007). Thus, over the 13-year forecast period, it is possible that the Day-1 benefits could double from the $71 million realized in the Reference Case to about $140 million. However, since the quantitative costs of a Day-1 RTO is $775 million, even a doubling of the Day-1 RTO benefits would be significantly less than the costs. The Delayed Day-2 RTO benefit increases slightly with the $2/MWh increase in the dispatch hurdles. When the commitment hurdles are reduced by 50%, the Delayed Day-2 RTO benefits decline but by only 12%.

CHAPTER FIVE
QUALITATIVE RTO COSTS AND BENEFITS

5.1 Introduction

The quantitative analysis of costs and benefits did not address all aspects of the impacts of a GridFlorida RTO. This was in large part because there is no agreed upon approach in the industry for assessing some issues. Also, in some cases, the issues are outside the scope of this study.

As explained in more detail in this section, some of these issues include:

- **Investment Efficiency** – The GridFlorida RTO modeling did not assess the impact on investment efficiency. Note between 2005 and 2016, at 2.5 percent demand growth, generation investments in Florida would be roughly \$10 billion[43]. Higher demand growth at historical levels and a longer time horizon would raise that above \$10 billion and transmission investment would add to this amount. In light of the importance of this issue, most of this discussion focuses on alternative perspectives related to investment efficiency.

- **Bilateral Long-Term Contracting** – The quantitative modeling focused on very short-term spot markets, though over a long time period. Derivative markets such as long-term power sales were not analyzed.

[43]This is calculated by taking the 2004 peak load in Florida of 43 GW, adding a reserve margin of 20%, and growing that requirement by 2.5% per year to determine the number of additional megawatts required. We then multiply that by the average cost per kilowatt of new capacity – we used \$600/kW to derive the \$10 billion figure Mathematically, this is: [43 GW peak x 1.2 reserve margin x $(1.025)^{11}$ – (43 GW peak x 1.2) current installed capacity] x 600 \$/kW cost of new capacity x 1,000,000 kW/GW. We note that the FRCC reserve margin requirement is 15%. However, the three investor-owned utilities (about 77% of FRCC load) have agreed with the FPSC to maintain a 20% reserve margin.

- **Contract Path Scheduling** – The quantitative analysis did not explicitly address the benefits of eliminating contract path scheduling. However, this issue was largely addressed implicitly.
- **Market Power** – The quantitative analysis assumed competitive markets in all scenarios, and hence, possible effects of a GridFlorida RTO on competition were not addressed. This is a complex topic and largely beyond the scope of this study, though some dimensions are briefly identified.
- **Utility Administrative/Operational Cost Analysis** – The direct administrative and operational cost impacts on utilities associated with a GridFlorida RTO are not within the scope of this study.
- **Transition Risks** – The quantitative analysis did not address the potential for operational or financial problems during the transition from the status quo to a GridFlorida RTO.
- **Scope, Organizational, and Regulatory Issues** – There are several organizational issues that arise when a large new organization like a GridFlorida RTO is created. These range from the option value associated with the ability to meet unexpected needs and the potential for unnecessary scope expansion. Regulatory issues may also arise due to the division of jurisdiction between the FPSC, RTO and FERC.
- **Other** - There are several other intangible issues that may apply to the creation of the GridFlorida RTO, including utility return on equity and incentives; management of intra-regional tariffs; efficiency and standards; and merchant power plants.

Each of these items is discussed below.

5.2 Investment Efficiency

The MAPS modeling used to develop the quantitative benefit estimates assumes that there will be considerable investments in new power plants and in electric transmission infrastructure between 2005 and 2016. Within Florida, the applicants and other stakeholders specified these investments, and outside Florida, ICF did so. These investments are especially large in Florida, serving one of the fastest growing populations in the U.S.

However, the level of investments are fixed in the GridFlorida analysis across all scenarios, i.e., across the Base Case and both Day One and the delayed Day Two scenarios. In other words, the quantitative analysis does not estimate the potential impact of GridFlorida RTO on investment efficiency. This applies to both generation and transmission, and contrasts with short-term power plant dispatch and unit commitment, which do vary in the GridFlorida RTO scenarios. This lack of treatment of investment effects in part reflects the lack of methodological consensus on how to model the change in long-term investments in response to the GridFlorida RTO. Furthermore, such a study would significantly increase the scope of the analysis. Hence, a key issue that is discussed qualitatively is the effect of GridFlorida, positive or negative, benefit or cost, on this important aspect of the power sector.

Under GridFlorida RTO, there could be improvements in investment decision-making. This could apply to the siting, quantity and timing of new power plants, transmission lines and other system elements.

There are four main reasons why this might happen under a Day-2 RTO, while under a Day-1 RTO, only the last three apply:

- **Power Price Information** – There is expected to be a very large increase in the amount of power price information under GridFlorida, and potentially a significant improvement in its quality. It is unclear how such an increase would affect transmission investments. The most dramatic change by far would be under Day-2. There are approximately 2,000 nodes or locations in Florida on the high-voltage system[44] for which power prices might become available on an hourly basis. For each location, there would be day-ahead and real-time prices, and hence, 35 million prices per year (8,760 hours times 2 types of prices times 2,000 nodes). In other markets, even more price information is available, as real time prices are calculated as frequently as every few seconds. In addition, there might be prices available for other products such as operating reserves. All of this information would be available to the public, as with MISO, ISO-NE, NYISO, and PJM, at no extra cost above those already estimated.

  The potential value of all this information is that it could provide investment signals for regulators, utilities, investors, and consumers. For example, in the hypothetical case in which nodal prices in southern Florida show significant premiums over northern Florida, these differential could signal the need to site more new power plants, concentrate demand-side management (DSM) programs, or increase fuel delivery capability there, or to increase electric transmission capability to South Florida. In theory,

[44] 69 kV and higher.

prices would reflect marginal generation costs in Florida, grid congestion and marginal transmission losses, although practical experience in existing RTO markets indicates that realized prices are higher than marginal costs. Conversely, a lack of power price differentials in Florida would inhibit potentially excessive investments in transmission and other activities. In any case, under GridFlorida price differentials could become a salient feature of the power situation and an additional benchmark for evaluating investments.

This price information would be subject to market monitoring, and there would be large volumes of transactions underlying the data. In contrast, current power price information is either limited in terms of granularity (hours, locations) or liquidity (few data points).

The impact of such pricing is unclear. While economic theory suggests that such pricing signals would benefit the market, in practice the promise of more efficient investment in RTO markets due to such pricing is unclear. Other mechanisms, such as locational installed capacity markets, and transmission investment incentives have been applied to influence investment decisions in several restructured markets. Where restructured markets have succeeded in encouraging investment, it is unclear whether this is due to more price information or the success of regional planning processes. It may be premature to judge the prospects of better timing and location of generation and transmission due to power price information. In addition, the physical realities of transmission and generation siting and access to fuel are likely to influence near-term marginal pricing signals, suggesting that such price signals are not definitive indicators of asset locations.

- **Elimination of Pancaking** – Pancaking refers to having multiple charges – one for each wheel or utility system crossed - along the contract path of the transaction. In both Day-1 and Day-2, "pancaking" of transmission charges would be eliminated and there would be only one charge for transactions within GridFlorida, regardless of the source and sink location in GridFlorida. This approach aligns the tariff charges for electricity transmission more closely with marginal costs, which are usually lower than tariff rates. If there is no congestion, marginal costs for electric transmission equal losses, which can be a fraction of the tariff charges, especially if several utilities are involved. The quantitative analysis indicates that depancaking will have some effect on operations, but it could also have an effect on investment that is not currently captured. By eliminating pancaking of transmission charges, some utilities would have less incentive to have direct transmission ties to avoid pancaking, and hence, potentially some transmission facilities may be avoided. Also, as a result of de-pancaking, some customers may see an increase in transmission costs while others see a decrease due to cost shifts.

- **Central and Integrated Transmission Planning** – Currently, longer-term planning is carried out separately by each investor-owned and public utility. Under GridFlorida, that planning vis-à-vis transmission might improve in both Day-1 and Day-2, as it becomes centrally coordinated for peninsular Florida as a whole. Recognizing the potential benefits of integrated transmission planning, Florida utilities have taken steps towards a more coordinated planning process at the regional level (FRCC), so some of this potential benefit may be realized without the formation of an RTO.

- **Industry Transparency** – Much of current activity is undertaken by utilities under the jurisdiction of regulatory authorities. This can place large burdens on regulators to review utility activity and information – e.g., ATC calculations, planning analyses, etc. In addition, one of the main drivers behind FERC's activities in promoting RTOs and issuing different orders (e.g., Order 888) is its wish to ensure open and non-discriminatory access to the grid. In this context, having the RTO provide such information is consistent with these objectives. Having said that, there have been no formal complaints filed at FERC regarding the calculation of ATC, or discriminatory treatment. The regulatory burden under an RTO with competitive markets will shift to efforts to ensure these entities with market power do not abuse it, which may result in more regulation. Under a GridFlorida RTO, in addition to public price information, there would be increases in transparency through RTO reports and public information on the grid's condition, planning considerations, etc. A review of RTO websites reveals that these entities publicly provide substantial amounts of such information. Like price information, this increased transparency could improve the efficiency of investments.

No analysis was conducted to assess the adequacy of the Florida transmission system.

5.3 Bilateral Long-Term Contracting

ICF's quantitative analysis of power markets covers a long-term period, i.e., through 2016. However, the cost and benefits analysis was focused on the impacts of creating a GridFlorida RTO on short-term markets, e.g., day-ahead and real time prices. It is expected that the efficiency of these short-term markets will improve relative to the current market, and as a result, could improve the efficiency of longer-term contract and derivative markets as well. No estimate was made of this benefit. In this context, the most common derivative would likely be long-term power sales ranging from several months to several years. These long-term contracts can better manage seller and buyer risks, resulting in less exposure to market volatility and uncertainty. On the other hand, hedging consumer risk with longer term contracts has its own risks as well, since a premium may be paid to secure price stability.

The magnitude of the demand for bilateral long-term contracts in Florida is not insignificant. Florida already has a process for long-term contracting for new plants, including competitive bidding for new power supply. In addition, there are multiple public power entities with a history of long-term contracting. Also, current Florida law limits un-contracted merchants to steam units under 75 MW, and this encourages entities to sign contracts, though the volume might be more if that restriction was less. Also, since there is no retail competition in Florida, the "buy side" demand for such contracts is limited to utility purchases rather than direct purchases. On the other hand, there is a large public power sector acting for consumers.

In some ways, this factor is related to the investment planning discussion above. The more optimal the level of generation and transmission investment, the more long-term contracts may be developed to incorporate this enhanced mix of assets.

5.4 Contract Path Scheduling

Contract path scheduling refers to the practice of assuming that the flows of power in a sale from utility to utility travel via a chosen geographic path, regardless of whether a third utility is affected by what are known as parallel path flows. This can be inefficient, since the third utility might have a more economic use for the transmission capacity, but is unable to utilize it due to other utilities' transactions. This inefficiency would remain to the extent that not all of the utilities in Peninsular Florida participate in GridFlorida. The business as usual case was modeled in GEMAPS without contract path scheduling, and assumed that all Peninsular Florida utilities participate in GridFlorida. GEMAPS models actual path transmission.

Much of the effect of contract path scheduling is captured by the use of hurdles to model inefficiencies in the system in the Base Case. However, it is possible that some inefficiencies were not modeled, and hence, the benefits of the elimination of contract path scheduling in both Day-1 and Day-2 may be understated.

5.5 Market Power

The quantitative analysis assumes perfect competition in both the Base Case and the RTO GridFlorida cases. Market power – i.e., less than perfect competition – is inefficient, and raises equity issues, as margin is transferred form buyers to sellers. Thus, if GridFlorida RTO increases or decreases market power, then it would have additional costs or benefits.

It is unclear whether market power would increase or decrease under a GridFlorida RTO. As more decisions reflect bidding and markets, the level of concentration in the Florida generation sector could increase opportunities for raising prices, since those selling power may tend to bid to supply power at the marginal cost of the next supplier, rather than at their cost. In this context, increasing the reliance on markets could increase wholesale costs.

On the other hand, an RTO will provide full-time market monitoring and the possible sanction of requiring large owners of generation to bid at variable costs if they are deemed to possess or exercise market power. In addition, creating the GridFlorida RTO would separate the operation of transmission from entities which also have generation. Lastly, the existence of price data, centralized commitment and dispatch, and an independent transmission operator might increase competition among participants.

5.6 Utility Administrative/Operational Cost Analysis

The cost analysis was limited to the GridFlorida RTO. However, there are other potential direct administrative/operational costs and benefits (cost savings) at utilities associated with the GridFlorida RTO not included in the cost analysis. On the cost side, utilities could incur training, coordination and other costs to interact with GridFlorida. On the cost savings side, some tasks now handled by the companies or the control zones could be transferred to GridFlorida.

5.7 Transition Risks

ICF's quantitative analysis assumes that the likelihood of operational or financial transition costs is the same across scenarios. Since the RTO will maintain utility control zones, this assumption seems reasonable in the case of operational risks. ICF did not address FTRs or any one participation initial allocation method or FTR market risks to individual market participants. However, there could be unanticipated problems as a GridFlorida RTO begins operations, particularly as utilities learn how to participate in FTR and short-term markets organized that the RTO administer. For example, as participants work with complicated issues such as FTR nominations and bids, they may make decisions that are not optimal, thus spending more than necessary. Thus, there may be risks with changing the structure of the industry and the requirements placed on its participants.

5.8 Scope and Organizational Issues

Several organizational issues can arise from the creation of large organizations like a GridFlorida RTO. On the positive side, the GridFlorida RTO could be a platform for other services – ones not yet contemplated - which may be beneficial. On the other hand, there may be a tendency to scope "creep" – new activities which cost more than they are worth. Another issue is whether not-for-profit entities will have cost controls that are as effective as private companies. Regulatory issues also arise due to question related to the appropriate division of jurisdiction between the FPSC, GridFlorida and FERC. Working through these jurisdictional issues would require time as well as legal and regulatory resources.

5.9 Return on Equity (ROE) and Incentives

There may be different regulatory treatment of utilities and RTOs. This might be a function of state versus federal regulation, which is beyond the scope of this study. FERC might approve higher rates of return for transmission than would the state, which would encourage transmission investments, but also raise rates. FERC has approved higher returns on equity for transmission assets in certain RTOs[45]. Higher ROEs for transmission assets within GridFlorida have not been included in ICF's analysis.

5.10 Management of Inter-Regional Tariffs

The quantitative analysis did not examine the effect of an RTO on inter-regional tariffs. For example, one could argue that if GridFlorida existed, it is more likely that pancaking of tariffs, transmission capacity ("seams), and other problems in relation to neighboring areas could be easier to address. On the other hand, Florida developments might be highly unrelated to developments in the Southern Company and other Southeastern regions.

5.11 Efficiency and Standards

The modeling does not address terms and conditions, procedural streamlining, etc. There are numerous areas where GridFlorida might standardize individual utility terms and conditions that could lower costs. For example, there are significant differences between utilities in the calculation of ATC, and in such areas as the treatment of losses and payment for non-performance in transactions between them. At present, there is little transparency with regard to these factors, and the existence of GridFlorida would help harmonize these differences, and could thus increase predictability and lower risks.

[45] This benefit may only apply to wholesale uses of the transmission system.

5.12 Merchant Power Plants

Some regions of the country have large amounts of capacity in merchant power plants which have no contracts for long-term sales. Rather, they sell into the wholesale spot markets. In contrast, in Florida, merchant plants exist, but generally have long-term contracts. There could be greater new merchant supply if the markets were made more open to spot sales. Currently, the law in Florida is that in order to obtain licensing for new steam power plants larger than 75 MW, they must have secured long-term contracts for their power. Because of changes in spot and merchant activity due to the creation of an RTO, legislative changes might occur if these markets were shown to be more efficient, though continuing to require demand to be demonstrated via contract may still be appropriate.

5.13 Summary of Qualitative Factors

The table below summarizes the potential impacts of each qualitative factor under a Day-1 and Day-2 RTO.

Exhibit 5-1
Potential Impact of Qualitative Factors in Day-1 and Day-2 RTOs

Qualitative Factor	Potential Day-1 Impact		Potential Day-2 Impact	
	Costs	Benefits	Costs	Benefits
Investment Efficiency				
Transmission		√		√
Generation		√		√
Bilateral Long-Term Contracting		√		√
Elimination of Contract Path Scheduling		√		√
Transition Risks	√		√	
Market Transparency		√		√
Scope, Organizational and Regulatory Issues	√		√	
Other factors				
ROE		-		-
Inter-Regional Tariffs		√		√
Efficiency and Standards		√		√
Merchant Power Plants		√		√

CHAPTER SIX
JURISDICTIONAL AND NON-JURISDICTIONAL GRIDFLORIDA QUANTITATIVE RTO COSTS AND BENEFITS

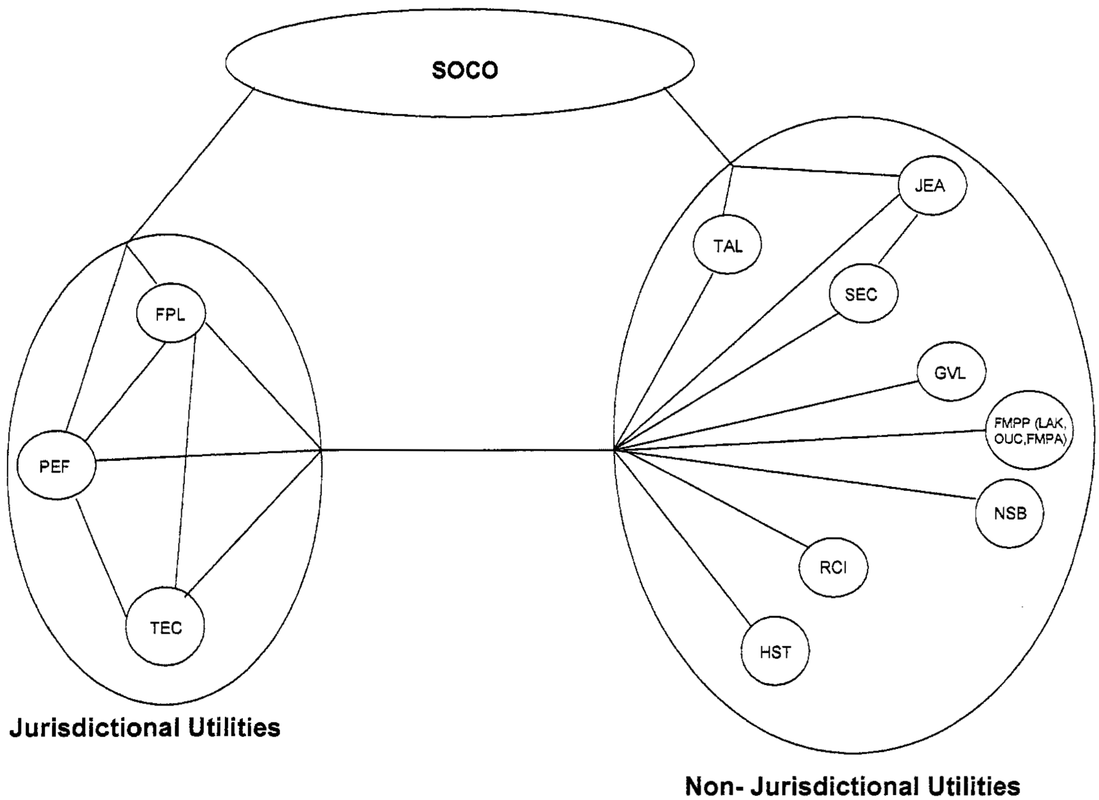
The quantitative RTO costs and benefits from the Day-1 and the Delayed Day-2 cases were disaggregated between consumers of Peninsular Florida jurisdictional and non-jurisdictional utilities. We have referred to the consumers of these utilities as jurisdictional and non-jurisdictional consumers because as ratepayers the costs or benefits associated with the formation of the RTO ultimately accrue to them through their utilities. The jurisdictional consumers are the ratepayers of FPL, PEF and TECO and all other Peninsular Florida consumers are classified as non-jurisdictional consumers. The approach used to disaggregate these costs and benefits is discussed in this chapter. Additionally, we assess transmission owner cost shifts that arise from blending all transmission facilities under the proposed GridFlorida tariff filed by the applicants with the FPSC.

6.1 Allocation of Quantitative RTO Benefits

The approach used to disaggregate the quantitative RTO benefits amongst the two consumer groups has been simplified in this exercise. A more detailed approach would have required additional effort that was not in the scope of the work. Thus, the results of the disaggregated RTO costs and benefits between jurisdictional and non-jurisdictional consumers should be interpreted as an estimate of the allocation rather than a definitive representation of the allocation.

One can think of these two groups as comprising two super control areas in Peninsular Florida with a direct tie line between themselves and, each with a tie line connection with Southern Company. See Exhibit 6-1.

Exhibit 6-1
Re-Configured GridFlorida Market Used For Disaggregating Benefits between Jurisdictional and Non-jurisdictional Consumers



PEF: Progress Energy Florida, FPL: Florida Power & Light Company, TEC: Tampa Electric Company, RCI: Reedy Creek Improvement District, SOCO: Southern Company, JEA: Jacksonville Electric, TAL: City of Tallahassee Electric Department, SEC: Seminole Electric Cooperative, LAK: Lakeland Electric, OUC: Orlando Utilities Company, FMPA: Florida Municipal Power Authority, NSB: New Smyrna Beach, GVL: Gainesville Regional Utilities, HST: City of Homestead

External power imports to the jurisdictional consumers was assumed to flow across the FPL and PEF ties with Southern Company and that to the non-jurisdictional consumers was assumed to flow across the JEA and TALL ties. The direct tie between these two hypothetical super control areas was assumed to be the sum of the existing tie-line capability between jurisdictional and non-jurisdictional control areas.

The jurisdictional and non-jurisdictional consumer groups are assumed to serve their load through a combination of local generation, external imports across the Peninsular Florida/Southern company ties and direct bilateral trades between the two entities. Each consumer group accrues RTO benefits or costs through the changes they adopt to economically serve their load as a result of the change in market structure i.e., from the Base Case to Day-1 only operation or Day-2 operation. The three possible ways each consumer group economically responds to a change in market structure is to:

- change their local power generation;
- change their external power imports;
- change their volume of bilateral power sales/purchases

We illustrate how these quantitative RTO benefits are disaggregated between the two consumer groups using the Delayed Day-2 RTO benefits realized in Year 4 (2007). Exhibit 6-2 shows the annual jurisdictional consumer load is 189,209 GWh and the annual non-jurisdictional consumer load is 55,359 GWh.[46] The jurisdictional consumers increase their local generation from 179,723 GWh in the Base Case at a production cost of approximately $4.71 billion to 181,750 GWh at a production cost $4.77 billion in Day-

[46] See Exhibit 6.2, Line 7

2.[47] Thus, the jurisdictional consumers increase the production costs of their local generation by approximately $56 million. In contrast, the non-jurisdictional consumers generate less power in Day-2 than in the Base Case hence they realize a net saving of approximately $136 million ($1,290,137 - $1,153,332) in production costs.[48] Thus, the combined savings to both parties from internal production costs is approximately $80 million ($136 million - $56 million).[49]

Exhibit 6-2
Disaggregated Day-2 Quantitative RTO Benefits Between Jurisdictional and Non-jurisdictional Consumers – Year 4 (000 2004$)

Line #	Year 4 (2007)	Column A	Column B	Column C	Column D
		Jurisdictional		**Non-Jurisdictional**	
		Base Case	**Day-2 Case**	**Base Case**	**Day-2 Case**
1	***YEAR 4 PENINSULAR FLORIDA BENEFITS BY CATEGORY***				
2	Total Peninsular Florida Benefits (000 $)	106,000			
3	Component of Benefits from Internal Generation (000$)	80,424			
4	Component of Benefits from Southern Imports (000$)	25,576			
5					
6	***GENERATION AND IMPORTS DATA***				
7	Total Load plus Estimated Losses [50] (GWh)	189,209		55,359	
8	Additional Losses (GWh)	1,976	1,950	427	418
9	Total Internal Generation [51] (GWh)	179,723	181,750	49,473	47,276
10	Southern Imports (GWh)	9,945	10,044	7,830	7,866
11	Total Internal Generation plus Southern Imports (GWh)	189,668	191,794	57,303	55,142
12	Bilateral Import (GWh)	2,672	2,011	1,155	2,647
13	Net Bilateral Import (GWh)	1,517			636
14					
15	***BILATERAL TRANSACTION DETAIL***				
16	Realized Annual Average Bilateral Import Cost ($/MWh)	34.81	32.20	36.24	36.96
17	Total Annual Bilateral Import Cost Without Avoided Costs (000$)	93,021	64,759	41,877	97,829

[47] See Exhibit 6.2, Lines 9 and 29; Col. A and Col. B
[48] See Exhibit 6.2, Line 3
[49] See Exhibit 6.2, Line 3
[50] Takes Seminole's Partial Load requirements and FMPA's load out of FP&L and PEF service territories
[51] Takes into account all the units which are owned by the two parties i.e., jurisdiction and non jurisdiction consumers but excludes firm resources in Southern Co.

18	***Avoided Cost***				
19	Realized Annual Average Alternative Supply Cost ($/MWh)	36.49	34.45	39.05	40.56
20	Annual Average Avoided Cost ($/MWh)	1.68	2.25	2.81	3.60
21	Total Annual Alternative Supply Cost (000$)	97,515	69,284	45,125	107,351
22	Total Annual Saving from Bilateral Imports (000$)	4,494	4,526	3,249	9,523
23	Avoided Import Cost to Net Bilateral Importer (000$)	1,245			4,997
24	50% of Avoided Import Cost Allotted to Buyer (Cost) (000$)	623			2,499
25	50% of Avoided Import Cost Allotted Seller (Gain) (000$)		-2,499	-623	
26	Total Annual Import Cost With Avoided Costs (000$)	93,644	62,260	41,254	100,327
27					
28	***INTERNAL PRODUCTION COST***				
29	Production Cost - GridFlorida (000 $)	4,709,936	4,766,317	1,290,137	1,153,332
30					
31	***EXTERNAL IMPORTS***				
32	Differential in Southern Imports (GWh) - Day 2 minus Base Case	99		36	
33					
34	***SUMMARY***				
35	GridFlorida Production Cost Savings (000 $)	-56,381		136,805	
36	Incremental Saving from External Imports	18,755		6,820	
37	Intra GridFlorida Bilateral Interchange Settlement (000$)	90,457		-90,457	
38	**Total Disaggregated Benefits (000 $)**	52,832		53,168	

However the total Day-2 RTO benefits to all Peninsular Florida consumers in Year 4 is approximately $106 million.[52] Therefore the remaining $26 million of the benefits is associated with external imports from outside the Peninsular Florida region.[53] The residual benefits associated with external imports are distributed between the jurisdictional and non-jurisdictional consumers based on incremental import share and this is discussed later.

Both jurisdictional and non-jurisdictional consumers import power from each other during the year in both the Base Case and the Day-2 Case. In the Base Case, the

[52] See Exhibit 6.2, Line 2
[53] See Exhibit 6.2, Line 4

jurisdictional consumers import a total of 2,672 GWh from the non-jurisdictional consumers in some of the hours of the year and the non-jurisdictional consumers import a total of 1,155 GWh from the jurisdictional consumers in the other hours of the year. Similarly, in the Day-2 Case, the jurisdictional consumers bilaterally import 2,011 GWh and the non-jurisdictional consumers import 2,647 GWh.[54]

In each hour, each exporting party is assumed to serve its load with its least expensive generation first before exporting its relatively more expensive generation. Thus, we determine the average cost of the residual generation exported by the exporting party in each hour and sum that across all hours to determine the total cost of generation exported by each party in each year. In the Base Case, the total cost of bilateral exports of the jurisdictional consumers to the non-jurisdictional consumers was $41.9 million and that of the non-jurisdictional consumers to the jurisdictional consumers was $93 million. Similarly, in Day-2 the total cost of bilateral exports from jurisdictional consumers was $97.8 million and that of the non-jurisdictional consumers was $64.8 million. The implied annual average costs of these exports/imports were determined by dividing the cost by the total generation exported/imported.[55]

It is assumed that the benefits of these bilateral transactions are shared by both transacting entities – the buyer and the seller. Settling these transactions at the cost of the selling entity provides all the benefits of the transaction to the buying entity. Therefore, we estimated the least cost available alternatives to the buying entity should the buying entity forgo the bilateral transaction and we assumed that with perfect market information, both entities will settle the bilateral transaction at a cost that equally shares

[54] See Exhibit 6.2, Line17
[55] See Exhibit 6.2, Line 2.

the margin between the sellers production cost and the buyers alternative power supply cost. In the Base Case, the margin between the jurisdictional consumer imports and their avoided costs is $4.5 million (another $4.5 million in the Day-2 Case) and that for the non-jurisdictional consumer imports and their avoided costs is $3.3 million ($9.5 million in the Day-2 Case).[56] This margin is shared equally and captured as an incremental cost to the buyer but a saving for the seller. Thus, in the Base Case, the jurisdictional consumers import more power than the non-jurisdictional consumers so the net increase in their bilateral import cost is $0.6 million ($4.5 million/2 - $3.2 million/2).[57] This $0.6 million is transferred to the non-jurisdictional consumers as a saving. Similarly, in the Day-2 case, the non-jurisdictional consumers import more power than the jurisdictional consumers so the net increase in their bilateral import costs is $2.5 million ($9.5 million/2 - $4.5 million/2) which is also transferred to the jurisdictional consumers as a saving.[58] Thus, the full cost of the bilateral transaction to each entity is the true production cost plus the additional margin in the case of the buying entity and minus the margin in the case of the selling entity. In the Base Case, the total jurisdictional consumer bilateral import cost is $93.6 million ($93 million + $0.6 million) and the total non-jurisdictional consumer bilateral import cost is $41.3 million ($41.9 million - $0.6 million). Similarly in the Day-2 Case the total jurisdictional consumer bilateral import cost is $62.3 million ($64.8 million - $2.5 million) and the total non-jurisdictional consumer bilateral import cost is $100.3 million ($97.8 million + $2.5 million).[59]

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[56] See Exhibit 6.2, Line 22
[57] See Exhibit 6.2, Line 24, Col. A
[58] See Exhibit 6.2, Line 24, Col. D and Line 25, Col. B
[59] See Exhibit 6.2, Line 26 = Line 17 + Line 24+ Line 25

The bilateral import in the Base Case reflects a net cost of $52.3 million ($93.6 - $41.3) to jurisdictional consumers which would reflect a gain to the non-jurisdictional consumers. Similarly the bilateral import in the Day-2 case reflects a net gain of $38.1 million ($100.3 million - $62.3 million) to the jurisdictional consumers which would be a net cost to non-jurisdictional consumers. The net change in bilateral transaction cost to jurisdictional consumers will be the Day-2 cost (-$38.1 million) minus the Base Case cost ($52.3 million). Thus the cost to jurisdictional consumers would be -$90.5 million (-$38.1 million – $52.3 million). This negative cost of -$90.5 million is a gain of $90.5 million to jurisdictional consumers and is also captured as the cost in increased bilateral transaction cost to the non-jurisdictional consumers.[60]

Both consumer groups are net external power importers. The RTO benefits associated with imports into Peninsular Florida is approximately $26 million which is shared between the two consumer groups based on incremental import share.[61] The jurisdictional consumers increased their external imports by 99 MW while the non-jurisdictional consumers increased their external imports by 36 MW.[62] Based on incremental import share, the jurisdictional consumers earned approximately $19 million and the non-jurisdictional consumers earned approximately $7 million.

Therefore the overall RTO benefit to the jurisdictional consumers in Year 4 is the sum of their saving in power imports from the non-jurisdictional consumers ($90.5 million) plus their share of the benefits associated with external power imports ($19 million) minus the increase in their local generation production costs ($56 million). Therefore the net

[60] See Exhibit 6.2, Line 37
[61] See Exhibit 6.2, Line 4
[62] See Exhibit 6.2, Line 32

RTO benefit to the jurisdictional consumers is approximately $52.8 million.[63] This implies that as a result of the change in market structure, the jurisdictional consumers earned $52.8 million in benefits in Year 4 by saving $90.5 million in their bilateral transaction costs (from switching from a net bilateral power importer to a net bilateral power exporter to the non-jurisdictional consumers), and saved $18.8 million from additional external imports but increased generation from their own resources in Day-2 at an incremental production cost of $56.4 million.

Similarly, the quantitative RTO benefit to the non-jurisdictional consumers in Year 4 is the saving in their local generation production costs ($136.8 million) plus their share of benefits associated with external imports ($7 million) minus their cost in reduced power exports to the jurisdictional consumers ($90 million). Therefore the net RTO benefit to the non-jurisdictional consumers in Year 4 is $53.2 million.[64] Thus, as a result of the change in market structure, the non-jurisdictional consumers realized $53.2 million in RTO benefits in Year 4 by saving $136 million in production costs by reducing their local generation and they also saved $7 million by increasing their external imports but lost $90.5 million by becoming net power importers from the jurisdictional consumers in Day-2.

The same procedure was applied to disaggregate the Day-1 RTO benefits between jurisdictional consumers and non-jurisdictional consumers. Exhibit 6-3 shows the disaggregated Day-1 RTO benefits for Year 4. Under Day-1 RTO operation the jurisdictional consumers receive $4.4 million in RTO benefits and the non-jurisdictional consumers receive $3.6 million in benefits.

[63] See Exhibit 6.2, Line 38
[64] See Exhibit 6.2, Line 38

Exhibit 6-3
Disaggregated Day-1 RTO Benefits Between Jurisdictional and Non-jurisdictional Consumers – Year 4 (000 2004$)

Line #	Year 4 (2007)	Column A	Column B	Column C	Column D
		Jurisdictional		Non-Jurisdictional	
		Base Case	Day-1 Case	Base Case	Day-1 Case
1	***YEAR 4 PENINSULAR FLORIDA BENEFITS BY CATEGORY***				
2	Total Peninsular Florida Benefits (000 $)	4,403			
3	Component of Benefits from Internal Generation (000$)	3,615			
4	Component of Benefits from Southern Imports (000$)	8,018			
5					
6	***GENERATION AND IMPORTS DATA***				
7	Total Load plus Estimated Losses [65] (GWh)	189,209	189,209	55,359	55,359
8	Additional Losses (GWh)	1,976	2,033	427	456
9	Total Internal Generation [66] (GWh)	179,723	178,701	49,473	50,569
10	Southern Imports (GWh)	9,945	9,961	7,830	7,826
11	Total Internal Generation plus Southern Imports (GWh)	189,668	188,662	57,303	58,395
12	Bilateral Import (GWh)	2,672	3,423	1,155	843
13	Net Bilateral Import (GWh)	1,517	2,580		
14					
15	***BILATERAL TRANSACTION DETAIL***				
16	Realized Annual Average Bilateral Import Cost ($/MWh)	34.81	34.73	36.24	36.33
17	Total Annual Bilateral Import Cost Without Avoided Costs (000$)	93,021	118,881	41,877	30,646
18	***Avoided Cost***				
19	Realized Annual Average Alternative Supply Cost ($/MWh)	36.49	36.42	39.05	39.34
20	Annual Average Avoided Cost ($/MWh)	1.68	1.68	2.81	3.00
21	Total Annual Alternative Supply Cost (000$)	97,515	124,644	45,125	33,178
22	Total Annual Saving from Bilateral Imports (000$)	4,494	5,763	3,249	2,532
23	Avoided Import Cost to Net Bilateral Importer (000$)	1,245	3,231		
24	50% of Avoided Import Cost Allotted to Buyer (Cost) (000$)	623	1,616		
25	50% of Avoided Import Cost Allotted Seller (Gain) (000$)			-623	-1,616
26	Total Annual Import Cost With Avoided Costs (000$)	93,644	120,497	41,254	29,031
27					
28	***INTERNAL PRODUCTION COST***				
29	Production Cost - GridFlorida (000 $)	4,709,936	4,671,299	1,290,137	1,324,372

[65] Takes Seminole's Partial Load requirements and FMPA's load out of FP&L and PEF service territories

[66] Takes into account all the units which are owned by the two parties i.e., jurisdiction and non jurisdiction consumers but excludes firm resources in Southern Co.

30			
31	***EXTERNAL IMPORTS***		
32	Differential in Southern Imports (GWh) - Day 2 minus Base Case	16	-4
33			
34	***SUMMARY***		
35	GridFlorida Production Cost Savings (000 $)	38,638	-34,235
36	Incremental Saving from External Imports	4,820	-1,205
37	Intra GridFlorida Bilateral Interchange Settlement (000$)	-39,076	39,076
38	**Total Disaggregated Benefits (000 $)**	4,382	3,636

Overall the jurisdictional consumers earn 42% of the benefits and the non-jurisdictional consumers earn 58% of the Delayed Day-2 RTO benefits on an NPV basis. Exhibit 6-4 shows the disaggregated benefits for the two consumer groups for the Day-1 RTO and the Delayed Day-2 RTO operation for each year of the 13 year forecast period.

Exhibit 6-4
Jurisdictional and Non-jurisdictional Day-1 and Delayed Day-2 RTO Benefits.
(Million 2004$)

Year	Day-1 Benefits		Delayed Day-2 Benefits	
	Jurisdictional Consumers	Non-jurisdictional Consumers	Jurisdictional Consumers	Non-jurisdictional Consumers
2004	16	1	16	1
2005	1	4	1	4
2006	2	3	2	3
2007	4	4	53	53
2008	1	4	49	69
2009	0	7	33	66
2010	-5	9	36	59
2011*	-5	8	40	68
2012	-5	8	44	77
2013*	-4	8	53	78
2014	-3	9	62	78
2015*	-10	17	64	76
2016	-17	25	65	74
NPV (Years 1-13)	-11	82	411	557

Discounted using a 3.15 percent real discount rate; * Interpolated

The non-jurisdictional consumers realize most of the Day-1 RTO benefits. In NPV terms, the non-jurisdictional consumers earn $82 million but the jurisdictional consumers incur a loss of $11 million. Similarly, the non-jurisdictional consumers earn the bulk of the Delayed Day-2 RTO benefits. In NPV terms, the jurisdictional consumers earn $411 million (42%) of the Delayed Day-2 RTO benefits while the non-jurisdictional consumers earn $557 million (58%). Exhibit 6-5 shows the actual imports in each case and Exhibit 6-6 shows the incremental jurisdictional consumer imports.

Exhibit 6-5
Jurisdictional Utility Power Imports and Exports from Non-Jurisdictional Consumers in the Base Case, Day-1 RTO Case and Delayed Day-2 RTO Case

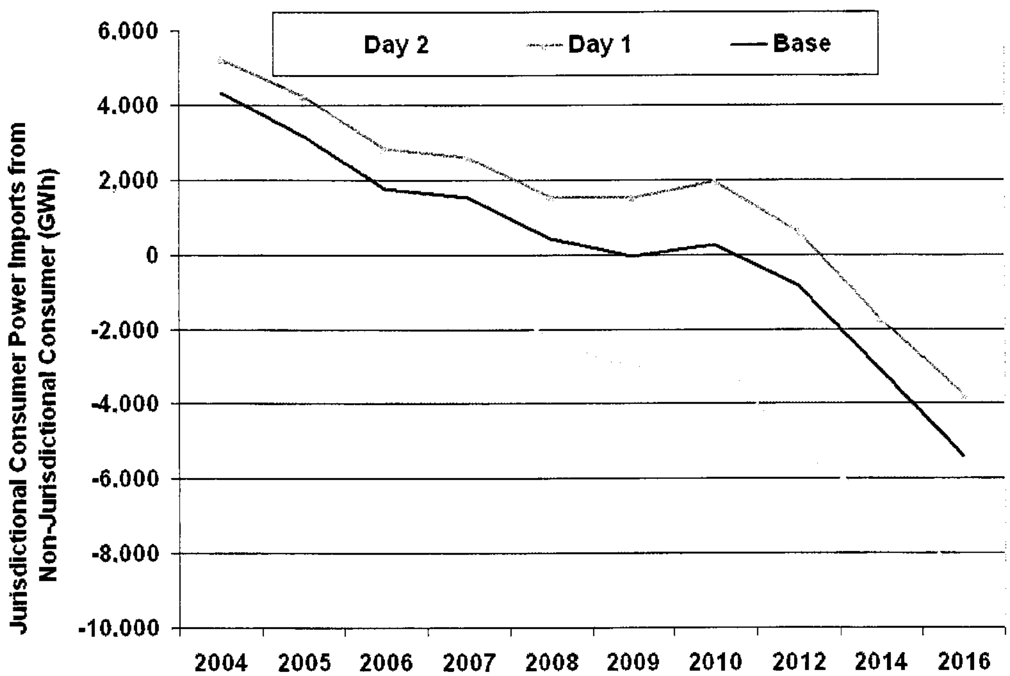
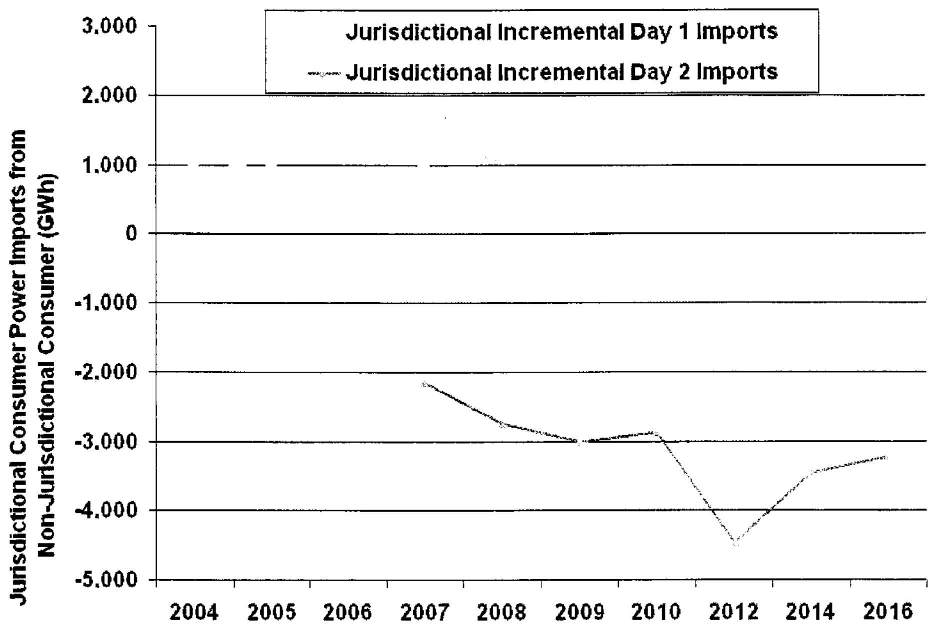


Exhibit 6-6
Incremental Jurisdictional Consumer Power Imports from Non-Jurisdictional Consumers in Day-1 and Delayed Day-2 RTO Cases



Additional disaggregated benefits results for each year is provided in Appendix E for both the Delayed Day-2 RTO Case and the Day-1 RTO Case.

6.2 Allocation of RTO Costs

The RTO costs were allocated to Jurisdictional and non-jurisdictional consumers based on their respective load ratio share. Of the total GridFlorida load, the share of the jurisdictional consumer loads is approximately 77%[67] and the non-jurisdictional consumer load share is 23%[68]. Using these percentages, the Day-1 and Delayed Day-2 RTO costs were allocated to the two groups. Exhibit 6-7 shows the disaggregated costs

[67] This is derived by dividing the 2004 jurisdictional consumers energy requirements by the GridFlorida (jurisdictional and non-jurisdictional) total energy requirements for 2004 i.e. [77%= 175,012GWh/ (175,012+51,255) GWh)]. The energy requirements were provided by GridFlorida applicants and stakeholders.

[68] This is derived by dividing the 2004 non-jurisdictional consumers energy requirements by the GridFlorida (jurisdictional and non-jurisdictional) total energy requirements for 2004 i.e. [23%= 51,255GWh/ (175,012+51,255) GWh)]. The energy requirements were provided by GridFlorida applicants and stakeholders.

for the two consumer groups for the Day-1 only RTO and the Delayed Day-2 RTO for each year of the 13 year forecast period based on their load ratio share in each year.

Exhibit 6-7
Jurisdictional and Non-jurisdictional Day-1 and Delayed Day-2 RTO Cash Expenses (Million 2004$)

Year	Day-1 RTO Costs		Delayed Day-2 RTO Costs	
	Jurisdictional	Non-Jurisdictional	Jurisdictional	Non-Jurisdictional
2004	68	20	68	20
2005	68	20	68	20
2006	69	20	69	20
2007	69	20	119	35
2008	70	20	121	35
2009	44	13	97	28
2010	44	13	97	28
2011	44	13	98	29
2012	45	13	84	25
2013	45	13	85	25
2014	45	13	85	25
215	46	14	86	25
2016	46	14	86	26
NPV (Years 1-13)	$599	$176	$968	$284

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

Exhibit 6-8 shows the net benefits in (2004$ NPV) to both jurisdictional and non-jurisdictional consumers.

Exhibit 6-8
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Net Benefits	-610	-93	-704	-558	274	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

Thus, under Day-1 RTO operation, both jurisdictional and non-jurisdictional consumers incur losses. The jurisdictional consumers incur almost 87% ($610 million) of the GridFlorida-wide consumer loss and the non-jurisdictional consumers incur 13% ($93 million) of the loss. Under Delayed Day-2 RTO operation, the jurisdictional consumers incur a loss but the non-jurisdictional consumers earn a benefit. The loss to jurisdictional consumers ($558 million) is almost twice the GridFlorida-wide loss of 284 million. The gain to non-jurisdictional consumers is $274 million.

6.3 Transmission Owner Cost Shifts

Currently, the annual revenue requirements of transmission owners in GridFlorida are recovered under wholesale transmission rates and bundled retail rates. The proposed GridFlorida RTO tariff filed by the GridFlorida Applicants with the FPSC is designed to ensure that the GridFlorida RTO will be able to fully reimburse the annual revenue requirements of the GridFlorida transmission owners. In turn, Transmission Owners will be required to purchase transmission from the GridFlorida RTO in order to meet native load obligations. If the expense the transmission owner incurs to purchase transmission service on behalf of native load customers is greater than the transmission owner's revenue requirements in bundled rates, then there is a cost increase, or shift. Except for the loss of "pancaked" transaction revenue in years six through ten, the sum of the GridFlorida Transmission Owner's revenue requirements are unchanged. Therefore, cost shifts arise from the change in the allocation of the revenue requirements among the various transmission users.

In order to mitigate these cost shifts, the RTO tariff provides a gradual phase-out of individual system pancaked rates to a single GridFlorida-wide system rate. Under a single GridFlorida transmission rate, the revenue requirements of all transmission owners will be recovered from all Load Serving Entities (LSEs) serving load in Peninsular Florida based on their load ratio share. Although the total transmission revenues to be collected from LSEs are designed to be adequate to meet the total revenue requirements of all Peninsular Florida transmission owners, cost shifts occur between the transmission owners as the revenue requirements of all transmission facilities are blended into a pool under a single system rate. Cost shifts occur when utilities invest at a lower rate on a per kW basis than others, when the embedded costs of higher cost utilities are blended with lower cost utilities, and when costs of Transmission Dependent Utilities facilities are included in transmission rates.

Under the proposed GridFlorida tariff filed by the GridFlorida Applicants with the FPSC in March 2004, the Applicants proposed specific mechanisms to phase-in cost shifts and each one of them is discussed below:

> <u>Phasing in to System-wide or "Postage Stamp" rates:</u> The tariff provides for a phase-in to a single system-wide rate in the first nine years of operations. Initially in years one through five, existing transmission facilities (those transmission facilities in service as of 12/31 of the year before the GridFlorida RTO begins commercial operations) are recovered through zonal rates and all new facilities are recovered through the system rate. Zones are set based on the current transmission providers' transmission service area.

During years one through nine, all transactions that sink in GridFlorida[69] bear a zonal charge and a system charge. The applicable transmission owner's zonal rate is applied to all transactions that sink in its zone. The system rate is applied to all transactions.

During years six through ten, the revenue requirements of existing facilities are moved out of zonal rates and into the system rate at 20% per year such that all revenue requirements are recovered in the system rate beginning in year 10.

Exhibit 6-9
GridFlorida Revenue Requirements Under "Pancaked" Transmission Rates and Under the Proposed GridFlorida Tariff
(Thousands 2004$)

Year	Existing Facilities		New Facilities	Total	
	Base Case	Change Case		Base Case	Change Case
Year 1	$596,730	$596,730	$36,705	$633,435	$633,435
Year 2	$587,358	$587,358	$81,334	$668,693	$668,693
Year 3	$577,259	$577,259	$129,211	$706,470	$706,470
Year 4	$570,930	$570,930	$171,414	$742,344	$742,344
Year 5	$561,698	$561,698	$214,035	$775,733	$775,733
Year 6	$554,072	$555,221	$257,254	$811,326	$812,475
Year 7	$545,552	$546,725	$298,818	$844,370	$845,542
Year 8	$534,445	$536,204	$346,425	$880,870	$882,628
Year 9	$524,805	$527,149	$389,475	$914,280	$916,625
Year 10	$514,847	$517,466	$430,939	$945,786	$948,405
Year 11	$505,945	$507,834	$471,173	$977,118	$979,007
Year 12	$495,700	$497,589	$517,560	$1,013,260	$1,015,149
Year 13	$485,660	$487,549	$557,243	$1,042,902	$1,044,791

Exhibit 6-9 provides the annual GridFlorida-wide revenue requirements for both existing and new facilities and the combined annual revenue requirements under the existing tariff and the proposed GridFlorida tariff. The difference between the

[69] Transactions that do not sink within the GridFlorida footprint will bear a through-and-out charge, rather than a zonal charge. The Through-and-out rate is based on the load-weighted average of the transmission owners' zonal rates.

total Base Case and Change Case revenues represents the loss of pancaked transmission revenues after Year 5.

Phasing in the costs of Transmission Dependent Utilities (TDUs): Seminole and FMPA are TDUs that have loads and resources embedded in FPL and PEF's service areas. Currently, transmission providers are not required to pay for facilities of TDUs unless those facilities are integrated into the transmission provider's system. TDUs have two options to have the costs of their existing facilities included in GridFlorida rates. One option is a phase-in of all TDU facilities at 20% per year such that 100% of the TDU facilities are included in GridFlorida Zonal rates beginning in year 5. The second option provides for the immediate inclusion in zonal rates for those facilities, and only those facilities, that are determined to be integrated by FERC. The option must be selected at the time the TDU joins GridFlorida and cannot be changed. The implication of each of these choices is described below. In either case, a TDU adder is included in the zonal charges for transactions that sink in FPL or PEF's zone to recover the costs of TDU facilities that are to be included in GridFlorida rates as determined by the option selected. PEF and FPL bear additional costs for TDU facilities and TDUs receive the benefit of reduced costs.

In years six through ten, the TDU facilities that have been included in zonal rates, either through phase-in or through FERC determination of integration, are moved out of the zonal rate and into the system rate at 20% per year such that in year ten, TDU facility costs, along with all other transmission facility costs, are born by all GridFlorida customers.

Exhibit 6-10 provides the annual TDU revenue requirements for both existing and new facilities. Existing facilities are split between the zones that they are to be phased into: east (FPL) and west (Progress).

Exhibit 6-10 TDU Revenue Requirements
(Thousands 2004$)

Year	Existing Facilities				New Facilities	
	FMPA East	Seminole East	FMPA West	Seminole West	FMPA	Seminole
Year 1	$23,520	14,016	$6,860	7,938	1,758	1,629
Year 2	$23,050	13,640	$6,723	7,779	7,928	4,163
Year 3	$22,589	11,471	$6,588	7,624	9,140	6,697
Year 4	$22,137	11,109	$6,457	7,471	10,416	8,869
Year 5	$21,694	10,755	$6,327	7,322	17,382	10,824
Year 6	$21,260	10,408	$6,201	7,175	17,962	12,236
Year 7	$20,835	10,068	$6,077	7,032	20,315	13,231
Year 8	$20,418	9,735	$5,955	6,891	27,559	13,756
Year 9	$20,010	9,408	$5,836	6,753	28,606	14,480
Year 10	$19,610	9,088	$5,720	6,618	29,058	15,114
Year 11	$19,218	8,774	$5,605	6,486	29,058	15,494
Year 12	$18,833	8,467	$5,493	6,356	35,936	16,055
Year 13	$18,457	8,165	$5,383	6,229	35,936	16,616

Phasing out Long-term Pancake Rate Charges

Pancaking of transmission charges occurs when a transmission customer bears more than one transmission charge within Peninsular Florida for a single transaction. The GridFlorida tariff provides that long-term firm point-to-point transmission charges be "de-pancaked" over years six through ten[70]. All charges except the charge for the zone where the transaction sinks are reduced by 20% per year starting in year six and are eliminated in year ten. Pancaked charges for transactions that involve more than one transmission customer will not be "de-

[70] Short-term point-to-point transmission charges are de-pancaked on day one of GridFlorida operations.

pancaked" unless the load where the transaction sinks receives the benefit of the reduced transmission charges.

Exhibit 6-11 shows the expected "pancaked" transmission revenues under the Base Case and under the proposed GridFlorida Tariff (Change Case). As described above the GridFlorida Tariff filed with the FPSC phases out "pancaked" transmission revenues over a 10-year period.

Exhibit 6-11
Projected "Pancaked" Transmission Revenues under the Existing Tariff (Base Case) and Under the GridFlorida RTO Tariff (Change Case)
(Thousands 2004$)

"Pancaked" Revenues		
Year	**Base Case**	**Change Case**
Year 1	$30,202	$30,202
Year 2	$27,036	$27,036
Year 3	$24,847	$24,847
Year 4	$19,134	$19,134
Year 5	$16,565	$16,565
Year 6	$12,625	$11,476
Year 7	$9,811	$8,639
Year 8	$9,811	$8,053
Year 9	$8,566	$6,222
Year 10	$7,857	$5,238
Year 11	$6,305	$4,416
Year 12	$6,305	$4,416
Year 13	$6,305	$4,416
NPV (Years 1-13)[71]	**$164,763**	**$153,551**

The pancaked revenues under the GridFlorida tariff extends through Year 10 to Year 13 in Exhibit 6-11 represent those transactions that are not de-pancaked as described above.

[71] Using a real discount rate of 3.15%

The costs shifts described below were estimated in accordance with the pricing structure of the GridFlorida RTO tariff. For purposes of modeling the transmission owner cost shifts, a comparison is made of the amount of revenue requirements the transmission owner's native load must bear before and after implementation of GridFlorida. Pre-GridFlorida, we assume that the Transmission owner's native load revenue requirement responsibility is its zonal load ratio share of the transmission owner's revenue requirement (reduced for pancaked transmission revenue). Currently, a Transmission Owner's native load is not required to bear costs for transmission facilities that the Transmission Owner does not use. They also receive the benefit of pancaked transmission revenues. Post-GridFlorida, under the phase-in plans described above, native load bears revenue requirement responsibility for all transmission facilities in GridFlorida, including TDU facilities, and experiences increased revenue requirements as pancaked revenues are eliminated.

For example, FPL revenue requirement (reduced for pancaked transmission revenues) under current rates is allocated to network customers based on its zonal load ratio share - 90.61% to FPL native load; 6.04% to Seminole load in FPL territory and 3.35% to FMPA load in FPL territory. Similarly the total revenue requirement for PEF under current rates is allocated by zonal load ratio share - 79.4% to PEF native load; 14.36% to Seminole load in PEF's territory and 6.23% to FMPA's load in PEF's territory. Under GridFlorida RTO operation in Years 1 through 9, the revenue requirements of each utility will be recovered based on a combination of zonal and GridFlorida-wide system load ratio share.

Exhibit 6-12 shows the Year 1 load-ratio-share by utility zone used to allocate each utility's base case transmission revenue requirements and the change case existing transmission revenue requirements, and the Year 1 GridFlorida load ratio share that would be used to allocate each utility's transmission revenue requirement for new facilities under the GridFlorida tariff. The zonal load ratio share and the GridFlorida load ratio share vary on a year-by-year basis based on each utility's peak demand growth.

Exhibit 6-12
Year 1 Zonal and GridFlorida-wide Load Ratio Share (LRS)

Year 2004	Zonal LRS	System-wide LRS
FPL	90.61%	45.97%
FMPA – East (FPL)	3.35%	1.70%
SECI - East (FPL)	6.04%	3.06%
FMPA – West (PEF)	6.23%	1.63%
SECI - West (PEF)	14.36%	3.76%
Progress	79.40%	20.77%
OUC	100%	2.71%
TECO	100%	9.93%
Gainesville	100%	1.04%
JEA	100%	6.24%
Lakeland	100%	1.40%
Tallahassee	100%	1.35%
RCID	100%	0.43%

Exhibit 6-13 shows the revenue requirements for existing and new facilities by utility for Year 1.

Exhibit 6-13
Year 1 Revenue Requirements
(Thousands 2004$)

Year 1 (2004)	Existing Facilities	New Facilities
FPL	$299,392	$ 18,179
FMPA - East (FPL)	$23,520	$ 1,035
SECI - East (FPL)	$14,016	$ 1,303
FMPA - West (PEF)	$6,860	$ 723
SECI - West (PEF)	$7,938	$ 326
Progress	$131,362	$ 9,367
OUC	$15,151	$ 1,040
TECO	$37,664	$ 2,170
Gainesville	$4,530	$ 66
JEA	$29,422	$ 1,562
Lakeland	$16,756	$ 53
Tallahassee	$6,983	$ 48
RCID	$3,136	$ 832

Total Costs Shifts: The total cost shifts are estimated by comparing the transmission companies' native load's load ratio share of transmission costs pre-GridFlorida RTO to the load ratio share of costs post GridFlorida RTO.

Exhibit 6-14 shows the Year 1 cost shifts for each utility's native load pre and post the GridFlorida RTO and the relevant summary for jurisdictional and non-jurisdictional utilities. Overall the jurisdictional consumers incur a cost shift of $11,217,000 and the non-jurisdictional consumers earn that as a benefit.

Exhibit 6-14
Year 1 Transmission Owner Cost Shifts
(Thousands 2004$)

	Native Load Revenue Requirement Allocation		
Utility	**Base Case**	**Change Case**	**Shifts**
FPL	287,746	294,951	7,205
Progress	111,742	114,280	2,538
FMPA-East (FPL)	35,207	29,735	(5,472)
FMPA-West (PEF)	16,355	14,459	(1,896)
FMPA-Total	51,562	44,194	(7,368)
SECI-East (FPL)	34,492	30,865	(3,626)
SECI-West (PEF)	28,479	27,025	(1,454)
SECI – Total	62,971	57,890	(5,080)
OUC	16,191	16,147	(44)
TECO	39,834	41,308	1,474
Gainesville	4,596	4,910	314
JEA	30,984	31,713	729
Lakeland	16,809	17,271	462
Tallahassee	7,032	7,478	446
RCID	3,968	3,292	(676)
TOTAL (Peninsular Florida)	633,435	633,434	(1)
Jurisdictional Consumers	439,322	450,539	11,217
Non-Jurisdictional Consumers	194,113	182,895	(11,218)

Thus in Year 1, the jurisdictional consumers subsidize the non-jurisdictional consumers by $11 million (2004$) in transmission costs. Over the 13-year forecast period and in net present value terms, the jurisdictional consumers subsidize the non-jurisdictional consumers by approximately $525 million in transmission payments. See Exhibit 6-15.

Exhibit 6-15
Annual Jurisdictional and Non-Jurisdictional Cost Shifts
(Thousands 2004$)

Year	Jurisdictional costs	Non-Jurisdictional Benefits
Year 1	$ 11,217	$ 11,217
Year 2	$ 26,108	$ 26,108
Year 3	$ 35,655	$ 35,655
Year 4	$ 46,279	$ 46,279
Year 5	$ 60,223	$ 60,223
Year 6	$ 59,788	$ 58,640
Year 7	$ 59,723	$ 58,551
Year 8	$ 63,178	$ 61,419
Year 9	$ 62,001	$ 59,656
Year 10	$ 59,913	$ 57,294
Year 11	$ 56,901	$ 55,012
Year 12	$ 59,937	$ 58,048
Year 13	$ 57,807	$ 55,918
NPV (Years 1-13) [72]	$ 531,454	$ 520,337

[1] Using a real discount rate of 3.15%

Data and Assumptions

Data to calculate the cost shifting estimates were provided by the participating transmission owners. Other assumptions were developed by the Project Steering Committee. Year 1 existing facilities revenue requirements were assumed to be equal to the transmission revenue requirements at December 31, 2003. Future years' existing facility revenue requirements were reduced by 2% per year to approximate the net effect of retirements, depreciation and increased O&M on revenue requirements. Revenue requirements for new facilities were estimated by applying a fixed carrying charge rate to accumulated gross plant in service. No revenue requirements were provided by FMPA, Homestead, New Smyrna Beach or Reedy Creek. In consultation with FMPA, the revenue requirements that were provided in the 2002 GridFlorida pricing

[72] Using a real discount rate of 3.15%

team study[73] were used. FMPA's carrying charge rate was assumed to be equal to Seminole's. Reedy Creek's revenue requirements provided in the 1999 study were used and Reedy Creek carrying charge rate was assumed to be equal to OUC's rate. Homestead and New Smyrna Beach were not included for cost shift estimation due to lack of data. The Investor Owned Utilities' (IOUs') carrying charge rate was assumed to be the same as was used in the prior studies, 17%. Pancaked revenues were not available for the non-jurisdictional utilities, except JEA.

[73] The GridFlorida stakeholders previously have prepared studies to evaluate the impact of cost shifts. The first study was performed in 2000 utilizing 1999 data which was updated in 2002 for the ISO compliance filing at the FPSC.

CHAPTER SEVEN
CONCLUSIONS

This study examined the costs and benefits to Peninsular Florida consumers of transforming the current decentralized market to a centrally organized market under two modes of operation – a Day-1 only RTO and a Delayed Day-2 RTO. A Day-1 Only RTO configuration reflects 13 years of decentralized company operation, but with a single transmission provider under a single GridFlorida-wide transmission tariff. A Delayed Day-2 RTO configuration comprises three initial years of Day-1 operation, followed by 10 years of Day-2 operation. Under Day-2 operation, unit commitment and dispatch for the entire Peninsular Florida region is centralized under the GridFlorida RTO, and all market participants take transmission service from the RTO under a single tariff. Each of these two RTO modes of operation is compared to a Base Case that reflects the decentralized market as-is, with individual company and control area operation, multiple transmission providers and "pancaked" transmission rates.

The primary costs and benefits of market transformation (such as envisioned under GridFlorida) come from four principal sources: 1) operational efficiency, 2) investment efficiency, 3) efficiencies in market participant operations, and 4) the net cost of forming and maintaining a new RTO. In this study, only selected aspects of operational efficiencies were explicitly quantified. Potential efficiencies from investments and those aspects of operational efficiencies that were not explicitly quantified were treated qualitatively. The change in market participant operational costs in working with the new RTO was not included in the scope of this study.

The quantitative results of this study alone do not provide the net costs and benefits to Peninsular Florida consumers of an RTO except when considered together with the qualitative factors and the change in costs associated with changes in existing utility operational costs as a result of forming the RTO. All the quantitative results in this chapter are in year 2004 net present value (NPV) dollars. Also, the results are determined before accounting for qualitative costs and benefits, and before any benefits or costs associated with the change in each market participant's operation as a direct result of the formation of the RTO.

For this assessment, the costs and benefits to Peninsular Florida has been forecast over a 13-year planning period, which in calendar years may be referred to as 2004 through 2016, but which can be more appropriately thought of as Year 1 through Year 13. The quantitative benefits to Peninsular Florida consumers of Day-1 Only RTO operation is $71 million over this period, but the quantitative start-up and operating costs of a "greenfield" Day-1 RTO with wholly new physical facilities, systems and personnel is $775 million. Thus, the Day-1 RTO configuration reflects a net quantitative loss of $704 million. The quantitative benefits under a Delayed Day-2 RTO case are much higher at $968 million. However, the start-up and operating costs of a "greenfield" Delayed Day-2 RTO with all new facilities is $1.25 billion. Hence the Delayed Day-2 RTO also reflects a net loss of $285 million. Exhibit 7-1 summarizes these findings along with the results of the sensitivity cases described in the following paragraphs.

The quantitative benefits of the Day-1 RTO and Delayed Day-2 RTO indicate that the majority of the benefits to Peninsular Florida consumers come from centralized market operation, especially from centralized unit commitment. The model calibration exercise revealed through the realized hurdle rates that the inefficiencies associated with unit commitment are by far larger than those associated with dispatch. This outcome is not surprising because in Peninsular Florida, more than ten entities separately commit units to meet load for a system with a total peak load of approximately 43 GW[74]. Contrast this with systems such as PJM (116 GW); NYISO (31 GW) and ISO-NE (25 GW) where a single entity performs unit commitment. Secondary benefits arise from centralized dispatch, but the inefficiencies associated with dispatch are not nearly as large as those associated with unit commitment, as there is already a high level of connectivity between control areas in Florida and most transactions occur between adjacent systems. The need for transactions wheeled through multiple systems in Florida is typically limited in both frequency and size. Thus, the benefits of eliminating "pancaked" transmission charges may not be as significant in Peninsular Florida as in other US power markets. Additionally, most transmission service provided in Florida is Network Service, as opposed to Point-to-Point Service, and utilities pay for transmission based on their respective load ratio share of the embedded cost of the transmission system, giving them Network Customer priority. As such, their transactions are not subject to additional wheeling charges. For these reasons, maintaining a decentralized unit commitment and dispatch operation under a Day-1 RTO configuration, similar to the existing market, is expected to yield only moderate benefits.

[74] The three jurisdictional utilities comprise almost 77% of the load and the incremental benefit of centralized unit commitment may not be as large as the incremental benefit of unit commitment for the eight non-jurisdictional utilities that perform centralized unit commitment.

Qualitative Factors. There are also various qualitative factors that should be considered along with the quantitative costs and benefits estimated for the Day-1 and Delayed Day-2 RTO operations. The qualitative factors that are expected to provide benefits in both Day-1 and Day-2 RTO configurations are:

- Investment efficiencies due to the availability of price signals from centralized markets;
- Long term bilateral transactions that may be enabled because of the elimination of pancaked transmission charges and other inefficiencies associated with transmission scheduling in decentralized markets, such as the elimination of transmission scheduling by Contract Path;
- Market transparency enabled by spot markets with posted prices;
- Ease of participation by power marketers and merchant generation;
- Potential for higher rates of return, increased efficiency and high operational standards.

On the qualitative cost side, the introduction of the RTO could introduce transition risks as the market moves from a decentralized operation to a centralized operation, and the RTO's scope in terms of organizational and regulatory requirements could also expand beyond what has been anticipated in this study.

Sensitivity Analyses. Two sensitivities were performed as a part of this study.

- A first sensitivity analysis performed was the case of Jacksonville Electric Authority (JEA) and Tallahassee (TALL) as non-participants in the GridFlorida RTO (referred to as the "JEA and TALL Out Case"). This case assumed the possibility that JEA and TALL could decline to be participants of a GridFlorida RTO due to their close proximity to Georgia and their previous involvement with the now suspended SeTrans RTO. The likelihood of JEA and TALL out of a GridFlorida RTO would result in a smaller GridFlorida RTO in terms of geographic footprint and peak demand.

- The second sensitivity analysis assumed that in comparison to the simulation model used for the analysis, a Day-2 market would still have some inherent inefficiencies associated with demand uncertainty and the fact that transactions would have some minimum sizes as would transaction margins. For example, in the simulation model used for this analysis, demand is known with perfect certainty therefore unit commitment tends to be more precise than would be achievable in actual practice. Similarly, minimum transaction sizes and/or transaction margins are often smaller in the model than in actual practice and that tends to increase trade volumes. Exhibit 7-1 shows results of both the Reference Case and sensitivity analyses. All the sensitivity analyses yielded lower quantitative benefits than in the Reference Case.

Exhibit 7-1
Summary of Quantitative RTO Costs and Benefits (Million 2004$)
NPV (Years 1-13)[75]

Case	RTO Operation	RTO Benefits	RTO Costs[1]	Net Benefit/Costs[2]
Reference Cases	Day-1 Only	71	775	-704
	Delayed Day-2	968	1,253	-285
JEA and TALL Out Case	Delayed Day-2	891	1,253	-362
Market Imperfection Case	Delayed Day-2	810	1,253	-443

[1]Discounted using a 3.15 percent real discount rate
[2]The RTO Costs presented are only costs associated with the new RTO entity. Changes in existing utility operational costs have not been considered in this estimate

The quantitative RTO benefits of a smaller GridFlorida RTO with JEA and TALL as non-participants are $891 million. The JEA and TALL loads together are approximately 7.5% of the total GridFlorida RTO load, and the benefits reflect a reduction of approximately 8% when compared to the Delayed Day-2 RTO quantitative benefits in the Reference case. The costs of the "greenfield" RTO would remain unchanged, therefore the net quantitative loss to Peninsular Florida consumers with JEA and TALL as non-participants of GridFlorida is $362 million.

In the market imperfection sensitivity analysis case, the quantitative Delayed Day-2 RTO benefits were as low as $810 million and with the RTO costs unchanged, the loss to Peninsular Florida consumers would be as high as $443 million.

[75] Discounted using a 3.15 percent real discount rate

7.1 Jurisdictional and Non-Jurisdictional RTO Costs/Benefits and Transmission Owner Cost Shifts

The quantitative RTO costs and benefits in the Reference Case were disaggregated between consumers of the utilities that are jurisdictional and those that are non-jurisdictional to the FPSC. The benefits to each of these two groups were estimated from the change in their local generation and bilateral transactions between the two groups and external imports. The non-jurisdictional utilities receive $82 million, which represents approximately 116% of the Day-1 RTO benefits. The non-jurisdictional utilities incur a loss of 16% of the Day-1 RTO benefits, i.e., $11 million. Although these benefits/losses are not that large compared to the Delayed Day-2 RTO case, the elimination of "pancaked" transmission charges seems to favor the non-jurisdictional utilities. The jurisdictional utilities import a very small amount of power from the non-jurisdictional utilities especially in the early years even after taking the Seminole and FMPA loads out of the FPL and PEF territories.

Exhibit 7-2
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Net Benefits	-610	-93	-704	-558	274	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

Similarly, jurisdictional utilities receive 42%, i.e., $411 million of the Delayed Day-2 RTO benefits and the non-jurisdictional consumers receive 58%, i.e., $557 million. The non-jurisdictional consumers receive the bulk of the benefits under a Delayed Day-2 RTO operation because the Day-2 benefits of centralized unit dispatch for the eight non-jurisdictional entities are larger than the benefits for the three jurisdictional entities.

The quantitative RTO costs were also disaggregated between the two groups based on load ratio share i.e. 77% for the jurisdictional consumers and 23% for the non-jurisdictional consumers. Using these ratios, in the Day-1 RTO case, the jurisdictional consumers would incur a cost of $599 million and the non-jurisdictional consumers would incur a cost of $176 million. In the Delayed Day-2 RTO case, the jurisdictional consumers would incur a cost of $969 million, and the non-jurisdictional consumers would incur a cost of $284 million.

Combined in the Day-1 RTO case, the jurisdictional consumers would incur a loss of $610 million and the non-jurisdiction consumers would incur a loss of $93 million. In the Day-2 RTO case, the jurisdictional consumers would incur a loss of $558 million, but the non-jurisdictional consumers would earn a benefit of $274 million.

When the transmission facilities of all Peninsular Florida utilities are blended in under the proposed GridFlorida tariff filed by the GridFlorida Applicants in March 2003, significant transmission owner cost shifts would arise. Jurisdictional transmission owners incur a cost shift of approximately $525 million from the non-jurisdictional transmission owners i.e., the jurisdictional consumers subsidize the non-jurisdictional consumers by $525 million in transmission payments. Exhibit 7-3 shows the combined effect of transmission owner cost shifts and jurisdictional and non-jurisdictional benefits and costs. While the overall GridFlorida consumer cost/benefit remain unchanged, the inclusion of the transmission owner cost shifts exacerbates the quantitative loss to jurisdictional consumers and improves the benefits to non-jurisdictional consumers.

Exhibit 7-3
Summary of Jurisdictional and Non-jurisdictional Consumer Day-1 and Delayed Day-2 RTO Costs and Benefits (2004 Million$)

NPV (Years 1-13)	Day-1 Only Operation			Delayed Day-2 Operation		
	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit	Jurisdictional	Non-Jurisdictional	Total GridFlorida Consumer Benefit
RTO Benefits	-11	82	71	411	557	968
RTO Costs	599	176	775	969	284	1,253
Transmission Owner Costs[76] (Cost Shifts)	525	-525	-	525	-525	-
Net Benefits	-1,135	431	-704	-1,083	798	-285

Note: Includes principal payments on amortized startup costs. Discounted using a 3.15 percent real discount rate.

7.2 Summary of Conclusions

ICF's analysis shows that the quantitative benefits of a Delayed Day-2 RTO operation are significant, and range from $810 million to $968 million in the scenarios in this study. However, the cost of a "greenfield" Delayed Day-2 RTO with wholly new systems, physical facilities and personnel, designed along FERC's Standard Market Design principles, is also very significant at $1.25 billion. The prospects of a Day-1 RTO are bleak, especially if designed along a "greenfield" RTO with wholly new systems, personnel and physical facilities, because the benefits of a Day-1 RTO operation are not nearly as large as a Delayed Day-2 RTO operation, while the fixed costs are high.

[76] The Transmission Owner costs shifts have been estimated based on the GridFlorida tariff filed with the FPSC by the GridFlorida Applicants. However the quantitative RTO benefits have been estimated using a simplified form of the tariff structure because the tariff as filed did not lend itself to analytic modeling. Thus, the net benefits shown in Exhibit 7-3 should be interpreted as indicative rather than definitive.

The overall outcome of net benefits or costs to Peninsular Florida consumers depends on both quantitative and qualitative aspects of the RTO. If the net benefits from the qualitative factors should be within the range of $285 million and $443 million then the GridFlorida Delayed Day-2 RTO could breakeven under the scenarios examined in this study.

This study also indicates that the non-jurisdictional consumers would receive net positive benefits of $798 million from the implementation of a GridFlorida Delayed Day-2 RTO while jurisdictional consumers would receive a net loss of $1.1 billion. While the overall GridFlorida consumer cost/benefit remains unchanged, the RTO cost allocation and the transmission owner cost shifts exacerbates the quantitative loss to jurisdictional consumers and improves the benefits to non-jurisdictional consumers.

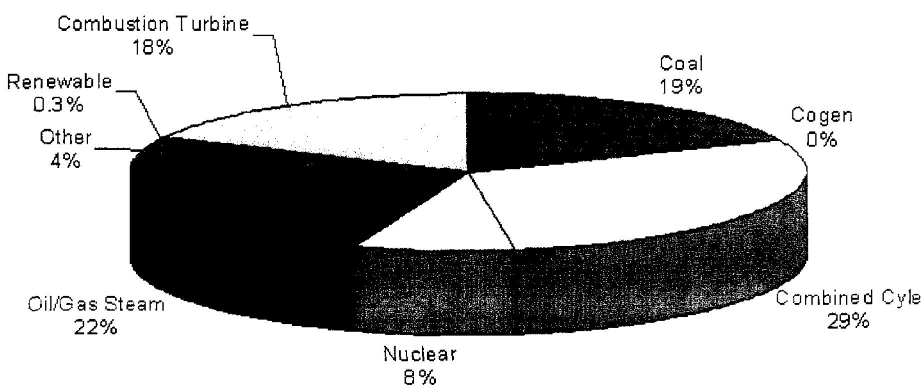
APPENDIX A
ASSUMPTIONS

Exhibit A-1
FRCC 2004 Peak Demand and Net Energy for Load

	2004 Summer Peak Demand and Growth through 2016	2004 Net Energy for Load and Growth through 2016
2004 Forecast	42,999	226,267
2005	2.5%	2.5%
2006	2.5%	2.5%
2007	2.5%	2.5%
2008	2.2%	2.2%
2009	2.3%	2.3%
2010	2.4%	2.4%
2011	2.3%	2.3%
2012	2.3%	2.3%
2013	2.3%	2.3%
2014	2.3%	2.3%
2015	2.3%	2.3%
2016	2.2%	2.2%
Simple Average 2004 - 2016	2.3%	2.3%

Note: **Annual peak demand and expected growth rates were provided directly by the Applicants and Stakeholders**

Exhibit A-2
FRCC Installed Capacity by Type – 2003 (GW)



Total Capacity – 50.6 GW

Note: Data above includes dedicated generation facilities outside physical FRCC boundaries

Exhibit A-3
Key Environmental Assumptions

Parameter	Treatment
SO_2 Regulations	Phase II Acid Rain – no tightening of current legislation assumed
NO_X Regulations	NO_X OTR[77]; SIP[78] Call[79]
CO_2 Regulations	None
Mercury Regulations	None
Allowance Prices (2003$/ton)	SO2
2004	188
2005	201
2006	215
2007	230
2008	245
2009	261
2010	288
2012	311
2014	337
2016	349

Source: ICF

Exhibit A-4
Henry Hub Forecast

Year	Reference Case	
	2003 $/MMBtu	Nominal [80]$/MMBtu
2004	5.73	5.86
2005	5.24	5.48
2006	4.70	5.03
2007	4.17	4.56
2008	4.27	4.77
2009	3.71	4.24
2010	3.60	4.21
2011	3.71	4.43
2012	3.83	4.68
2013	4.07	5.08
2014	3.98	5.08
2015	3.64	4.75
2016	3.80	5.07

Source: ICF

[77] Ozone Transport Region
[78] State Implementation Plan
[79] The SIP Call does not affect the state of Florida
[80] Assumes an inflation rate of 2.25%

Exhibit A-5
Florida Delivered Gas Price Forecast (2003 $/MMBtu)

Year	Henry Hub	Basis Differential	Delivered
2004	5.73	0.39	6.12
2005	5.24	0.39	5.63
2006	4.70	0.39	5.09
2007	4.17	0.39	4.56
2008	4.27	0.39	4.66
2009	3.71	0.39	4.10
2010	3.60	0.39	3.99
2011	3.71	0.39	4.10
2012	3.83	0.39	4.22
2013	4.07	0.39	4.46
2014	3.98	0.39	4.37
2015	3.64	0.39	4.03
2016	3.80	0.39	4.19

Source: ICF

Note: The above table reflects average regional delivered spot natural gas prices including basis differentials and LDC charges. LDCs are assumed average $0.07/MMBtu regionally. Newly constructed plants are not expected to pay any LDCs, however will incur by-pass or connection charges.
Source: ICF

Exhibit A-6
Florida Delivered Oil Price Forecast (2003 $/MMBtu)

Year	Distillate Oil	1% Sulfur Residual Oil
2004	6.71	5.23
2005	5.67	4.33
2006	5.62	4.31
2007	5.52	4.25
2008	5.64	4.40
2009	5.55	4.34
2010	5.40	4.22
2011	5.49	4.28
2012	5.58	4.34
2013	5.68	4.41
2014	5.79	4.47
2015	5.89	4.53
2016	5.96	4.59

Source: ICF

Note:
Oil product prices were determined using ICF estimates of refinery margins and productivity changes over time
Transportation differentials are used to reflect delivered prices to facilities operating in the GridFlorida territory

APPENDIX B
CALIBRATION RESULTS

Exhibit B-1
2003 Peninsula Florida Generation* and Imports (GWh) – Reported 2003 Historical versus Network Resource Case Calibration

Control Area (A)	Reported Historical 2003 Generation (GWh) (B)	ICF Model Calibration (GWh) (C)	Deviation of Model Calibration from Historical (GWh) (D)=C-B	% Deviation of Model Calibration from Historical (E)=((D)/B*100)
Total Dispatch for Peninsular Florida *	185,235	186,549	1,314	1%
Imports from Southern **	21,529	20,853	-676	-3%

Source: GridFlorida Applicants and Stakeholder
The total reported capacity and generation is the sum of the 2003 unit capacity and dispatch reported by Florida Power & Light, Progress Energy Florida, Tampa Electric Company, Seminole Electric Cooperative and member systems, Gainesville Regional Utilities, Jacksonville Electric Authority, Florida Municipal Power Agency (FMPA) member systems, Orlando Utilities Commission, Lakeland Electric, City of Tallahassee Electric Department. Excludes resources of New Smyrna Beach, Reedy Creek Improvement District and City of Homestead

Exhibit B-2

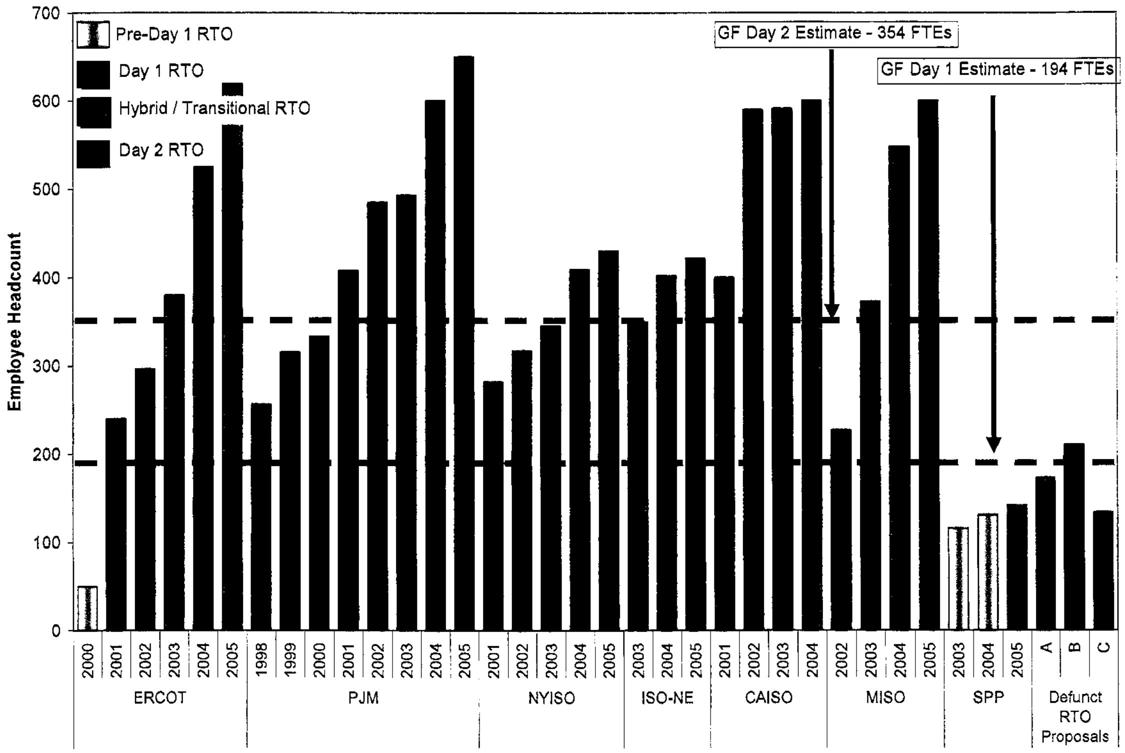
2003 Generation* (GWh) by Control Area – Reported 2003 Historical versus Network Resource Case Calibration

Control Area (A)	Reported Historical 2003 Generation (GWh) (B)	ICF Model Calibration (GWh) (C)	Deviation of Model Calibration from Historical (GWh) (D)=C-B	% Deviation of Model Calibration from Historical (E)=((D)/B*100)
FP&L	89,859	88,452	-1,407	-2%
Progress	36,334	36,640	306	1%
TECO	15,775	15,537	-238	-2%
Seminole	12,349	11,830	-519	-4%
City of Tallahassee	2,375	2,881	506	21%
Jacksonville	12,323	12,460	137	1%
Gainesville	1,809	1,668	-141	-8%
FMPP	14,409	17,082	2,673	19%

*Source: GridFlorida Applicant and Stakeholder Data Submissions

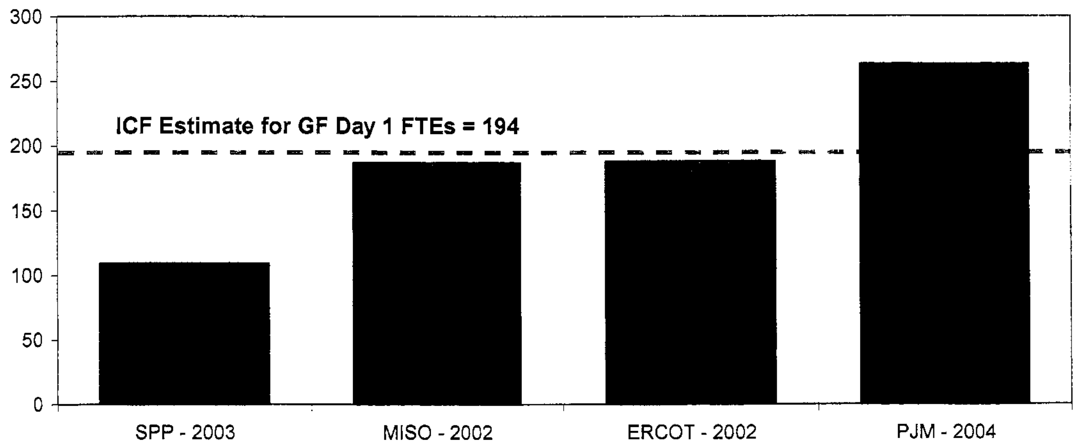
APPENDIX C
SELECT BENCHMARKING RESULTS

Exhibit C-1
Comparison of Grid Florida RTO and Existing ISO/ RTO Employee Counts



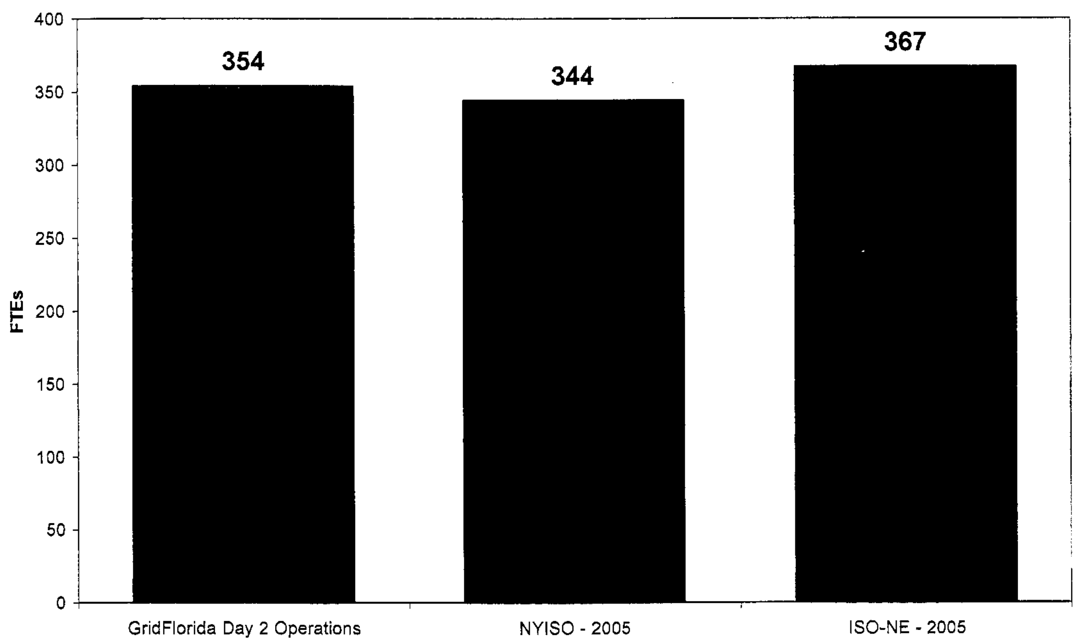
Source: RTO contacts, annual reports, budget proceedings and other publicly available sources.

Exhibit C-2
GridFlorida FTE Estimates vs. FERC Estimates of Day 1 Staff Needs



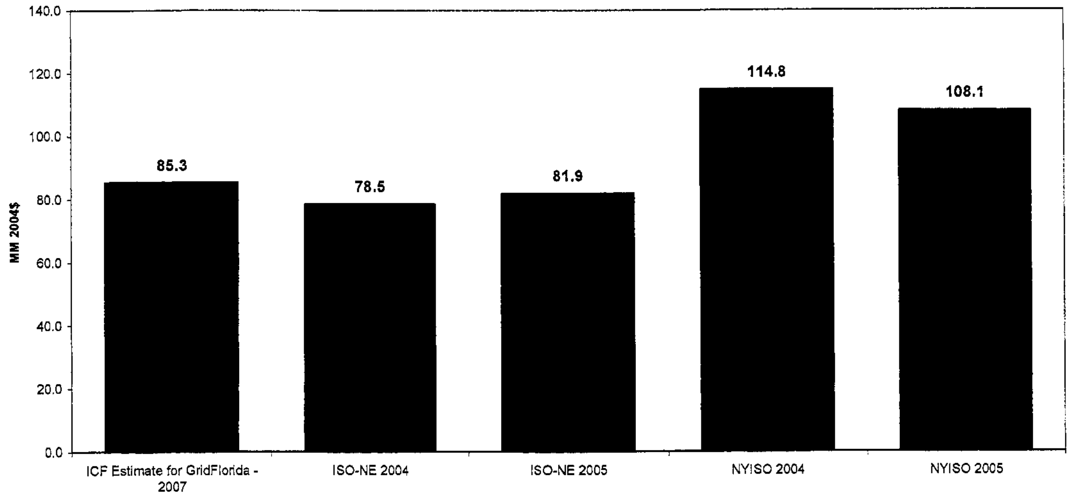
Source: ICF Consulting, "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization" Docket No. PL04-16-000, October 2004

Exhibit C-3
Comparable Day 2 FTE Count for GridFlorida, ISO-NE, and NYISO



Note: ISO-NE and NYISO FTE counts adjusted to match specified GridFlorida RTO functions.
Source: ICF worked directly with ISO-NE and NYISO to develop the FTE comparability estimates

Exhibit C-4
Comparison of GridFlorida Day 2 Operating Costs with Existing ISOs

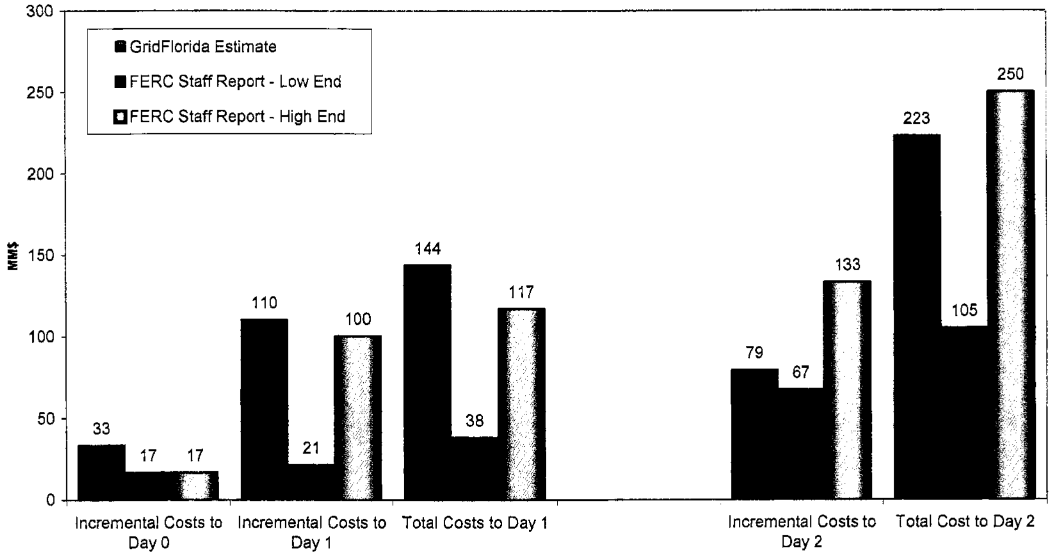


Notes:
All estimates exclude debt service, capital expenses, blackout related expenses (NYISO 2004), and FERC fees.
GridFlorida 2004 total demand – 226 TWh; NYISO 2004 total demand – 160 TWh; ISO-NE 2004 total demand – 131 TWh
GridFlorida 2004 peak demand – 43.0; NYISO 2004 peak demand – 28.4 GW; ISO-NE 2004 peak demand – 23.7 GW

Sources:
GridFlorida – ICF Consulting 4.20.2005
ISO-NE 2004 - http://www.iso-ne.com/committees/budget_and_finance/2004/2004-09-02/2005%20Budget%20Materials%20for%20BF%209-2-04.pdf
ISO-NE 2005 - http://www.iso-ne.com/committees/budget_and_finance/2004/2004-05-13/March%20Forecast%20for%20year%20end%202004.pdf

NYISO 2004 -
http://www.nyiso.com/services/documents/groups/mc_budgets_stdrds_perf_sub/09_26_03/ver2_092603_bsp_presentation.pdf
NYISO 2005 - mdex.nyiso.com/publish/Document/49bd70_ffbd1dd2ea_-7f650a03015f?rev=1&action=download&_property=Attachment

Exhibit C-5
ICF Start-up Costs Estimates vs. the FERC Staff Report



Source: ICF Consulting, "Staff Report on Cost Ranges for the Development and Operation of a Day One Regional Transmission Organization" Docket No. PL04-16-000, October 2004

APPENDIX D
RTO COST MODEL DETAIL

Final

Estimate of GridFlorida Capital and Annual Operating Costs for Day 1 and Day 2 Operations

Prepared by: ICF Consulting

Prepared for: GridFlorida Applicants and Stakeholders

August 30, 2005

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ICF CONSULTING

Line #	GridFlorida Startup Cost Detail - Day 0 (2004$) - Draft Final Item	Cost 000$	% of Total	Notes
5				
6	Costs Incurred Through 12/31/2003	18,969	57%	Source: GridFlorida Applicants
7	Estimated Incremental costs to Day 0 (provided by GridFlorida Applicants)	14,400	43%	Source: GridFlorida Applicants
8	**Total Costs to Day 0**	**33,369**		
		19.0		

GridFlorida Startup Cost Detail - Day 1 (2004$) - Draft Final

Line #	Item	Cost 000$	% of Total	Notes
5				
6	**Facilities**			
7	**HQ**			
8	Interim office space (25,000 sq. ft 9 months)	640	1%	Source: ICF regional survey
9	Pre-operation HQ occupancy (9 months)	1,647	1%	Source: ICF regional survey
10	Facility hardening ($35 per sf)	3,511	3%	Source: ICF
11	Leasehold improvements (control center upgrades and furnishings)	200	0%	Source: ICF
12	Facility design support	176	0%	Source: ICF regional survey
13	Secure access system	86	0%	Source: ICF
14	IT network infrastructure	291	0%	Source: ICF
15	Telecom infrastructure	352	0%	Source: ICF
16	Office furniture	1,371	1%	Source: Vendor quotes
17	Backup generator and UPS (includes installation and contingency)	2,600	2%	Source: Vendor quotes
18	**Backup Control Center/Disaster Recovery Facility (BCC)**			
19	Backup generator and UPS (includes installation and contingency)	1,000	1%	Source: Vendor quotes
20	Office furniture	78	0%	Source: Vendor quotes
21	Pre-operation BCC occupancy (6 months)	284	0%	Source: ICF
22	**Facility Subtotal**	12,237	11%	
23				
24	**Corporate Inception**			
25	Executive staff and board recruiting (industry standard 33 percent of annual salary)	1,474	1%	Source: ICF
26	Non-executive staff recruiting ($1,500 average per FTE)	267	0%	Source: ICF
27	Relocation expense (FRCC industry standard)	5,648	5%	ICF regional survey
28	External legal fees (includes corporate inception, market rules development support, regulatory filings, etc...)	8,000	7%	Source: ICF
29	Consultant fees (systems procurement, contract management, and organizational design)	1,000	1%	Source: ICF
30	Travel and business expenses during inception	207	0%	Source: ICF
31	External financial and operational audits	200	0%	Source: ICF
32	**Corporate Inception Subtotal**	16,796	15%	
33				
34	**Systems**			
35	IT network and architecture design consultant	1,000	1%	Source: ICF
36	Energy Management System (EMS) - (includes hardware, software licenses, SCADA, powerflow model, training, scheduling and tagging needs, user terminals, and contingency analysis software; HQ and backup sites included)	14,000	13%	Source: Vendor quotes
37	EMS simulation and training system (hardware and software licenses)	3,000	3%	Source: Vendor quotes
38	EMS customization contingency	3,000	3%	Source: ICF estimate
39	Independent control zone communication and frame relay initiation	900	1%	Source: Vendor quotes
40	Market monitor inception (outsourced)	500	0%	Source: Vendor quotes
41	OASIS inception (includes customer portal)	2,000	2%	Source: Vendor quotes
42	Map board	1,868	2%	Source: Vendor quotes
43	Transmission models (GE MAPS, PSSE, etc)	645	1%	Source: GridFlorida Applicants
44	Commercial Operations / Billing and Settlement systems (includes HW/SW for: data acquisition, billing and settlement, customer relations, database licenses, systems integration, 3 environments, system rollout, and contingency)	6,500	6%	Source: ICF
45	**System Subtotal**	33,413	30%	
46				
47	**Operating Costs Prior to Day 1**			
48	Salary, benefits, and payroll taxes during inception (assumes max of 18 months in place preceding Day 1 operations)	33,887	31%	Note: average 14 month employment for 194 FTEs preceding Day 1
49	Board of directors expense during inception (in place 18 months preceding operation)	1,470	1%	Source: FERC Form 1
50	Executive signing bonus (15 percent)	583	1%	Source: ICF industry survey
51	Non-executive signing bonus (5 percent)	629	1%	Source: ICF industry survey
52	Insurance during inception (18 months)	1,892	2%	Source: FERC Form 1
53	PC Lease during inception (average 12 months)	267	0%	Source: ICF industry survey
54	Repro services during inception (12 months)	351	0%	Source: ICF
55	Telecom during inception (average 12 months)	488	0%	Source: ICF industry survey
56	Payroll administration (18 months)	203	0%	industry standard 1% of salary expense
57	Benefit administration (18 months)	406	0%	industry standard 2% of salary expense
58	**Operating Costs to Day 1**	40,175	36%	
59				
60	Subtotal - ICF Day 1 Startup Costs	102,622	93%	
61	Day 0 Costs interest during construction for 18 month ramp-up period @ 4.2 percent	2,162	2%	Source: ICF
62	Day 1 Costs interest during construction for 18 month ramp-up period @ 4.2 percent	5,427	5%	Source: ICF
63	Contingency	-	0%	
64	**Total ICF Day 1 Estimate (including IDC)**	**110,210**	100%	
65				
66	Estimated costs to Day 0	33,369		Source: GridFlorida Applicants
67	**Total Costs to Day 1**	**143,579**		

ICF

GridFlorida Startup Cost Detail - Day 2 Incremental (2004$) - Draft Final

Line #	Item	Cost 000$	% of Total	Notes/Source
5				
6	**Facilities**			
7	**HQ**			
8	Facility hardening ($35 per sf)	1,552	2%	
9	Facility design support	76	0%	Source: ICF regional survey
10	IT network infrastructure	240	0%	Source: ICF
11	Telecom infrastructure	290	0%	Source: ICF
12	Office furniture	1,016	1%	Source: Vendor quotes
13	**Facility Subtotal**	3,174	4%	
14				
15	**Corporate Inception**			
16	External legal fees	-	0%	Note: assumes all Day 2 needs are met in house
17	Executive staff recruiting (industry standard 33 percent of annual salary)	1,139	1%	Source: ICF
18	Non-executive staff recruiting ($1,500 average per FTE)	215	0%	Source: ICF
19	Relocation expense (FRCC industry standard)	2,400	3%	ICF regional survey
20	Consultant Fees (market design, organizational design)	1,000	1%	Source: ICF
21	Travel and business expenses	189	0%	Source: ICF
22	External financial and operational audits	200	0%	Source: ICF
23	Systems procurement, and contract management	1,531	2%	Source: ICF
24	**Corporate Inception Subtotal**	6,673	8%	
25				
26	**Systems**			
27	Real-time market system (HW/SW)	4,000	5%	Source: Vendor quotes
28	Day ahead market system (HW/SW)	5,000	6%	Source: Vendor quotes
29	FTR market system (HW/SW)	6,000	8%	Source: Vendor quotes
30	Commercial operations / Billing and Settlement systems (includes incremental HW / SW upgrades, customer relationship system upgrades, incremental market participant portals, integration with market systems, and contingency)	4,500	6%	Source: Vendor quotes
31	Off-site data warehouse	7,425	9%	Source: Vendor quotes
32	Market monitor expansion (outsourced)	1,500	2%	Source: Vendor quotes
33	BCC market systems (DA, RT, FTR)	5,850	7%	Source: Vendor quotes
34	Market simulation and training system (DA, RT, FTR)	4,000	5%	Source: Vendor quotes
35	**Systems Subtotal**	38,275	48%	
36				
37	**Operating Costs Prior to Day 2**			
38	Executive signing bonus (15 percent)	450	1%	Source: ICF
39	Non-executive signing bonus (5 percent)	539	1%	Source: ICF
40	Salary, benefits, and payroll taxes during inception (assumes max of 18 months in place preceding day 2 operations)	25,069	32%	Note: average 15 month employment for incremental FTEs preceding Day 2
41	Insurance during inception (18 months)	-	0%	Source: FERC Form 1
42	PC Lease during inception (average 12 months)	187	0%	Source: ICF industry survey
43	Repro services during inception	193	0%	Source: ICF
44	Telecom during inception (average 12 months)	342	0%	Source: ICF industry survey
45	Payroll administration (18 months)	90	0%	Industry standard 1% of salary expense
46	Benefit administration (18 months)	300	0%	Industry standard 2% of salary expense
47	**Operating Costs Prior to Day 2**	27,169	34%	
48				
49	Subtotal - ICF Day 2 Estimate without IDC	75,292	95%	
50	Interest during construction for 18 month ramp-up period @ 4.2 percent	3,981	5%	Source: ICF
51	Contingency	-	0%	NA
52	**Total ICF Day 2 Estimate (including IDC)**	**79,273**	100%	
53				
54	Estimated costs to Day 0	33,369		Source: GridFlorida applicants
55	Estimated costs to Day 1	110,210		Source: ICF
56	**Total Costs to Day 2**	**222,851**		

ICF

GridFlorida Annual Operating Cost Detail - Day 1 Only ($000)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2004 % of Total	Notes
Facilities															
HQ															
Headquarters lease	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	2,196	4%	Approx. 97,000 sq ft @ 22.8 per year
Utilities	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	2%	Electric, water, sewer
Corporate telecom	471	471	471	471	471	471	471	471	471	471	471	471	471	1%	Non-EMS and control center costs; include long distance, equipment, etc...
Backup control center															
Utilities	218	218	218	218	218	218	218	218	218	218	218	218	218	0%	Electric, water, sewer
Backup control center lease	569	569	569	569	569	569	569	569	569	569	569	569	569	1%	25,000 sq ft @ 22.8 per year
Facilities Subtotal	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**4,454**	**7%**	
Staffing															
Board of Directors expense	990	999	1,009	1,020	1,030	1,040	1,050	1,061	1,072	1,082	1,093	1,104	1,115	2%	Non salary expense (travel, meetings, etc...); Source: FERC Form 1
Salary, benefits and payroll tax expense by division (assumes 1% annual real salary escalation)															
Office of the President	946	956	965	975	985	994	1,004	1,014	1,025	1,035	1,045	1,056	1,066	2%	6 FTEs
Control Center Ops	6,883	6,951	7,021	7,091	7,162	7,234	7,306	7,379	7,453	7,527	7,603	7,679	7,755	11%	51 FTEs
EMS IT Support	2,090	2,111	2,132	2,154	2,175	2,197	2,219	2,241	2,264	2,286	2,309	2,332	2,355	3%	14 FTEs
Planning and Engineering	3,481	3,516	3,551	3,587	3,623	3,659	3,695	3,732	3,770	3,807	3,845	3,884	3,923	6%	25 FTEs
Member Services	1,974	1,994	2,013	2,034	2,054	2,074	2,095	2,116	2,137	2,159	2,180	2,202	2,224	3%	14 FTEs
Legal and Regulatory	2,030	2,050	2,070	2,091	2,112	2,133	2,154	2,176	2,198	2,220	2,242	2,264	2,287	3%	11 FTEs
Corporate Services	3,364	3,398	3,432	3,466	3,501	3,536	3,571	3,607	3,643	3,679	3,716	3,753	3,791	5%	26 FTEs
Corporate IT Support	1,950	1,970	1,989	2,009	2,029	2,050	2,070	2,091	2,112	2,133	2,154	2,176	2,197	3%	13 FTEs
Committee and Working Group Support	427	431	436	440	444	449	453	458	462	467	472	476	481	1%	3 FTEs
Security	2,112	2,133	2,155	2,176	2,198	2,220	2,242	2,265	2,287	2,310	2,333	2,357	2,380	3%	17 FTEs
Commercial Operations	845	854	862	871	880	888	897	906	915	924	934	943	952	1%	5 FTEs
Market Monitor	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	NA
Billing and Settlement	1,327	1,340	1,353	1,367	1,381	1,394	1,408	1,422	1,437	1,451	1,466	1,480	1,495	2%	9 FTEs
Mature Market Functions	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	NA
Annual performance bonus (15% average)	2,463	2,488	2,513	2,538	2,563	2,589	2,615	2,641	2,667	2,694	2,721	2,748	2,775	4%	
Total Salary and Benefit Cost	**30,882**	**31,191**	**31,503**	**31,818**	**32,136**	**32,457**	**32,782**	**33,109**	**33,441**	**33,775**	**34,113**	**34,454**	**34,798**	**50%**	**194 total FTEs**
Systems															
ICCP expense	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	3,339	5%	Source: ICF
Billing and settlement system maintenance and license	192	192	192	192	192	192	192	192	192	192	192	192	192	0%	Vendor quote
EMS maintenance, license, and 24-hr support	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750	3%	Vendor quote
OASIS maintenance and license fees	200	200	200	200	200	200	200	200	200	200	200	200	200	0%	Vendor quote
Transmission models (GE MAPS, PSSE, OPF, etc) maintenance and license fees	118	118	118	118	118	118	118	118	118	118	118	118	118	0%	
Systems Subtotal	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**5,598**	**9%**	
Outsourced Functions															
Market monitor	500	505	510	515	520	526	531	536	541	547	552	558	563	1%	Vendor quote
Training (EMS OASIS, billing and settlement, etc...)	626	632	638	645	651	658	664	671	678	685	691	698	705	1%	Source: ICF; includes system operations, dispatch, etc...
Payroll administration	185	187	189	190	192	194	196	198	200	202	204	206	208	0%	Industry standard 1% of salary expense
Benefit administration	370	373	377	381	385	389	392	396	400	404	408	413	417	1%	Industry standard 2% of salary expense
Annual external audit	150	150	150	150	150	150	150	150	150	150	150	150	150	0%	Source: ICF
Accounting and tax compliance	700	707	714	721	728	736	743	750	758	766	773	781	789	1%	Source: ICF
Repro services	351	355	358	362	365	369	373	377	380	384	388	392	396	1%	Source: ICF
Branding, marketing, and PR Expenses	103	103	103	103	103	103	103	103	103	103	103	103	103	0%	Source: ICF
Outsourced Subtotal	**2,985**	**3,012**	**3,040**	**3,068**	**3,096**	**3,124**	**3,153**	**3,182**	**3,211**	**3,241**	**3,271**	**3,301**	**3,332**	**5%**	
Other/Misc															
Insurance	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	1,261	2%	Source: FERC Form 1
Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	NA - assumed not-for-profit
Travel and business expenses	138	138	138	138	138	138	138	138	138	138	138	138	138	0%	Source: ICF
Community relations	308	311	314	317	321	324	327	330	334	337	340	344	347	0%	Source: ICF
Relocation expenses	310	314	317	320	323	326	330	333	336	340	343	346	350	1%	Assumes 4.8 percent turnover annually; Source: Dynamics of Economic Well-Being: Labor Force Turnover, 1996-1999, Bureau of Census
PC lease	238	238	238	238	238	238	238	238	238	238	238	238	238	0%	$93/month; 10 percent contingency
IT Other	489	489	489	489	489	489	489	489	489	489	489	489	489	1%	Includes network maintenance, ISP, remote access, email, software licenses, and training
Miscellaneous	652	652	652	652	652	652	652	652	652	652	652	652	652	1%	Office supplies, consumables, postage etc...; Source: ICF
Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
Incremental FERC Fees	2,259	2,316	2,385	2,442	2,495	2,551	2,614	2,674	2,736	2,798	2,862	2,925	2,991	4%	
Other/Misc Subtotal	**5,656**	**5,719**	**5,795**	**5,858**	**5,918**	**5,980**	**6,049**	**6,116**	**6,184**	**6,253**	**6,324**	**6,394**	**6,466**	**9%**	
Subtotal - ICF Day 1 Operating Costs	**49,576**	**49,975**	**50,389**	**50,796**	**51,202**	**51,614**	**52,036**	**52,460**	**52,888**	**53,322**	**53,760**	**54,201**	**54,649**	**80%**	
Capital and Interest Expenses															
Interest expense on capitalized Day 0 and Day 1 startup costs	7,849	6,442	4,957	3,392	1,741	-	-	-	-	-	-	-	-	13%	Assumes 5 year payoff of startup costs. 100% debt @ 5.5% interest
Recapitalization of Day 1 investment	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	4,249	7%	
Interest expense on recapitalization	232	423	570	670	722	722	722	722	722	722	722	722	722	0%	
Capital and Interest Expenses Subtotal	**12,330**	**11,114**	**9,776**	**8,311**	**6,712**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**4,971**	**20%**	
Total Day 1 Annual Cash Expenses	**61,906**	**61,089**	**60,166**	**59,107**	**57,914**	**56,585**	**57,007**	**57,431**	**57,859**	**58,293**	**58,730**	**59,172**	**59,620**	**100%**	**Note, excludes depreciation**
2004-2016 NPV of Day 1 Operating Costs @ 3.15 % real discount	**640,308**														

GridFlorida Annual Operating Cost Detail - Day Two Incremental ($000) - Real 2004$

GridFlorida Annual Operating Cost Detail - Day 2 Incremental ($000)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2007 % of Total	Notes
Facilities															
HQ															
Headquarters lease	-	-	-	956	956	956	956	956	956	956	956	956	956	2%	Incremental 42,000 sq ft @ 22.8 per year
Incremental utilities	-	-	-	435	435	435	435	435	435	435	435	435	435	1%	Electric, water, sewer
Corporate telecom	-	-	-	412	412	412	412	412	412	412	412	412	412	1%	Non-EMS and control center costs; include long distance, equipment, etc...
Facilities Subtotal	-	-	-	1,803	1,803	1,803	1,803	1,803	1,803	1,803	1,803	1,803	1,803	4%	
Incremental Staffing															
Board of Directors Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na
Salary, benefits and payroll tax expense by division (assumes 1% annual real salary escalation from 2002)															
Office of the President	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na
Control Center Ops	-	-	-	5,024	5,074	5,125	5,176	5,228	5,280	5,333	5,386	5,440	5,495	10%	35 incremental FTEs
EMS IT Support	-	-	-	2,530	2,555	2,581	2,606	2,632	2,659	2,685	2,712	2,739	2,767	5%	18 incremental FTEs
Planning and Engineering	-	-	-	3,321	3,354	3,388	3,421	3,456	3,490	3,525	3,560	3,596	3,632	7%	24 incremental FTEs
Member Services	-	-	-	2,105	2,126	2,147	2,169	2,190	2,212	2,234	2,257	2,279	2,302	4%	12 incremental FTEs
Legal and Regulatory	-	-	-	601	607	613	619	625	631	638	644	651	657	1%	3 incremental FTEs
Corporate Services	-	-	-	653	659	666	673	679	686	693	700	707	714	1%	4 incremental FTEs
Corporate IT Support	-	-	-	1,219	1,231	1,244	1,256	1,268	1,281	1,294	1,307	1,320	1,333	2%	10 incremental FTEs
Committee and Working Group Support	-	-	-	129	130	132	133	134	136	137	139	140	141	0%	1 incremental FTEs
Security	-	-	-	222	224	226	229	231	233	236	238	240	243	0%	2 incremental FTEs
Commercial Operations	-	-	-	4,302	4,345	4,388	4,432	4,476	4,521	4,566	4,612	4,658	4,705	9%	25 incremental FTEs
Market Monitor	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na
Billing and Settlement	-	-	-	2,000	2,020	2,040	2,061	2,081	2,102	2,123	2,144	2,166	2,187	4%	12 incremental FTEs
Market Design and Mature Market Functions (ramps up	-	-	-	-	1,211	2,445	2,470	2,495	2,519	2,545	2,570	2,596	2,622	0%	14 incremental FTEs
Annual performance bonus (15% average)	-	-	-	1,985	2,114	2,245	2,267	2,290	2,313	2,336	2,359	2,383	2,407	4%	
Total Salary and Benefit Cost	-	-	-	24,090	25,650	27,239	27,511	27,786	28,064	28,345	28,628	28,915	29,204	48%	160 incremental FTEs
Systems															
ICCP expense	-	-	-	668	668	668	668	668	668	668	668	668	668	1%	Source: ICF
Billing and settlement system maintenance	-	-	-	608	608	608	608	608	608	608	608	608	608	1%	Vendor quote
OASIS maintenance and license fees	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	vendor quote
Real-time market system maintenance	-	-	-	500	500	500	500	500	500	500	500	500	500	1%	Vendor quote
Day-ahead market system maintenance	-	-	-	600	600	600	600	600	600	600	600	600	600	1%	Vendor quote
FTR market system maintenance	-	-	-	300	300	300	300	300	300	300	300	300	300	1%	Vendor quote
Off-site data warehouse maintenance	-	-	-	400	400	400	400	400	400	400	400	400	400	1%	Source: ICF
Systems Subtotal	-	-	-	3,076	3,076	3,076	3,076	3,076	3,076	3,076	3,076	3,076	3,076	6%	
Outsourced Functions															
Market monitor	-	-	-	1,545	1,608	1,624	1,641	1,657	1,674	1,690	1,707	1,724	1,741	3%	Vendor quote
Training (market systems, billing and settlement)	-	-	-	968	977	987	997	1,007	1,017	1,027	1,038	1,048	1,058	2%	Source: ICF; includes market system training
Payroll administration	-	-	-	144	154	163	165	166	168	170	171	173	175	0%	Industry standard 1% of salary expense
Benefit administration	-	-	-	288	307	326	329	333	336	339	343	346	350	1%	Industry standard 2% of salary expense
Annual external audit	-	-	-	150	150	150	150	150	150	150	150	150	150	0%	Source: ICF
Accounting and tax compliance	-	-	-	577	583	589	595	601	607	613	619	625	631	1%	Source: ICF
Credit analysis	-	-	-	682	689	696	703	710	717	724	731	739	746	1%	Source: ICF
Repro services	-	-	-	193	195	197	199	201	203	205	207	209	211	0%	
Branding, marketing, and PR expenses	-	-	-	103	103	103	103	103	103	103	103	103	103	0%	Source: ICF
Outsourced Subtotal	-	-	-	4,652	4,767	4,836	4,882	4,928	4,975	5,022	5,070	5,118	5,167	9%	
Other/Misc															
Insurance	-	-	-	1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472	1,472	3%	Source: FERC Form 1
Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	na - assumed not-for-profit
Travel and business expenses	-	-	-	126	126	126	126	126	126	126	126	126	126	0%	
Community relations	-	-	-	451	456	460	465	469	474	479	484	488	493	1%	
Relocation expenses	-	-	-	96	97	98	99	100	101	102	103	104	105	0%	Assumes 4.8 percent turnover annually; Source: Dynamics of Economic Well-Being: Labor Force Turnover, 1996-1999, Bureau of Census
PC lease	-	-	-	196	196	196	196	196	196	196	196	196	196	0%	Source: ICF
IT Other	-	-	-	403	403	403	403	403	403	403	403	403	403	1%	Includes network maintenance, ISP, remote access, email, software
Miscellaneous	-	-	-	538	538	538	538	538	538	538	538	538	538	1%	Office supplies, consumables, postage etc...; Source: ICF
Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	0%	
Incremental FERC Fees				3,479	3,556	3,635	3,725	3,811	3,898	3,987	4,078	4,168	4,262	7%	
Other/Misc Subtotal	-	-	-	6,762	6,844	6,929	7,024	7,116	7,209	7,304	7,400	7,496	7,596	14%	
Incremental Day 2 Annual Operating Costs	-	-	-	40,383	42,139	43,883	44,296	44,709	45,127	45,550	45,977	46,407	46,845	81%	
Capital and Interest Expenses															
Interest expense on capitalized Day 2 startup costs	-	-	-	4,334	3,557	2,737	1,873	961	-	-	-	-	-	9%	Assumes 5 year payoff of startup costs. 100% debt @ 5.5% interest
Recapitalization of Day 2 investment	-	-	-	4,999	4,999	4,999	4,999	4,999	4,999	4,999	4,999	4,999	4,999	10%	
Interest expense on recapitalization	-	-	-	273	493	656	760	801	776	750	722	692	661	1%	
Capital and Interest Expenses Subtotal	-	-	-	9,606	9,049	8,393	7,632	6,762	5,775	5,749	5,721	5,691	5,660	19%	
Incremental Day 2 Annual Operating Costs	-	-	-	49,989	51,188	52,275	51,928	51,471	50,902	51,298	51,698	52,099	52,505	100%	Note, excludes depreciation
2004-2016 NPV of Incremental Day 2 Operating Costs @ 3.15 % real discou	409,848														

ICF

APPENDIX E
DISAGGREGATED RTO BENEFITS

Summary of Disaggregated Benefits (Day-1)

Disaggregated Benefits	2004	2005	2006	2007	2008	2009	2010	2011*	2012	2013*	2014	2015*	2016
Jurisdictional Consumers [1] (000 Nominal $)	16,583	1,448	1,769	4,684	1,513	-550	-5,446	-5,761	-6,077	-4,757	-3,437	-12,785	-22,133
Non Jurisdictional Consumers [2] (000 Nominal $)	849	3,680	3,573	3,887	4,334	7,957	9,827	9,623	9,419	10,225	11,031	21,868	32,704
Total Peninsular Florida Benefits (000 Nominal $)	17,432	5,128	5,342	8,571	5,847	7,407	4,381	3,861	3,342	5,468	7,595	9,083	10,571
% Allocation													
Jurisdictional Consumers	95%	28%	33%	55%	26%	-7%	-124%	-149%	-182%	-87%	-45%	-141%	-209%
Non Jurisdiction Consumers	5%	72%	67%	45%	74%	107%	224%	249%	282%	187%	145%	241%	309%
Projected Jurisdictional Load (GWhs)	175,012	179,473	184,898	189,209	193,609	197,852	202,654	207,227	211,799	216,557	221,315	226,178	231,041
Projected Non Jurisdictional Load (GWhs)	51,255	52,496	53,973	55,359	56,316	57,683	59,165	60,680	62,195	63,751	65,307	66,911	68,514
	23%	77%											
Jurisdictional Consumer Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Non Jurisdictional Consumer Benefit per unit (cents/kWh)	0.00	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.03	0.05
Peninsular Florida Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Day 1 Costs (000 Nominal $)	87,649	90,224	92,841	95,472	98,120	63,243	65,149	67,110	69,132	71,217	73,366	75,581	77,866
Allocation of Delayed Day 2 RTO Cost [3]													
Jurisdictional Consumers	67,794	69,806	71,864	73,861	76,011	48,967	50,427	51,910	53,439	55,020	56,650	58,326	60,057
Non Jurisdiction Consumers	19,855	20,418	20,978	21,611	22,109	14,276	14,722	15,200	15,693	16,197	16,717	17,255	17,809
Net Day 1 Benefits (000 Nominal $)													
Jurisdictional Consumers	-51,212	-68,358	-70,094	-69,177	-74,498	-49,517	-55,873	-57,671	-59,516	-59,776	-60,086	-71,111	-82,190
Non Jurisdiction Consumers	-19,006	-16,738	-17,405	-17,723	-17,776	-6,320	-4,896	-5,578	-6,274	-5,972	-5,685	4,613	14,895
Net Day 1 Benefits (000 2004 $)													
Jurisdictional Consumers	-51,212	-66,854	-67,043	-64,710	-68,154	-44,304	-48,890	-49,353	-49,811	-48,928	-48,100	-55,672	-62,930
Non Jurisdiction Consumers	-19,006	-16,370	-16,647	-16,579	-16,262	-5,654	-4,284	-4,773	-5,251	-4,888	-4,551	3,612	11,404

Net Present Value - Delayed Day1 Benefits (000 2004 $)	
Jurisdictional Consumers	**($610,554)**
Non Jurisdiction Consumers	**($92,936)**

Notes:

[1] The Jurisdictional consumers are the customers of Florida Power and Light, Progress Energy and Tampa Electric

[2] The Non-Jurisdiction consumers include customers of Seminole Electrc, Jacksonville Electric, Tallahassee, FMPA, Reedycreek, City of Homestead, OUC, Lakeland Electric, Gainsville Electric, New Smyrna Beach

[3] Based on Load Ratio share

* Interpolated

All Benefits are in Nominal Dollars

Summary of Disaggregated Benefits (Delayed Day-2)

Disaggregated Benefits	2004	2005	2006	2007	2008	2009	2010	2011*	2012	2013*	2014	2015*	2016
Jurisdictional Consumers [1] (000 Nominal $)	16,583	1,448	1,769	56,478	54,099	36,528	40,882	46,573	52,263	64,771	77,279	81,410	85,542
Non Jurisdictional Consumers [2] (000 Nominal $)	849	3,680	3,573	56,838	75,773	73,431	67,157	79,847	92,538	94,687	96,835	96,468	96,100
Total Peninsular Florida Benefits (000 Nominal $)	17,432	5,128	5,342	113,317	129,871	109,960	108,039	126,420	144,801	159,458	174,114	177,878	181,642
% Allocation													
Jurisdictional Consumers	95%	28%	33%	50%	42%	33%	38%	37%	36%	41%	44%	46%	47%
Non Jurisdiction Consumers	5%	72%	67%	50%	58%	67%	62%	63%	64%	59%	56%	54%	53%
Projected Jurisdictional Load (GWhs)	175,012	179,473	184,898	189,209	193,609	197,852	202,654	207,227	211,799	216,557	221,315	226,178	231,041
Projected Non Jurisdictional Load (GWhs)	51,255	52,496	53,973	55,359	56,316	57,683	59,165	60,680	62,195	63,751	65,307	66,911	68,514
	23%	77%											
Jurisdictional Consumer Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.03	0.03	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04
Non Jurisdictional Consumer Benefit per unit (cents/kWh)	0.00	0.01	0.01	0.10	0.13	0.13	0.11	0.13	0.15	0.15	0.15	0.14	0.14
Peninsular Florida Benefit per unit (cents/kWh)	0.01	0.00	0.00	0.05	0.05	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06
Delayed Day 2 RTO Costs (000 Nominal $)	87,649	90,224	92,841	164,105	170,459	139,341	143,550	147,805	129,951	133,889	137,947	142,127	146,440
Allocation of Delayed Day 2 RTO Cost [3]													
Jurisdictional Consumers	67,794	69,806	71,864	126,959	132,049	107,887	111,111	114,328	100,453	103,438	106,516	109,680	112,947
Non Jurisdiction Consumers	19,855	20,418	20,978	37,146	38,410	31,454	32,439	33,477	29,498	30,451	31,431	32,447	33,494
Net Day 2 Benefits (000 Nominal $)													
Jurisdictional Consumers	-51,212	-68,358	-70,094	-70,481	-77,950	-71,358	-70,229	-67,755	-48,190	-38,667	-29,237	-28,270	-27,405
Non Jurisdiction Consumers	-19,006	-16,738	-17,405	19,692	37,363	41,977	34,718	46,370	63,040	64,236	65,404	64,021	62,606
Net Day 2 Benefits (000 2004 $)													
Jurisdictional Consumers	-51,212	-66,854	-67,043	-65,930	-71,312	-63,845	-61,452	-57,983	-40,332	-31,650	-23,404	-22,132	-20,983
Non Jurisdiction Consumers	-19,006	-16,370	-16,647	18,420	34,182	37,558	30,379	39,682	52,761	52,579	52,356	50,122	47,936

Net Present Value - Delayed Day 2 Benefits (000 2004 $)	
Jurisdictional Consumers	**($557,230)**
Non Jurisdiction Consumers	**$273,786**

Notes:

[1] The Jurisdictional consumers are the customers of Florida Power and Light, Progress Energy and Tampa Electric

[2] The Non-Jurisdiction consumers include customers of Seminole Electrc, Jacksonville Electric, Tallahassee, FMPA, Reedycreek, City of Homestead, OUC, Lakeland Electric, Gainsville Electric, New Smyrna Beach

[3] Based on Load Ratio share

* Interpolated

All Benefits are in Nominal Dollars